BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 52

In the Matter of PACIFICORP 2011 Integrated Resource Plan	STAFF'S FINAL COMMENTS AND RECOMMENDATIONS

Following are Staff's final comments and recommendations related to the PacifiCorp's 2011 Integrated Resource Plan (IRP). In these final comments, Staff discusses its analyses and conclusions regarding the IRP, and addresses concerns raised by the Citizens Utility Board (CUB), the Industrial Customers of Northwest Utilities (ICNU), the Northwest Energy Coalition (NWEC), the Oregon Department of Energy (ODOE), the Renewable Northwest Project (RNP), and the Sierra Club. In addition, Staff addresses issues raised by PacifiCorp in its reply comments and Supplemental Coal Replacement Study. Staff recognizes these comments do not address all of the concerns raised in this docket. In its proposed draft order Staff provides a comprehensive discussion of the concerns raised by parties.

Staff recommends that the Commission acknowledge PacifiCorp's 2011 IRP with revised Action Items as reflected below. Staff explains in the discussion below the reasons underlying these recommended revisions.

Action Item 1 - Renewables/Distributed Generation

Wind

- Acquire up to 800 MW of wind resources by 2020, dictated by regulatory and market developments such as (1) renewable/clean energy standards, (2) carbon regulations, (3) federal tax incentives, (4) economics, (5) natural gas price forecasts, (6) regulatory support for investments necessary to integrate variable energy resources, and (7) transmission developments. The 800-megawatt level is supported by consideration of regulatory compliance risks and public policy interest in clean energy resources.

- 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 dry hole risk.

Geothermal

- The Company identified over 100 MW of geothermal resources as part of a least-cost resource portfolio. Continue to refine resource potential estimates and update resource costs in 2011-2012 for further economic evaluation of resource opportunities. Continue to, explicitly, include geothermal projects as eligible resources in future all-source RFPs.

Solar

- Evaluate procurement of Oregon solar photovoltaic resources in 2011 via the Company's solar RFP.

- 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 late 2011 and 2012, using the Company's own analysis of Wasatch Front roof top solar potential and experience with the Oregon solar pilot program. As recommended in the Company's response to comments under Docket No. 07-035-T14, the Company requested that the Utah Commission establish "a process in the fall of 2011 to determine whether a continued or expanded solar program in Utah is appropriate and how that program might be structured."

- Investigate, and pursue if cost-effective from an implementation standpoint, commercial/residential solar ~~hot~~ water heating programs.

  - The 2011 IRP preferred portfolio includes 30 MW of solar ~~hot~~ water heating resources by 2020 (18 MW in the east side and 12 MW in the west side).

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 2011-2020 (10 MW in the east side and 42 MW in the west side)

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.

Initiate a consultant study in 2011 or 2012 on incremental capacity value and ancillary service benefits of energy storage. The study will include the following elements:

1) Definition of and suggest metrics by which to measure flexibility (applicable to all flexibility resources including: thermal, demand response (DR), and storage)

2) An inventory of existing flexibility needs and the adequacy or capability of existing assets to meet them

3) A projection of flexibility needs in the IRP timeframe to successfully integrate projected VER additions

4) A comparison of benefits and costs of obtaining flexibility from the range of flexible resources (conventional thermal, DR, storage, etc.)

- A discussion of the potential for other sources of flexibility, such as regional VER integration efforts (including but not limited to the EIM proposal) to reduce integration requirements and costs.

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.

Action Item 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.

- Recognizing the complexity of implementing DSM Classes 1, 2 and 3, and CVR programs across its service territory, and the need to rely more upon market purchases to meet loads, PacifiCorp will pursue implementing the Staff alternative portfolio shown in Attachment 1in lieu of the preferred portfolio. If, after demonstrating it diligently pursued implementation of the Staff alternative portfolio, PacifiCorp finds the resulting demand-side resources and market purchases insufficient to meet the need, it may file an IRP Update to justify acquiring supply-side resources to fulfill the remaining need.

- ~~Issue an all-source RFP in late 2011 or early 2012 for acquisition of peaking/intermediate/baseload resources by the summer of 2016.~~

  - ~~This acquisition corresponds to the 597 MW 2016 CCCT proxy resource (F Class 2x1).~~

- PacifiCorp will reexamine the timing and type of post-2014 gas resources and other resource changes as part of the 2011 business planning process and preparation of the 2011 IRP Update. The reexamination will include documentation of capital cost/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.

Action Item 3 - Firm Market Purchases

- Acquire up to 1,400 MW of economic front office transactions or power purchase agreements as needed until the beginning of summer 2014, unless cost-effective long-term resources are available and their acquisition is in the best interests of customers.

  - 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.

Action Item 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 CO2 and other environmental compliance requirements.

  - Successfully complete the dense-pack coal plant turbine upgrade projects scheduled for 2011 and 2012, totaling 31 MW

  - Complete the remaining turbine upgrade projects by 2021, totaling an incremental 34.2 MW, subject to continuing review of project economics.

- Seek to meet the Company's updated aggregate coal plant net heat rate improvement goal of 478 Btu/kWh by 2019.

- Continue to monitor turbine and other equipment technologies for cost-effective upgrade opportunities tied to future plant maintenance schedules.

Action Item 5 - Class 1 DSM

Acquire up to 250 MW of cost-effective Class 1 demand-side management programs for implementation in the 2011-2020 time frame.

- For 2012-2013, pursue up to 80 MW of the commercial curtailment product (which includes customer-owned standby generation opportunities) being procured as an outcome of the 2008 DSM RFP.

- Depending on final economics, pursue the remaining 170 MW for 2012-2020, consisting of additional curtailment opportunities and irrigation/residential direct load control.

Action Item 6 - Class 2 DSM

- Acquire ~~up to 1,200~~1,800 MW of cost-effective Class 2 programs by 2020, including 1,200 MW in the eastern supply territory~~equivalent to about 4,533 GWh. This includes programs in Oregon acquired through the Energy Trust of Oregon~~.
  - Procure through the currently active DSM RFP and subsequent DSM RFPs.

- In the next IRP, the Company will evaluate alternatives for ramping up DSM 2 in a way that is equal to supply side resource development and procurement.

- In the next IRP, the Company will provide an analysis of alternatives to the current bundling method for modeling and evaluating energy efficiency measure supply curves.

- In the Company's next IRP, it will provide an analysis of the sufficiency of current staffing levels to achieve programmatic cost effective energy efficiency targets established in this plan.

- 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.

- A conservation voltage reduction (CVR) acquisition project in PacifiCorp's Washington service area will begin in 2012 and end no later than 2018.

  The next filed PacifiCorp IRP will include an action plan item to acquire all of the available cost-effective CVR throughout its service area by 2022. This action item will be based primarily on information from Yakima and Walla Walla service areas. Cost-effectiveness analyses will use the same methodology as the modeling approach used in the Class 2 DSM decrement assessment in the 2011 IRP Addendum.~~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. (The Washington distribution energy efficiency study final report is scheduled for completion by the end of May 2011.)~~

Action Item 7 - Class 3 DSM

- ~~Continue to evaluate Class 3 DSM program opportunities.~~ By 2020 PacifiCorp will implement 262 MW of Class 1 and Class 3 DSM on the East side and 131 MW of Class 1 and Class 3 DSM on the West side using a combination of programs (TOU irrigation, Direct Load Control (DLC) Residential, Real-time pricing-Commercial & Industrial, Demand buy back, Critical Peak Pricing, etc.) as demonstrated in its sensitivity analysis, Case Study 31[1].

  In its next filed IRP PacifiCorp will report on the cost-effectiveness and status of its acquisition and implementation of Class 1 and Class 3 DSM.

  - ~~Evaluate program specification and cost-effectiveness in the context of IRP portfolio modeling, and monitor market changes that may remove the voluntary nature of Class 3 pricing products.~~

Action Item 8 - Planning and Modeling Process Improvements

- Continue to refine the System Optimizer modeling approach for analyzing coal utilization strategies under various environmental regulation and market price scenarios.

- PacifiCorp is required to file its next IRP Update in March 2012. The IRP Update will include a revised Supplemental Coal Replacement Study. The Company will investigate whether there is flexibility in the emerging environmental regulations that would allow the Company to avoid early compliance costs by offering to shut

[1] 2011 IRP, Appendix D, p. 129.

down individual units prior to the end of their useful lives. The Company will also conduct further plant specific analysis to determine whether this tradeoff would be in the ratepayers' interest. In these additional analyses the Company will correct, as appropriate, its treatment of depreciation for the period after 2030.

- Continue to coordinate with PacifiCorp's transmission planning department on improving transmission investment analysis using the IRP models.

- Incorporate plug-in electric vehicles and Smart Grid technologies as a discussion topic for the next IRP.

- 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 identify its members within 30 days of the effective date of the IRP Order. Within 30 days of the effective date of the 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.

- PacifiCorp will develop its 2011 IRP Update based on a 12 percent planning reserve margin, unless a different PRM is justified by a marginal cost study comparing costs of portfolios that are optimized for achieving the various PRMs, and including estimates of the marginal benefits from a greater PRM. The study will use loss-of-load hours and unserved energy as the dependent variables.

Transmission Action Items

PacifiCorp will provide, for the Wallula to McNary project (Energy Gateway Segment A), prior to seeking regulatory acknowledgement of this project:

1. An analysis showing that another wind project will be developed in the Wallula area, resulting in more revenues to achieve a benefit-cost ratio equal to, or at least, one; and

2. An analysis quantifying other non-economic benefits. (e.g. the project is necessary as a contingency for addressing abnormal operating conditions)

PacifiCorp requests regulatory acknowledgement of the Mona to Terminal project (Energy Gateway Segment C).

PacifiCorp will provide, for the Sigurd to Red Butte project (Energy Gateway Segment G), prior to seeking regulatory acknowledgement of this project:

1. An analysis including other economic benefits and quantifying other non-economic benefits to achieve a benefit-cost ratio equal to, or at least, one.

2. An analysis (e.g. the project's Investment Appraisal Document) demonstrating that the alternative chosen is the most cost-effective alternative.

In future IRPs, the Company will include in its portfolio scenario any transmission project for which acknowledgment is requested, regardless of its size or scope.

Final Comments

Staff has organized its final comments by subject, cross referencing the related IRP Action Item.

Evaluation of Environmental Compliance Costs for Existing Coal-fired Plants (Action Item 8)

Recommended Requirement

To further evaluate the cost effectiveness of continuing to operate its coal fired resources, Staff recommends PacifiCorp should be directed to complete and present with its 2011 IRP Update, in March 2012, additional analyses centered around alternative environmental compliance approaches coupled with early retirement for the coal resources believed to be most economically sensitive to environmental compliance costs. In these additional analyses the Company should correct, if appropriate, its treatment of depreciation for the period after 2030.

Discussion

Staff concluded in its initial comments that PacifiCorp's 2011 IRP failed to provide a comprehensive evaluation of the compliance of its existing coal fired generation resources with new, draft, and anticipated environmental regulations. With its reply comments, the Company filed a Supplemental Coal Replacement Study.

The Supplemental Coal Replacement Study expanded the list of potential environmental regulations considered in the coal plant replacement analysis. The analysis included costs to comply with the Regional Haze Rules / BART process, costs to comply with the EPA's proposed utility hazardous air pollutants (HAPs) MACT rulemaking, additional costs for selective catalytic reduction across the Company's coal fleet, costs to comply with emerging rules for coal combustion residuals (CCR), and costs to modify cooling water intake structures at existing plants to comply with Section 316(b) of the Clean Water Act. PacifiCorp reconsidered its modeling assumption that existing coal units could only be replaced by brownfield natural gas resources located at the same site and expanded its modeling to allow for a wide range of potential replacement resource options. The modeling was also updated to force the decommissioning of coal plants at the end of their depreciable lives. The Carbon plant is assumed to be decommissioned at the end of 2020, the Dave Johnston plant at the end of 2027, and the Naughton plant at the end of 2030. The Supplemental Coal Replacement Study also included an updated range of natural gas price scenarios and carbon dioxide regulation cost scenarios.

PacifiCorp summarized the results of the supplemental study as follows:

> "Among all three scenarios evaluated in the Coal Replacement Study, none of the PacifiCorp coal resources were displaced by replacement resource alternatives before the end of the 20-year planning period or before the end of the currently approved depreciable life of each resource. In each of these scenarios, existing coal resources were assigned incremental investment costs consistent with the most current emissions control plan, plus the incremental SCR costs across the Company's generation units discussed above and in Confidential Appendix A. The analysis also incorporated cost estimates to address expected CCR regulations and upgrades to water intake structures. These findings support the basic conclusions drawn from the 2011 IRP coal utilization sensitivity analysis and show that PacifiCorp's coal fleet, with planned incremental investments, will continue to provide reliable and least cost electric service to customers. Moreover, the Coal Replacement Study shows that planned coal investments are cost effective among a range of future market price and CO2 cost outcomes."

In Staff's opinion, the Supplemental Coal Replacement Study sufficiently solidifies the basis of the IRP. In doing so there is now a basis for evaluation of whether the candidate resource portfolios satisfy the IRP goal to select a portfolio of resources with the best combination of cost and risk for the utility and ratepayers. Staff commends the Company for expanding the list of potential environmental regulations and for allowing for a wider range of potential replacement resource options in the coal plant replacement analysis.

Staff identified a potential flaw in the modeling used in the supplemental coal study. Staff believes there is inconsistent treatment of coal plant depreciation expense beyond the end of planning period. Staff believes PacifiCorp appropriately included the net present value of this expense in the cost stream associated with early retirement, but inappropriately excluded the net present value of this expense from the cost stream associated with pollution control investment and continued operation of the plant. Staff is concerned this may bias the results in favor of continued operation of the plants. Staff recommends that this issue be addressed as part of an additional coal replacement study analyses to be submitted with the Company's 2011 IRP Update in March 2012.

Staff also recommends that PacifiCorp be required to further investigate whether there is flexibility in the emerging environmental regulations that would allow the Company to avoid early compliance costs by offering to shut down individual units prior to the end of their useful lives. In addition, Staff recommends that PacifiCorp conduct further plant specific analysis to determine whether this tradeoff would be in the ratepayers' interest. Staff agrees with PacifiCorp that plant retirement should be the result-not the objective-of this investigation and analysis. Staff recommends that the Company be required to provide this additional analysis in their 2011 IRP Update in March 2012.

Energy Efficiency (Class 2 DSM) Resource Analysis (Action Item 6)

Recommended Requirement

Staff recommends the first bullet of IRP Action Item 6 be modified to read:

- Acquire ~~up to 1,200~~1,800 MW of cost-effective Class 2 programs by 2020, including 1,200 MW in the eastern supply territory~~equivalent to about 4,533 GWh. This includes programs in Oregon acquired through the Energy Trust of Oregon~~.
  - Procure through the currently active DSM RFP and subsequent DSM RFPs.

Staff also recommends adding the following bullets after the first bullet of Action Item 6:

- In the next IRP, the Company will evaluate alternatives for ramping up DSM 2 in a way that is equal to supply side resource development and procurement.

- In the next IRP, the Company will provide an analysis of alternatives to the current bundling method for modeling and evaluating energy efficiency measure supply curves.

- In the Company's next IRP, it will provide an analysis of the sufficiency of current staffing levels to achieve programmatic cost effective energy efficiency targets established in this plan.

Discussion

IRP Guideline 1a. states that all resources must be evaluated on a consistent and comparable basis. IRP Guideline 1c states that the primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers. Staff appreciates that the Company has increased the amount of energy efficiency in this IRP compared to the 2009 IRP. Staff also appreciates the points made in the Company's reply comments. However, Staff, along with NWEC and CUB, believes the Company is underestimating the amount and speed of energy efficiency that can be achieved in states other than Oregon, and as a result supply side resources are being chosen which customers will pay more for and be subject to greater risks.

Total savings compared to load

State	% of Annual Load Forecast (MWh)	% of Forecasted Coincident Peak Load (MW)	% of total DSM 2 in Preferred Portfolio (MW)
Oregon	22%	21%	48%
Washington	7%	7%	7%
California	1%	1%	1%
Utah	42%	47%	38%
Wyoming	18%	13%	5%
Idaho	9%	10%	3%

Oregon represents 22 percent of total load in MWh and 21 percent of the forecasted coincident peak load, and 48 percent of the total DSM capacity in the preferred portfolio. Staff believes there should not be such a discrepancy between how much cost effective energy efficiency is possible in Oregon versus other states. Oregon has been weatherizing electric homes since 1978, so there should be even more savings per unit load available in states with newer programs where lots of “low hanging energy efficiency fruit” still remains.

Washington and Oregon have similar geography and weather conditions, and both states have relatively strong program histories. The primary difference is that in Oregon, programs are administered by the Energy Trust of Oregon, whereas in Washington programs are administered by PacifiCorp. In this IRP, the ratio of Oregon to Washington forecasted contribution to coincident peak load in 2020 is three (2,644 MW in OR and 894 MW in WA). However, the ratio of 2020 DSM 2 capacity in Oregon to Washington in the preferred portfolio is seven (562 MW in Oregon to 79 MW in Washington). Oregon is realizing more than double the savings per unit load than its neighbor Washington. Staff has looked into this issue and has been unable to identify why Washington is getting so much less DSM 2 per unit load than Oregon. Measures that are cost effective in Oregon should also be cost effective in Washington. Staff suspects that that the Company could more aggressively pursue energy efficiency in Washington and in other states.

Resource Potential Study

PacifiCorp hired CADMUS to update its resource potential study for all states, except Oregon. Basically, PacifiCorp’s model has selected roughly half of the energy efficiency its consultant CADMUS deemed to be technically available and achievable. CADMUS estimated that by 2030 there would be 2,651 MW of technical and achievable "peak capacity impact savings" in WA, CA, ID, UT, and WY.[2] PacifiCorp's preferred portfolio has only 1,531 MW "nameplate savings" in 2030 for the same states. In Utah alone, CADMUS suggests there was 2,013 MW of "peak" technical and achievable savings availably by 2030. PacifiCorp's preferred portfolio contains only 976 MW of "nameplate savings." The Company will likely argue that not all resources identified by CADMUS are cost effective and so were not selected by the model. However, all the Oregon energy efficiency, which is a much greater percentage of load, was selected by the model. This calls into question the criteria being used to select measures by PacifiCorp in states other than Oregon.

The CADMUS report shows only total peak savings for 2030. To estimate the potential for 2020, if the CADMUS peak impact savings for 2030 were divided by two (1,326 MW) and then added to the 2020 savings estimates for Oregon (562 MW), the result equals 1,887 MW in 2020. This is conservative in that the CADMUS number actually represents a peak capacity impact savings, not installed capacity. Staff recommends that PacifiCorp's 2020 action item be modified to say that 1,800 MW of savings be achieved by 2020 and that 1,200 MW of that be in the eastern supply territory.

Ramp Rates

Ramp rates refer to how quickly DSM 2 measures can be achieved. Ramp rates are based on:

a) Adoption rates of energy efficiency - a function of the market

b) Ramp rates of specific programs - a function of programs and how they are implemented by the Company

CADMUS proposed market ramp rates in their resource potential study. PacifiCorp modified those ramp rates based on the "Company's specific implementation constraints not accounted for in the potential assessment."[3] The Company does not indicate specifically how ramp rates were modified, or the basis for those modifications. In addition, it has not clearly presented the ramp rates used. On page 9 of its reply comments, PacifiCorp states that it believes the ramp rate assumptions adopted for the IRP portfolio modeling reflect prudent consideration of company-specific implementation constraints not accounted for in the potential assessment. Staff is concerned that Company staffing levels and level of effort it is putting into these programs in states other than Oregon are unnecessarily limiting how quickly program ramp rates can grow to the point where they correspond to the ramp rates described as possible by CADMUS.

[2] CADMUS projects estimates of peak capacity impacts per state by "spreading annual potential by state, sector, segment, and end use over hourly load shapes to estimate hourly demand savings. The peak impacts represent the average demand savings in the top 40 hours of system load."
[3] See page 9 of the Company's response comments

In response to Staff data request 180, the Company indicates the system optimizer model does not have logic to ramp energy efficiency such that it is available when needed. As a result, ramp rates must be manually input to the model in the form of the maximum annual amounts that the Company allows the model to select. The System Optimizer model performs an economic evaluation of energy efficiency measures against other resources as well as capacity needed in each year to derive the amount of Class 2 DSM that is selected. Staff believes it is likely that cost effective Class 2 DSM is being missed through this iteration of manually inputting ramping limitations for analysis by the model.

In practice, supply side resources are planned and essentially “ramped up” (through RFPs, pre-construction, construction, etc) well in advance of their need so they are fully available when needed. Staff believes that demand side resources are not being treated equally with supply side resources in how they are being planned for and ramped up in advance of need so they are available when needed.

Although the total achievable Class 2 DSM in this plan increased over the 2009 IRP, modifications were made to the resource availability assumption inputs (i.e., ramp rates) resulting in less energy efficiency in early years (2011-2020) and more in later years (2021-2030) for all states other than Oregon. Staff believes this has the effect of favoring supply-side resources in the near term.

Staff recommends that in the next IRP the Company provide an evaluation of alternatives for ramping up class DSM 2, such that Class 2 DSM resources are treated equally with supply side resources in terms of development and procurement.

Total Savings versus Capacity

The Company reported a total achievable potential of 4,253 MW of forecasted DSM 2 capacity contributions by 2030 (including OR and all states evaluated by CADMUS, as reported above). Of this, only 2,557 MW (60 percent) made it into the preferred portfolio for 2030. For 2020, the Company reported a total achievable potential of 1,887 MW of DSM 2 potential by 2020. Of this, only 1,186 MW was selected for the preferred portfolio (62 percent). Of the 1,186 MW that was selected for the preferred portfolio, only 566 MW (or 48 percent) is assumed to be available at the time of annual system coincident peak in 2020.

Staff believes that the Company can achieve more than the projected total savings, and therefore more capacity savings. Staff also questions the capacity factors used for efficiency measures in each state and the basis for those capacity factors. For instance, in Oregon, the capacity planning factor for the lowest price bundle is 0.22, but for the next two bundles the capacity planning factor was set at zero.

Bundles

The Company bundles measures together for input to its model. Staff is concerned that the current bundling methodology and selection of endpoints for each bundle is arbitrary, confusing, and causing less DSM 2 to be selected than other resources. The Company claims in its reply comments that the size and range of the cost bundles vary, but the variations are by design and that the bundles are more granular (less difference between the low and high costs in the bundle) at the lower end of the cost spectrum. Staff does not believe this to be true because the lowest cost bundle (after a bundle that contains only compact fluorescent lights (CFL)) contains all measures whose levelized costs are between zero and $70/MWh for a cost range or "delta" of $70/MWh. The next nine bundles have price differences, or "deltas" of $10, $10, $10, $10, $20, $70, $560, with the highest price bundle having a price range of $150.

The lowest price bundle (0-$70/MWh) contains by far the most potential savings (65% of total savings in Utah). Staff is concerned that the large range of this bundle causes the levelized cost to be so high that it may not be selected by the model. For example, this bundle, which contains measures that cost between zero and $70/MWh, has an overall bundle cost cost of $57/MWh. The next most expensive bundle has a bundle cost of $74/MWh. For comparison purposes, a CCCT costs approximately $65/MWh with no price on carbon or roughly $70/MWh with a $19 carbon tax. By contrast, all of the Oregon measures are fit into three bundles with average prices of $47, $59 and $54/MWh.

Staff is concerned that bundling these many measures into one large bundle is causing the model to exclude many measures that would otherwise be cost effective, particularly at the low end of costs. Staff also believes this bundling method is unnecessarily arbitrary and confusing. Staff recommends that in the next IRP the Company provide an analysis of alternative to the current bundling method for modeling and evaluating energy efficiency measure supply curves.

Staffing Levels

Staffing levels, while not typically addressed in an IRP, are relevant to the extent they interfere with the ability to deliver the least cost and least risk alternative to customers. As mentioned previously, Staff is concerned that PacifiCorp's staffing levels are limiting the program implementation rates and therefore ramp rates and savings.

There are a numerous caveats in evaluating staffing levels and comparing staffing levels for DSM programs. Variables include how many programs are outsourced; who does the outreach, rebate processing, who does evaluation, program development, clerical, IRP and other staff, etc. However, it is still interesting to note that PacifiCorp serves 1.7 million customers and has only 12.8

full time equivalents (FTE) assigned to Class 2 DSM companywide in 2011 and 10.6 FTE in 2010. It is recognized that PacifiCorp uses an RFP process for procurement of DSM 2. However, Staff is concerned that even so, the staffing levels are limiting how much DSM 2 can be achieved.

As an admittedly imperfect comparison, the ETO has 77 approved FTE and 6-8 interns and temporary employees. The ETO also uses an outsourced program delivery model. Another comparison is with Puget Sound Energy, which has roughly 123 FTE working on Energy Efficiency, and roughly 1 million electric customers and about 800,000 gas customers. Idaho Power in 2010 had only 492,072 customers, and had 31 FTE employees working on energy efficiency and demand response.

Summary and Staff's Alternative Portfolio

Staff believes that PacifiCorp can achieve more cost effective DSM 2 in states other than Oregon, and that it is in the best interest of Oregon customers for them to do so. Staff believes that PacifiCorp can achieve 600 MW more conservation by 2020 than represented in the Company's preferred portfolio and that out of the total 1,800 MW, 1,200 MW can come from the eastern territory, thereby reducing the need for new supply side resources to meet peak demand in the east.

In Staff's alternative portfolio (discussed below) an additional 84 MW of Class 2 DSM was included in the East by 2020, with ramping starting in 2016. Only 1 additional MW was included in the West by 2020., As presented in Staff's comments above, a combined potential of DSM 2 savings of up to 600 MW is available. Staff believes including only 85 MW of DSM 2 savings in the Staff alternative portfolio is quite conservative and attainable.

Load Control (Class 1 DSM) and Price Response (Class 3 DSM) Resource Analysis (Action Items 5 and 7)

Recommended Requirement

Staff recommends the Company actively acquire all economic Class 3 DSM resources, as soon as possible. The Company should focus on time-of-use for irrigation, DLC programs, critical peak pricing programs and demand buy-back programs as soon as 2013, and ramp-up to the levels identified in its Case Study 31 by 2020. The Company should report the status of its acquisition and implementation of Class 3 DSM in its next IRP. To accomplish Staff's recommendation IRP Action Item 7 - Class 3 DSM should be revised to read as follows:

- ~~Continue to evaluate Class 3 DSM program opportunities.~~ By 2020 PacifiCorp will implement 262 MW of Class 1 and Class 3 DSM on the East side and 131

MW of Class 1 and Class 3 DSM on the West side using a combination of programs (TOU irrigation, Direct Load Control (DLC) Residential, Real-time pricing-Commercial & Industrial, Demand buy back, Critical Peak Pricing, etc.) as demonstrated in its sensitivity analysis, Case Study 31[4].

In its next filed IRP PacifiCorp will report on the cost-effectiveness and status of its acquisition and implementation of Class 1 and Class 3 DSM.

~~Evaluate program specification and cost-effectiveness in the context of IRP portfolio modeling, and monitor market changes that may remove the voluntary nature of Class 3 pricing products.~~

Discussion

Staff maintains its position on Class 1 and Class 3 DSM measures outlined in its initial comments. Staff also echoes NWEC's concern that the Company has not actively acquired all economic DSM resources. Below, Staff provides support for its recommendations and responds to PacifiCorp's reply comments.

Class 1 DSM

The comments from Staff and NWEC related to PacifiCorp's Class 1 DSM as "being only a "minimal amount" of Class 1" are intended to focus on the fact that, while PacifiCorp's preferred portfolio chooses 250 MW of Class 1, and achieves the maximum amount of Class 1 potential indicated in the Cadmus study, the Company seems to be less than confident that it will implement the entire 250 MW of Class 1. The IRP Action Plan implies that 170 MW of the 250 MW selected in the preferred portfolio may never be implemented based upon economic viability. PacifiCorp points out in its reply comments that Staff and NWEC overlook the fact that the preferred portfolio "is effectively pursuing 575 MW Class 1 DSM, or 92 percent of the achievable technical potential identified in the Camus study, before accounting for any percentage of the opportunity that is uneconomic."

PacifiCorp's sensitivity study (Case 32) demonstrates that small amounts of additional Class 1 resource acquisitions (85-90 MW) defer the 2015 and 2019 CCCTs by one year.[5] This indicates to Staff that even small amounts of Class 1 resource acquisitions are worth pursuing. Staff recognizes that PacifiCorp is effectively pursuing 92 percent of the achievable technical potential identified by the Cadmus study, but Staff points out that the Cadmus Study indicates that the potential Class 1 resource acquisition is as much as 3,312 MW, or six times more than what PacifiCorp is effectively pursuing. Staff does not recommend revision of Action Item 5, but it does encourage PacifiCorp to continue to actively acquire all economic Class 1 resources.

[4] 2011 IRP, Appendix D, p. 129.
[5] 2011 IRP, Chapter 8, p. 246.

Class 3 DSM

PacifiCorp fails to model "any" Class 3 DSM in its 2011 IRP preferred portfolio. In the IRP, the Company explains the reasons that Class 3 DSM resource selections are not included for capacity planning purposes.

Staff highlights the following from PacifiCorp's sensitivity modeling:

Excerpts from 2011 IRP, Chapter 8, pg. 246:

> Case 31 included Class 3 DSM rate products as resource options using the medium natural gas and CO2 tax assumptions defined for Case 7. As noted in Chapter 7, the dispatchable irrigation load control programs were assumed to be substituted by a mandatory Time of Use (TOU) rate schedule with rates set sufficiently high to induce the desired load shifting behavior. This substitution occurs in 2015, when a TOU rate structure is assumed to be instituted. The resource potentials account for interaction effects between Class 1 and Class 3 resources.
>
> A total of 262 MW of Class 3 DSM was selected in the east and 131 MW selected in the west. The net gain in load control resources is 122 MW, which accounts for reduced Class 1 DSM capacity (70 MW) and the displacement of the dispatchable irrigation load control program (201 MW). This additional DSM capacity is sufficient to defer the second and third CCCT resources by one year. The portfolio PVRR decreased by about $236 million due to the relatively low cost of administering 3 DSM programs.

PacifiCorp's sensitivity study indicates that implementing the "relatively low cost" DSM programs can result in a deferment of the second and third CCCT resources by one year. Yet, PacifiCorp chooses "none" of the 514 MW of Class 3 potential in its preferred portfolio.

Staff's alternative portfolio, discussed below, caused the system optimizer model to choose 126 MW of mandatory TOU in the West and with other additions avoids the 2016 CCCT entirely, and focused only on Class 3 TOU with mandatory participation. In its reply comments, PacifiCorp resists Staff's alternative portfolio, which contemplates 125 MW of Class 3 DSM in the West modeled as mandatory time-varying rates for irrigation. The Company states that "there is considerable controversy regarding mandatory time-varying rates and that it is unrealistic to assume that Oregon would approve mandatory Class 3 DSM programs in time to affect the investment decision for the next major resource." This reason is somewhat perplexing. In Staff's opinion, controversy is not a compelling deterrent from pursuing the least-cost, least-risk portfolio.

PacifiCorp's sensitivity analysis for DSM-Case Study 31 models an assortment of Class 1 and Class 3 DSM programs, including; DLC Residential, Real-time pricing-Commercial & Industrial, Demand buy back, Critical Peak Pricing and TOU for irrigators. The fact that the Staff alternative portfolio caused the model to choose mandatory TOU should not distract from the fact that the Company has an assortment of DSM programs to choose from, in addition to TOU for irrigators. The table below presents the assortment of DSM programs modeled in Case Study 31. The total amount of DSM on the East side is 292.5 MW and 155 MW on the West side, considerably more than included in the Staff alternative portfolio. Staff believes this larger amount of DSM will allow for selecting a portfolio of DSM programs, while accounting for the interaction effects between the Class 1 and Class 3 DSM.

DSM Class 1 and Class 3 Programs

Program	Resource Totals 2014 (MW)
East	
DSM, Class 1, Utah, Coolkeeper	11
DSM, Class 3, Goshen, Critical Peak	1
DSM, Class 3, Goshen, TOU Irrig	60
DSM, Class 3, Utah, Critical Peak, Comm/Ind	19
DSM, Class 1, Utah, Curtailment	21
DSM, Class 3, Utah, Demand-buy back-Comm/Ind	6
DSM, Class 1, Utah, DLC, Res.	29
DSM, Class 3,Utah, Real Time Pricing, Comm/Indus	5
DSM, Class 3, Utah, TOU Irrig	117
DSM, Class 3, Wyoming, Critical Peak, Comm/Ind	11
DSM, Class 3, Wyoming, Demand-buy back-Comm/Ind	5
DSM, Class 3,Wyoming, Real Time Pricing, Comm/Indus	3
DSM, Class 3, Wyoming, TOU Irrig	5
DSM, East Total	292.5
West	
DSM Class 1, Walla Walla-DLC Res	1
DSM, Class 1, Oregon/California-Curtailment	16
DSM, Class 1, Oregon/California -DLC Res	6
DSM, Class 3, Oregon, Critical Peak Pricing	6
DSM, Class 3, California, TOU, Irrigation	26
DSM, Class 3, Oregon, TOU Irrigation	72
DSM, Class 3, Walla Walla, TOU, Irrigation	7
DSM, Class 3, Yakima, TOU, Irrigation	21
DSM, West Total	155

Conclusion

Staff believes PacifiCorp's reluctance to implement Class 3 DSM unnecessarily raises cost and/or risk for Oregon customers. Staff notes that Idaho Power has successfully implemented DSM programs similar to PacifiCorp's Class 1 and Class 3 programs since early 2003, boasting nearly 250 MW peak savings in 2010 in its irrigation sector demand response alone.

Distribution Energy Efficiency (Action Item 6 continued)

Recommended Requirement

Staff recommends the following action item be substituted for the third bullet in PacifiCorp's 2011 Action Item 6 in the IRP:

- A CVR acquisition project in PacifiCorp's Washington service area will begin in 2012 and end no later than 2018.

  The next filed PacifiCorp IRP will include an action plan item to acquire all of the available cost-effective conservation voltage reduction (CVR) throughout its service area by 2022. This action item will be based primarily on information from Yakima and Walla Walla service areas. Cost-effectiveness analyses will use the same methodology as the modeling approach used in the Class 2 DSM decrement assessment in the 2011 IRP Addendum.

Discussion

Staff maintains the positions on conservation voltage reduction (CVR) measures discussed in its initial comments. Below, Staff provides the reasoning for its positions and responds to PacifiCorp's reply comments.

History

From Order No. 10-066; Entered 02/24/2010 -- LC 47:

Modifications agreed to by PacifiCorp pursuant to Staff's recommendations: …Revised Action Items [and] Additional Action Items [first eight items omitted]***…***

"9. In the next IRP planning cycle, PacifiCorp will incorporate its assessment of distribution efficiency potential resources for planning purposes." (pp. 25-27)."

Staff Assessment of “incorporation” of CVR in PacifiCorp’s 2011 IRP

Staff asserts that the Company’s proposed portfolio in the 2011 Final IRP did not include distribution efficiency potential resources (a.k.a. Conservation Voltage Reduction or CVR) for planning purposes.

The IRP refers to a draft assessment of economic potential for CVR in the Yakima and Walla Walla service areas. PacifiCorp conducted an optimizer sensitivity test on the potential from these two areas. This test showed CVR to be a cost-effective resource.

PacifiCorp’s proposed CVR action item in the 2011 IRP is overly vague

Staff notes that its data request 12 asked “Please explain the meaning of the term “leverage” in the phrase “Leverage the distribution energy efficiency analysis of 19 distribution feeders in Washington”” in Action Item 6 in Table 9.1 – IRP Action Plan Update.”

In response PacifiCorp stated:

“The Company is now investigating the cost-effectiveness of applying CVR [based on results from the consultant’s study of Washington feeders] to specific Washington feeders. … The Oregon evaluation will use methods and lessons learned from the Washington study. … The Company plans to initiate investigation of the Oregon circuits in 2012, and will define a project timeline at that time.”

The IRP filed in LC 52 did not fulfill the agreement in Order No. 10-066. Even if PacifiCorp’s response above were substituted for Action Item 6, the revised 2011 action plan would not assure that the next IRP would fulfill the February 2010 agreement.

In its reply comments, PacifiCorp asserts that CVR acquisition on a system-wide basis is inappropriate as a candidate preferred portfolio resource option for the IRP because the resource's achievable potential and supply-cost relationship cannot yet be determined. This, they assert, prevents appropriate resource options from being developed and modeled for each state.

Staff notes that while there is uncertainty about any planning estimate, zero is clearly an incorrect estimate of the resource potential. Staff also asserts that based on analyses in the NW Power and Planning Council’s 6th Power Plan, studies by the Electric Power Research Institute, activities by other utilities and the Commonwealth study conducted for the Company, there is wealth of information that could provide a high quality estimate of CVR resource potential.

Staff proposes that in the next plan PacifiCorp develop an estimate using the Washington experience and any other information the Company finds relevant. Staff is not trying to predetermine the planning estimates of the CVR resource in the next plan.

PacifiCorp's reply comments provide no information about when alternative estimates of CVR potential might be available.

Given the schedule for CVR in Washington in Appendix 1 of the Company's reply comments, providing Company-wide cost and resource estimates in the next IRP and including CVR as a resource in the plan is doable and appropriate. Appendix 1 provides no information about the Company's plans to implement CVR in Oregon or other states.

In its reply comments PacifiCorp has not provided any specific reasons that it expects using the Washington experience would underestimate or overestimate the CVR resource potential in other states. If the Company believes that studies in other states, similar to the Commonwealth's study of Washington feeders, are essential for planning purposes, then it should design and conduct those studies as soon as possible. The Company has not indicated how the electrical topology of the 19 circuits studied by Commonwealth is atypical of its system. If so, it is unclear why PacifiCorp chose those circuits for is first study on its system.

CVR potential for PacifiCorp

Beginning in 2003 the Northwest Energy Efficiency Alliance (NEEA) conducted pilot studies with NW utilities. PacifiCorp participated in this study. Based on NEEA's final report in 2008,[6] the NWPCC included CVR saving for the region in its February 2010 *NWPCC 6th Power Plan*. The NWPCC projected 350 avg. MW of achievable CVR potential under a cost of $40 per MWh (2006$).[7] Extrapolating these CVR savings to PacifiCorp yields an estimate of 130 aMW.

The Electric Power Research Institute now has a fully operation program to help utilities implement CVR. NEEA has regionally approved protocols for assessing CVR potential. In 2009 Idaho Power Company implemented CVR at 6 Substations. The net annual value of saved energy and capacity is $313,000. Based on this success, IPC is planning to implement CVR at eight more substations in 2012. This work is being done with solely with IPC funds.

In 2008 when PacifiCorp assessed CVR in its last IRP process, it could reasonably argue that CVR was a new and untested resource option. In May of 2011, it completed a detailed economic study of 19 of its circuits in Yakima and

6 http://neea.org/research/reports/E08-192.pdf
7 Page 4-13 of http://www.nwcouncil.org/energy/powerplan/6/final/SixthPowerPlan_Ch4.pdf.

Walla Walla.[8] Based on an extrapolation of this study, Staff projects achievable cost-effective CVR savings for the PacifiCorp system of at least 64 MW (coincident peak) and 37 aMW (generation).

While these amounts of capacity and energy are small, the dollar value of the savings is large. PacifiCorp's consultant estimated a present value of savings of $2.5 million for 15 of the 19 circuits studied. Extrapolated to all of PacifiCorp, this represents a present value of $180 million. Even if this actual savings are only half this estimate, CVR belongs in PacifiCorp's preferred portfolio. In comparison the difference between the present value of revenue requirements for PacifiCorp's preliminary and revised preliminary preferred portfolios is $23.6 million (stochastic mean, p. 225 Vol. 1). This difference resulted from shifting the on-line date for the second CCCT from 2015 to 2016.

Staff asserts that the likely dollar savings from CVR are sufficient for the Commission to modify the Company's proposed IRP Action Item 6 on CVR. It is unresponsive to the needs of PacifiCorp customers, even with the clarification from PacifiCorp in its reply comments. To achieve acknowledgement of its next IRP, PacifiCorp's action plan should have an action item to acquire all the cost-effective CVR savings by a reasonable end date.

Appropriate timing of CVR rollout

The Staff proposed date of 2022 to complete CVR in the alternative action item above is based on the consultant's estimate of a seven year capital plan for Yakima and Walla Walla (Study page 59). While PacifiCorp is implementing CVR in Washington, it should prepare detailed CVR plans for all of its other service areas. PacifiCorp should implement CVR for the rest of its service area between 2015 and the end of 2022. The next eleven years is more than enough time for a careful and orderly roll-out of CVR.

Staff finds it reasonable for the Company to develop a realistic and effective timeline for CVR implementation. The Company's reply comments Appendix 1 does not indicate when the Company plans to complete its implementation of CVR in Washington. It also provides no information about its plans to implement CVR in the other states.

Staff advocates discussing CVR in other PacifiCorp states as part of the LC52. In its reply comments PacifiCorp objects to the Commission mandating project commitment dates for situs resources in other states. Staff asserts that it is valid for the Commission to examine the Company's CVR performance in other states.

[8] *Washington Distribution Energy Efficiency Study – Final Report*; by Commonwealth Associates as a contractor to PacifiCorp; May 2011

Staff notes that the Commission can judge the effects on the rates charged to Oregon customers from whether or not the Company acquires CVR throughout its system. This review can occur as part of the IRP process and in setting rates.

Support for estimates of CVR savings in Staff's Alternative Portfolio

Staff developed the CVR estimates of potential based, in part, on an examination of the Commonwealth study performed for PacifiCorp. Based on the Stage 1 measures in the study, Staff estimated a range of achievable economic energy savings of 0.59 to 0.83 percent of load.

Staff finds that this range is in the low end of published estimates. For example, the NWPCC 6th Power Plan estimates an achievable economic CVR saving of 1.6 percent of the Pacific NW energy loads by 2029. The NWPCC estimate is based on technologies that are commercially available now.

Staff assumed a cumulative savings by 2020 of 0.43 percent of energy loads – conservatively based on only Stage 1 measures. PacifiCorp's System Optimizer model used only about half of this economic potential to produce the Staff Alternative Portfolio – making the CVR component of the alternative portfolio even more conservative, and therefore reasonably attainable.

Firm Market Purchases (Action Item 3)

Recommended Requirement

None

Discussion

PacifiCorp presents in IRP Table 6.18 the maximum purchases available at six market hubs. The IRP does not include sufficient data for Staff to confirm these limits. Staff believes market purchases are a credible source of capacity and energy, and the preferred portfolio may not be exploiting these to full advantage.

Staff's further inquiry, through data requests, yielded nothing that would increase or decrease the front office supply/resource limitations listed in IRP Table 6.18 (Vol. I, page 151). As a result, while Staff's alternative portfolio (discussed below) makes greater utilization of front office transactions than does the Company's preferred portfolio, it does not go beyond the Table 6.18 limitations.

Capacity Planning Reserve Margin Determination (Action Item 8 continued)

Recommended Requirement

PacifiCorp will develop its 2011 IRP Update based on a 12 percent planning reserve margin, unless a different PRM is justified by a marginal cost study comparing costs of portfolios that are optimized for achieving the various PRMs, and including estimates of the marginal benefits from a greater PRM. The study should use loss-of-load hours and unserved energy as the dependent variables.

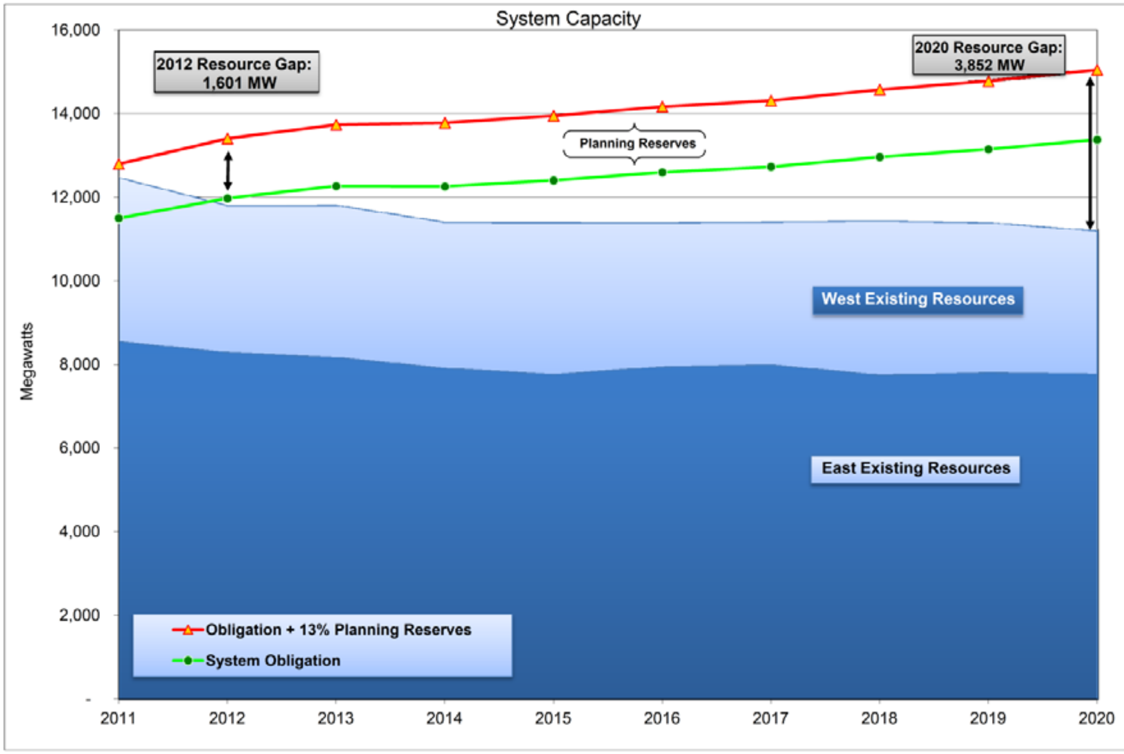
Discussion

Staff commented that PacifiCorp applied a "long-term reliability planning standard" to come up with its initial planning reserve margin (PRM) target, then adjusted it downwards as a proxy for the Northwest Power Pool's reserve sharing benefit, and came up with a figure of 13 percent. Reliability benefits of using non-firm transmission capacity to access off-system generation were not incorporated in this evaluation.

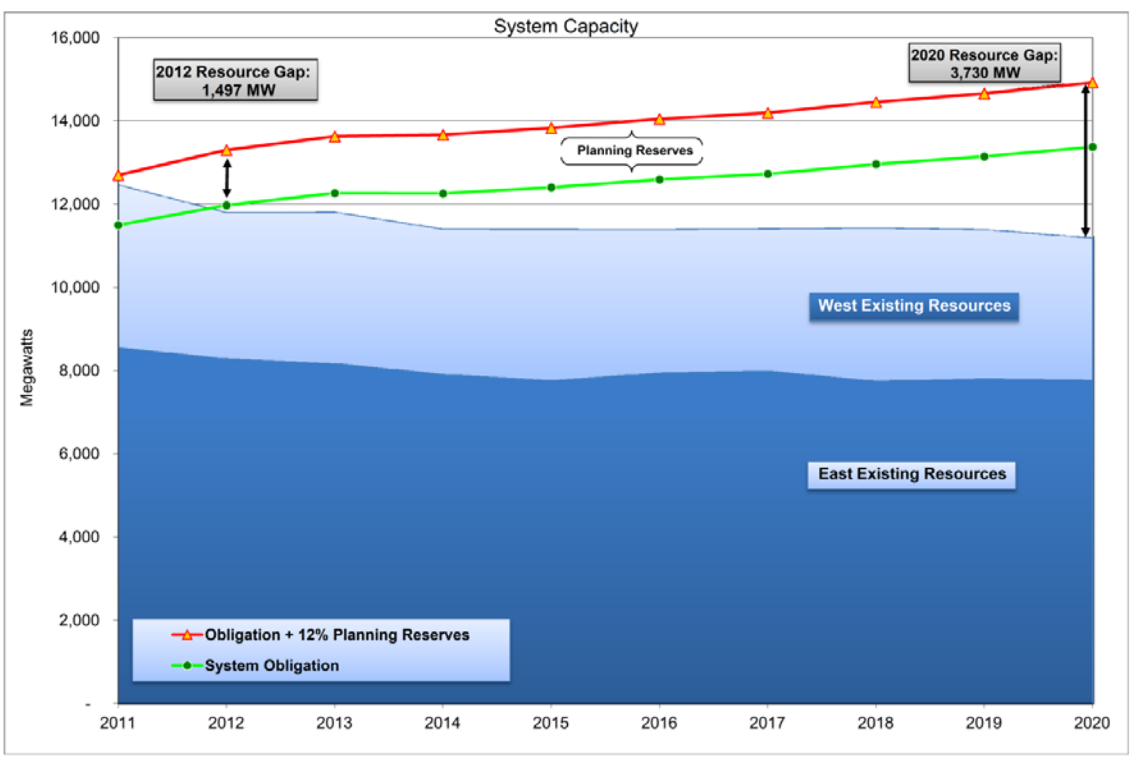
While the marginal costs for a range of PRMs were presented in IRP Appendix J, estimates of the marginal benefits of a13 percent PRM target were absent. Staff questions the usefulness of the presented marginal cost analysis. In comparing the PVRR of a 12 percent PRM portfolio with the PVRR of a 13 percent PRM portfolio, the incremental PRM values were achieved by adding simple-cycle combustion turbines (SCCTs) to a minimum-PRM portfolio. Staff considers this methodology to be a shortcoming of the risk analysis portion of the IRP**.** With aggregate loads approaching 15,000 MW in 2020, a one percent increase in PRM translates to more than 100 MW of extra capacity.

Staff requested, in data request 61, data behind the capacity balance determination presented in IRP Chapter 5. Using the supplied data, Staff was able to generate figures showing the Company's capacity position with both a 13 percent and 12 percent PRM. The figures are presented below for reference. Staff notes no difference in the date when the Company becomes capacity deficient and relatively little difference in the magnitude of the deficiency.

System Capacity with 13 Percent PRM



System Capacity with 12 Percent PRM



Whether PacifiCorp adopts a capacity PRM of 13 percent or maintains the current level of 12 percent is not a major concern on the part of Staff, partly because of the conservative assumptions built into the Company's formulation of its PRM and partly because Staff found no difference in the date when the Company becomes capacity deficient and relatively little difference in the magnitude of the deficiency. Having said this, Staff continues to believe that the contents of IRP Appendix J, which appeared to be the beginnings of a cost-benefit foundation for its PRM determination, was not convincing. Staff found that the costs of achieving the various PRM levels were not based upon portfolios that had been optimized for that purpose and no benefits, in the form of levels of unserved-energy avoidance, were provided. Instead, PacifiCorp used the historic industry standard of adopting a PRM that would be consistent with achieving a cumulative loss-of-load expectation of twenty-four hours in ten years.

ICNU "recommend[s] the Commission reject the higher 13 percent planning margin [PRM] the Company is seeking in its 2011 IRP and, at a minimum, maintain the current 12 percent margin." For the reasons stated above, Staff is neutral as regards this recommendation. ICNU voiced other concerns regarding the PRM – some of which were acknowledged as meritorious by PacifiCorp. As a concession in its reply comments, the Company did recognize "merit in discussing the role of non-firm transmission in the IRP," but argued that such a "major change" would require further deliberation by the Company "as well as other state commissions and stakeholders…." In its eleven pages of comments, ICNU presented the following arguments to support rejecting PacifiCorp's 13 percent PRM:

1. May was the month from PacifiCorp's LOLP (loss-of-load-probability) study that had the largest quantity of expected unserved energy[9] (i.e., where the utility lacked capability from within its own resource portfolio for meeting the load). Due to its being a low load month generally and part of the hydro run-off season particularly, May is also a low cost month when the spot market can be relied upon favorably as supplementing the utility's own reserve resources. The existence of a cheap alternative to internal reserves during a period when the reserves are most likely to be needed reduces the value of having the internal reserve.

2. ICNU cites a California Independent System Operator (CAISO) study which indicates that California will possess a 59 percent PRM in 2014.[10] Such reinforces the notion that a cheaper, market alternatives to internal reserves will be available, at least to the northwest.

---

[9] Explanation: Being a low load month makes May an attractive period for off-loading large baseload plants for the purpose of conducting preventive maintenance. Having such plants temporarily unavailable renders the utility more exposed to being unable to meet its load in the event of another plant going down due to some unforeseen equipment failure.

[10] Possible explanation: The exacting renewable portfolio standard requires a fairly large amount of back-up thermal capability, which is available to serve as a reserve resource.

3. ICNU performs a rudimentary cost-benefit analysis of PRM utilizing loss-of-load hours and unserved energy as the dependent variable. The conclusions were that increasing the PRM might have little effect on the loss-of-load hours in the northwest (i.e., depending upon the location of the reserve resource), and that the cost of additional reserves vastly exceeds the benefit.

Need for a 2016 Combined-Cycle Combustion Turbine Resource (Action Item 2)

Recommended Requirement

Recognizing the complexity of implementing DSM Classes 1, 2 and 3, and conservation voltage reduction (CVR) programs across its service territory, and the need to rely more upon market purchases to meet loads, Staff recommends that PacifiCorp pursue implementing the Staff alternative portfolio shown in Attachment 1 in lieu of its preferred portfolio. If, after demonstrating it diligently pursued implementation of the Staff alternative portfolio, PacifiCorp finds the resulting demand-side resources and market purchases insufficient to meet the need, it may file an IRP Update to justify acquiring supply-side resources to fulfill the remaining need. Attendant with implementing Staff's alternative portfolio is the recommendation that the 2014 CCCT construction proceed as planned and a request for proposals (RFP) for the 2019 CCCT proceed if updated load forecasts still identify the need.

Discussion

In its initial comments Staff reported it would continue to evaluate the need for additional post-2014 thermal resources. Staff's initial comments also reported its intention to evaluate the system capacity and energy positions of PacifiCorp's preferred portfolio and other top performing portfolios to assess how well the new resource additions match the capacity and energy need, and to assess market risk. Having done so, Staff's concerns related to PacifiCorp's preferred portfolio are presented below.

As documented above in the discussions of Energy Efficiency (Class 2 DSM) Resource Analysis, Load Control (Class 1 DSM) and Price Response (Class 3 DSM) Resource Analysis, Distribution Energy Efficiency, and Capacity Planning Reserve Margin Determination, Staff identified significant uncaptured resources that, in Staff's opinion, could indefinitely postpone construction of the proposed 2016 CCCT resource. Recognizing the complexity of implementing DSM Classes 1, 2 and 3, and conservation voltage reduction (CVR) programs across its service territory, and the need to rely more upon market purchases to meet loads, Staff recommends that PacifiCorp pursue implementing the Staff alternative portfolio (shown in Attachment 1) in lieu of its preferred portfolio. If, after demonstrating it diligently pursued implementation of the Staff alternative portfolio, PacifiCorp finds the resulting demand-side resources and market purchases insufficient to meet the need, it may file an IRP Update to justify acquiring supply-side resources to fulfill the remaining need. Attendant with implementing Staff's alternative portfolio is the recommendation that the 2014 CCCT construction proceed as planned and a request for proposals (RFP) for the 2019 CCCT proceed if updated load forecasts still identify the need.

Staff notes PacifiCorp's reply comments related to RNP's concern over selection of a CCCT in lieu of an SCCT, citing use of a stochastic cost adjustment that reduces CCCT capital costs. Staff also questions whether selecting a CCCT, which is typically a base load resource, to fulfill a capacity need, frequently met with an SCCT, is indeed the least cost alternative. Staff believes the capital cost/operating cost tradeoff between a CCCT and SCCT needs to be documented in future IRPs or IRP Updates. Staff believes, however, the bias toward CCCT resources that may exist does not likely significantly impact the analysis results. As a result, Staff does not recommend, for this IRP, a change in the Company's approach.

Staff confirmed PacifiCorp's forecast of both a capacity and energy deficit in the first ten years of the planning period, under base case assumptions. On a capacity basis with a 13 percent planning reserve margin, Staff confirmed PacifiCorp's forecast of a 326 megawatt (MW) capacity deficit in 2011, growing to a 2,767 MW capacity deficit in 2016.

On an annual energy basis (using maximum dependable capability of existing resources and a 13 percent planning reserve margin), PacifiCorp forecasts heavy load hour resource surpluses through 2014. Staff believes it is most revealing to evaluate the energy balance without a planning reserve margin, based on the economic dispatch of existing resources, and for all hours. On this basis, using data provided by PacifiCorp, Staff identified for 2011 an energy surplus of 1,546 average MW (aMW). In 2016, Staff identified an energy deficit of 551 aMW, and in 2020 a deficit of 2,016 aMW.

Retail sales by PacifiCorp have been volatile over the past 18 years. This history shows that PacifiCorp loads were strongly affected by the economic recessions that began in 2001and 2008. It also indicates flat or negative growth can extend for many years following a recession. While load growth in other parts of PacifiCorp's service area will differ from the Oregon portion, there is good reason to question whether total loads in the next few years will grow at the rate projected by PacifiCorp. Recognizing this fact leads Staff to believe there is good reason to consider flexibility in meeting the Company's resource needs.

Portfolio Selection

PacifiCorp's preferred portfolio includes adding three CCCTs in the 2014 to 2019 time period. Staff is concerned about this irreversible cost commitment given uncertainties in load forecasts and accompanying market conditions, and the risk of natural gas prices rising again to levels seen in the last decade. Staff's preference is a portfolio that offers planning flexibility to accommodate the three CCCTs if circumstances warrant, but with the primary intention of meeting the energy and capacity need with a more flexible approach. Furthermore, it is Staff's belief that even if PacifiCorp's forecasts are entirely accurate, a portfolio could be implemented, at a similar cost and risk as the Company's preferred portfolio, but without the irreversible cost commitment that could prove burdensome in the event that the forecasts are not accurate.

Staff's alternative portfolio

PacifiCorp's preferred portfolio includes adding CCCTs in years 2014, 2016, and 2019 (the first is designated as Utah North and the latter two as Utah South). Staff proposes an alternative portfolio that postpones the 2016 CCCT plant indefinitely, and substitutes additional demand-side resources sufficient to achieve the same planning reserve margin (13 percent) as is targeted with the preferred portfolio. The Staff alternative portfolio is shown on Attachment 1.

Staff's alternative portfolio adds more third-quarter, heavy-load-hour front-office transactions (FOT 3Q HLH) in both the eastern and western regions of the Company's service territory (with the associated West-to-East transfers), more Class 2 DSM (i.e. energy efficiency), more Class 3 DSM (i.e. using for demonstration purposes, mandatory agricultural TOU pricing in Oregon, California, and Washington[11]), and more CVR[12]. The precise amounts of those resources were determined for modeling by the Company, employing its System Optimizer model(s).

Related to FOT 3Q HLH, Staff initially commented that the IRP does not include sufficient data to confirm the limits in IRP Table 6.18. Staff stated its belief that market purchases are a credible source of capacity and energy, and the preferred portfolio may not be exploiting these to full advantage. Staff's further inquiry, through data requests, yielded nothing that would increase or decrease the front office supply/resource limitations listed in IRP Table 6.18 (Vol. I, page 151). As a result, while Staff's alternative portfolio makes greater utilization of front office transactions than does the Company's preferred portfolio, it does not go beyond the Table 6.18 limitations.

Advantages and disadvantages of Staff's alternative portfolio

The primary advantage of the proposed 2016 CCCT is PacifiCorp would be less reliant upon market purchases to meet its load. The primary disadvantages are that PacifiCorp would be acquiring that self-sufficiency at a cost that could not be

[11] Idaho and Utah already have, or are planned to have, extensive agricultural DSM (demand-side-management).
[12] It would build upon the pilot having been conducted in Washington

reversed in the event that the anticipated growth in load, or the opportunity to make off-system spot sales in the off/shoulder-peak hours/seasons, were not forthcoming, and at a cost that would include the risk of natural gas prices returning to those of the last decade. The chief advantage of Staff's alternative portfolio is its downward flexibility in terms of being able to incrementally scale back supply-side resource additions. Its disadvantages would lie in the complexity of implementing DSM Classes 1, 2 and 3 and CVR programs across its service territory, and having to rely more upon market purchases to meet loads.

General results from the supporting quantitative studies

PacifiCorp used both a deterministic and a stochastic approach in estimating the twenty-year present-value-revenue-requirements (PVRRs) associated with the various portfolios that it investigated. The deterministic approach employed ten combinations of carbon dioxide (CO2) costs and natural gas costs, in conjunction with load forecasts, as it estimated the PVRRs. Based upon the "nominal" combination (i.e., $19/ton CO2 costs and "Low" natural gas costs), the Staff alternative portfolio is comparable to, but has a slightly lower (0.09 percent) PVRR than, the preferred portfolio, and has about a one percent higher PVRR than PacifiCorp's Portfolio Case 3 (i.e. the preferred portfolio without 2100 MW in wind additions). For the nine other CO2 and natural gas cost combinations, the Staff alternative portfolio's PVRR is comparable to, but smaller than, the preferred portfolio's (with a difference ranging from 0.9 percent to 1.6 percent).

The stochastic PVRR estimation approach employs 100 Monte Carlo simulation runs where electricity prices, loads, natural gas prices, and thermal and hydro unit availabilities are allowed to vary based upon statistical distributions. Two sets of results were produced: one based upon CO2 costs of $19/ton, and the other at $0. The stochastic PVRR comparisons between the Staff alternative portfolio, the preferred portfolio, and the preferred portfolio "without wind" are comparable with the deterministic results under the nominal conditions. Apart from those comparisons, it is noteworthy that the upper 95th percentile PVRR for the Staff alternative portfolio is slightly less (on the order of 0.1 percent) than that of the preferred portfolio and preferred portfolio without wind for both the $0 and $19/ton CO2 price cases. Given CO2 at $0, the PVRR for the Staff alternative portfolio is slightly less (0.4 percent) than the PVRR of the preferred portfolio, but just under two percent greater than the preferred portfolio "without wind."

While not calling into question the quantitative study results, Staff noted that, counter-intuitively, PacifiCorp's deterministic studies show Staff's alternative portfolio resulting in more on-peak and off-peak sales revenues than would the preferred portfolio. The counter-intuitive sales revenue results may arise from the proportion of generation available for sale during peak price periods in the Staff alternative portfolio compared to the preferred portfolio.

Wind Resource Costs and Capacity Factors (Action Item 1)

Recommended Requirement

In the next IRP, PacifiCorp should 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. In addition, in future IRPs PacifiCorp should include a projection for wind acquisition with and without geothermal until a clearer picture emerges regarding the dry hole risk issue.

Discussion

Staff, in its initial comments, expressed no concern over the wind acquisition plans in Action Item 1. Staff notes the concerns raised by RNP and NWEC regarding wind costs, capacity factors and wind integration. However, PacifiCorp's stated reasons for not acquiring wind sooner than 2018 are related primarily to uncertainty over gas price, CO2 cost and availability of more cost effective geothermal. Initial capital cost and assumed capacity factor were also considerations but were not the deciding factors. Staff concludes that the concerns raised by RNP and NWEC regarding initial cost and capacity factor are addressed sufficiently in the IRP and PacifiCorp's reply comments. As a result, Staff recommends no change to the Company's short term wind acquisition plan. Should RNP and NWEC have continuing concerns in these areas, Staff believes the concerns are best resolved in the next IRP cycle. Staff addresses concerns about the wind integration model in Section III.A.8 below.

PacifiCorp used a statistically based "peak load carrying capability" (PLCC) method to derive capacity contribution from wind. The method uses resource availability and standard deviation of resource availability as inputs to a calculation of capacity contribution.[13] However, some of PacifiCorp's wind resources have only been in operation since 2010, providing little data. In the next IRP, PacifiCorp should 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.

Wind acquisition was greatly affected by assumptions regarding geothermal. PacifiCorp's model identified over 100 MW of geothermal as part of a least cost portfolio. However, the preferred portfolio does not include geothermal because of uncertainty over dry hole risk. Instead, PacifiCorp proposes to acquire "geothermal equivalent wind", using a formula based on ratio of wind and geothermal capacity factors. Thus, much of the wind generation described in Action Item 1 is actually a proxy for geothermal. The possibility of acquiring cost effective geothermal prior to 2018 is reason to support deferring new wind acquisition, at least for the next IRP cycle. Staff addresses PacifiCorp's geothermal plans and its steps to address dry hole risk by pursuing power

[13] The method is fully described in the paper cited in IRP footnote 35.

purchase agreements with third party developers in Section III.A.9 below. Staff believes future IRP cycles should include a projection for wind acquisition with and without geothermal. This projection would be useful particularly for purposes of planning transmission, which has a very long lead time.

Regarding the issues raised by RNP and NWEC, capacity factor and capital costs were not the dominant factors in the Company's wind acquisition plans. As PacifiCorp pointed out in Chapter 8 of the IRP, wind acquisition depended more on RPS requirements, incentives, level of cost effective geothermal development, carbon regulation, and gas price. PacifiCorp's response to the concern over assignment of Energy Gateway costs to wind resources is consistent with Staff's review of the transmission plan. For example, PacifiCorp did characterize the Wallula to McNary segment as largely driven by wind development, but the Utah segments were driven more by load growth in Utah[14]. PacifiCorp states that it will begin adding new wind resources in 2018. By that time, there will be more data and newer data on capital costs and capacity factor, and more up to date information on regulations and incentives. Since wind generation has a shorter lead time than CCCT generation or transmission, Staff believes there is no need to change the wind acquisition plans proposed in this IRP cycle. As a result, Staff believes continuing concerns by RNP and NWEC regarding capital cost and capacity factor assumptions can be addressed in the next IRP cycle.

Wind Integration Study (Action Item 8 continued)

Recommended Requirement

Staff strongly supports the timely establishment of a technical review committee (TRC) to assist PacifiCorp with navigating through the rapidly evolving VER integration issues for PacifiCorp's next wind integration study. Further, Staff recommends that this technical review committee be formed as soon as possible and that it be fully engaged to review the Company's proposals for analytical methods and data to be used in the study. To this end, Staff recommends that the Commission direct PacifiCorp to establish the TRC and identify its members within 30 days of the effective date of its Order. Finally, Staff recommends that PacifiCorp immediately establish a schedule for the study, including full opportunity for stakeholder involvement and progress reviews by the TRC that will allow the final study to be submitted with the Company's next IRP. Staff recommends that the Commission direct PacifiCorp to establish the schedule within 30 days of the effective date of its Order.

Discussion

The basis of variable energy resource (VER) integration cost analysis and the development of analytical techniques to measure them are evolving rapidly. Party

[14] Staff's detailed review of PacifiCorp's transmission plan appears below, in section III.A.12 of these comments

comments indicate a diversity of concerns regarding the process, methods, and data of the Wind Integration Study. Staff believes that the specific wind integration study concerns presented by parties fall outside the IRP process, and therefore does not recommend addressing them beyond recognizing what PacifiCorp provided in its reply comments. As noted by PacifiCorp in its reply comments, while wind integration is important from operational and rate-making perspective, it currently has a negligible impact on the Company's long-term wind resource acquisition strategy.

Staff strongly supports the timely establishment of a technical review committee (TRC) to assist PacifiCorp with navigating through the rapidly evolving VER integration issues for PacifiCorp’s next wind integration study. Staff’s recommendation is described above.

Geothermal Resources (Action Item 1 continued)

Recommended Requirement

Staff recommends future All-source RFPs explicitly invite geothermal developers to bid.

Discussion

PacifiCorp identified over 100 MW of geothermal as part of a least cost portfolio. However, Action Item 1 does not include short term acquisition of geothermal because of inability to recover development costs, particularly dry hole risk.[15] ODOE and RNP recommended that PacifiCorp work with stakeholders to address that risk. Staff agrees that by relying on independent geothermal developers, PacifiCorp would shift dry hole risk to third parties. ODOE and RNP requested that the Commission direct the Company to hold a geothermal-only RFP. In its response, PacifiCorp stated that it did invite geothermal developers to bid in its all-source RFP, and will do so again in a January 2012 all-source RFP.

Staff does not recommend directing the Company to hold a geothermal only RFP. Staff sees no reason why a geothermal only RFP would produce more bids than an All-source RFP. As a result, Staff disagrees with ODOE and RNP in this matter. Staff recommends future All-source RFPs explicitly invite geothermal developers to bid. Staff notes that the upcoming All-source RFP is proposed for issuance in January 2012, and is still in draft form. Staff believes that, to the extent the current All-source RFP is not conducive to geothermal development,

[15] Action Item 1 does not exclude geothermal completely. The company states that it will include geothermal projects as eligible resources in all-source RFP’s.

there is still time for stakeholders to discuss ways to address that concern in the All-source RFP process.[16]

Regarding recovery of dry hole risk, Staff does not believe that working with stakeholders is likely to yield a solution to dry hole risk. Staff believes the main barrier to recovery of costs associated with dry hole risk is the “used and useful” requirement. Further, Staff believes dry hole risk is a rate making issue and therefore outside the IRP process. As a result of the above, Staff disagrees with ODOE and RNP regarding dry hole risk in the context of this IRP.

Renewable Portfolio Standard Compliance Strategy (Action Item 1 continued)

Recommended Requirement

Expand the next IRP to include discussion of RPS compliance strategies and the role of REC sales and purchases. The Company is cautioned to be selective in its discussion to avoid conflict between the IRP, RPS Implementation Plan, and RPS Compliance Report.

Discussion

ODOE commented that the IRP is the appropriate place for PacifiCorp to evaluate alternate RPS compliance strategies and compare pros and cons of plans to sell RECs, acquire unbundled RECs, and follow other RPS compliance strategies. PacifiCorp, in its response comments, agreed to expand the next IRP to include discussion of RPS compliance strategies and the role of REC sales and purchases. PacifiCorp’s response comments included certain cautions about the handling of confidential information pertaining to RECs, and the need to coordinate information prepared for the IRP with information prepared for state RPS compliance reports.

Staff supports ODOE’s suggestion, adding its own caution that the IRP, RPS Implementation Plan, and RPS Compliance Report be coordinated so that they do not conflict.

Transmission Planning and Energy Gateway (Transmission Action Item)

Recommended Requirement

Staff recommends not acknowledging the Wallula to McNary and Sigurd to Red Butte projects unless and until the Company provides a demonstration, as discussed further below, that the alternative chosen is the most cost-effective alternative.

---

[16] Staff also notes of the Geothermal Information Request (IR) which PacifiCorp has opened from October 5, 2011 through October 31, 2011. The results of that IR could inform the final content of the All-source RFP.

Staff also recommends that in future IRPs the Company should include in its portfolio scenario any transmission project for which acknowledgment is requested, regardless of its size or scope.

Discussion

PacifiCorp requested that the Commission acknowledge three transmission projects scheduled to be in service by 2014.[17] These three projects are:

1. Wallula to McNary project (Energy Gateway Segment A);
2. Mona to Terminal project (Energy Gateway Segment C); and
3. Sigurd to Red Butte project (Energy Gateway Segment G).

Staff recommends not acknowledging the Wallula to McNary and Sigurd to Red Butte projects unless and until the Company provides a demonstration, as discussed further below, that the alternative chosen is the most cost-effective alternative.

Staff agrees with the Company's approach that the Energy Gateway is an overall expansion plan and each Energy Gateway project will be justified individually based on a combination of benefits. Staff followed this approach when analyzing the three transmission projects requested to be acknowledged in PacifiCorp's 2011 IRP. Staff believes approaching the Energy Gateway in this manner resolves the concerns outlined in comments by RNP and NWEC. Further, Staff concurs with PacifiCorp's reply comments as they relate to the Hemingway to Captain Jack project and FERC Order 1000, thus addressing related concerns by NWEC.

Wallula to McNary Project (Energy Gateway Segment A)

The Wallula to McNary transmission project consists of approximately 30 miles of single circuit 230 kV line between the Wallula, Washington substation and the McNary Oregon, substation near Umatilla, Oregon. The project cost is estimated at approximately $30 million. [18, 19]

In the body of PacifiCorp's 2011 Integrated Resource Plan (IRP), the Wallula to McNary project is not mentioned (i.e., neither in Chapter 4, "Transmission Planning" nor in Chapter 7, "Modeling Approach") until Chapter 10, "Transmission Expansion Action Plan," where the Company requests that this project be acknowledged.

[17] See PacifiCorp's 2011 IRP, Volume I, Chapter 10, "Transmission Expansion Action Plan," pages 282-285.
[18] See Docket No. UM 1495, Staff 200 Bless/13, lines 17-24, at http://edocs.puc.state.or.us/efdocs/HTB/um1495htb15551.pdf.
[19] For specific capital costs of this project, see confidential attachment of PacifiCorp's response to Staff Data Request 52.

Staff asked the Company to explain whether the Wallula to McNary project was included in the scenario or portfolio analysis of PacifiCorp's 2011 IRP. In PacifiCorp's response to Staff data request 35,[20] the Company stated:

"The Wallula to McNary 230 kV line was not included in Scenario 1 (Base Case) through Scenario 7 analysis. The segment consists of approximately 30 miles of 230 KV transmission line in response to transmission service requests to move 120 megawatts from the Wallula to the McNary substation. The segment is now part of the transmission system upgrades similar to any other projects required to serve customers and therefore, was not part of the Energy Gateway scenario analysis."

Staff recognizes that the estimated capital costs of $0.03 billion and the scope of this project are much less than the $1.00 billion[21, 22] estimated capital costs of the other two projects (i.e., Mona to Terminal and Sigurd to Red Butte) for which the Company is requesting acknowledgment in its 2011 IRP; however, Staff believes that if the Company requests acknowledgment of a transmission project in its IRP, such project should be included in its portfolio analysis. Nevertheless, Staff reviewed this project and analyzed its benefits and costs as if it were a standalone project.

Cost-Benefit Analysis

Using the information provided by PacifiCorp, Staff analyzed the project from two perspectives: the economic net benefits[23] and the non-economic net benefits.[24]

Economic Benefits

Regarding economic net benefits, the economic benefit-cost ratio[25] of the project is 0.82, which means that the economic benefits are less than (but relatively close to) the economic costs on a present value basis. Additionally, based on Docket No. UM 1495,[26] in which Staff analyzed the net present value of revenue requirement (PVRR) under different scenarios regarding initial capital cost and future transmission subscription,[27] Staff provided the following table, which

---

20 See PacifiCorp's response to Staff Data Request 35.

21 To arrive at this number, Staff subtracted the $800 million capital costs of the Populus to Terminal project (http://nttg.biz/site/index2.php?option=com_docman&task=doc_view&gid=623&Itemid=31) from the approximately $1.8 billion capital cost of the base case scenario (the base case scenario includes the Populus to Terminal project, Mona to Oquirrh project, Sigurd to Red Butte project, and Harry Allen upgrade; see PacifiCorp's 2011 IRP, Volume I, Chapter 7, page 169.)

22 For specific information on the capital costs for each segment of the Energy Gateway project, see confidential attachment of PacifiCorp's response to Staff Data Request 52.

23 In this context, the "net economic benefits" of a project are calculated by subtracting the "economic costs" from the "economic benefits" of the project on a present value basis. It is also known as "net financial benefits."

24 The "non-economic net benefits" are also called "non-economic benefits" or "non-financial benefits."

25 In this context, the "economic benefit-cost ratio" is the quotient produced by dividing the present value of economic benefits by the present value of economic costs.

26 Docket No. UM 1495 refers to PacifiCorp's petition for a Certificate of Public Convenience and Necessity for the Wallula to McNary transmission project.

27 See Docket No. UM 1495, Staff 200 Bless/10-15 at http://edocs.puc.state.or.us/efdocs/HTB/um1495htb15551.pdf

presents the additional subscription needed in years 2016, 2018, and 2020 for the project to break even.[28]

Additional Subscription[29] Needed to Reach the Economic Benefit-Cost Ratio of 1.00			
Capital Cost Sensitivities	New Subscription Beginning Years		
	2016	2018	2020
Base Cost	33 MW	38 MW	44 MW
Base Cost Plus 25%	78 MW	90 MW	105 MW
Base Cost Plus 50%	124 MW	145 MW	166 MW

Staff also asserted that "based on a range of scenarios for the cost of the project and utilization of the proposed line, it is likely that the economic benefits of the project will equal the economic costs on a net present value basis." [30]

Additionally, as represented in Docket No. UM 1495:

"Staff [noted] that, due to uncertainties inherent in any project, the benefits to Pacific Power customers are not certain. Staff [concluded] however, that its economic analysis showed a reasonable likelihood that the project's benefits exceed its costs.

Staff [added] that any risk to Oregon Pacific Power customers is offset by the benefits to EWEB's customers. Staff [estimated] that the M2W Line will provide net benefits to EWEB customers of $1.4 million per year. Staff [added] that, over the 50 year life of the project, this equals a NPVRR benefit of $14.8 million to EWEB customers. Staff therefore [concluded] that, if EWEB customers are included in the analysis, Oregonians clearly benefit from the project."[31]

Finally, in Order No. 11-366 of Docket No. UM 1495 entered on September 22, 2011[32], the Commission granted a Certificate of Public Convenience and Necessity for the Wallula to McNary transmission line. [33] However, the Commission also stated:

---

[28] The break-even point in this context is the point at which transmission revenues cover all costs on a net present basis; therefore, the project has a net revenue requirement of zero when subscription revenues equal annual costs on a net present basis. See Docket No. 1495, Staff/200 Bless/11 at http://edocs.puc.state.or.us/efdocs/HTB/um1495htb15551.pdf. Alternatively, the economic benefit-cost ratio is 1.

[29] The total capacity of the transmission line is 400 MW.

[30] See Docket No. UM 1495, Staff 200 Bless/3, lines 15 to 18 at http://edocs.puc.state.or.us/efdocs/HTB/um1495htb15551.pdf

[31] See Order No. 11-366 of Docket No. UM 1495, page 8.

[32] See http://apps.puc.state.or.us/orders/2011ords/11-366.pdf

[33] See Order No. 11-366 of Docket No. UM 1495, page 12.

"[I]n making this decision, we emphasize that our inquiry and analysis in this case are limited. We are not acting in our traditional ratemaking capacity in this proceeding. As noted above, ORS 758.015 provides this Commission to issue a CPCN to facilitate the condemnation of land necessary for the construction of transmission lines. Thus our decision here is akin to a governmental resolution of necessity to condemn private land. We are granting condemnation authority only. Because we are not pre-approving the M2W Line or making any determinations about future cost recovery, we make no specific conclusions about the effect of the project on Pacific Power's Oregon customers. Contrary to the analysis provided by Pacific Power and Staff, we limit our public interest determination based on the project's cost and benefits to all Oregonians. Whether the M2W Line specifically benefits Pacific Power's customers will be addressed in other proceedings, in which Pacific Power will need to provide additional supporting information." [34]

Non-economic Benefits

The project has the following non-economic benefits:

- The project is necessary for PacifiCorp's current native load served from the Wallula substation as a contingency for addressing abnormal operating conditions. [35, 36]

- The project is necessary for PacifiCorp to be capable of serving its future native load in the Walla Walla area once the Walla Walla to Wallula sub-segment (26 miles) has been built.[37, 38]

- The project is necessary to provide transmission access for proposed wind generation in the area per the Federal Energy Regulatory Commission Open Access Transmission Tariff requirements. [39, 40]

- The project has entered into two transmission service contracts for service from Wallula to McNary to move the output from a total of 120 MW of generation resources to markets. [41, 42]

---

[34] See Order No. 11-366 of Docket No. UM 1495, pages 8 and 9.
[35] See PacifiCorp's response to Staff Data Request 72, part "a," .
[36] See PacifiCorp's response to Staff Data Request 100, part "a,".
[37] The Walla Walla to McNary segment (56 miles) comprises the Walla Walla to Wallula sub-segment (26 miles) and the Wallula to McNary sub-segment (30 miles). Acknowledgement of the Wallula to McNary sub-segment was requested in PacifiCorp's 2011 IRP, Volume I, Chapter 10, "Transmission Expansion Action Plan," pages 282 and 283.
[38] See PacifiCorp's response to Staff Data Request 100, part "a,".
[39] See PacifiCorp's response to Staff Data Request 72, part "b," .
[40] See non-confidential part of PacifiCorp's response to Staff Data Request 48.
[41] See PacifiCorp's 2011 IRP, Volume I, Chapter 10, "Transmission Expansion Action Plan," page 283, second paragraph.
[42] See PacifiCorp's response to Staff Data Request 72, part "e,".

- This project has been assessed and compared to a transmission line alternative which is approximately 130 percent more expensive.[43]

- The project is represented by the Company as meeting Commitment 34c of the MidAmerican Energy Holdings Company acquisition of PacifiCorp.[44, 45]

Conclusion

Because the economic benefit-cost ratio of the project is less than one, Staff recommends not acknowledging the Wallula to McNary transmission project, unless and until the Company provides:

1. An analysis showing that another wind project will be developed in the Wallula area, resulting in more revenues to achieve a benefit-cost ratio equal to, or at least, one; and

2. An analysis quantifying other non-economic benefits. (e.g. the project is necessary as a contingency for addressing abnormal operating conditions)

Staff also recommends that in future IRPs the Company should include in its portfolio scenario any transmission project for which acknowledgment is requested, regardless of its size or scope.

Mona to Terminal Project (Energy Gateway Segment C)

The Mona to Terminal project comprises two segments: the Mona to Oquirrh segment and the Oquirrh to Terminal segment.

The Mona to Oquirrh segment consists of a single circuit 500 kV line that will run approximately 69 miles between the new Clover substation to be built near the existing Mona substation in Juab County to the new Limber substation to be constructed in Tooele County, and a double circuit 345 kV line extending approximately 31 miles between the Limber substation and the existing Oquirrh substation in West Jordan. The Oquirrh to Terminal segment consists of a double circuit 345 kV line running approximately 14 miles between the Oquirrh substation and the Terminal substation.[46]

[43] See confidential attachment of PacifiCorp's response to Staff Data Request 48, page 5.
[44] See PacifiCorp's 2011 IRP, Volume I, Chapter 10, "Transmission Expansion Action Plan," page 283, third paragraph.
[45] See PacifiCorp's response to Staff Data Request 70.
[46] See PacifiCorp's 2011 IRP, Volume I, Chapter 10, "Transmission Expansion Action Plan," page 284, first paragraph.

The capital cost of the Mona to Terminal project including the Sigurd to Red Butte project and the Harry Allen upgrade is approximately $1 billion.[47, 48]

Escalation of Costs

In Chapter 4 of PacifiCorp's 2011 IRP, the Company selects and models seven Energy Gateway scenarios using the Company's System Optimizer capacity expansion tool. These scenarios ranged from a "base case" scenario with minimal transmission planning (including only the Populus to Terminal, Mona to Oquirrh, and Sigurd to Red Butte projects) to the full "incremental" Energy Gateway strategy (including Energy Gateway West, Aeolus to Mona, and west-side projects).[49] In Chapter 10 of PacifiCorp's 2011 IRP, the Company requests acknowledgment of the Mona to Oquirrh and Oquirrh to Terminal segments, which PacifiCorp refers to collectively as Energy Gateway Segment C.[50]

In Chapter 4, the Company mentions only the Mona to Oquirrh segment, but in Chapter 10, the Company requests acknowledgment of both segments: the Mona to Oquirrh segment and the Oquirrh to Terminal segment.

In PacifiCorp's supplemental response to Staff data request 33,[51] the Company shows that the capital cost values used in analyzing scenarios in Chapter 4 include the costs of the Oquirrh to Terminal segment; in other words, the capital costs of the Mona-Terminal project (both segments) are included in Chapter 4 of PacifiCorp's IRP.

Staff observes a 12 percent cost discrepancy between the capital costs of the Mona to Terminal project as represented in PacifiCorp's confidential response to Staff Data Request 52[52] and the capital costs represented in PacifiCorp's confidential supplemental response to Staff data request 33.

Cost-Benefit Analysis

Using the information provided by PacifiCorp, Staff analyzed the project from two perspectives: the economic net benefits[53] and non-economic net benefits.[54]

---

[47] For arriving at this number, Staff subtracted the $800 million capital costs of the Populous to Terminal project (http://nttg.biz/site/index2.php?option=com_docman&task=doc_view&gid=623&Itemid=31) from the approximated $1.8 billion capital cost of the base case scenario. The base case scenario includes the Populus to Terminal project, Mona to Oquirrh segment, Sigurd to Red Butte segment, and Harry Allen upgrade (See PacifiCorp's 2011 IRP, Volume I, Chapter 7, page 169.)

[48] For information of capital costs for each segment of the Energy Gateway project, see confidential attachment of PacifiCorp's response to Staff Data Request 52.

[49] See PacifiCorp's 2011 IRP, Volume I, Chapter 4, "Transmission Planning," page 67.

[50] See PacifiCorp's 2011 IRP, Volume I, Chapter 10, "Transmission Expansion Action Plan," page 284.

[51] See confidential attachment of PacifiCorp's first supplemental response to Staff Data Request 33, workbook "Attach OPUC 33 -2 CONF 1st Supp," worksheet "Capital Cost EG1."

[52] See confidential attachment of PacifiCorp's response to Staff Data Request 52.

[53] In this context, the "net economic benefits" of a project are calculated by subtracting of the "economic costs" from the "economic benefits" of the project in a present value basis. It is also known as "net financial benefits."

[54] The "non-economic net benefits" are also called "non-economic benefits" or "non-financial benefits."

Regarding economic net benefits and focusing only on the Mona to Oquirrh segment, in response to Staff data request 43, [55] PacifiCorp provided the Investment Appraisal Document for the Mona to Oquirrh segment, in which the Company provided the economic benefits of the project represented by the present value of variable production cost savings calculated using the Company's IRP Production and Resource Model[56] and economic costs of the project represented by the PVRR. The project presents an economic benefit-cost ratio[57] of 0.95. Focusing on the combined Mona to Terminal project, the project presents an economic benefit-cost ratio of 1.12; [58] in other words, the expected economic benefits of the project are greater than the economic costs on a present value basis.

The Mona to Terminal project has the following non-economic benefits:

- The project is necessary for PacifiCorp to be able to serve its current native load.[59]

- The existing transmission system has limited capability to deliver energy into the largest load center in Utah (the Wasatch Front area.) [60, 61]

- The Mona Substation is a critical hub through which power is imported from PacifiCorp's southern intertie lines. It also serves as an important interconnection point with other sources of generation. [62]

- This project is key to maintaining reliability since the capacity north of the Mona substation is fully subscribed and constrained. [63]

- This project has been assessed and compared to an alternative transmission line which costs approximately 40 percent more.[64]

- This project is key to maintaining the Company's compliance with mandated North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability and performance standards during

---

55 See confidential attachment of PacifiCorp's response to Staff Data Request 43.

56 The Company provided the present value of variable production cost savings under four scenarios, which were averaged by Staff.

57 In this context, the "economic benefit-cost ratio" is the quotient yielded by dividing the present value of economic benefits by the present value of economic costs.

58 See confidential attachment of PacifiCorp's response to Staff Data Request 93.

59 See PacifiCorp's response to Staff Data Request 76, part "a,".

60 See PacifiCorp's 2011 IRP, Volume I, Chapter 10, "Transmission Expansion Action Plan," page 284, second paragraph.

61 See PacifiCorp's response to Staff Data Request 98.

62 See PacifiCorp's 2011 IRP, Volume I, Chapter 10, "Transmission Expansion Action Plan," page 284, second paragraph.

63 See PacifiCorp's 2011 IRP, Volume I, Chapter 10, "Transmission Expansion Action Plan," page 284, second paragraph.

64 See confidential attachment of PacifiCorp's response to Staff Data Request 43, page 13.

normal system operations and during certain transmission system and generation plant outages. [65, 66]

Conclusion

Staff recommends acknowledging the Mona to Terminal project, based on the information provided by the Company.

Sigurd to Red Butte Project (Energy Gateway Segment G)

The Sigurd to Red Butte project, part of Gateway South, is a single circuit 345kV line that runs approximately 160 miles between the Sigurd substation near Richfield, Utah, and an expanded Red Butte substation near Central in Washington County, Utah. [67]
The capital cost of the Sigurd to Red Butte project, including the Mona to Terminal project and the Harry Allen upgrade, is approximately $1 billion.[68, 69]

Cost Benefit Analysis

In Staff Data Request 44,[70] Staff asked PacifiCorp to provide the financial analysis justifying the Sigurd to Red Butte project, to which PacifiCorp responded that "The Sigurd to Red Butte final authorization has not been secured yet because the project is still in the detail scoping phase. Therefore, an Investment Appraisal Document has not been created, but will be completed before final authorization." Staff followed up on this response in Staff Data Request 94,[71] to which the Company responded by providing certain financial information.

Staff reviewed the information provided by the Company, but found no evidence that the Company has evaluated any alternative to the proposed single circuit 345 kV line. Alternatives could include a transmission line with a different voltage, a new generating resource in the Red Butte substation surroundings, or other options.

Using the information provided by PacifiCorp, Staff analyzed the project from two perspectives: the economic net benefits[72] and the non-economic net benefits.[73]

---

65 See PacifiCorp's 2011 IRP, Volume I, Chapter 10, "Transmission Expansion Action Plan," page 284, second paragraph.

66 See also PacifiCorp's response to Staff Data Request 49.

67 See PacifiCorp's 2011 IRP, Volume I, Chapter 10, "Transmission Expansion Action Plan," page 285, first paragraph.

68 To arrive at this number, Staff subtracted the $800 million capital costs of the Populous to Terminal project (http://nttg.biz/site/index2.php?option=com_docman&task=doc_view&gid=623&Itemid=31) from the approximately $1.8 billion capital cost of the base case scenario. The base case scenario includes the Populus to Terminal segment, Mona to Oquirrh segment, Sigurd to Red Butte segment, and Harry Allen upgrade (see PacifiCorp's 2011 IRP, Volume I, Chapter 7, page 169).

69 For specific information on the capital costs for each segment of the Energy Gateway project, see confidential attachment of PacifiCorp's response to Staff Data Request 52.

70 See PacifiCorp's response to Staff Data Request 44.

71 See confidential attachment of PacifiCorp's response to Staff Data Request 94.

72 In this context, the "net economic benefits" of a project are the subtraction of the "economic costs" from the "economic benefits" of the project. It is usually compared in a present value basis. It is also known as "net financial benefits."

73 The "non-economic net benefits" are also called "non-economic benefits" or "non-financial benefits."

In the confidential response to Staff Data Request 94, the Company provided the economic benefits of the project represented by the present value of variable production cost savings calculated using the Company's IRP Production and Resource Model and the economic costs of the project represented by the PVRR. The project presents an economic benefit-cost ratio of 0.44; in other words, the expected economic benefits of the project are lower than the economic costs on a net present value basis.

From the non-economic perspective, the benefits of the Sigurd to Red Butte project are:

- The project is necessary to be able to serve PacifiCorp's native load.[74]

- The project is necessary because the capacity of the southwest Utah transmission system, including the existing Sigurd to Three Peaks to Red Butte 345 kV transmission line, is fully utilized and cannot provide adequate service under all expected operating conditions. Loads in southwestern Utah are forecasted to surpass the capabilities of the existing transmission system. Without the project, peak load in southwest Utah cannot be served reliably in the event of transmission line outages or major equipment contingencies.[75, 76]

- The Sigurd to Red Butte project will improve the transmission system's ability to transport energy into southwest and central Utah, as well as high-growth urban areas in and around Salt Lake City and along the Wasatch Front.[77]

- The project is key to maintaining the Company's compliance with mandated North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability and performance standards as necessary during normal system operations and system outage conditions.[78, 79]

Conclusion

Because the economic benefit-cost ratio of the project is less than one, Staff recommends not acknowledging the Sigurd to Red Butte transmission project, unless and until the Company provides:

[74] See PacifiCorp's response to Staff Data Request 78, part "a," .
[75] See PacifiCorp's 2011 IRP, Volume I, Chapter 10, "Transmission Expansion Action Plan," page 285, second paragraph.
[76] See confidential attachment of PacifiCorp's response to Staff Data Request 50, page 5.
[77] See PacifiCorp's 2011 IRP, Volume I, Chapter 10, "Transmission Expansion Action Plan," page 285, second paragraph.
[78] See PacifiCorp's non-confidential part of response to Staff Data Request 50.
[79] See PacifiCorp's 2011 IRP, Volume I, Chapter 10, "Transmission Expansion Action Plan," page 285, third paragraph.

1. An analysis including other economic benefits and quantifying other non-economic benefits to achieve a benefit-cost ratio equal to, or at least, one.

2. An analysis (e.g. the project's Investment Appraisal Document) demonstrating that the alternative chosen is the most cost-effective alternative.

Energy Storage (Action Item 1 continued)

Recommended Requirement

Staff recommends that the consultant storage study in IRP Action Item 1 be framed in the overall context of flexibility needs, sources and adequacy, and that the study include the following elements:

1) Definition of and suggest metrics by which to measure flexibility (applicable to all flexibility resources including: thermal, demand response (DR), and storage)

2) An inventory of existing flexibility needs and the adequacy or capability of existing assets to meet them

3) A projection of flexibility needs in the IRP timeframe to successfully integrate projected VER additions

4) A comparison of benefits and costs of obtaining flexibility from the range of flexible resources (conventional thermal, DR, storage, etc.)

5) A discussion of the potential for other sources of flexibility, such as regional VER integration efforts (including but not limited to the EIM proposal) to reduce integration requirements and costs.

Discussion

As an initial matter, Staff concurs with PacifiCorp that a consideration of the value and benefits of storage is warranted. However, Staff encourages PacifiCorp to consider storage within the broader context of flexibility needs, sources and adequacy and to consider how this emerging need, driven largely by the rapid introduction of variable energy resources (VERs), fits within the overall analytical framework of system planning.

Energy storage adds operational flexibility allowing a balancing area's system to respond rapidly and accurately to changing load conditions. Such flexibility arising from the various storage technologies could be beneficial from the very short term (second-to-second frequency regulation, for example) to intra-hour ramping and to diurnal or weekly time periods. Storage may be able to more economically absorb the wear and tear on traditional automated generator control (AGC) thermal units now being used to respond to net load variations resulting from increasing penetration of VERs, primarily wind and solar. Storage is neither a pure capacity asset nor a pure energy (or simple arbitrage) asset; it is a flexibility asset, in some cases even providing transmission support. Further, the values of storage go well beyond simple time-shifting arbitrage and vary with technology and the role of storage in system operations. With these preliminary thoughts in mind, Staff recommends that the consultant storage study in IRP Action Item 1 be framed in the overall context of flexibility needs, sources and adequacy, and that the study include the elements listed above.

Adherence of the Plan to Integrated Resource Planning Guidelines

<u>Recommended Requirement</u>

None

<u>Discussion</u>

Among parties to this docket there was unanimous agreement that PacfiCorp's 2011 IRP, as filed on March 31, 2011, did not comply with Guidelines 4(g) and 1(c) because it failed to provide a comprehensive evaluation of the compliance of its existing coal fired generation resources with new, draft, and anticipated environmental regulations. IRP Guideline 4(g) requires the utility to identify key assumptions about the future, including assumptions about future environmental compliance costs. IRP Guideline 1(c) sets the primary goal of the IRP to be the selection of a portfolio of resources with the best combination of cost and risk for the utility and ratepayers. Without a comprehensive evaluation of these environmental compliance costs, parties commented it was not possible to determine whether any of the candidate resource portfolios meet this standard.

In response to this deficiency, PacifiCorp submitted a Supplemental Coal Replacement Study with its Reply Comments on September 21, 2011. The study evaluated, on a unit by unit basis, whether its coal fired resources would be more economic than a replacement resource when including the additional cost of bringing those resources in full compliance with new, draft, and anticipated environmental regulations. The Coal Study concluded PacifiCorp's coal fleet, with planned incremental investments, will continue to provide reliable and least cost electric service to customers.

By including the Supplemental Coal Replacement Study, Staff believes the PacifiCorp 2011 IRP reasonably complies with the IRP Guidelines. Staff notes that Guideline 4a, which requires an explanation of how the utility met each substantive and procedural requirement, was not provided. Refer to Attachment 2, prepared by Staff, for a table presentation of compliance by Guideline.

This concludes Staff's Final Comments.

Dated at Salem, Oregon, this 13th day of October, 2011.

Erik Colville

Erik Colville
Senior Utility Analyst
Electric Rates & Planning

Attachment 1
Staff Alternative Portfolio

Study Name: I11C03_6_OPUC158

Study Description: 2011 IRP Preferred portfolio modified for OPUC Data Request #158 (Add CVR, and Class III DSM, No other until 2021). (8/19/2011 5:56:15 PM)

PVRR: $40,040

		Capacity (MW)																				Resource Totals 2/	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																							
	CCCT F 2x1	-	-	-	625	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	597	625	1,222
	CCCT H 1x1	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	475	475
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Wind, WY, 35	-	-	-	-	-	-	-	140	300	200	200	200	200	200	100	100	100	100	100	-	640	1,940
	Wind, Project II	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Total Wind	-	-	-	-	-	-	-	300	300	200	200	200	200	200	100	100	100	100	100	-	800	2,100
	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	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	8	8
	DSM, Class 1, UT-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, GO-DLC-IRR	-	-	-	-	8	-	-	-	-	-	1	-	-	-	-	1	-	-	-	-	8	10
	DSM, Class 1, UT-Curtail	-	43	-	-	-	6	22	-	-	-	-	-	-	-	-	-	-	-	-	-	71	71
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	45	40	-	-	-	-	-	-	-	-	-	-	-	-	85	85
	DSM, Class 1, UT-DLC-IRR	-	-	-	-	6	6	-	-	-	-	1	-	-	-	-	2	-	-	-	-	11	14
	DSM, Class 1, UT-Sch-TES	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1 Total	6	48	-	-	14	12	67	44	-	-	2	-	-	-	-	3	-	-	-	-	190	195
	DSM, Class 2, GO	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	14	38
	DSM, Class 2, UT	45	49	41	44	54	71	70	70	55	74	62	60	57	60	60	65	60	63	64	66	573	1,189
	DSM, Class 2, WY	3	4	4	5	5	6	7	7	7	8	9	9	11	13	14	18	20	23	29	31	55	232
	Conservation Voltage Reduction, East	-	-	-	13	5	5	5	5	-	-	-	-	-	-	-	-	-	-	-	-	33	33
	DSM, Class 2 Total	48	53	46	63	66	83	84	84	64	84	73	70	70	76	77	86	82	89	95	99	675	1,492
	Micro Solar - WH	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	-	-	-	-	-	-	-	-	-	24	26
	FOT Mead Q3	-	168	264	-	99	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	63	32
	FOT Utah Q3	200	219	248	-	-	160	200	250	-	209	250	-	-	-	-	-	-	-	-	-	149	87
	FOT Mona-3 Q3	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 Q3	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	1/ Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	163	231	309	-	258	36	2	N/A	100
	1/ Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	17	184	214	-	283	302	-	N/A	100
	1/ Growth Resource Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37	156	-	454	352	-	N/A	100
West																							
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	-	0.3	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, WM-Curtail	-	-	36	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	36	36
	DSM, Class 1, WM-DLC-RES	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 3, CA-TOU-IRR	-	-	-	26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 3, OR-TOU-IRR	-	-	-	72	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	72
	DSM, Class 3, WW-TOU-IRR	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 3, YA-TOU-IRR	-	-	-	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	21
	DSM, Class 1 Total	-	-	36	126	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	168	168
	DSM, Class 2, WA	4	4	4	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	4	46	89
	DSM, Class 2, WM	51	51	54	59	60	60	59	52	52	52	52	52	52	52	52	52	44	36	36	36	551	1,016
	DSM, Class 2, YA	6	6	6	6	6	6	6	7	7	7	8	7	7	9	9	7	6	6	6	7	61	134
	Conservation Voltage Reduction, West	-	-	-	7	2	2	2	2	-	-	-	-	-	-	-	-	-	-	-	-	15	15
	DSM, Class 2 Total	61	61	65	77	73	72	72	65	63	63	65	64	64	66	66	63	54	46	46	47	673	1,254
	OR Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	OR Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - WH	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	-	-	-	-	-	-	-	-	-	16	18
	FOT COB Q3	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	32
	FOT MidColumbia Q3	-	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	360	380
	FOT MidColumbia Q3 - 2	-	271	211	215	249	257	273	295	318	340	-	-	-	-	-	-	-	-	-	-	243	121
	FOT West Main Q3	-	50	50	50	50	50	50	50	-	50	50	50	50	50	50	50	50	50	50	50	40	45
	1/ Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	205	199	211	52	35	204	95	80	45	N/A	112
	1/ Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	51	189	-	-	-	768	-	342	649	N/A	200
	1/ Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	128	101	145	328	283	171	169	334	340	N/A	200
	Annual Additions, Long Term Resources	137	196	168	904	167	197	233	519	912	358	353	339	339	346	248	257	241	240	246	748		
	Annual Additions, Short Term Resources	350	1,259	1,473	1,115	1,148	1,266	1,223	1,295	1,018	1,299	1,000	1,134	1,239	1,287	1,581	1,747	1,894	2,010	2,196	1,787		
	Total Annual Additions	487	1,455	1,640	2,019	1,315	1,462	1,457	1,814	1,930	1,656	1,353	1,473	1,579	1,633	1,829	2,005	2,135	2,250	2,443	2,534		

1/ Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

2/ Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

1

Attachment 2
Guideline Compliance Table

PacifiCorp 2011 Integrated Resource Plan (IRP)

In considering whether to acknowledge an Integrated Resource Plan, the Public Utility Commission of Oregon reviews the Plan for adherence with its Guidelines for resource planning. The following table presents Staff's review of the IRP for adherence with Commission Guidelines, with each Guideline addressed separately. A complete copy of the Guidelines can be found in Commission Order No. 07-002 and Order No. 08-339.

Guideline		**Description**	**Location Where Addressed in IRP**
1	Substantive Requirements	Under Guideline 1, an electric utility should: a. Evaluate all resources on a consistent and comparable basis; b. Consider risk and uncertainty; c. Select a portfolio with the best combination of expected costs and associated risks and uncertainty for the utility and its customers; and, d. Be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	Chapters 7 and 8 evaluate resources on a consistent and comparable basis. Chapters 3 and 7 consider risk and uncertainty, Chapter 8 selects a portfolio considering costs, risks and uncertainty. Chapter 8 evaluates consistency with energy policies.
2	Procedural Requirements	Guideline 2 is a description of procedural requirements that require a utility to include the public as well as other utilities in the IRP planning process.	Chapter 2 describes compliance with procedural requirements.
3	Plan Filing, Review, and Updates	Guideline 3 states that a utility must file its IRP two years from the date of acknowledgement of the previous plan.	Chapter 2 discusses filing, review and updates.
4	Plan Components	Guideline 4 requires a utility to include 14 components in its IRP evaluation.	Component 1 (4a), which requires an explanation of how the utility met each substantive and procedural requirement, was not provided. The other 13 components are addressed in Chapters 3 through 10.
5	Transmission	Guideline 5 requires the Company to consider transmission as a resource option, taking into	Chapters 4 and 10 specifically address transmission. Transmission is also a

Guideline		Description	Location Where Addressed in IRP
		consideration its value for making additional purchases and sales, accessing less costly resources in remote locations, and improving reliability.	component of Chapters 7 and 8.
6	Conservation	Guideline 6 requires a utility to perform a conservation potential study periodically for its entire service territory. In addition, the Company should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.	Chapters 5 through 9 address conservation measures.
7	Demand Response	Guideline 7 states that a utility should evaluate demand response resources; including voluntary rate programs on par with other options for meeting energy, capacity, and transmission needs.	Chapters 5 through 9 address demand response.
8	Environmental Costs	Guideline 8, as modified by Order No. 08-339, contains four requirements: a base case scenario, alternative portfolios against the base case scenarios, a trigger point analysis, and an Oregon compliance portfolio. The first requirement directs the Company to model what it considers to be the most likely regulatory compliance future for greenhouse gas emissions, as well as other possible credible scenarios. The second requirement discusses the treatment of these scenarios in its risk-analysis, PVRR cost and risk measures, and end-effect considerations. The third requirement directs the utility to identify a carbon dioxide compliance scenario that would lead to the selection of a portfolio that is substantially different from the preferred portfolio. The final requirement discusses the need for a separate portfolio, consistent with Oregon energy policies, if none of the previous portfolios achieves that consistency.	Chapters 3, 6, 7, 8 and 9 include environmental cost considerations.
9	Direct Access Load	Under Guideline 9 an electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.	Chapter 5 presents the load-resource balance, but does not address exclusion of customer loads served by alternative electricity suppliers.

Guideline		Description	Location Where Addressed in IRP
10	Multi-state Utilities	Guideline 10 requires multi-state utilities to plan its generation and transmission systems on an integrated system basis that achieves a best cost/risk portfolio for its retail customers.	The analysis and results presented in the IRP are on an integrated system basis.
11	Reliability	Under Guideline 11, an electric utility should: a. Analyze reliability within the risk modeling of the actual portfolios being considered b. Determine loss of load probability (LOLP), expected planning reserve margin, and expected and worst-case unserved energy by year, and c. Demonstrate that the selected portfolio achieves the utility's stated reliability, risk and cost objectives	Chapters 7 and 8 address reliability.
12	Distributed Generation	Guideline 12 recommends that utilities should evaluate distributed generation technologies on par with other supply-side resources.	Chapters 6 through 8 evaluate distributed generation.
13	Resource Acquisition	Guideline 13 establishes requirements for acquiring resources in the utility's action plan.	Chapters 3, 9 and 10 address resource acquisition.

ORDER NO.

ENTERED

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 52

In the Matter of	)	
	)	PROPOSED ORDER
PACIFICORP	)	
	)	
2011 Integrated Resource Plan.		

DISPOSITION: PLAN ACKNOWLEDGED WITH EXCEPTIONS AND REQUIREMENTS FOR NEXT IRP UPDATE.

I. INTRODUCTION

PacifiCorp (PacifiCorp or the Company) seeks acknowledgement of its 2011 Integrated Resource Plan (IRP). This filing is in accordance with Public Utility Commission of Oregon (Commission) Order No. 07-002, as corrected by Order No. 07-047[1], which requires all regulated energy utilities operating in Oregon to engage in integrated resource planning. We acknowledge the plan with certain exceptions and requirements for the next IRP update that are discussed below.

The Commission requires regulated energy utilities to prepare integrated resource plans within two years of acknowledgment of the last plan. Prior to resource decision-making, utilities must involve the Commission and the public in their planning process. Substantively, the Commission requires that energy utilities: (1) evaluate resources on a consistent and comparable basis; (2) consider risk and uncertainty; (3) make the primary goal of the process selecting a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers; and (4) create a plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies. See Order No. 07-002.

The Commission "acknowledges" resource plans that satisfy the procedural and substantive requirements, and that seem reasonable at the time acknowledgment is given.

[1] The Commission originally adopted least-cost planning in Order No. 89-507 (Docket UM 180). The Commission updated the utility planning process in Docket UM 1056.

II. PROCEDURAL HISTORY

PacifiCorp filed its 2011 IRP on March 31, 2011. A prehearing conference was held May 9, 2011, and a schedule adopted. Petitions to intervene were granted on behalf of Industrial Customers of Northwest Utilities (ICNU), Renewable Northwest Project (RNP), Oregon Department of Energy (ODOE), Community Action Partnership of Oregon, Portland General Electric (PGE), Northwest Energy Coalition (NWEC), and Sierra Club. The Citizens' Utility Board (CUB) intervened by right.

On August 9, 2011 a technical workshop was held for parties in the docket. PacifiCorp presented its IRP to the Commission at a Special Public Meeting on August 19, 2011. Staff and intervenor initial comments were filed August 25, 2011. Company reply comments were filed September 21, 2011, along with a Supplemental Coal Replacement Study. Staff final comments and this draft order were filed October 13, 2011.

III. DISCUSSION

The primary issues in this IRP are discussed below, with the most significant discussed first. Each issue is also correlated with its corresponding Action Item in PacifiCorp's IRP.

A. Issues

1. Evaluation of Environmental Compliance Costs for Existing Coal-fired Plants (Action Item 8)

a. Parties' Positions

Initial Comments:

Staff, ODOE, CUB, Sierra Club, RNP, and NWEC criticized the lack of a comprehensive analysis of environmental compliance costs for PacifiCorp's coal plant facilities in the 2011 IRP.

CUB pointed to rate increases of 59 percent since the 2005 MidAmerican Energy Holdings Company acquisition of PacifiCorp largely being caused by the Company's capital investment strategies, including coal plant clean air technology investments. CUB stated the portfolio selection in the IRP is biased towards capital investment and did not consider whether reducing coal plant investment would be least risk to ratepayers.

Sierra Club noted that costs for pollution control upgrades could exceed $4.2 billion from 2005-2023, costs that are not described and accounted for in the IRP. Further, the IRP should include analyses on the range of possible regulatory futures for nitrogen oxides, sulfur dioxides, and mercury, and evaluate the economic merit of pursing the pollution control upgrades versus retiring coal plant facilities. The Company should be required to develop “Continued Use and Operations” (COU) studies for each generating resource and use the results to inform IRP portfolio selection based on least cost for rate payers. Sierra Club also asserted that PacifiCorp has established a pattern throughout its service territory of omitting environmental costs in forward planning efforts. Ratepayers are therefore exposed to “extraordinary costs and regulatory risks” by not including in the IRP a least-cost strategy for dealing with the cost of environmental compliance.

ODOE noted that the financial risk associated with investing in pollution control upgrades for aging coal plants have not been analyzed, and suggested PacifiCorp be required to “undertake a futuristic and holistic review” of all coal plant facilities that may be subject to best available retrofit technology (BART) and maximum achievable control technology (MACT) compliance.

RNP stated that with regard to coal, the IRP loses sight of the political shift towards a clean energy economy and that PacifiCorp should be scaling back from an aging coal fleet. It concurred with other stakeholders on the need for a transparent financial analysis of continuing coal plant investments that demonstrates it’s a good investment in the context of a reasonable forecast of compliance costs associated with future environmental regulation.

NWEC stated the IRP fails to consider modeling scenarios that consider cost of coal plant upgrades against other potential resources. NWEC urged the Commission to provide adequate time and scheduling flexibility to enable a thorough review of coal plant economic analyses.

In its reply comments, PacifiCorp stated that the IRP complied with the IRP Guidelines in that it incorporated the Company's emissions control project costs, including mercury MACT compliance costs, reasonably ascertainable at the time that the IRP model data was undergoing development. PacifiCorp further stated that the Supplemental Coal Replacement Study filed with its reply comments further addresses concerns raised by the parties. The Supplemental Coal Replacement Study expanded the list of potential environmental regulations considered in the coal plant replacement analysis. The analysis included costs to comply with the Regional Haze Rules / BART process, costs to comply with the EPA’s proposed utility hazardous air pollutants (HAPs) MACT rulemaking, additional costs for selective catalytic reduction across the Company’s coal fleet, costs to comply with emerging rules for coal combustion residuals (CCR), and costs to modify cooling water intake structures at existing plants to comply with Section 316(b) of the Clean Water Act. PacifiCorp reconsidered its modeling assumption that existing coal units could only be replaced by brownfield natural gas resources located at the same site and expanded its modeling to allow for a wide range of potential replacement resource options. The modeling was also updated to force the decommissioning of coal plants at the end of their depreciable lives. The Carbon plant is assumed to be decommissioned at the end of 2020, the Dave Johnston plant at the end of 2027, and the Naughton plant at the end of 2030. The Supplemental Coal Replacement

Study also included an updated range of natural gas price scenarios and carbon dioxide regulation cost scenarios.

PacifiCorp summarized the results of the supplemental study as follows:

> "Among all three scenarios evaluated in the Coal Replacement Study, none of the PacifiCorp coal resources were displaced by replacement resource alternatives before the end of the 20-year planning period or before the end of the currently approved depreciable life of each resource. In each of these scenarios, existing coal resources were assigned incremental investment costs consistent with the most current emissions control plan, plus the incremental SCR costs across the Company's generation units discussed above and in Confidential Appendix A. The analysis also incorporated cost estimates to address expected CCR regulations and upgrades to water intake structures. These findings support the basic conclusions drawn from the 2011 IRP coal utilization sensitivity analysis and show that PacifiCorp's coal fleet, with planned incremental investments, will continue to provide reliable and least cost electric service to customers. Moreover, the Coal Replacement Study shows that planned coal investments are cost effective among a range of future market price and CO2 cost outcomes."

Finally, PacifiCorp went on to comment on the flexibility afforded by environmental regulations and what it characterized as the perceived ability to avoid early compliance costs by offering to shut down individual units prior to the end of their useful life. PacifiCorp cautioned against assuming that there is near term certainty regarding the environmental requirements. It stated that there is a great deal of uncertainty associated with many of these emerging requirements. PacifiCorp also stated that the goal of its emissions control plan is to ensure compliance with environmental regulations governing its operations while providing the least cost generation portfolio for customers. PacifiCorp indicated that plant retirement should be a consequence or potential result-not the objective-of its evaluation of environmental compliance options. Given these views, the Company believes that attempting to analyze hypothetical compliance scenarios without specific information regarding regulatory flexibility will not produce meaningful results.

Staff Final Comments:

Staff concluded in its initial comments that PacifiCorp's 2011 IRP failed to provide a comprehensive evaluation of the compliance of its existing coal fired generation resources with new, draft, and anticipated environmental regulations. In Staff's opinion, the Supplemental Coal Replacement Study sufficiently solidifies the basis of the IRP. Staff commends the Company for expanding the list of potential environmental regulations and for allowing for a wider range of potential replacement resource options in the coal plant replacement analysis.

Staff identified a potential flaw in the modeling used in the supplemental coal study. Staff claims that there is inconsistent treatment of coal plant depreciation expense beyond the end of planning period. According to Staff, PacifiCorp appropriately includes the net present value of this expense in the cost stream associated with early retirement, but inappropriately excludes the net present value of this expense from the cost stream associated with pollution control investment and continued operation of the plant. According to Staff this may bias the results in favor of continued operation of the plants. Staff recommends, however, that this issue be addressed as part of an additional coal replacement study analyses to be submitted with the Company's 2011 IRP Update.

Staff also recommended that PacifiCorp be required to further investigate whether there is flexibility in the emerging environmental regulations that would allow the Company to avoid early compliance costs by offering to shut down individual units prior to the end of their useful lives. In addition, Staff recommended that PacifiCorp conduct further plant specific analysis to determine whether this tradeoff would be in the ratepayers' interest. Staff agreed with PacifiCorp that plant retirement should be the result-not the objective-of this investigation and analysis. Staff recommended that the Company be required to provide this additional analysis in their 2011 IRP Update, in March 2012.

b. Resolution

We agree with PacifiCorp and Staff that the Supplement Coal Replacement Study further advances the economic analysis of coal plant replacement. However, we still view this study as a proof-of-concept analysis. We do not find that the study has been fully vetted, and agree with Staff that there should be further review of the modeling and further investigation and analysis of the potential for flexibility in the emerging environmental regulations.

All of our acknowledgement decisions in this IRP are influenced by the uncertainty surrounding PacifiCorp's coal fleet. We precede with the remaining acknowledgment decisions in this case, relying on the preliminary result from the Supplemental Coal Replacement Study, because we expect PacifiCorp to complete its upcoming IRP Update in March 2012. If the results of the coal plant replacement analysis in the IRP Update are significantly different from these preliminary results, then the Company can ask us to consider these acknowledgment decisions again at that time. Action Item 8 is revised to include the following:

Action Item 8 - Planning and Modeling Process Improvements

- PacifiCorp is required to file its next IRP Update in March 2012. The IRP Update will include a revised Supplemental Coal Replacement Study. The Company will investigate whether there is flexibility in the emerging environmental regulations that would allow the Company to avoid early compliance costs by offering to shut down individual units prior to the end of their useful lives. The Company will also conduct further plant specific analysis to determine whether this tradeoff would be in the ratepayers' interest. In these additional analyses the Company will correct, as appropriate, its treatment of depreciation for the period after 2030.

2. Energy Efficiency (Class 2 DSM) Resource Analysis (Action Item 6)

a. Parties' Positions

Initial Comments:

NWEC compared PacifiCorp's energy efficiency resources with the 2011 Cadmus Report, and stated that the preferred portfolio will result in a 25 percent deficiency in meeting the Northwest Power and Conservation Council (NWPCC) 6th plan's 20-year efficiency target for the state of Washington. NWEC noted that information comparing Class 2 DSM to the Council's target is not provided for Oregon, and expressed concern about the overall amount of energy efficiency reflected in the IRP relative to the Council's 6th plan targets. NWEC also noted that Class 2 DSM ramp rates are not reported for Oregon, and are inadequately documented in states for which they are reported. NWEC commented that ramp rates reported for Wyoming and Idaho are low considering the east side's growth in energy efficiency opportunities. NWEC recommended that the Company be required in future IRP-related filings to report Oregon's share of the energy efficiency targets identified in the Council's 6th plan.

CUB stated the Company is not meeting its own consultant's (Cadmus) suggested ramp rate for energy efficiency.

Staff commented that Class 2 DSM savings are described as those achieved through technological advancements in equipment, appliances, lighting, and structures. Staff reported it intended to evaluate whether PacifiCorp's modeling inputs and methodology favor supply-side resources over demand-side resources and whether specific modifications to Action Item 6 (1,200 MW of Class 2 DSM by 2020) will be recommended.

Staff noted PacifiCorp groups energy efficiency measures into bins based on levelized costs. The size of the bins created by PacifiCorp varies greatly and seemed to Staff to be arbitrary. Staff reported it was looking into whether PacifiCorp's designation, of which measures go into which bins, and the resulting "average" bin cost is limiting how much Class 2 DSM is being selected.

Staff also commented it was investigating changes to ramp rates since the last IRP and examining whether PacifiCorp's method for ramping up efficiency, once a bin is determined by the model to be cost effective, is favoring supply-side resources in the near term.

Lastly, Staff observed the 2010 resource potential study completed by Cadmus evaluated Class 2 DSM potential for all states other than Oregon. A study of Oregon's Class 2 DSM potential was completed by the Energy Trust of Oregon (ETO). Staff intended to evaluate whether efficiency measure levelized costs for other states are significantly higher than for Oregon and the implications of that difference on how much efficiency is selected by PacifiCorp.

PacifiCorp's reply comments noted, in regard to NWEC's point comparing conservation opportunities and targets between the IRP and NWPCC's 6th Power Plan, it should be emphasized that the use of utility commissioned potential assessments are more relevant sources of information for resource planning than reliance on regional study data and opportunity estimates. The Company pointed out, that to ensure the Company is cognizant of and considers all possible energy efficiency opportunities available in the construction of its resource plans, it relies on independent third-party assessments of energy efficiency opportunities specific to the customer demographics and loads found in its service areas.

In response to Staff, NWEC and CUB, the Company commented it believes that the ramp rate assumptions adopted for the IRP portfolio modeling reflect prudent consideration of company-specific implementation constraints not accounted for in the potential assessments.

Regarding Staff's contention that the Company's aggregation of energy efficiency measures into bundles may restrict resource selection, PacifiCorp noted that its approach was designed to minimize such resource selection bias with the recognition that the model can accommodate only a limited number of bundles.

Staff Final Comments:

IRP Guideline 1a. states that all resources must be evaluated on a consistent and comparable basis. IRP Guideline 1c states that the primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers. Staff appreciates that the Company has increased the amount of energy efficiency in this IRP compared to the 2009 IRP. Staff also appreciates the points made in the Company's reply comments. However, Staff, along with NWEC and CUB, believed that the Company is underestimating the amount and speed of energy efficiency that can be achieved in states other than Oregon, and as a result supply side resources are being chosen which customers will pay more for and be subject to greater risks.

<u>Revised Action Item</u>

Staff recommends the first bullet of IRP Action Item 6 be modified to read:

- Acquire ~~up to 1,200~~<u>1,800</u> MW of cost-effective Class 2 programs by 2020, <u>including 1,200 MW in the eastern supply territory</u>~~equivalent to about 4,533 GWh. This includes programs in Oregon acquired through the Energy Trust of Oregon~~.

– Procure through the currently active DSM RFP and subsequent DSM RFPs.

Staff also recommends adding the following bullets after the first bullet of Action Item 6:

- In the next IRP, the Company will evaluate alternatives for ramping up DSM 2 in a way that is equal to supply side resource development and procurement.

- In the next IRP, the Company will provide an analysis of alternatives to the current bundling method for modeling and evaluating energy efficiency measure supply curves.

- In the Company's next IRP, it will provide an analysis of the sufficiency of current staffing levels to achieve programmatic cost effective energy efficiency targets established in this plan.

Total savings compared to load

Oregon represents 22 percent of total load in MWh and 21 percent of the forecasted coincident peak load, and 48 percent of the total DSM capacity in the preferred portfolio. Staff believes there should not be such a discrepancy between how much cost effective energy efficiency is possible in Oregon versus other states. Oregon has been weatherizing electric homes since 1978, so there should be even more savings per unit load available in states with newer programs where lots of "low hanging energy efficiency fruit" still remains.

Washington and Oregon have similar geography and weather conditions, and both states have relatively strong program histories. The primary difference is that in Oregon, programs are administered by the Energy Trust of Oregon, whereas in Washington programs are administered by PacifiCorp. In this IRP, the ratio of Oregon to Washington forecasted contribution to coincident peak load in 2020 is three. However, the ratio of 2020 DSM 2 capacity in Oregon to Washington in the preferred portfolio is seven. Staff suspects that that the Company could more aggressively pursue energy efficiency in Washington and in other states.

Resource Potential Study

PacifiCorp hired CADMUS to update its resource potential study for all states, except Oregon. Basically, PacifiCorp's model has selected roughly half of the energy efficiency its consultant CADMUS deemed to be technically available and achievable in WA, CA, ID, UT and WY.[2] The Company will likely argue that not all resources identified by CADMUS are cost effective and so were not selected by the model.

[2] CADMUS projects estimates of peak capacity impacts per state by "spreading annual potential by state, sector, segment, and end use over hourly load shapes to estimate hourly demand savings. The peak impacts represent the average demand savings in the top 40 hours of system load."

However, all the Oregon energy efficiency, which is a much greater percentage of load, was selected by the model. This calls into question the criteria being used to select measures by PacifiCorp in states other than Oregon.

The CADMUS report shows only total peak savings for 2030. To estimate the potential for 2020, if the CADMUS peak impact savings for 2030 were divided by two (1,326 MW) and then added to the 2020 savings estimates for Oregon (562 MW), the result equals 1,887 MW in 2020. This is conservative in that the CADMUS number actually represents a peak capacity impact savings, not installed capacity. Staff recommends that PacifiCorp's 2020 action item be modified to say that 1,800 MW of savings be achieved by 2020 and that 1,200 MW of that be in the eastern supply territory.

Ramp Rates

Ramp rates refer to how quickly DSM 2 measures can be achieved. Ramp rates are based on:

a) Adoption rates of energy efficiency - a function of the market

b) Ramp rates of specific programs - a function of programs and how they are implemented by the Company

CADMUS proposed market ramp rates in their resource potential study. PacifiCorp modified those ramp rates based on the "Company's specific implementation constraints not accounted for in the potential assessment."[3] On page 9 of its reply comments, PacifiCorp states that it believes the ramp rate assumptions adopted for the IRP portfolio modeling reflect prudent consideration of company-specific implementation constraints not accounted for in the potential assessment. Staff is concerned that Company staffing levels and level of effort it is putting into these programs in states other than Oregon are unnecessarily limiting how quickly program ramp rates can grow to the point where they correspond to the ramp rates described as possible by CADMUS.

In response to Staff data request 180, the Company indicates the system optimizer model does not have logic to ramp energy efficiency such that it is available when needed, thus requiring manual input. The System Optimizer model performs an economic evaluation of energy efficiency measures against other resources as well as capacity needed in each year to derive the amount of Class 2 DSM that is selected. Staff believes it is likely that cost effective Class 2 DSM is being missed through this iteration of manually inputting ramping limitations for analysis by the model.

In practice, supply side resources are planned and essentially "ramped up" (through RFPs, pre-construction, construction, etc) well in advance of their need so they are fully available when needed. Staff believes that demand side resources are not being

[3] From page 9 of the Company's response comments

treated equally with supply side resources in how they are being planned for and ramped up in advance of need so they are available when needed.

Although the total achievable Class 2 DSM in this plan increased over the 2009 IRP, modifications were made to the resource availability assumption inputs (i.e., ramp rates) resulting in less energy efficiency in early years (2011-2020) and more in later years (2021-2030) for all states other than Oregon. Staff believes this has the effect of favoring supply-side resources in the near term.

Staff recommends that in the next IRP the Company provide an evaluation of alternatives for ramping up class DSM 2, such that Class 2 DSM resources are treated on par with supply side resources in terms of development and procurement.

Total Savings versus Capacity

The Company reported a total achievable potential of forecasted DSM 2 capacity contributions by 2030 (including OR and all states evaluated by CADMUS, as reported above). Of this, only 60 percent made it into the preferred portfolio for 2030. For 2020, only 62 percent of the total for that year was selected for the preferred portfolio. Of the 62 percent that was selected for the preferred portfolio, only 48 percent is assumed to be available at the time of annual system coincident peak in 2020.

Staff believes that the Company can achieve more than the projected total savings, and therefore more capacity savings. Staff also questions the capacity factors used for efficiency measures in each state and the basis for those capacity factors. For instance, in Oregon the capacity planning factor for the lowest price bundle is 0.22, but for the next two bundles the capacity planning factor was set at zero.

Bundles

The Company bundles measures together for input to its model. Staff is concerned that the current bundling methodology and selection of endpoints for each bundle is arbitrary, confusing, and causing less DSM 2 to be selected than other resources. The Company claims in its reply comments that the size and range of the cost bundles vary, but the variations are by design and that the bundles are more granular (less difference between the low and high costs in the bundle) at the lower end of the cost spectrum. Staff does not believe this to be true, as discussed further in its Final Comments.

Staff is concerned that bundling these many measures into one large bundle is causing the model to exclude many measures that would otherwise be cost effective, particularly at the low end of costs. Staff also believes this bundling method is unnecessarily arbitrary and confusing. Staff recommends that in the next IRP the Company provide an analysis of alternative to the current bundling method for modeling and evaluating energy efficiency measure supply curves.

Staffing Levels

Staffing levels, while not typically addressed in an IRP, are relevant to the extent they interfere with the ability to deliver the least cost and least risk alternative to customers. As mentioned previously, Staff is concerned that PacifiCorp's staffing levels are limiting the program implementation rates and therefore ramp rates and savings.

Summary and Staff's Alternative Portfolio

Staff believes that PacifiCorp can achieve more cost effective DSM 2 in states other than Oregon, and that it is in the best interest of Oregon customers for them to do so. Staff believes that PacifiCorp can achieve 600 MW more conservation by 2020 than represented in the Company's preferred portfolio and that out of the total 1,800 MW, 1,200 MW can come from the eastern territory, thereby reducing the need for new supply side resources to meet peak demand in the east.

In Staff's alternative portfolio, discussed below, an additional 84 MW of Class 2 DSM was included in the East by 2020, with ramping starting in 2016. Only 1 additional MW was included in the West by 2020. As presented in Staff's comments above, a combined potential of DSM 2 savings of up to 600 MW is available. Staff believes including only 85 MW of DSM 2 savings in the Staff alternative portfolio is conservative and attainable.

b. Resolution

We concur with party comments that PacifiCorp did not include the maximum amount of cost effective Class 2 DSM in its preferred portfolio. As a result, we agree with Staff's proposed action item revisions and additions to increase Class 2 DSM, as follows:

Action Item 6 - Class 2 DSM

- Acquire ~~up to 1,200~~1,800 MW of cost-effective Class 2 programs by 2020, including 1,200 MW in the eastern supply territory~~equivalent to about 4,533 GWh. This includes programs in Oregon acquired through the Energy Trust of Oregon~~.
  - Procure through the currently active DSM RFP and subsequent DSM RFPs.
- In the next IRP, the Company will evaluate alternatives for ramping up DSM 2 in a way that is equal to supply side resource development and procurement.
- In the next IRP, the Company will provide an analysis of alternatives to the current bundling method for modeling and evaluating energy efficiency measure supply curves.

- In the Company's next IRP, it will provide an analysis of the sufficiency of current staffing levels to achieve programmatic cost effective energy efficiency targets established in this plan.

3. Load Control (Class 1 DSM) and Price Response (Class 3 DSM) Resource Analysis (Action Items 5 and 7)

a. Parties' Positions

Initial Comments:

NWEC stated that the IRP commits to only 80MW out of the 250MW called for in the IRP Action Plan. PacifiCorp's assertion of lowered expectation for irrigation load control program capacity does not appear to be explained or justified in the IRP.

Staff noted PacifiCorp categorizes demand response into Class 1 and Class 3 resources. Class 1 is dispatchable load control, scheduled irrigation and thermal energy storage. Class 3 is considered as contributing to system reliability and represents programs such as critical peak pricing, curtailable rates and demand buyback.

Staff commented, in response to the Commission's order acknowledging its 2008 IRP, which required the Company to go farther in evaluating the cost and amount of resources that can be gained from Class 1 and Class 3 DSM, PacifiCorp updated its 2007 independent study performed by the Cadmus Group. The Cadmus study indicates Achievable Technical Potential of 536 MW of Class 1 DSM and 357 MW of Class 3 DSM by 2030. However, in the preferred portfolio the Company selects only an average of 160 MW of Class 1 DSM and no Class 3 DSM.

Finally, Staff noted PacifiCorp continues to exclude Class 3 DSM and include only a minimal amount of Class 1 DSM in its preferred portfolio. Staff believes that these two classes of DSM have the potential to displace the Company's need for a supply-side resource in 2016.

PacifiCorp stated in its reply comments that, regarding acquisition of Class 1 DSM resources, Staff and NWEC are overlooking the contribution of the Company's existing Class 1 programs to the overall resource potential. Further, concerning Class 3 DSM, many of the Class 3 resource opportunities compete within their own class of DSM. For example, the Company pointed out Class 3 commercial critical peak pricing, commercial and industrial demand buyback, and real-time pricing compete with each other for controllable loads. In conclusion, the Company stated as Class 3 DSM resource selections are not included for capacity planning purposes (for reasons explained in the plan; e.g. inadequate firmness and reliability), not taking these product interactions into consideration posed no risk of over-reliance (or double counting the potential) of Class 1 and Class 3 resources in the IRP.

Staff Final Comments:

Staff maintains its position on Class 1 and Class 3 DSM measures outlined in its initial comments. Staff also echoes NWEC's concern that the Company has not actively acquired all economic DSM resources. Below, Staff provides support for its recommendations and responds to PacifiCorp's reply comments.

Revised Action Item

Staff recommends the Company actively acquire all economic Class 3 DSM resources, as soon as possible. The Company should focus on time-of-use for irrigation, DLC programs, critical peak pricing programs and demand buy-back programs as soon as 2013, and ramp-up to the levels identified in its Case Study 31 by 2020. The Company should report the status of its acquisition and implementation of Class 3 DSM in its next IRP. To accomplish Staff's recommendation IRP Action Item 7 - Class 3 DSM should be revised to read as follows:

- ~~Continue to evaluate Class 3 DSM program opportunities.~~ By 2020 PacifiCorp will implement 262 MW of Class 1 and Class 3 DSM on the East side and 131 MW of Class 1 and Class 3 DSM on the West side using a combination of programs (TOU irrigation, Direct Load Control (DLC) Residential, Real-time pricing-Commercial & Industrial, Demand buy back, Critical Peak Pricing, etc.) as demonstrated in its sensitivity analysis, Case Study 31[4].

  In its next filed IRP PacifiCorp will report on the cost-effectiveness and status of its acquisition and implementation of Class 1 and Class 3 DSM.

  - ~~Evaluate program specification and cost-effectiveness in the context of IRP portfolio modeling, and monitor market changes that may remove the voluntary nature of Class 3 pricing products.~~

Class 1 DSM

The comments from Staff and NWEC related to PacifiCorp's Class 1 DSM as "being only a "minimal amount" of Class 1" are intended to focus on the fact that, while PacifiCorp's preferred portfolio chooses 250 MW of Class 1, and achieves the maximum amount of Class 1 potential indicated in the Cadmus study, the Company seems to be less than confident that it will implement the entire 250 MW of Class 1. The IRP Action Plan implies that 170 MW of the 250 MW selected in the preferred portfolio may never be implemented based upon economic viability. PacifiCorp points out in its reply comments that Staff and NWEC overlook the fact that the preferred portfolio "is effectively pursuing 575 MW Class 1 DSM, or 92 percent of the achievable technical potential identified in the Camus study, before accounting for any percentage of the opportunity that is uneconomic."

[4] 2011 IRP, Appendix D, p. 129.

PacifiCorp’s sensitivity study (Case 32) demonstrates that small amounts of additional Class 1 resource acquisitions (85-90 MW) defer the 2015 and 2019 CCCTs by one year.[5] This indicates to Staff that even small amounts of Class 1 resource acquisitions are worth pursuing. Staff recognizes that PacifiCorp is effectively pursuing 92 percent of the achievable technical potential identified by the Cadmus study, but Staff points out that the Cadmus Study indicates that the potential Class 1 resource acquisition is as much as 3,312 MW, or six times more than what PacifiCorp is effectively pursuing. Staff does not recommend revision of Action Item 5, but it does encourage PacifiCorp to continue to actively acquire all economic Class 1 resources.

Class 3 DSM

PacifiCorp fails to model “any” Class 3 DSM in its 2011 IRP preferred portfolio. In the IRP, the Company explains the reasons that Class 3 DSM resource selections are not included for capacity planning purposes.

Staff highlights the following from PacifiCorp’s sensitivity modeling:

Excerpts from 2011 IRP, Chapter 8, pg. 246:

> Case 31 entailed including Class 3 DSM rate products as resource options using the medium natural gas and CO2 tax assumptions defined for Case 7. As noted in Chapter 7, the dispatchable irrigation load control programs were assumed to be substituted by a mandatory Time of Use (TOU) rate schedule with rates set sufficiently high to induce the desired load shifting behavior. This substitution occurs in 2015, when a TOU rate structure is assumed to be instituted. The resource potentials account for interaction effects between Class 1 and Class 3 resources.
>
> A total of 262 MW of Class 3 DSM was selected in the east and 131 MW selected in the west. The net gain in load control resources is 122 MW, which accounts for reduced Class 1 DSM capacity (70 MW) and the displacement of the dispatchable irrigation load control program (201 MW). This additional DSM capacity is sufficient to defer the second and third CCCT resources by one year. The portfolio PVRR decreased by about $236 million due to the relatively low cost of administering 3 DSM programs.

PacifiCorp’s sensitivity study indicates that implementing the “relatively low cost” DSM programs can result in a deferment of the second and third CCCT resources by one year. Yet, PacifiCorp chooses “none” of the 514 MW of Class 3 potential in its preferred portfolio.

---

[5] 2011 IRP, Chapter 8, p. 246.

Staff's alternative portfolio, discussed below, caused the system optimizer model to choose 126 MW of mandatory TOU in the West and with other additions avoids the 2016 CCCT entirely, and focused only on Class 3 TOU with mandatory participation. In its reply comments, PacifiCorp resists Staff's alternative portfolio, which contemplates 125 MW of Class 3 DSM in the West modeled as mandatory time-varying rates for irrigation. The Company states that "there is considerable controversy regarding mandatory time-varying rates and that it is unrealistic to assume that Oregon would approve mandatory Class 3 DSM programs in time to affect the investment decision for the next major resource." In Staff's opinion, controversy is not a compelling deterrent from pursuing the least-cost, least-risk portfolio.

PacifiCorp's sensitivity analysis for DSM-Case Study 31 models an assortment of Class 1 and Class 3 DSM programs, including; DLC Residential, Real-time pricing-Commercial & Industrial, Demand buy back, Critical Peak Pricing and TOU for irrigators. The fact that the Staff alternative portfolio caused the model to choose mandatory TOU should not distract from the fact that the Company has an assortment of DSM programs to choose from, in addition to TOU for irrigators. The table presented in Staff's Final Comments presents the assortment of DSM programs modeled in Case Study 31. The total amount of DSM on the East side is 292.5 MW and 155 MW on the West side, considerably more than included in the Staff alternative portfolio. Staff believes this larger amount of DSM will allow for selecting a portfolio of DSM programs, while accounting for the interaction effects between the Class 1 and Class 3 DSM.

Conclusion

Staff believes PacifiCorp's reluctance to implement Class 3 DSM unnecessarily raises cost or risk, or both, for Oregon customers. Staff notes that Idaho Power has successfully implemented DSM programs similar to PacifiCorp's Class 1 and Class 3 programs since early 2003, boasting nearly 250 MW peak savings in 2010 in its irrigation sector demand response alone.

b. Resolution

We encourage PacifiCorp to continue to actively acquire all economic Class 1 DSM resources. We also note the lack of Class 3 DSM in the Company's preferred portfolio. To rectify this Class 3 DSM shortcoming, we adopt Staff's recommended revisions to IRP Action Item 7, as follows:

Action Item 7 - Class 3 DSM

- ~~Continue to evaluate Class 3 DSM program opportunities.~~ By 2020 PacifiCorp will implement 262 MW of Class 3 DSM on the East side and 131 MW of Class 3 DSM on the West side using a combination of programs (TOU irrigation, DLC Residential, Real-time pricing-Commercial & Industrial, Demand buy back, Critical Peak Pricing, etc.) as demonstrated in its sensitivity analysis, Case Study 31[6].

In its next filed IRP PacifiCorp will report on the cost-effectiveness and status of its acquisition and implementation of Class 3 DSM.

~~Evaluate program specification and cost-effectiveness in the context of IRP portfolio modeling, and monitor market changes that may remove the voluntary nature of Class 3 pricing products.~~

4. Distribution Energy Efficiency (Action Item 6 continued)

a. Parties' Positions

Initial Comments:

In Order No. 10-066, the Commission acknowledged the Company's 2008 IRP but included an additional action item to incorporate an assessment of distribution efficiency potential resources in its next IRP. Staff stated that the Company had not fully complied with this action item because: (1) the System Optimizer sensitivity scenario study indicated that conservation voltage reduction (CVR) is cost-effective and therefore should be acquired system-wide; and (2) if CVR resources had been included in the preferred portfolio, it would have affected resource selection. Staff then recommended modifications to PacifiCorp's current CVR action plan item.

In reply comments, PacifiCorp stated that to demonstrate progress for the 2011IRP, the Company proposed to test the System Optimizer resource set-up and selection impact of a "trial" Washington CVR resource provided by the consultant for the Washington CVR study, Commonwealth Associates, Inc. Because the data were preliminary and not validated by the Company, the resource testing was never meant to prove the cost-effectiveness of the resource or draw conclusions regarding energy savings scalability to other load areas.

PacifiCorp stated further it remained concerned that CVR is inappropriate as a candidate preferred portfolio resource option for the IRP because the resource's achievable potential and supply-cost relationship cannot yet be determined so that appropriate resource options can be developed and modeled for each state.

Concerning Staff's action item recommendations, the Company objected to mandating project commitment dates for situs resources in other states, and based solely on a cursory resource "extrapolation" analysis with identified flaws and unfounded assumptions. With this said, PacifiCorp proposed to work with Staff to develop a modified CVR action item using PacifiCorp's draft CVR implementation plan as the basis. This implementation plan, included as Appendix 1 of its reply comments, was

[6] 2011 IRP, Appendix D, p. 129.

intended to provide the planning specificity desired by Staff and cover activities for the next two years-an appropriate timeframe for the action plan.

Staff Final Comments:

Staff maintains the positions on conservation voltage reduction (CVR) measures discussed in its initial comments. Below, Staff provides the reasoning for its positions and responds to PacifiCorp's reply comments.

Revised Action Item

Staff recommends the following action item be substituted for the third bullet in PacifiCorp's 2011 Action Item 6 in the IRP:

- A CVR acquisition project in PacifiCorp's Washington service area will begin in 2012 and end no later than 2018.

  The next filed PacifiCorp IRP will include an action plan item to acquire all of the available cost-effective conservation voltage reduction (CVR) throughout its service area by 2022. This action item will be based primarily on information from Yakima and Walla Walla service areas. Cost-effectiveness analyses will use the same methodology as the modeling approach used in the Class 2 DSM decrement assessment in the 2011 IRP Addendum.

Staff Assessment of "incorporation" of CVR in PacifiCorp's 2011 IRP

Staff asserts that the Company's proposed portfolio in the 2011 Final IRP did not include distribution efficiency potential resources (a.k.a. Conservation Voltage Reduction or CVR) for planning purposes, as required in Order No. 10-066.

The IRP refers to a draft assessment of economic potential for CVR in the Yakima and Walla Walla service areas. PacifiCorp conducted an optimizer sensitivity test on the potential from these two areas. This test showed CVR to be a cost-effective resource. Staff asked the Company to explain the meaning of the term "leverage" in the phrase "Leverage the distribution energy efficiency analysis of 19 distribution feeders in Washington"" in IRP Action Item 6. In response, PacifiCorp stated it is now investigating the cost-effectiveness of applying CVR [based on results from the consultant's study of Washington feeders] to specific Washington feeders, the Company plans to initiate investigation of the Oregon circuits in 2012, and it will define a project timeline at that time. Staff believes, even if PacifiCorp's response above were substituted for Action Item 6, the revised 2011 action plan would not assure that the next IRP would fulfill the Order No. 10-066 requirement to incorporate its assessment of distribution efficiency potential resources for planning purposes.

In its reply comments, PacifiCorp asserts that CVR acquisition on a system-wide basis is inappropriate as a candidate preferred portfolio resource option for the IRP because the resource's achievable potential and supply-cost relationship cannot yet be determined. This, they assert, prevents appropriate resource options from being developed and modeled for each state. Staff notes that while there is uncertainty about any planning estimate, zero is clearly an incorrect estimate of the resource potential. Staff also asserts that based on analyses in the NWPCC's 6th Power Plan, studies by the Electric Power Research Institute, activities by other utilities and the Commonwealth study conducted for the Company, there is wealth of information that could provide a high quality estimate of CVR resource potential. Staff proposes that in the next plan PacifiCorp develop an estimate using the Washington experience and any other information the Company finds relevant. Staff is not trying to predetermine the planning estimates of the CVR resource in the next plan.

PacifiCorp's reply comments provide no information about when alternative estimates of CVR potential might be available. Given the schedule for CVR in Washington in Appendix 1 of the Company's reply comments, providing Company-wide cost and resource estimates in the next IRP and including CVR as a resource in the plan is doable and appropriate. Appendix 1 provides no information about the Company's plans to implement CVR in Oregon or other states.

In its reply comments, PacifiCorp has not provided any specific reasons that it expects using the Washington experience would underestimate or overestimate the CVR resource potential in other states. If the Company believes that studies in other states, similar to the Commonwealth's study of Washington feeders, are essential for planning purposes, then it should design and conduct those studies as soon as possible. The Company has not indicated how the electrical topology of the 19 circuits studied by Commonwealth is atypical of its system. If so, it is unclear why PacifiCorp chose those circuits for is first study on its system.

CVR potential for PacifiCorp

Beginning in 2003 the Northwest Energy Efficiency Alliance (NEEA) conducted pilot studies with NW utilities. PacifiCorp participated in this study. Based on NEEA's final report in 2008,[7] the NWPCC included CVR saving for the region in its February 2010 NWPCC 6th Power Plan. The NWPCC projected 350 avg. MW of achievable CVR potential under a cost of $40 per MWh (2006$).[8] Extrapolating these CVR savings to PacifiCorp yields an estimate of 130 aMW.

In 2008 when PacifiCorp assessed CVR in its last IRP process, it could reasonably argue that CVR was a new and untested resource option. The Electric Power Research Institute now has a fully operation program to help utilities implement CVR. NEEA has regionally approved protocols for assessing CVR potential. In addition, in 2009 Idaho Power Company implemented CVR at 6 Substations with net annual value of saved energy and capacity of $313,000. Based on this success, IPC is planning to

---

[7] http://neea.org/research/reports/E08-192.pdf

[8] Page 4-13 of http://www.nwcouncil.org/energy/powerplan/6/final/SixthPowerPlan_Ch4.pdf.

implement CVR at eight more substations in 2012. This work is being done with solely with IPC funds. In Staff's opinion, CVR is no longer a new and untested resource.

In May of 2011, the Company completed a detailed economic study of 19 of its circuits in Yakima and Walla Walla.[9] Based on an extrapolation of this study, Staff projects achievable cost-effective CVR savings for the PacifiCorp system of at least 64 MW (coincident peak) and 37 aMW (generation). While these amounts of capacity and energy are small, the dollar value of the savings is large. PacifiCorp's consultant estimated a present value of savings of $2.5 million for 15 of the 19 circuits studied. Extrapolated to all of PacifiCorp, this represents a present value of $180 million. Even if this actual savings are only half this estimate, CVR belongs in PacifiCorp's preferred portfolio.

Staff asserts that the likely dollar savings from CVR are sufficient for the Commission to modify the Company's proposed IRP Action Item 6 on CVR. The Company is unresponsive to the needs of PacifiCorp customers, even with the clarification from PacifiCorp in its reply comments. To achieve acknowledgement of its next IRP, PacifiCorp's action plan should have an action item to acquire all the cost-effective CVR savings by a reasonable end date.

Appropriate timing of CVR rollout

The Staff proposed date of 2022 to complete CVR in the alternative action item above is based on the consultant's estimate of a seven year capital plan for Yakima and Walla Walla. While PacifiCorp is implementing CVR in Washington, it should prepare detailed CVR plans for all of its other service areas. PacifiCorp should implement CVR for the rest of its service area between 2015 and the end of 2022. The next eleven years is more than enough time for a careful and orderly roll-out of CVR. Staff finds it reasonable for the Company to develop a realistic and effective timeline for CVR implementation.

In its reply comments PacifiCorp objects to the Commission mandating project commitment dates for situs resources in other states. Staff asserts that it is valid for the Commission to examine the Company's CVR performance in other states. Staff notes that the Commission can judge the effects on the rates charged to Oregon customers from whether or not the Company acquires CVR throughout its system. This review can occur as part of the IRP process and in setting rates.

Support for estimates of CVR savings in Staff's Alternative Portfolio

Staff developed the CVR estimates of potential based, in part, on an examination of the Commonwealth study performed for PacifiCorp. Based on the Stage 1 measures in the study, Staff estimated a range of achievable economic energy savings of 0.59 to 0.83 percent of load.

[9] *Washington Distribution Energy Efficiency Study – Final Report*; by Commonwealth Associates as a contractor to PacifiCorp; May 2011

Staff finds that this range is in the low end of published estimates. For example, the NWPCC 6th Power Plan estimates an achievable economic CVR saving of 1.6 percent of the Pacific NW energy loads by 2029. The NWPCC estimate is based on technologies that are commercially available now.

Staff assumed a cumulative savings by 2020 of 0.43 percent of energy loads – conservatively based on only Stage 1 measures. PacifiCorp's System Optimizer model used only about half of this economic potential to produce the Staff Alternative Portfolio (discussed below) – making the CVR component of the alternative portfolio even more conservative, and therefore reasonably attainable.

b. Resolution

We recognize the complexity of implementing system-wide CVR. We also recognize we acknowledged the Company's 2008 IRP but included an additional action item to incorporate an assessment of distribution efficiency potential resources in its next IRP. We agree with Staff that the Company has not fully complied with this action item.

We believe it is reasonable that the Company develop a realistic and effective timeline for CVR implementation. We agree that the discussion of CVR needs to involve CVR in other PacifiCorp states and believe it is valid for the Commission to examine the Company's CVR performance in other states. In addition, even though CVR is funded situs, we agree that does not prevent us from judging the effects on the rates charged to Oregon customers resulting from the Company's CVR acquisitions, or lack thereof. If PacifiCorp chooses to build generating resources instead of less costly demand-side resources, we should examine the prudency of the generating resources acquired on behalf of Oregon ratepayers.

We direct the replacement of the third bullet in PacifiCorp's 2011 IRP Action Item 6 as recommended by Staff, as follows:

Action Item 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.

- A conservation voltage reduction (CVR) acquisition project in PacifiCorp's Washington service area will begin in 2012 and end no later than 2018.

  The next filed PacifiCorp IRP will include an action plan item to acquire all of the available cost-effective CVR throughout its service area by 2022. This action item will be based primarily on information from Yakima and Walla Walla service areas. Cost-effectiveness analyses will use the same methodology as the modeling approach used in the Class 2 DSM decrement assessment in the 2011 IRP Addendum.~~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. (The Washington distribution energy efficiency study final report is scheduled for completion by the end of May 2011.)~~

5. Capacity Planning Reserve Margin Determination (Action Item 8 continued)

a. Parties' Positions

Initial Comments:

Staff, ICNU, and ODOE expressed concern about PacifiCorp's 13 percent target capacity planning reserve margin (PRM). Staff and ICNU pointed out shortcomings of PacifiCorp's Loss of Load Probability (LOLP) study and decision to change its capacity PRM from 12 to 13 percent.

ICNU stated the Commission should reject the Company's proposed 13 percent PRM and, at minimum, maintain the current 12 percent margin. It stated the LOLP study used to model suggested PRM did not properly model the region's Contingency Reserve Sharing Program (CRSP), and instead, the model substituted proxy data from a different utility with a different reserve obligation. The study also did not account for regional initiatives to adjust power scheduling and balancing. It failed to capture market purchase opportunities, especially given the surplus of hydropower from spring run-off, and the significant surplus capacity forecast in California. ICNU also stated the Company appears to discount the fact that unserved energy amounts are relatively constant across all planning reserve levels, and predicates the PRM increase solely on achieving a one-in-ten year loss of load probability with no consideration given to the amount of energy unserved during these events. The result is that customers will pay too much for relatively small incremental improvements in unserved energy value.

Staff commented that PacifiCorp applied a "long-term reliability planning standard" to come up with its initial planning reserve margin (PRM) target, then adjusted it downwards as a proxy for the Northwest Power Pool's reserve sharing benefit, and came up with a figure of 13 percent. Reliability benefits of using non-firm transmission capacity to access off-system generation were not incorporated in this evaluation.

While the marginal costs for a range of PRMs were presented in IRP Appendix J, estimates of the marginal benefits of a13 percent PRM target were absent. Staff questions the usefulness of the presented marginal cost analysis. In comparing the PVRR of a 12 percent PRM portfolio with the PVRR of a 13 percent PRM portfolio, the incremental PRM values were achieved by adding SCCTs to a minimum-PRM portfolio. Staff considers this methodology to be a shortcoming of the risk analysis portion of the IRP.

With aggregate loads approaching 15,000 MW in 2020, a one percent increase in PRM translates to 150 MW of extra capacity.

Regarding Staff's comment that the Company failed to consider the reliability benefits of nonfirm transmission capacity, PacifiCorp agreed that non-firm transmission capacity may be used on an operational basis to address emergency situations to the extent the non-firm transmission is available. However, a resource planning principle that has been in effect for many years-and which has been accepted by all state commissions-is that the transmission system should be modeled based on firm transmission rights in line with serving retail customer loads reliably. It stated both the LOLP study and IRP portfolio modeling are consistent in this regard.

Concerning Staff’s comment regarding marginal cost analysis and the use of SCCTs as the proxy reliability resource, the Company acknowledged that the LOLP study was not designed to assess the trade-off between reliability and costs/benefits. In regard to the use of SCCTs as the reliability resource, the Company stated this is a standard practice for this type of study.

Regarding the modeling of power pool contingency reserves, PacifiCorp stated that modeling the CRSP would be complex and not practical to implement for the IRP. Rather than excluding the CRSP benefit from the study, PacifiCorp used the Public Service Company of Colorado (PSCo) PRM impact estimate for the Rocky Mountain Reserve Group's reserve sharing program. While PacifiCorp intends to work with Ventyx to model CRSP for the next LOLP study, it stated there is no basis to conclude that "proper modeling could reduce PacifiCorp's estimated planning reserve margin, to a greater extent than the PSCo/Ventyx PRM reduction estimate.

PacifiCorp replied related to considering on-going collaborative regional initiatives in the LOLP study. The Company stated, as noted in Chapter 4 of the IRP, these initiatives are in their early stages. Costs, benefits, and impacts of specific initiatives have yet to be demonstrated or quantitatively characterized in a fashion suitable for system modeling.

PacifiCorp commented that considering spot market purchases as a reliability resource does not comport with capacity adequacy planning principles adopted by PacifiCorp and other electric utilities. While the Company's IRP models simulate the buying and selling of energy for system balancing purposes, spot market purchases are considered a non-firm resource unsuitable for inclusion in the determination of capacity positions. Further, the Company states excess energy available in May and June due to surplus northwest hydro generation does nothing to address system coincident peak capacity requirements that occur in late July. Finally, party comments regarding the impact of incremental resource location and type on Loss of Load Hours have merit. The Company intends to investigate, with Ventyx support, improvements to the LOLP estimation methodology to better integrate System Optimizer capacity expansion capabilities and stochastic production cost modeling.

Staff Final Comments:

Whether PacifiCorp adopts a capacity PRM of 13 percent or maintains the current level of 12 percent is not a major concern on the part of Staff, partly because of the conservative assumptions built into the Company's formulation of its PRM and partly because Staff found no difference in the date when the Company becomes capacity deficient and relatively little difference in the magnitude of the deficiency. Figures showing a comparison between the 13 percent and 12 percent PRM are provided in Staff's Final Comments. However, Staff continues to believe that the contents of IRP Appendix J, which appeared to be the beginnings of a cost-benefit foundation for its PRM determination was not convincing.

ICNU "recommend[s] the Commission reject the higher 13 percent planning margin [PRM] the Company is seeking in its 2011 IRP and, at a minimum, maintain the current 12 percent margin." For the reasons stated above, Staff is neutral as regards this recommendation. ICNU voiced other concerns regarding the PRM – some of which were acknowledged as meritorious by PacifiCorp. As a concession in its reply comments, the Company did recognize "merit in discussing the role of non-firm transmission in the IRP," but argued that such a "major change" would require further deliberation by the Company "as well as other state commissions and stakeholders…."

b. Resolution

We agree with Staff and ICNU that the justification provided by PacifiCorp for increasing the PRM to 13 percent is not convincing. We are not compelled to direct PacifiCorp's use, in this IRP, of a PRM different than 13 percent. We are compelled, however, to require PacifiCorp to develop its 2011 IRP Update based on a 12 percent planning reserve margin, unless a different PRM is justified by a marginal cost study comparing costs of portfolios that are optimized for achieving the various PRMs and including estimates of the marginal benefits from a greater PRM. The study should use loss-of-load hours and unserved energy as the dependent variables. Action Item 8 is revised to include the following:

Action Item 8 - Planning and Modeling Process Improvements

- PacifiCorp will develop its 2011 IRP Update based on a 12 percent planning reserve margin, unless a different PRM is justified by a marginal cost study comparing costs of portfolios that are optimized for achieving the various PRMs, and including estimates of the marginal benefits from a greater PRM. The study will use loss-of-load hours and unserved energy as the dependent variables.

6. Need for a 2016 Combined-Cycle Combustion Turbine Resource (Action Item 2)

a. Parties' Positions

Initial Comments:

CUB stated PacifiCorp's bias towards capital investment is demonstrated in the request for combined-cycle combustion turbine (CCCT) resources in the IRP rather than meeting peak capacity requirements through other means, such as energy efficiency programs and the use of more flexible, less costly simple-cycle combustion turbines (SCCT).

RNP and Sierra Club asserted the IRP presents a weak analysis and justification for CCCT resource investments, and that the resource investment poses a risk to future flexible resource mix strategies. Alternatives to CCCT investment, such as DSM, SCCT and other options, were mentioned to supply forecasted capacity needs if they were fairly analyzed.

RNP stated the Commission should require an evaluation of the economic value of resource flexibility before acknowledging the CCCTs to meet capacity need. RNP also stated the portfolio may erroneously favor CCCT resources due to a 16 percent capital discount credit, and suggested the Commission seek to understand the significance of this bias in skewing portfolio selection.

In its reply comments, the Company stated it conducted rigorous system economic modeling to come up with its preferred portfolio. It believes that it has appropriately and fairly represented the costs, availability, dispatch characteristics, and risks of resource options in determining relative cost-effectiveness for meeting load requirements. PacifiCorp argued that the premise that a 600 MW capacity need in 2016 can be made up-reliably and economically-with more DSM and market purchases is faulty.

Finally, the Company pointed out that the IRP action plan includes reexamining the timing and type of post-2014 gas resources and other resource changes as part of the 2011 business planning process and preparation of the 2011 IRP Update. This reexamination, it says, will be incorporated as part of the All-source Request for Proposals planned for issuance in early January 2012.

The Company then responded to RNP's claims that SCCTs are more economical than CCCTs by virtue of lower capital costs. It noted the capital cost difference between CCCTs and SCCTs has narrowed significantly, to the point where they are almost the same. Moreover, the Company pointed out a comparison of capital costs alone does not capture the cost tradeoffs between these two resource alternatives, concluding that even modest heat rate differences, owing to the 30 to 40 year design life of natural gas resources, can significantly affect life cycle costs.

Staff Final Comments:

As documented above in the discussions of Energy Efficiency (Class 2 DSM) Resource Analysis, Load Control (Class 1 DSM) and Price Response (Class 3 DSM) Resource Analysis, Distribution Energy Efficiency, and Capacity Planning Reserve Margin Determination, Staff identified significant uncaptured resources that, in Staff's opinion, could indefinitely postpone construction of the proposed 2016 CCCT resource. Recognizing the complexity of implementing DSM Classes 1, 2 and 3, and conservation voltage reduction (CVR) programs across its service territory, and the need to rely more upon market purchases to meet loads, Staff recommends that PacifiCorp pursue implementing the Staff alternative portfolio (shown in Staff Final Comments Attachment 1) in lieu of its preferred portfolio. If, after demonstrating it diligently pursued implementation of the Staff alternative portfolio, PacifiCorp finds the resulting demand-side resources and market purchases insufficient to meet the need, it may file an IRP Update to justify acquiring supply-side resources to fulfill the remaining need. Attendant with implementing Staff's alternative portfolio is the recommendation that the 2014 CCCT construction proceed as planned and a request for proposals (RFP) for the 2019 CCCT proceed if updated load forecasts still identify the need.

Staff notes PacifiCorp's reply comments related to RNP's concern over selection of a CCCT in lieu of an SCCT. Staff also questions whether selecting a CCCT, which is typically a base load resource, to fulfill a capacity need, frequently met with an SCCT, is indeed the least cost alternative. Staff believes the capital cost/operating cost tradeoff between a CCCT and SCCT needs to be documented in future IRPs or IRP Updates.

Staff confirmed PacifiCorp's forecast of both a capacity and energy deficit in the first ten years of the planning period, under base case assumptions. On a capacity basis with a 13 percent planning reserve margin, Staff confirmed PacifiCorp's forecast of a 326 megawatt (MW) capacity deficit in 2011, growing to a 2,767 MW capacity deficit in 2016.

On an annual energy basis (using maximum dependable capability of existing resources and a 13 percent planning reserve margin), PacifiCorp forecasts heavy load hour resource surpluses through 2014. Staff believes it is most revealing to evaluate the energy balance without a planning reserve margin, based on the economic dispatch of existing resources, and for all hours. On this basis, using data provided by PacifiCorp, Staff identified for 2011 an energy surplus of 1,546 average MW (aMW). In 2016, Staff identified an energy deficit of 551 aMW, and in 2020 a deficit of 2,016 aMW.

Retail sales by PacifiCorp have been volatile over the past 18 years. This history shows that PacifiCorp loads were strongly affected by the economic recessions that began in 2001and 2008. It also indicates flat or negative growth can extend for many years following a recession. While load growth in other parts of PacifiCorp's service area will differ from the Oregon portion, there is good reason to question whether total loads in the next few years will grow at the rate projected by PacifiCorp. Recognizing this fact leads

Staff to believe there is good reason to consider flexibility in meeting the Company's resource needs.

Portfolio Selection

PacifiCorp's preferred portfolio includes adding three CCCTs in the 2014 to 2019 time period. Staff is concerned about this irreversible cost commitment given uncertainties in load forecasts and accompanying market conditions, and the risk of natural gas prices rising again to levels seen in the last decade. Staff's preference is a portfolio that offers planning flexibility to accommodate the three CCCTs if circumstances warrant, but with the primary intention of meeting the energy and capacity need with a more flexible approach. Furthermore, it is Staff's belief that even if PacifiCorp's forecasts are entirely accurate, a portfolio could be implemented, at a similar cost and risk as the Company's preferred portfolio, but without the irreversible cost commitment that could prove burdensome in the event that the forecasts are not accurate.

Staff's alternative portfolio

PacifiCorp's preferred portfolio includes adding CCCTs in years 2014, 2016, and 2019 (the first is designated as Utah North and the latter two as Utah South). Staff proposes an alternative portfolio that postpones the 2016 CCCT plant indefinitely, and substitutes additional demand-side resources sufficient to achieve the same planning reserve margin (13 percent) as is targeted with the preferred portfolio. The Staff alternative portfolio is shown in Staff Final Comments Attachment 1.

Staff's alternative portfolio adds more third-quarter, heavy-load-hour front-office transactions (FOT 3Q HLH) in both the eastern and western regions of the Company's service territory (with the associated West-to-East transfers), more Class 2 DSM (i.e. energy efficiency), more Class 3 DSM (i.e. using for demonstration purposes, mandatory agricultural TOU pricing in Oregon, California, and Washington[10]), and more CVR[11]. The precise amounts of those resources were determined for modeling by the Company, employing its System Optimizer model(s).

Related to FOT 3Q HLH, Staff initially commented that the IRP does not include sufficient data to confirm the limits in IRP Table 6.18. Staff stated its belief that market purchases are a credible source of capacity and energy, and the preferred portfolio may not be exploiting these to full advantage. Staff's further inquiry, through data requests, yielded nothing that would increase or decrease the front office supply/resource limitations listed in IRP Table 6.18 (Vol. I, page 151). As a result, while Staff's alternative portfolio makes greater utilization of front office transactions than does the Company's preferred portfolio, it does not go beyond the Table 6.18 limitations.

[10] Idaho and Utah already have, or are planned to have, extensive agricultural DSM (demand-side-management).

[11] It would build upon the pilot having been conducted in Washington

Advantages and disadvantages of Staff's alternative portfolio

The primary advantage of the proposed 2016 CCCT is PacifiCorp would be less reliant upon market purchases to meet its load. The primary disadvantages are that PacifiCorp would be acquiring that self-sufficiency at a cost that could not be reversed in the event that the anticipated growth in load, or the opportunity to make off-system spot sales in the off/shoulder-peak hours/seasons, were not forthcoming, and at a cost that would include the risk of natural gas prices returning to those of the last decade. The chief advantage of Staff's alternative portfolio is its downward flexibility in terms of being able to incrementally scale back supply-side resource additions. Its disadvantages would lie in the complexity of implementing DSM Classes 1, 2 and 3 and CVR programs across its service territory, and having to rely more upon market purchases to meet loads.

General results from the supporting quantitative studies

PacifiCorp used both a deterministic and a stochastic approach in estimating the twenty-year present-value-revenue-requirements (PVRRs) associated with the various portfolios that it investigated. The deterministic approach employed ten combinations of carbon dioxide (CO2) costs and natural gas costs, in conjunction with load forecasts, as it estimated the PVRRs. Based upon the "nominal" combination (i.e., $19/ton CO2 costs and "Low" natural gas costs), the Staff alternative portfolio is comparable to, but has a slightly lower (0.09 percent) PVRR than, the preferred portfolio, and has about a one percent higher PVRR than PacifiCorp's Portfolio Case 3 (i.e. the preferred portfolio without 2100 MW in wind additions). For the nine other CO2 and natural gas cost combinations, the Staff alternative portfolio's PVRR is comparable to, but smaller than, the preferred portfolio's (with a difference ranging from 0.9 percent to 1.6 percent).

The stochastic PVRR estimation approach employs 100 Monte Carlo simulation runs where electricity prices, loads, natural gas prices, and thermal and hydro unit availabilities are allowed to vary based upon statistical distributions. Two sets of results were produced: one based upon CO2 costs of $19/ton, and the other at $0. The stochastic PVRR comparisons between the Staff alternative portfolio, the preferred portfolio, and the preferred portfolio "without wind" are comparable with the deterministic results under the nominal conditions. Apart from those comparisons, it is noteworthy that the upper 95th percentile PVRR for the Staff alternative portfolio is slightly less (on the order of 0.1 percent) than that of the preferred portfolio and preferred portfolio without wind for both the $0 and $19/ton CO2 price cases. Given CO2 at $0, the PVRR for the Staff alternative portfolio is slightly less (0.4 percent) than the PVRR of the preferred portfolio, but just under two percent greater than the preferred portfolio "without wind."

While not calling into question the quantitative study results, Staff noted that, counter-intuitively, PacifiCorp's deterministic studies show Staff's alternative portfolio resulting in more on-peak and off-peak sales revenues than would the preferred portfolio. The counter-intuitive sales revenue results may arise from the proportion of generation available for sale during peak price periods in the Staff alternative portfolio compared to the preferred portfolio.

Staff notes RNP's comment that System Optimizer resource selection is biased towards CCCTs over SCCTs and market purchases, citing PacifiCorp's use of a stochastic cost adjustment that reduces CCCT capital costs. Staff believes, however, the bias that may exist does not likely significantly impact the analysis results. As a result, Staff does not recommend, for this IRP, a change in the Company's approach.

b. Resolution

We agree with Staff's observation that there is good reason to consider flexibility in meeting the Company's resource needs. We also agree with Staff that a portfolio could be implemented, at a similar cost and risk as the Company's preferred portfolio, but without the irreversible cost commitment that could prove burdensome in the event that the forecasts are not accurate. As a result, in lieu of the PacifiCorp preferred portfolio, we adopt Staff's alternative portfolio that postpones the 2016 CCCT plant indefinitely and substitutes additional demand-side resources sufficient to achieve the same planning reserve margin as is targeted with its preferred portfolio. In adopting Staff's alternative portfolio, we recognize the complexity of implementing DSM Classes 1, 2 and 3, and CVR programs across PacifiCorp's service territory, and the need to rely more upon market purchases to meet loads. In so recognizing, if, after diligently pursuing implementation of the Staff alternative portfolio, PacifiCorp finds the resulting demand-side resources and market purchases insufficient to meet the need, the Company may file an IRP Update to justify acquiring supply-side resources to fulfill the remaining need. Attendant with implementing Staff's alternative portfolio is the recognition that the 2014 CCCT construction will proceed as planned and an RFP for the 2019 CCCT will proceed if updated load forecasts still identify the need. Revised Action Item 2 is as follows:

Action Item 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.

- Recognizing the complexity of implementing DSM Classes 1, 2 and 3, and CVR programs across its service territory, and the need to rely more upon market purchases to meet loads, PacifiCorp will pursue implementing the Staff alternative portfolio (shown in Staff Final Comments Attachment 1) in lieu of the preferred portfolio. If, after demonstrating it diligently pursued implementation of the Staff alternative portfolio, PacifiCorp finds the resulting demand-side resources and market purchases insufficient to meet the need, it may file an IRP Update to justify acquiring supply-side resources to fulfill the remaining need.
- ~~Issue an all-source RFP in late 2011 or early 2012 for acquisition of peaking/intermediate/baseload resources by the summer of 2016.~~

~~This acquisition corresponds to the 597 MW 2016 CCCT proxy resource (F Class 2x1).~~

- PacifiCorp will reexamine the timing and type of post-2014 gas resources and other resource changes as part of the 2011 business planning process and preparation of the 2011 IRP Update. 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.

7. Wind Resource Costs and Capacity Factors (Action Item 1)

a. Parties' Positions

Initial Comments:

NWEC stated that PacifiCorp's analysis of wind integration costs repeat the same mistakes identified in the 2008 IRP, and result in inflated costs that prevent the model from selecting accurate levels of wind energy. It also stated that despite significant decrease in the cost of wind turbines since 2008, wind capital costs are slightly higher in the 2011 IRP than in the 2008 IRP.

RNP stated that it is troubled by the scarcity of wind in the base case portfolio results. It asserted that wind resource costs are overstated largely because they are saddled with the full burden of the Energy Gateway Transmission project – costs that RNP believes should be shared across generation resources. It noted that the modeled transmission topology was significantly transformed in the 2011 IRP to introduce "wind resource bubbles" that are constrained such that any wind resource built within a bubble causes an incremental investment for an Energy Gateway pathway. Wind is the only resource whose selection forces incremental investment in Energy Gateway. RNP stated this is discriminatory and "at odds with the broad-based benefits created by new transmission infrastructure." RNP also asserted that wind capital costs are too high by virtue of: 1) a flawed wind integration cost; 2) the Company's even distribution of resources quantities by cost level; and 3) incorporation of other costs not documented in the 2011 IRP. RNP also stated that PacifiCorp's generic wind capacity factors appear low in comparison to other data, such as that from Northwest Power and Conservation Council. RNP recommended the Commission require the next IRP update to explore opportunities for reducing integration costs, and model the cost-savings in the next IRP.

PacifiCorp responded that its capital costs in the 2011 IRP were lower than the wind capital costs from 2008. PacifiCorp stated that it based its wind capacity factors on operating data from its own facilities. Regarding the assignment of Energy Gateway costs, PacifiCorp responded that it assigned the incremental cost of transmission needed to interconnect the wind with the grid.

Staff Final Comments:

Staff, in its initial comments, expressed no concern over the wind acquisition plans in Action Item 1. Staff notes the concerns raised by RNP and NWEC regarding wind costs, capacity factors and wind integration. However, PacifiCorp's stated reasons for not acquiring wind sooner than 2018 are related primarily to uncertainty over gas price, CO2 cost and availability of more cost effective geothermal. Initial capital cost and assumed capacity factor were also considerations but were not the deciding factors. Staff concludes that the concerns raised by RNP and NWEC regarding initial cost and capacity factor are addressed sufficiently in the IRP and PacifiCorp's reply comments. As a result, Staff recommends no change to the Company's short term wind acquisition plan. Should RNP and NWEC have continuing concerns in these areas, Staff believes the concerns are best resolved in the next IRP cycle. Staff addresses concerns about the wind integration study in Section III.A.8 below.

PacifiCorp used a statistically based "peak load carrying capability" (PLCC) method to derive capacity contribution from wind. The method uses resource availability and standard deviation of resource availability as inputs to a calculation of capacity contribution.[12] In the next IRP, PacifiCorp should 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.

Wind acquisition was greatly affected by assumptions regarding geothermal. PacifiCorp's model identified over 100 MW of geothermal as part of a least cost portfolio. However, the preferred portfolio does not include geothermal because of uncertainty over dry hole risk. Instead, PacifiCorp proposes to acquire "geothermal equivalent wind", using a formula based on ratio of wind and geothermal capacity factors. Thus, much of the wind generation described in Action Item 1 is actually a proxy for geothermal. Staff addresses PacifiCorp's geothermal plans and its steps to address dry hole risk by pursuing power purchase agreements with third party developers in Section III.A.9 below. Staff believes future IRP cycles should include a projection for wind acquisition with and without geothermal. This projection would be useful particularly for purposes of planning transmission, which has a very long lead time.

Regarding the issues raised by RNP and NWEC, capacity factor and capital costs were not the dominant factors in the Company's wind acquisition plans. As PacifiCorp pointed out in Chapter 8 of the IRP, wind acquisition depended more on RPS requirements, incentives, level of cost effective geothermal development, carbon regulation, and gas price. PacifiCorp's response to the concern over assignment of Energy Gateway costs to wind resources is consistent with Staff's review of the transmission plan. Since wind generation has a shorter lead time than CCCT generation or transmission, Staff believes there is no need to change the wind acquisition plans

[12] The method is fully described in the paper cited in IRP footnote 35.

proposed in this IRP cycle. As a result, Staff believes continuing concerns by RNP and NWEC regarding capital cost and capacity factor assumptions can be addressed in the next IRP cycle.

b. Resolution

We agree with Staff that concerns regarding initial cost and capacity factor are addressed sufficiently in the IRP and PacifiCorp's reply comments. As a result, we direct no change to the Company's short term wind acquisition plan. Should there be continuing concerns in these areas, we believe the concerns are best resolved in the next IRP cycle. We also agree with Staff and direct that the Company's future IRPs 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, and include a projection for wind acquisition with and without geothermal. Action Item 1 is revised to include the following:

Action Item 1 - Renewables/Distributed Generation

Wind

- 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.

8. Wind Integration Study (Action Item 8 continued)

a. Parties' Positions

Initial Comments:

RNP, NWEC and ODOE expressed concern with the validity of the wind integration study. RNP and NWEC believe that the Company did not meet the expectations for wind integration set forth in the 2009 IRP acknowledgement. All three parties recommended the next wind study be conducted by an independent technical review committee approved by Commission or NREL staff. RNP added the review should incorporate industry standard principles and allow for a minimum 60-day stakeholder review period.

RNP stated the wind integration study lacks credibility due to numerous technical and methodological flaws that result in a substantially inflated reserve requirement that diminishes selection of wind resources and may exaggerate costs to ratepayers. RNP stated that an incorrect mathematical formula was applied to calculate the combined error of load and wind, resulting in 22 percent overestimate of reserve requirements. The study duplicates several wind facilities several times, which increases reserve requirements because diversity of separate wind facilities is lost. RNP said this undermines the credibility of the study. It stated the study relies on unvalidated synthetic data and expressed concern with the simulation methodology based on time-lagged correlation with existing historical data. RNP estimated that deficiencies in the study result in nearly doubling the cost of integrating wind resources. When RNP's estimated cost was modeled, the portfolio selected 60 percent more wind resources. Finally, RNP asserted that the study process did not engage the concerns expressed by stakeholders; the compressed timeline did not provide time for the study to be adequately evaluated and concerns responded to before it was filed.

ODOE expressed concern about the validity of using National Renewable Energy Laboratory (NREL) proxy data to estimate the output of "missing" sites.

Staff offered no wind integration study initial comments.

The Company's reply comments noted it will continue to investigate methodological concerns raised in the public input meetings and written comments for the next wind integration study. The Company noted, however, it is premature to claim that PacifiCorp's wind integration cost should be significantly less than the value published in the 2010 study. The Company also reiterated that it responded to the issues RNP raised in this round of comments at the time the 2010 Study was being performed. Regarding concerns on the handling of the public process and data verification, the Company stressed that wind integration analysis is an evolving activity for the Company and that it had developed a fundamentally new methodology in response to comments from the prior wind integration study. Based on this experience, and the expectation that the complexity of wind integration analysis will only increase over time, the Company stated it does not agree that the Commission should set a firm deadline for the study, so that the Company has the latitude to report wind integration study results as an IRP supplement. PacifiCorp also continued to emphasize that while wind integration is important from operational and rate-making perspectives, it currently has a negligible impact on the Company's long-term wind resource acquisition strategy.

Related to Technical Review Committee establishment, the Company commented it intends to establish a technical review committee as indicated in Action Item 8 in PacifiCorp's IRP action plan. The Company disagreed with RNP's recommendation that the committee's members must be approved by Staff (or NREL staff) on the basis that this is unnecessary. Nonetheless, the Company agreed to consider recommendations from parties with regard to individuals that might be well suited to serve as a committee member.

Staff Final Comments:

The basis of variable energy resource (VER) integration cost analysis and the development of analytical techniques to measure them are evolving rapidly. Party comments indicate a diversity of concerns regarding the process, methods, and data of the Wind Integration Study. Staff believes that the specific wind integration study concerns presented by parties fall outside the IRP process, and therefore does not recommend addressing them beyond recognizing what PacifiCorp provided in its reply comments. As noted by PacifiCorp in its reply comments, while wind integration is important from operational and rate-making perspective, it currently has a negligible impact on the Company's long-term wind resource acquisition strategy.

Staff strongly supports the timely establishment of a technical review committee (TRC) to assist PacifiCorp with navigating through the rapidly evolving VER integration issues for PacifiCorp's next wind integration study. Further, Staff recommends that this technical review committee be formed as soon as possible and that it be fully engaged to review the Company's proposals for analytical methods and data to be used in the study. To this end, Staff recommends that the Commission direct PacifiCorp to establish the TRC and identify its members within 30 days of the effective date of its Order. Finally, Staff recommends that PacifiCorp immediately establish a schedule for the study, including full opportunity for stakeholder involvement and progress reviews by the TRC that will allow the final study to be submitted with the Company's next IRP. Staff recommends that the Commission direct PacifiCorp to establish the schedule within 30 days of the effective date of its Order.

b. Resolution

We agree with parties that a technical review committee will be an asset to future wind integration study efforts. As a result, we adopt Staff's recommendations and direct the Company to:

- Establish a TRC to assist the Company with the rapidly evolving VER integration issues for its next wind integration study.

- Form the TRC within 30 days of the effective date of this order, so that it is fully engaged to review the Company's proposals for analytical methods and data to be used in the study

- Also, within 30 days of the effective date of this order, establish a schedule for the study, 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.

Action Item 8 is revised to include the following:

Action Item 8 - Planning and Modeling Process Improvements

- 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 identify its members within 30 days of the effective date of the IRP Order. Within 30 days of the effective date of the 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.

9. Geothermal Resources (Action Item 1 continued)

a. Parties' Positions

Initial Comments:

ODOE and RNP expressed dissatisfaction with PacifiCorp's progress on promoting geothermal resources in light of the Company's finding that geothermal resource options were found to be cost-effective in portfolio modeling. Both said the Commission should require PacifiCorp to conduct a geothermal-only RFP because geothermal power purchases may be cost-effective relative to Company self-build options. RNP stated a geothermal-only RFP would allow the resource to be evaluated more accurately and against the same parameters as other resources. It would also provide a framework for PacifiCorp to justify an affiliate transaction with CalEnergy if it is competitive with other bidders.

ODOE pointed to geothermal as a potential means of compliance with Oregon's Renewable Portfolio Standards, and stated that the financial risk of "dry-hole" exploration should be addressed.

ODOE and RNP suggested that the Company initiate discussions with stakeholders about policy options for distributing the risk of resource development.

In its reply comments, the Company commented it is important to note that it did not eliminate geothermal generation from consideration, even though this resource was excluded from the preferred portfolio. Page 131 of the IRP summarizes the Company's plans to continue analyzing geothermal opportunities, which is reflected in the IRP action plan on page 254.

PacifiCorp also stated that it did invite geothermal developers to bid in its All-source RFP, and will do so again in a January 2012 All-source RFP. The Company also stated it does not believe it is prudent for the Commission to compel it to conduct a geothermal-only RFP, since such an RFP would conflict with the All-source RFP planned for issuance in January 2012. Further, the Company stated any geothermal resource selected in a geothermal-only RFP would need to be justified in terms of both need and cost relative to final bids selected from the All-source RFP.

Staff Final Comments:

Staff does not recommend directing the Company to hold a geothermal only RFP. Staff sees no reason why a geothermal only RFP would produce more bids than an All-source RFP. As a result, Staff disagrees with ODOE and RNP in this matter. Staff recommends future All-source RFPs explicitly invite geothermal developers to bid. Staff notes that the upcoming All-source RFP is proposed for issuance in January 2012, and is still in draft form. Staff believes that, to the extent the current All-source RFP is not conducive to geothermal development, there is still time for stakeholders to discuss ways to address that concern in the All-source RFP process.[13]

Regarding recovery of dry hole risk, Staff does not believe that working with stakeholders is likely to yield a solution to dry hole risk. Staff believes the main barrier to recovery of costs associated with dry hole risk is the "used and useful" requirement. Further, Staff believes dry hole risk is a rate making issue and therefore outside the IRP process. As a result of the above, Staff disagrees with ODOE and RNP regarding dry hole risk in the context of this IRP.

b. Resolution

We agree with Staff that the results of a geothermal only RFP would not likely result differently than those of an All-source RFP. Therefore, we decline ODOE's and RNP's recommendation to require such an RFP. We do, however, direct PacifiCorp to explicitly invite geothermal developers to bid in response to All-source RFPs. As a result Action Item 1 is revised as follows:

Action Item 1 - Renewables/Distributed Generation

Geothermal

- The Company identified over 100 MW of geothermal resources as part of a least-cost resource portfolio. Continue to refine resource potential estimates and update resource costs in 2011-2012 for further economic evaluation of resource opportunities. Continue to, explicitly, include geothermal projects as eligible resources in future all-source RFPs.

10. Renewable Portfolio Standard Compliance Strategy (Action Item 1 continued)

a. Parties' Positions

Initial Comments:

ODOE commented that the IRP is the appropriate place for PacifiCorp to evaluate alternate RPS compliance strategies and compare pros and cons of plans to sell RECs, acquire unbundled RECs, and follow other RPS compliance strategies. PacifiCorp, in its response comments, agreed to expand the next IRP to include discussion of RPS compliance strategies and the role of REC sales and purchases. PacifiCorp's response comments included certain cautions about the handling of confidential information

[13] Staff also notes of the Geothermal Information Request (IR) which PacifiCorp has opened from October 5, 2011 through October 31, 2011. The results of that IR could inform the final content of the All-source RFP.

pertaining to RECs, and the need to coordinate information prepared for the IRP with information prepared for state RPS compliance reports. PacifiCorp also noted that the IRP action plan already includes an action item on RPS compliance strategies. (See page 255.)

Staff Final Comments:

Staff supports ODOE's suggestion, adding its own caution that the IRP, RPS Implementation Plan, and RPS Compliance Report be coordinated so that they do not conflict.

b. Resolution

We agree with ODOE, Staff, and PacifiCorp, and direct the Company to expand the next IRP to include discussion of RPS compliance strategies and the role of REC sales and purchases. We also agree with Staff's caution for the Company to be selective in its discussion to avoid conflict between the IRP, RPS Implementation Plan, and RPS Compliance Report. Action Item 1 is revised to include the following:

Action Item 1 - Renewables/Distributed Generation

<u>Renewable Portfolio Standard Compliance</u>

- Develop and refine strategies for renewable portfolio standard compliance in California and Washington

- <u>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.</u>

11. Transmission Planning and Energy Gateway (Transmission Action Item)

a. Parties' Positions

Initial Comments:

NWEC stated that the Energy Gateway project reflects the priorities and perspective of the previous decade. NWEC raised the question of how well the gateway project addresses the needs of coming decades, including reliability, support for resource and system diversity, financial risk, and eventual coal plant retirement. NWEC stated its concern with the system strategy and regional alignment of the two long-haul branches of Energy Gateway: Gateway West and Gateway South. It questioned the assessment criteria for these branches, which are primarily for bulk long haul power transfer from new development areas to load centers. It expressed concern that the alignment of the new transmission projects will determine where new renewable energy development will occur, particularly with respect to its cost effectiveness in integrating renewable generation sources with non-renewable sources such as coal. NWEC questioned to what degree could the alignment of Energy Gateway "provide cover" for extended operation of coal plants despite regulatory emission requirements and carbon price risk. It stated that a more structured approach to coal plant retirement over the 20-year period would free up existing transmission capacity that could carry new renewables as well as defer and possibly lead to realignment of the major Energy Gateway branches.

NWEC stated that fundamental questions regarding the Hemingway-Captain Jack transmission lines have not been addressed in the IRP, including the main purpose of the lines, and what reliability, congestion and renewable energy objectives the lines will achieve for Oregon customers.

NWEC also stated the IRP contains little discussion regarding the Gateway project's interaction with major interconnecting and adjacent transmission paths and broader western interconnection.

NWEC recommended in the next IRP cycle PacifiCorp should be required to develop a new transmission planning framework derived from principles and requirements of FERC Order 1000, and using tools being developed in the WECC/RTEP process.

RNP stated that transmission planning should continue to develop within the context of a regulatory future that favors renewable resources.

Staff commented that it continues to investigate the cost-effectiveness of the Sigurd to Red Butte project. Staff reviewed the information provided by the Company, but found no evidence that the Company had evaluated any alternative to the proposed single circuit 345 kV line. Alternatives Staff mentioned included a transmission line with a different voltage, a new generating resource in the area of the Red Butte substation, or other options.

In its reply comments, the Company commented it is important to note that Energy Gateway is the overall expansion program and, as is noted in the Transmission Planning chapter of the IRP (Chapter 4, page 63), each Energy Gateway segment will be justified individually based on a combination of benefits. These benefits include net power cost savings, reliability, capital offsets for renewable resource development in low yield geographic regions, and system loss reductions. Each segment continues to be re-evaluated during the Company's annual business plan and IRP cycles to ensure optimal benefits and timing before moving forward with permitting and construction. Segments could be deferred or not constructed, depending on conditions or alternatives, if evaluations prove the need or timing has shifted.

PacifiCorp commented Staff's observation that it "found no evidence that the Company had evaluated any alternative to the proposed Sigurd to Red Butte single circuit 345 kV line" is fair given the level of detail provided in the IRP. The Company responded to Staff's suggested alternatives, including a new generating resource near the Red Butte substation, by stating they are not viable given the Company's reliability obligations. Further, the Company stated it is not a valid option to add a PacifiCorp resource at Red Butte to serve third-party network customer loads, which represent the majority of load in that area.

Related to NWEC's comments, the Company stated, as with all Energy Gateway segments, the benefits of the Hemingway to Captain Jack project will be thoroughly evaluated before the Company pursues investment in permitting and, ultimately, construction. Should the system and customer benefits of the alternative proposed projects exceed those expected from the Hemingway to Captain Jack project, it would be prudent for the Company to pursue these options instead. Until that time, additional details on the projects proposed by Idaho Power and PGE are available in their IRPs and internet resources.

As a FERC-jurisdictional transmission provider, PacifiCorp commented it is subject to compliance with Order 1000 and is in coordination within its planning sub-region and with inter-regional planning entities to develop and implement open planning processes consistent with Order 1000. The Company will then determine, at the appropriate time, how best to assimilate aspects of the FERC Order 1000 planning process into the IRP in light of PacifiCorp's broader resource planning framework, and considering state IRP standards and guidelines and impacts to IRP filing schedules.

Staff Final Comments:

PacifiCorp requested that the Commission acknowledge three transmission projects scheduled to be in service by 2014.[14] These three projects are:

1. Wallula to McNary project (Energy Gateway Segment A);
2. Mona to Terminal project (Energy Gateway Segment C); and
3. Sigurd to Red Butte project (Energy Gateway Segment G).

Staff recommends not acknowledging the Wallula to McNary and Sigurd to Red Butte projects unless and until the Company provides a demonstration, as discussed further below, that the alternative chosen is the most cost-effective alternative.

Staff agrees with the Company's approach that the Energy Gateway is an overall expansion plan and each Energy Gateway project will be justified individually based on a combination of benefits. Staff followed this approach when analyzing the three transmission projects requested to be acknowledged in PacifiCorp's 2011 IRP. Staff believes approaching the Energy Gateway in this manner resolves the concerns outlined in comments by RNP and NWEC. Further, Staff concurs with PacifiCorp's reply comments as they relate to the Hemingway to Captain Jack project and FERC Order 1000, thus addressing related concerns by NWEC.

[14] See PacifiCorp's 2011 IRP, Volume I, Chapter 10, "Transmission Expansion Action Plan," pages 282-285.

Wallula to McNary Project (Energy Gateway Segment A)

The Wallula to McNary transmission project consists of approximately 30 miles of single circuit 230 kV line between the Wallula, Washington substation and the McNary Oregon, substation near Umatilla, Oregon. The project cost is estimated at approximately $30 million. [15, 16]

In the body of PacifiCorp's 2011 Integrated Resource Plan (IRP), the Wallula to McNary project is not mentioned (i.e., neither in Chapter 4, "Transmission Planning" nor in Chapter 7, "Modeling Approach") until Chapter 10, "Transmission Expansion Action Plan," where the Company requests that this project be acknowledged. Staff recognizes that the estimated capital costs of $0.03 billion and the scope of this project are much less than the $1.00 billion[17, 18] estimated capital costs of the other two projects (i.e., Mona to Terminal and Sigurd to Red Butte) for which the Company is requesting acknowledgment in its 2011 IRP; however, Staff believes that if the Company requests acknowledgment of a transmission project in its IRP, such project should be included in its portfolio analysis. Nevertheless, Staff reviewed this project and analyzed its benefits and costs as if it were a standalone project.

Cost-Benefit Analysis

Using the information provided by PacifiCorp, Staff analyzed the project from two perspectives: the economic net benefits[19] and the non-economic net benefits.[20]

Economic Benefits

Regarding economic net benefits, the economic benefit-cost ratio[21] of the project is 0.82, which means that the economic benefits are less than (but relatively close to) the economic costs on a present value basis. Additionally, based on Docket No. UM 1495,[22] in which Staff analyzed the net present value of revenue requirement (PVRR) under different scenarios regarding initial capital cost and future transmission subscription,[23] Staff identified that additional subscription is needed in years 2016, 2018, and 2020 for

---

15 See Docket No. UM 1495, Staff 200 Bless/13, lines 17-24, at http://edocs.puc.state.or.us/efdocs/HTB/um1495htb15551.pdf.

16 For specific capital costs of this project, see confidential attachment of PacifiCorp's response to Staff Data Request 52.

17 To arrive at this number, Staff subtracted the $800 million capital costs of the Populus to Terminal project (http://nttg.biz/site/index2.php?option=com_docman&task=doc_view&gid=623&Itemid=31) from the approximately $1.8 billion capital cost of the base case scenario (the base case scenario includes the Populus to Terminal project, Mona to Oquirrh project, Sigurd to Red Butte project, and Harry Allen upgrade; see PacifiCorp's 2011 IRP, Volume I, Chapter 7, page 169.)

18 For specific information on the capital costs for each segment of the Energy Gateway project, see confidential attachment of PacifiCorp's response to Staff Data Request 52.

19 In this context, the "net economic benefits" of a project are calculated by subtracting the "economic costs" from the "economic benefits" of the project on a present value basis. It is also known as "net financial benefits."

20 The "non-economic net benefits" are also called "non-economic benefits" or "non-financial benefits."

21 In this context, the "economic benefit-cost ratio" is the quotient produced by dividing the present value of economic benefits by the present value of economic costs.

22 Docket No. UM 1495 refers to PacifiCorp's petition for a Certificate of Public Convenience and Necessity for the Wallula to McNary transmission project.

23 See Docket No. UM 1495, Staff 200 Bless/10-15 at http://edocs.puc.state.or.us/efdocs/HTB/um1495htb15551.pdf

the project to break even.[24] Staff also asserted that "based on a range of scenarios for the cost of the project and utilization of the proposed line, it is likely that the economic benefits of the project will equal the economic costs on a net present value basis." [25]

Additionally, as represented in Docket No. UM 1495:

> *"Staff [noted] that, due to uncertainties inherent in any project, the benefits to Pacific Power customers are not certain. Staff [concluded] however, that its economic analysis showed a reasonable likelihood that the project's benefits exceed its costs.*
>
> *Staff [added] that any risk to Oregon Pacific Power customers is offset by the benefits to EWEB's customers. Staff [estimated] that the M2W Line will provide net benefits to EWEB customers of $1.4 million per year. Staff [added] that, over the 50 year life of the project, this equals a NPVRR benefit of $14.8 million to EWEB customers. Staff therefore [concluded] that, if EWEB customers are included in the analysis, Oregonians clearly benefit from the project."*[26]

Finally, in Order No. 11-366 of Docket No. UM 1495 entered on September 22, 2011[27], the Commission granted a Certificate of Public Convenience and Necessity for the Wallula to McNary transmission line. [28] However, the Commission also stated:

> *"[I]n making this decision, we emphasize that our inquiry and analysis in this case are limited. We are not acting in our traditional ratemaking capacity in this proceeding. As noted above, ORS 758.015 provides this Commission to issue a CPCN to facilitate the condemnation of land necessary for the construction of transmission lines. Thus our decision here is akin to a governmental resolution of necessity to condemn private land. We are granting condemnation authority only. Because we are not pre-approving the M2W Line or making any determinations about future cost recovery, we make no specific conclusions about the effect of the project on Pacific Power's Oregon customers. Contrary to the analysis provided by Pacific Power and Staff, we limit our public interest determination based on the project's cost and benefits to all Oregonians. Whether the M2W Line specifically benefits Pacific Power's customers will be addressed in other proceedings, in which Pacific Power will need to provide additional supporting information."* [29]

[24] The break-even point in this context is the point at which transmission revenues cover all costs on a net present basis; therefore, the project has a net revenue requirement of zero when subscription revenues equal annual costs on a net present basis. See Docket No. 1495, Staff/200 Bless/11 at http://edocs.puc.state.or.us/efdocs/HTB/um1495htb15551.pdf. Alternatively, the economic benefit-cost ratio is 1.

[25] See Docket No. UM 1495, Staff 200 Bless/3, lines 15 to 18 at http://edocs.puc.state.or.us/efdocs/HTB/um1495htb15551.pdf

[26] See Order No. 11-366 of Docket No. UM 1495, page 8.

[27] See http://apps.puc.state.or.us/orders/2011ords/11-366.pdf

[28] See Order No. 11-366 of Docket No. UM 1495, page 12.

[29] See Order No. 11-366 of Docket No. UM 1495, pages 8 and 9.

Non-economic Benefits

The project has the following non-economic benefits:

- The project is necessary for PacifiCorp's current native load served from the Wallula substation as a contingency for addressing abnormal operating conditions. [30, 31]

- The project is necessary for PacifiCorp to be capable of serving its future native load in the Walla Walla area once the Walla Walla to Wallula sub-segment (26 miles) has been built.[32, 33]

- The project is necessary to provide transmission access for proposed wind generation in the area per the Federal Energy Regulatory Commission Open Access Transmission Tariff requirements. [34, 35]

- The project has entered into two transmission service contracts for service from Wallula to McNary to move the output from a total of 120 MW of generation resources to markets. [36, 37]

- This project has been assessed and compared to a transmission line alternative which is approximately 130 percent more expensive.[38]

- The project is represented by the Company as meeting Commitment 34c of the MidAmerican Energy Holdings Company acquisition of PacifiCorp. [39, 40]

Conclusion

Because the economic benefit-cost ratio of the project is less than one, Staff recommends not acknowledging the Wallula to McNary transmission project, unless and until the Company provides:

1. An analysis showing that another wind project will be developed in the Wallula area, resulting in more revenues to achieve a benefit-cost ratio equal to, or at least, one; and

---

[30] See PacifiCorp's response to Staff Data Request 72, part "a," .

[31] See PacifiCorp's response to Staff Data Request 100, part "a,".

[32] The Walla Walla to McNary segment (56 miles) comprises the Walla Walla to Wallula sub-segment (26 miles) and the Wallula to McNary sub-segment (30 miles). Acknowledgement of the Wallula to McNary sub-segment was requested in PacifiCorp's 2011 IRP, Volume I, Chapter 10, "Transmission Expansion Action Plan," pages 282 and 283.

[33] See PacifiCorp's response to Staff Data Request 100, part "a,".

[34] See PacifiCorp's response to Staff Data Request 72, part "b," .

[35] See non-confidential part of PacifiCorp's response to Staff Data Request 48.

[36] See PacifiCorp's 2011 IRP, Volume I, Chapter 10, "Transmission Expansion Action Plan," page 283, second paragraph.

[37] See PacifiCorp's response to Staff Data Request 72, part "e,".

[38] See confidential attachment of PacifiCorp's response to Staff Data Request 48, page 5.

[39] See PacifiCorp's 2011 IRP, Volume I, Chapter 10, "Transmission Expansion Action Plan," page 283, third paragraph.

[40] See PacifiCorp's response to Staff Data Request 70.

2. An analysis quantifying other non-economic benefits. (e.g. the project is necessary as a contingency for addressing abnormal operating conditions)

Staff also recommends that in future IRPs the Company should include in its portfolio scenario any transmission project for which acknowledgment is requested, regardless of its size or scope.

Mona to Terminal Project (Energy Gateway Segment C)

The Mona to Terminal project comprises two segments: the Mona to Oquirrh segment and the Oquirrh to Terminal segment. The Mona to Oquirrh segment consists of a single circuit 500 kV line that will run approximately 69 miles between the new Clover substation to be built near the existing Mona substation in Juab County to the new Limber substation to be constructed in Tooele County, and a double circuit 345 kV line extending approximately 31 miles between the Limber substation and the existing Oquirrh substation in West Jordan. The Oquirrh to Terminal segment consists of a double circuit 345 kV line running approximately 14 miles between the Oquirrh substation and the Terminal substation. [41]

The capital cost of the Mona to Terminal project including the Sigurd to Red Butte project and the Harry Allen upgrade is approximately $1 billion.[42, 43]

Escalation of Costs

In Chapter 4, the Company mentions only the Mona to Oquirrh segment, but in Chapter 10, the Company requests acknowledgment of both segments: the Mona to Oquirrh segment and the Oquirrh to Terminal segment. In PacifiCorp's supplemental response to Staff data request 33,[44] the Company shows that the capital cost values used in analyzing scenarios in Chapter 4 include the costs of the Oquirrh to Terminal segment; in other words, the capital costs of the Mona-Terminal project (both segments) are included in Chapter 4 of PacifiCorp's IRP. Staff observes a 12 percent cost discrepancy between the capital costs of the Mona to Terminal project as represented in PacifiCorp's confidential response to Staff Data Request 52[45] and the capital costs represented in PacifiCorp's confidential supplemental response to Staff data request 33.

[41] See PacifiCorp's 2011 IRP, Volume I, Chapter 10, "Transmission Expansion Action Plan," page 284, first paragraph.

[42] For arriving at this number, Staff subtracted the $800 million capital costs of the Populous to Terminal project (http://nttg.biz/site/index2.php?option=com_docman&task=doc_view&gid=623&Itemid=31) from the approximated $1.8 billion capital cost of the base case scenario. The base case scenario includes the Populus to Terminal project, Mona to Oquirrh segment, Sigurd to Red Butte segment, and Harry Allen upgrade (See PacifiCorp's 2011 IRP, Volume I, Chapter 7, page 169.)

[43] For information of capital costs for each segment of the Energy Gateway project, see confidential attachment of PacifiCorp's response to Staff Data Request 52.

[44] See confidential attachment of PacifiCorp's first supplemental response to Staff Data Request 33, workbook "Attach OPUC 33 -2 CONF 1st Supp," worksheet "Capital Cost EG1."

[45] See confidential attachment of PacifiCorp's response to Staff Data Request 52.

Cost-Benefit Analysis

Using the information provided by PacifiCorp, Staff analyzed the project from two perspectives: the economic net benefits[46] and non-economic net benefits.[47]

Regarding economic net benefits and focusing only on the Mona to Oquirrh segment, in response to Staff data request 43, [48] PacifiCorp provided the Investment Appraisal Document for the Mona to Oquirrh segment, in which the Company provided the economic benefits of the project represented by the present value of variable production cost savings calculated using the Company's IRP Production and Resource Model[49] and economic costs of the project represented by the PVRR. The project presents an economic benefit-cost ratio[50] of 0.95. Focusing on the combined Mona to Terminal project, the project presents an economic benefit-cost ratio of 1.12; [51] in other words, the expected economic benefits of the project are greater than the economic costs on a present value basis.

The Mona to Terminal project has the following non-economic benefits:

- The project is necessary for PacifiCorp to be able to serve its current native load.[52]
- The existing transmission system has limited capability to deliver energy into the largest load center in Utah (the Wasatch Front area.) [53, 54]
- The Mona Substation is a critical hub through which power is imported from PacifiCorp's southern intertie lines. It also serves as an important interconnection point with other sources of generation. [55]
- This project is key to maintaining reliability since the capacity north of the Mona substation is fully subscribed and constrained. [56]
- This project has been assessed and compared to an alternative transmission line which costs approximately 40 percent more.[57]

---

[46] In this context, the "net economic benefits" of a project are calculated by subtracting of the "economic costs" from the "economic benefits" of the project in a present value basis. It is also known as "net financial benefits."

[47] The "non-economic net benefits" are also called "non-economic benefits" or "non-financial benefits."

[48] See confidential attachment of PacifiCorp's response to Staff Data Request 43.

[49] The Company provided the present value of variable production cost savings under four scenarios, which were averaged by Staff.

[50] In this context, the "economic benefit-cost ratio" is the quotient yielded by dividing the present value of economic benefits by the present value of economic costs.

[51] See confidential attachment of PacifiCorp's response to Staff Data Request 93.

[52] See PacifiCorp's response to Staff Data Request 76, part "a,".

[53] See PacifiCorp's 2011 IRP, Volume I, Chapter 10, "Transmission Expansion Action Plan," page 284, second paragraph.

[54] See PacifiCorp's response to Staff Data Request 98.

[55] See PacifiCorp's 2011 IRP, Volume I, Chapter 10, "Transmission Expansion Action Plan," page 284, second paragraph.

[56] See PacifiCorp's 2011 IRP, Volume I, Chapter 10, "Transmission Expansion Action Plan," page 284, second paragraph.

[57] See confidential attachment of PacifiCorp's response to Staff Data Request 43, page 13.

- This project is key to maintaining the Company's compliance with mandated North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability and performance standards during normal system operations and during certain transmission system and generation plant outages.[58, 59]

Conclusion

Staff recommends acknowledging the Mona to Terminal project, based on the information provided by the Company.

<u>Sigurd to Red Butte Project (Energy Gateway Segment G)</u>

The Sigurd to Red Butte project, part of Gateway South, is a single circuit 345kV line that runs approximately 160 miles between the Sigurd substation near Richfield, Utah, and an expanded Red Butte substation near Central in Washington County, Utah.[60] The capital cost of the Sigurd to Red Butte project, including the Mona to Terminal project and the Harry Allen upgrade, is approximately $1 billion.[61, 62]

Cost Benefit Analysis

In Staff Data Request 44,[63] Staff asked PacifiCorp to provide the financial analysis justifying the Sigurd to Red Butte project, to which PacifiCorp responded that "The Sigurd to Red Butte final authorization has not been secured yet because the project is still in the detail scoping phase. Therefore, an Investment Appraisal Document has not been created, but will be completed before final authorization." Staff followed up on this response in Staff Data Request 94,[64] to which the Company responded by providing certain financial information.

Staff reviewed the information provided by the Company, but found no evidence that the Company has evaluated any alternative to the proposed single circuit 345 kV line. Alternatives could include a transmission line with a different voltage, a new generating resource in the Red Butte substation surroundings, or other options.

---

[58] See PacifiCorp's 2011 IRP, Volume I, Chapter 10, "Transmission Expansion Action Plan," page 284, second paragraph.

[59] See also PacifiCorp's response to Staff Data Request 49.

[60] See PacifiCorp's 2011 IRP, Volume I, Chapter 10, "Transmission Expansion Action Plan," page 285, first paragraph.

[61] To arrive at this number, Staff subtracted the $800 million capital costs of the Populous to Terminal project (http://nttg.biz/site/index2.php?option=com_docman&task=doc_view&gid=623&Itemid=31) from the approximately $1.8 billion capital cost of the base case scenario. The base case scenario includes the Populus to Terminal segment, Mona to Oquirrh segment, Sigurd to Red Butte segment, and Harry Allen upgrade (see PacifiCorp's 2011 IRP, Volume I, Chapter 7, page 169).

[62] For specific information on the capital costs for each segment of the Energy Gateway project, see confidential attachment of PacifiCorp's response to Staff Data Request 52.

[63] See PacifiCorp's response to Staff Data Request 44.

[64] See confidential attachment of PacifiCorp's response to Staff Data Request 94.

Using the information provided by PacifiCorp, Staff analyzed the project from two perspectives: the economic net benefits[65] and the non-economic net benefits.[66] In the confidential response to Staff Data Request 94, the Company provided the economic benefits of the project represented by the present value of variable production cost savings calculated using the Company's IRP Production and Resource Model and the economic costs of the project represented by the PVRR. The project presents an economic benefit-cost ratio of 0.44; in other words, the expected economic benefits of the project are lower than the economic costs on a net present value basis.

From the non-economic perspective, the benefits of the Sigurd to Red Butte project are:

- The project is necessary to be able to serve PacifiCorp's native load.[67]

- The project is necessary because the capacity of the southwest Utah transmission system, including the existing Sigurd to Three Peaks to Red Butte 345 kV transmission line, is fully utilized and cannot provide adequate service under all expected operating conditions. Loads in southwestern Utah are forecasted to surpass the capabilities of the existing transmission system. Without the project, peak load in southwest Utah cannot be served reliably in the event of transmission line outages or major equipment contingencies.[68, 69]

- The Sigurd to Red Butte project will improve the transmission system's ability to transport energy into southwest and central Utah, as well as high-growth urban areas in and around Salt Lake City and along the Wasatch Front.[70]

- The project is key to maintaining the Company's compliance with mandated North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability and performance standards as necessary during normal system operations and system outage conditions.[71, 72]

Conclusion

Because the economic benefit-cost ratio of the project is less than one, Staff recommends not acknowledging the Sigurd to Red Butte transmission project, unless and until the Company provides:

1. An analysis including other economic benefits and quantifying other non-economic benefits to achieve a benefit-cost ratio equal to, or at least, one.

---

[65] In this context, the "net economic benefits" of a project are the subtraction of the "economic costs" from the "economic benefits" of the project. It is usually compared in a present value basis. It is also known as "net financial benefits."
[66] The "non-economic net benefits" are also called "non-economic benefits" or "non-financial benefits."
[67] See PacifiCorp's response to Staff Data Request 78, part "a," .
[68] See PacifiCorp's 2011 IRP, Volume I, Chapter 10, "Transmission Expansion Action Plan," page 285, second paragraph.
[69] See confidential attachment of PacifiCorp's response to Staff Data Request 50, page 5.
[70] See PacifiCorp's 2011 IRP, Volume I, Chapter 10, "Transmission Expansion Action Plan," page 285, second paragraph.
[71] See PacifiCorp's non-confidential part of response to Staff Data Request 50.
[72] See PacifiCorp's 2011 IRP, Volume I, Chapter 10, "Transmission Expansion Action Plan," page 285, third paragraph.

2. An analysis (e.g. the project's Investment Appraisal Document) demonstrating that the alternative chosen is the most cost-effective alternative.

b. Resolution

We find that the Company's reply comments sufficiently address the ODOE and NWEC initial comments. PacifiCorp's reply comments do not, however, resolve Staff's comment regarding the lack of justification for the Wallula to McNary or Sigurd to Red Butte projects. As a result, we agree with Staff and decline to acknowledge the Wallula to McNary and Sigurd to Red Butte projects unless and until the Company provides a demonstration that the alternative chosen is the most cost-effective alternative. The Transmission Action Items are revised as follows:

Transmission Action Items

PacifiCorp will provide, for the Wallula to McNary project (Energy Gateway Segment A), prior to seeking regulatory acknowledgement of this project:

1. An analysis showing that another wind project will be developed in the Wallula area, resulting in more revenues to achieve a benefit-cost ratio equal to, or at least, one; and

2. An analysis quantifying other non-economic benefits. (e.g. the project is necessary as a contingency for addressing abnormal operating conditions)

PacifiCorp requests regulatory acknowledgement of the Mona to Terminal project (Energy Gateway Segment C).

PacifiCorp will provide, for the Sigurd to Red Butte project (Energy Gateway Segment G), prior to seeking regulatory acknowledgement of this project:

1. An analysis including other economic benefits and quantifying other non-economic benefits to achieve a benefit-cost ratio equal to, or at least, one.

2. An analysis (e.g. the project's Investment Appraisal Document) demonstrating that the alternative chosen is the most cost-effective alternative.

In future IRPs, the Company will include in its portfolio scenario any transmission project for which acknowledgment is requested, regardless of its size or scope.

12. Energy Storage (Action Item 1 continued)

a. Parties' Positions

As an initial matter, Staff concurs with PacifiCorp that a consideration of the value and benefits of storage is warranted. However, Staff encourages PacifiCorp to consider storage within the broader context of flexibility needs, sources and adequacy and to consider how this emerging need, driven largely by the rapid introduction of variable energy resources (VERs), fits within the overall analytical framework of system planning.

Energy storage adds operational flexibility allowing a balancing area's system to respond rapidly and accurately to changing load conditions. Such flexibility arising from the various storage technologies could be beneficial from the very short term (second-to-second frequency regulation, for example) to intra-hour ramping and to diurnal or weekly time periods. Storage may be able to more economically absorb the wear and tear on traditional automated generator control (AGC) thermal units now being used to respond to net load variations resulting from increasing penetration of VERs, primarily wind and solar. Storage is neither a pure capacity asset nor a pure energy (or simple arbitrage) asset; it is a flexibility asset, in some cases even providing transmission support. Further, the values of storage go well beyond simple time-shifting arbitrage and vary with technology and the role of storage in system operations. With these preliminary thoughts in mind, Staff recommends that the consultant storage study in IRP Action Item 1 be framed in the overall context of flexibility needs, sources and adequacy, and that the study include the following elements:

1) Definition of and suggest metrics by which to measure flexibility (applicable to all flexibility resources including: thermal, demand response (DR), and storage)

2) An inventory of existing flexibility needs and the adequacy or capability of existing assets to meet them

3) A projection of flexibility needs in the IRP timeframe to successfully integrate projected VER additions

4) A comparison of benefits and costs of obtaining flexibility from the range of flexible resources (conventional thermal, DR, storage, etc.)

5) A discussion of the potential for other sources of flexibility, such as regional VER integration efforts (including but not limited to the EIM proposal) to reduce integration requirements and costs.

b. Resolution

We adopt Staff's recommendations related to the Company's Action Item 1 for Energy Storage. Action Item 1 is revised as follows:

Action Item 1 - Renewables/Distributed Generation

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.

- Initiate a consultant study in 2011 or 2012 on incremental capacity value and ancillary service benefits of energy storage. The study will include the following elements:

1) Definition of and suggest metrics by which to measure flexibility (applicable to all flexibility resources including: thermal, demand response (DR), and storage)

2) An inventory of existing flexibility needs and the adequacy or capability of existing assets to meet them

3) A projection of flexibility needs in the IRP timeframe to successfully integrate projected VER additions

4) A comparison of benefits and costs of obtaining flexibility from the range of flexible resources (conventional thermal, DR, storage, etc.)

13. Adherence of the Plan to Integrated Resource Planning Guidelines

a. Parties' Positions

Initial Comments:

Among parties to this docket there was unanimous agreement that PacfiCorp's 2011 IRP, as filed on March 31, 2011, did not comply with Guidelines 4(g) and 1(c) because it failed to provide a comprehensive evaluation of the compliance of its existing coal fired generation resources with new, draft, and anticipated environmental regulations. IRP Guideline 4(g) requires the utility to identify key assumptions about the future, including assumptions about future environmental compliance costs. IRP Guideline 1(c) sets the primary goal of the IRP to be the selection of a portfolio of resources with the best combination of cost and risk for the utility and ratepayers. Without a comprehensive evaluation of these environmental compliance costs, parties commented it was not possible to determine whether any of the candidate resource portfolios meet this standard.

In response to this deficiency, PacifiCorp submitted a Supplemental Coal Replacement Study with its Reply Comments on September 21, 2011. The study evaluated, on a unit by unit basis, whether its coal fired resources would be more economic than a replacement resource when including the additional cost of bringing those resources in full compliance with new, draft, and anticipated environmental regulations. The Coal Study concluded PacifiCorp's coal fleet, with planned incremental investments, will continue to provide reliable and least cost electric service to customers.

Staff Final Comments:

By including the Supplemental Coal Replacement Study, Staff believes the PacifiCorp 2011 IRP reasonably complies with the IRP Guidelines. Staff notes that Guideline 4a, which requires an explanation of how the utility met each substantive and procedural requirement, was not provided. Refer to Staff Final Comments Attachment 2, prepared by Staff, for a table presentation of compliance by Guideline.

b. Resolution

In considering whether to acknowledge a resource plan, this Commission reviews the Plan for adherence to our Guidelines for resource planning. By including the Supplemental Coal Replacement Study, we conclude that PacifiCorp's 2011 IRP reasonably meets the Integrated Resource Planning Guidelines.

B. CONCLUSION

Jurisdiction

PacifiCorp is a public utility in Oregon that provides electric service to the public as defined by ORS 757.005.

PacifiCorp is a public utility subject to the jurisdiction of the Commission.

PacifiCorp's 2011 Integrated Resource Plan, as modified in this order, reasonably adheres to the principles of resource planning set forth in Order No. 07-002 and should be acknowledged with the following requirements:

Requirement:

The 2011 IRP Action Items are ordered to be revised as follows:

Action Item 1 - Renewables/Distributed Generation

<u>Wind</u>

- Acquire up to 800 MW of wind resources by 2020, dictated by regulatory and market developments such as (1) renewable/clean energy standards, (2) carbon regulations, (3) federal tax incentives, (4) economics, (5) natural gas price forecasts, (6) regulatory support for investments necessary to integrate variable energy resources, and (7) transmission developments. The 800-megawatt level is supported by consideration of regulatory compliance risks and public policy interest in clean energy resources.

- 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 dry hole risk.

Geothermal

- The Company identified over 100 MW of geothermal resources as part of a least-cost resource portfolio. Continue to refine resource potential estimates and update resource costs in 2011-2012 for further economic evaluation of resource opportunities. Continue to, explicitly, include geothermal projects as eligible resources in future all-source RFPs.

Solar

- Evaluate procurement of Oregon solar photovoltaic resources in 2011 via the Company‘s solar RFP.

- 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 late 2011 and 2012, using the Company‘s own analysis of Wasatch Front roof top solar potential and experience with the Oregon solar pilot program. As recommended in the Company‘s response to comments under Docket No. 07-035-T14, the Company requested that the Utah Commission establish "a process in the fall of 2011 to determine whether a continued or expanded solar program in Utah is appropriate and how that program might be structured."

- Investigate, and pursue if cost-effective from an implementation standpoint, commercial/residential solar ~~hot~~ water heating programs.

    - The 2011 IRP preferred portfolio includes 30 MW of solar ~~hot~~ water heating resources by 2020 (18 MW in the east side and 12 MW in the west side).

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 2011-2020 (10 MW in the east side and 42 MW in the west side)

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.

  Initiate a consultant study in 2011 or 2012 on incremental capacity value and ancillary service benefits of energy storage. The study will include the following elements:

  5) Definition of and suggest metrics by which to measure flexibility (applicable to all flexibility resources including: thermal, demand response (DR), and storage)

  6) An inventory of existing flexibility needs and the adequacy or capability of existing assets to meet them

  7) A projection of flexibility needs in the IRP timeframe to successfully integrate projected VER additions

  8) A comparison of benefits and costs of obtaining flexibility from the range of flexible 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.

Action Item 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.

- Recognizing the complexity of implementing DSM Classes 1, 2 and 3, and CVR programs across its service territory, and the need to rely more upon market purchases to meet loads, PacifiCorp will pursue implementing the Staff alternative portfolio (shown in Staff Final Comments Attachment 1) in lieu of the preferred portfolio. If, after demonstrating it diligently pursued implementation of the Staff alternative portfolio, PacifiCorp finds the resulting demand-side resources and market purchases insufficient to meet the need, it may file an IRP Update to justify acquiring supply-side resources to fulfill the remaining need.
- ~~Issue an all-source RFP in late 2011 or early 2012 for acquisition of peaking/intermediate/baseload resources by the summer of 2016.~~

  - ~~This acquisition corresponds to the 597 MW 2016 CCCT proxy resource (F Class 2x1).~~

- PacifiCorp will reexamine the timing and type of post-2014 gas resources and other resource changes as part of the 2011 business planning process and preparation of the 2011 IRP Update. The reexamination will include documentation of capital cost/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.

Action Item 3 - Firm Market Purchases

- Acquire up to 1,400 MW of economic front office transactions or power purchase agreements as needed until the beginning of summer 2014, unless cost-effective long-term resources are available and their acquisition is in the best interests of customers.

  – 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.

Action Item 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.

- Successfully complete the dense-pack coal plant turbine upgrade projects scheduled for 2011 and 2012, totaling 31 MW
- Complete the remaining turbine upgrade projects by 2021, totaling an incremental 34.2 MW, subject to continuing review of project economics.
- Seek to meet the Company's updated aggregate coal plant net heat rate improvement goal of 478 Btu/kWh by 2019.
- Continue to monitor turbine and other equipment technologies for cost-effective upgrade opportunities tied to future plant maintenance schedules.

Action Item 5 - Class 1 DSM

Acquire up to 250 MW of cost-effective Class 1 demand-side management programs for implementation in the 2011-2020 time frame.

- For 2012-2013, pursue up to 80 MW of the commercial curtailment product (which includes customer-owned standby generation opportunities) being procured as an outcome of the 2008 DSM RFP.
- Depending on final economics, pursue the remaining 170 MW for 2012-2020, consisting of additional curtailment opportunities and irrigation/residential direct load control.

Action Item 6 - Class 2 DSM

- Acquire ~~up to 1,200~~1,800 MW of cost-effective Class 2 programs by 2020, including 1,200 MW in the eastern supply territory~~equivalent to about 4,533 GWh. This includes programs in Oregon acquired through the Energy Trust of Oregon~~.
  - Procure through the currently active DSM RFP and subsequent DSM RFPs.
- In the next IRP, the Company will evaluate alternatives for ramping up DSM 2 in a way that is equal to supply side resource development and procurement.
- In the next IRP, the Company will provide an analysis of alternatives to the current bundling method for modeling and evaluating energy efficiency measure supply curves.

- In the Company's next IRP, it will provide an analysis of the sufficiency of current staffing levels to achieve programmatic cost effective energy efficiency targets established in this plan.

- 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.

- A conservation voltage reduction (CVR) acquisition project in PacifiCorp's Washington service area will begin in 2012 and end no later than 2018.

  The next filed PacifiCorp IRP will include an action plan item to acquire all of the available cost-effective CVR throughout its service area by 2022. This action item will be based primarily on information from Yakima and Walla Walla service areas. Cost-effectiveness analyses will use the same methodology as the modeling approach used in the Class 2 DSM decrement assessment in the 2011 IRP Addendum.~~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. (The Washington distribution energy efficiency study final report is scheduled for completion by the end of May 2011.)~~

Action Item 7 - Class 3 DSM

- ~~Continue to evaluate Class 3 DSM program opportunities.~~ By 2020 PacifiCorp will implement 262 MW of Class 3 DSM on the East side and 131 MW of Class 3 DSM on the West side using a combination of programs (TOU irrigation, DLC Residential, Real-time pricing-Commercial & Industrial, Demand buy back, Critical Peak Pricing, etc.) as demonstrated in its sensitivity analysis, Case Study 31[73].

  In its next filed IRP PacifiCorp will report on the cost-effectiveness and status of its acquisition and implementation of Class 3 DSM.

  - ~~Evaluate program specification and cost-effectiveness in the context of IRP portfolio modeling, and monitor market changes that may remove the voluntary nature of Class 3 pricing products.~~

[73] 2011 IRP, Appendix D, p. 129.

Action Item 8 - Planning and Modeling Process Improvements

- Continue to refine the System Optimizer modeling approach for analyzing coal utilization strategies under various environmental regulation and market price scenarios.

- PacifiCorp will complete and present with its 2011 IRP Update additional Supplemental Coal Replacement Study analyses centered around alternative environmental compliance approaches coupled with early retirement for the coal resources believed to be most economically sensitive to environmental compliance costs. In these additional analyses the Company will correct, as appropriate, its treatment of depreciation for the period after 2030.

- Continue to coordinate with PacifiCorp's transmission planning department on improving transmission investment analysis using the IRP models.

- Incorporate plug-in electric vehicles and Smart Grid technologies as a discussion topic for the next IRP.

- 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 identify its members within 30 days of the effective date of the IRP Order. Within 30 days of the effective date of the 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.

- PacifiCorp will develop its 2011 IRP Update based on a 12 percent planning reserve margin, unless a different PRM is justified by a marginal cost study comparing costs of portfolios that are optimized for achieving the various PRMs, and including estimates of the marginal benefits from a greater PRM. The study will use loss-of-load hours and unserved energy as the dependent variables.

Transmission Action Items

PacifiCorp will provide, for the Wallula to McNary project (Energy Gateway Segment A), prior to seeking regulatory acknowledgement of this project:

1. An analysis showing that another wind project will be developed in the Wallula area, resulting in more revenues to achieve a benefit-cost ratio equal to, or at least, one; and

2. An analysis quantifying other non-economic benefits. (e.g. the project is necessary as a contingency for addressing abnormal operating conditions)

PacifiCorp requests regulatory acknowledgement of the Mona to Terminal project (Energy Gateway Segment C).

PacifiCorp will provide, for the Sigurd to Red Butte project (Energy Gateway Segment G), prior to seeking regulatory acknowledgement of this project:

1. An analysis including other economic benefits and quantifying other non-economic benefits to achieve a benefit-cost ratio equal to, or at least, one.

2. An analysis (e.g. the project's Investment Appraisal Document) demonstrating that the alternative chosen is the most cost-effective alternative.

In future IRPs, the Company will include in its portfolio scenario any transmission project for which acknowledgment is requested, regardless of its size or scope.

Effect of the Plan on Future Rate-making Actions

Order No. 89-507 set forth the Commission's role in reviewing and acknowledging a utility's least-cost plan as follows:

> The establishment of least-cost planning in Oregon is not intended to alter the basic roles of the Commission and the utility in the regulatory process. The Commission does not intend to usurp the role of utility decision-maker. Utility management will retain full responsibility for making decisions and for accepting the consequences of the decisions. Thus, the utilities will retain their autonomy while having the benefit of the information and opinion contributed by the public and the Commission….
>
> Acknowledgment of a plan means only that the plan seems reasonable to the Commission at the time the acknowledgment is given. As is noted elsewhere in this order, favorable rate-making treatment is not guaranteed by acknowledgment of a plan. *See* Order No. 89-507 at 6 and 11.
>
> The Commission affirmed these principles in Docket UM 1056.[74]

This order does not constitute a determination on the rate-making treatment of any resource acquisitions or other expenditures undertaken pursuant to PacifiCorp's 2008 IRP. As a legal matter, the Commission must reserve judgment on all rate-making issues. Notwithstanding these legal requirements, we consider the integrated resource planning process to complement the rate-making process. In rate-making proceedings in which the reasonableness of resource acquisitions is considered, the Commission will give considerable weight to utility actions which are consistent with acknowledged integrated resource plans. Utilities will also be expected to explain actions they take which may be inconsistent with Commission-acknowledged plans.

---

[74] *See* Order No. 07-002 at 24.

IV. ORDER

IT IS ORDERED that the 2011 Integrated Resource Plan filed by PacifiCorp on March 31, 2011, is acknowledged in accordance with the terms of this order and Order No. 07-002 as corrected by Order No. 07-047.

Made, entered, and effective ______________________________.

______________________________	______________________________
Susan Ackerman	**John Savage**
Commissioner	Commissioner

CERTIFICATE OF SERVICE

LC 52

I certify that I have this day served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 13th day of October, 2011 at Salem, Oregon.

Kay Barnes

Kay Barnes
Public Utility Commission
Regulatory Operations
550 Capitol St NE Ste 215
Salem, Oregon 97301-2551
Telephone: (503) 378-5763

LC 52
SERVICE LIST – PARTIES

***OREGON DEPARTMENT OF ENERGY** VIJAY A SATYAL **(C)** SENIOR POLICY ANALYST	 625 MARION ST NE SALEM OR 97301 vijay.a.satyal@state.or.us
REBECCA SHERMAN **(C)** SENIOR POLICY ANALYST	625 MARION ST NE SALEM OR 97301 rebecca.sherman@state.or.us
***OREGON DEPARTMENT OF JUSTICE** JANET L PREWITT **(C)** ASSISTANT AG	 NATURAL RESOURCES SECTION 1162 COURT ST NE SALEM OR 97301-4096 janet.prewitt@doj.state.or.us
CITIZENS' UTILITY BOARD OF OREGON GORDON FEIGHNER **(C)** ENERGY ANALYST	 610 SW BROADWAY, STE 400 PORTLAND OR 97205 gordon@oregoncub.org
ROBERT JENKS **(C)** EXECUTIVE DIRECTOR	610 SW BROADWAY, STE 400 PORTLAND OR 97205 bob@oregoncub.org
G. CATRIONA MCCRACKEN **(C)** LEGAL COUNSEL/STAFF ATTY	610 SW BROADWAY, STE 400 PORTLAND OR 97205 catriona@oregoncub.org
COMMUNITY ACTION PARTNERSHIP OF OREGON JESS KINCAID ENERGY PARTNERSHIP COORDINATOR	 PO BOX 7964 SALEM OR 97301 jess@caporegon.org
DAVISON VAN CLEVE IRION A SANGER **(C)** ASSOCIATE ATTORNEY	 333 SW TAYLOR - STE 400 PORTLAND OR 97204 mail@dvclaw.com
ESLER STEPHENS & BUCKLEY JOHN W STEPHENS **(C)**	 888 SW FIFTH AVE STE 700 PORTLAND OR 97204-2021 stephens@eslerstephens.com; mec@eslerstephens.com

NW ENERGY COALITION	
WENDY GERLITZ **(C)** SENIOR POLICY ASSOCIATE	1205 SE FLAVEL PORTLAND OR 97202 wendy@nwenergy.org
FRED HEUTTE **(C)** SENIOR POLICY ASSOCIATE	PO BOX 40308 PORTLAND OR 97240-0308 fred@nwenergy.org
PACIFIC POWER	
MARY WIENCKE	825 NE MULTNOMAH ST, STE 1800 PORTLAND OR 97232-2149 mary.wiencke@pacificorp.com
PACIFICORP ENERGY	
PETE WARNKEN MANAGER, IRP	825 NE MULTNOMAH - STE 600 PORTLAND OR 97232 irp@pacificorp.com
PACIFICORP, DBA PACIFIC POWER	
OREGON DOCKETS	825 NE MULTNOMAH ST, STE 2000 PORTLAND OR 97232 oregondockets@pacificorp.com
PORTLAND GENERAL ELECTRIC	
RANDY DAHLGREN	121 SW SALMON ST - 1WTC0702 PORTLAND OR 97204 pge.opuc.filings@pgn.com
BRIAN KUEHNE	121 SW SALMON STREET 3WTC BR06 PORTLAND OR 97204 brian.kuehne@pgn.com
V. DENISE SAUNDERS	121 SW SALMON ST 1WTC1301 PORTLAND OR 97204 denise.saunders@pgn.com
PUBLIC UTILITY COMMISSION	
ERIK COLVILLE **(C)**	PO BOX 2148 SALEM OR 97308-2148 erik.colville@state.or.us
PUC STAFF--DEPARTMENT OF JUSTICE	
JASON W JONES **(C)**	BUSINESS ACTIVITIES SECTION 1162 COURT ST NE SALEM OR 97301-4096 jason.w.jones@state.or.us

REGULATORY & COGENERATION SERVICES INC	
DONALD W SCHOENBECK **(C)**	900 WASHINGTON ST STE 780 VANCOUVER WA 98660-3455 dws@r-c-s-inc.com
RENEWABLE NORTHWEST PROJECT	
MEGAN WALSETH DECKER **(C)**	421 SW 6TH AVE #1125 PORTLAND OR 97204-1629 megan@rnp.org
JIMMY LINDSAY **(C)**	421 SW 6TH AVE #1125 PORTLAND OR 97204-1629 jimmy@rnp.org
SIERRA CLUB	
JEFF SPEIR **(C)**	85 SECOND ST., 2ND FLR SAN FRANCISCO CA 94105 jeff.speir@sierraclub.org
SIERRA CLUB LAW PROGRAM	
GLORIA D SMITH **(C)**	85 SECOND STREET SAN FRANCISCO CA 94105 gloria.smith@sierraclub.org
SYNAPSE ENERGY	
JEREMY FISHER **(C)**	485 MASSACHUSETTS AVE., STE 2 CAMBRIDGE MA 02139 jfisher@synapse-energy.com