PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
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December 5, 2011

***VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY***

Oregon Public Utility Commission
550 Capitol Street NE, Ste 215
Salem, OR 97301-2551

Attn: Filing Center

**RE: LC 52 – PacifiCorp's Reply to Staff Public Meeting Report
December 6, 2011 Public Meeting Agenda Item 3**

Enclosed for filing by PacifiCorp d/b/a Pacific Power is a reply to the Staff public meeting report dated December 1, 2011. PacifiCorp submits these comments in advance of the December 6, 2011 public meeting in order to better facilitate the discussion.

Please contact Joelle Steward, Regulatory Manager, at (503) 813-5542, for questions on this matter.

Sincerely,

Andrea L. Kelly
Vice President, Regulation

Enclosure

cc: Service List – LC 52

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document, on the date indicated below by email and/or US Mail, addressed to said parties at his or her last-known address(es) indicated below.

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Dated: December 5, 2011

Ariel Son
Coordinator, Regulatory Operations

Reply to the Oregon Staff Public Meeting Report on
PacifiCorp's 2011 Integrated Resource Plan

I. Introduction

PacifiCorp filed its 2011 Integrated Resource Plan (IRP) with the Public Utility Commission of Oregon (Commission) on March 31, 2011 in accordance with the terms of Order No. 10-066 and 2008 IRP acknowledgment order requirements. As part of the IRP acknowledgment schedule, Public Utility Commission of Oregon staff (Staff) issued its public meeting report on acknowledgement of the 2011 IRP on December 1, 2011, along with its proposed acknowledgment order. Staff recommends acknowledgement with revised action items, and most notably, with the exception for action items related to 1) the issuance of an all source request for proposal (RFP) for acquisition of peaking/intermediate/baseload resource in 2016, 2) acquisition of Class 1, 2 and 3 demand-side management (DSM), and 3) transmission project segments for Wallula to McNary and Sigurd to Red Butte.

The Company offers this reply to the Oregon Staff's December 1, 2011 public meeting report. First, the Company responds to Staff's proposed action item revisions regarding the supplemental coal replacement study. Second, the Company provides further information to the Commission with respect to PacifiCorp's current and planned activity associated with the pursuit of Demand Side Management (DSM) resources, additional context and background with respect to the challenges that the Company faces in each state with respect to the implementation of DSM programs, and alternative action items associated with DSM for the Commission's consideration. Lastly, the Company responds to Staff's other action plan changes.

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

Staff's October 13, 2011 final comments found that the Company's Supplemental Coal Replacement study "sufficiently solidified the basis of the IRP." Staff recommended a modified action item 8 to include a revised Supplemental Coal Replacement Study in the IRP Update in March 2012. The Company agreed with the revised action item with the exception of a provision requiring a correction to the treatment of depreciation in the study. After conducting additional analysis of the Company's study in response to comments by other parties, Staff again concluded in its December 1, 2011 public meeting report that the Company's Supplemental Coal Replacement Study presents sufficient evidence to support the continued use of the existing coal resources as part of the resource strategy with the best combination of cost and risk. However, Staff recommended additional modifications to the revised action item 8 to address concerns raised by other parties. The revised action item 8 is as follows:

> *PacifiCorp will file its next IRP Update in March 2012. The IRP Update will include a revised Supplemental Coal Replacement Study. The revised Study 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 provide a concise explanation and transparent example of its treatment of post-2030 costs, will provide an analysis that shows the results of treatments of environmental investments made prior to 2015 both avoidable and unavoidable, and provide additional natural gas and CO2 cost scenarios that pair high CO2 and low natural gas prices and low CO2 and high natural gas prices. To guide and inform the revised Study, the Company will schedule a workshop with stakeholders to occur in January 2012. PacifiCorp will invite to this workshop representatives from each of its regulatory jurisdictions. The Company will develop and seek Commission acknowledgement of specific action items related to coal plan investments.

PacifiCorp agrees with the revised action item 8. The Company's Supplemental Coal Replacement Study evaluated specific pollution control investment costs for all coal units, and in this way, represents a "unit-by-unit" study that was completed from a system perspective as is done with all resource portfolio modeling in the IRP. The Company agrees with Staff's recommendation to schedule a workshop, open to parties in all jurisdictions in January 2012, that will allow a collaborative discussion around the parties' concerns. In particular, the Company would welcome an opportunity to better define the parties' requests for a unit-by-unit analysis and treatment for pre-2015 pollution control costs so that an updated analysis can be produced for the IRP update with clear and reasonable expectations.

With regard to parties' comments on the treatment of pre-2015 costs, Staff "concludes that considering the pre-2015 investments in the Study as unavoidable likely does not significantly bias the Study conclusion." The Company agrees with Staff's conclusion, but will work with parties during the January 2012 workshop to ensure that the scope of the updated analysis is expanded to contemplate how avoidance of pre-2015 costs affects the study conclusions.

III. Demand-Side Management (Action Items 5, 6 and 7)

Staff does not recommend acknowledgement of the Company's action plan items related to Class 1, 2 and 3 DSM (action items 5, 6 and 7, respectively) because Staff believes that the Company "is underestimating the amount and speed of energy efficiency that can be achieved in states other than Oregon." As a result, Staff does not recommend that the Commission acknowledge the part of action item 2 for an all source RFP to acquire a supply-side resource to fill the Company's projected resource need in 2016. In response, the Company reiterates its position and concerns in the Company's November 3, 2011 reply to Staff's final comments. The assumptions used in the Company's conservation supply curve modeling are consistent with standard industry practice and are reasonable. As in past years, the Company will hold a public input meeting to discuss the conservation supply curve inputs and modeling for the next IRP. The Company encourages Staff and all parties to actively engage in the planning meetings.

DSM is a situs resource. As such, while the Company plans on a system-wide basis, individual DSM investment decisions are subject to specific state involvement and actions. Staff's position does not take this into account, disregarding the regulatory and other challenges the Company faces in its states and implies that other states are not engaged in DSM development. However, as described below, there are efforts underway in each state to pursue DSM resources. Below, the Company provides additional information on the DSM activities in other states. The Company also offers additional action items for the Commission's consideration in regards to DSM in Oregon.

<u>DSM Resource Planning</u>

The resource planning tools, Class 1 and Class 2 DSM resource options, are incorporated into PacifiCorp's IRP on a comparable basis as supply-side resources at quantities and costs identified through a comprehensive system-wide DSM resource conservation potential assessment (CPA) prepared by an independent third-party efficiency consultant. This work was accompanied by a similar CPA undertaken by the Energy Trust of Oregon which was used to inform the IRP of energy efficiency related DSM resource opportunities available in Oregon. From this information the IRP selected all the resources provided for which the IRP identified as cost-effective compared to supply side alternatives[1] Attachment A shows Class 2 selections in total and by state as a percent of sales (historic results for 2008-2010 and as forecasted in the 2011 IRP for years 2011-2020). Attachment A shows that Oregon, Washington and Utah are projected to acquire approximately equal amounts across the first 10 years of the plan in terms of first year savings as a percent of forecasted load, despite Utah's higher projected load growth. It also shows that results may vary year by year due to the occasional large project or other one-time event e.g. Oregon State University project completed in 2010, demonstrating that it's more relevant to track this metric with the considerations noted below over time rather than cite a given year's accomplishment for comparison purposes.

PacifiCorp acknowledges that some parties lean heavily on the DSM metric of projected energy savings as a percent of load. While it is one measure of performance, like its predecessor, DSM expenditures as a percent of retail sales, it has its shortcoming. For one, it ignores a utility's work in Class 1 and Class 3 resource activity, an area of DSM resource acquisition not widely pursued by all utilities. It also doesn't differentiate between the reported results of dual fuel utilities versus electric only utilities. Electric only utilities do not report DSM savings associated with electric to gas space and water heating conversions (fuel switching) which instead are accounted for in the utilities load forecast. Further, it doesn't account for retail pricing differences that can impact customer participation in DSM programs, geographical delivery differences (urban dense areas verses rural service areas), state specific advantages (regional credits, state tax credits, regulatory position on inclusion of non-energy benefits and other priority considerations) and often have inconsistent methodologies in terms of the denominator used (fixed year value verses an escalating value based on a utilities growth assumptions over the planning period). Lastly, the denominator may include some utility loads which are not participating in utility DSM programs, like large customers on special contract rates that self-perform their efficiency projects which are not captured in utility DSM program reporting.

[1] Oregon provided three rather than nine cost bundles for the development of supply curves, each pre-screened for cost-effectiveness therefore the IRP accepting all the resource provided. In all other PacifiCorp jurisdictions the total achievable technical potential, regardless of cost, was provided the IRP for economic screening and DSM resource selection.

Resource ramp rates (also referred to as DSM acquisition or deployment schedules) are a concern for Staff and others parties such as the Sierra Club who argue that the Company's ramp rates are overly conservative and may put limitations on the DSM resources selected. It is important to note that the market ramp rates in all states "end" at the same place, acquiring 100 percent of the achievable technical potential that was identified as cost-effective within the planning period. The ramp rates do not limit total acquisition but rather realistically assess the timing in which they can likely be acquired. Ramp rates are for planning purposes only and are not used to limit the Company's pursuit of cost-effective resources earlier than planned. The application of ramp rates is consistent with planning conventions used by the Energy Trust of Oregon in providing resource opportunities the IRP, Northwest Power Planning Council in the development of their 6th Power Plan, and other leading utilities. Staff's November 28, 2011 comments include a table of the delta for each state (excluding Oregon) between the Cadmus' technical achievable savings identified in megawatts (MW) by 2030 compared to the Class 2 DSM resources actually selected in the Preferred Portfolio. Staff's comment on the table is that it does not believe that the Company has adequately explained the difference between the projected total savings noted and the resources actually selected for the Preferred Portfolio. The Company's response is that the delta values shown in the table are the result of economic screening of these DSM resource opportunities by the IRP modeling process, not by any achievable assumption on the part of the Company.
Staff also points to Case Study 31 as evidence that there is more DSM that could be pursued, specifically Class 3 DSM. In Case Study 31 the Company makes no attempt to account for the interactions between Class 1 and Class 3 resource potentials. The Company's existing Class 1 resources (loads already under management) include 324 MW of residential air conditioning and irrigation load management resources. The 2011 IRP has selected, pending final economics, an additional 250 MW of Class 1 resources. With the additional selections the Company is effectively pursuing 575 MW of the identified 623 MW of Class 1 resources identified in the Cadmus study; 92 percent before accounting for resources that are found to be uneconomic.
As explained on page 139 of the 2011 IRP, "In providing the data for the construction of Class 3 DSM supply curves, the Company did not make an effort to net out one product's resource potential against a competing product". To illustrate how these resources might net out consider the Class 3 resource opportunities are dominated by a "mandatory" irrigation time-of-use program whose potential was assessed and product created as a possible replacement for the Class 1 irrigation load management programs. The study showed that the opportunity for the time-of-use program might be as high as 307 MW; 60% of the overall Class 3 opportunity identified in the Cadmus assessment and would completely replace rather than add to the Class 1 irrigation load management opportunities.

Other observations are:

- Oregon supply curve error resulted in overstatement of MW savings of 274 MW by 2020.
- Smaller more rural markets are projected to perform at lower levels initially.
- Wyoming is the least mature market (2009 program introductions).
- The percent of load metric can understate DSM activity e.g. Class 1 resources.
- States with faster projected growth require greater savings year on year to maintain metric e.g. Utah and Wyoming loads are forecasted to grow on average 1 percent and 1.5 percent respectfully more per year than Oregon through 2020.

Class 3 resources, while not relied upon as a planning resource in the same manner as Class 1 and Class 2 resources, are well represented in the IRP (see Class 3 pricing products listed by state and schedule in Attachment B). Class 3 DSM resources use customer price signals to encourage customers to shift their usage away from peak to non-peak usage periods. The impact of Class 3 DSM resources are realized in the historic load trend line, the basis of the load forecast used in the development of the Company's IRP. In this manner they are functionally present in the plan, but in quantities that are not measurable due to year-by-year baseline usage fluctuations of participating customers. Unlike the set measurements available for Class 1 and Class 2 demand side resources, which are generally locked in once equipment is installed or the end-use equipment is under the control of the utility, Class 3 resources are variable based on customer behavior. For this reason, the Company believes that within this variability there is a given level of load management realized—it's just not readily quantifiable.

While the Company's CPA vendor attempts to quantify the gross resource availability of Class 3 resources by state, they make no effort, given the lack of data, to net out the quantity of current Class 3 resources realized through the Company's existing Class 3 pricing products. For this reason, the Company is uncertain how much additional Class 3 resources are truly available or for that matter whether the consultant's attempt to quantify those potentials has much validity (too little market data exists nationally to accurately assist in this quantification). This situation is not unusual from utility to utility as measurement and verification of Class 3 resources is extremely difficult, regardless of whether the interval metering exists needed to deliver these programs. Furthermore, most utilities rely on Class 3 resources similarly to PacifiCorp trusting that pricing programs have some measure of impact on customer behavior, especially in markets with high retail rates which allow for greater flexibility in price product design.

"Diligent Pursuit" of DSM

PacifiCorp is diligently pursuing all means to improve both the efficiency of its customer loads as well as better manage customer peak loads using a variety of tools. Attachment B identifies the current DSM program activity as well as the planned activity. Table A below shows the historical performance in first year savings through 2011[2], the 2011 integrated resource plan (IRP) targets for years 2012 through 2021, and a comparison of the Company's actual results for 2009-2011 compared to the 2008 IRP targets. This shows that PacifiCorp continues to deliver on its IRP targets and demonstrate growth in reliance on DSM in resource planning.

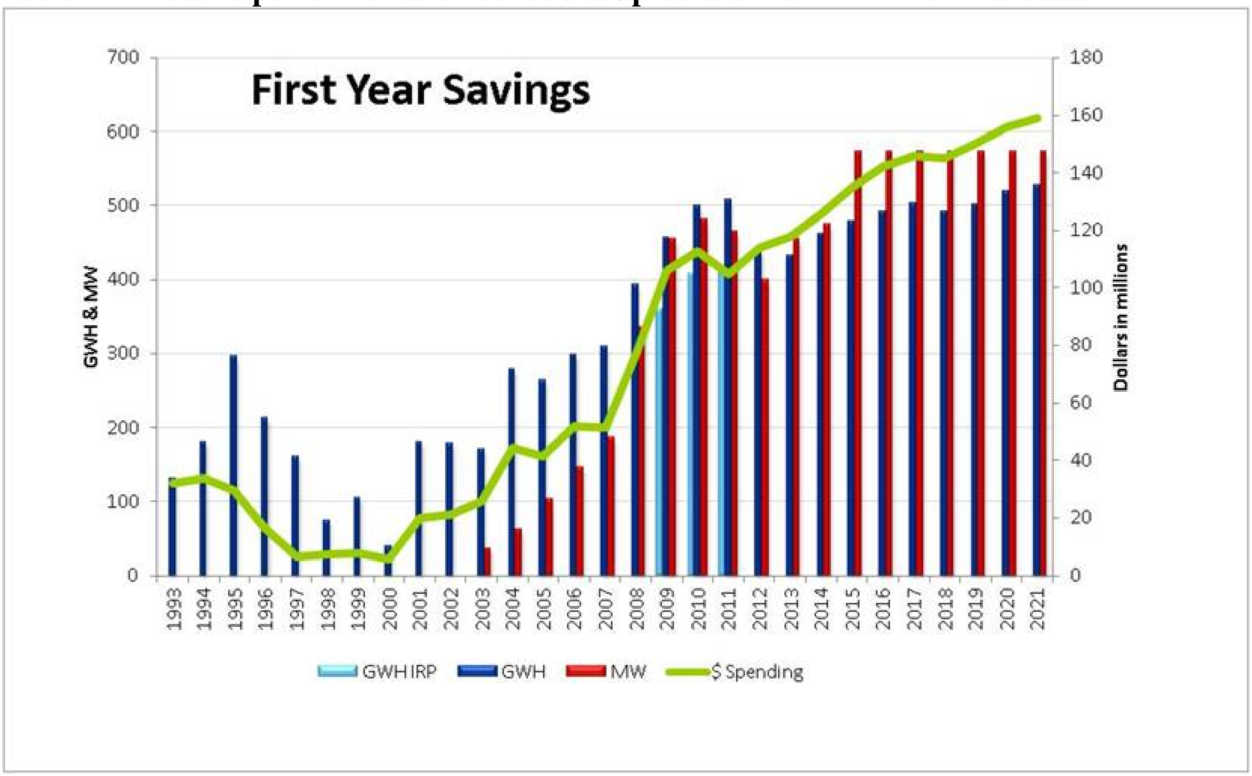
The company current programs provide incentives for all major customer classifications; residential, agricultural, commercial and industrial. In addition, program offering applies to both existing and new applications. Furthermore, the Company is currently increasing incentives and raising project caps on its business programs. The Company recently received approval from the Wyoming Public Service Commission for a "program improvement plan" that provides for program enhancements to the 2009 program set as well as a broader communications platform to increase customer awareness (10 months from filing to approval). The Company is also in negotiations to secure a vendor for our commercial curtailment program and is seeking procurement approval of a residential home comparison report program offering. Program work

[2] 2011 results represent actual results through October and forecasted results for November and December.

is underway to incorporate greater services and incentives in the pursuit of energy management related savings (i.e., O&M and other investments to optimize operations at a facility). Lastly, the Company is revising residential and business programs to account for emerging LED technologies and consumer electronics. To ensure businesses relocating to areas served by PacifiCorp or business served by PacifiCorp that are expanding use energy efficiently, the Company is actively working with economic development agencies and organizations. This approach has result in reductions in the need for new resources to address expanding industrial base[3].

Below is the link to PacifiCorp's Demand side management website where the following materials can be readily accessed: 1) Conservation Potential Assessment documents, 2) annual state performance reports, 3) program impact and process evaluations, and 4) customer program information.
http://www.pacificorp.com/es/dsm.html

Table A - Historic performance since 1993 coupled with 2011 IRP DSM forecast



Funding for outreach and education beyond program specific communications has increased significantly over the last three years and now totals just under $2m annually. The funding is used to educate customers on the importance energy efficiency, low cost – no cost energy efficiency opportunities and the availability of utility technical and financial assistance in achieving savings. The company activity works with state and local agencies and business to fully leverage its investment in outreach and communications[4].

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[3] Project includes retail, manufacturing and data centers.
[4] Current projects include the partnerships with the State of Utah, Questar Gas and the Utah Jazz and as well as an emerging partnership with the State of Wyoming.

State Regulatory Climates

Notwithstanding the considerable progress made in the implementation of DSM resources, each of the Company's states has unique characteristics and regulatory climates, which are important to understand program planning. Described below, in detail for each state, are those unique characteristics, many of which present challenges for DSM implementation. Additionally, the Company has advisory groups in all states in order to obtain stakeholder input and ensure planning program delivery transparency and input. In addition to their involvement in the IRP planning meetings, the advisory platforms are consulted on all demand side activity from communications and recovery to program concepts, design and delivery. Local advisory groups are also involved in measurement and verification activities and program evaluations and subsequent program modifications.

California

PacifiCorp faces challenges in California that are attributable to the size and nature of its service territory. The Company's service territory is a very small portion (0.22 percent) of the overall California population. Further, the pace of growth in the service territory is only a quarter of the overall state population growth. The service territory is also thirty-two times less densely populated than the rest of the state and the customers are largely residential and lower- and middle-income households. Communication within the market is limited to print and local radio, with the primary communications being driven from the Medford and Klamath Falls media market. With the exception of a select few large industrial customers and prison, business sector is dominated by smaller commercial customers. Irrigation load is over 12 percent, mostly made up of small growers.

In 2008, PacifiCorp launched its current DSM program in California, following approval from the California Public Utilities Commission. That program grew from less than 500 MWh in 2008 to almost 3,000 MWh of annual sales acquisition in 2010. Planning is done on a 3-year cycle, in alignment with larger investor-owned utilities (2008-2011, extended 2012, will likely be extended again in 2013). The California advisory group meets on as-needed basis, minimum annually, and has participation from the following:

- Division of Ratepayer Advocates
- California Public Utilities Commission staff
- Low Income Oversight Board

Idaho

Two large industrial customers are responsible for a significant portion of the Company's energy sales in Idaho. These customers are served under special retail contracts and do not participate in utility-funded DSM programs. Therefore, energy-efficiency or conservation undertaken by these customers is not reported through utility activity. The remaining load is made up of agricultural customers, residential customers with similar characteristics to the Company's California customers, and low-density commercial customers. In addition to being difficult to implement for economic reasons, savings from agricultural DSM programs are difficult to measure and quantify – weather, crop decisions, equipment rotations and the use of seasonal leases can make analysis challenging. While Class 2 resource work is challenging, Idaho is second only to Utah in class 1 resources. DSM recovery is under review by the Idaho Public Utilities Commission, as well as the Multi-State Protocol Standing Committee. The Idaho advisory group meets on as-needed basis, minimum annually, and has participation from the following:

- Idaho Public Utilities Commission staff
- Idaho Irrigation Pumpers Association
- Community Action Partnership Association
- Idaho Conservation League

Utah

In Utah, the Company has achieved significant growth in DSM acquisition in both Class 1 and Class 2 DSM from 2001 to 2010. Utah is a diverse state and the Company's service territory has continued growth potential. While consideration is given to all five of the cost effectiveness tests identified in the California protocol, the Utah Public Service Commission relies mostly on the utility cost test (UCT) in determining the cost effectiveness of Class 1 and Class 2 demand-side resources. Unlike the total resource cost relied upon in PacifiCorp's other jurisdictions, the UCT includes only that portion of a participant's equipment costs that is paid for by the utility in the form of an incentive. This improves program economics and in most cases lead to higher levels of DSM resources being identified as cost-effective. [5]. Communications and outreach is well funded. In 2009, the Company received approval to invest $1.5m annually in communication and outreach activities. Approximately 11 percent of the industrial load in Utah is governed by special contracts. These customers do not participate directly in utility funded DSM programs. Therefore, energy-efficiency or conservation undertaken by these customers is not reported through utility activity reducing both opportunity and reported savings as a percent of load. These customers do however both invest in energy efficiency improvements at their facilities and provide available capacity reductions to the Company when needed through separate interruptible agreements. Increased investment in DSM has resulted in increased regulatory and advisory board oversight. Utah advisory group meets a minimum of quarterly and has participation from the following:

  - Utah Association of Energy Users (UAE)
  - Energy Strategies
  - Southwest Energy Efficiency Project (SWEEP)
  - Utah Clean Energy (UCE)
  - Wasatch Clean Air Coalition
  - Questar Gas
  - State Energy Office
  - Western Resource Advocates
  - Salt Lake Community Action Program
  - Utah Public Service Commission Staff
  - Office of Consumer Services
  - Department of Public Utilities (DPU)
  - Division of Facilities Construction and Management
  - Individual Commercial and Industrial Customers (i.e. Kennecott, ATK and Walmart)

[5] In cases where the customer costs excluded are greater than the excluded benefits e.g. non-energy benefits which typically are small and in some states (Utah included) are not considered.

- ETC Group

Washington

Under the Washington Energy Independence Act (EIA or I-937) the Company was required to set cost-effective conservation targets beginning in 2010. Conservation is defined as any reduction in the electric power consumption resulting from increases in the efficiency of energy use, production, or distribution. Under I-937, there is a 100 percent cost-effectiveness requirement, with significant attention on measurement, savings, and costs. Failure to achieve the biennial conservation targets results in penalties. Passage of I-937 increased administrative requirements, measurement and verification, planning and reporting, as well as pressure to rely on regional unit energy savings data (RTF) verses utility specific evaluations and other relevant data sources. Under the terms and condition approved by the Washington Utilities and Transportation Commission the Company has been able to increase funding for communication and outreach. The Washington advisory group meets a minimum of quarterly and has participation from the following:

- Washington Utilities and Transportation Commission staff
- Public Counsel
- State Energy Office
- Northwest Energy Coalition
- Northwest Energy Efficiency Council
- Opportunity Council
- World Institute for a Sustainable Humanity

Wyoming

In Wyoming, the Company faces challenges to DSM acquisition associated with the nature of its service territory as well as the relative newness of DSM programs to that state. The Company is the first major utility in Wyoming to introduce DSM. The newness of programs and lack of energy efficiency infrastructure (other utility activity or market transformation organizations such as NEEA) is providing for early challenges. The Company's DSM programs were launched in Wyoming relatively recently, in 2009. The Company's Wyoming service territory is vast in size with a very low customer density, which contributes to delivery challenges and slower ramp-up opportunities. In addition, the Company's Wyoming customers, dominated by a small number of large industrial loads. The Company is working with the State of Wyoming on a targeted energy efficiency and outreach initiative and will be discussing approaches to increase participation in the programs with the staff of the Wyoming Public Service Commission. The Wyoming advisory group meets on as-needed basis, minimum annually and has participation from the following:

- Office of Consumer Advocate
- Wyoming Business Council/State Energy Office
- Southwest Energy Efficiency Project
- Wyoming Industrial Energy Consumers
- Wyoming Public Service Commission staff

Additional DSM Action Plan Items

The Company will agree to add the following action plan items:

Regarding Class 1 and 3 DSM:

- For 2012 – 2013, pursue up to 80MW[6] of the commercial curtailment product (which includes customer-owned standby generation opportunities) being procured as an outcome of 2008 DSM RFP. Company will seek approval to implement a commercial curtailment program in Oregon, Washington and Utah in the 1st quarter 2012 or provide an update on the status of those programs.

- Company will complete an analysis of the economic feasibility of Class 1 irrigation load control in the west in the 2nd quarter 2012. If the analysis suggests Class 1 irrigation load control is economic in the west, the Company will source delivery of a program in a Request for Proposal concurrent with the re-sourcing of program delivery in the east, in 3rd quarter 2012. If the analysis proves Class 1 irrigation load control is not economic the Company will investigate, through a pilot program, Class 3 irrigation time-of-use as an alternative approach to managing irrigation loads in Oregon.

Regarding Class 2 DSM:

- For 2012 – 2014, pursue additional energy efficiency savings through a residential customer energy reporting pilot being procured as an outcome of the 2008 DSM RFP. The Company will seek approval to implement the program in Washington and Utah in 2012 and will evaluate the potential for integration in the Idaho and Wyoming energy efficiency portfolio in 2013.

Regarding Conservation Voltage Control (CVR):

- In 2012, begin implementing system improvements in Washington state on circuits where energy savings have been deemed cost effective, while closely monitoring actual project costs and benefits. The cost/benefit segment of this analysis will include the total present value costs for the system improvements necessary to operate at a reduced voltage, and the avoided present value costs of purchased power. The avoided costs include calculations for demand reduction and energy savings from end use (customer appliances), line loss, and transformer no-load loss. PacifiCorp will also commission a detailed study of other Washington circuits where savings are expected to be cost effective based on a preliminary analysis of the most influential parameters , which include the expected end-use voltage optimization factor, the achievable voltage change, and each circuit's energy consumption.

- PacifiCorp will apply its new knowledge gained of CVR in Washington to evaluate CVR in Oregon, and will produce a technical white paper during 2012 summarizing findings to date. The white paper will include a high-level estimate of the potential energy savings available in Oregon for inclusion in the 2013 IRP. By year-end 2012, PacifiCorp will provide Oregon commission staff a presentation on PacifiCorp's high level CVR potential energy savings in Oregon.

[6] 107 MW between 2011-2020

IV. Revisions to Other Action Items

Transmission Planning and Energy Gateway

Staff does not recommend acknowledgement of the Wallula to McNary and Sigurd to Red Butte projects unless and until the Company provides an analysis including economic benefits and quantifying other noneconomic benefits to achieve a benefit-cost ratio equal to or exceeding one (transmission action item). In response, the Company reiterates its position in the Company's November 3, 2011 reply to Staff's final comments and offers these additional comments.

The Company agrees with the reply comments made by RNP, noting their concern that, with respect to non-economic benefits, "Staff's approach to evaluating transmission additions may be evolving in an overly narrow direction." The Company is also concerned about the use of potentially restrictive metrics for transmission project assessment before there has been opportunity to identify and develop quantification methodologies for the range of benefits which may be associated with transmission projects. This concern is grounded in the fact that currently in the west there is no mandated standard or accepted methodology for analyzing and assessing economic and non-economic benefits of transmission projects. The fact that there does not currently exist an off-the-shelf solution is evidenced by the Federal Energy Regulatory Commission's issuance of Order No. 1000, which requires jurisdictional transmission providers to work within their respective regional planning groups to identify and define regional planning and cost allocation processes, including project benefits and beneficiaries and which select transmission projects for cost allocation based on which projects meet the needs of the region most efficiently or cost effectively. Notably in the order, FERC declined to establish a mandatory benefit to cost threshold. Developing these new processes will require identification and development of benefits quantification methodologies, uses of which are not limited to regional projects but also, more broadly, to transmission needs reflected in PacifiCorp's IRP.

As previously cautioned by the Company, even the most rigorously tested and verifiable data and modeling assumptions can be a subject of contention among stakeholders and for this reason it is important to use a collaborative approach. To this end, the Company appreciates Staff's comment that it will work with the Company and interveners to develop reasonable, justifiable metrics for non-economic benefits in order to further demonstrate proposed transmission projects' long-term value to customers. Given the parallels between Staff's recommendation related to this action item and the directives of Order No. 1000, Staff's input in the Order No. 1000 compliance process is integral to development of the required methodologies, metrics and potential outcomes resulting from FERC's transmission planning reforms. Accordingly, the Company strongly encourages Oregon Commission Staff and any interested stakeholder to engage in these regional efforts, rather than any individual state-led effort, which may result in duplication or inconsistency.

Capacity Planning Reserve Margin (Action Item 8)

In its public meeting , Staff did not recognize PacifiCorp's statement made in its Reply to Staff Final Comments (filed with the Commission on November 3, 2011) that it is not practical to expect PacifiCorp to conduct marginal cost studies or adopt the 12% planning reserve margin (PRM) for portfolio modeling given the March 2012 deadline for the 2011 IRP Update. The Company noted that the 2011 IRP Update is based on the resource portfolio prepared for the business plan currently under development, which is expected to be approved in mid-December 2011. Consequently, changing the PRM is not possible at this stage. The Company believes it is appropriate to discuss the planning reserve margin and associated evaluation of supply adequacy as part of its next IRP public input process, at which time Staff and other stakeholders in all jurisdictions can voice their concerns and methodological proposals.

Attachment A - Class 2 selections in total and by state as a percent of sales

2008-2010 Historical IRP Energy Selections													
Source annual loads - Table A.9 (both MWH savings and loads @ generator)													
	Actuals												
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
California	518	2,734	3,237	3,400	4,200	4,100	5,700	6,800	7,200	7,600	7,700	7,400	7,900
Idaho	11,540	16,363	13,096	6,900	8,500	9,400	13,300	15,800	18,000	19,400	20,000	19,700	21,200
Oregon	138,681	124,478	199,000	133,902	134,400	142,000	154,400	155,800	153,300	151,600	129,900	129,900	129,900
Utah	193,328	247,799	218,755	206,400	229,500	208,600	214,900	222,200	235,700	242,400	247,800	257,200	269,800
Washington	48,323	57,383	41,727	36,100	37,700	41,400	40,600	40,800	39,500	40,000	39,900	40,900	42,000
Wyoming	0	8,061	23,239	19,600	24,600	26,800	32,500	37,000	37,300	41,200	45,300	45,100	47,900
Energy Savings (MWH)	**392,389**	**456,817**	**499,054**	**406,302**	**438,900**	**432,300**	**461,400**	**478,400**	**491,000**	**502,200**	**490,600**	**500,200**	**518,700**
Annual Loads	57,524,671	55,727,196	55,791,015	60,943,004	62,724,523	64,123,381	65,731,984	67,100,630	68,723,561	69,733,302	70,967,836	72,219,008	73,595,355
% load	0.68%	0.82%	0.89%	0.67%	0.70%	0.67%	0.70%	0.71%	0.71%	0.72%	0.69%	0.69%	0.70%
% load adj special contracts	0.73%	0.87%	0.97%	0.72%	0.75%	0.72%	0.75%	0.76%	0.76%	0.77%	0.74%	0.74%	0.75%
% loads adj for SC & WY	0.90%	1.05%	1.15%	0.84%	0.87%	0.84%	0.86%	0.87%	0.87%	0.87%	0.83%	0.83%	0.85%
mW value each year	0	0	0	81	89	83	86	90	94	95	93	95	99
mW value cumulative	0	0	0	81	170	253	339	429	523	618	711	806	905
California	518	2,734	3,237	3,400	4,200	4,100	5,700	6,800	7,200	7,600	7,700	7,400	7,900
.9% load growth / actual useage	945,551	907,744	878,611	954,604	969,067	972,280	982,164	991,175	1,002,320	1,009,109	1,018,716	1,028,331	1,039,248
% load - normal ramp	0.1%	0.3%	0.4%	0.4%	0.4%	0.4%	0.6%	0.7%	0.7%	0.8%	0.8%	0.7%	0.8%
2011 IRP mW value				1	1	1	1	1	1	1	1	1	2
Idaho	11,540	16,363	13,096	6,900	8,500	9,400	13,300	15,800	18,000	19,400	20,000	19,700	21,200
2.4% load growth	3,709,127	3,224,759	3,598,301	3,721,679	3,804,258	3,937,679	4,106,332	4,234,971	4,357,547	4,415,978	4,473,968	4,532,675	4,598,606
% load - normal ramp	0.3%	0.5%	0.4%	0.2%	0.2%	0.2%	0.3%	0.4%	0.4%	0.4%	0.4%	0.4%	0.5%
adj special contracts	0.6%	0.8%	0.7%	0.3%	0.4%	0.4%	0.5%	0.6%	0.7%	0.7%	0.7%	0.7%	0.7%
2011 IRP mW value				1	2	2	1	3	4	4	4	4	5
Oregon	138,681	124,478	199,000	133,902	134,400	142,000	154,400	155,800	153,300	151,600	129,900	129,900	129,900
1.4% load growth	14,832,836	14,187,670	13,391,196	14,968,933	15,487,788	15,669,033	15,853,824	16,038,453	16,283,652	16,419,176	16,602,014	16,789,205	16,998,651
% load - deployment schedule	0.9%	0.9%	1.5%	0.9%	0.9%	0.9%	1.0%	1.0%	0.9%	0.9%	0.8%	0.8%	0.8%
Revised estimate mW				27	27	28	31	31	31	30	26	26	26
Utah	193,328	247,799	218,755	206,400	229,500	208,600	214,900	222,200	235,700	242,400	247,800	257,200	269,800
2.4% load growth	23,854,727	23,258,399	23,618,460	26,106,815	26,746,468	27,389,581	28,151,361	28,805,998	29,650,389	30,196,791	30,840,594	31,491,637	32,188,156
% load - aggressive ramp	0.8%	1.1%	0.9%	0.8%	0.9%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%
% load adj special contracts	0.9%	1.2%	1.0%	0.9%	0.9%	0.8%	0.8%	0.8%	0.9%	0.9%	0.9%	0.9%	0.9%
2011 IRP mW value				42	47	39	40	41	44	45	46	48	50
Washington	48,323	57,383	41,727	36,100	37,700	41,400	40,600	40,800	39,500	40,000	39,900	40,900	42,000
.4% load growth	4,355,871	4,462,667	4,201,165	4,579,565	4,676,478	4,703,107	4,754,379	4,809,526	4,880,687	4,921,944	4,977,007	5,030,425	5,089,930
% load - aggressive ramp	1.1%	1.3%	1.0%	0.8%	0.8%	0.9%	0.9%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%
2011 IRP mW value				7	8	8	8	8	8	8	8	8	8
Wyoming	0	8,061	23,239	19,600	24,600	26,800	32,500	37,000	37,300	41,200	45,300	45,100	47,900
2.9% load growth (2x OR)	9,826,559	9,685,957	10,103,282	10,611,408	11,040,464	11,451,701	11,883,924	12,220,507	12,548,966	12,770,304	13,055,537	13,346,735	13,680,764
% load - slow ramp	0.0%	0.1%	0.2%	0.2%	0.2%	0.2%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.4%
2011 IRP mW value				3	4	5	5	6	6	7	8	8	8

Notes:

1) “SC” is special contracts.
2) Version of this table provided Staff on November 23, 2011 included sales from SE Idaho in total state calculation of savings as percent of load (SE Idaho loads are included in the IRP for planning purposes however the Company does not directly serve those loads/customers).

Attachment B – DSM Program Activity, existing and planned 2011-2020

Program Class	Description	Existing MW	2011 IRP Plan (cumulative)	State
1	Residential/small commercial air conditioner load control	123 MW	218 MW	Utah
	Irrigation load management	37 MW 164 MW 201 MW	37 MW 184 MW 5 MW[7] 13 MW[8] 9 MW[9] 248 MW	Utah Idaho California Oregon Washington
	Commercial curtailment	0 MW	71 MW 36 MW 107 MW (plan) 13MW[10]	Utah Oregon Washington
	Interruptible contracts	281 MW	281 MW	Utah and Idaho
2	Energy efficiency program activity[11]	2008 IRP 1,779,000 MWH 161,000 MWH 407,000 MWH 1,533,000 MWH 296,000 MWH 59,000 MWH 4,235,000 MWH/904 MW[12]	2,335,000 MWH/442 MW 152,000 MWH/30 MW 357,000 MWH/60 MW 1,415,000 MWH/283 MW[13] 399,000 MWH/79 MW 62,000 MWH/11 MW 4,720,000 MWH/905 MW	Utah Idaho Wyoming Oregon Washington California

[7] If proves not to be economic will consider other capacity control options.
[8] If proves not to be economic will consider other capacity control options.
[9] If proves not to be economic will consider other capacity control options.
[10] If proves not to be economic will consider other capacity control options.
[11] Complete portfolio of programs for residential, agricultural, governmental and business customers modified by state for customer demographics and usage and for state protocols
[12] 2008 IRP, Table 8.44, page, 245 – listed by load bubble rather than state as in the case of the 2011 IRP.
[13] Corrected MW contribution from Oregon, initial supply-curve composition was over reliant on resources from the residential sector and under reliant on higher load profile commercial sector.

Program Class	Description	Existing MW	2011 IRP Plan (cumulative)	State
3	Energy Exchange	0-37 MW (assumes no other Class 1 commercial curtailment or Class 3 DSM competing products running)	Not used as a planning resource, leveraged as economic and reliability resource dependent on market prices/system loads.	Available in all states, 37 MW based on potential identified in Utah and Wyoming
	Residential time-of-use or time-of-day (optional)	Unavailable	Not a planning resource. Impact of customer behavior picked up in historical loads – basis for IRP load forecast.	Utah (Sch. 2) Oregon (Sch. 4/210). Idaho (Sch. 36)
	Inverted rate pricing	Unavailable	Not a planning resource. Impact of customer behavior picked up in historical loads – basis for IRP load forecast.	Utah – Seasonal Wyoming – Seasonal Oregon – standard Washington - standard California – standard Idaho - standard
	General service (business sector and irrigation) time-of-use and time-of-day time, either energy or demand (combination of mandatory and optional)	Unavailable	Not a planning resource. Impact of customer behavior picked up in historical loads – basis for IRP load forecast.	Washington (Sch.47T,48T) California (Sch. AT48) Idaho (Sch. 35, 35A) Wyoming (Sch.33,46,48) Utah (Sch. 6A, 6B, 8, 9, 9A, 10/TOD [14]option,, 31) Oregon (Sch. 23&41/210[15], 47 and 48)

[14] Optional TOD for Utah agricultural (irrigation) customers.
[15] Optional TOD for Oregon agricultural (irrigation) customers under direct access option.

Program Class	Description	Existing MW	2011 IRP Plan (cumulative)	State
4	Public Outreach (PowerForward)	0-80 MW Summer	Not a planning resource. State of Utah program which PacifiCorp participates. Program is leveraged as economic and reliability resource dependent on market prices/system loads.	Utah
	Energy Efficiency messaging/Education (watts*smart* and Turn the Answers On)	Unavailable	Not a planning resource. Impact of customer behavior picked up in historical loads – basis for IRP load forecast.	All states