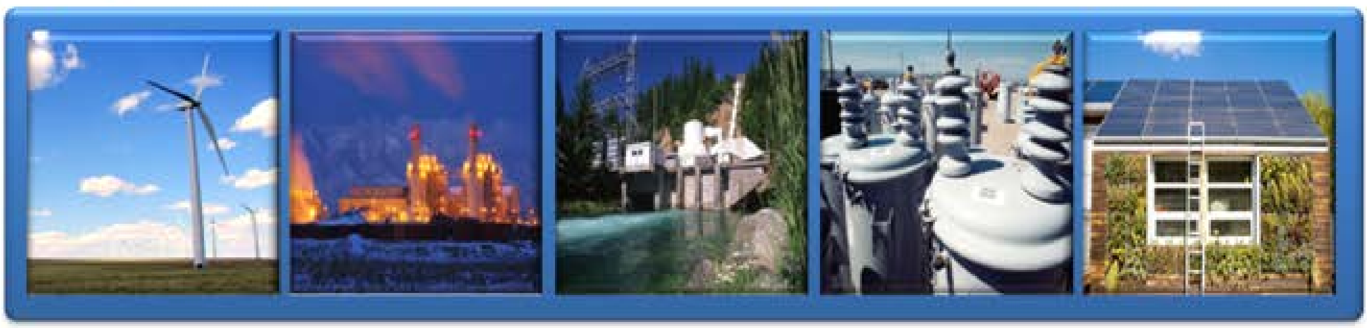
PACIFICORP | Rocky Mountain Power
Pacific Power
PacifiCorp Energy

2011
Integrated Resource Plan Update



Let's turn the answers on.

Redacted Version

March 30, 2012

This 2011 Integrated Resource Plan Update (2011 IRP Update) report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

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Cover Photos (Left to Right):
Wind: *McFadden Ridge I*
Thermal-Gas: *Lake Side Power Plant*
Hydroelectric: *Lemolo 1 on North Umpqua River*
Transmission: *Distribution Transformers*
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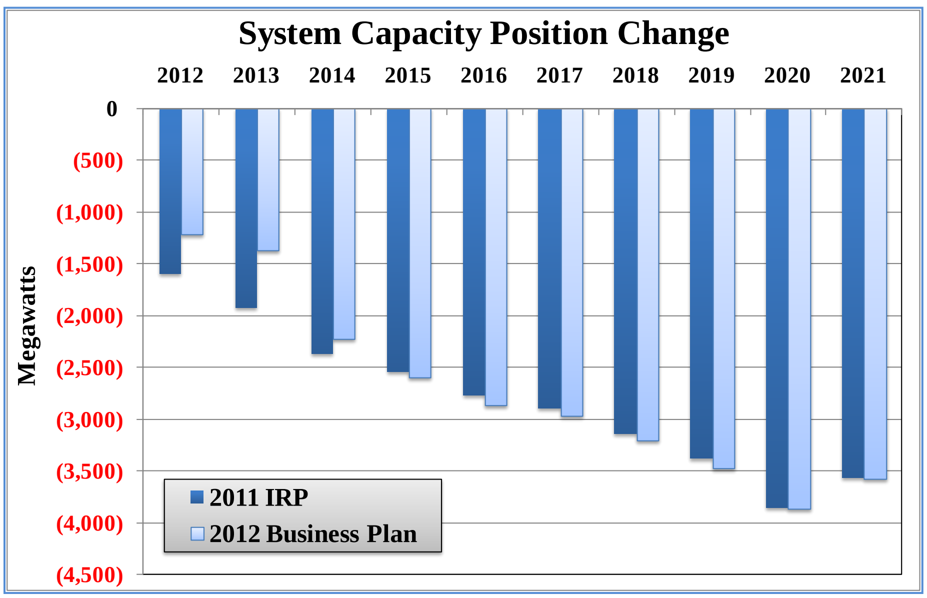
EXECUTIVE SUMMARY

This 2011 Integrated Resource Plan (IRP) update report describes resource planning and procurement activities that occurred subsequent to the filing of the 2011 IRP in March 2011, and presents PacifiCorp's revised resource portfolio and IRP Action Plan. The resource portfolio reflects the outcome of the Company's 10-year business planning process for 2012-2021, culminating in the "2012 Business Plan" approved by the MidAmerican Energy Holdings Company Board of Directors in December 2011. The revised IRP Action Plan comprises more implementation details for existing action items as well as new action items.

Key Assumption Updates

The figure below shows that the short capacity system position in the 2012 Business Plan has improved by 383 megawatts (MW) in 2012, 553 MW in 2013 and 149 MW in 2014 as compared to the 2011 IRP. In 2015 and 2016, the system capacity position in the 2012 Business Plan is shorter by 48 MW and 93 MW, respectively. Over the period 2017 through 2021, the system capacity position is on average 48 MW shorter in the 2012 Business Plan than in the 2011 IRP.



Key assumption and forecast changes between the 2012 Business Plan and the 2011 IRP include the following:

- Load and resource updates, including:
  - Continued sluggish economy and deferral of expected new industrial and commercial loads.
  - Termination of the Southeast Idaho Exchange Agreement in 2016, which removed PacifiCorp's obligation for providing about 189 MW of firm peak load for Bonneville Power Administration's Idaho customers net of BPA Idaho resources, that is offset by reduced power purchases of nearly 200 MW in PacifiCorp West Balancing Area.
  - Several industrial customers' increased use of self-generation to offset retail loads.

  - The assumption that certain PURPA Qualifying Facilities will elect to self-generate through 2016 rather than sell their output to PacifiCorp, reducing the amount of supply that can be used to meet load obligations.
  - The assumed retirement of the Carbon coal-fired plant as of January 1, 2015.[1]
  - Updated capacity ratings for a number of existing owned generating units, along with termination of the Grant Mid-Columbia hydro contract in 2013.
  - Cancellation of two coal plant turbine upgrade projects (Huntington 2 in 2016 and Hayden 2 in 2021).

- Other updates, including:
  - Lower forecasted natural gas and wholesale electricity prices relative to the 2011 IRP, favoring natural gas fueled resources and market purchases.
  - An updated evaluation of Renewable Portfolio Standard compliance requirements and strategy that assumes federal renewable tax incentives will not be extended beyond December 31, 2012. The updated evaluation of RPS compliance requirements indicated that some wind resource capacity could be deferred to help reduce power supply costs during the planning window.
  - A net 50 MW increase in front office transaction (FOT) acquisition capabilities in the PacifiCorp West Balancing area.
  - A net decrease of about 250 MW in FOT acquisition capabilities in the PacifiCorp East balancing area, driven mainly by uncertainty regarding the availability of Utah North capacity following the expiration of an existing 200 MW contract that expires in December 2013.
  - A one to three year delay in several Energy Gateway transmission project segment in-service dates due to continued challenges in planning for, permitting, and building these transmission expansion projects. Affecting the timing of Wyoming wind additions is a one-year delay in the Windstar to Populus segment of Energy Gateway West.

The Company also modified its assumptions regarding future regulation of carbon emissions. For resource portfolio modeling and the September 2010 price curve used for the 2011 IRP, carbon dioxide (CO_2) pricing started in 2015 at $19/short ton; whereas, for the 2012 Business Plan and August 2011 curve, CO_2 pricing starts in 2021 at $16/ton. The slow economic recovery, in tandem with predictions of sustained low natural gas prices and lack of momentum for CO_2 legislation, has altered expectations.

2012 Business Plan Resource Portfolio

Table ES.1 reports the 2012 Business Plan portfolio resources, showing the years for which the resources are available to meet summer peak loads, along with a comparison to the 2011 IRP resources. The key resource changes with respect to the 2011 IRP preferred portfolio, for the 2012-2021 planning period, include the following:

- Prior to 2015, lower market prices and increased access to market increases overall reliance on FOTs in the west, which are more than offset by reduced market purchases in the east

[1] The compliance deadline based on the Environmental Protection Agency's recently finalized Mercury and Air Toxics Standards (MATS) is April 16, 2015.

driven by less market access, reduced loads, and the 200 MW Utah capacity purchase. On a system basis, reliance on FOTs in the 2012 Business Plan declines by 95 MW in 2012, 241 MW in 2013, and 129 MW in 2014 as compared to the 2011 IRP.

- Given the 2016 capacity deficit increased by 93 MW, the need for a 2016 resource remains unchanged in the 2012 business plan, and the increased need relative to the 2011 IRP is largely met with incremental FOT acquisitions.
- Deferral of 550 MW of wind resources over the period 2018 through 2021 in the 2012 business plan is driven by a revised RPS compliance analysis that is consistent with a lower load forecast, assumed delays in prospective federal RPS policy implementation, a delay of the Windstar to Populus Energy Gateway transmission project (from year-end 2017 to year-end 2018), and the assumed unavailability of federal production tax credits for the 10-year planning period.
- With favorable wholesale electricity prices driven by lower natural gas prices, the 2012 Business Plan portfolio includes an additional 138 MW of west side FOTs and a 393 MW CCCT in 2019, which is smaller than the 475 MW CCCT included in the 2011 IRP preferred portfolio.

Table ES.1 – 2012 Business Plan Portfolio, 2012-2021

2012 Business Plan Portfolio

		Capacity (MW)											Resource Total
	Resource	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2012-2021**
East													
	CCCT F 2x1	-	-	-	637	-	597	-	-	-	-	-	**1,234**
	CCCT G 1x1 Dry-Cooled	-	-	-	-	-	-	-	-	393	-	-	**393**
	Coal Plant Turbine Upgrades	16	19	2	-	-	-	-	-	-	-	-	**21**
	Wind *	-	-	-	-	-	-			225	225	-	**450**
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	1	**10**
	DSM, Class 1	6	70	-	20	91	-	-	-	-	-	-	**181**
	DSM, Class 2	47	53	46	48	51	54	56	58	60	63	62	**550**
	Micro Solar Watering Heating	-	-	-	-	-	-	-	-	-	-	-	**-**
	Utah Capacity Purchase **	200	200	200	-	-	-	-	-	-	-	-	**400**
	Front Office Transactions ***	17	17	150	300	331	300	300	300	296	300	54	
West													
	Coal Plant Turbine Upgrades	-	-	12	-	-	-	-	-	-	-	-	**12**
	CHP - Biomass	4	4	4	4	4	4	4	4	4	4	4	**42**
	DSM, Class 1	-	-	57	-	6	-	-	-	-	-	-	**63**
	DSM, Class 2	61	61	65	70	71	70	70	62	62	62	63	**655**
	Solar (Oregon)	4	4	4	3	3	-	-	-	-	-	-	**15**
	Micro Solar Watering Heating	-	-	-	-	-	-	-	-	-	-	-	**-**
	Front Office Transactions ***	130	927	838	761	892	567	596	735	533	795	714	
	Annual Additions, Long Term Resources	**139**	**213**	**191**	**783**	**227**	**726**	**131**	**125**	**745**	**355**	**130**	
	Annual Additions, Short Term Resources	**347**	**1,145**	**1,188**	**1,061**	**1,223**	**867**	**896**	**1,035**	**829**	**1,095**	**768**	
	Total Annual Additions	**486**	**1,358**	**1,378**	**1,844**	**1,450**	**1,593**	**1,027**	**1,160**	**1,574**	**1,450**	**897**	

* In-service dates reflect the year in which wind resources contribute to meeting summer system peak load requirements. For the 2012 Business Plan, actual in-service dates are November of the prior year. For example, the resources shown in 2019 (225 MW) have an in-service date of November 1, 2018.

** Utah Capacity Purchase is treated as an existing resource in the load & resource balance, having been executed in August 2011. Annual capacity amounts are not additive.

*** Front Office Transactions amounts reflect one-year transaction periods, and are not additive.

Difference - 2012 Business Plan Less 2011 IRP Preferred Portfolio

		Capacity (MW)											Resource Total
	Resource	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2012-2021**
East													
	CCCT F 2x1	-	-	-	12	-	-	-	-	-	-	-	12
	CCCT G or H 1x1	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Coal Plant Turbine Upgrades	4	-	-	-	-	(18)	-	-	-	-	(2)	(20)
	Wind	-	-	-	-	-	-	-	(300)	(75)	25	(200)	(550)
	CHP - Biomass	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2	-	-	-	-	-	-	-	-	-	-	-	-
	Micro Solar Watering Heating	-	(3)	(3)	(3)	(3)	(3)	(3)	(3)	-	-	-	(18)
	Utah Capacity Purchase / FOT	-	-	(4)	(26)	(250)	-	(72)	(217)	-	(245)	-	
	Front Office Transactions	17	(151)	(264)	(264)	(68)	(25)	-	-	(4)	-	(246)	
West													
	Coal Plant Turbine Upgrades	-	-	8	-	-	-	-	(8)	-	-	-	-
	CHP - Biomass	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2	-	-	-	-	-	-	-	-	-	-	-	-
	Solar (Oregon)	-	-	-	-	-	-	-	-	-	-	-	-
	Micro Solar Watering Heating	-	(2)	(2)	(2)	(2)	(2)	(2)	(1)	-	-	-	(12)
	Front Office Transactions	(20)	56	26	161	392	117	146	285	138	345	314	
	Annual Additions, Long Term Resources	**4**	**(4)**	**4**	**7**	**(4)**	**(22)**	**(4)**	**(312)**	**(157)**	**25**	**(202)**	
	Annual Additions, Short Term Resources	**(3)**	**(95)**	**(241)**	**(129)**	**74**	**92**	**74**	**68**	**134**	**100**	**68**	
	Total Annual Additions	**2**	**(99)**	**(238)**	**(122)**	**69**	**70**	**69**	**(244)**	**(23)**	**125**	**(135)**	

IRP Action Plan Update

Table ES.2 presents the updated 2011 IRP Action Plan. Activities already completed by the Company have been removed from the Action Plan and summarized in Table 6.2 of this report. The Company's updates to the 2011 IRP Action Plan reflect more specificity concerning resource procurement and study activities during the first four years of the Action Plan. A key change concerns the scope of the needs assessment supporting PacifiCorp's planned acquisition of resources by the summer of 2016. The Company has committed to updating the resource needs assessment (a capacity load and resource balance, along with new resource acquisition forecasts based on the outcome of 2012 procurement-related activities) in preparation for the bid evaluation phase of its all-source Request for Proposals. As required by the Public Utility Commission of Oregon in its recent PacifiCorp 2011 IRP acknowledgment order (issued March 9, 2012), the Company will request that the Oregon commission schedule a discovery and comment period for IRP stakeholders subsequent to preparation of this additional resource needs assessment.

Table ES.2 – IRP Action Plan Update

Action Item	Category	Action(s)
1	Renewables/ Distributed Generation	**Wind** • Acquire cost effective wind resources to satisfy renewable portfolio standard requirements, diversify portfolio risk and reduce emissions. Incremental wind resource acquisition does not begin until the end of 2018 due to the need for incremental transmission capacity to be able to deliver remote resource generation to load and the associated in-service date of Energy Gateway West. Acquire 450 MW of incremental wind resources in 2019 and 2020. • In the next IRP, PacifiCorp will track and report the statistics used to calculate capacity contribution from its wind resources as a means of testing the validity of the PLCC method. • Future IRP cycles will include a projection for wind acquisition with and without geothermal until a clearer picture emerges regarding geothermal dry hole risk. • The Company will continue to refine the wind integration modeling approach; establish a technical review committee (TRC) and a schedule and project plan for the next wind integration study. The TRC will be formed and members identified within 30 days of the effective date of the [Oregon] IRP Order. Within 30 days of the effective date of the [Oregon] IRP Order, a schedule for the study will be established, including full opportunity for stakeholder involvement and progress reviews by the TRC that will allow the final study to be submitted with the next IRP. **Geothermal** • Continue to refine resource potential estimates and update resource costs in 2012 for further economic evaluation of resource opportunities. Continue to explicitly include geothermal projects as eligible resources in future all-source RFPs. **Solar** • Acquire additional Oregon solar resource through RFPs or other means in order to meet the Company's 8.7 MW compliance obligation. • Work with Utah parties to investigate solar program design and deployment issues and opportunities in 2012 as part of the Public Service Commission of Utah's investigative docket (No. 11-035-104) on expanding the Solar Incentive Program.[2] • Investigate, and pursue if cost-effective from an implementation standpoint, commercial/residential solar water heating programs. Program cost-effectiveness and targets will be evaluated as part of resource planning efforts to be conducted during 2012. • In the context of the Oregon solar RFPs, analyze the trade-offs between early and later acquisition of solar resources. **Combined Heat & Power (CHP)** • Pursue opportunities for acquiring biomass CHP resources, primarily through the PURPA Qualifying Facility contracting process. – The preferred portfolio contains 52 MW of CHP resources for 2012-2021 (10 MW in the east side and 42 MW in the west side).[3] **Energy Storage** • Proceed with an energy storage demonstration project, subject to Utah Commission approval of the Company's proposal to defer and recover expenditures through the demand-side management surcharge.

[2] Rocky Mountain Power, "Re: Docket No. 07-035-T14 – Three year assessment of the Solar Incentive Program", December 15, 2010.
[3] CHP resource opportunities will be evaluated as part of resource planning efforts to be conducted during 2012.

<table>
<tr><th>Action Item</th><th>Category</th><th>Action(s)</th></tr>
<tr><td></td><td></td><td>• Conduct a study of grid flexibility for accommodating variable energy resources (VER) as part of the next IRP filing. The study will include the following elements:
– Definition of and suggest metrics by which to measure flexibility (applicable to all flexibility resources including: thermal, demand response (DR), and storage).
– An inventory of existing flexibility needs and the adequacy or capability of existing assets to meet them.
– A projection of flexibility needs in the IRP timeframe to successfully integrate project VER additions.
– A comparison of benefits and costs of obtaining flexibility from the range of flexibility resources (conventional thermal, DR, storage, etc).
<u>Renewable Portfolio Standard Compliance</u>
• Develop and refine strategies for renewable portfolio standard compliance in California and Washington.
• PacifiCorp will expand the next IRP to include discussion of RPS compliance strategies and the role of REC sales and purchases. The Company will be selective in its discussion to avoid conflict between the IRP, RPS Implementation Plan and RPS Compliance Report.</td></tr>
<tr><td>2</td><td>Intermediate / Base-load Thermal Supply-side Resources</td><td>• Acquire a combined-cycle combustion turbine resource at the Lake Side site in Utah by the summer of 2014; the plant is proposed to be constructed by CH2M Hill E&C, Inc. (“CH2M Hill”) under the terms of an engineering, procurement, and construction (EPC) contract. This resource corresponds to the 2014 CCCT proxy resource included in the 2011 IRP preferred portfolio.
• PacifiCorp will reexamine the timing and type of post-2014 gas resources and other resource changes as part of the 2012 business planning process and all-source bid evaluation for 2016 resources. The reexamination will include documentation of capital cost and operating cost tradeoffs between resource types.
– Consider siting additional gas-fired resources in locations other than Utah. Investigate resource availability issues including water availability, permitting, transmission constraints, access to natural gas, and potential impacts of elevation.
– Continue conducting the all-source RFP for potential acquisition of peaking/intermediate/baseload resources by the summer of 2016 to fill any remaining resource need indicated by an updated load and resource balance reflecting the results of DSM RFPs, acquisition of front office transactions, reserve margin sensitivity analysis, and other relevant information.</td></tr>
<tr><td>3</td><td>Firm Market Purchases</td><td>• Acquire economic front office transactions or power purchase agreements as needed through summer 2016.
– Resources will be procured through multiple means, such as periodic mini-RFPs that seek resources less than five years in term, and bilateral negotiations.
• Closely monitor the near-term and long-term need for front office transactions and adjust planned acquisitions as appropriate based on market conditions, resource costs, and load expectations.
– Actively search for market options that could cost-effectively defer acquisition or construction of a 2016 CCCT resource.</td></tr>
<tr><td>4</td><td>Plant Efficiency Improvements</td><td>• Continue to pursue economic plant upgrade projects—such as turbine system improvements and retrofits—and unit availability improvements to lower operating costs and help meet the Company’s future CO_2 and other environmental</td></tr>
</table>

Action Item	Category	Action(s)
		compliance requirements. – Complete the remaining turbine upgrade projects by 2013, totaling an incremental 33.0 MW, subject to continuing review of project economics.[4] – Seek to meet the Company's updated aggregate coal plant net heat rate improvement goal of 478 Btu/kWh by 2019.[5] – Continue to monitor turbine and other equipment technologies for cost-effective upgrade opportunities tied to future plant maintenance schedules. • For the next IRP complete a study of cost-effective and reliable production efficiency opportunities at generating facilities (station load reduction opportunities not currently being captured in the IRP) where the Company has sole ownership of the facility. The resource opportunities identified will be modeled against competing demand and supply-side resources in the next IRP. Those selected will be targeted for completion by 2015 provided plant outages are not required.
5	**Class 1 DSM**	Acquire at least 140 MW of incremental cost-effective demand-side management resource by 2013 and up to 250 MW by 2015. – Finalize an agreement for the commercial curtailment product (which includes customer-owned standby generation opportunities). If cost effective, the company will file for approval by the 3rd quarter of 2012. – Complete an analysis of the economic feasibility of Class 1 irrigation load control in the west by the second quarter of 2012. If the analysis suggests Class 1 irrigation load control is economic in the west, the Company will source delivery of a program through a Request for Proposal concurrent with the re-sourcing of Class 1 irrigation load control program delivery in the east by the third quarter of 2012. – Issue an RFP in 2012 to re-procure the delivery of the Cool Keeper program following the 2013 control season. For the RFP, the Company will seek market approaches acceptable to Utah regulators to expand the program beyond its current level beginning in 2014.
6	**Class 2 DSM**	• Acquire at least 900 MW[6]and up to 1,800 MW of cost-effective Class 2 programs by 2020, equivalent to at least 4,533 GWh and up to 9,066 GWh. Acquire at least 520 MW and up to 1000 MW of cost-effective Class 2 DSM by 2016. – The Company filed the Utah and Washington residential home comparison report programs in March 2012. Investigate broader applications by the end of 2014 that can be implemented by 2016. – By 3rd quarter 2012 the Company will submit for commission approval a plan to acquire energy efficiency resources from the Company's Special Contract customers in Utah and Idaho that can be reliably verified and delivered by 2016, and will pursue those resources provided the Commissions in those states approve a cost-recovery mechanism for the plan. – The Company will seek to acquire all cost-effective resources that are available from the system-wide (except Oregon) RFP for residential and small commercial sector savings issued in March 2012. The cost effectiveness analysis will consider any adverse impact on the existing DSM programs. The results of the RFP will be known prior to the Company seeking acknowledgement of the final short list for the all-source RFP. The Company will promptly file for commission approvals to implement the cost-effective programs.

[4] The redline correction reflects updated project information for the approved 2012 Business Plan.
[5] *PacifiCorp Energy Heat Rate Improvement Plan*, April 2010.
[6] Adjusted to reflect 2011 IRP's initial MW contribution from Class 2 resources expected to be acquired in Oregon (reduces the MW contribution from Oregon from 562 MWs by 2020 to 283 MWs, a 279 MW reduction.

<table>
<tr><th>Action Item</th><th>Category</th><th>Action(s)</th></tr>
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For the next IRP, prior to beginning modeling and screening of DSM, and as part of the public input process, provide an analysis of alternatives to the current supply curve bundling and ramping methods for modeling energy efficiency measures.
By the end of 2012 provide an analysis of the sufficiency of current staffing levels to achieve programmatic cost effective energy efficiency targets established in this plan.
Leverage the distribution energy efficiency analysis of 19 distribution feeders in Washington (conducted for PacifiCorp by Commonwealth Associates, Inc.) for analysis of potential distribution energy efficiency in other areas of PacifiCorp’s system provided the Company receives approval by the appropriate Commission for recovery of the study cost through the demand-side customer efficiency surcharge. (The Washington distribution energy efficiency study final report was completed December 26, 2011.)

– Include in the 2013 IRP a detailed plan and schedule to implement cost-effective CVR in each state as approved by the state.
– By May 1, 2012 the company will schedule a work shop in each of its major states with commission staff to present findings of the Washington CVR evaluation.
– By the end of 2012 perform a high-level screening of 40 percent of its distribution circuits in each of the states to identify circuits where cost effective energy savings appears viable and detailed circuit study is warranted provided the Company receives approval by the appropriate Commission for recovery of the study cost through the demand-side customer efficiency surcharge.
– By the end of 2013 perform a high-level screening of the remaining 60 percent of its distribution circuits in each of the states to identify circuits where cost-effective energy savings appear viable and detailed circuit study is warranted provided the Company receives approval by the appropriate state commission for recovery of the study cost through the demand-side customer efficiency surcharge.
– In the 2013 IRP include the results of the CVR evaluation to date.

</td></tr>
<tr><td>7</td><td>Class 3 DSM</td><td>

During 2012 update the Conservation Potential Assessment to more accurately reflect Class 1 and 3 DSM resource opportunities in regards to 1) market and regulatory capabilities and climates in each state, 2) interactions within and between Class 1 and Class 3 resource potentials identified, and 3) the impact of existing Class 3 programs on product potential.
During 2012 have a third-party consultant review and prepare a report on how other utilities treat price-responsive products in their resource planning process (for example, as an adjustment to their load forecast and/or as a firm planning resource), and prepare a recommendation on how the Company might apply contributions from price products to help defer investments in other resource options cost-effectively.
For the 2013 IRP provide a sensitivity analysis, similar to portfolio development Case 31 in the 2011 IRP, that more accurately reflects incremental Class 3 product opportunities (incremental to Class 1 products, other Class 3 products, and to existing impacts of Class 3 products the Company is already running).
Implement in Utah and Washington (subject to regulatory approvals) residential information pilots to test the effects of providing customers greater amounts of usage information on the quantity of electricity they consume. The pilots will leverage the existing AMR metering currently available in these states.

– Pilots will consist of three test groups each receiving varying levels of usage information:
o Group 1 - Home comparison reports and energy conservation suggestions

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Action Item	Category	Action(s)
		o Group 2 - Daily usage data through Home Energy Monitoring software (key component to pricing products) o Group 3 – Home comparison reports, energy savings suggestions, and daily usage data through Home Energy Monitoring software Pilots will be implemented in 2012, run throughout 2013, and an analysis and recommendation prepared in 2014, prior to the development of the 2015 IRP. • If the analysis of Class 1 irrigation load control in the west (see action item 5) indicates that such programs are non-economic, investigate, through a pilot program in Oregon a Class 3 irrigation time-of-use program as an alternative approach for managing irrigation loads in the west.
8	**Planning and Modeling Process Improvements**	Incorporate plug-in electric vehicles and Smart Grid technologies as a discussion topic for the next IRP.
9	**Transmission**	In the scenario definition phase of the IRP process, the Company will address with stakeholders the inclusion of any transmission projects on a case-by-case basis. – Develop an evaluation process and criteria for evaluating transmission additions. – Review with stakeholders which transmission projects should be included and why. – Based on the outcome of these steps, PacifiCorp will provide appropriate transmission segment analysis for which the Company requests acknowledgement (including Wallula to McNary and Sigurd to Red Butte).
10	**Planning Reserve Margin**	As part of the updated resource needs assessment to be conducted for the all-source RFP, include the results of a System Optimizer portfolio sensitivity analysis comparing the resource and cost impacts of a 12 percent versus 13 percent planning reserve margin.

CHAPTER 1 – INTRODUCTION

This 2011 Integrated Resource Plan (IRP) Update Report describes resource planning activities that occurred subsequent to the filing of the 2011 Integrated Resource Plan in March 2010, and presents the Company's revised resource portfolio and IRP action plan. These activities centered on preparation of the Company's 10-year business plan for the period 2012-2021 (2012 Business Plan).

To support business plan development, PacifiCorp used its capacity expansion optimization model, *System Optimizer*, to help refine the resource portfolio based on updates to forecasted loads, resources, market prices, and other model inputs. The updated resource portfolio also incorporates resource decisions made outside of an optimization modeling context. These resource decisions reflect an analysis of state renewable portfolio standard (RPS) compliance requirements as well as capital expenditure and operating cost constraints developed by the corporate finance department with input from the PacifiCorp business units (PacifiCorp Energy, Pacific Power, and Rocky Mountain Power). The financial constraints ensure that the business plan is financially supportable and affordable to customers, while at the same time complying with all regulations and the MidAmerican Energy Holdings Company (MEHC) PacifiCorp acquisition commitments.

This report first describes the planning environment for 2011, focusing on PacifiCorp's business planning development, resource procurement initiatives, emissions/climate change regulatory outlook, and Energy Gateway transmission planning and project completion forecast (Chapter 2). Next, Chapters 3 and 4 describe the changes to key inputs and assumptions relative to those used for the 2011 IRP. The updated resource portfolio is then presented along with the updated IRP Action Plan (Chapters 5 and 6).

Appendices include the following:

- Redacted Appendix A – Coal Replacement Study Update
- Appendix B – Additional Load Forecast Details

CHAPTER 2 – PLANNING ENVIRONMENT

Business Plan Development

PacifiCorp developed the 2012 Business Plan as a result of a robust review and update of assumptions and budgetary constraints. The Plan was approved by the MEHC Board on December 9, 2011. It incorporated investments in transmission infrastructure and thermal and renewable resources needed to support future load obligations, maintain transmission system reliability, and meet current/prospective regulatory requirements.

A main finding of the 2012 business planning process was that given the current load forecast and sluggish economic recovery, continued reexamination of the need and timing for capital investments was necessary. Where appropriate and feasible, the Company eliminated or deferred investments and reduced operating expenditures. A primary focus of this effort was on the acquisition of wind resources to economically meet state renewable portfolio standards in light of diminishing prospects for continued federal renewable tax incentives and carbon regulation during the 10-year business planning horizon. An updated evaluation of RPS compliance requirements indicated that some wind resource capacity could be deferred to help reduce power supply costs during the planning window. Another key focus was consideration of investments to address current and emerging federal emission control standards. The planning assumptions for two of PacifiCorp's 26 coal units—Carbon Units 1 and 2—are described in the next section.

During 2011, the Company also continued to address challenges associated with the Energy Gateway transmission expansion project. In-service dates have been updated relative to those assumed for the 2011 IRP. These date adjustments, combined with the lack of additional transmission capacity on the existing system, prompted a one-year deferral of planned wind resources dependent on the availability of new transmission.

Disposition of the Carbon Coal-fired Plant

The EPA's recently promulgated Mercury and Air Toxics Standards (MATS) incorporate specific emissions requirements for mercury, non-mercury metallic HAPs (hazardous air pollutants), and acid gases. The current emissions profiles of the Company's Carbon Units 1 and 2 do not demonstrate compliance with MATS limits for the pollutants regulated under that rule. Emissions control equipment currently installed on the units is limited to electrostatic precipitators for particulate matter control. The units have not been retrofitted with scrubbers, baghouses, or other emissions control equipment that would foster the units' abilities to comply. The Company is in the process of assessing emerging technologies, namely dry sorbent injection into the combustion processes of the units, in order to identify possible MATS compliance options. Should the testing provide positive results for all MATS regulated emissions, the Company will further assess the long-term commercial viability of such emerging technologies, as well as the ability of said technologies to support compliance with other emissions regulations such as National Ambient Air Quality Standards (NAAQS) and long-term Regional Haze Rule planning. The Company has assessed the feasibility and economics of major environmental equipment retrofits of Carbon Units 1 and 2 in the past and did not identify viable least-cost options, accounting for risk and uncertainty, for the units. The Company has also assessed conversion of the units to natural gas as a fuel source and did not find that approach to result in favorable economics nor an acceptable emissions profile for long-term environmental compliance. Each of those assessments will be further reviewed against current environmental requirements and economic drivers to ensure that the most current and appropriate inputs are being assessed.

While the assessments described above will continue, the Company does not expect to identify a least-cost option, accounting for risk and uncertainty, other than retiring Carbon Units 1 and 2. For resource planning purposes, these units were assumed to retire as of January 1, 2015.[7] However, the Company is also currently assessing potential transmission system impacts associated with potential retirement of the Carbon units, particularly with respect to long-term regional transmission system reliability, that may result in a need to request an extension of the compliance deadline for the Carbon facility to accommodate transmission system improvements. The initial results of said study are expected in April 2012. Should reliability concerns or other considerations support the need for an extended compliance schedule, the Company will work within the conditions included within the MATS regulations and administrative guidance to request an appropriate compliance extension.

Resource Procurement Update

The following sections summarize procurement activities initiated in 2011 that influenced 2012 Business Plan development.

Lake Side 2 Combined-Cycle Combustion Turbine Project

On April 20, 2011, the Public Service Commission of Utah approved PacifiCorp's decision to build the Lake Side 2 CCCT plant for service by June 2014, and conditionally granted a Certificate of Public Convenience and Necessity (CPCN) enabling the Company to proceed with construction. CH2M Hill Engineers Inc. is the engineering, procurement and construction contractor for the project.

All-Source Request for Proposals

PacifiCorp issued its all-source RFP on January 6, 2012 for acquisition of resources by June 1, 2016. This RFP seeks up to approximately 600 MW of base load, intermediate load and summer peak (3rd-quarter) resources. For the 2012 Business Plan, the Company assumed the 2016 acquisition of the generic CCCT included in the 2011 IRP preferred portfolio. As noted in the revised IRP Action Plan, the Company may opt to contract for more or less capacity and energy depending upon an updated resource needs assessment and other factors. The Public Utility Commission of Oregon approved the RFP on March 27, 2012. Bids are due May 9, 2012. Acknowledgment of the resulting final bid short list by the Oregon Commission is expected in October 2012, and a final resource

[7] The compliance deadline based on the Environmental Protection Agency's recently finalized MATS is April 16, 2015.

decision is expected by early 2013. At that time, the Company will file an application for a "major resource" approval proceeding in Utah.

The RFP documents and support materials are available for download from the Company's RFP Web site: http://www.pacificorp.com/sup/rfps/asrfp2016.html.

Solar Request for Proposals

On November 30, 2010, PacifiCorp issued a solar photovoltaic resource RFP for projects up to two MW (alternating current) located in Oregon. The solar RFP was issued in response to Oregon Statute ORS 757.370, which requires the Company to acquire 8.7 MW_{ac} of qualifying solar photovoltaic system capacity by 2020. As a result of the RFP, the Company awarded a development contract for a two-megawatt, 9,000 panel solar installation near Lakeview, Oregon. Construction is scheduled to begin in May 2012, and the project is expected to start commercial operations in October 2012.

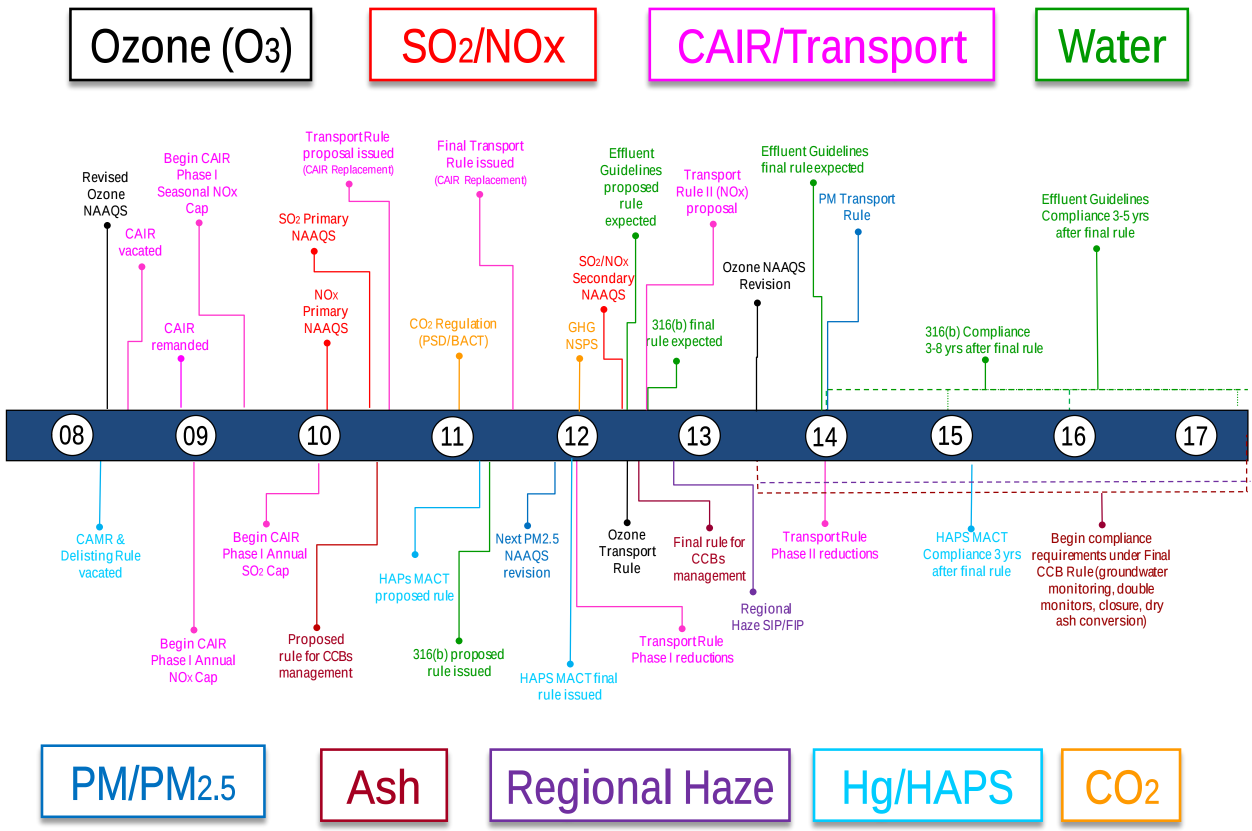
Emerging Environmental Regulations Overview

PacifiCorp's parent company, MidAmerican Energy Holdings Company, has been an active member of the Edison Electric Institute (EEI) modeling group, especially regarding the analysis of potential EPA regulatory scenarios.

In January 2011, the EEI published a report titled "Potential Impacts of Environmental Regulation on the U.S. Generation Fleet", which reflects a collaborative effort by the EEI and its members to model a variety of prospective EPA rules for air quality, greenhouse gases (GHGs), coal combustion residuals and cooling water intakes. The report summarizes the potential impact of uncertain regulatory outcomes on unit retirements, idling, capacity additions, pollution control installations, and capital expenditures, based on national-level average input assumptions. The results contained in the report help guide PacifiCorp's long-term environmental planning.

The EPA has undertaken a multiple-path approach to minimize air, land and water-based environmental impacts. Many environmental regulations from the EPA are in various stages of parallel development, as represented in the timeline in Figure 2.1.

Figure 2.1 – EPA Regulatory Timeline for the Utility Industry



[1]

Each of these regulations could have an impact on PacifiCorp's long-term environmental plan, could change dispatch scenarios, and could ultimately impact the economic viability of PacifiCorp's electric generation units.

PacifiCorp continues to evaluate the potential impact of climate change legislation at the federal level. The impact of federal climate change legislation would vary significantly depending on key criteria. While measures to regulate GHG emissions at the federal level were considered by the United States Congress in 2010, comprehensive climate change legislation has not been adopted. Further, in April 2011, the United States House of Representatives voted 255-177 on a bill (H.R. 910) that would prevent the EPA from regulating GHG emissions. No action has been taken by the Senate on the bill.

The EPA regulatory timeline above identifies several categories of regulations for *non-GHG* emissions, some of which are represented below:

Clean Air Act (CAA) Criteria Pollutants

Currently, PacifiCorp's generation units must comply with the CAA which is implemented by state agencies and subject to EPA approval and oversight. The CAA requires the EPA to set National NAAQS for certain pollutants considered harmful to the environment and public health. For a specific NAAQS, the EPA and/or a state agency identifies various control measures that when implemented are meant to achieve an ambient air quality standard for a certain pollutant.

PM, SO_2, ozone, NO_2, carbon monoxide and lead are frequently grouped together under the CAA because each of these categories is linked to one or more NAAQS. The criteria pollutants, while undesirable, are not toxic in typical concentrations in the ambient air. Under the CAA, they are regulated differently from other types of emissions, such as HAPs and GHGs which will be mentioned below. As a result of its periodic review of the NAAQS, the EPA established new standards for NO_2, PM, and SO_2. In addition, the EPA was expected to complete reconsideration of the previously established ozone standards in 2011. However on September 2, 2011, President Obama requested that EPA Administrator Jackson withdraw the draft ozone standard because the standard would be reconsidered in 2013 and he did not support implementation of a new standard that would be reconsidered shortly after issuance.

President Obama cited concern about the new standard negatively affecting jobs and economic recovery. This recent decision is indicative of the level of environmental rulemaking uncertainty.

Regional Haze

The EPA's rule to address Regional Haze visibility concerns drives emission reductions from steam electric plants operating in PacifiCorp's service territories. On June 15, 2005, the EPA issued amendments to its July 1999 Regional Haze rule. The amendments apply to provisions of the Regional Haze rule that require emission controls known as Best Available Retrofit Technology (BART) for steam electric plants with emissions that have the potential to impact visibility. These emissions of primary concern include $PM_{2.5}$, NO_X, and SO_2. The 2005 amendments included final guidelines, known as BART guidelines, for states to use in determining which steam electric plants must install controls and the type of controls the steam electric plants must implement during the program's first five-year planning period. States were given until December 2007 to develop their implementation plans, in which states were responsible for identifying the facilities, including steam electric plants that would be required to reduce criteria pollutant emissions under BART, as well as establishing BART emissions limits for those facilities. These facilities, after undergoing a review of their emissions and their contribution to visibility impairment, may be required to install additional emission control equipment no later than five years after the EPA approves a state's Regional Haze implementation plan. In 2008, the state of Utah submitted its regional haze state implementation plan to the EPA for approval, and the state of Wyoming submitted its plan in January 2011. The EPA has not yet provided its initial or final approval or disapproval of the Wyoming or Utah state implementation plans. The EPA's rejection of other regional haze state implementation plans has resulted in lawsuits being filed by states and affected entities. Such appeals were pending before the Tenth Circuit Court of Appeals by New Mexico and Oklahoma at the time the 2012 Business Plan was approved in December 2011.

Mercury and Air Toxics Standards (MATS)

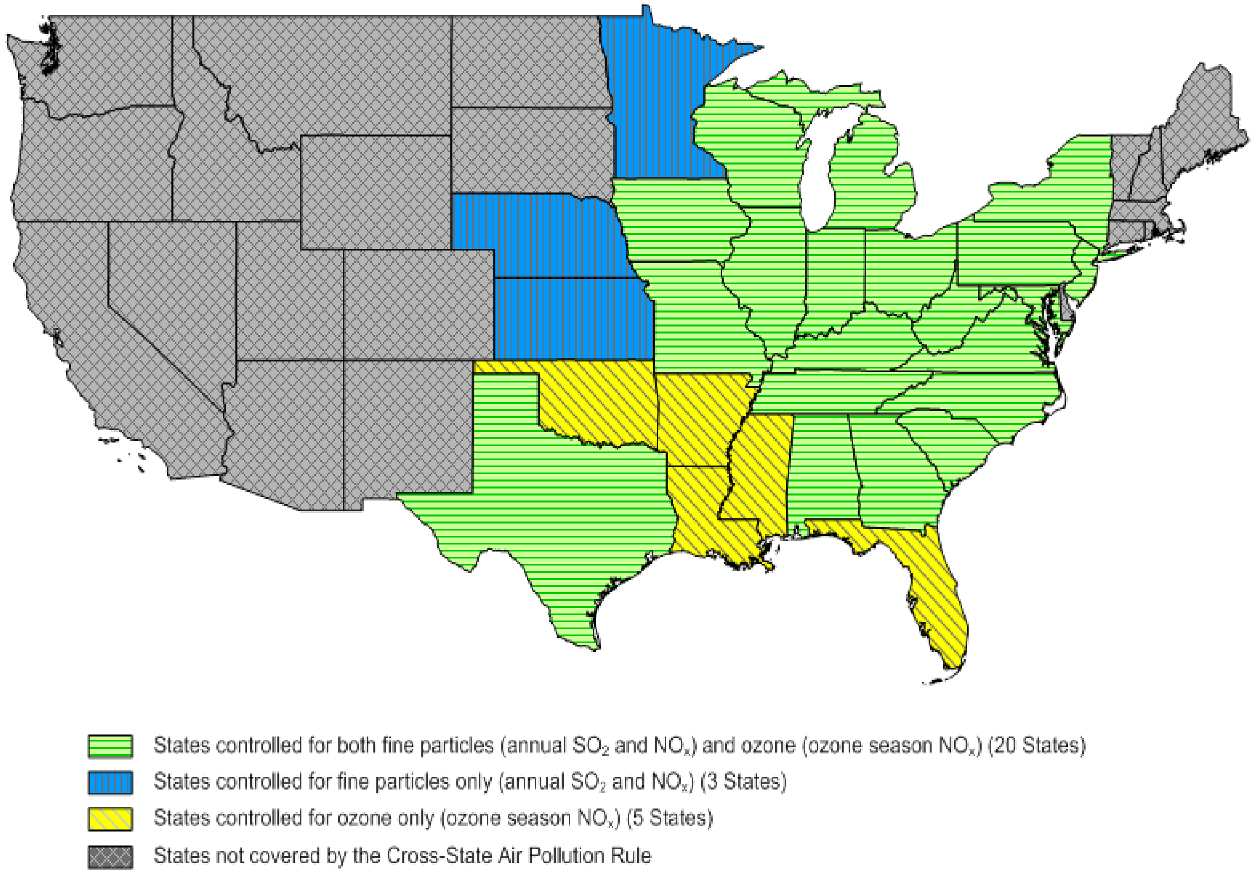
In March 2005, the EPA issued the Clean Air Mercury Rule (CAMR) to permanently limit and reduce mercury emissions from coal-fueled steam electric plants under a market-based cap-and-trade program. However, the CAMR was vacated in February 2008, with the court finding the mercury rules inconsistent with the stipulations of Section 112 of the CAA. A replacement rule, proposed in March 2011, was published in the Federal Register February 16, 2012, and will become final in April 2012. The MATS rule requires existing coal-fueled generating facilities to achieve stringent emission standards for mercury, acid gases and other non-mercury hazardous air pollutants within three years after the rule is final, with individual sources granted an additional year to comply if approved by the permitting authority. Mercury emissions control equipment is included in PacifiCorp's environmental and capital plans. Emissions control equipment for SO_2 and particulate matter assist in achieving compliance with the MATS.

Cross-State Air Pollution Rule

On July 6, 2011, the EPA finalized a rule which requires new reductions in SO_2 and NO_X emissions from electricity generating units in 27 states. This rule, known as the Cross-State Air Pollution Rule (CSAPR), requires emission reductions to take effect starting January 1, 2012, for SO_2 and annual NO_X reduction, and May 1, 2012, for ozone season NO_X reduction. The CSAPR was intended to replace the Bush administration's Clean Air Interstate Rule (CAIR), which was vacated in July 2008 and rescinded by a federal court because it failed to effectively address pollution from upwind states that is hampering efforts by downwind states to comply with PM and ozone NAAQS. CSAPR also replaces the July 2009 EPA proposed Clean Air Transport Rule intended to help states attain NAAQS established in 1997 for fine PM and ozone emissions. Implementation of the CSAPR was stayed by the D.C. Circuit Court of Appeals in December 2011 pending consideration of several petitions for review before the court; the court held that the CAIR should be administered pending the resolution of the pending petitions for review.

PacifiCorp does not own generation units in states identified by the CSAPR and is not directly impacted; however, PacifiCorp continues to monitor other CSAPR related state and supplementary EPA actions and pending challenges of the CSAPR for indications that these actions extend the geographic extent of impacted states. Figure 2.2 is a map of the CSAPR impacted states, and includes states covered in the EPA's supplemental notice of proposed rulemaking (SNPR).

Figure 2.2 – Cross-State Air Pollution Rule Impacted States



The EPA regulatory timeline above also identifies several key initiatives for regulating GHG emissions. These are outlined below.

New Source Review and Prevention of Significant Deterioration

On May 13, 2010, the EPA issued a final rule that addresses GHG emissions from stationary sources under CAA permitting programs, known as the greenhouse gas "tailoring" rule. This final rule sets thresholds for GHG emissions that define when permits under the NSR, PSD and Title V Operating Permit programs are required for new and existing steam electric plants. This final rule "tailors" the requirements of CAA permitting programs to limit which facilities will be required to obtain PSD and Title V permits. The GHG tailoring rule required new or modified sources of GHG emissions to determine the best available control technology for their GHG emissions beginning in January 2011. Litigation is currently pending in the D.C. Circuit Court of Appeals on EPA's GHG endangerment finding and the tailoring rule, with oral arguments schedule to take place in February 2012.

New Source Performance Standards (NSPS)
NSPS are established under the CAA for certain industrial sources of emissions determined to endanger public health and welfare, and must be reviewed every eight years. On December 23, 2010, in a settlement reached with several states and environmental groups in New York v. EPA,

the EPA agreed to promulgate emissions standards covering GHGs from new and existing fossil-fueled electric generating units under Section 111 of the CAA by July 26, 2011 (which was subsequently extended) and issue final regulations by May 26, 2012. On March 27, 2012, the EPA issued proposed rules to limit emissions of greenhouse gases from new fossil-fueled power plants to 1,000 pounds per megawatt-hour, the impacts of which will be addressed in PacifiCorp's forthcoming resource planning efforts.

Regional Climate Change Initiatives

While national GHG legislation has yet to be successfully adopted, regional and state initiatives continue with the active development of climate change regulations that are likely to impact PacifiCorp. The Western Climate Initiative was established as a comprehensive regional effort to reduce GHG emissions by 15% below 2005 levels by 2020 through a cap-and-trade program that includes the electricity sector. The Western Climate Initiative initially included the state of California, Montana, New Mexico, Oregon, Utah, Washington and the Canadian provinces of British Columbia, Manitoba, Ontario and Quebec. However, only California, British Columbia and Quebec are moving forward under the initiative, with the other states focused on efforts to design, promote and implement cost-effective policies to reduce GHG emissions and crate economic opportunities.

State-Specific Initiatives

Many states have developed climate action plans and formed legislative advisory groups. PacifiCorp continues to actively monitor and participate in state and regional policy discussions relevant to all of its retail jurisdictions.

In October 2011, the California Air Resources Board adopted a GHG cap-and-trade program with an effective date of January 1, 2012; compliance obligations will be imposed on entities beginning in 2013. California also adopted a greenhouse gas emissions performance standard (S.B. 1368) that precludes long-term investments in base load generation (through ownership or through long-term contract) in power plants unless the facility meets a GHG emission rate of 1,100 pounds per megawatt hour.

Oregon and Washington Initiatives

The Washington and Oregon governors signed executive orders in May 2007 and August 2007, respectively, establishing economy-wide goals for the reduction of GHGs in their respective states. Washington's goals seek to: (1) by 2020, reduce emissions to 1990 levels; (2) by 2035, reduce emissions to 25 percent below 1990 levels; and (3) by 2050, reduce emissions to 50 percent below 1990 levels, or 70 percent below Washington's forecasted emissions in 2050. Oregon's goals seek to: (1) by 2010, cease the growth of Oregon GHG emissions; and (2) by 2020, reduce greenhouse gas levels to 10 percent below 1990 levels. Each state's legislation also calls for state government developed policy recommendations in the future to assist in the monitoring and achievement of these goals.

In addition, both Washington and Oregon have adopted GHG emission performance standards of 1,100 pounds of carbon dioxide per megawatt hour and prohibit electric utilities from entering into long-term financial commitments (e.g., new ownership investments or new or renewed contracts with a term of five or more years) unless any base load generation supplied under long-term financial commitments comply with the GHG emissions performance standards.

Water Quality Standards

In March 2011, the EPA released a proposed rule under §316(b) of the Clean Water Act to regulate cooling water intakes at existing facilities. The proposed rule establishes requirements for all power generating facilities that withdraw more than two million gallons per day, based on total design intake capacity, of water from waters of the United States and use at least 25% of the withdrawn water exclusively for cooling purposes. PacifiCorp's Dave Johnston generating facility withdraws more than two million gallons per day of water from waters of the United States. PacifiCorp's Jim Bridger, Naughton, Gadsby, Hunter, Carbon and Huntington generating facilities currently utilize closed cycle cooling towers, but also withdraw more than two million gallons of water per day. The proposed rule includes impingement (i.e., when fish and other organisms are trapped against screens when water is drawn into a facility's cooling system) mortality standards to be met through average impingement mortality or intake velocity design criteria and entrainment (i.e., when organisms are drawn into the facility) standards to be determined on a case-by-case basis. The standards are required to be met as soon as possible after the effective date of the final rule, but no later than eight years thereafter. The rule is required to be finalized by the EPA by July 2012. Assuming the final rule is issued by July 2012, PacifiCorp's generating facilities impacted by the final rule will be required to complete impingement and entrainment studies in 2013.

Coal Combustion Byproduct Disposal

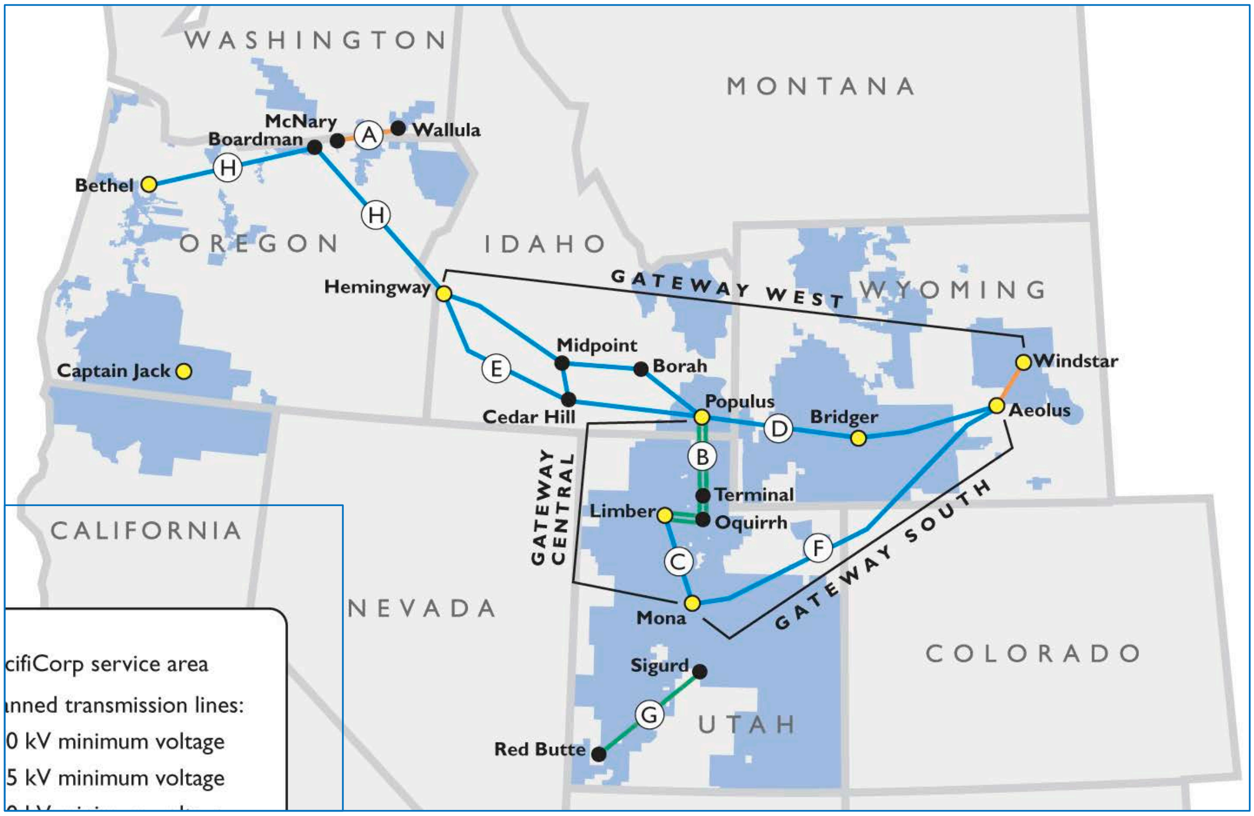
In December 2008, an ash impoundment dike at the Tennessee Valley Authority's Kingston power plant collapsed after heavy rain, releasing a significant amount of fly ash and bottom ash, coal combustion byproducts, and water to the surrounding area. In light of this incident, federal and state officials have called for greater regulation of the storage and disposal of coal combustion byproducts. In May 2010, the EPA released a proposed rule to regulate the management and disposal of coal combustion byproducts, presenting two alternatives to regulation under the RCRA. Under the first option, coal combustion byproducts would be regulated as special waste under RCRA Subtitle C and the EPA would establish requirements for coal combustion byproducts from the point of generation to disposition, including the closure of disposal units. Alternatively, the EPA is considering regulation under RCRA Subtitle D under which it would establish minimum nationwide standards for the disposal of coal combustion byproducts. Under both options, surface impoundments utilized for coal combustion byproducts would have to be cleaned and closed unless they could meet more stringent regulatory requirements; in addition, more stringent requirements would be implemented for new ash landfills and expansions of existing ash landfills. PacifiCorp operates 16 surface impoundments and six landfills that contain coal combustion byproducts. These ash impoundments and landfills may be impacted by the newly proposed regulation, particularly if the materials are regulated as hazardous or special waste under RCRA Subtitle C. The public comment period closed in November 2010. The EPA has not indicated when the rule will be finalized, and the substance of the final rule is not known. The United States House of Representatives passed H.R. 2273 in October 2011, which would regulate coal combustion byproducts under RCRA Subtitle D. A Senate bill similar to the House bill has been introduced, but action has not been taken on the bill. PacifiCorp has begun evaluating surface impoundment and landfill compliance plan options to ensure that physical infrastructure decisions are aligned with the potential outcomes of the rulemaking.

Energy Gateway Transmission Program Planning

The Energy Gateway transmission program continues to play an important role in the Company's commitment to provide safe, reliable, reasonably priced electricity to meet the needs of our customers. Energy Gateway's design and extensive footprint provides needed system reliability improvements and supports the development of a diverse range of cost-effective resources required for meeting customers' energy needs. Energy Gateway has been included as a component of the IRP for multiple cycles as a solution for delivering the least cost resource portfolio. The company is continuing to develop methods, in parallel with current industry best practices and regional transmission planning requirements, to better quantify all the benefits of transmission that are essential to serving customers. For example, Energy Gateway is designed to relieve operating limitations, increase capacity, and improve operations and reliability in the existing electric transmission grid. See below under "Transmission Expansion Planning for the 2013 IRP" for a discussion of Energy Gateway's substantial benefits and the Company's efforts to demonstrate—and quantify where possible—these benefits more comprehensively than traditional methods of net power cost and least-cost analysis have afforded.

Several Energy Gateway developments have occurred since the Company's March 2011 IRP was filed, including reaching construction and permitting milestones, adjusting in-service dates for future segments, adjusting configuration for one segment, and making progress on joint-development projects. Also, in response to direction from state regulators, the Company has committed through a new IRP Action Plan item to address with stakeholders the evaluation and inclusion of any transmission projects in the IRP, which includes efforts to develop a stakeholder process to identify and quantify a broad range of transmission benefits. An updated Energy Gateway map is provided below as Figure 2.3.

Figure 2.3 – Energy Gateway Map



Energy Gateway Transmission Project Updates

Wallula to McNary (Segment A): The Public Utility Commission of Oregon issued a Certificate of Public Convenience and Necessity (CPCN) in September 2011. The Company is currently completing work with property owners to finalize rights of way and continues to work with federal agencies to complete permitting activities and obtain federal rights of way. The line is expected to be in service in the 2012-2013 timeframe.

Mona to Oquirrh (Segment C): Construction began in May 2011. Mona to Oquirrh is the second major segment of Energy Gateway to be constructed, following Populus to Terminal (Segment B) which was placed in service in November 2010. As of the time of this filing, construction access roads are in place for approximately 91 miles of the transmission line path; foundations have been constructed for approximately 315 of the structures; approximately 120 of the single-circuit 500 kV lattice towers and 43 of the double-circuit 345 kV monopole towers have been erected; and six miles of single-circuit 500 kV conductor has been strung. The project remains on schedule for completion in May 2013.

Gateway West (Segments D and E): The Bureau of Land Management (BLM) published its Draft Environmental Impact Statement (EIS) for the Gateway West project in July 2011. Also, in October 2011, it was announced that Gateway West was one of seven transmission projects in the U.S. selected by the federal Rapid Response Team for Transmission for prioritized permitting. While these are positive developments, the BLM's Draft EIS was delayed 29 months from its original permitting schedule and no agency preferred route was included, injecting further complexity into project timeline and public involvement process. Additionally, as part of the settlement agreement reached in the Company's 2010-2011 Wyoming general rate case, the Company committed to filing for a CPCN for future Energy Gateway projects in Wyoming, and a CPCN-like proceeding for future projects located partially or wholly outside of Wyoming.[8] This commitment came in response to stakeholder and regulatory interest in having an opportunity for review and input on whether project expenditures are reasonable and in the public interest before construction begins. While the Company agrees that this approach will help further demonstrate the value of the planned Energy Gateway segments, it is an additional step and will require additional time. Based on this and the EIS schedule uncertainty, the Company has revised its in-service targets for both segments of Gateway West—Windstar to Populus and Populus to Hemingway. See Table 2.1 below for updated segment in-service dates.

Additionally, the Company determined, and announced in February 2012, that one new 230 kV line between the Windstar and Aeolus substations and a rebuild of the existing 230 kV line is sufficient for meeting customer needs and the objective of the Gateway West project, and that the second new 230 kV line planned between Windstar and Aeolus is no longer needed. This decision resulted from the Company's ongoing focus on meeting customer needs, taking stakeholder feedback into consideration, and finding the best balance between cost and risk for customers.

Gateway South (Segment F): The BLM's Notice of Intent was published in the Federal Register in April 2011, followed by public scoping meetings throughout the project area in May and June. Comments on this project from agencies and other interested stakeholders will be considered as the BLM develops the draft EIS, which is expected in summer of 2013. Based on experience permitting other major segments of Energy Gateway, as well as the additional time required for the new CPCN requirement in Wyoming (see Gateway West update above), the Company has extended the estimated in-service range for this project one year. See Table 2.1.

Sigurd to Red Butte (Segment G): The BLM published a Draft EIS for the Sigurd to Red Butte project in May 2011, and it is anticipated the final EIS will be published in May 2012. Permitting, surveying, right of way acquisition and engineering will continue according to the present schedule. The construction contract is expected to be awarded before the end of 2012. Based on moderated load growth and incremental system reliability improvements in southwest Utah, the Company decided it is in the best interests of our customers to defer the in-service date for this project one year, from June 2014 to June 2015. See Table 2.1.

West of Hemingway (Segment H): Energy Gateway Segment H represents a significant improvement in the connection between PacifiCorp's east and west control areas and will help deliver more diverse resources to serve PacifiCorp's Oregon, Washington and California customers. Originally planned as a single circuit 500 kV line from the Hemingway substation south of Boise, Idaho, to the Captain Jack substation near Klamath Falls, Oregon, the Company has continued to pursue alternative joint-development opportunities on other proposed lines west of Hemingway. In January 2012, the Company signed a permitting agreement with Idaho Power and the Bonneville Power Administration (BPA) on the proposed Boardman to Hemingway

[8] Final Stipulation and Agreement, Wyoming Docket No. 20000-384-ER-10, Record No. 12702, Section 13(a) (June 6, 2011)

project, and continues discussions with Portland General Electric on its proposed Cascade Crossing project (Boardman to Bethel). The Hemingway to Captain Jack alternative will remain under consideration as these joint development alternatives mature.

Table 2.1 – Energy Gateway Segment In-Service Dates

Segment	2011 IRP	2012 Business Plan
Segment A: Wallula to McNary	2012-2013 (no change)	
Segment C: Mona to Oquirrh	2013	May 2013
Segment C: Oquirrh to Terminal	2014	June 2015
Segment D: Windstar to Populus [1/]	2015-2017	2016-2018
Segment E: Populus to Hemingway [1/]	2015-2018	2017-2021
Segment F: Aeolus to Mona [1/]	2017-2019	2017-2020
Segment G: Sigurd to Red Butte	2014	Summer 2015
Segment H: West of Hemingway	Sponsor driven [2/]	

[1/] For portfolio modeling purposes, the last year in the date range is assumed to be the in-service date. An end-of-year convention is used. For example, the in-service date for Windstar to Populus is December 31, 2018.

[2/] Segment H alternatives are under consideration and project in-service dates are sponsor driven. As a conservative planning assumption, Segment H projects are deferred past the 10-year planning period for portfolio modeling purposes.

Transmission Expansion Planning for the 2013 IRP

Based on feedback from the Public Utility Commission of Oregon during its 2011 IRP acknowledgment proceeding, the Company committed to the following additional IRP action item for the 2013 IRP:

- In the scenario definition phase of the IRP process, the Company will address with stakeholders the inclusion of any transmission projects on a case-by-case basis.
  - Develop an evaluation process and criteria for evaluating transmission additions.
  - Review with stakeholders which transmission projects should be included and why.
  - Based on the outcome of these steps, PacifiCorp will provide appropriate transmission segment analysis for which the Company requests acknowledgement (including Wallula to McNary and Sigurd to Red Butte).

Concurrently with this directive, PacifiCorp is exploring options for expanding its transmission benefit evaluation process beyond the traditional methods of net power cost and least-cost analysis. Benefits identification and measurement is fundamental to the planning and cost allocation approach envisioned in FERC Order No. 1000. The Company is actively exploring these options through evaluation of how benefits are measured by various ISOs/RTOs and through its Order No. 1000 compliance efforts with the Northern Tier Transmission Group. Common to these efforts are four primary categories of transmission projects: reliability, economic, public policy and interconnection/merchant projects. Each category has unique drivers and objectives, and each transmission project often has a primary driver but may also accomplish more than one objective, such as a project needed for reliability that also provides economic efficiency benefits and/or helps meet public policy requirements.

Evaluation metrics may vary for each category of project shown in Table 2.2 depending on the objectives that are met.

Table 2.2 – Transmission Expansion Project Categories

	Reliability	**Policy**	**Economic / Market Efficiency**	**Interconnect / Merchant**
Primary Driver	NERC Transmission Planning criteria	Statutory or regulatory directive	Facilitate market transactions	Tariff-driven
Objective	Reliability	Policy compliance	Lower costs to customers	Merchant-proposed
Evaluation	Load growth / reliability	Optimize resources and transmission	Quantitative benefits	Projects must comply with standards
Evaluation Metrics				
Metric 1	Reliability benefits	Public Policy benefits	Economic benefits	Reliability benefits
Metric 2	Economic benefits	Reliability benefits	Public Policy benefits	Economic benefits
Metric 3	Public Policy benefits	Economic benefits	Reliability benefits	Public Policy benefits
Additional Metrics	TBD	TBD	TBD	TBD

The Company is developing a proposed evaluation process for IRP stakeholder review at a 2013 IRP public input meeting based on Table 2.2 and screening criteria to identify projects suitable for analysis using the IRP modeling framework.

CHAPTER 3 – RESOURCE NEEDS ASSESSMENT UPDATE

Introduction

This chapter presents the update to PacifiCorp's resource needs assessment, focusing on the 10-year planning period covered by the 2012 Business Plan (2012-2021). Revisions to the Company's long-term load forecast, resources, and capacity position are addressed. Appendix B provides additional tables showing the November 2011 load forecast net of Class 2 DSM load reductions.

Coincident Peak Load Forecast

Load Forecast

For the 2012 Business Plan, PacifiCorp updated its load forecast in November 2011. Relative to the load forecast prepared for the 2011 IRP, PacifiCorp system sales and coincident peak dropped for the planning period. The main driver for the residential, commercial and industrial class declines was revised expectations across all sectors regarding economic conditions, timing of new industrial and commercial load, and several industrial customers' increased use of self-generation to offset retail loads.

Tables 3.1 and 3.2 report the November 2011 annual load and coincidental peak load forecasts, respectively. Note that this forecast data excludes load reduction projections from new energy efficiency measures (Class 2 DSM), since such load reductions are included as resources in the System Optimizer model. Tables 3.3 and 3.4 show the forecast changes relative to the 2011 IRP load forecast for loads and coincident system peaks, respectively.

Table 3.1 – Forecasted Annual Load Growth, 2012 through 2021 (Megawatt-hours)

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2012	61,869,475	14,633,531	4,489,106	939,964	25,870,440	9,932,573	3,754,354	2,249,508
2013	63,290,621	14,878,262	4,524,843	945,224	26,610,204	10,266,692	3,794,710	2,270,687
2014	65,199,437	15,215,187	4,562,715	949,910	27,547,018	10,670,403	3,952,903	2,301,301
2015	66,762,988	15,425,484	4,596,856	954,678	28,183,414	11,198,588	4,069,785	2,334,185
2016	67,365,028	15,650,722	4,654,570	963,498	29,095,245	11,659,925	4,195,615	1,145,452
2017	68,546,156	15,922,162	4,684,798	984,073	30,042,583	12,627,590	4,284,951	0
2018	69,732,563	16,100,139	4,729,516	989,512	30,690,560	12,878,798	4,344,040	0
2019	70,923,698	16,275,349	4,773,472	994,961	31,322,719	13,168,649	4,388,547	0
2020	72,241,763	16,477,506	4,824,727	1,002,175	32,045,903	13,452,010	4,439,442	0
2021	73,201,929	16,585,884	4,849,416	1,003,722	32,604,382	13,690,560	4,467,965	0
Annual Average Growth Rate for 2012-2021								
2012-21	**1.9%**	**1.4%**	**0.9%**	**0.7%**	**2.6%**	**3.6%**	**2.0%**	

Table 3.2 – Forecasted Annual Coincidental Peak Load (Megawatts)

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2012	10,176	2,270	753	160	4,712	1,251	693	337
2013	10,418	2,348	760	159	4,801	1,305	700	345
2014	10,735	2,406	770	156	4,985	1,348	718	351
2015	10,985	2,433	782	159	5,121	1,389	750	351
2016	10,882	2,462	789	162	5,251	1,439	777	
2017	11,201	2,509	796	168	5,389	1,544	794	
2018	11,394	2,536	807	169	5,508	1,570	804	
2019	11,578	2,563	811	170	5,623	1,600	811	
2020	11,777	2,594	820	168	5,753	1,625	816	
2021	11,976	2,619	827	170	5,872	1,657	831	
Annual Average Growth Rate for 2012-2021								
2012-21	1.8%	1.6%	1.0%	0.7%	2.5%	3.2%	2.0%	

Table 3.3 – Annual Load Growth Change: November 2011 Forecast Less November 2010 Forecast (Megawatt-hours)

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2012	(3,088,933)	(854,257)	(187,373)	(29,103)	(876,028)	(1,107,891)	(49,903)	15,623
2013	(3,097,638)	(790,771)	(178,264)	(27,057)	(779,378)	(1,185,009)	(142,969)	5,809
2014	(2,835,690)	(638,638)	(191,663)	(32,254)	(604,344)	(1,213,521)	(153,429)	(1,841)
2015	(2,679,066)	(612,969)	(212,671)	(36,497)	(622,584)	(1,021,920)	(165,187)	(7,239)
2016	(3,745,944)	(632,929)	(226,117)	(38,822)	(555,143)	(889,040)	(161,932)	(1,241,960)
2017	(3,605,144)	(497,014)	(237,146)	(25,036)	(154,209)	(142,714)	(131,027)	(2,417,998)
2018	(3,691,571)	(501,876)	(247,491)	(29,204)	(150,035)	(176,739)	(129,928)	(2,456,298)
2019	(3,789,923)	(513,856)	(256,954)	(33,370)	(168,918)	(178,086)	(144,128)	(2,494,611)
2020	(3,894,745)	(521,144)	(265,203)	(37,074)	(142,253)	(228,755)	(159,164)	(2,541,153)
2021	(3,964,333)	(522,989)	(273,950)	(41,711)	(102,144)	(280,392)	(171,903)	(2,571,242)

Table 3.4 – Annual Coincidental Peak Growth Change: November 2011 Forecast Less November 2010 Forecast (Megawatts)

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2012	(540)	(127)	(60)	(3)	(224)	(125)	3	(4)
2013	(542)	(81)	(42)	(5)	(273)	(119)	(21)	(2)
2014	(517)	(60)	(47)	(8)	(246)	(123)	(32)	(2)
2015	(516)	(63)	(48)	(7)	(233)	(120)	(37)	(8)
2016	(858)	(66)	(53)	(6)	(223)	(106)	(40)	
2017	(759)	(47)	(59)	(3)	(213)	(30)	(37)	
2018	(800)	(48)	(86)	(4)	(217)	(31)	(38)	
2019	(800)	(48)	(69)	(4)	(222)	(32)	(43)	
2020	(830)	(50)	(74)	(6)	(222)	(43)	(48)	
2021	(839)	(51)	(79)	(6)	(213)	(49)	(47)	

Resource Updates

Existing and Firm Planned Resources

The main changes to existing and firm planned[9] resource capacity in the updated 2012 Business Plan load and resource balance relative to the 2011 IRP are summarized below.

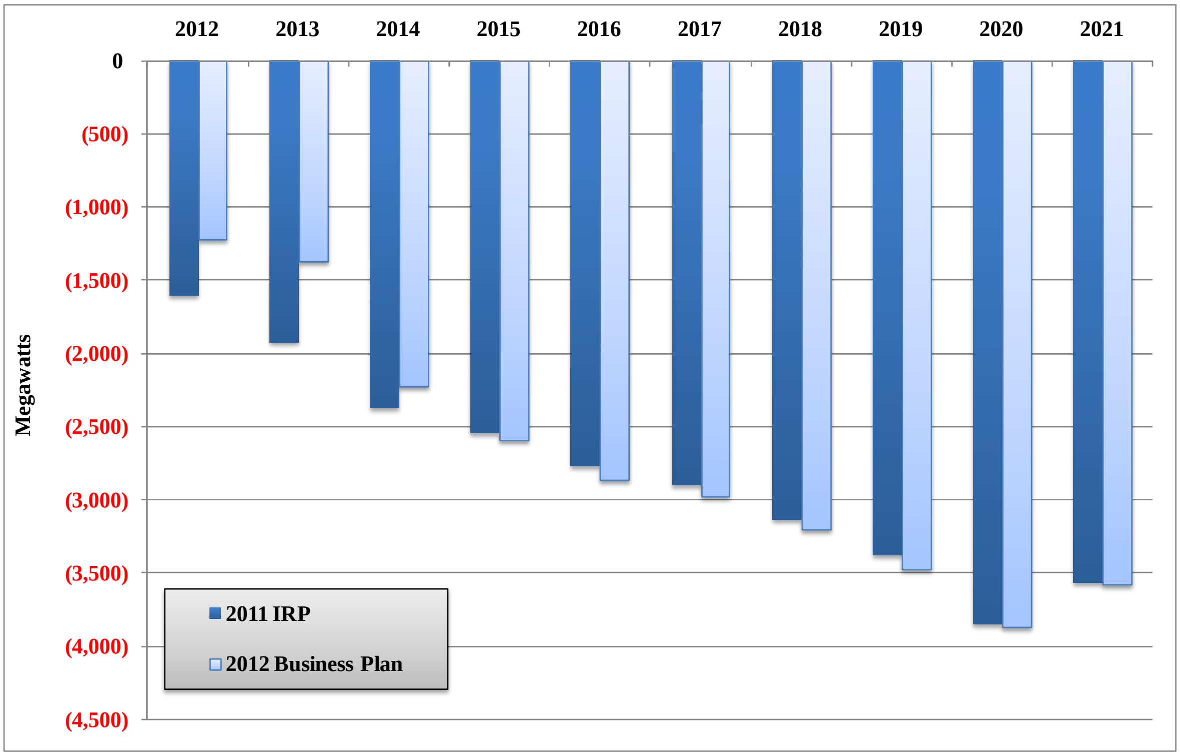
- Coal plant turbine upgrade capacity is lower by 20 MW, reflecting elimination of the Huntington 2 project in 2016 and Hayden 2 project in 2021.
- The Company entered into new PURPA Qualifying Facility contracts with existing industrial customers, representing an 81 MW capacity increase beginning in 2017. There were also new biomass and wind QF contracts totaling 21 MW and 15 MW, respectively. PacifiCorp also assumed that several industrial customers and PURPA Qualifying Facilities will use self-generation rather than selling their output to the Company through 2016, thereby reducing loads and resource capacity.
- A “Utah North” capacity purchase for 200 MW for August 2011 through December 2013.
- The termination of the Southeast Idaho Exchange Agreement effective as of June 2016, which removed PacifiCorp’s obligation for providing firm peak load for Bonneville Power Administration’s Idaho customers. This firm peak load is partially offset by the availability of BPA’s Idaho resources, which count towards meeting the system peak load requirement. Termination of this exchange agreement also reduces power purchases in the PacifiCorp West Balancing Area.
- Retirement of the Carbon units 1 and 2 as of December 31, 2014.[10] The Company determined that plant retirement was the least-cost option to investing in equipment retrofits to comply with emission requirements for mercury, non-mercury metallic hazardous air pollutants (HAPs), and acid gases (See Chapter 2).
- Updated capacity ratings for a number of owned existing generating units, along with termination of the Grant Mid-Columbia hydro contract in 2013.

Updated Capacity Load and Resource Balance

Figure 3.1 compares the annual capacity positions for the 2011 IRP and the 2012 Business Plan, covering 2012 through 2021. Both assume a 13 percent planning reserve margin (PRM). Relative to the 2011 IRP, the annual capacity deficit for the 2012 Business Plan decreased by an average of about 362 MW for 2012-2014, reflecting lower forecasted loads and acquisition of the three-year 200 MW Utah capacity purchase. For 2015-2021, the annual capacity deficit increased by an average of about 55 MW.

[9] “Firm planned” resources constitute those for which construction or purchase contracts have been signed, or are included in the Company’s 10-year budget.
[10] The compliance deadline based on the Environmental Protection Agency’s recently finalized MATS is April 16, 2015.

Figure 3.1 – Capacity Position Comparison, 2011 IRP versus the 2012 Business Plan



Of note given the Company's issuance of an all-source RFP for 2016 resources, the capacity deficit is forecasted to increase by 93 MW in that year relative to the 2011 IRP. This increase in the capacity deficit is a result of decreasing resource capacity that more than offsets decreasing forecasted peak loads. A detailed comparison of the system capacity position for 2016 is provided as Table 3.5. As indicated, the 806 MW decrease in the obligation (loads plus firm sales) is offset by the 888 MW decrease in resource capacity and net 11 MW increase in reserve requirements.

As noted above, key drivers to the updated capacity position include an updated load forecast that reflects revised expectations across all sectors regarding economic conditions, the termination of the Southeast Idaho Exchange Agreement in 2016, the assumed retirement of the 172 MW Carbon coal-fired plant as of January 1, 2015, the expectation that several industrial customers and PURPA Qualifying Facilities will use self-generation rather than selling their output to the Company through 2016, and cancellation of the Huntington 2 and Hayden 2 turbine upgrade projects in 2016 and 2021 respectively.

Table 3.5 – Detailed 2016 Capacity Position Comparison, 2011 IRP versus the 2012 Business Plan

	2011 IRP	2012 Business Plan	Business Plan Less IRP
Starting Starting Position, 2016	**(2,767)**	**(2,861)**	**(93)**
Resources			
Thermal [1/]	8,602	8,327	(275)
Hydro	1,088	1,006	(81)
Renewable	247	261	14
Purchases [2/]	508	130	(378)
Load Control	329	329	0
Interruptible Contracts	281	281	0
Qualifying Facilities	343	175	(168)
Total	11,397	10,509	(888)
Obligation			
Load	11,742	10,882	(860)
Sales	853	907	54
Total	12,595	11,789	(806)
Reserves			
Planning reserves	1,492	1,436	(56)
Non-owned reserves [3/]	77	144	67
Total	1,569	1,580	11

1/ 275 MW reduction reflects the Carbon plant retirement (172 MW), updated unit ratings for existing units, and a net decrease in turbine capacity upgrades.

2/ Southeast Idaho Exchange Agreement termination causes a 356 MW load decrease, which is offset by a 200 MW west-side purchase decrease and 168 MW Idaho resource decrease.

3/ Additional reserves held for PURPA Qualifying Facilities' self-serve load requirements.

Figures 3.2 through 3.4 show the capacity peak load and resource gaps for the system, PacifiCorp East, and PacifiCorp West Balancing Areas, respectively, if no additional resources are acquired (the initial load & resource balance). Table 3.6 reports the capacity load and resource line items, while Table 3.7 provides the line item differences between 2012 Business Plan and 2011 IRP balances with no additional resources acquired.

Figure 3.2 – System Coincident Peak Loads and Resources, 2012 Business Plan

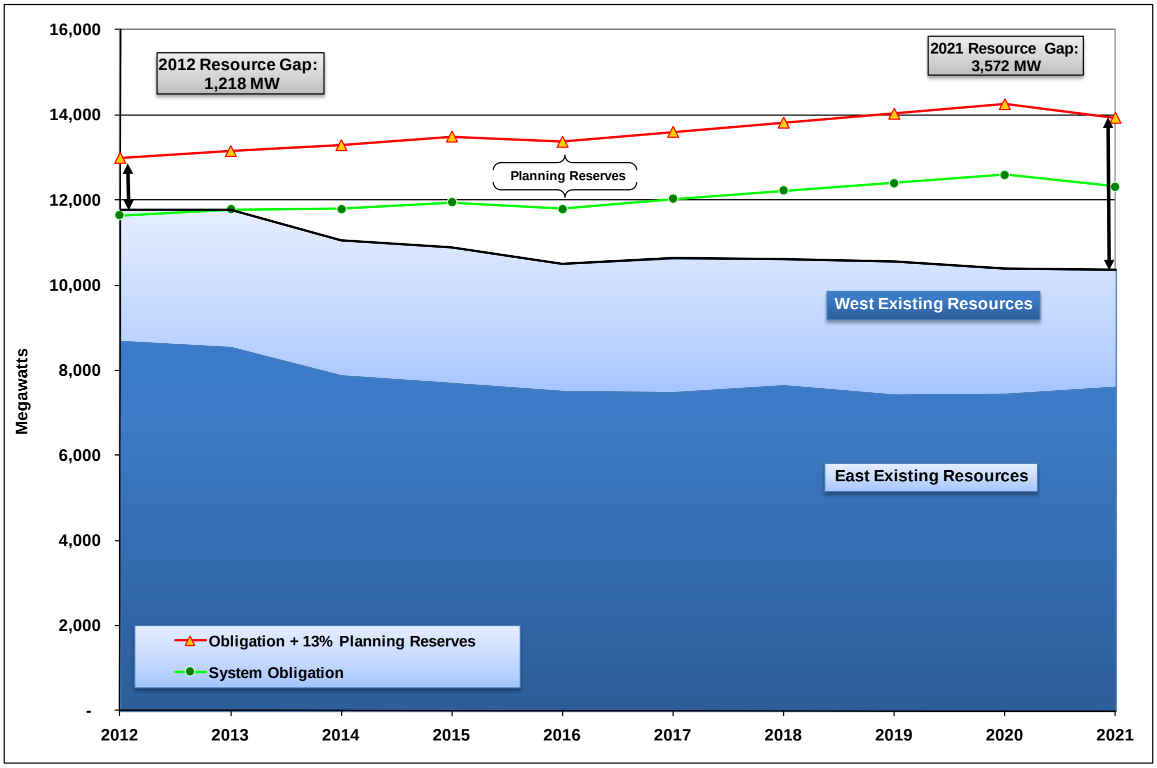


Figure 3.3 – East Coincident Peak Loads and Resources, 2012 Business Plan

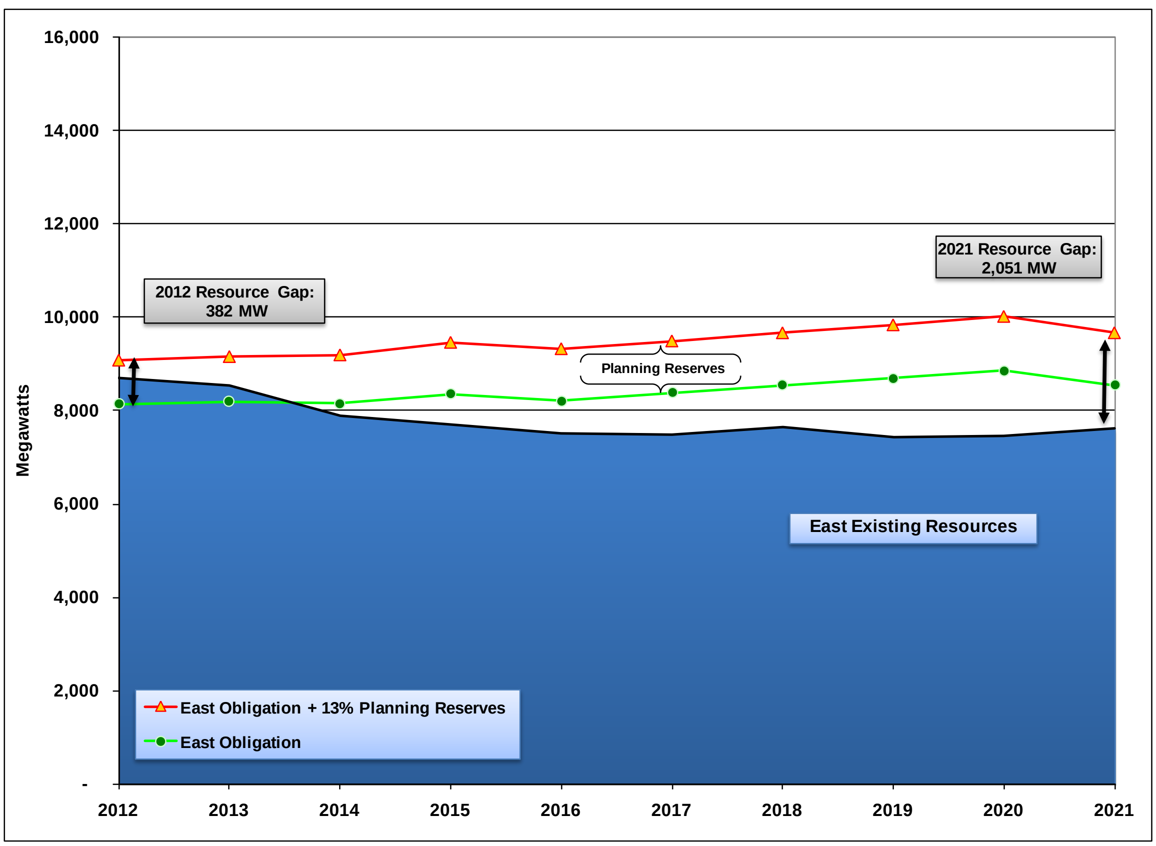


Figure 3.4 – West Coincident Peak Load and Resources, 2012 Business Plan

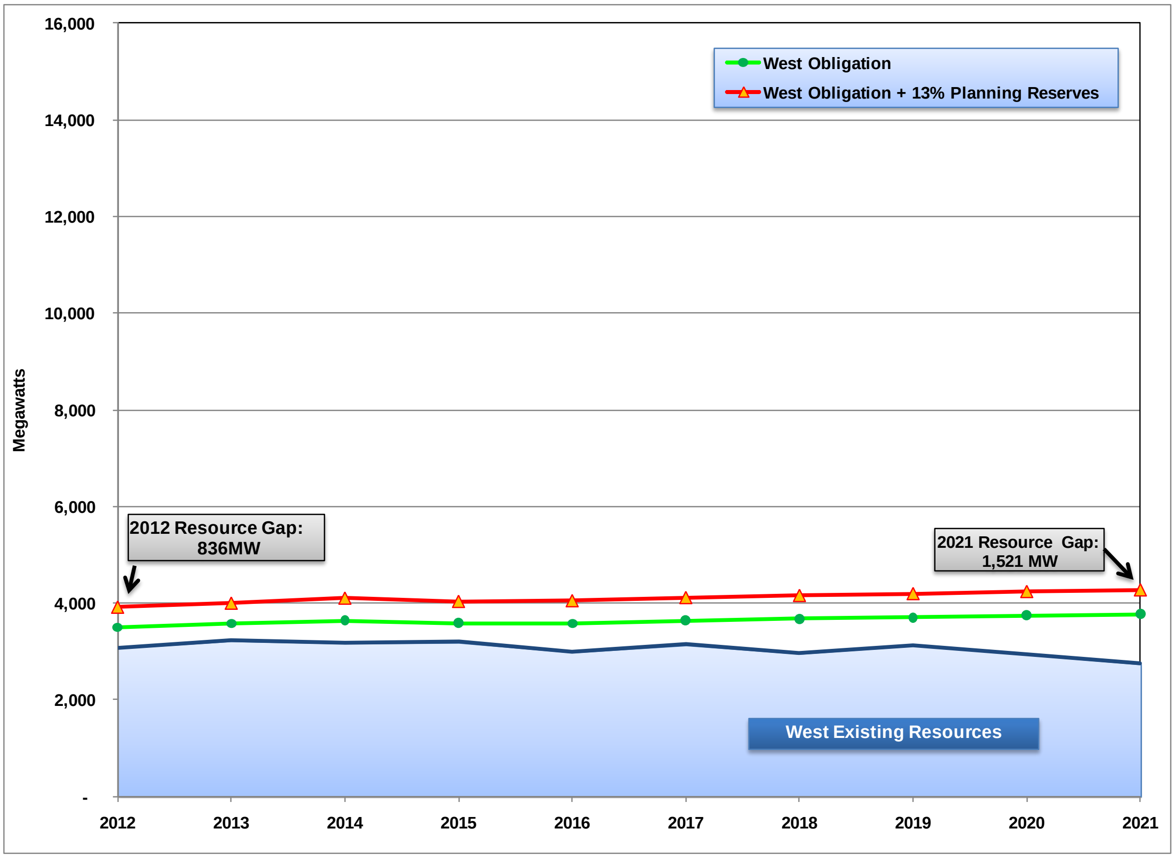


Table 3.6 – Capacity Load and Resource Balance, Megawatts (13% Target Reserve Margin)

Calendar Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
East										
Thermal	5,983	5,984	5,976	5,804	5,802	5,796	5,796	5,796	5,796	5,796
Hydroelectric	126	132	132	132	128	128	128	128	128	128
Class 1 DSM	329	329	329	329	329	329	329	329	329	329
Renewable	175	175	175	173	173	173	173	173	173	170
Purchase	905	804	304	304	116	116	116	116	116	91
Qualifying Facilities	79	94	94	94	94	236	236	236	236	236
Interruptible	281	281	281	281	281	281	281	281	281	281
Transfers	813	747	589	584	590	426	588	368	387	581
East Existing Resources	**8,691**	**8,546**	**7,880**	**7,700**	**7,512**	**7,485**	**7,647**	**7,426**	**7,445**	**7,612**
Load	6,993	7,151	7,403	7,611	7,468	7,727	7,882	8,034	8,195	8,360
Sale	1,147	1,045	745	745	745	659	659	659	659	179
East Obligation	**8,140**	**8,196**	**8,148**	**8,356**	**8,213**	**8,386**	**8,541**	**8,693**	**8,854**	**8,539**
Planning reserves	835	856	940	967	973	996	1,016	1,036	1,057	1,019
Non-owned reserves	98	98	98	133	133	106	106	106	106	106
East Reserves	**933**	**954**	**1,038**	**1,101**	**1,106**	**1,101**	**1,122**	**1,141**	**1,162**	**1,125**
East Obligation + Reserves	**9,073**	**9,150**	**9,187**	**9,457**	**9,320**	**9,487**	**9,663**	**9,834**	**10,016**	**9,664**
East Position	**(382)**	**(603)**	**(1,306)**	**(1,756)**	**(1,807)**	**(2,002)**	**(2,016)**	**(2,408)**	**(2,571)**	**(2,051)**
East Reserve Margin	**8%**	**5%**	**(3%)**	**(8%)**	**(9%)**	**(11%)**	**(11%)**	**(15%)**	**(16%)**	**(11%)**
West										
Thermal	2,517	2,529	2,529	2,529	2,524	2,505	2,505	2,505	2,505	2,505
Hydroelectric	882	851	872	877	878	877	864	819	650	650
Class 1 DSM	-	-	-	-	-	-	-	-	-	-
Renewable	88	88	88	88	88	88	88	88	88	88
Purchase	326	430	202	207	15	15	15	5	5	5
Qualifying Facilities	80	80	80	80	80	86	86	86	86	86
Transfers	(812)	(747)	(588)	(584)	(589)	(426)	(589)	(369)	(388)	(584)
West Existing Resources	**3,082**	**3,231**	**3,184**	**3,198**	**2,996**	**3,144**	**2,968**	**3,133**	**2,945**	**2,749**
Load	3,183	3,267	3,332	3,374	3,414	3,474	3,512	3,544	3,582	3,616
Sale	313	313	312	212	162	162	162	162	162	157
West Obligation	**3,496**	**3,580**	**3,644**	**3,586**	**3,576**	**3,636**	**3,674**	**3,706**	**3,744**	**3,773**
Planning reserves	412	410	447	439	463	471	476	481	486	490
Non-owned reserves	10	10	10	10	10	7	7	7	7	7
West Reserves	**422**	**420**	**458**	**450**	**473**	**477**	**482**	**488**	**493**	**496**
West Obligation + Reserves	**3,918**	**4,000**	**4,102**	**4,036**	**4,050**	**4,113**	**4,156**	**4,194**	**4,237**	**4,270**
West Position	**(836)**	**(768)**	**(918)**	**(838)**	**(1,054)**	**(969)**	**(1,188)**	**(1,061)**	**(1,292)**	**(1,521)**
West Reserve Margin	**(11%)**	**(8%)**	**(12%)**	**(10%)**	**(16%)**	**(14%)**	**(19%)**	**(16%)**	**(21%)**	**(27%)**
System										
Total Resources	**11,773**	**11,778**	**11,064**	**10,899**	**10,509**	**10,630**	**10,615**	**10,560**	**10,391**	**10,361**
System Obligation	**11,635**	**11,776**	**11,792**	**11,942**	**11,789**	**12,022**	**12,215**	**12,399**	**12,598**	**12,313**
Reserves	**1,356**	**1,374**	**1,496**	**1,550**	**1,580**	**1,579**	**1,604**	**1,629**	**1,655**	**1,621**
Obligation + 13% Planning Reserves	**12,991**	**13,149**	**13,289**	**13,492**	**13,369**	**13,601**	**13,819**	**14,028**	**14,253**	**13,934**
System Position	**(1,218)**	**(1,372)**	**(2,225)**	**(2,594)**	**(2,861)**	**(2,971)**	**(3,204)**	**(3,468)**	**(3,862)**	**(3,572)**
Reserve Margin	**2%**	**1%**	**(6%)**	**(9%)**	**(11%)**	**(12%)**	**(13%)**	**(15%)**	**(18%)**	**(16%)**

Table 3.7 – 2012 Business Plan Capacity Balance Less 2011 IRP Capacity Balance

Calendar Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
East										
Thermal	(44)	(44)	(52)	(224)	(244)	(250)	(250)	(250)	(250)	(253)
Hydroelectric	(6)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Class 1 DSM	-	-	-	-	-	-	-	-	-	-
Renewable	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Purchase	200	200	-	-	(168)	(168)	(168)	(168)	(168)	(168)
Qualifying Facilities	(107)	(113)	(113)	(113)	(113)	30	30	30	30	30
Interruptible	-	-	-	-	-	-	-	-	-	-
Transfers	362	333	133	273	91	(121)	289	7	59	(4)
East Existing Resources	**401**	**373**	**(35)**	**(68)**	**(437)**	**(512)**	**(103)**	**(385)**	**(333)**	**(398)**
Load	(351)	(415)	(402)	(398)	(733)	(650)	(662)	(678)	(701)	(703)
Sale	150	-	-	-	-	-	-	-	-	-
East Obligation	**(201)**	**(415)**	**(402)**	**(398)**	**(733)**	**(650)**	**(662)**	**(678)**	**(701)**	**(703)**
Planning reserves	(78)	(106)	(52)	(52)	(74)	(63)	(64)	(66)	(69)	(70)
Non-owned reserves	28	28	28	63	63	35	35	35	35	35
East Reserves	**(51)**	**(78)**	**(25)**	**11**	**(11)**	**(28)**	**(29)**	**(31)**	**(34)**	**(35)**
East Obligation + Reserves	**(252)**	**(493)**	**(427)**	**(387)**	**(744)**	**(678)**	**(691)**	**(709)**	**(735)**	**(738)**
East Position	**653**	**866**	**391**	**319**	**307**	**165**	**588**	**325**	**403**	**339**
East Reserve Margin	**7%**	**9%**	**4%**	**3%**	**2%**	**0%**	**5%**	**1%**	**2%**	**2%**
West										
Thermal	(35)	(26)	(26)	(26)	(31)	(37)	(45)	(45)	(45)	(45)
Hydroelectric	(76)	(107)	(86)	(81)	(81)	(81)	(94)	(83)	(95)	(95)
Class 1 DSM	-	-	-	-	-	-	-	-	-	-
Renewable	17	17	17	17	17	17	17	17	17	17
Purchase	79	99	(23)	(13)	(210)	(240)	(254)	(280)	(237)	(238)
Qualifying Facilities	(56)	(56)	(56)	(56)	(56)	(50)	(50)	(50)	(50)	(50)
Transfers	(360)	(331)	(131)	(273)	(90)	121	(289)	(9)	(58)	2
West Existing Resources	**(431)**	**(405)**	**(305)**	**(433)**	**(451)**	**(270)**	**(715)**	**(450)**	**(468)**	**(409)**
Load	(191)	(128)	(116)	(117)	(127)	(110)	(138)	(122)	(131)	(137)
Sale	54	54	54	54	54	54	54	54	54	54
West Obligation	**(137)**	**(74)**	**(62)**	**(63)**	**(73)**	**(56)**	**(84)**	**(68)**	**(77)**	**(83)**
Planning reserves	(28)	(22)	(5)	(6)	18	24	22	28	21	20
Non-owned reserves	4	4	4	4	4	-	-	-	-	-
West Reserves	**(24)**	**(18)**	**(1)**	**(3)**	**22**	**24**	**22**	**28**	**21**	**20**
West Obligation + Reserves	**(161)**	**(92)**	**(63)**	**(65)**	**(51)**	**(32)**	**(61)**	**(40)**	**(56)**	**(62)**
West Position	**(270)**	**(313)**	**(242)**	**(368)**	**(400)**	**(239)**	**(654)**	**(410)**	**(413)**	**(347)**
West Reserve Margin	**(8%)**	**(9%)**	**(7%)**	**(10%)**	**(12%)**	**(7%)**	**(18%)**	**(11%)**	**(11%)**	**(10%)**
System										
Total Resources	**(29)**	**(32)**	**(341)**	**(500)**	**(888)**	**(782)**	**(818)**	**(835)**	**(801)**	**(807)**
System Obligation	**(338)**	**(489)**	**(464)**	**(461)**	**(806)**	**(706)**	**(746)**	**(746)**	**(778)**	**(786)**
Reserves	**(75)**	**(97)**	**(26)**	**8**	**11**	**(4)**	**(7)**	**(4)**	**(13)**	**(14)**
Obligation + 13% Planning Reserves	**(412)**	**(585)**	**(489)**	**(452)**	**(795)**	**(709)**	**(753)**	**(749)**	**(791)**	**(800)**
System Position	**383**	**553**	**149**	**(48)**	**(93)**	**(73)**	**(65)**	**(86)**	**(10)**	**(8)**
Reserve Margin	**3%**	**4%**	**1%**	**(1%)**	**(2%)**	**(2%)**	**(2%)**	**(2%)**	**(2%)**	**(2%)**

Referencing Table 3.7, the significant differences in line items reflect the following changes:

PacifiCorp East

- Thermal – The capacity decrease in 2015 is due to the assumed retirement of the 172 MW Carbon coal plant, as well as de-rates for several coal units for which environmental control equipment is being installed. Cancellation of turbine upgrade projects further reduces capacity by 18 MW in 2016 and by approximately 2 MW in 2021.
- Purchase – The increase in capacity for 2012-2013 is due to the new 200 MW August 2011 Utah capacity purchase. The termination of the Southeast Idaho exchange contract with the Bonneville Power Administration in June 2016 accounts for a 168 MW capacity decrease beginning in 2016.

- Loads – The large decrease is attributable to lower forecasted loads and the removal of the load service obligation for BPA's customers as a result of termination of the Southeast Idaho Exchange Agreement.
- Qualifying Facilities – For planning purposes, the Company assumed that certain PURPA Qualifying Facilities are electing to self-generate through 2016 rather than sell their output to PacifiCorp. This assumptions results in about a 150 MW capacity decrease.
- Sales – Reflects a new two-year contract for sales of up to 150 MW for years 2011-2012.
- Transfers – Reflects an increase in economic imports of capacity from PacifiCorp West as determined by the System Optimizer capacity expansion model.[11]

PacifiCorp West

- Thermal and Hydro – Updated capacity ratings for a number of owned existing generating units, along with termination of the Grant Mid-Columbia hydro contract in 2013.
- Renewable – A renewed contract for Stateline Wind and Seattle City Light integration and exchange agreement accounts for the 17 MW increase.
- Purchase – The large drop in purchase capacity in 2016 is due to cancellation of the Southeast Idaho exchange contract with BPA, reflecting removal of power deliveries from BPA into PacifiCorp's system.
- Qualifying Facilities – The capacity decrease reflects contract updates along with the addition of two biomass facilities in Oregon and California.
- Sales – The increased capacity is mainly attributable to the new Stateline Wind and Seattle City Light integration and exchange agreement, as well as other minor contract updates.
- Transfers – Reflects an increase in economic exports from PacifiCorp West to PacifiCorp East as determined by the System Optimizer capacity expansion model.

Planning Reserve Margin Sensitivity Analysis

The Company analyzed the impact of a one percent decrease in the planning reserve margin, focusing on how this would change the net capacity position in 2016. Changing the planning reserve margin from 13% to 12% equates to a 96 MW reduction in the 2016 obligation, which almost entirely offset by the 93 MW increase in the 2016 capacity deficit in the 2012 Business Plan as compared to the 2011 IRP. As such, it is unlikely that a one percent change in the planning reserve margin would in and of itself change the need for the 2016 resource identified in both the 2011 IRP preferred portfolio and in the 2012 Business Plan resource portfolio. However, consistent with its action plan, the Company will perform an updated resource needs assessment for the All-source Request for Proposals, to be prepared during the third quarter of 2012, that will include an updated load and resource balance, an updated assessment of cost effective DSM and market purchases, and a sensitivity analysis assuming a 12% planning reserve margin.

[11] West-to-east and east-to-west transfers should be identical. However, decimal precision of a transmission loss parameter internal to the System Optimizer model results in a slight discrepancy (less than 2 MW) between reported values.

CHAPTER 4 – MODELING ASSUMPTIONS UPDATE

General Assumptions and Price Inputs

Study Period and Date Conventions

In line with the 2011 IRP, portfolio modeling for the 2012 business plan entailed executing the System Optimizer model for a 20-year period beginning January 1, 2011 and ending December 31, 2030. Future resources reflected in model simulations are given an in-service date of January 1st of a given year except as noted. The System Optimizer model requires in-service dates designated as the first day of a given month.

Escalation Rates, Renewable Tax Credits, and Other Financial Parameters

The escalation rate increased from 1.8 percent for the 2011 IRP to 1.9 percent for the 2012 business plan. For the System Optimizer model, a single escalation rate value is used.

The after-tax weighted average cost of capital (WACC) used for the 2012 Business Plan is 7.15 percent, whereas for the 2011 IRP the WACC was 7.17 percent.

Natural Gas and Power Market Price Updates

The 2012 business plan portfolio modeling was based on the August 31, 2011 price curves, downloaded from the Company's forward price system. The price curves reflect June 30, 2011 MIDAS[12] power and gas curves blended with market forwards as of August 31, 2011. Price curves are developed with market forwards for the first six years, a blending of market forwards and a fundamentals forecast for year seven, and a pure fundamentals forecast for subsequent years. These price curve components are used for both natural gas and electricity prices. The fundamentals forecast for natural gas is selected from a variety of external sources with consideration given to underlying supply/demand assumptions, forecast documentation, peer-to-peer forecast price comparisons, date of issuance, and forecast horizon. The fundamentals forecast for natural gas is then a key input to the internally derived estimation of the fundamentals forecast for electricity, which is produced with MIDAS.

Natural Gas Market Prices

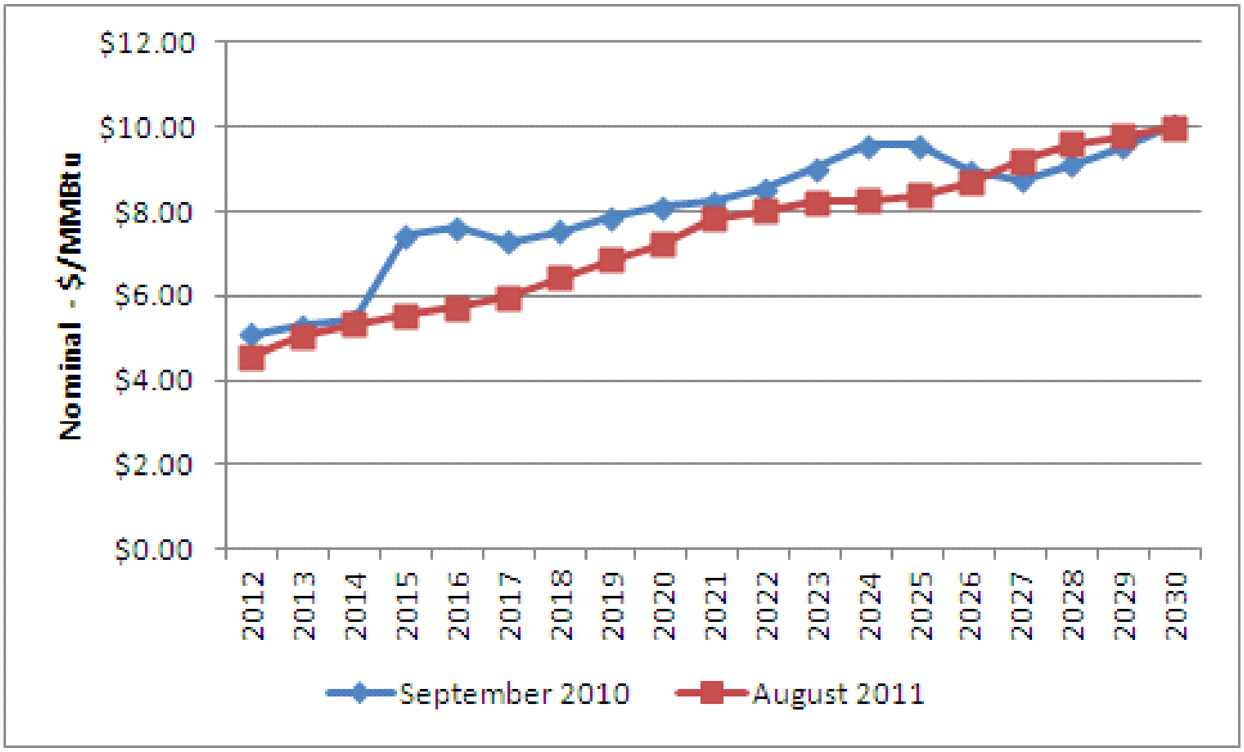
The September 2010 natural gas price curve is based upon an external long-term gas price forecast issued in September 2010. The September 2010 natural gas curve assumes CO_2 pricing starts in 2015, and reflects a fundamentals-based forecast influenced by cost-effective domestic supply opportunities largely due to growth in unconventional shale gas plays.

[12] MIDAS, which stands for Multi-objective Integrated Decision Analysis System, is a chronological dispatch model licensed from Ventyx Energy LLC. The model has a detailed representation of supply and demand variables influential to western power markets, and is used to develop the PacifiCorp's long-term electricity price forecast.

The August 2011 natural gas curve is based on a long-term natural gas forecast issued in April 2011, and assumes carbon pricing starts in 2021. Both forecasts assume a considerable portion of natural gas demand is met by unconventional shale production. For the September 2010 forecast used for the 2011 IRP, 38% of natural gas demand by 2020 was assumed to be met with shale production, while 45% is included for the August 2011 forecast.

Figure 4.1 compares the nominal annual Henry Hub natural gas prices from the September 2010 and August 2011 curves.

Figure 4.1 – Henry Hub Natural Gas Prices (Nominal)



Power Market Prices

The natural gas fundamentals forecast described above is a key input to the MIDAS model, and consequently, the gas curve shape is reflected in electricity prices from the September 2010 and August 2011 curves. Figures 4.2 through 4.4 compare the average annual electricity prices for the Palo Verde and Mid-Columbia market hubs from the September 2010 and August 2011 curves.

Figure 4.2 – Average Annual Flat Palo Verde Electricity Prices

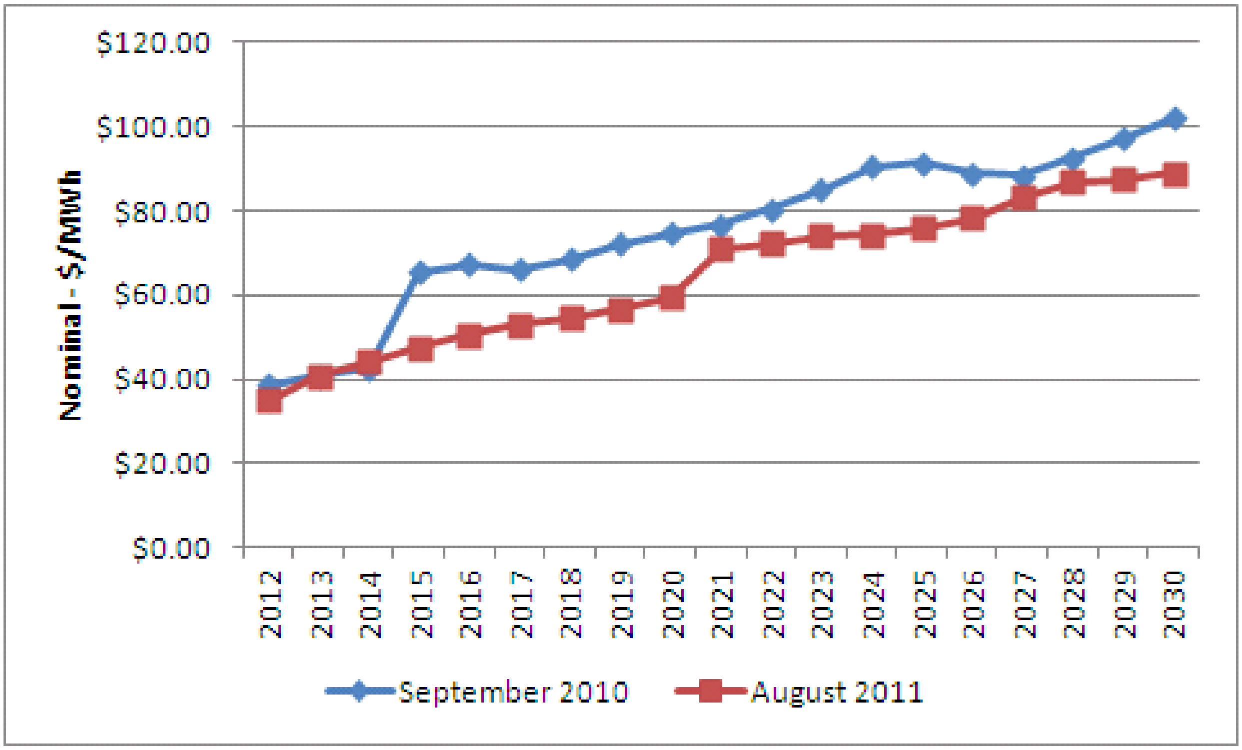


Figure 4.3 – Average Annual Heavy Load Hour Palo Verde Electricity Prices

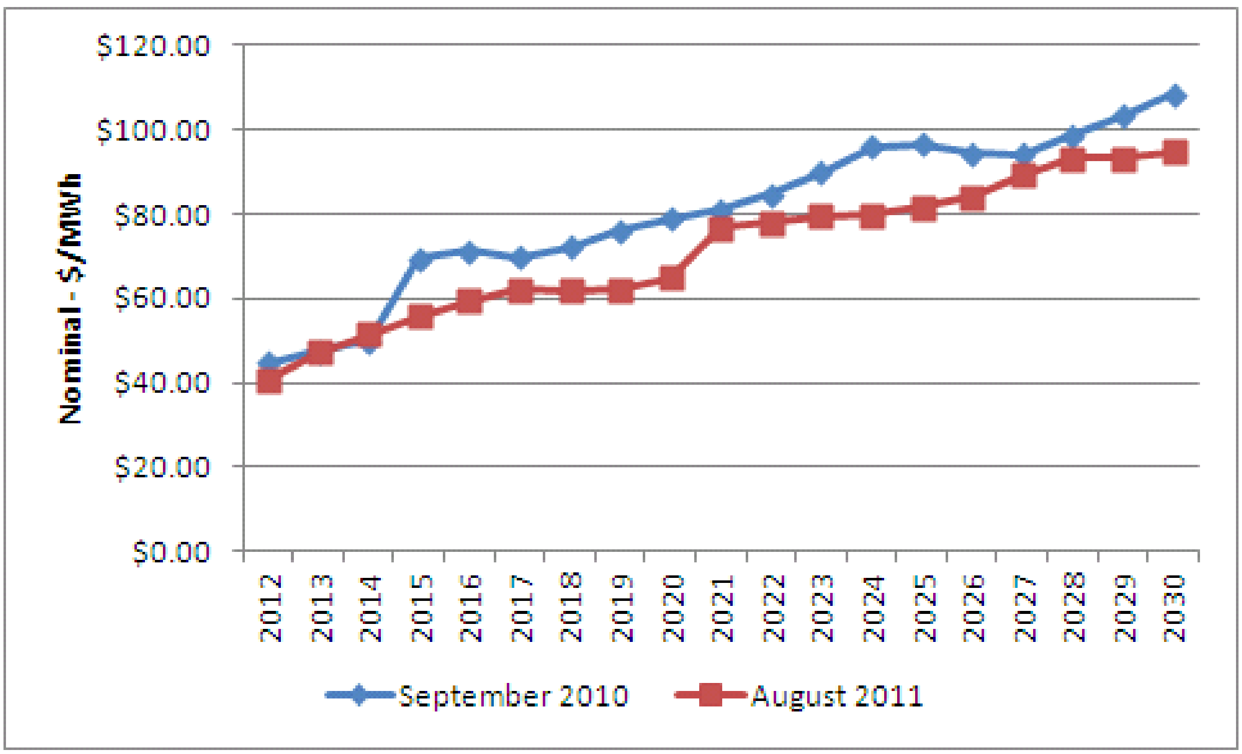
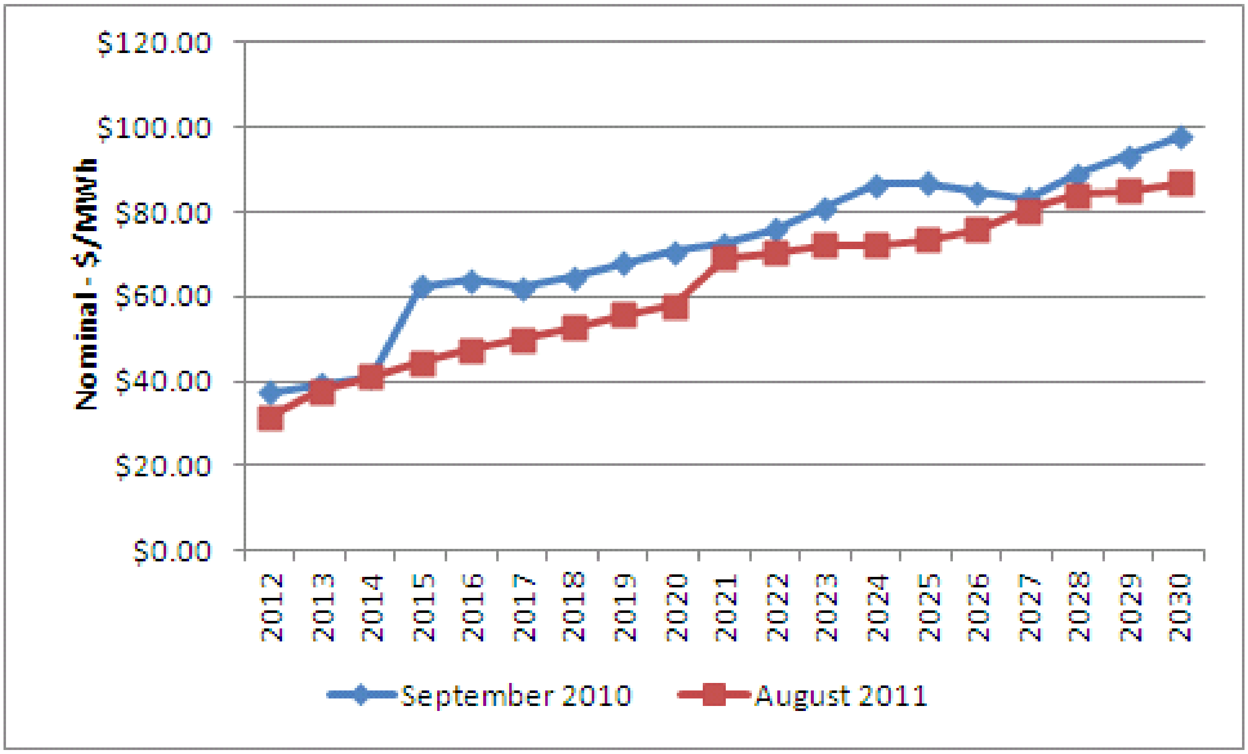


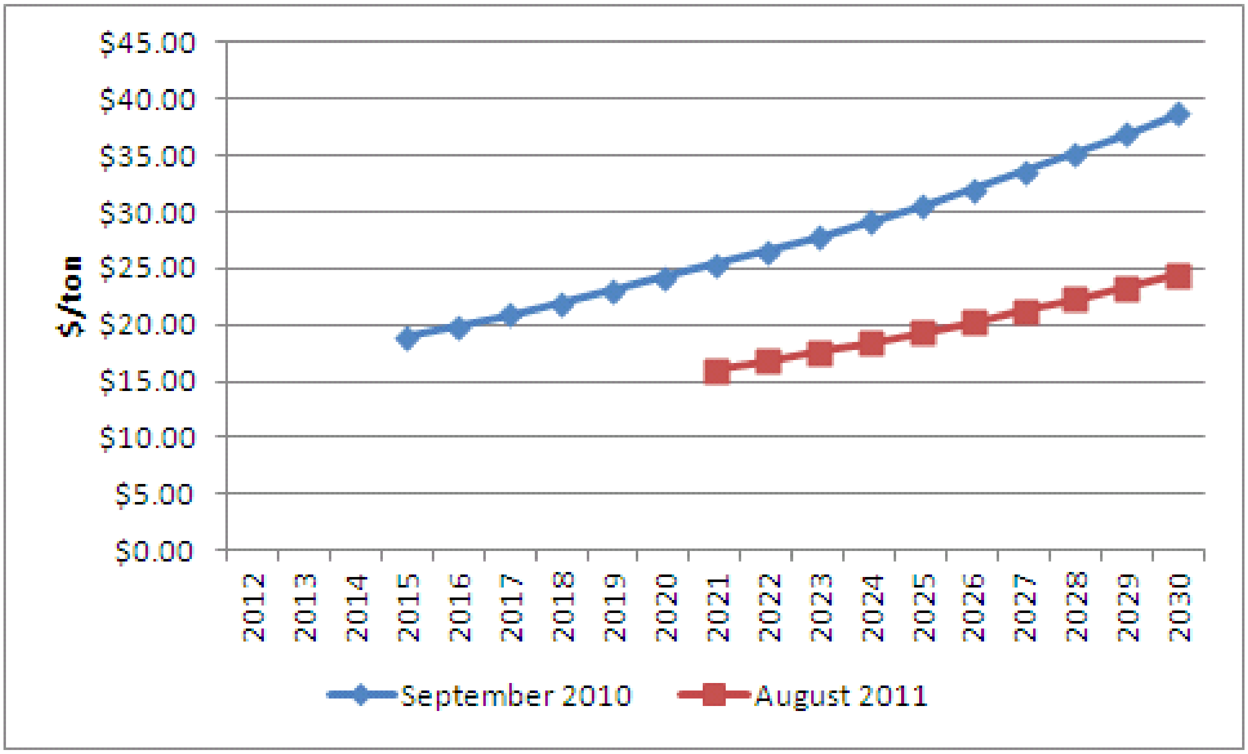
Figure 4.4 – Average Annual Flat Mid-Columbia Electricity Prices



Carbon Dioxide Emission Costs and Compliance

The Company updated both carbon dioxide prices and the timing of the start of CO_2 regulations. Subsequent to the adoption of CO_2 regulatory assumptions for the 2011 IRP, federal CO_2 policy expectations have changed with regard to timing, pricing, and design across all surveyed forecast services. The slow economic recovery, in tandem with predictions of sustained low natural gas prices and lack of momentum for CO_2 legislation, has significantly altered expectations as recent as a year ago. For portfolio modeling and the September 2010 curve used for the 2011 IRP, CO_2 pricing started in 2015 at $19/ton, whereas for the August 2011 curve, CO_2 pricing starts in 2021 at $16/ton. Both the prior and current CO_2 price forecasts escalate at inflation plus 3 percent. Figure 4.5 compares the CO_2 nominal price assumptions for September 2010 and August 2011. Assumptions for the August 2011 CO_2 projection were based upon review of the most recent price forecasts from several forecasters, all of whom have pushed out projected start dates for potential carbon legislation and have also reduced their previous price forecasts for CO_2.

Figure 4.5 – Comparison of Carbon Dioxide Emissions Modeling Assumptions

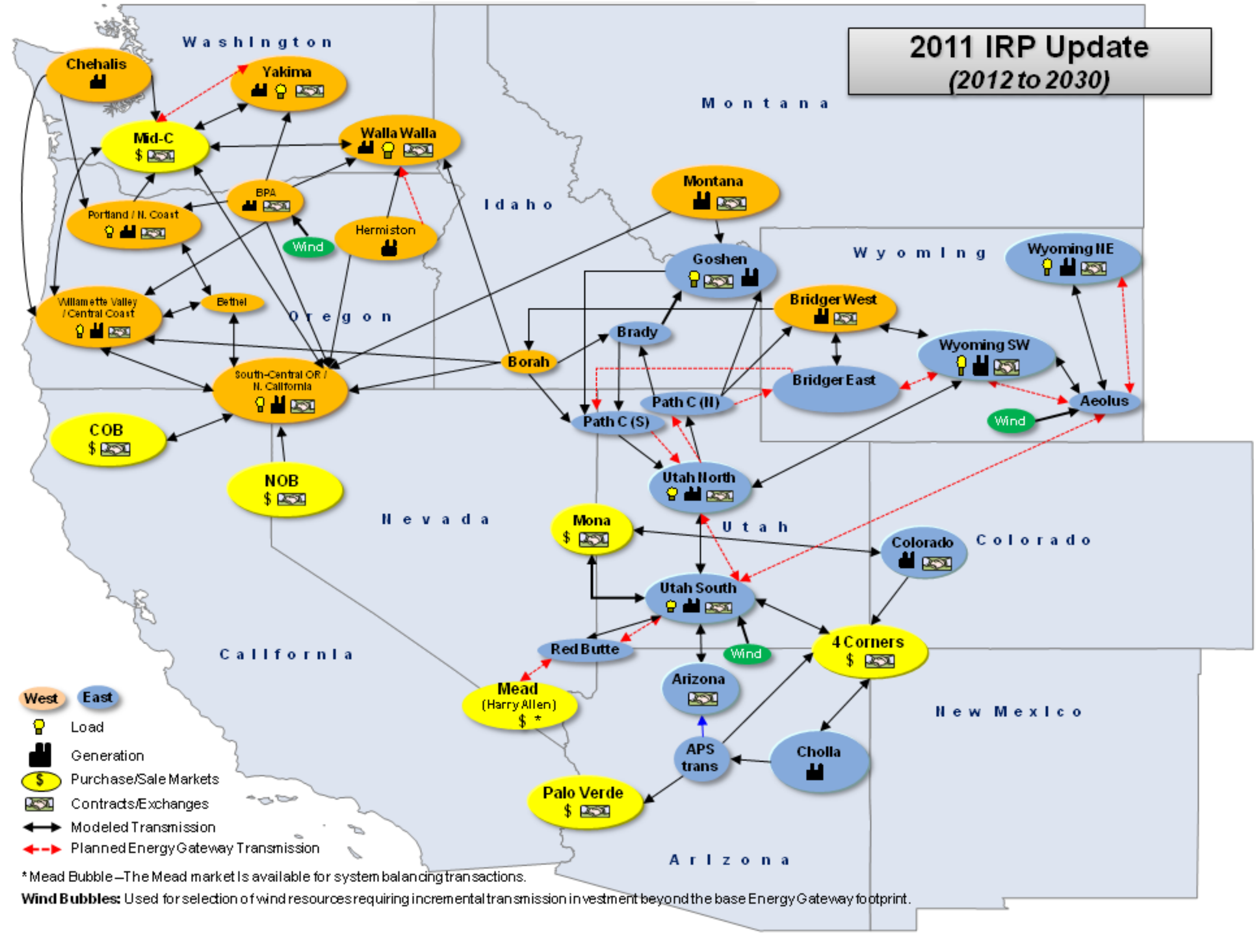


Transmission Topology

PacifiCorp updated the transmission topology to include a Nevada-Oregon-Border (NOB) market hub with a 100 MW market depth limit and a 200 MW transmission path rating to the "South Central OR/North California" topology bubble, reflecting availability of the Pacific direct current (DC) inter-tie to serve loads in central Oregon. This topology change was introduced when the BPA exchange agreement was terminated in August 2011, which previously served load in central Oregon.

The topology was also updated to reflect the modified Energy Gateway segment in-service dates listed in Table 2.1. Finally, the transmission path from the California-Oregon-Border (COB) to South Central OR/North California hub was adjusted to enable the full import of COB FOT (up to 400 MW) to the west side of the system. The previous topology only enabled the model to access existing FOT transactions through 2015.

Figure 4.5 – Transmission Topology



Front Office Transactions

For the 2012 business plan, a number of changes were made to annual front office transaction (FOT) acquisition limits. These changes include the following:

- As mentioned above, a new NOB market hub was added that assumes this illiquid market could potentially support 100 MW. Transmission capability from a legacy control to this market is 200 MW, but the market depth at this location is difficult to project. The Company recognizes this is an illiquid market that makes it difficult to forecast market depth. The Company plans to reassess this assumption based on its experience with short term market requests for proposals that will include this new market hub.
- A 74 MW reduction in availability from the Mead market in 2013 and 2014, reflecting the latest public posting of available transmission transfer capability from the Red Butte substation in southwest Utah to Utah loads.
- Elimination of the Utah North (250 MW) and Southern Oregon/North California (50 MW) limits. The 200 MW Utah FOT limit represented assumed availability of market purchases from a generator located in Utah through 2013. The Company cannot be certain that this Utah North capacity will remain available to the Company following the expiration of this

Utah capacity purchase. The removal of the 50 MW available from Southern Oregon/North California reflects improvements in the west-side topology.

The net impact of these changes is a 200 MW decrease in the system-wide FOT limit in most years of the planning horizon. Table 4.1 compares the annual maximum FOT availability by market hub for the 2012 Business Plan and 2011 IRP.

Table 4.1 – Front Office Transaction Availability Limits, 2012 Business Plan vs. 2011 IRP

2012 Business Plan

FOT Limits (MW)	Products	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
East	Mead HLH 3rd Quarter	190	190	190	190	100	100	-	-	-	-	-
	Mona HLH 3rd Quarter	200	200	300	300	300	300	300	300	300	300	300
	Four Corners HLH 3rd Quarter	-	-	-	-	-	-	-	-	-	-	-
West	Mid Columbia HLH 3rd Qtr or Flat	400	400	400	400	400	400	400	400	400	400	400
	Mid Columbia HLH 3rd Quarter (price premium)	375	375	375	375	375	375	375	375	375	375	375
	COB HLH 3rd Qtr or Flat	400	400	400	400	400	400	400	400	400	400	400
	Nevada Oregon Border HLH 3rd Qtr or Flat	100	100	100	100	100	100	100	100	100	100	100
	TOTAL LIMIT	**1,665**	**1,665**	**1,765**	**1,765**	**1,675**	**1,675**	**1,575**	**1,575**	**1,575**	**1,575**	**1,575**

2011 IRP

FOT Limits (MW)	Products	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
East	Mead HLH 3rd Quarter	190	190	264	264	100	100	-	-	-	-	-
	Mona HLH 3rd Quarter	200	200	300	300	300	300	300	300	300	300	300
	Utah North HLH 3rd Quarter	250	250	250	250	250	250	250	250	250	250	250
	Four Corners HLH 3rd Quarter	-	-	-	-	-	-	-	-	-	-	-
West	Mid Columbia HLH 3rd Qtr or Flat	400	400	400	400	400	400	400	400	400	400	400
	Mid Columbia HLH 3rd Quarter (price premium)	375	375	375	375	375	375	375	375	375	375	375
	Southern Oregon/Northern California HLH 3rd Qtr	50	50	50	50	50	50	50	50	50	50	50
	COB HLH 3rd Qtr or Flat	400	400	400	400	400	400	400	400	400	400	400
	TOTAL LIMIT	**1,865**	**1,865**	**2,039**	**2,039**	**1,875**	**1,875**	**1,775**	**1,775**	**1,775**	**1,775**	**1,775**
	2012 Business Plan less 2011 IRP	**(200)**	**(200)**	**(274)**	**(274)**	**(200)**	**(200)**	**(200)**	**(200)**	**(200)**	**(200)**	**(200)**

Supply-side Resources

The supply side resource costs and performance parameters did not change from the 2011 IRP to the 2012 business plan. Resource options reviews for the 2011 IRP and 2012 business plan were completed just a few months apart (early January and March 2011, respectively). Experience with the Lake Side 2 combined-cycle combustion turbine (CCCT) acquisition confirmed the relative accuracy of the 2011 values, and thus no adjustments were considered necessary. Also, there were no national trends suggesting movement in generation construction costs between the two resource options reviews.

The only resource change pertains to the description of the advanced combustion turbine technology for CCCT plants. The 2012 business plan used a "J" machine to represent advanced combustion turbine technology with the same costs assigned to the "Advanced" combined-cycle technology reported in the 2011 IRP. In addition, the "G" and "H" CCCT machines were combined as a single option based on the similarity in the expected output from these machines; previously this was only identified as the 'G" option.

CHAPTER 5 – PORTFOLIO DEVELOPMENT

Introduction

PacifiCorp used the System Optimizer capacity expansion optimization model to develop resource portfolios based on inputs and assumptions updated throughout the business planning process. For this portfolio development, the Company devised wind resource acquisition targets outside of the portfolio modeling effort, and treated these targets as a fixed resource schedule in the capacity expansion modeling. The Company also applied the demand-side management and combined heat & power (CHP) resources from the 2011 IRP preferred portfolio as fixed resource schedules to align with that planning effort. As a consequence of this resource treatment, as well as classification of the Lake Side 2 CCCT plant as a firm resource addition in 2014, the System Optimizer model was used to balance capacity and energy with gas-fired resources (after 2014) and front office transactions. This chapter first describes the development of the wind schedule, and then presents the 2012 Business Plan portfolio along with a comparison to the 2011 IRP preferred portfolio.

Wind Resources and Renewable Portfolio Standard Compliance

Table 5.1 presents a comparison of the wind additions schedule for the 2012 Business Plan and 2011 IRP. Installed wind capacity additions for the 2012 Business Plan are lower than for the 2011 IRP through 2024; however, the total wind capacity through 2030 is approximately the same as the 2011 IRP—about 2,100 MW. The revised wind schedule reflects an updated analysis of annual RPS compliance requirements and strategy, a change in the planned in-service date for Energy Gateway West, and lower forecasted loads, while at the same time maintaining the long-term regulatory compliance/incentive uncertainty, long-run public policy goals, and risk mitigation benefits of zero carbon, zero fuel cost renewable resources as identified in the 2011 IRP. In particular, the additional wind resources included past 2024 provide fuel diversification benefits, and are consistent with the 2011 IRP decision to require additional wind based on the belief that state and federal policies, in the long term, will support expansion of renewable energy.

Development of wind targets required to meet current state and expected future federal renewable portfolio standards is discussed in the next section.

Table 5.1 – Wind Additions Schedule, 2012 Business Plan vs. 2011 IRP

	Installed Capacity, MW [1/]													Total
Source	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2018-2030**
2012 Business Plan [2/]	-	225	225	-	150	100	75	200	200	200	200	250	250	2,075
2011 IRP	300	300	200	200	200	200	200	100	100	100	100	100	-	2,100
Difference	(300)	(75)	25	(200)	(50)	(100)	(125)	100	100	100	100	150	250	(25)

1/ Wind resources are shown in the year for which they contribute to meeting summer peak load requirements. In-service dates for business plan wind resources are November of the prior year. For example, the resources shown in 2019 (225 MW) have an in-service date of November 1, 2018.
2/ Excludes wind PURPA Qualifying Facility capacity changes made subsequent to 2011 IRP filing in March 2011, and reflected in the 2012 Business Plan. Planned QF wind capacity is up by 34 MW relative to the 2011 IRP.

Renewable Portfolio Standard Compliance

PacifiCorp's RPS compliance analysis was based on the following assumptions:

- The analysis represents a deterministic view of known state RPS requirements and expected federal RPS requirements, but does not contemplate the prospects for alternate long-term policy outcomes that might influence long-term renewable resource needs.
- The Company continues to plan for the full Energy Gateway transmission footprint as documented in the 2011 IRP.
- A federal RPS is in place starting in 2017 with target generation levels comparable to that proposed by Representatives Henry Waxman and Edward Markey in their "American Clean Energy and Security Act of 2009".
- Washington state legislation expands the geographic scope for defining qualifying renewable resources to a WECC-wide basis effective by 2015, thereby allowing system-wide renewable generation to be applied to Washington RPS requirements using the 2010 Protocol inter-jurisdictional cost allocation methodology.
- Current state RPS rules for sales, purchases, and banking of Renewable Energy Credits (RECs) are applied. For example, Oregon allows REC banking for future RPS compliance for qualifying resources acquired since January 1, 2007, while use of unbundled RECs for annual RPS compliance is capped at 20 percent.[13]
- The Company adds sufficient wind in Wyoming to meet federal RPS requirements, with costs allocated on a system basis.
- Incremental wind capacity in Wyoming is procured to meet Oregon, Washington, and California RPS requirements with costs allocated to Oregon, Washington, and California customers (i.e., costs are on a "situs" basis).
- Wyoming wind resources are assumed to have a 35 percent capacity factor, consistent with the 2011 IRP.
- Future compliance for Utah's cost-effective renewable resource goal of 20 percent by 2025 is met through current Utah eligible resources and associated banked RECs.[14]
- RECs acquired to meet Oregon, Washington, and California RPS requirements are also eligible for meeting federal RPS requirements.
- No more than 400 MW of installed wind capacity is added per year to help mitigate customer rate impacts.
- The 2.2 cents/kilowatt-hour renewable production tax credit (PTC) for wind, which expires December 31, 2012, is not extended.

Table 5.2 summarizes the state and federal annual RPS targets on a "percentage of retail sales" basis, the targets translated into megawatt-hour requirements, and the quantity of megawatt-hours available from existing eligible renewable resources. Based on starting annual RPS positions for Oregon, Washington, California, and federal compliance, the minimum amount of future Wyoming wind resource capacity was added on a year by year basis to ensure that no compliance shortfall results in any year. This RPS compliant wind schedule is shown in Table 5.3. (In-service dates are November 1st of the years shown.) Note that acquisition of an

[13] Unbundled RECs are RECs purchases separately from the associated renewable generation.
[14] See Utah Code §54-17-603. The Company filed its first Carbon Reduction Progress Report in December 2009, which indicated that estimated eligible qualifying electricity in 2025 far exceeded the retails sales target. The target was 4,934,433 MWh, while the estimated amount of qualifying electricity, including banked amounts, was 53,584,905 MWh.

incremental 1,175 MW of wind is needed to comply with RPS requirements through 2030, given the assumptions outlined above. Incremental wind resources included in the IRP Update resource portfolio totaling 2,075 MW through the end of 2030 includes an additional 900 MW of wind resource additions distributed across the 2025-2030 period that are in excess of the wind resource additions required to meet known state RPS requirements and expected federal RPS requirements. As discussed previously, these additional long-term wind resources in the IRP Update portfolio are included in recognition of long-term regulatory compliance/incentive uncertainty, long-run public policy goals, and risk mitigation benefits of zero carbon, zero fuel cost renewable resources. Please see the Energy Gateway Transmission Program Planning section in Chapter 2 for discussion on transmission project benefits beyond the single purpose of delivering incremental wind resources. An overview of the RPS compliance picture for each state and on a federal basis is provided below.

Table 5.2 – Renewable Portfolio Standard Targets, Requirements, and Eligible Existing Resources by State

RPS Percentage Targets

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Oregon	5.0%	5.0%	5.0%	15.0%	15.0%	15.0%	15.0%	15.0%	20.0%	20.0%	20.0%	20.0%	20.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%
Washington	3.0%	3.0%	3.0%	9.0%	9.0%	9.0%	9.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
California	20.0%	20.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%
Federal (Renewable)						4.5%	7.1%	7.1%	9.8%	9.8%	12.4%	12.4%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%

RPS Requirements (MWh)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Oregon	671,769	671,979	683,926	2,064,198	2,075,264	2,071,002	2,075,268	2,081,553	2,787,636	2,781,660	2,782,818	2,783,956	2,796,358	3,489,833	3,495,683	3,505,705	3,531,658	3,536,045	3,552,803
Washington	122,749	123,091	122,940	368,791	369,507	369,774	369,447	616,145	616,766	615,590	613,007	611,183	610,518	608,856	606,740	606,522	607,442	607,278	606,023
California	170,252	169,870	212,585	212,670	213,388	212,575	212,498	212,553	280,705	279,678	279,546	278,451	278,249	275,989	274,943	273,785	273,893	271,993	271,349
Federal						2,500,712	4,011,590	4,063,027	5,699,472	5,741,852	7,361,613	7,432,797	9,129,392	9,192,699	9,279,857	9,375,935	9,502,522	9,567,235	9,659,749

Eligible Existing Resources (MWh)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Oregon	1,363,473	1,400,715	1,378,891	1,363,608	1,356,585	1,346,904	1,342,213	1,343,893	1,316,523	1,316,523	1,283,000	1,283,000	1,176,495	1,169,376	1,123,872	1,120,093	1,116,316	1,116,316	1,028,786
Washington	92,607	91,061	89,441	400,312	400,326	398,236	398,174	397,980	390,144	390,145	379,559	379,559	379,559	378,504	365,329	365,329	365,329	365,329	337,690
California	171,376	171,188	170,693	169,739	168,438	168,233	167,952	156,671	148,186	127,320	125,116	125,095	125,076	124,837	122,152	122,145	122,143	122,147	116,468
Federal	5,232,773	5,417,002	5,420,156	5,424,945	5,439,002	5,439,008	5,439,017	5,439,009	5,439,012	5,439,013	5,296,907	5,296,908	5,296,908	5,282,745	5,105,864	5,105,864	5,105,864	5,105,864	4,734,815

Table 5.3 – RPS Compliant Wind Additions Schedule
(Resource in-service dates are November 1st of the indicated years)

Year	Wind Resource Additions, Oregon, Washington, and California Allocated		Wind Resource Additions, System Allocated		Cumulative Total
	Incremental Capacity (MW)	Cumulative Capacity (MW)	Incremental Capacity (MW)	Cumulative Capacity (MW)	
2012	0	0	0	0	0
2013	0	0	0	0	0
2014	0	0	0	0	0
2015	0	0	0	0	0
2016	0	0	0	0	0
2017	0	0	0	0	0
2018	225	225	0	0	225
2019	225	450	0	0	450
2020	0	450	0	0	450
2021	150	600	0	0	600
2022	100	700	0	0	700
2023	75	775	0	0	775
2024	75	850	0	0	850
2025	75	925	0	0	925
2026	0	925	100	100	1,025
2027	0	925	50	150	1,075
2028	0	925	50	200	1,125
2029	0	925	50	250	1,175
2030	0	925	0	250	1,175

Oregon RPS Compliance

Figure 5.1 indicates how Oregon RPS compliance is forecasted to be met through 2030 on an annual basis. As shown in the table, RPS requirements are fully met by surrendering accumulated bundled banked RECs through 2019. Beginning in 2020, generation from eligible existing and planned renewable resources ("current year generation surrendered") is needed to meet the annual RPS requirements. By 2030, nearly the entire RPS requirement is met through eligible resource generation.

Washington RPS Compliance

Figure 5.2 shows the Washington annual RPS compliance positions. In the near term (through 2015), RPS requirements are met by generation from eligible renewable facilities and a small quantity of unbundled RECs. Beginning in 2016, the Company begins to increasingly rely on banked bundled RECs to help meet RPS compliance requirements. Due to growth in the bundled REC bank balance, the Company anticipates selling bundled RECs beginning in 2024. As noted above, this compliance strategy assumes that Washington legislation enables use of WECC-wide bundled RECs by 2015.

California RPS Compliance

Figure 5.3 shows the California annual RPS compliance positions. Compliance is achieved predominately through renewable resource acquisition with costs allocated on a situs basis to California. A combination of unbundled RECs and bundled RECs from the accumulated bank balance are also used for compliance.

Federal RPS Compliance

Figure 5.4 shows the federal annual RPS compliance positions assuming compliance targets comparable to the Waxman-Markey Bill. By virtue of meeting state RPS compliance targets, the need to surrender RECs that are allocated on a system basis is not needed until 2026.

Figure 5.1 – Oregon RPS Compliance Position

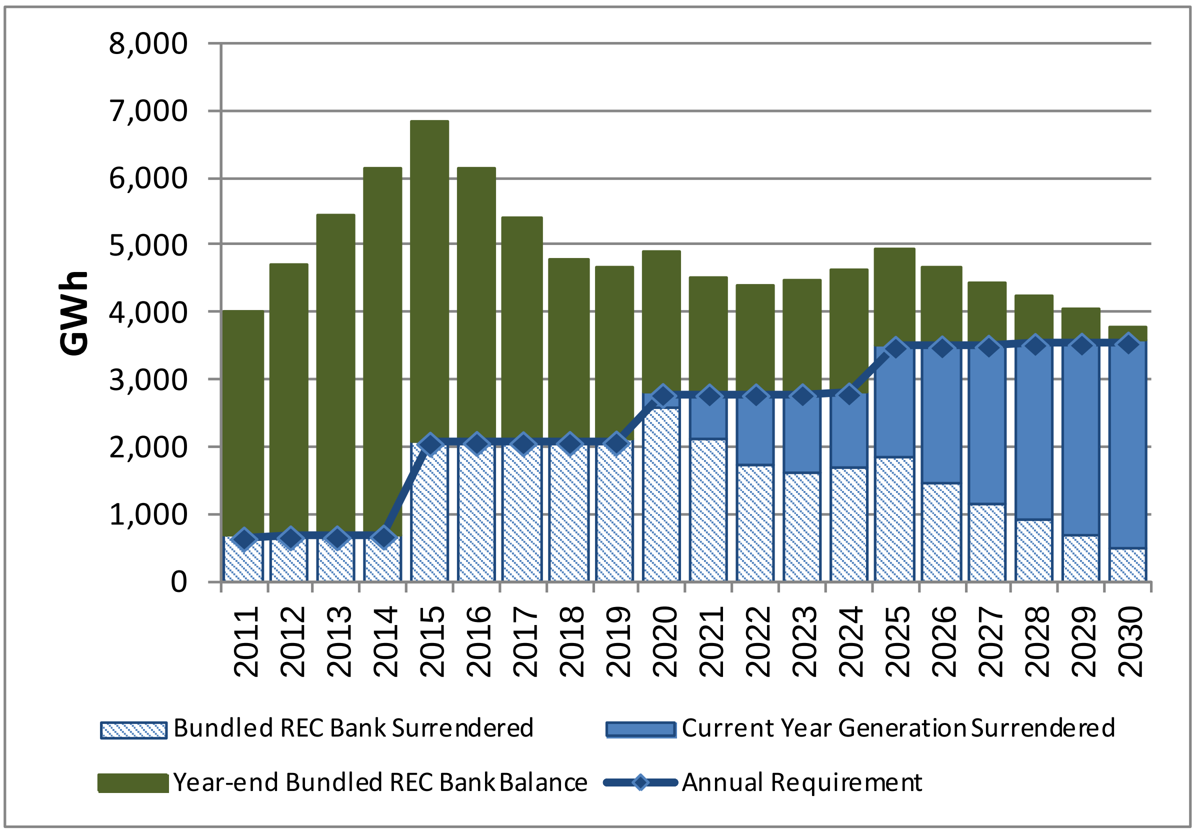


Figure 5.2 – Washington RPS Compliance Position

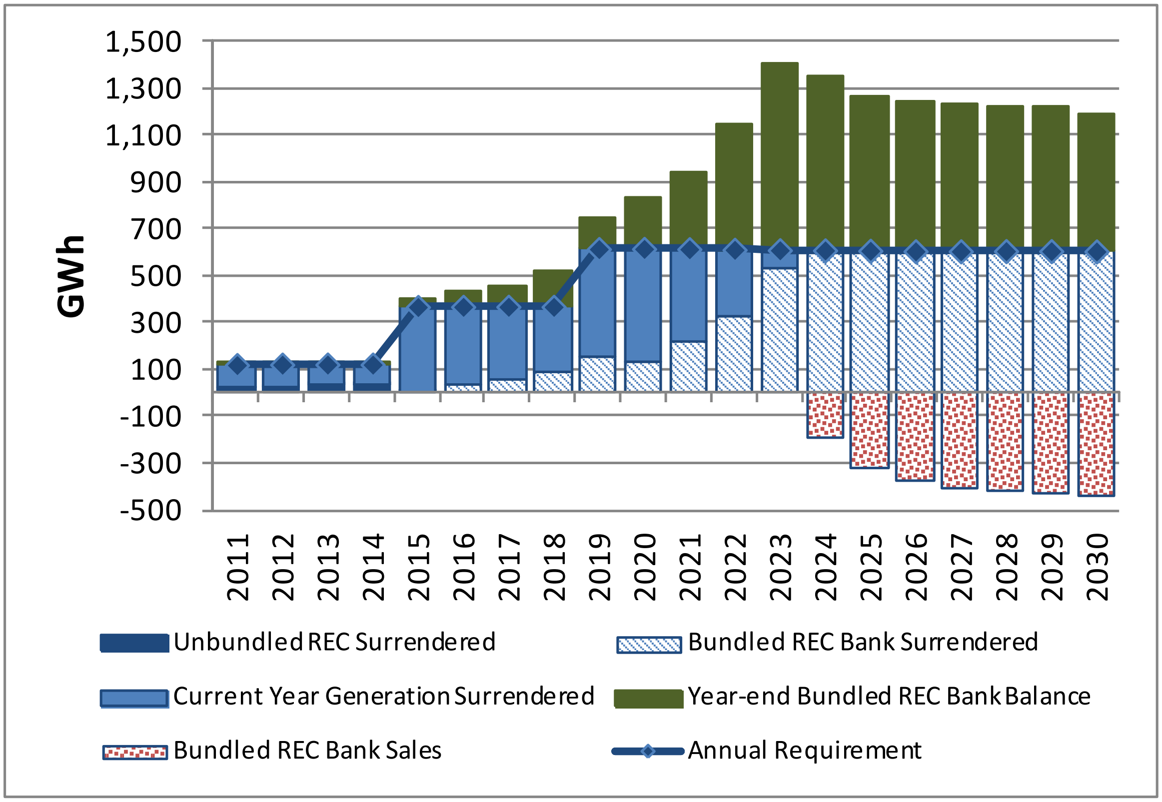


Figure 5.3 – California RPS Compliance Position

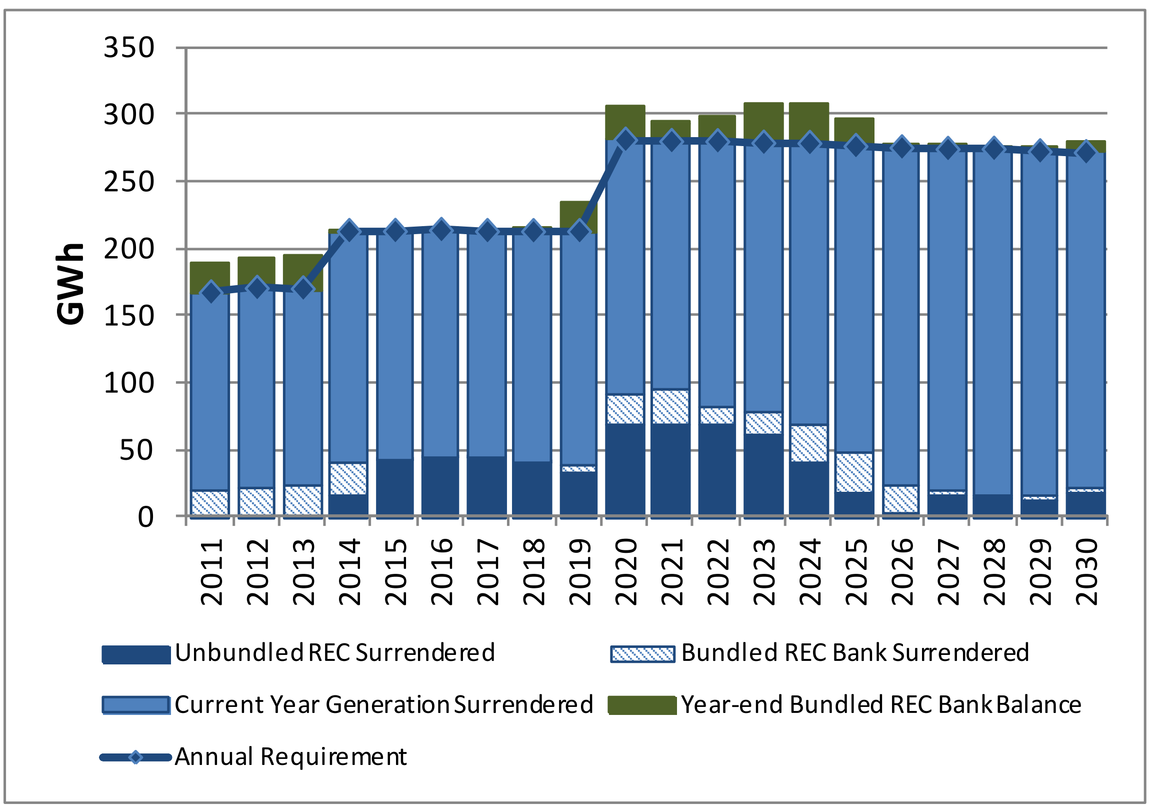
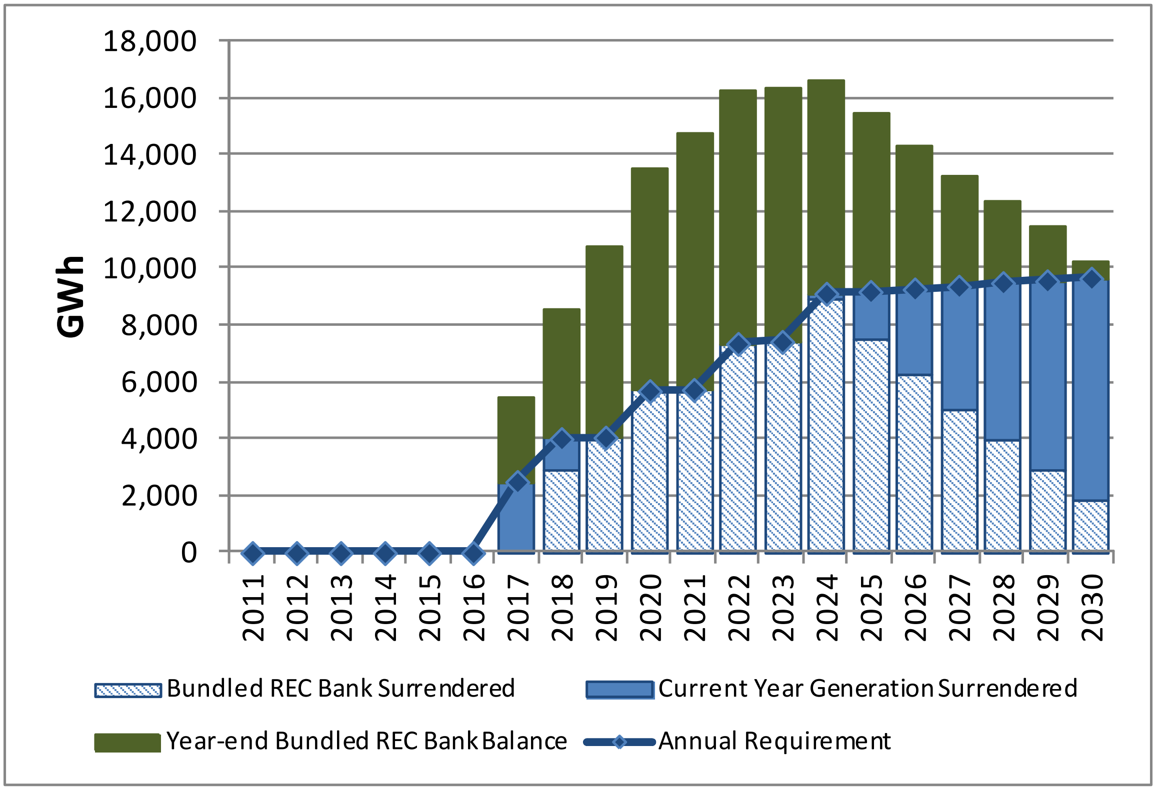


Figure 5.4 – Federal RPS Compliance Position



2012 Business Plan Resource Portfolio

Table 5.4 summarizes the annual megawatt capacity and timing of resources for both the 2012 Business Plan and 2011 IRP portfolios for the comparative 10-year period, 2012-2021. Note that for wind resources the in-service dates reflect the year for which they contribute to meeting summer peak load requirements to maintain comparability with the 2011 IRP wind schedule. In-service dates for 2012 Business Plan resources are November 1st of the prior year. A more detailed table of portfolio resources is provided as Table 5.5. The most significant differences between the two portfolios for the 10-year planning period include the following:

- Prior to 2015, lower market prices and increased access to market increases overall reliance on FOTs in the west, which are more than offset by reduced market purchases in the east driven by less market access and reduced loads. On a system basis, reliance on FOTs in the 2012 Business Plan declines by 95 MW in 2012, 241 MW in 2013, and 129 MW in 2014 as compared to the 2011 IRP.
- Given the 2016 capacity deficit increased by 93 MW, the need for a 2016 resource remains unchanged in the 2012 business plan, and the increased need relative to the 2011 IRP is largely met with incremental FOT acquisitions.
- Deferral of 550 MW of wind resources over the period 2018 through 2021 in the 2012 business plan is driven by a revised RPS compliance analysis that is consistent with a lower load forecast, assumed delays in prospective federal RPS policy implementation, a delay of the Windstar to Populus Energy Gateway transmission project (from year-end 2017 to year-

end 2018), and the assumed unavailability of federal production tax credits for the 10-year planning period.

- With favorable wholesale electricity prices driven by lower natural gas prices, the 2012 Business Plan portfolio includes an additional 138 MW of west side FOTs and a 393 MW CCCT in 2019, which is smaller than the 475 MW CCCT included in the 2011 IRP preferred portfolio.

Table 5.6 shows the capacity load & resource balance for 2012-2021 with 2012 Business Plan resources included.

Table 5.4 – Comparison of 2012 Business Plan with 2011 IRP Preferred Portfolio

2012 Business Plan Portfolio

	Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Resource Total 2012-2021
East													
	CCCT F 2x1	-	-	-	637	-	597	-	-	-	-	-	1,234
	CCCT G 1x1 Dry-Cooled	-	-	-	-	-	-	-	-	393	-	-	393
	Coal Plant Turbine Upgrades	16	19	2	-	-	-	-	-	-	-	-	21
	Wind *	-	-	-	-	-	-			225	225	-	450
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	1	10
	DSM, Class 1	6	70	-	20	91	-	-	-	-	-	-	181
	DSM, Class 2	47	53	46	48	51	54	56	58	60	63	62	550
	Micro Solar Watering Heating	-	-	-	-	-	-	-	-	-	-	-	-
	Utah Capacity Purchase **	200	200	200	-	-	-	-	-	-	-	-	400
	Front Office Transactions ***	17	17	150	300	331	300	300	300	296	300	54	
West													
	Coal Plant Turbine Upgrades	-	-	12	-	-	-	-	-	-	-	-	12
	CHP - Biomass	4	4	4	4	4	4	4	4	4	4	4	42
	DSM, Class 1	-	-	57	-	6	-	-	-	-	-	-	63
	DSM, Class 2	61	61	65	70	71	70	70	62	62	62	63	655
	Solar (Oregon)	4	4	4	3	3	-	-	-	-	-	-	15
	Micro Solar Watering Heating	-	-	-	-	-	-	-	-	-	-	-	-
	Front Office Transactions ***	130	927	838	761	892	567	596	735	533	795	714	
	Annual Additions, Long Term Resources	**139**	**213**	**191**	**783**	**227**	**726**	**131**	**125**	**745**	**355**	**130**	
	Annual Additions, Short Term Resources	**347**	**1,145**	**1,188**	**1,061**	**1,223**	**867**	**896**	**1,035**	**829**	**1,095**	**768**	
	Total Annual Additions	**486**	**1,358**	**1,378**	**1,844**	**1,450**	**1,593**	**1,027**	**1,160**	**1,574**	**1,450**	**897**	

* In-service dates reflect the year in which wind resources contribute to meeting summer system peak load requirements. For the 2012 Business Plan, actual in-service dates are November of the prior year. For example, the resources shown in 2019 (225 MW) have an in-service date of November 1, 2018.

** Utah Capacity Purchase is treated as an existing resource in the load & resource balance, having been executed in August 2011. Annual capacity amounts are not additive.

*** Front Office Transactions amounts reflect one-year transaction periods, and are not additive.

2011 IRP - Preferred Portfolio

	Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Resource Total 2012-2021
East													
	CCCT F 2x1	-	-	-	625	-	597	-	-	-	-	-	1,222
	CCCT H 1x1	-	-	-	-	-	-	-	-	475	-	-	475
	IC Aero WYSW	-	-	-	-	-	-	-	-	-	-	-	-
	SCCT Aero UT	-	-	-	-	-	-	-	-	-	-	-	-
	Coal Plant Turbine Upgrades	12	19	2	-	-	18	-	-	-	-	2	41
	Wind	-	-	-	-	-	-	-	300	300	200	200	1,000
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	1	10
	DSM, Class 1	6	70	-	20	91	-	-	-	-	-	-	181
	DSM, Class 2	47	53	46	48	51	54	56	58	60	63	62	550
	Micro Solar Watering Heating	-	3	3	3	3	3	3	3	-	-	-	18
	Front Office Transaction - Utah 3rd Qtr HLH *	200	200	204	26	250	-	72	217	-	245	-	
	Front Office Transactions **	-	168	414	564	399	325	300	300	300	300	300	
West													
	Coal Plant Turbine Upgrades	-	-	4	-	-	-	-	8	-	-	-	12
	CHP - Biomass	4	4	4	4	4	4	4	4	4	4	4	42
	DSM, Class 1	-	-	57	-	6	-	-	-	-	-	-	63
	DSM, Class 2	61	61	65	70	71	70	70	62	62	62	63	655
	Solar (Oregon)	4	4	4	3	3	-	-	-	-	-	-	15
	Micro Solar Watering Heating	-	2	2	2	2	2	2	1	-	-	-	12
	Front Office Transactions **	150	871	811	600	500	450	450	450	395	450	400	
	Annual Additions, Long Term Resources	**134**	**217**	**187**	**776**	**232**	**749**	**136**	**437**	**902**	**330**	**332**	
	Annual Additions, Short Term Resources	**350**	**1,240**	**1,429**	**1,190**	**1,149**	**775**	**822**	**967**	**695**	**995**	**700**	
	Total Annual Additions	**484**	**1,457**	**1,616**	**1,966**	**1,381**	**1,524**	**958**	**1,404**	**1,597**	**1,325**	**1,032**	

* Utah Capacity Purchase was modeled as a Front Office Transaction for the 2011 IRP.

** Front Office Transactions amounts reflect one-year transaction periods, and are not additive.

Difference - 2012 Business Plan Less 2011 IRP Preferred Portfolio

	Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Resource Total 2012-2021
East													
	CCCT F 2x1	-	-	-	12	-	-	-	-	-	-	-	12
	CCCT G or H 1x1	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Coal Plant Turbine Upgrades	4	-	-	-	-	(18)	-	-	-	-	(2)	(20)
	Wind	-	-	-	-	-	-	-	(300)	(75)	25	(200)	(550)
	CHP - Biomass	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2	-	-	-	-	-	-	-	-	-	-	-	-
	Micro Solar Watering Heating	-	(3)	(3)	(3)	(3)	(3)	(3)	(3)	-	-	-	(18)
	Utah Capacity Purchase / FOT	-	-	(4)	(26)	(250)	-	(72)	(217)	-	(245)	-	
	Front Office Transactions	17	(151)	(264)	(264)	(68)	(25)	-	-	(4)	-	(246)	
West													
	Coal Plant Turbine Upgrades	-	-	8	-	-	-	-	(8)	-	-	-	-
	CHP - Biomass	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2	-	-	-	-	-	-	-	-	-	-	-	-
	Solar (Oregon)	-	-	-	-	-	-	-	-	-	-	-	-
	Micro Solar Watering Heating	-	(2)	(2)	(2)	(2)	(2)	(2)	(1)	-	-	-	(12)
	Front Office Transactions	(20)	56	26	161	392	117	146	285	138	345	314	
	Annual Additions, Long Term Resources	**4**	**(4)**	**4**	**7**	**(4)**	**(22)**	**(4)**	**(312)**	**(157)**	**25**	**(202)**	
	Annual Additions, Short Term Resources	**(3)**	**(95)**	**(241)**	**(129)**	**74**	**92**	**74**	**68**	**134**	**100**	**68**	
	Total Annual Additions	**2**	**(99)**	**(238)**	**(122)**	**69**	**70**	**69**	**(244)**	**(23)**	**125**	**(135)**	

Table 5.5 – 2012 Business Plan Portfolio, Detail Level

	Resource	Capacity (MW)																				Resource Totals	
		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2012-2021	2012-2030
East																							
	CCCT F 2x1 (Utah North, Utah South)	-	-	-	637	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,234	1,234
	CCCT G or H (Utah South)	-	-	-	-	-	-	-	-	393	-	-	-	-	-	-	358	-	-	-	-	393	751
	Intercooled Aero (Wyoming)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	86	86	-	-	171
	SCCT Aero (Utah)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	118	-	-	-	-	118	-	236
	Utah Capacity Purchase *	-	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	400	400
	Coal Plant Turbine Upgrades	16	19	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	21
	Wind, Wyoming, 35% Capacity Factor **	-	-	-	-	-	-	-	-	225	225	-	150	100	75	200	200	200	200	250	250	450	2,075
	Total Wind	-	-	-	-	-	-	-	-	225	225	-	150	100	75	200	200	200	200	250	250	450	2,075
	CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	19
	DSM, Class 1, Utah Cool Keeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1, Idaho DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	5	-	-	8	13
	DSM, Class 1, Utah, Curtailment	-	43	-	-	29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	71	71
	DSM, Class 1, Utah, DLC-Residential	-	22	-	-	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	85
	DSM, Class 1, Utah DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1 Total	**6**	**70**	**-**	**20**	**91**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**5**	**-**	**-**	181	186
	DSM, Class 2, Idaho	1	2	2	3	3	4	4	4	4	5	5	5	6	6	6	6	6	6	6	6	36	90
	DSM, Class 2, Utah	42	47	39	40	41	44	45	46	48	50	48	55	51	53	53	57	52	55	54	56	448	934
	DSM, Class 2, Wyoming	3	4	5	5	6	6	7	8	8	8	10	10	12	15	16	20	24	28	35	37	67	264
	DSM, Class 2 Total	**47**	**53**	**46**	**48**	**51**	**54**	**56**	**58**	**60**	**63**	**62**	**70**	**69**	**74**	**75**	**84**	**82**	**89**	**95**	**99**	550	1,288
	FOT Mead Q3 HLH ***	17	17	-	-	31	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	N/A
	FOT Mona-3 Q3 HLH ***	-	-	-	300	300	300	300	300	296	300	54	138	225	300	300	300	300	300	300	300	N/A	N/A
	FOT Mona-4 Q3 HLH ***	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	N/A
West																							
	Coal Plant Turbine Upgrades	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	42	80
	DSM, Class 1, Washington, DLC-Irrigation	-	-	2	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	DSM, Class 1, Oregon, Curtailment	-	-	36	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	36	36
	DSM, Class 1, Oregon, DLC-Irrigation	-	-	13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 1, California, DLC-Irrigation	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1 Total	**-**	**-**	**57**	**-**	**6**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	63	63
	DSM, Class 2, California	1	1	1	1	1	1	1	1	1	2	1	1	2	2	2	2	2	2	2	2	12	29
	DSM, Class 2, Oregon	53	53	56	61	62	61	60	52	52	52	52	52	52	52	52	52	44	36	36	36	562	976
	DSM, Class 2, Washington	7	8	8	8	8	8	8	8	8	8	9	10	10	10	10	8	8	8	8	9	81	162
	DSM, Class 2 Total	**61**	**61**	**65**	**70**	**71**	**70**	**70**	**62**	**62**	**62**	**63**	**63**	**64**	**65**	**65**	**63**	**54**	**46**	**46**	**46**	655	1,167
	OR Solar Capacity Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	OR Solar Incentive Program Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	FOT COB Q3 HLH ***	130	400	400	400	392	255	279	326	180	342	342	318	342	342	342	342	342	342	342	342	N/A	N/A
	FOT NOB Q3 HLH ***	-	100	100	100	100	-	-	100	-	100	-	100	100	100	100	100	100	100	100	100	N/A	N/A
	FOT MidColumbia Q3 HLH ***	-	400	338	261	400	312	317	309	353	354	372	308	296	280	393	216	344	358	396	395	N/A	N/A
	FOT MidColumbia Q3 HLH, price premium ***	-	27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	N/A
	Annual Additions, Long Term Resources	**339**	**213**	**191**	**783**	**227**	**726**	**131**	**350**	**745**	**130**	**280**	**239**	**213**	**344**	**463**	**710**	**342**	**481**	**482**	**269**		
	Annual Additions, Short Term Resources	**147**	**945**	**988**	**1,061**	**1,223**	**867**	**896**	**1,035**	**829**	**1,095**	**768**	**864**	**962**	**1,022**	**1,135**	**957**	**1,085**	**1,099**	**1,138**	**1,137**		
	Total Annual Additions	**486**	**1,158**	**1,178**	**1,844**	**1,450**	**1,593**	**1,027**	**1,385**	**1,574**	**1,225**	**1,047**	**1,103**	**1,175**	**1,365**	**1,598**	**1,667**	**1,427**	**1,580**	**1,620**	**1,405**		

* The three-year Utah Capacity Purchase began in August 2011 after the coincident system peak; capacity values are thus shown only for years 2012-2013. Annual capacity values are additive.

** Wind resources are shown in the year for which they contribute to meeting summer peak load requirements. In-service datas for 2012 Business Plan wins resources are November of the prior year. For example, the resources shown in 2019 (225 MW) have an in-service date of November 1, 2018.

*** Front Office Transaction (FOT) amounts reflect one-year transaction periods, and are not additive.

Table 5.6 – 2012 Business Plan Capacity Load and Resource Balance (13% Planning Reserve Margin)

Calendar Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
East										
Thermal	5,983	5,984	5,976	5,804	5,802	5,796	5,796	5,796	5,796	5,796
Hydroelectric	126	132	132	132	128	128	128	128	128	128
Class 1 DSM	329	329	329	329	329	329	329	329	329	329
Renewable	175	175	175	173	173	173	173	173	173	170
Purchase	905	804	304	304	116	116	116	116	116	91
Qualifying Facilities	79	94	94	94	94	236	236	236	236	236
Interruptible	281	281	281	281	281	281	281	281	281	281
Transfers	1,068	1,054	683	941	386	361	482	183	287	182
East Existing Resources	**8,946**	**8,853**	**7,974**	**8,057**	**7,308**	**7,420**	**7,541**	**7,241**	**7,345**	**7,213**
Combined Heat and Power	2	3	4	5	6	7	8	9	10	11
Class 1 DSM	65	65	85	176	176	176	176	176	176	176
Class 2 DSM	74	89	129	172	217	263	312	361	414	465
Front Office Transactions	17	150	300	331	300	300	300	296	300	54
Gas	0	0	637	637	1,234	1,234	1,234	1,627	1,627	1,627
Wind	0	0	0	0	0	0	0	12	24	24
East Planned Resources	**158**	**307**	**1,155**	**1,321**	**1,932**	**1,980**	**2,029**	**2,481**	**2,550**	**2,357**
East Total Resources	**9,105**	**9,161**	**9,129**	**9,378**	**9,241**	**9,400**	**9,570**	**9,723**	**9,896**	**9,570**
Load	6,993	7,151	7,403	7,611	7,468	7,727	7,882	8,034	8,195	8,360
Sale	1,147	1,045	745	745	745	659	659	659	659	179
East Obligation	**8,140**	**8,196**	**8,148**	**8,356**	**8,213**	**8,386**	**8,541**	**8,693**	**8,854**	**8,539**
Planning reserves (13%)	841	842	874	879	883	900	914	927	941	929
Non-owned reserves	98	98	98	133	133	106	106	106	106	106
East Reserves	**939**	**940**	**972**	**1,012**	**1,016**	**1,005**	**1,019**	**1,033**	**1,047**	**1,034**
East Obligation + Reserves	**9,079**	**9,136**	**9,120**	**9,368**	**9,230**	**9,391**	**9,560**	**9,726**	**9,901**	**9,573**
East Position	**26**	**24**	**9**	**10**	**11**	**9**	**10**	**(3)**	**(5)**	**(3)**
East Reserve Margin	**13.3%**	**13.3%**	**13.1%**	**13.1%**	**13.1%**	**13.1%**	**13.1%**	**13.0%**	**12.9%**	**13.0%**
West										
Thermal	2,517	2,529	2,529	2,529	2,524	2,505	2,505	2,505	2,505	2,505
Hydroelectric	882	851	872	877	878	877	864	819	650	650
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Renewable	88	88	88	88	88	88	88	88	88	88
Purchase	326	430	202	207	15	15	15	5	5	5
Qualifying Facilities	80	80	80	80	80	86	86	86	86	86
Transfers	(1,066)	(1,055)	(682)	(940)	(386)	(361)	(481)	(184)	(290)	(184)
West Existing Resources	**2,828**	**2,923**	**3,090**	**2,842**	**3,199**	**3,209**	**3,076**	**3,318**	**3,043**	**3,149**
Combined Heat and Power	8	13	17	21	25	29	34	38	42	46
Class 1 DSM	0	57	57	63	63	63	63	63	63	63
Class 2 DSM	29	43	59	76	93	109	123	138	153	168
Front Office Transactions	927	838	761	892	567	596	735	533	795	714
Solar	3	5	6	7	7	7	7	7	7	7
West Planned Resources	**968**	**955**	**900**	**1,059**	**755**	**805**	**963**	**780**	**1,061**	**999**
West Total Resources	**3,796**	**3,878**	**3,990**	**3,902**	**3,954**	**4,014**	**4,039**	**4,098**	**4,104**	**4,148**
Load	3,183	3,267	3,332	3,374	3,414	3,474	3,512	3,544	3,582	3,616
Sale	313	313	312	212	162	162	162	162	162	157
West Obligation	**3,496**	**3,580**	**3,644**	**3,586**	**3,576**	**3,636**	**3,674**	**3,706**	**3,744**	**3,773**
Planning reserves (13%)	288	288	333	305	369	371	356	386	355	367
Non-owned reserves	10	10	10	10	10	7	7	7	7	7
West Reserves	**298**	**298**	**344**	**316**	**379**	**377**	**362**	**392**	**361**	**374**
West Obligation + Reserves	**3,794**	**3,878**	**3,988**	**3,902**	**3,956**	**4,014**	**4,037**	**4,098**	**4,105**	**4,147**
West Position	**2**	**0**	**2**	**(0)**	**(1)**	**1**	**3**	**(0)**	**(1)**	**1**
West Reserve Margin	**13.1%**	**13.0%**	**13.1%**	**13.0%**	**13.0%**	**13.0%**	**13.1%**	**13.0%**	**13.0%**	**13.0%**
System										
Total Resources	**12,901**	**13,039**	**13,119**	**13,280**	**13,195**	**13,415**	**13,609**	**13,821**	**14,000**	**13,718**
Obligation	**11,635**	**11,776**	**11,792**	**11,942**	**11,789**	**12,022**	**12,215**	**12,399**	**12,598**	**12,313**
Reserves	**1,237**	**1,238**	**1,315**	**1,328**	**1,396**	**1,383**	**1,382**	**1,425**	**1,408**	**1,408**
Obligation + 13% Planning Reserves	**12,872**	**13,014**	**13,108**	**13,270**	**13,185**	**13,405**	**13,597**	**13,824**	**14,006**	**13,720**
System Position	**28**	**25**	**11**	**9**	**10**	**10**	**12**	**(4)**	**(6)**	**(2)**
Reserve Margin	**13.2%**	**13.2%**	**13.1%**	**13.1%**	**13.1%**	**13.1%**	**13.1%**	**13.0%**	**13.0%**	**13.0%**

Resource Strategies

Resource modeling and acquisition strategies for the resource types other than wind are summarized below.

Thermal Resources

PacifiCorp utilized the System Optimizer model to select the type and timing of projected proxy post-2014 gas-fired resources.[15] However, unlike the biennial IRP process, the process and schedule for the business plan does not allow for multiple simulations of varying load forecasts and other assumptions, stochastic model risk analysis or modeling of multiple potential futures vetted with public stakeholder feedback. As a result, the business plan resource portfolio leverages the results of the most recent filed IRP, recognizes substantive changes that have occurred since the IRP, and continues to seek a balanced outcome of stakeholder interests that maintains reliability at the lowest cost adjusted for risk. The gas resource options modeled for both the business planning and IRP processes are representative (or proxy) resources with forecasted capacity sizes, costs, and performance attributes that will differ from resources actually evaluated and acquired through PacifiCorp's procurement process.

The need for thermal resources in 2016 will also be reassessed in preparation for the bid evaluation phase of the Company's all-source RFP for 2016 resources (See Chapter 2). This resource needs assessment will include a revised load and resource balance that accounts for updated load forecasts and new DSM and FOT resource acquisition forecasts based on the outcome of revised Action Plan procurement-related activities. As required by the Public Utility Commission of Oregon in its recent PacifiCorp 2011 IRP acknowledgment order (issued March 9, 2012), the Company will request that the Commission schedule a discovery and comment period for IRP stakeholders subsequent to preparation of this additional resource needs assessment.[16]

Regarding coal turbine capacity upgrades, PacifiCorp canceled some of the projects due to capital constraints and concerns over environmental issues. The total project capacity stands at 33 MW for 2012-2021, whereas the 2011 IRP preferred portfolio included 53 MW for the same period.

Demand-side Management and Distributed Generation

As mentioned above, the 2011 IRP preferred portfolio's DSM resource additions were fixed in the 2012 Business Plan portfolio. This was intended to maintain acquisition target continuity for program procurement purposes.[17]

[15] PacifiCorp removed growth resources as capacity expansion options after 2020 in line with the modeling conducted for the 2011 IRP supplemental coal replacement study filed with the state commissions on September 21, 2011. As explained in the supplemental study, growth resources, which are ascribed costs derived from the Company's forward electricity price curves, do not accurately reflect the costs and risks associated with replacement resources requiring capital investment and ongoing fixed costs.

[16] See page 7 of Public Utility Commission of Oregon Order No. 12-082, Docket No. LC 52. The Oregon Commission's acknowledgment order is available for download at: http://apps.puc.state.or.us/orders/2012ords/12-082.pdf .

[17] A 2012 Business Plan System Optimizer run allowing optimization of DSM resource selection resulted in nearly the same amount of capacity as that included in the 2011 IRP preferred portfolio. For example, the DSM-optimized Business Plan portfolio had 2,589 MW of energy efficiency capacity for 2011-2030 versus 2,562 MW for the 2011 IRP preferred portfolio.

The solar water heating capacity identified in the 2011 IRP preferred portfolio was removed from the 2012 Business Plan portfolio given that the evaluation of program cost-effectiveness and implementation potential had not been started during business plan preparation, and thus a supportable and firm program budget could not be developed. The analysis of a solar water heating program is slated for 2012 as described in Action Item 1 of the revised IRP Action Plan.

Front Office Transactions

PacifiCorp relied on the System Optimizer model to select the type, quantity, and timing of front office transactions to maintain the annual planning reserve margin, subject to the annual capacity limits reported in Table 4.1. Similar to the representation of thermal source options, front office transactions represent a range of potential market products whose costs, amounts and timing will differ from resources actually evaluated and acquired through PacifiCorp's procurement process.

CHAPTER 6 – ACTION PLAN UPDATE

This chapter provides the updated IRP Action Plan. The Action Plan update is presented as Table 6.1. Action plan activities completed are summarized in Table 6.2.

Table 6.1 – IRP Revised Action Plan

Action Item	Category	Action(s)
1	**Renewables/ Distributed Generation**	**<u>Wind</u>** • Acquire cost effective wind resources to satisfy renewable portfolio standard requirements, diversify portfolio risk and reduce emissions. Incremental wind resource acquisition does not begin until the end of 2018 due to the need for incremental transmission capacity to be able to deliver remote resource generation to load and the associated in-service date of Energy Gateway West. Acquire 450 MW of incremental wind resources in 2019 and 2020. • In the next IRP, PacifiCorp will track and report the statistics used to calculate capacity contribution from its wind resources as a means of testing the validity of the PLCC method. • Future IRP cycles will include a projection for wind acquisition with and without geothermal until a clearer picture emerges regarding geothermal dry hole risk. • The Company will continue to refine the wind integration modeling approach; establish a technical review committee (TRC) and a schedule and project plan for the next wind integration study. The TRC will be formed and members identified within 30 days of the effective date of the [Oregon] IRP Order. Within 30 days of the effective date of the [Oregon] IRP Order, a schedule for the study will be established, including full opportunity for stakeholder involvement and progress reviews by the TRC that will allow the final study to be submitted with the next IRP. **<u>Geothermal</u>** • Continue to refine resource potential estimates and update resource costs in 2012 for further economic evaluation of resource opportunities. Continue to explicitly include geothermal projects as eligible resources in future all-source RFPs. **<u>Solar</u>** • Acquire additional Oregon solar resource through RFPs or other means in order to meet the Company's 8.7 MW compliance obligation. • Work with Utah parties to investigate solar program design and deployment issues and opportunities in 2012 as part of the Public Service Commission of Utah's investigative docket (No. 11-035-104) on expanding the Solar Incentive Program.[18] • Investigate, and pursue if cost-effective from an implementation standpoint, commercial/residential solar water heating programs. Program cost-effectiveness and targets will be evaluated as part of resource planning efforts to be conducted during 2012. • In the context of the Oregon solar RFPs, analyze the trade-offs between early and later acquisition of solar resources. **<u>Combined Heat & Power (CHP)</u>** • Pursue opportunities for acquiring biomass CHP resources, primarily through the PURPA Qualifying Facility contracting process. – The preferred portfolio contains 52 MW of CHP resources for 2012-2021 (10 MW in the east side and 42 MW in the west side).[19] **<u>Energy Storage</u>** • Proceed with an energy storage demonstration project, subject to Utah Commission approval of the Company's proposal to defer and recover expenditures through the demand-side management surcharge.

[18] Rocky Mountain Power, "Re: Docket No. 07-035-T14 – Three year assessment of the Solar Incentive Program", December 15, 2010.
[19] CHP resource opportunities will be evaluated as part of resource planning efforts to be conducted during 2012.

Action Item	Category	Action(s)
		• Conduct a study of grid flexibility for accommodating variable energy resources (VER) as part of the next IRP filing. The study will include the following elements: – Definition of and suggest metrics by which to measure flexibility (applicable to all flexibility resources including: thermal, demand response (DR), and storage). – An inventory of existing flexibility needs and the adequacy or capability of existing assets to meet them. – A projection of flexibility needs in the IRP timeframe to successfully integrate project VER additions. – A comparison of benefits and costs of obtaining flexibility from the range of flexibility resources (conventional thermal, DR, storage, etc). **Renewable Portfolio Standard Compliance** • Develop and refine strategies for renewable portfolio standard compliance in California and Washington. • PacifiCorp will expand the next IRP to include discussion of RPS compliance strategies and the role of REC sales and purchases. The Company will be selective in its discussion to avoid conflict between the IRP, RPS Implementation Plan and RPS Compliance Report.
2	**Intermediate / Base-load Thermal Supply-side Resources**	• Acquire a combined-cycle combustion turbine resource at the Lake Side site in Utah by the summer of 2014; the plant is proposed to be constructed by CH2M Hill E&C, Inc. (“CH2M Hill”) under the terms of an engineering, procurement, and construction (EPC) contract. This resource corresponds to the 2014 CCCT proxy resource included in the 2011 IRP preferred portfolio. • PacifiCorp will reexamine the timing and type of post-2014 gas resources and other resource changes as part of the 2012 business planning process and all-source bid evaluation for 2016 resources. The reexamination will include documentation of capital cost and operating cost tradeoffs between resource types. – Consider siting additional gas-fired resources in locations other than Utah. Investigate resource availability issues including water availability, permitting, transmission constraints, access to natural gas, and potential impacts of elevation. – Continue conducting the all-source RFP for potential acquisition of peaking/intermediate/baseload resources by the summer of 2016 to fill any remaining resource need indicated by an updated load and resource balance reflecting the results of DSM RFPs, acquisition of front office transactions, reserve margin sensitivity analysis, and other relevant information.
3	**Firm Market Purchases**	• Acquire economic front office transactions or power purchase agreements as needed through summer 2016. – Resources will be procured through multiple means, such as periodic mini-RFPs that seek resources less than five years in term, and bilateral negotiations. • Closely monitor the near-term and long-term need for front office transactions and adjust planned acquisitions as appropriate based on market conditions, resource costs, and load expectations. – Actively search for market options that could cost-effectively defer acquisition or construction of a 2016 CCCT resource.
4	**Plant Efficiency Improvements**	• Continue to pursue economic plant upgrade projects—such as turbine system improvements and retrofits—and unit availability improvements to lower operating costs and help meet the Company’s future CO_2 and other environmental compliance requirements.

Action Item	Category	Action(s)
		– Complete the remaining turbine upgrade projects by 2013, totaling an incremental 33.0 MW, subject to continuing review of project economics.[20] – Seek to meet the Company's updated aggregate coal plant net heat rate improvement goal of 478 Btu/kWh by 2019.[21] – Continue to monitor turbine and other equipment technologies for cost-effective upgrade opportunities tied to future plant maintenance schedules. • For the next IRP complete a study of cost-effective and reliable production efficiency opportunities at generating facilities (station load reduction opportunities not currently being captured in the IRP) where the Company has sole ownership of the facility. The resource opportunities identified will be modeled against competing demand and supply-side resources in the next IRP. Those selected will be targeted for completion by 2015 provided plant outages are not required.
5	**Class 1 DSM**	Acquire at least 140 MW of incremental cost-effective demand-side management resource by 2013 and up to 250 MW by 2015. – Finalize an agreement for the commercial curtailment product (which includes customer-owned standby generation opportunities). If cost effective, the company will file for approval by the 3rd quarter of 2012. – Complete an analysis of the economic feasibility of Class 1 irrigation load control in the west by the second quarter of 2012. If the analysis suggests Class 1 irrigation load control is economic in the west, the Company will source delivery of a program through a Request for Proposal concurrent with the re-sourcing of Class 1 irrigation load control program delivery in the east by the third quarter of 2012. – Issue an RFP in 2012 to re-procure the delivery of the Cool Keeper program following the 2013 control season. For the RFP, the Company will seek market approaches acceptable to Utah regulators to expand the program beyond its current level beginning in 2014.
6	**Class 2 DSM**	• Acquire at least 900 MW[22]and up to 1,800 MW of cost-effective Class 2 programs by 2020, equivalent to at least 4,533 GWh and up to 9,066 GWh. Acquire at least 520 MW and up to 1000 MW of cost-effective Class 2 DSM by 2016. – The Company filed the Utah and Washington residential home comparison report programs in March 2012. Investigate broader applications by the end of 2014 that can be implemented by 2016. – By 3rd quarter 2012 the Company will submit for commission approval a plan to acquire energy efficiency resources from the Company's Special Contract customers in Utah and Idaho that can be reliably verified and delivered by 2016, and will pursue those resources provided the Commissions in those states approve a cost-recovery mechanism for the plan. – The Company will seek to acquire all cost-effective resources that are available from the system-wide (except Oregon) RFP for residential and small commercial sector savings issued in March 2012. The cost effectiveness analysis will consider any adverse impact on the existing DSM programs. The results of the RFP will be known prior to the Company seeking acknowledgement of the final short list for the all-source RFP. The Company will promptly file for commission approvals to implement the cost-effective programs. • For the next IRP, prior to beginning modeling and screening of DSM, and as part of the public input process, provide an analysis of alternatives to the current supply curve bundling and ramping methods for modeling energy efficiency measures.

[20] The redline correction reflects updated project information for the approved 2012 Business Plan.
[21] *PacifiCorp Energy Heat Rate Improvement Plan*, April 2010.
[22] Adjusted to reflect 2011 IRP's initial MW contribution from Class 2 resources expected to be acquired in Oregon (reduces the MW contribution from Oregon from 562 MWs by 2020 to 283 MWs, a 279 MW reduction.

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<tr><th>Action Item</th><th>Category</th><th>Action(s)</th></tr>
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By the end of 2012 provide an analysis of the sufficiency of current staffing levels to achieve programmatic cost effective energy efficiency targets established in this plan.
Leverage the distribution energy efficiency analysis of 19 distribution feeders in Washington (conducted for PacifiCorp by Commonwealth Associates, Inc.) for analysis of potential distribution energy efficiency in other areas of PacifiCorp’s system provided the Company receives approval by the appropriate Commission for recovery of the study cost through the demand-side customer efficiency surcharge. (The Washington distribution energy efficiency study final report was completed December 26, 2011.)

Include in the 2013 IRP a detailed plan and schedule to implement cost-effective CVR in each state as approved by the state.
By May 1, 2012 the company will schedule a work shop in each of its major states with commission staff to present findings of the Washington CVR evaluation.
By the end of 2012 perform a high-level screening of 40 percent of its distribution circuits in each of the states to identify circuits where cost effective energy savings appears viable and detailed circuit study is warranted provided the Company receives approval by the appropriate Commission for recovery of the study cost through the demand-side customer efficiency surcharge.
By the end of 2013 perform a high-level screening of the remaining 60 percent of its distribution circuits in each of the states to identify circuits where cost-effective energy savings appear viable and detailed circuit study is warranted provided the Company receives approval by the appropriate state commission for recovery of the study cost through the demand-side customer efficiency surcharge.
In the 2013 IRP include the results of the CVR evaluation to date.

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<tr><td>7</td><td>Class 3 DSM</td><td>

During 2012 update the Conservation Potential Assessment to more accurately reflect Class 1 and 3 DSM resource opportunities in regards to 1) market and regulatory capabilities and climates in each state, 2) interactions within and between Class 1 and Class 3 resource potentials identified, and 3) the impact of existing Class 3 programs on product potential.
During 2012 have a third-party consultant review and prepare a report on how other utilities treat price-responsive products in their resource planning process (for example, as an adjustment to their load forecast and/or as a firm planning resource), and prepare a recommendation on how the Company might apply contributions from price products to help defer investments in other resource options cost-effectively.
For the 2013 IRP provide a sensitivity analysis, similar to portfolio development Case 31 in the 2011 IRP, that more accurately reflects incremental Class 3 product opportunities (incremental to Class 1 products, other Class 3 products, and to existing impacts of Class 3 products the Company is already running).
Implement in Utah and Washington (subject to regulatory approvals) residential information pilots to test the effects of providing customers greater amounts of usage information on the quantity of electricity they consume. The pilots will leverage the existing AMR metering currently available in these states.

Pilots will consist of three test groups each receiving varying levels of usage information:

Group 1 - Home comparison reports and energy conservation suggestions
Group 2 - Daily usage data through Home Energy Monitoring software (key component to pricing products)
Group 3 – Home comparison reports, energy savings suggestions, and daily usage data through Home Energy

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Action Item	Category	Action(s)
		Monitoring software Pilots will be implemented in 2012, run throughout 2013, and an analysis and recommendation prepared in 2014, prior to the development of the 2015 IRP. • If the analysis of Class 1 irrigation load control in the west (see action item 5) indicates that such programs are non-economic, investigate, through a pilot program in Oregon a Class 3 irrigation time-of-use program as an alternative approach for managing irrigation loads in the west.
8	**Planning and Modeling Process Improvements**	Incorporate plug-in electric vehicles and Smart Grid technologies as a discussion topic for the next IRP.
9	**Transmission**	In the scenario definition phase of the IRP process, the Company will address with stakeholders the inclusion of any transmission projects on a case-by-case basis. – Develop an evaluation process and criteria for evaluating transmission additions. – Review with stakeholders which transmission projects should be included and why. – Based on the outcome of these steps, PacifiCorp will provide appropriate transmission segment analysis for which the Company requests acknowledgement (including Wallula to McNary and Sigurd to Red Butte).
10	**Planning Reserve Margin**	As part of the updated resource needs assessment to be conducted for the all-source RFP, include the results of a System Optimizer portfolio sensitivity analysis comparing the resource and cost impacts of a 12 percent versus 13 percent planning reserve margin.

Table 6.2 – Completed Action Plan Activities

Action Item	Activity	Status
1 – Solar	Evaluate procurement of Oregon solar photovoltaic resources in 2011 via the Company's solar RFP.	The Company completed this action item. The Black Cap solar project (2 MW) near Lakeview, Oregon will begin construction in May, 2012 and be placed into service in October 2012.
1 – Energy Storage	Initiate a consultant study in 2011 on incremental capacity value and ancillary service benefits of energy storage.	PacifiCorp completed the energy storage study.
4 – Plant Efficiency Improvements	Successfully complete the dense-pack coal plant turbine upgrade projects scheduled for 2011 and 2012, totaling 31 MW.	The Company completed the planned turbine upgrade projects in the first quarter of 2012, totaling 19 MW.
6 – Class 2 DSM	Apply the 2011 IRP conservation analysis as the basis for the Company's next Washington I-937 conservation target setting submittal to the Washington Utilities and Transportation Commission for the 2012-2013 biennium. The Company may refine the conservation analysis and update the conservation forecast and biennial target as appropriate prior to submittal based on final avoided cost decrement analysis and other new information.	The 2012-2013 Washington Initiative 937 conservation plan and biennial targets based on the 2011 Integrated Resource Plan was filed on January 31, 2012 and is currently available for comment.
9 – Coal	The Company will include in its 2011 IRP update an updated Coal Replacement Study focusing on those units analyzed in a screening analysis.[23] – The updated Coal Replacement Study was performed using the System Optimizer model and will explore a range of natural gas prices and CO_2 costs in varying combinations. – The updated Coal Replacement Study	The Company completed the Coal Replacement Study, which is included as Appendix A of this document.

[23] As a condition for Oregon Commission acknowledgment of the 2011 IRP, the Company held a coal unit replacement analysis workshop for Oregon intervenors covered under the Commission's protective order in February 2011. The purpose of the workshop was to present results of a screening model intended for prioritization of coal units for the more robust analysis covered under this action item and presented as Appendix A. Details are provided in the revised IRP action plan filed with the Oregon Commission on January 9, 2012, which is available for download from the Oregon Commission's Web site: http://apps.puc.state.or.us/edockets/docket.asp?DocketID=16704. For the benefit of other state IRP stakeholders covered under commission protective orders, the Company is providing briefings on the screening model results subsequent to the filing of this 2011 IRP Update report.

Action Item	Activity	Status
	will discuss and evaluates flexibility in the emerging environmental regulations and the associated economics that may present options to the Company to avoid early compliance costs by offering to shut down certain individual units prior to the end of their currently approved depreciable lives. – In the updated Study, the Company will provide a concise explanation and transparent example of its treatment of post-2030 costs and will provide an analysis that shows the results of treatments of environmental investments made prior to 2015 both avoidable and unavoidable.	

REDACTED APPENDIX A – COAL REPLACEMENT STUDY UPDATE

Introduction

The 2011 IRP included a coal utilization sensitivity analysis designed to investigate, as a modeling proof-of-concept, the impacts of CO_2 cost and gas price scenarios on the existing coal fleet accounting for incremental capital investments required to meet emerging environmental regulations. These proof-of-concept sensitivities paved the way for the confidential coal replacement study, which was issued as a supplement to the 2011 IRP in September 2011.

The supplemental coal replacement study, reflecting design improvements and more current assumptions than those used in the coal utilization sensitivities, was performed using PacifiCorp's System Optimizer capacity expansion model (SO Model), which is traditionally used to evaluate least cost resource portfolios by adding new resources that can meet projected peak load obligations inclusive of a planning margin. The objective of the coal replacement study was to test how a range of commodity prices and CO_2 prices influence the economic tradeoffs that might cause coal resources to be displaced by replacement resources prior to the end of their currently approved depreciable lives. The supplemental coal replacement study has since been updated and a more detailed analysis has been performed on individual coal units. Specifically, the updated coal replacement study incorporates the following methodological advancements and assumption updates:

- A screening model was developed to prioritize more detailed analysis using the SO Model. Based on the results of this screening analysis, a present value revenue requirement differential (PVRR(d)) study was performed on eight specific coal units among a range of different scenarios.

- A broader spectrum of natural gas price and CO_2 price scenarios were developed for the more detailed unit specific analysis. In addition to a base case, two different natural gas price scenarios were analyzed assuming a base case view of CO_2 prices, two different CO_2 scenarios were analyzed assuming a base case view of natural gas prices, and an additional scenario was analyzed that pairs low natural gas prices with high CO_2 prices.

- Resource replacement options were expanded to include incremental wind resources, and where applicable, brown field gas conversion alternatives. The wind and gas conversion resource replacement options are in addition to the green field natural gas resource, front office transactions (FOTs), and demand side management (DSM) resource replacement options considered in the original coal replacement study.

- The SO Model was configured such that all incremental environmental investments planned for coal units that could be avoided in the event of early retirement and replacement or conversion to natural gas are excluded in the years preceding implementation of early retirement and replacement or conversion to natural gas decisions.

- A broad range of assumptions used in the updated coal replacement study have been updated consistent with those used in the business plan unless more current information was available. The assumptions updated include costs for incremental environmental capital investments, costs for coal unit run rate O&M, costs for coal unit run rate capital, costs for mining capital, and coal fuel costs.

Environmental Compliance for Coal Resources

Regulatory Backdrop

Chapter 2 of the 2011 IRP Update provides an overview of emerging environmental regulations, and the updated coal replacement study includes incremental coal resource capital investments for committed, planned, and proxy environmental compliance projects consistent with these emerging environmental regulations. The coal investments included in the updated coal replacement study are required to reduce emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_X), particulate matter (PM), mercury (Hg), and other pollutants to meet best available retrofit technology (BART) requirements under EPA's regional haze rules and EPA's recently promulgated MATS. Moreover, the coal investments included in the updated coal replacement study are expected to support compliance with increasingly more stringent NAAQS that have been and are continuing to be adopted for criteria pollutants.

As was done in the original coal replacement study, additional coal investment costs are included in the updated coal replacement study for additional selective catalytic reduction (SCR) projects not currently identified in the state implementation plans for regional haze.[24] While no Company commitments or agency actions have been taken that require installation of this expanded list of SCR projects, the costs have been included in the analysis to conservatively capture the effect of potentially significant incremental pollution control capital investments that could be required by environmental agencies. The updated coal replacement study also continues to include costs for emerging regulations of coal combustion byproducts (CCB) under the Resource Conservation and Recovery Act (RCRA) and cooling water intake structures under §316(b) of the Clean Water Act (316(b)).

Compliance Flexibility

PacifiCorp's efforts to explore environmental compliance flexibility have been primarily focused on the installation of controls to address BART requirements under the EPA's Regional Haze Rules. Of the 19 coal-fueled units operated by PacifiCorp, 14 are BART-eligible.[25] Through its involvement in the Western Regional Air Partnership, PacifiCorp worked with states, tribes, and federal agencies to develop and implement regional planning processes to improve visibility in

[24] This includes incremental SCR costs over the 2023 to 2026 timeframe at Hunter units 1-3, Huntington units 1-2, and Wyodak.
[25] PacifiCorp has an ownership interest in 26 coal-fueled units and operates 19 of those units. Among the 7 coal units in which PacifiCorp is not the operator, 4 units are BART-eligible.

national parks and wilderness areas in the western United States. PacifiCorp's early efforts, beginning in 1999, with state agencies in Utah and Wyoming led to the development of PacifiCorp's Comprehensive Air Initiative (CAI). The CAI was developed and has been executed with a focus on maintaining a reasonable balance between protecting the interests of customers, meeting the obligation to serve the current and reasonably projected demands of our customers, and complying with environmental requirements, all in the face of an uncertain regulatory environment. Particular examples of the flexibility applied to the CAI planning include the timing established for installation of SCR technology across its BART-eligible units, as well as PacifiCorp's efforts to appeal SCR requirements.

As part of its BART determination process, the Wyoming Department of Environmental Quality (WDEQ) required the installation of SCR and a bag house at Naughton Unit 3 by December 31, 2014, based on the unit's emissions and modeled visibility impacts. Because Wyoming was the first state to require SCR as BART, PacifiCorp appealed the WDEQ's decision to the Environmental Quality Council. In the appeal, a procedural schedule was set that would not have allowed the State of Wyoming to timely submit a State Implementation Plan; to avoid the imposition of a Federal Implementation Plan, PacifiCorp and the WDEQ ultimately agreed to settle the appeal in November 2010, clearing the path for the timely submittal of the Wyoming Regional Haze State Implementation Plan in January 2011. The EPA is under a consent decree to issue its preliminary determination to approve, disapprove, or partially approve/partially disapprove the Wyoming Regional Haze State Implementation Plan by May 15, 2012 and take final action by October 15, 2012.

An industry example of environmental compliance flexibility that is often presented as a basis for comparison is the Portland General Electric (PGE) Boardman facility. In assessing compliance flexibility in the context of a settlement such as that achieved by PGE at its Boardman facility, it is important to note that Boardman is a single unit facility with largely uncontrolled emissions. To provide a comparison to a BART-eligible facility within the PacifiCorp fleet, the Company's Naughton Unit 3 is part of a three-unit plant with common facilities and infrastructure to accommodate all three units. Existing emission controls at Naughton Unit 3 include a scrubber, low-NO_X burners, an electrostatic precipitator (ESP) and a flue gas conditioning system. Table A.1 below reflects some of the key distinctions between the Boardman facility and Naughton Unit 3 that would ultimately impact environmental compliance flexibility decision-making.

Table A.1 – Distinctions between Boardman and Naughton Unit 3 that would Impact Compliance Flexibility

Description	Boardman	Naughton 3
Facility size	Approximately 600 MW, single unit	Unit 3 is a 330 MW unit; there are three units at the plant, with a total capacity of 700 MW
Existing controls	First generation low-NO_X burners, ESP	Wet scrubber (installed in 1997); low-NO_X burners (installed in 1999); ESP and flue gas conditioning system
Litigation drivers	Sierra Club lawsuit EPA New Source Review Notice of Violation	None
Assumed plant/unit life	2040 with controls (i.e., 30 years of operation)	Current depreciation life 2029 (costs of controls calculated over 20 years)

Despite the current requirement under the submitted Wyoming Regional Haze State Implementation Plan to install SCR and a bag house at Naughton Unit 3 by December 31, 2014, PacifiCorp's updated coal replacement study includes evaluation of additional compliance scenarios to avoid the equipment installation and, thus, the capital investment. Due to Naughton Unit 3's NO_X emissions profile and its modeled impacts on Class I areas, even under an alternate compliance scenario, NO_X emission reductions from Unit 3 are likely to be required by the EPA, at the latest, within five years from the date the State Implementation Plan is approved or EPA implements a Federal Implementation Plan. Fuel switching to natural gas may be a potential solution as an alternative compliance strategy. Any alternative compliance strategy would be subject to approval by the WDEQ through a permit amendment, an amendment to the SCR and baghouse appeal settlement agreement between the Company and WDEQ before the Environmental Quality Council, amendment of the Wyoming Regional Haze State Implementation Plan, and acceptance by the EPA. Under a gas conversion scenario, because it would be contemplated that no add-on NO_X controls such as SCR or SNCR be included, the overall NO_X benefit is limited.

The pursuit of BART compliance flexibility and deferred requirements and associated controls for any unit is complicated by the additional requirement to comply with the EPA's recently promulgated MATS rules by April 2015. For example, without the bag house project discussed above, Naughton Unit 3 is unlikely to be able to comply with the non-mercury metals (with particulate matter as a surrogate) emissions limits on its own. At Naughton, PacifiCorp is currently assessing its ability to utilize emissions averaging provisions under the MATS; such a scenario contemplates the averaging of emissions at Naughton Unit 3 with Units 1 and 2 to achieve the required emission limits for mercury, acid gases and non-mercury metals through their established surrogates. It is likely that, regardless of the ability to utilize an emissions-averaging plan, the Naughton Unit 3 would have to be de-rated to achieve compliance with the particulate matter limits without installation of a bag house.

Entities may ultimately have the ability to, at the discretion of the Title V permitting authority and for cause shown, to obtain a compliance extension of up to a year under the MATS; any additional compliance extension past April 2016 for up to another year is subject to a rigorous review establishing the unit as a reliability-critical unit. PacifiCorp will also be assessing its facilities' MATS compliance plans against this compliance flexibility provision.

Coal Replacement Study Approach

Screening Analysis

The updated coal replacement study provides a more in-depth analysis of specific coal units in PacifiCorp's coal fleet than the original study issued September 2011. A screening model was developed to prioritize which units to include in this detailed unit specific analysis, focusing on the 18 BART-eligible coal units in which the Company has an ownership interest.[26] The screening model is a spreadsheet based analysis tool that compares the market value of energy netted against the operating and capital revenue requirement for a given coal unit with the market value of energy netted against the operating and capital revenue requirement for a proxy natural gas replacement resource. For screening purposes, the proxy natural gas replacement resource was assumed to be a gas-fired combined CCCT plant scaled to the size of the coal unit being analyzed.

For each of the 18 BART-eligible units analyzed, the energy revenues net of costs for the coal unit were netted against the revenues net of costs for the proxy CCCT resource. For each unit and among a range of natural gas price and CO_2 price scenarios, the relative economics between the coal unit and proxy CCCT resource were reported on a nominal levelized dollar per kilowatt month basis and ranked.[27] Those units whose ranking consistently showed less favorable economics relative to the proxy CCCT were identified as candidates for inclusion in the detailed unit-specific analysis to be performed with the SO Model. Based upon the results of this screening analysis, with consideration given to the timing of when incremental environmental capital investment decisions must be made, eight coal units were chosen to be analyzed using the SO Model. Combined, the incremental investment costs required or reasonably anticipated for these units account for nearly 87 percent of the incremental environmental investments planned among all 26 units in the PacifiCorp coal fleet through 2017. The units chosen for more detailed analysis and the types of investments required are summarized in Table A.2.

[26] PacifiCorp operates 19 coal units, and 14 of these units are BART eligible (Naughton 1-3, Jim Bridger 1-4, Dave Johnston 3-4, Wyodak, Hunter 1-2, and Huntington 1-2). There are 7 additional coal units in which PacifiCorp has an ownership interest, but is not the operator, and 4 of these units are BART eligible (Craig 1-2, Hayden 1-2).

[27] For screening purposes, a limited number of natural gas and CO_2 price scenarios that inherently show downside risk to coal investments were analyzed. Additional natural gas price and CO_2 price scenarios, discussed later in this Appendix, were analyzed for the more detailed modeling performed using the SO Model. These scenarios consider both downside and upside risk to coal investments.

Table A.2 – Units Analyzed in the Updated Coal Replacement Study

Coal Unit	Committed/Required Investments (In-service Year)	Other Investments Planned but not Committed (In-service Year)
Naughton Unit 3	SCR (2014) Bag House (2014) Mercury (2014)	CCB (2013, 2015, 2017) 316(b) (2017)
Jim Bridger Unit 3	SCR (2015) Mercury (2014)	CCB (2013, 2014, 2015, 2019) 316(b) (2017)
Jim Bridger Unit 4	SCR (2016) Mercury (2014) Scrubber Upgrade (2012)	CCB (2013, 2014, 2015, 2019)
Hunter Unit 1	Bag House (2014) Mercury (2012) Low NO_X Burner (2014)	SCR (2026) CCB (2016, 2020, 2021) 316(b) (2017)
Craig Unit 1	SNCR (2017)	CCB (2019, 2020)
Craig Unit 2	SCR (2016)	CCB (2019, 2020)
Hayden Unit 1	SCR (2015)	CCB (2014, 2020)
Hayden Unit 2	SCR (2016)	CCB (2014, 2020)

System Optimizer Model Simulations

In the updated coal replacement study, unit specific analysis requires two SO Model simulations to establish a PVRR(d) among a range of natural gas price and CO_2 price scenarios – an optimized simulation and a change case simulation. In the optimized simulation, the SO Model determines the least cost resource portfolio. In its determination of the least cost resource portfolio, the SO Model considers whether continued operation of each coal unit inclusive of incremental investments is lower cost than avoiding certain incremental coal investments achieved through either early retirement and replacement or conversion to natural gas. In the change case simulation, the SO Model is forced to produce a suboptimal resource portfolio by not allowing it to make the preferred decision from the optimized simulation for the specific unit being studied.

For instance, if an optimized simulation chooses to continue to operate a coal unit and incur costs for incremental investments planned for that unit, the change case simulation would force that unit to avoid the incremental coal investments and choose the lowest cost replacement resource alternative. Conversely, if an optimized simulation chooses to avoid incremental coal investments and replaces a unit with a resource alternative (or alternatives), the change case simulation would force that unit to continue to operate inclusive of any incremental planned coal investments. The difference in system costs between the two portfolios for any given natural gas price and CO_2 price scenario establishes the PVRR(d) and indicates how favorable or unfavorable incremental environmental capital investments committed or planned for coal each coal unit are in relation to the next best alternative.

Optimized simulations were performed among six different natural gas price and CO_2 price scenarios, which are described in more detail later in this appendix, and therefore, six different optimized simulations were completed using the SO Model. For the optimized simulations, the SO Model was configured such that all of the coal units operated by PacifiCorp could:

(1) Continue to operate and incur operating expenses and capital revenue requirement expenses inclusive of incremental environmental investments;

(2) Retire before the end of their currently approved depreciable lives given available replacement resource alternatives, or;

(3) Where applicable, convert to natural gas as a compliance alternative to the incremental environmental investments planned for the unit as a coal-fueled facility.

With this configuration, results from the optimized simulations show, for all of the coal units operated by PacifiCorp, whether early retirement and replacement or conversion to natural gas is the least cost alternative among a range of natural gas price and CO_2 price scenarios. However, results from the optimized simulations alone do not produce a PVRR(d), which identifies the magnitude of the change in cost resulting from early retirement or gas conversion alternatives. The change case simulations, performed for those units identified through the screening analysis as described above, are required to produce the PVRR(d) for each natural gas price and CO2 price scenario.

Because PacifiCorp does not have unilateral rights to retire early or convert to natural gas the coal units it does not operate, the SO Model was configured to not allow early retirement and replacement or gas conversion for these units in the optimized simulations. This includes the Craig and Hayden units chosen for the more detailed PVRR(d) analysis, and was implemented to ensure the PVRR(d) results for those units we do operate are not influenced by potential early retirement and replacement decisions that PacifiCorp cannot unilaterally control. Therefore, all change case simulations required to establish the PVRR(d) for the Craig and Hayden units force early retirement. Table A.3 summarizes how the SO Model simulations were structured for the updated coal replacement study.

Table A.3 – Structure of SO Model Simulations

Coal Units	Treatment in Optimized Simulations	Treatment in Change Case Simulations	PVRR(d) Analysis
Naughton 3, Jim Bridger 3&4, Hunter 1	Endogenous Early Retirement/Replacement or Conversion to Gas	Forced Suboptimal	Yes
Craig 1&2, Hayden 1&2	No Early Retirement/Replacement or Conversion to Gas	Forced Early Retirement/Replacement	Yes
Operated by PacifiCorp, but not selected through screening analysis	Endogenous Early Retirement/Replacement or Conversion to Gas	Endogenous Early Retirement/Replacement or Conversion to Gas	No
Not Operated by PacifiCorp, and not selected through screening analysis	No Early Retirement/Replacement or Conversion to Gas	No Early Retirement/Replacement or Conversion to Gas	No

Replacement Resource Alternatives

The updated coal replacement study allows a range of resource replacement options and compliance alternatives. As in the original coal replacement study, the updated analysis allows green field natural gas resources, FOTs, and DSM resources as replacement alternatives. In addition, the updated coal replacement study allows incremental wind resources to fill capacity requirements in the case of an early retirement for any given coal unit.[28] In addition to these resource replacement alternatives, a brown field gas conversion alternative has been included as compliance alternative for those units identified in the screening analysis that are operated by PacifiCorp. Gas conversion compliance alternatives were not developed and made available for the Craig and Hayden units because PacifiCorp does not have the ability to unilaterally pursue this compliance option. Moreover, the Colorado Public Utility Commission has approved Excel Energy's emission reduction plan to install NO_X controls on both Hayden units. Excel Energy developed their emissions reduction plan under Colorado's Clean Air-Clean Jobs Act enacted in April 2010. Table A.4 summarizes the resource replacement and gas conversion alternatives assumed in the updated coal replacement study.

[28] To ensure compliance with renewable portfolio standard obligations and to maintain the risk profile of the 2011 IRP Update resource portfolio, wind resources can be added in excess of those identified in the 2011 IRP Update resource portfolio.

Table A.4 – Timing and Availability of Replacement Resource Alternatives

Coal Unit	Assumed Compliance Date	Gas Conversion In-service Date	Green Field Natural Gas	DSM	FOTs	Incremental Wind
Naughton 3	12/31/2014	3/1/2015	Peaking (6/1/2015) CCCT (6/1/2016)	1/1/2015	1/1/2015	1/1/2015
Jim Bridger 3	12/31/2015	3/1/2016	Peaking (6/1/2016) CCCT (6/1/2016)	1/1/2016	1/1/2016	1/1/2016
Jim Bridger 4	12/31/2016	3/1/2017	Peaking (6/1/2017) CCCT (6/1/2017)	1/1/2017	1/1/2017	1/1/2017
Hunter 1	12/31/2014	3/1/2015	Peaking (6/1/2015) CCCT (6/1/2016)	1/1/2015	1/1/2015	1/1/2015
Craig 1	12/31/2017	n/a	Peaking (6/1/2018) CCCT (6/1/2018)	1/1/2018	1/1/2018	1/1/2018
Craig 2	12/31/2016	n/a	Peaking (6/1/2017) CCCT (6/1/2017)	1/1/2017	1/1/2017	1/1/2017
Hayden 1	12/31/2015	n/a	Peaking (6/1/2016) CCCT (6/1/2016)	1/1/2016	1/1/2016	1/1/2016
Hayden 2	12/31/2016	n/a	Peaking (6/1/2017) CCCT (6/1/2017)	1/1/2017	1/1/2017	1/1/2017
All other units operated by PacifiCorp	12/31/2014	n/a	Peaking 6/1/2015 CCCT 6/1/2016	1/1/2015	1/1/2015	1/1/2015

Coal Investment Costs

Investment costs considered in the updated coal replacement study would achieve compliance with emerging environmental regulations including proxy compliance costs for incremental SCR installations and for CCB and 316(b) projects. Cost assumptions for CCB projects continue to assume proposed requirements under subtitle D of RCRA will be established in 2012, and cost assumptions for 316(b) projects are based on proposed rules that would require modifications to existing electric generating plant cooling water intake structures that have a design capacity of more than two million gallons per day from surface waters to reflect the best technology available for minimizing adverse impacts on aquatic organisms.

Redacted Table A.5 below compares the amount of incremental investment costs included in the updated coal replacement study to the investment cost assumptions included in the original coal replacement study over the period 2012 through 2030. The updated assumptions are based upon the committed and planned investments in the business plan supplemented with the most current information available.

Redacted Table A.5 – Incremental Coal Investment Cost Assumptions, 2012 - 2030 ($ Million)

Description	2011 IRP Supplemental Coal Replacement Study	Updated Coal Replacement Study
Committed SO_2, NO_X, and PM project costs	XX	XX
Hg and MATS project costs	XX	XX
Incremental SCR NO_X project costs	XX	XX
CCB project costs	XX	XX
316(b) project costs	XX	XX
Total cost	XX	XX

Treatment of Post-2030 Costs

As with all capital costs evaluated in the IRP, incremental environmental capital cost inputs to the SO Model are converted to real levelized revenue requirement costs. Use of real levelized revenue requirement costs is an established and preferred methodology to account for analysis of capital investment decisions that have unequal lives and/or when it is not feasible to capture operating costs and benefits over the entire life of any given investment decision. To achieve this, the real levelized revenue requirement method spreads the return of investment (book depreciation), return on investment (equity and debt), property taxes and income taxes over the life of the investment. The result is an annuity or annual payment that grows at inflation such that the present value revenue requirement (PVRR) is identical to the PVRR of the nominal annual requirement when using the same nominal discount rate. For purposes of the coal replacement study and general IRP modeling, the PVRR is calculated inclusive of real levelized capital revenue requirement through the end of the 2030 planning period to align costs with the period over which benefits from the investment are realized.

Table A.6 provides inputs for a hypothetical calculation using the real levelized revenue requirement methodology for two different capital investment options. Investment A represents a $100m environmental capital investment for a 150 megawatt existing coal unit. For this example, it is assumed that the investment is placed in service by 2017 and that the existing coal unit has a currently expected depreciable life ending 2036. Investment B represents a 150 megawatt new $200m natural gas resource with a 2017 in service date and 30 year life. While hypothetical, the two investment alternatives are consistent with the type of investment tradeoffs being considered in the SO Model for the updated coal replacement study.

Table A.6 – Assumptions for a Real Levelized Revenue Requirement Calculation Applied to Two Different Hypothetical Investment Alternatives

Description	Investment A Incremental Coal Investment	Investment B Resource Replacement Investment
Resource size (MW)	150	150
Transfer to in-service cost ($m)	$100	$200
Transfer to in-service year ($m)	2017	2017
Book life (years)	20	30
Tax depreciation	20-year MACRS	20-year MACRS
Inflation rate	1.9%	1.9%
Nominal discount rate	7.154%	7.154%
Real discount rate	5.156%	5.156%

Using this example, the relationship in the PVRR between investments A and B over three different time periods is considered:

(1) Through the end of 2030, consistent with the IRP and the updated coal replacement study;

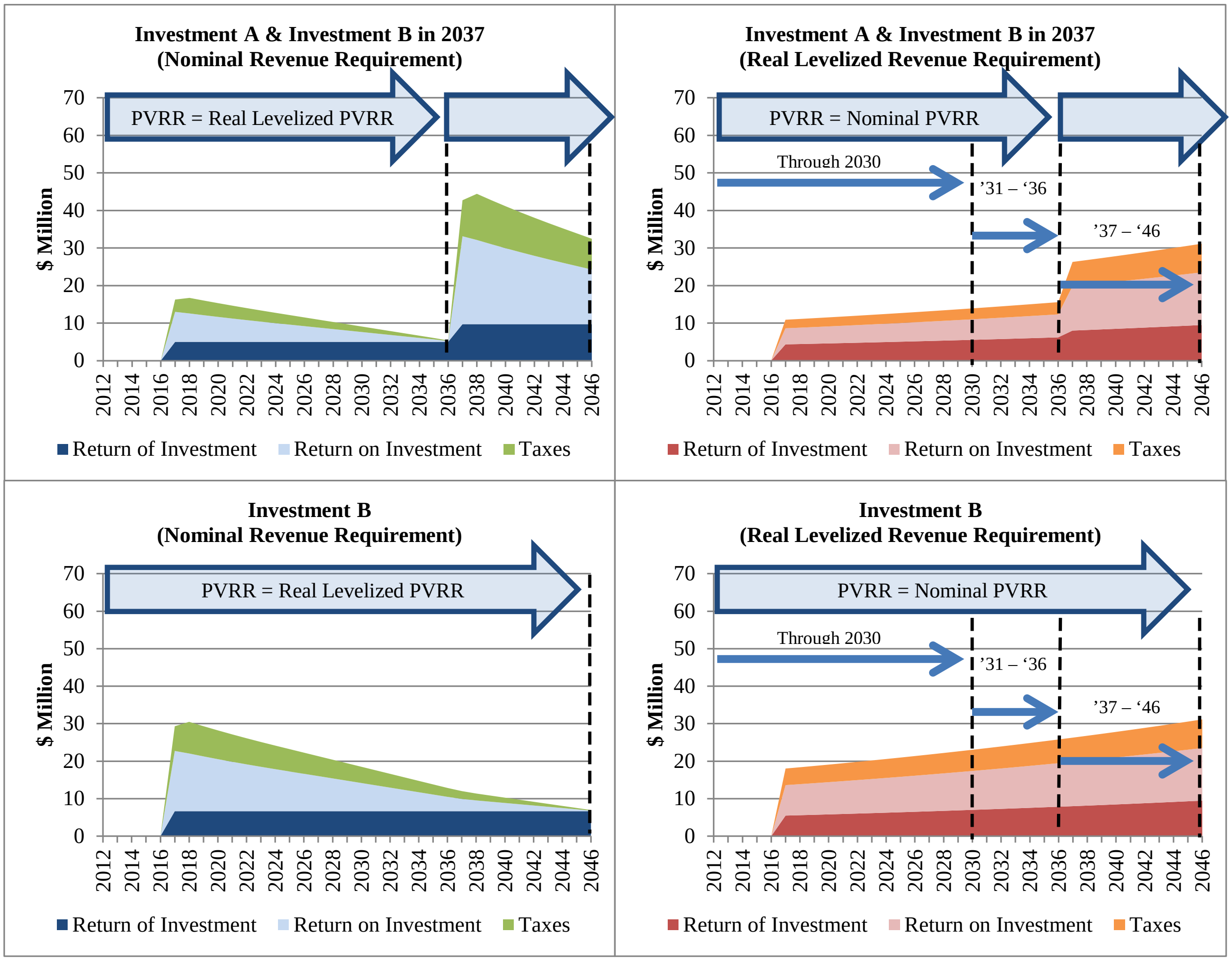
(2) Over the period 2031 to 2036, representing an extension to reach the end of the assumed life for investments in coal (investment A); and

(3) Over the period 2037 to 2046, representing an extension to reach the end of the assumed life for an investment in a natural gas resource alternative (investment B).

When comparing investments A and B through the end of 2046, we assume that investment A is supplemented by an incremental investment in 2037 to replace the capacity lost when investment A reaches the end of its assumed life. For this example, we will assume that investment A is replaced with a gas resource identical to investment B adjusted for inflation to account for the 2037 installation date. In working through this example, the revenue requirement is calculated for each alternative.

The nominal revenue requirement for investments A and B are comprised of the return of investment, return on investment, and taxes. The first year real levelized revenue requirement can also be quantified using the assumed real discount rate to calculate the annual payment required to achieve the same PVRR as the nominal revenue requirement over the life of each investment alternative. Figure A.1 shows the annual nominal revenue requirement and the annual real levelized revenue requirement, escalating at the rate of inflation, for hypothetical investment alternatives A and B. Note, as depicted in the figure, that the PVRR of the annual real levelized revenue requirement is equal to the PVRR of the annual nominal revenue requirement when calculated over the full life of investments A and B. Figure A.1 further depicts the three different PVRR time periods discussed above.

Figure A.1 – Annual Nominal and Real Levelized Revenue Requirement for Hypothetical Investment Alternatives A and B



The real levelized revenue requirement methodology is routinely used to circumvent the challenges of comparing costs for investments that have different lives because it places each investment alternative on equal footing by aligning capital revenue requirement costs with the period over which benefits from the investment are realized. This is demonstrated in Table A.7, which shows that when using the real levelized methodology, the PVRR of investment alternative A is precisely 60 percent of the cost of investment alternative B regardless of whether the PVRR term ends in 2030 or is extended to 2036 to reach the end of life assumed for the investment made on the coal unit (investment A). In other words, considering capital costs alone, the decision to make investments in the coal unit (investment A) would be the same regardless of whether the PVRR term were kept at 2030 or extended to 2036. Further, Table A.7 shows that costs over the period 2037 through 2046 are identical between the two investment alternatives (and would remain so beyond 2046).

Table A.7 – Comparison of the PVRR Relationship between Investments Alternatives A and B Using the Real Levelized Revenue Requirement Method

Year	Investment A & Investment B in 2037 Real Levelized Revenue Requirement ($m)	Investment B in 2017 Real Levelized Revenue Requirement ($m)	Investment A & Investment B in 2037 as a Percentage of Investment B in 2017 ($m)
2012	$0.00	$0.00	n/a
2013	$0.00	$0.00	n/a
2014	$0.00	$0.00	n/a
2015	$0.00	$0.00	n/a
2016	$0.00	$0.00	n/a
2017	$10.89	$18.04	60%
2018	$11.10	$18.39	60%
2019	$11.31	$18.73	60%
2020	$11.53	$19.09	60%
2021	$11.75	$19.45	60%
2022	$11.97	$19.82	60%
2023	$12.20	$20.20	60%
2024	$12.43	$20.58	60%
2025	$12.66	$20.97	60%
2026	$12.90	$21.37	60%
2027	$13.15	$21.78	60%
2028	$13.40	$22.19	60%
2029	$13.65	$22.61	60%
2030	$13.91	$23.04	60%
2031	$14.18	$23.48	60%
2032	$14.45	$23.93	60%
2033	$14.72	$24.38	60%
2034	$15.00	$24.85	60%
2035	$15.29	$25.32	60%
2036	$15.58	$25.80	60%
2037	$26.29	$26.29	100%
2038	$26.79	$26.79	100%
2039	$27.30	$27.30	100%
2040	$27.82	$27.82	100%
2041	$28.34	$28.34	100%
2042	$28.88	$28.88	100%
2043	$29.43	$29.43	100%
2044	$29.99	$29.99	100%
2045	$30.56	$30.56	100%
2046	$31.14	$31.14	100%

PVRR of Real Levelized Investment Costs over Varying Time Periods ($m)

2012 - 2030 PVRR	$79.47	$131.63	60%
2031 - 2036 PVRR	$20.26	$33.55	60%
2037 - 2046 PVRR	$37.66	$37.66	100%

Cost Recovery

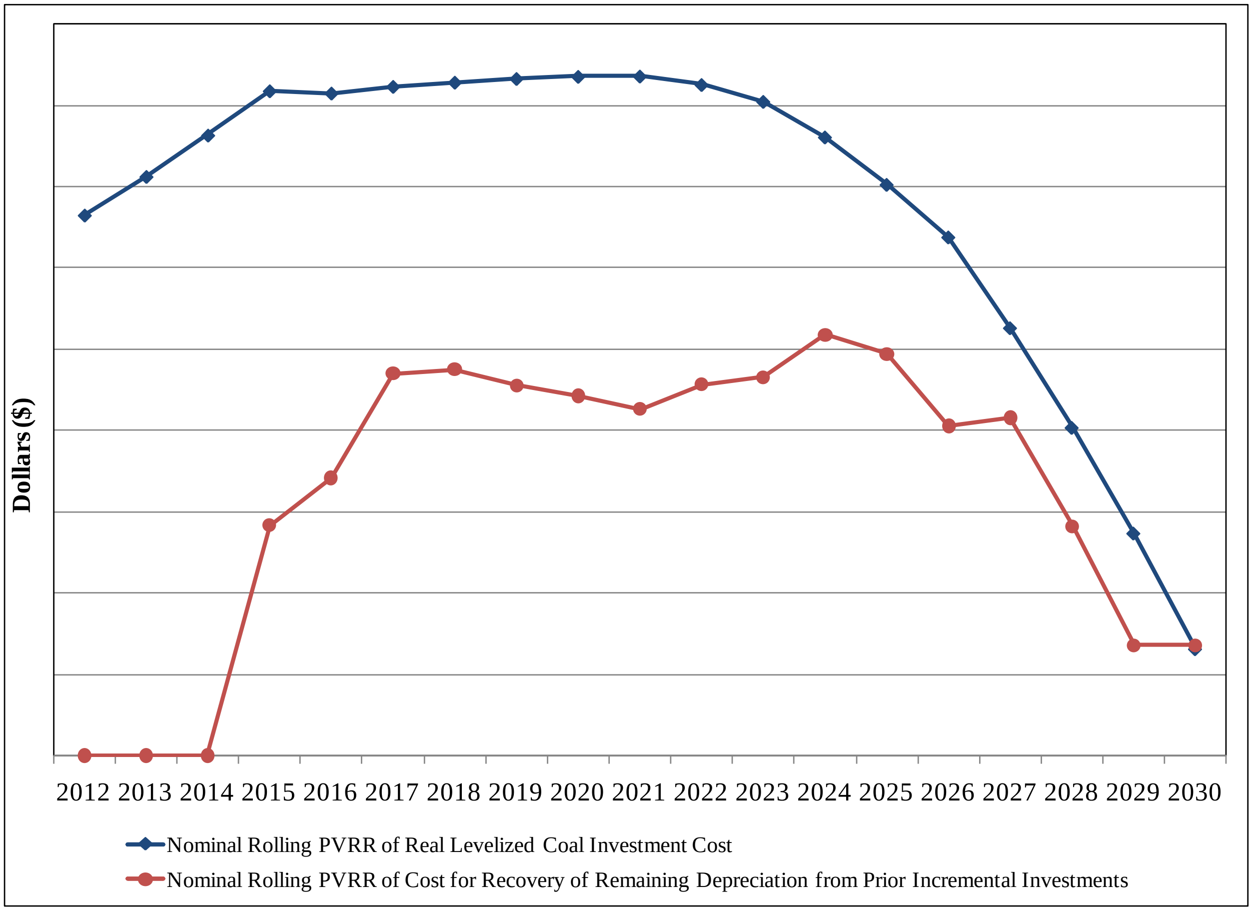
Costs for recovery of investments that were made or substantially completed prior to 2012 are not included in the updated coal replacement study because these costs are independent of the forward looking decision to make incremental environmental capital investments in coal resources. However, when analyzing the tradeoffs between making incremental environmental capital investments in coal resources and the potential alternatives of early retirement and replacement or conversion to natural gas, it is important to include recovery of costs for incremental capital investments made prior to the early retirement or gas conversion date. It is equally important to exclude the recovery of costs for incremental environmental capital investments that could otherwise be avoided in the event of early retirement and resource replacement or fuel conversion.

Redacted Figure A.2 shows how costs associated with incremental coal investments planned for SO_2, NO_X, PM, Hg, CCB, and 316(b) projects compare with costs for the recovery of prior incremental investment costs at any given point in time through the 2030 study period. The up-front capital for coal investment costs are converted to a real levelized cost consistent with the treatment of all capital costs in the System Optimizer model and as discussed in the preceding section. The nominal PVRR of these real levelized investment costs in any given year represents the cost of capital from that year through the end of the planning period in 2030 if investments are made and the coal resource is not retired early or converted to natural gas. The nominal PVRR of costs for the recovery of any remaining depreciation expense in any given year represents the recovery of costs for incremental investments made prior to that year. These are costs that would be incurred if future incremental investments are not made and coal resources are retired early or converted to natural gas in that year. The difference between these two streams of costs at any given point in time represent the capital cost tradeoff between making incremental coal investments and foregoing those investments in favor of early retirement or conversion to natural gas.

For example, as shown in Redacted Figure A.2, the PVRR of the remaining real levelized cost to make incremental coal investments across the fleet is approximately XX in 2014. At this point in time, there is no cost for recovery of investments made in prior years because these investments could be avoided in the event of early retirement and replacement or conversion to natural gas.[29] However, in 2020 the PVRR of the remaining real levelized cost to make incremental coal investments across the fleet is approximately XX. Early retirement and replacement or conversion to natural gas in 2020 would result in approximately XX of PVRR costs associated with the recovery of investments made prior to 2020 since these investments could not have been avoided in order to achieve compliance with emerging environmental regulations. This cost differential captures the timing tradeoff between decisions to either make incremental environmental capital investments in coal resources or move forward with early retirement and replacement or gas conversion alternatives.

[29] The PVRR of the annual real levelized revenue requirement cost that would be incurred over the period 2012 through 2015 assuming all incremental environmental investments in coal resources are made as planned equals approximately 3.7 percent of the PVRR of the annual real levelized revenue requirement cost over the period 2012 through 2030.

Redacted Figure A.2 – Annual Incremental Coal Resource Investment Cost vs. Annual Cost for Recovery of Investments Made in Prior Years



Decommissioning

As in the original coal replacement study, the updated coal replacement study includes the cost for decommissioning in the event of early retirement and resource replacement. Decommissioning expenses are assumed to be incurred in the year a unit is taken out of service. In this way, the PVRR for decommissioning expenses included in the updated coal replacement study captures the time value of money differential between decommissioning costs incurred sooner, in the event of early retirement and resource replacement, and decommissioning costs that would have otherwise been incurred at the end of a coal units currently approved depreciable life. Decommissioning expenses for gas conversion alternatives are not accelerated because the underlying asset largely remains intact. For gas conversion resource alternatives, decommissioning expenses are assumed to incur at the end of the currently approved depreciable life that is assumed for the coal unit that is being converted.

Natural Gas and CO_2 Scenarios

The updated coal replacement study was completed using the December 2011 official forward price curve as the base case. The base case December 2011 official forward price curve assumes that CO_2 prices begin at $16 per ton in 2021 and escalate at three percent above inflation thereafter. Five additional scenarios were developed to explore how results in the updated coal replacement study are affected by varying levels of gas price and CO_2 price assumptions. Two scenarios explore low and high natural gas price variations to the base case, and two scenarios explore low and high CO_2 price assumptions, accounting for any natural gas price response from changes in electric sector natural gas demand.[30] The fifth scenario combines high CO_2 price assumptions with a low natural gas price outlook adjusted to account for any natural gas price response due to changes in electric sector natural gas demand.

The scenarios were developed by first selecting low and high natural gas and CO_2 price forecasts that are consistent with the range in prices projected by third party sources. The resulting combinations of CO_2 and natural gas price assumptions were then used to develop a consistent set of electricity price forecasts.[31] Table A.8 summarizes the natural gas and CO_2 price scenarios used for the updated coal replacement study, with the scenario description indicating the first year CO_2 price assumption.

Table A.8 – Natural Gas and CO_2 Price Scenarios

Description	Natural Gas Prices	CO_2 Prices
Base Case, \$16 CO_2	Base Case (December 2011 FPC)	\$16/ton in 2021, escalating at 3% plus inflation
Low Gas, \$16 CO_2	Low	\$16/ton in 2021, escalating at 3% plus inflation
High Gas, \$16 CO_2	High	\$16/ton in 2021, escalating at 3% plus inflation
Base Gas, Zero CO_2	Base Case Adjusted for Price Response	No CO_2 costs
Base Gas, \$34 CO_2	Base Case Adjusted for Price Response	\$34/ton in 2018, escalating at 5% plus inflation
Low Gas, \$34 CO_2	Low Case Adjusted for Price Response	\$34/ton in 2018, escalating at 5% plus inflation

The low and high natural gas and CO_2 price assumptions serve as bookends around the base case December 2011 forward price curve. The range in low and high price assumptions were based upon the range of recent third party forecasts for both Henry Hub natural gas and CO_2 prices. Figure A.3 shows the base case, low, and high Henry Hub natural gas price assumptions against third party price projections. The low natural gas price forecast is tied to a third party low price scenario, which is characterized by strong and price resilient shale gas supply growth and stagnant exports of liquefied natural gas. The high natural gas price forecast is a blend of third party price scenarios. A blend of these two forecasts was used to impute some conservatism to the upside price scenario recognizing that most extreme high forecast reviewed is a strong outlier relative to price projections from other forecasters. Fundamental drivers to a high price scenario would include constraints or disappointments in shale gas production, linkage to rising oil prices through substantial new demand in the transportation sector, and/or significant increases in liquefied natural gas exports out of the United States market.

[30] The Integrated Planning Model (IPM®), a production cost simulation model covering the United States and Canada licensed from ICF International was used to derive the natural gas price response to changes in electric sector demand.

[31] MIDAS, an hourly chronological dispatch model covering the western United States power system used to produce the official forward price curve, was used to forecast wholesale power prices for the scenarios.

Figure A.3 – Comparison of Third Party Henry Hub Natural Gas Price Forecasts

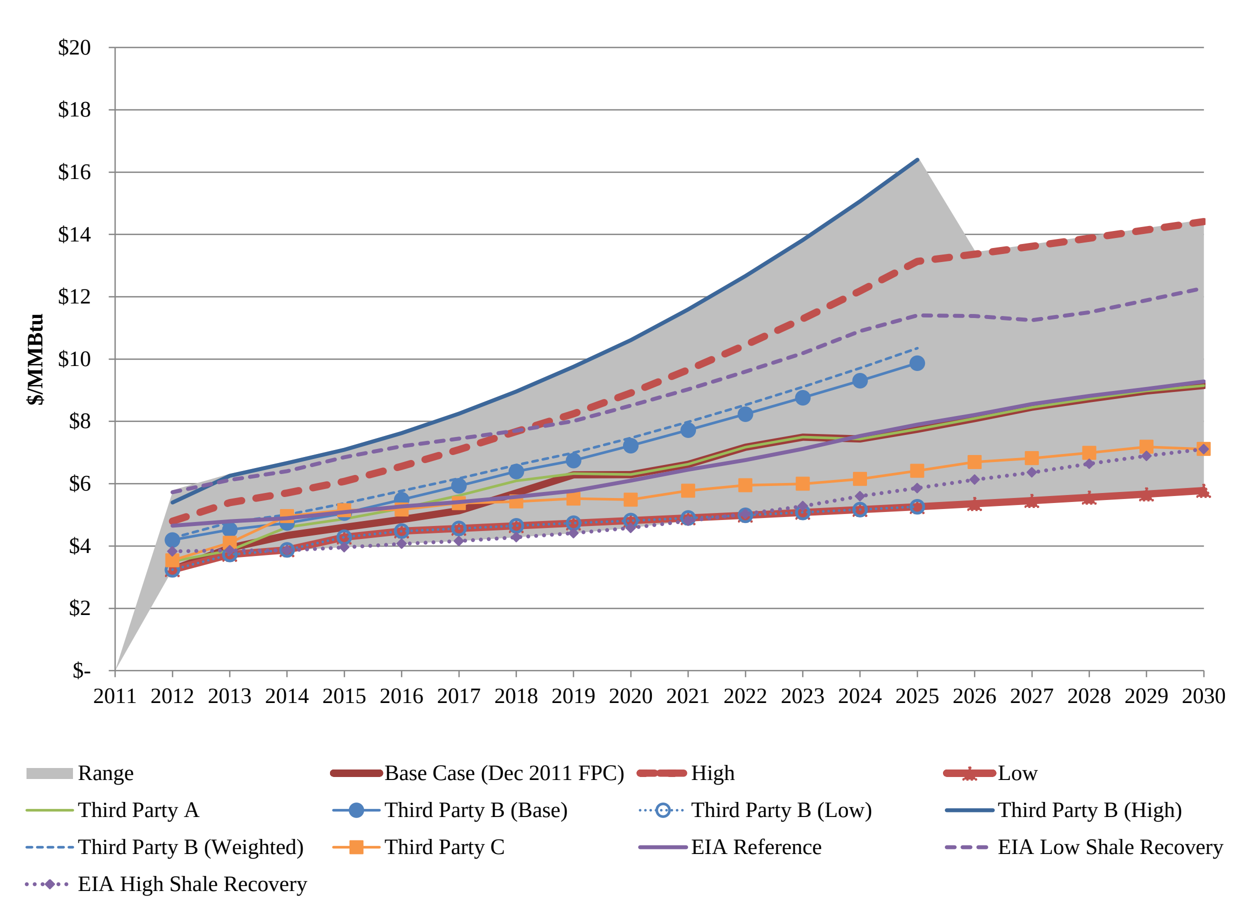


Figure A.4 shows the baseline CO_2 price assumptions alongside third party price projections. A zero CO_2 price is assumed for the low scenario recognizing that there has been limited activity in the CO_2 policy arena, and that there is a possibility that policy makers remain unwilling or unable to address the greenhouse gas issue over the study period. For the high case, prices are assumed to be consistent with the upper limit that would have been established under the American Power Act of 2010 with an assumed start date in 2018. The high case start date reflects both a higher price point and earlier start date relative to the base case.

Figure A.4 – Comparison of Third Party CO_2 Price Forecasts

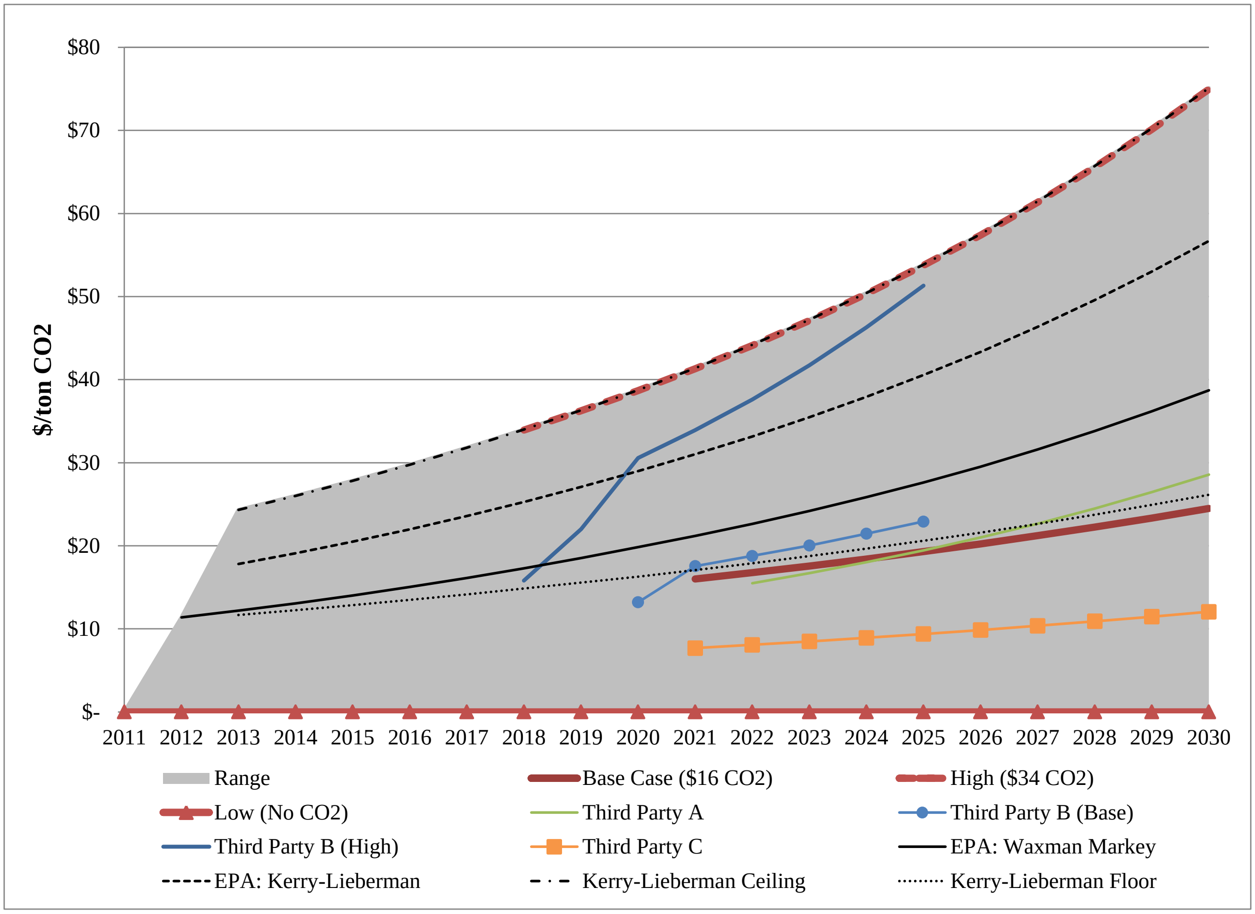
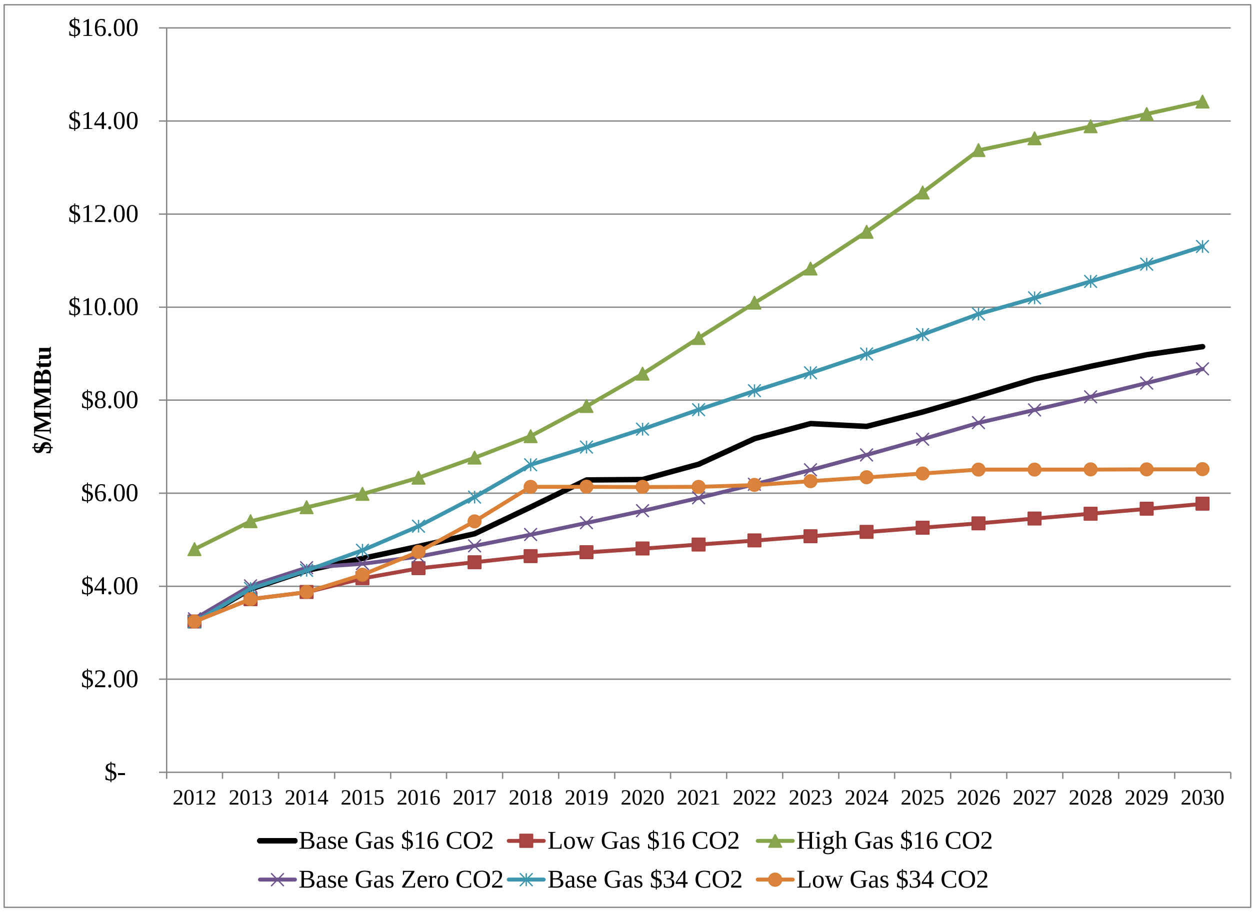


Figure A.5 shows Henry Hub natural gas price assumptions, accounting for any natural gas price response to changes in electric sector natural gas demand when CO_2 assumptions are changed, for the base case and all scenarios included in the updated coal replacement study.

Figure A.5 – Henry Hub Natural Gas Prices among All Scenarios Included in the Updated Coal Replacement Study



Results

Replacement Alternatives

Table A.9 summarizes the replacement resource alternatives selected by the SO Model, either in the optimized simulation or in the change case simulation, for each of the units selected for detailed analysis in the screening study. In other words, in the event that incremental environmental capital investments are not justified, natural gas conversion served as the most beneficial replacement resource alternative for Naughton unit 3, Jim Bridger units 3 & 4, and Hunter unit 1 among all replacement scenarios studied. In the event that incremental environmental capital investments were not justified at the Craig and Hayden units, which individually have a limited impact on the amount of firm capacity that can be transferred into the PacifiCorp system, the SO Model largely chose to slightly alter the timing and amount of FOTs.

Table A.9 – Selected System Optimizer Resource Replacement Alternatives to Capital Investment by Coal Unit

Coal Unit	Resource Alternative Selected by the SO Model (Year Implemented)
Naughton 3	Natural Gas Conversion (2015)
Jim Bridger 3	Natural Gas Conversion (2016)
Jim Bridger 4	Natural Gas Conversion (2017)
Hunter 1	Natural Gas Conversion (2015)
Craig 1	FOTs (Various)
Craig 2	FOTs (Various)
Hayden 1	FOTs (Various)
Hayden 2	FOTs (Various)

Detailed Analysis of Units Selected through the Screening Analysis

Redacted Figure A.6 summarizes the PVRR(d) results for all of the units selected through the screening analysis among the three market price scenarios that maintain the same CO_2 price assumptions – the base gas \$16 CO_2 scenario, the low gas \$16 CO_2 scenario, and the high gas \$16 CO_2 scenario. The figure shows a strong relationship between the levelized gas price at Opal, calculated over the period beginning with the first date investments must be implemented through 2030, and the nominal levelized PVRR(d) expressed on a levelized per kW basis. As shown by the trend in the figure, lower natural gas prices tend to favor alternatives to incremental environmental capital investment in coal, and higher natural gas prices favor coal investment.

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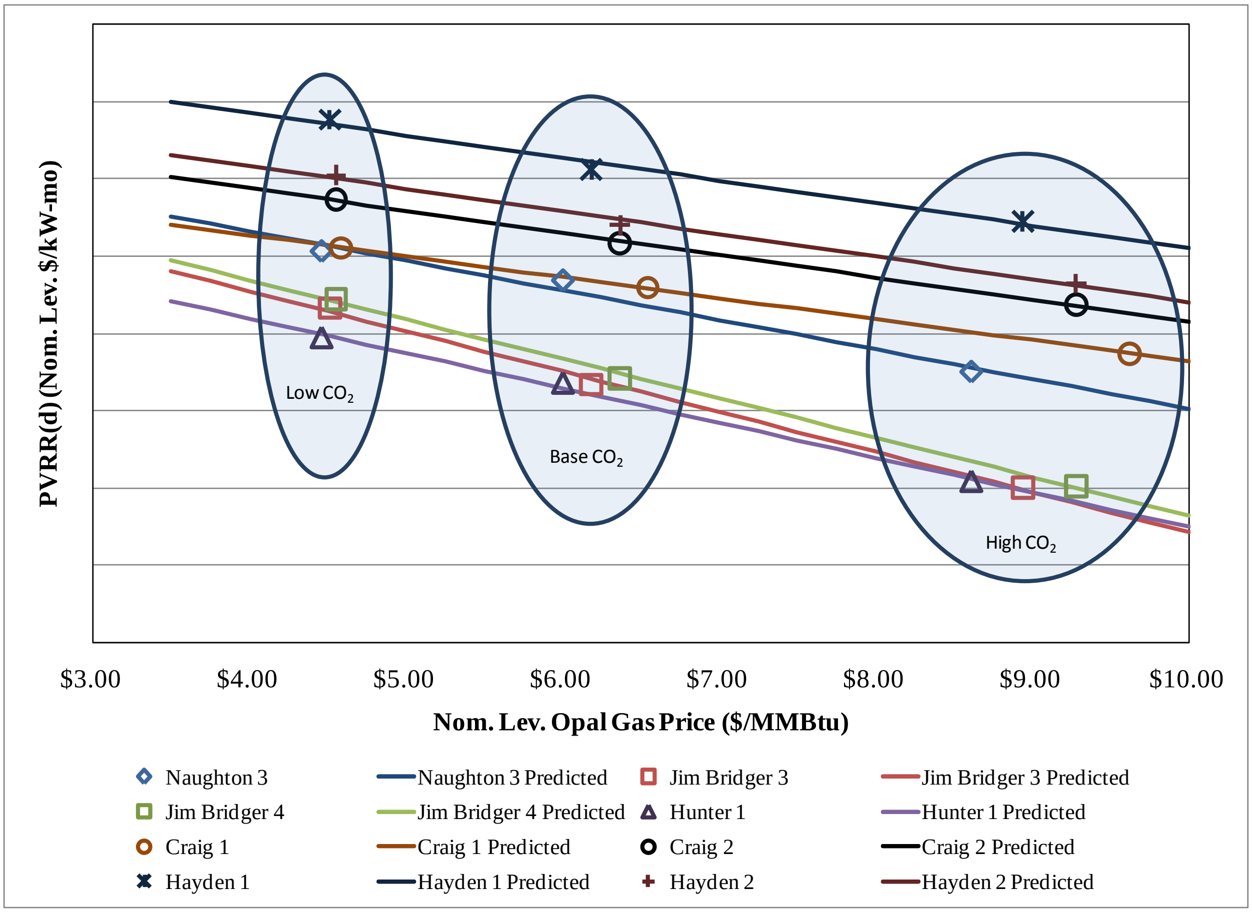
Redacted Figure A.6 – Impact of Natural Gas Prices on the PVRR(d) (Benefit)/Cost of Incremental Environmental Investments in Coal Resources



Redacted Figure A.7 summarizes the PVRR(d) results for all of the units selected through the screening analysis among the three market price scenarios that maintain the same underlying gas price assumptions – the base gas \$16 CO_2 scenario, the base gas Zero CO_2 scenario, and the base gas \$34 CO_2 scenario. The figure shows the relationship between the levelized CO_2 price, calculated over the period beginning with the first date investments must be implemented through 2030, and the nominal levelized PVRR(d) expressed on a levelized per kW basis. As shown by the trend in the figure, higher CO_2 prices tend to favor alternatives to incremental environmental capital investment in coal, and lower CO_2 prices favor coal investment.

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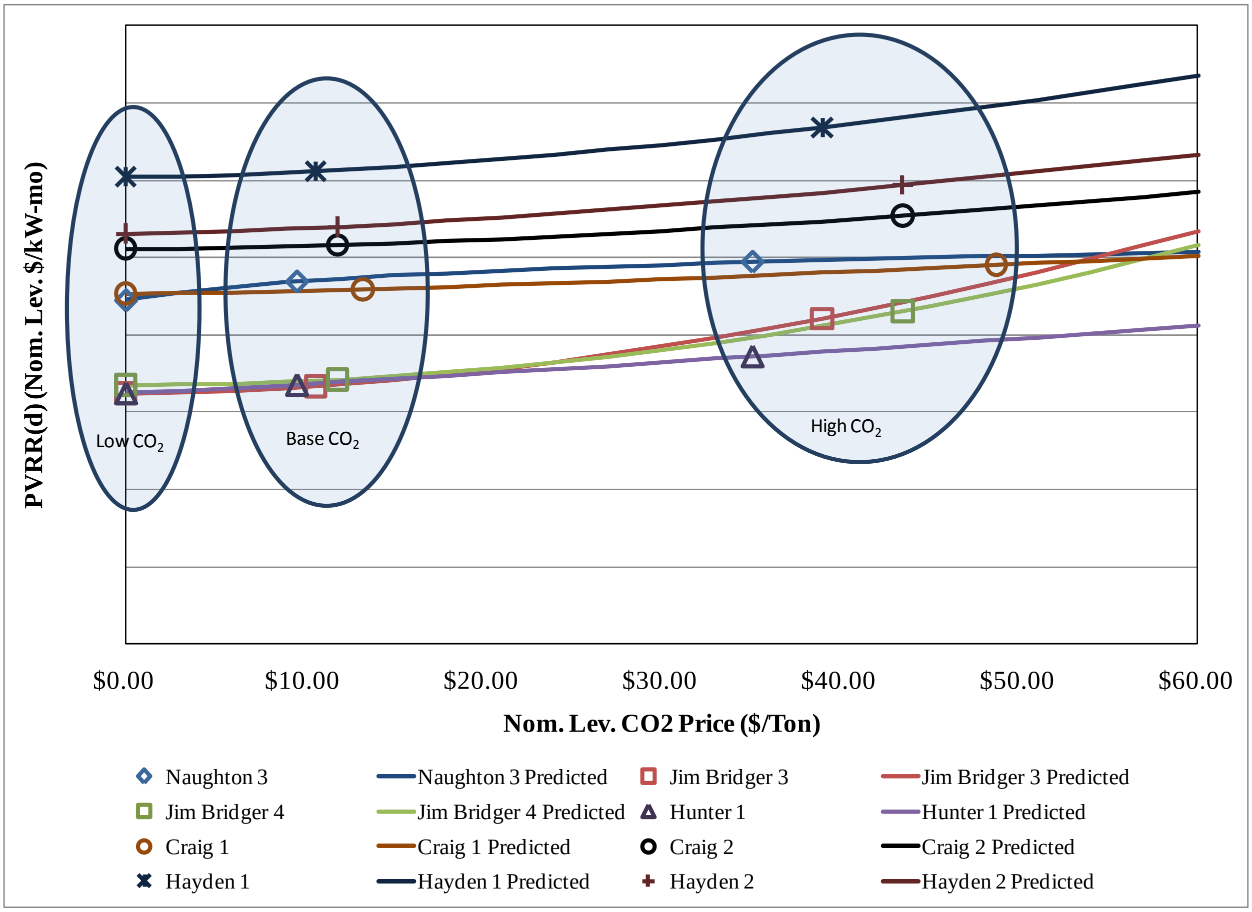
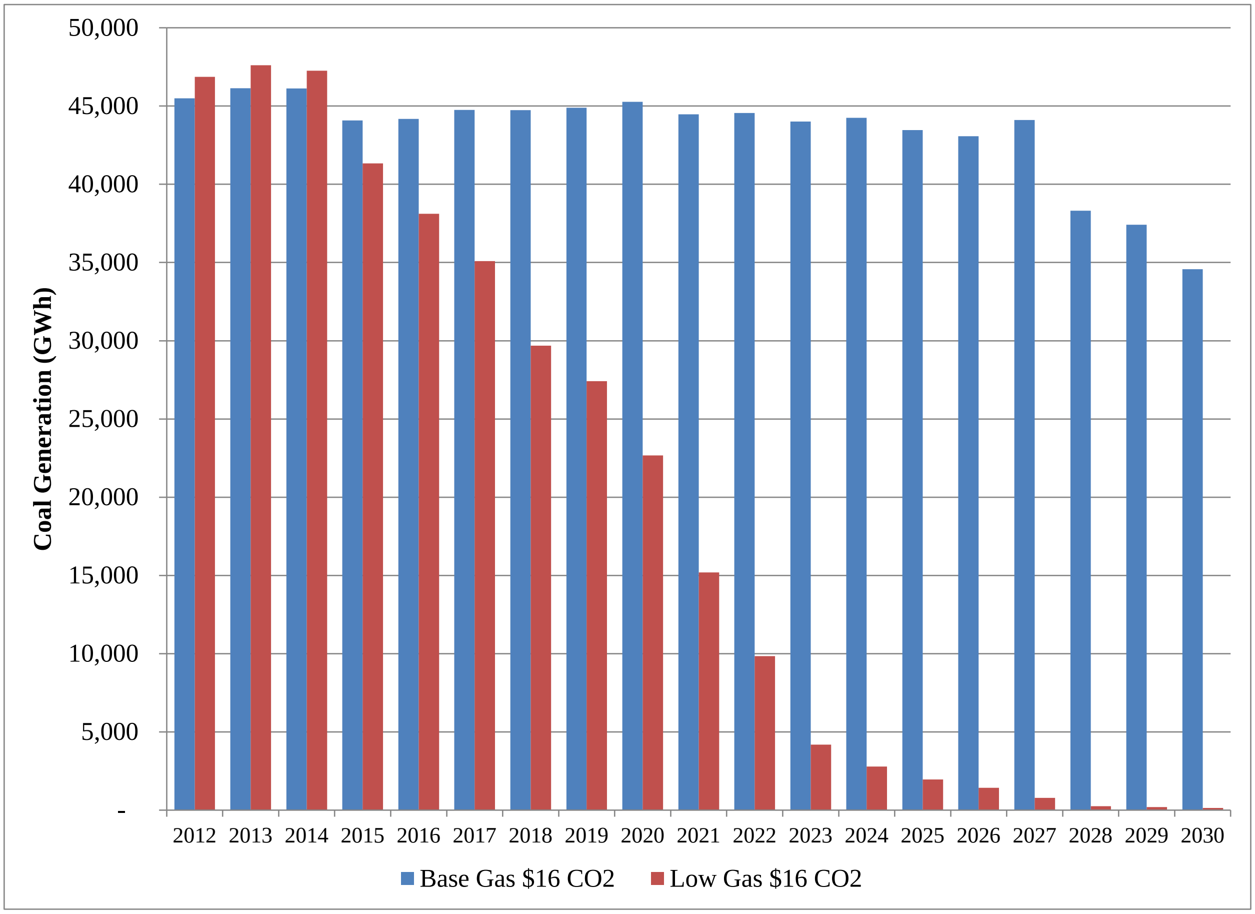
Redacted Figure A.7 – Impact of CO2 Prices on the PVRR(d) (Benefit)/Cost of Incremental Environmental Investments in Coal Resources



The additional scenario included in the updated coal replacement study that pairs low natural gas prices with the high $34 CO_2 price assumption shows that incremental environmental capital investments planned for the coal units identified through the screening analysis would be unfavorable to early retirement and replacement or gas conversion. Under this type of scenario, coal generation, which has traditionally served as a low cost and reliable source of base load generation, could become uneconomic when compared to alternative sources of energy. Such a scenario would impact not only PacifiCorp and its customers, as shown by the comparison of fleet-wide coal generation under the low gas $34 CO_2 scenario with fleet-wide coal generation under the base gas $16 CO_2 scenario in Figure A.8, but almost certainly impact the viability of coal generation across the country.

Figure A.8 – Fleet-wide Coal Generation in the Low Gas $34 CO2 Scenario as Compared to the Base Gas $16 CO2 Scenario



Conclusions

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In conclusion, the updated coal replacement study shows that the economic analysis of incremental environmental capital investments committed or planned for coal units as a means to meet compliance with emerging environmental regulations varies among specific coal units and is highly dependent upon assumptions for both natural gas prices and CO_2 prices. The study further highlights the challenge in having to make near-term capital investment decisions that are required to meet both known and uncertain environmental regulations in the face of tremendous uncertainty around the price of natural gas and coal costs 10 to 20 years into the future. Despite these challenges, the investment decisions must be made and compliance with known environmental regulations must be achieved. PacifiCorp welcomes maintaining an open dialogue with its state commissions and stakeholders as these decisions are studied through the IRP and ultimately implemented.

APPENDIX B – ADDITIONAL LOAD FORECAST DETAILS

The Load forecast presented in Chapter 3 represents the data used for capacity expansion modeling, and excludes load reductions from energy efficiency resources (Class 2 DSM). To arrive at the retail sales forecast, total Class 2 DSM is reduced by an estimated forecast of load reductions from existing DSM programs captured in the historical load data. This adjustment is intended to avoid double-counting of incremental DSM. The post-DSM load forecast then captures the energy savings from the incremental DSM. Tables A.1 and A.2 present the "post-DSM" load forecasts—energy and coincident peak loads, respectively, while Table A.3 presents the Class 2 DSM load reductions.

Table B.1 – Post-DSM: Annual Forecasted Loads in Megawatt-hours

Year	Total	OR	WA	CA	UT	WY	ID	SE ID
2012	**61,024,439**	14,365,268	4,415,308	932,426	25,434,524	9,888,389	3,739,017	2,249,508
2013	**62,199,759**	14,467,931	4,425,713	935,224	26,126,980	10,201,827	3,771,397	2,270,687
2014	**63,647,174**	14,650,454	4,422,959	934,237	26,848,845	10,573,075	3,916,303	2,301,301
2015	**64,732,342**	14,704,905	4,416,265	932,244	27,263,086	11,064,285	4,017,372	2,334,185
2016	**64,843,291**	14,776,833	4,434,492	933,870	27,939,197	11,488,286	4,125,161	1,145,452
2017	**65,522,361**	14,896,703	4,424,756	946,846	28,644,163	12,414,748	4,195,145	0
2018	**66,218,133**	14,944,746	4,429,576	944,589	29,044,372	12,620,651	4,234,199	0
2019	**66,909,140**	14,990,050	4,432,683	942,657	29,419,339	12,865,436	4,258,975	0
2020	**67,708,479**	15,062,300	4,441,986	941,977	29,872,729	13,100,876	4,288,611	0
2021	**68,142,226**	15,040,771	4,420,796	937,298	30,166,796	13,282,171	4,294,395	0
Annual Average Growth Rate for 2012-2021								
	1.2%	**0.5%**	**0.0%**	**0.1%**	**1.9%**	**3.3%**	**1.6%**	

Table B.2 – Post-DSM: Annual Forecasted Coincidental Peak Loads in Megawatts

Year	Total	OR	WA	CA	UT	WY	ID	SE ID
2012	**10,028**	2,232	738	157	4,606	1,263	691	341
2013	**10,228**	2,250	739	157	4,740	1,298	699	345
2014	**10,467**	2,283	745	153	4,880	1,338	716	351
2015	**10,632**	2,290	746	154	4,952	1,389	745	356
2016	**10,440**	2,295	748	156	5,037	1,433	771	0
2017	**10,670**	2,316	750	161	5,126	1,531	786	0
2018	**10,780**	2,321	755	161	5,197	1,552	794	0
2019	**10,875**	2,325	753	161	5,260	1,577	799	0
2020	**10,985**	2,335	758	157	5,336	1,596	802	0
2021	**11,094**	2,339	758	158	5,403	1,620	815	0
Annual Average Growth Rate for 2012-2021								
	1.1%	**0.5%**	**0.3%**	**0.1%**	**1.8%**	**2.8%**	**1.8%**	

Table B.3 – Class 2 DSM Megawatt-hours included in Post-DSM Load Forecast, 2012-2021

Year	Total	OR	WA	CA	UT	WY	ID
2012	**420,994**	96,919	21,102	3,832	257,962	36,498	4,682
2013	**454,798**	153,314	20,086	4,441	216,293	53,336	7,329
2014	**704,179**	222,045	34,364	8,261	342,265	81,956	15,289
2015	**970,541**	292,219	48,851	13,169	475,443	115,087	25,772
2016	**1,249,611**	359,857	61,990	18,510	622,186	148,582	38,486
2017	**1,539,648**	425,755	75,605	24,256	775,581	185,941	52,510
2018	**1,818,262**	470,017	89,156	30,099	934,372	227,403	67,217
2019	**2,106,368**	514,251	103,657	35,627	1,102,586	268,627	81,620
2020	**2,413,074**	558,486	119,261	41,667	1,283,404	312,704	97,551
2021	**2,727,472**	602,721	138,792	46,042	1,458,839	366,116	114,962