August 8, 2007

Public Review of the 2007 Integrated Resource Plan Draft Document: Follow-up Responses to Information Requests

This paper constitutes PacifiCorp's responses to a number of IRP public participant questions and requests pertaining to the 2007 Integrated Resource Plan draft distributed on April 20, 2007. As mentioned in Appendix F of the final 2007 IRP report, PacifiCorp intended to provide participants with responses to questions that were not addressed in the report.

1. Do the PacifiCorp plants meet the latest NSPS standards? Do they require the application of Best Available Control Technology (BACT)?

Response:

PacifiCorp plants meet the latest NSPS standards. Under the requirements of the regional haze rules, PacifiCorp's BART-eligible coal fired units must install controls that meet best available retrofit technology controls. In several, but not all cases, the BART controls being installed are equivalent to BACT controls. In Wyoming, as part of the regional haze program, the Division of Air Quality is currently reviewing technologies to determine the appropriate BART controls for the BART-eligible units located in their state. Their conclusions will determine if BACT controls are required.

2. What is PacifiCorp's action plan concerning locally owned renewable energy projects? How is PacifiCorp, in this IRP, complying with MEHC Acquisition Commitment U33?

Response:

In the Renewable Energy Action Plan[1] and 2007 Integrated Resource Plan[2], the Company has specific action items to acquire cost-effective renewable resources. The Company continues to support cost effective and safe community renewable energy projects using PURPA contracts, as part of the MEHC Acquisition Commitment U33, which states:

> U 33. MEHC and PacifiCorp will support cost effective and safe community renewable energy projects in Utah using PURPA contracts implemented under avoided cost tariffs approved by the Commission. If PURPA is no longer in effect in Utah before an alternate market for community renewable energy is developed, PacifiCorp will work with Utah stakeholders and the Commission to develop replacement procedures for new contracts. For the purpose of this Commitment,

[1] Renewable Energy Action Item #RA1: Continue to negotiate for the acquisition of cost-effective renewable resources until such time as the 1,400 megawatt goal is achieved.

[2] 2007 IRP Action Plan Item #1: Acquire 2,000 MW of renewables by 2013, including the 1,400 MW outlined in the Renewable Plan. Seek to add transmission infrastructure and flexible generating resources, such as natural gas, to integrate new wind resources.

community renewable energy projects are defined as: Locally owned renewable energy projects. Normally 1-10 MW standard contract PURPA projects and industrial cogen-type projects between 10 MW and 99 MW that use negotiated PURPA contracts. Projects can be: 1. Private ownership (example – several farmers in a wind project); 2. Municipal ownership (irrigation district small-hydro or local school; wind turbine); or 3. Combined municipal/private ownership projects (local community partnered with landowners).

In 2007 to date, the Company has executed the following renewable projects under Qualified Facility Agreements. The following renewable projects have executed QF PPAs and are operational:

Douglas Forest Products QF PPA (OR) – 6.25 MW
Siskiyou Energy Group QF PPA (CA) – 0.025 MW
DeRuyter Dairy QF PPA (WA) – 1.2 MW
Middle Fork Irrigation District QF PPA (OR) – 3.3 MW
Draper Irrigation District (UT) – 0.5 MW

The following renewable projects have been executed under Qualified Facility Agreements. However, they have not yet reached commercial operation:

Rickreall Dairy QF PPA (OR) – 0.9 MW
Schwendiman Farms LLC QF PPA (ID) – 20 MW
Evergreen BioPower QF PPA (OR) – 10 MW
Spanish Fork Wind Park II (UT) – 18.9 MW
Pioneer Ridge (UT) – 60 MW
Mountain Wind I (WY) – 60 MW
Mountain Wind II (WY) – 80 MW

Additionally, there are approximately 15-20 projects in active discussions and negotiations regarding their renewable projects representing over 100 MW.

3. **In MEHC Acquisition Commitment 42a the MEHC/PacifiCorp committed to reduce SF_6 emissions. Where in this IRP are SF_6 emissions addressed? If they are not addressed please explain why.**

Response:

This MEHC commitment is not germane to the IRP as the commitment relates primarily to existing distribution system asset management and upgrades, and therefore does not impact resource planning decisions. Below are relevant excerpts from the MEHC/PacifiCorp Commitment Annual Report that was filed June 1, 2007.

- Agreed to use 2004 as base reporting year for EPA purposes.
- Agreed to 5% annual SF_6 reduction.
- Memorandums of Understanding were executed between Rocky Mountain Power and

EPA on July 13, 2006, and between Pacific Power and EPA on July 13, 2006.

- The Company's annual report of estimated SF_6 emissions was submitted to the Environmental Protection Agency on March 23, 2007.
- Factory tours of circuit breaker manufacturers were performed and SF_6 leakage standards were discussed. A new circuit breaker blanket will be bid later this year with SF_6 emission requirements incorporated into the specifications.
- The SF_6 Handling Policy has been revised as well as equipment specifications.

4. In the fall of 2005 (between IRP 2004 and the IRP 2004 Update), the Company altered the way it calculates hydro capacity to conform to WECC reporting requirements. By changing its hydro assumptions, PacifiCorp improved the system position significantly. The increased capacity varied year by year, fluctuating between 640 MW and 450 MW over 2007-2014 timeframe.

However, WECC is in the process of modifying hydro assessments to incorporate the water flow sustainability.

a. Please provide a technical explanation supporting which methodology is most appropriate for long-term planning.

b. ***Please explain how the Company intends to meet its obligations in years when hydro flows are reduced and hot spells are sustained***

Also, between the IRP Update and the current IRP, hydro capacity increased an additional 175 MW.

c. Please explain the source of this increase

Response:

a. PacifiCorp's long term planning seeks to assure that resources are available to meet the annual system coincident peak load. In order to match hydro capacity to this peak load, the company uses the maximum dependable capability of each individual hydro-electric resource assuming there are no units on maintenance at the time of the annual system coincident peak.

With hydro resources that have storage and flexibility, PacifiCorp can reshape the power to meet peak loads by using the water at peak times. The one-hour sustained peak of flexible hydro generation is a reasonable way to consider the contribution of these resources to peak capacity.

For plants with operational constraints, such down-stream flow fluctuation limits, the ability of PacifiCorp to reshape the power this is best projected by the simulation models capture the peak contributions given the constraints.

b. In years when hydro flows are reduced and hot spells are sustained, the company will meet its obligations through increased use of its non-hydro resources, purchasing power from other entities, and reducing the amount of power it sells in the wholesale market.

The use of a planning reserve margin that exceeds the operating reserve requirements helps the company meet its load obligations in this kind of extreme situation.

c. There are a number of factors that account for the hydro capacity difference:
   - For the 2007 IRP, the full capacity of the flexible hydro resources (less a small outage deduction) was included; for the 2006 IRP Update, units undergoing planned maintenance at the time of system peak were excluded.
   - The unit test results were made available for Swift 2. The tests indicated that the new turbines produced 23 MW more power than the previous turbines.
   - PacifiCorp added the "Meaningful Priority" purchase power agreement as a planned resource.
   - Two power purchase contracts were reclassified as hydro resources for load and resource balance reporting.
   - The hydro forecast was updated between the IRP update and the current IRP.

5. A number of parties requested detailed wholesale contract information in formats similar to that provided in past PacifiCorp IRP reports.

Response:

In lieu of multiple customized versions of contract information tables, PacifiCorp has provided a spreadsheet with detailed annual contract data used for its load and resource balance determinations (see attachment, 2007IRP_Contracts_Response no. 5.xls). The spreadsheet also indicates if each annual contract line item is a new or updated item relative to the 2004 IRP.

6. On page 32 the text states "PacifiCorp and MEHC anticipate spending $1.2 billion over the next ten years to install necessary equipment under future emissions control scenarios to the extent that it is cost-effective." Please explain how and in what forum the Company plans to perform the cost-benefit analysis for these investments. Should such analysis be part of the Integrated Resource Planning evaluation? Does the $1.2 billion include mandatory requirements, i.e., mercury control on existing plants? Does it include those existing plant retrofit projects which are necessary for permit requirements to add new units at facilities? Please clarify and provide a table showing the value, project description, and location of the investments.

Response:

Each project will require a detailed appropriations requisition (APR) approval paper that will present alternatives and economics. In general, the projects will be approved based on the acquisition commitments, but if the cost becomes excessive on a $/ton removed basis, and the plant can be permitted and operated in an environmentally acceptable method with another alternative, then consideration will be given to the alternative solution. The evaluations will be done on a case by case basis. These analyses are not a part of the IRP, unless the resulting conclusion from the analysis is the removal of a generating resource or a significant change in the expected utilization of that resource. The referenced $1.2 billion dollars includes projects that are required to meet regional haze and mercury requirements, as well as developing PM2.5 and ozone regulations. The proposed projects are not necessary to permit new units at any of the facilities; however, since these projects lead to reductions in the ambient air shed, they may facilitate the addition of any new project proposed for the areas in which the facilities operate.

The table below shows the estimated cost of the clean air projects included in the $1.2 billion project total cost. Note that as detailed engineering is completed, these costs, as well as the expected control efficiencies, are expected to change.

Clean Air Projects		
Location/Unit	**Project Description**	**Value (Million $)**
Dave Johnston 1	Low NOx Burners	$8.0
Dave Johnston 2	Low NOx Burners	$8.9
Dave Johnston 3	New Dry Scrubber, Baghouse, Low NOx Burners	$133.2
Dave Johnston 4	New Dry Scrubber, Baghouse, Low NOx Burners	$177.9
Hunter 1	Scrubber Upgrade, Baghouse, Low NOx Burners	$86.8
Hunter 2	Scrubber Upgrade, Baghouse, Low NOx Burners	$57.1
Hunter 3	Low NOx Burners	$10.0
Huntington 1	Scrubber Upgrade, Baghouse, Low NOx Burners	$90.5
Huntington 2	New Wet Scrubber, Baghouse, Low NOx Burners	$128.3
Jim Bridger 1	Scrubber Upgrade, Low NOx Burners	$17.4
Jim Bridger 2	Scrubber Upgrade, Low NOx Burners	$11.1
Jim Bridger 3	Scrubber Upgrade, Low NOx Burners	$17.5
Jim Bridger 4	Scrubber Upgrade, Low NOx Burners	$9.3
Naughton 1	New Scrubber, Low NOx Burners	$78.5
Naughton 2	New Scrubber, Low NOx Burners	$105.2
Naughton 3	Baghouse	$97.6
Wyodak	Scrubber Upgrade, Baghouse, Low NOx Burners	$62.6
Cholla 4	New Wet Scrubber, Baghouse, Low	$143.0
Total		**$1,242.9**

7. **Page 86, Supply Side Resources: While the report indicates the source of the data used in developing the cost and performance profile for the potential resources, please explain why this data is relevant to PacifiCorp's system. For example, to the extent that major emissions modifications must be made at a facility in order to accommodate a new additional unit, it is unclear if these costs are included in the analysis. To the extent that these costs are not being taken into consideration, does it artificially reduce the total cost for a resource as compared with other resources, which, if all costs were considered, might actually be more economic?**

   Response:

   The EPRI Technical Assessment Guide® data served as a single consistent source of technology reference information for development of proxy resource options. The Company customized this data to more accurately reflect physical, financial, and market characteristics associated with siting facilities in its service territory. See the fourth bullet on page 14 of the 2007 IRP report for a discussion on the proxy resource concept.

   In response to the specific question on major emissions modifications for new plants, currently the company has no plans—and the 2007 IRP did not assume—that any of the company's currently planned emissions control projects are being installed in order to permit and construct new generating resources. Emission controls are being installed because of the need to reduce emissions from existing units in order to comply with existing or anticipated air regulations. That said, there may be cases in which reductions taken at a plant may provide some environmental benefit that allows for new resources to be constructed. These would be rare, site-specific, and not germane to a long-term resource planning exercise. For example, negotiated settlements are sometimes necessary in order to facilitate the permitting process. As a consequence, commitments are made to install additional controls for enhanced air quality. Capturing this level of cost detail for new resources in an IRP context would be impractical.

8. **Page 69, Class 3 Demand-Side Management: In this paragraph it states that Current system-wide participation in metered time-of-day and time-of-use programs exceeds 23,000 customers up from 15,000 in 2004. This number is curiously high based upon the 2005 EPAct discussions in Utah. For clarity and usefulness, please provide a breakdown not only by state and customer class but also, how many of these customers are on mandatory time-of-day/use options.**

   Response:

   The table below shows the requested breakdown of Class 3 DSM metered programs into state, customer class, and mandatory/optional participation for all customers whose energy charges are billed under time-of-use/ day pricing. Customers who are billed under time-of-use/ day pricing only with demand were excluded. This data was pulled from the database on July 17, 2007.

Data as of July 17, 2007		Number of Customers by Customer Class				
State	**Participation**	**Commercial**	**Industrial**	**Irrigation**	**Residential**	**Total**
Idaho	Optional				16,832	16,832
Idaho Subtotal					**16,832**	**16,832**
Oregon	Mandatory	97	126	13		236
	Optional	316	4	60	1,271	1,651
Oregon Subtotal		**413**	**130**	**73**	**1,271**	**1,887**
Utah	Mandatory	171	247			418
	Optional	1,655	245	2,625	449	4,974
Utah Subtotal		**1,826**	**492**	**2,625**	**449**	**5,392**
System Total	Mandatory	268	373	13		654
	Optional	1,971	249	2,685	18,552	23,457
Grand Total		**2,239**	**622**	**2,698**	**18,552**	**24,111**

9. **Page 49, Public Utility Regulatory Policies Act Provisions: The draft report addresses only three of the EPAct standards – and only addresses Utah's comments. Could you address the status of determinations in all of the applicable states?**

   Response:

   The attached file (named "EPAct_PURPA Update_No.9.xls") contains a status update for the six states in PacifiCorp's service territory. All five PURPA standards are addressed in the attachment which include: Smart Metering (Time-base), Interconnection, Net Metering, Fuel Source Diversity and Fossil Fuel Generation Efficiency.