BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON
LC 42

In the Matter of PACIFICORP 2007 Integrated Resource Plan.	STAFF'S INITIAL COMMENTS AND RECOMMENDATIONS

Following are staff's initial comments and recommendations on PacifiCorp's 2007 Integrated Resource Plan (IRP), organized according to guidelines the Commission adopted in Order No. 07-002.[1] First, however, staff responds to two general issues PacifiCorp raised in comments filed on October 12, 2007. Finally, staff provides initial recommendations on acknowledgment of major thermal resources in the IRP action plan. Attachment A consists of PacifiCorp's responses to selected data requests.

Before issuing final comments, recommendations and a proposed order, staff will further review the company's filed plan, responses to recent data requests and parties' comments.

I. General Issues

1) The company asserts that Commission acknowledgment "should pertain to plan reasonableness given information available to the Company *at the time the IRP was prepared.*" *See* PacifiCorp's Reply Comments, October 12, 2007, at 1 (emphasis added).

The implication is that the Commission should ignore any information it has at the time it issues the acknowledgment order. Such an interpretation of the Commission's acknowledgment standard could lead to absurd results. For example, would the company have expected the Commission to ignore the Western Energy Crisis of 2000-2001 when it considered acknowledgment at that time of a filed IRP action plan? Should the Commission acknowledge an action plan that emphasizes new long-term resource acquisitions if loads plummet and there is significant excess capacity in the market?

In its order on PacifiCorp's 2004 IRP, the Commission noted updates to the company's resource planning and acquisition activities that affected the IRP action plan. Specifically, the Commission noted that the company had suspended its Request for Proposals (RFP) process while it reviewed its resource needs, including timing and fuel type of the utility benchmark resource. Further, the Commission recognized that the company's filed IRP update included a revised action plan, based on updated inputs and assumptions that eliminated the 2009 natural gas-fired resource and delayed the coal resource from 2011 to 2012. The Commission also noted that, compared to the 2004 IRP, the update used more recent natural gas and market prices and lower cost

[1] As corrected by Order No. 07-047.

estimates for Integrated Gasification Combined Cycle (IGCC) coal technology. At the same time, the Commission stated that it did not consider the IRP update in its decision on the IRP. *See* Order No. 06-029 at 5-6, 12.

In Order No. 07-018 the Commission clarified that to obtain RFP approval, "a utility must account for all material changes since acknowledgement and provide, at a minimum, updated load forecasts, revised assumptions and recent resource additions." *See* footnote 4, page 3. In determining whether the level and type of resources PacifiCorp proposed to acquire was reasonable, the Commission accounted for information available at the time. *See* Order No. 07-018 at 5. Similarly, the Commission should take into account information available at the time it issues its acknowledgment order for a utility's resource plan. That acknowledgment order forms the basis of the Commission's review of the RFP. *Id.* at 4.

PacifiCorp expresses interest in exploring alternatives to the IRP process considering today's challenging planning environment, noting the rapid pace of regulatory developments. *See* PacifiCorp's Reply Comments, October 12, 2007, at 2. Staff points out that the Commission updated its IRP planning guidelines this year. To address regulatory developments related to greenhouse gas emissions, the Commission is currently reviewing treatment of environmental costs. *See* Docket UM 1302.

2) PacifiCorp states that parties have a misconception that the company has committed to building pulverized coal plants because "proxy" coal resources are part of the preferred portfolio. According to the company, "the purpose of a proxy resource is to represent the indicative characteristics of an asset-type resource that *might* be developed. When included in the preferred portfolio, the proxy resource informs action plan development and selection of benchmark resources for competitive procurements. It does <u>not</u> imply that PacifiCorp has decided to procure this specific resource or even this specific technology." The company further points out that the IRP action plan seeks "base load/intermediate load" resources. *See* PacifiCorp's Reply Comments, October 12, 2007, at 3 (emphasis in original).

Staff points out that benchmark resources are assets the company plans to build unless it gets a better deal in the marketplace. Specifically, unless circumstances change, the proxy resources in the company's preferred portfolio are the benchmark resources in the RFP process.[2] For example, the 2012 and 2014 proxy coal plants in the preferred portfolio are identical to the benchmark resources in the company's current RFP for base load resources.[3] Therefore, staff does not find fault with the parties' focus on pulverized coal resources in the preferred portfolio.

---

[2] If the utility plans to include a self-build option. The Commission defines a Benchmark Resource as "a site-specific, self-build option for which there is a commitment to proceed if it is the resource selected through the RFP." *See* Order No. 06-446 at 5.

[3] Further, the company has filed proposed RFP amendments in Utah that would add natural gas-fired benchmark resources in 2012, similar to action item 7 for the preferred portfolio.

II. Review of the Plan Based on the Commission's IRP Guidelines

Below staff provides its assessment of whether PacifiCorp's 2007 IRP meets each of the Commission's guidelines for resource planning. In so doing, staff recommends whether the company's action plan should be modified,[4] including direction for the next planning cycle pursuant to guideline 3e.

Guideline 1: Substantive Requirements

a. *All resources must be evaluated on a consistent and comparable basis.*

Staff addresses this requirement by major resource category, further below. First, however, staff addresses the specific guidance provided under guideline 1a.

- *All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power ... and demand-side options which focus on conservation and demand response.*

While the company discusses all types of resources in the IRP, it modeled only those highlighted in Tables 5.1 and 5.2. *See* IRP at 91, 93-94. The company fell short of fully considering certain resources that could be part of the best cost/risk portfolio.

Staff agrees with Renewable Northwest Project (RNP) that in the next planning cycle, PacifiCorp should model renewable resources such as geothermal, biomass and solar, rather than solely wind resources to serve as a "proxy" for all renewable resources. Staff also agrees with RNP that the company should more thoroughly evaluate both generation and direct use applications for solar energy resources. Solar water heating is a conservation measure that can reduce electric loads particularly during system peak hours.[5]

Pursuant to an agreed-upon modification to the last resource plan, PacifiCorp included several configurations and locations for IGCC coal plants in its modeling. However, the company did not allow its new Capacity Expansion Model (CEM) to select IGCC plants equipped with carbon capture and sequestration (CCS) except for the emissions performance standard scenario, explaining that CCS technology and costs are speculative.[6] Therefore, CO_2 emissions from IGCC plants were on par

---

[4] See the final section of this document for staff's recommendations related to major thermal resources in the action plan.

[5] As RNP points out, the analysis should reflect the expected cost of solar energy measures to the company – that is, after subsidies and customer contributions have been taken into account.

[6] The model did not select a sequestered IGCC plant, likely because the portfolio was developed using a base case adder of $8 per ton of CO_2. The company did not consider reasonable for portfolio development imposing both a high CO_2 adder and an emissions performance standard (based on performance of a gas-fired, combined-cycle combustion turbine). *See* PacifiCorp's response to Oregon Department of Energy Data Request No. 15a.

with emissions from supercritical pulverized coal plants. Staff recommends the following addition to the 2007 IRP action plan to address this issue in the future:

> <u>In the next planning cycle, include IGCC plants with carbon capture and sequestration as a resource option for selection.</u>

The company did not include nuclear passive safety and pumped storage technologies in portfolio modeling because their projected commercial operations date is beyond the 10-year acquisition horizon used in the IRP.[7] Staff recommends further consideration of these technologies in the next planning cycle.

- *Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.*

  Staff finds that the company met this requirement with the exception of testing intermediate-term market purchases and IGCC plants equipped with CCS technology, and renewable resources other than wind.

- *Consistent assumptions and methods should be used for evaluation of all resources.*

  Staff agrees with the company's assessment that it met this requirement. *See* IRP Technical Appendices at 173.

- *The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.*

  The company applied its after-tax WACC of 7.1 percent to discount all cost streams. *See* IRP Technical Appendices at 173.

Following are staff's assessments by resource category:

Demand-Side Management. The company's evaluation of conservation and demand response resources fails to meet the standard set in guideline 1a. The company has proposed enhanced analysis of these resources for its 2007 IRP annual update and next planning cycle. Staff recommends modifications to the 2007 IRP action plan to memorialize these commitments. Staff addresses these issues in more detail under guidelines 6 and 7.

Renewable Resources. The company failed to evaluate renewable resources on par with fossil-fuel resources in one key respect — the models did not evaluate any renewable resources except wind. In other words, wind resources served as a proxy for all renewable resources the company might acquire through 2016.

With the exception of a small upgrade to the Blundell geothermal facility and some planned small biomass projects, the company assumed an on-peak capacity

---

[7] The company used natural gas-fired "growth stations" to meet projected resource needs after 2018.

contribution for the remainder of the renewable resources in the action plan equivalent to wind's contribution. *See* PacifiCorp's response to Staff Data Request No. 39. *Assuming that nearly all of the incremental renewable resources will be wind plants overstates the capacity needed from other types of resources.*

Other potential renewable resources have far higher capacity factors. For example, the company assumes a capacity factor for Oregon biomass at 91 percent and east-side geothermal at 96 percent. These resources also are less costly. *See* Tables 5.3 and 5.4, IRP at 95-96. In contrast to its proxy approach for renewable resources, the company assumed capacity factors for fossil-fuel resources based on specific fuels, technologies and sites. *See* Tables 5.1 and 5.2, IRP at 93-94.

PacifiCorp asserts that the Commission acknowledged using wind as the proxy renewable resource for the company's 2004 IRP. However, the Commission was silent on this issue. *See* Order No. 06-029. In its order on PacifiCorp's RFP for base load resources, the Commission recognizes Oregon Department of Energy's (ODOE's) argument that the company may have overstated resource needs by assuming all renewable resources the company would acquire would be wind. *See* Order No. 07-018 at 5 (footnote 6).

In the 2004 IRP, the company included 1,400 MW of wind resources as "planned resources," and did not allow the models to choose additional amounts. Pursuant to an agreed-upon modification to that plan, in the 2007 IRP the company included wind as a resource option in the CEM. The MidAmerican Energy Holdings Company (MEHC) commitment of 400 MW by year-end 2007 was an assumption for all portfolios.

The "medium case" portfolio (with base case assumptions), Alternative Future 11, added 700 MW of renewable resources by 2016 for a total of 1,100 MW. On average, over the gamut of the alternative futures, the model added more than 1,200 MW of wind resources for a total of 1,600 MW. The company also performed a sensitivity analysis to test the quantity of wind selected in the event the federal production tax credit expired, but otherwise favorable conditions were in place. The model chose 1,900 MW of wind resources under this scenario.

Based on these results, the company selected 1,000 MW to 1,600 MW of additional wind resources (in addition to the 400 MW commitment) to be included in risk analysis portfolios. *See* Appendix J. Several of the risk analysis portfolios selected wind resources far beyond this level. *See* Table 7.2, IRP at 141. Finally, under a scenario with a regional greenhouse gas emissions performance standard,[8] the model selected 3,100 MW of wind resources by 2018 (including 1,900 MW by 2016). *See* IRP at 214. Staff finds these results supportive of acquiring the 2,000 MW in the action plan *at a minimum* on a best cost/risk basis.

Also following up on the amended 2004 action plan, Appendix J includes the results of PacifiCorp's updated study on wind integration costs. Staff finds reasonable the new

[8] Assuming a CO_2 cost adder of $8 per ton.

methodology for estimating load-following costs of wind resources. The results indicate that fewer reserves are needed compared with the company's previous estimates. For the preferred portfolio, the company estimates that 43 MW of additional load-following resources are needed due to the 2,000 MW of wind resources included.[9] The company used its Planning and Risk (PaR) model to compare studies with, and without, these additional load-following reserves to estimate this portion of wind integration costs at $1.10 per MWh.

In addition, PacifiCorp revised its modeling of system balancing costs by incorporating hourly wind data from multiple sites and applying that to the proxy wind resources by location and build pattern. The results are similar to the company's previous studies of such costs. System balancing costs increase with increasing amounts of wind. Figure J.5 shows that costs range from about $1 per MWh for 500 MW of wind to about $4 per MWh for 2,000 MW of wind.[10] Thus, the total estimated integration costs for the 2,000 MW of wind resources in the preferred portfolio is $5.10 per MWh of wind energy.

For determining the capacity contribution of wind projects on a peak hour, the company adopted as its standard the effective load carrying capability of wind projects. This is the amount of additional load the utility system can meet with the incremental wind resource without reducing reliability. *See* IRP Technical Appendices at 197-198. This method takes into account correlations among wind projects in an area and appears to be reasonable.

Appendix J also briefly discusses how various thermal resources affect wind integration costs, pursuant to the agreed-upon addition to the 2004 IRP action plan addressing renewable resources. *See* IRP Technical Appendices at 200. Staff finds this discussion inadequate and recommends the company address the issue in more detail in the next planning cycle. Coal plants are not easily ramped up and down to meet volatility in loads and wind generation. Flexible resources such as hydro and natural gas-fired plants, including peakers, are a far better fit for integrating large amounts of wind and other intermittent renewable resources. Further, with more jurisdictions adopting a Renewable Portfolio Standard (RPS), the future role of coal and other base load plants is unclear.

Staff notes that state mandates to acquire renewable resources impose constraints on the planning process that require utilities to deviate from a strict comparability standard for evaluating resource choices. In other words, utilities must include the minimum specified levels of renewable energy resources in their action plans.[11] Half of the states PacifiCorp serves — Oregon, Washington and California — now have an RPS in place.

---

[9] The CEM does not model reserve requirements. The company calculated the incremental load-following requirements outside of the main IRP models and added the required amounts in the PaR runs.
[10] Due to timing constraints, the CEM used system balancing cost estimates from the 2004 IRP. The PaR model implicitly accounts for system balancing costs.
[11] Subject to any cost cap or other safety valve, as well as analysis of conservation that reduces the load upon which the annual compliance level is calculated.

Utah's governor has announced plans to have a standard in place as well. Earlier this year, the U.S. House of Representatives passed a federal RPS for the first time.[12]

Pursuant to an agreed-upon modification to PacifiCorp's last resource plan, the company executed a master agreement with the Energy Trust of Oregon on April 6, 2006, to fund the above-market costs of new renewable energy resources. As intended, the agreement helped the company acquire wind facilities timely.

Market Purchases. In the current resource plan, the company allowed its CEM to select Front Office Transactions (FOTs) subject to limits imposed until 2018.[13] Limits at the following market hubs begin in 2012: 500 MW at Four Corners, 200 MW at Mona, and 250 MW each at West Main and Mid-Columbia. That contrasts with the 2004 IRP, which included 1,200 MW of FOTs as "planned resources" based on historic purchase levels found to be routinely cost-effective.

Staff does not object to PacifiCorp's general modeling approach in the 2007 IRP, which developed cost and risk metrics for portfolios with various amounts of FOTs. However, staff is not convinced that the amount of FOTs in the preferred portfolio represents the best cost/risk trade-off.

FOTs[14] system-wide in the preferred portfolio peak at 660 MW in 2013, representing only about half the amount included in the 2004 IRP. Further, the amount of FOTs drops to about 400 MW in the following year.[15]

On the east side of the system, FOTs in the preferred portfolio range from a low of just 3 MW in 2013 to less than 200 MW per year in the rest of the 10-year acquisition period. On the west side, FOTs range from a low of 64 MW in 2011 to a high of 657 MW in 2013. *See* Table 7.32, IRP at 184.

The company states that less reliance on FOTs tends to reduce market price risk exposure, but can increase or decrease mean stochastic cost depending on the make-up of the portfolio. Ultimately, the company concludes that its concern about long-term reliance on the market and exposure to market price risk leads to a resource management strategy to reduce that reliance. Among the sources of market price risk and uncertainty the company cites is an "extensive expansion" of renewable energy capacity in the Western interconnection (WECC). *See* IRP at 205. However, in referring to its market price forecasting model, the company stated earlier this planning cycle: "In MIDAS, renewable resources are low- to no-cost resources. The impact of adding renewable resources in MIDAS is to decrease average market prices." *See* PacifiCorp IRP public input meeting handout, May 10, 2006, at 34.[16] The company

---

[12] The U.S. House and Senate will hold conferences on a potential federal RPS this fall.
[13] At which point natural gas-fired "growth stations" are added.
[14] Third quarter, heavy-load hour purchases on the east side, and flat annual energy purchases on the west side, assumed to be transacted on a one-year basis.
[15] The company estimates only 336 MW of FOTs in 2011, the year in which it plans to add a West-side natural gas-fired CCCT.
[16] *See* http://www.pacificorp.com/File/File64812.pdf.

explains that renewable energy in and of itself is not the issue; however, a shifting resource mix, including natural gas plant expansion and a reduction in coal development, is a source of risk and uncertainty. Further, due to wind's intermittency, the addition of wind resources may cause utilities to rely on market purchases. *See* PacifiCorp's response to Staff Data Request No. 31.

Given that the addition of wind to the Western interconnection is likely to reduce average market prices, staff finds PacifiCorp's concerns about the impact of adding renewable resources to be without merit. In fact, staff finds that the company should take a hard look at low market price scenarios in analyzing its resource choices. Such possible futures point out the risks of capital-intensive, base load resources.

The company also raises concerns about "the potential tightening of the regional capacity balance in the next decade due to planned resources not being built as more utilities rely on the market to meet their future needs." *See* IRP at 205. The company points toward its review of utility IRPs, plus WECC assessments indicating a reduced regional capacity margin. Specifically, PacifiCorp notes that Portland General Electric (PGE) proposes to rely on intermediate-term market purchases. *Id.* On this point, staff notes that PGE is looking to *reduce* its short-term purchases, moving instead toward purchases of up to 10 years. The analysis of intermediate-term resources in PGE's 2007 IRP led the company to include 180 MW of power purchase agreements (PPAs) up to five years to address load uncertainty, and 192 MW of PPAs between six and 10 years as part of a bridging strategy until CO_2 compliance costs and technology options are better known.[17] *See* PGE's 2007 IRP filed in Docket LC 43.

In contrast, PacifiCorp did not analyze in its IRP such intermediate-term purchases. The company states that it is using its RFP for base load resources to address intermediate-term purchases. PPAs that provide at least 100 MW of capacity for a term of at least five years are eligible. *See* PacifiCorp's response to Staff Data Request No. 46. Addressing intermediate-term PPAs in the RFP is insufficient. Staff notes PGE's approach, which led the company to issue an RFP explicitly to attract PPAs for a term of six to 10 years. *See* Docket UM 1345. Staff proposes the following *addition* to PacifiCorp's IRP Action Plan to address this issue in the future:

> <u>In the next IRP, evaluate intermediate-term market purchases, modeling them as portfolio options that compete with other resource options, and analyze cost and risk</u>.

Distributed Generation. The company included dispatchable standby generation and combined heat and power (CHP) plants as resources for the Capacity Expansion Model to select. The preferred portfolio includes 100 MW of CHP resources. Although it does not include dispatchable standby generation, the company will pursue these resources in an RFP this year. The company addressed in a separate analysis potential reduction in transmission and distribution costs associated with CHP facilities, pursuant to Order

[17] The company also plans to issue RFPs for seasonally targeted capacity, from demand- and supply-side resources.

No. 06-029. DSG, CHP and solar energy resources are included in the company's six-state DSM assessment published after the IRP was filed. The company will use information from this study in its next IRP or action plan.

Fossil-Fuel Resources. For its initial analysis, the company allowed its optimization model to select unsequestered supercritical pulverized coal plants, unsequestered IGCC coal plants, natural gas-fired combined-cycle combustion turbines and simple-cycle combustion turbines. The company evaluated portfolios with and without such resources. The company allowed its optimization model to select a *sequestered* IGCC plant only for the emissions performance standard scenario, though it was not part of the resulting portfolio.[18] The company determined that the earliest in-service date of passive safety nuclear technology is outside the 10-year acquisition horizon.

Transmission. Staff finds the modeling of transmission options in the current IRP meets the Commission's resource comparability standard as well as the requirement from the last planning cycle to analyze transmission resources to reach resources that are shorter term or lower cost. Staff addresses the analysis further under Guideline 5.

b. *Risk and uncertainty must be considered.*

- *At a minimum, electric utilities should address the following sources of risk and uncertainty: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.*

  The company's stochastic modeling addresses five of the six minimum sources of risk and uncertainty that the plan must consider: load requirements, hydroelectric generation, plant forced outages, fuel prices and electricity prices. To address the cost to comply with future regulation of greenhouse gas emissions, the company conducted the Commission-required scenario analyses (0, $10, $25 and $40 in 1990$), modeled both cap-and-trade and tax strategies, and analyzed a portfolio that would comply with a regional emissions performance standard. The company also performed sensitivity studies with various combinations of low, medium and high levels of the following factors: load growth, natural gas and electricity prices, CO_2 compliance costs, renewable portfolio standards, renewable energy tax credits and achievable market potential for demand response programs.

- *Utilities should identify in their plans any additional sources of risk and uncertainty.*

  Additional sources of risk and uncertainty identified in the plan are capital costs, coal prices, the level of achievable DSM potential, availability of federal tax credits for renewable energy resources, and renewable portfolio standards.

---

[18] Likely because the scenario was run at a CO_2 adder of only $8 per ton.

c. *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.*

The company describes its selection and justification of the preferred portfolio on pp. 202-205 of the IRP. The company considered both expected costs and associated risks and uncertainties, relying heavily on the stochastic analysis results of the Group 2 risk analysis portfolios. Through 2011, the company plans to acquire renewable, DSM and CHP resources to diversify its portfolio and help comply with RPS and future CO_2 regulations. From 2012 to 2014, the company plans to acquire long-term assets with "complementary risk profiles (supercritical pulverized coal and CCCT resources)," along with front office transactions that provide planning flexibility. Over the long term, the company plans to reduce its reliance on short-term market purchases and include "flexible long-term assets with a small emissions footprint." *See* IRP at 202. The company also considered differences in preferences among the states it serves.

- *The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.*

  The company uses a 20-year study period for portfolio modeling and a real levelized revenue requirement methodology for treatment of end effects. Treatment of end effects as it relates to CO_2 costs is being addressed in Docket UM 1302. *See* guideline 4l for a discussion of shortened economic life for unsequestered, conventional coal plants.

- *Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.*

  The IRP complies with this standard.

- *To address risk, the plan should include, at a minimum:*

  1. *Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.*

     The plan complies with this requirement. The company uses standard deviation of stochastic production costs as the measure of cost variability. For measuring bad outcomes, the company measures Upper-Tail PVRR and includes its preferred "risk exposure" metric (Upper-Tail PVRR minus overall mean PVRR). *See* the discussion under guideline 4l.

2. *Discussion of the proposed use and impact on costs and risks of physical and financial hedging.*

The IRP includes a very brief discussion of hedging on p. 116. Staff recommends a more robust discussion in future IRPs.

- *The utility should explain in its plan how its resource choices appropriately balance cost and risk.*

The company provides cost vs. risk metrics on pp. 191-192 and 214-217 and ultimately explains its rationale for the preferred portfolio on p. 202. *See* further discussion under guideline 4l.

d. *The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.*

Oregon had not yet enacted an RPS at the time the company filed its resource plan. In response to staff's questions about how the company's plan puts it in a position to meet the renewable resource requirements of Oregon and other jurisdictions, the company provides a scenario whereby it meets the West Coast states' requirements through 2014.[19] *See* PacifiCorp's response to Staff Data Request No. 11. The company also provided analysis to demonstrate that its preferred portfolio would meet both state RPS requirements and two pending federal RPS bills. *See* PacifiCorp's response to Staff Data Request No. 27. Further, the company points toward the requirement in Senate Bill (SB) 838 to file RPS compliance plans. The first such plan is due by January 1, 2010. Staff finds these responses reasonable.

House Bill (HB) 3543 (2007 Session) established a state policy to stop the growth of Oregon greenhouse gas emissions by 2010; cut them 10 percent below 1990 levels by 2020; and reduce them at least 75 percent below 1990 levels by 2050. The legislation did not establish specific mechanisms for achieving these goals. A bill was proposed in the 2007 Session to establish an emissions performance standard, similar to the recently enacted California SB 1368 and Washington SB 6001, but was not adopted. A bill to establish a cap and trade system similar to California AB 32 also was proposed.

The Western Climate Initiative plans to establish by August 2008 a regional cap and trade system or other market mechanism to meet a regional emissions reductions goal of 15 percent below 2005 levels by 2020. Members include Oregon, Washington, California, Utah, New Mexico, Arizona, British Columbia and Manitoba. Legislation to adopt the proposed mechanism in Oregon is expected to be considered in the 2009 Session.

---

[19] Based on the Revised Protocol system energy allocation factor adopted previously by Oregon.

In adopting the Western Commissions' Joint Action Framework on Climate Change in 2006, the Oregon Commission committed to "Explore the development and implementation of greenhouse gas emissions standards for new long-term power supplies."[20]

While Oregon is likely to implement one or more of these CO_2 reduction mechanisms, the level of cost that may be imposed on the utilities is not yet known. It is clear, however, that PacifiCorp's preferred portfolio — which the company estimates would *increase* its CO_2 emissions about 8 percent by 2018 compared to today[21] — does not meet the goals for reducing greenhouse gas emissions in HB 3543. *See* IRP at 219. *Also see* further discussion under guideline 4m.

Guideline 2: Procedural Requirements

PacifiCorp met all procedural requirements.

a. *Public involvement in the preparation of the IRP*

The company provided extensive opportunities for public input. *See* IRP at 17-19 and Appendix F.

b. *The plan should include non-confidential information that is relevant to the company's resource evaluation and action plan.*

The company provided non-confidential information in the main IRP document and Technical Appendices, meeting handouts, via e-mail and in response to data requests.

c. *Draft IRP for public review and comment*

The company provided its draft IRP for public review and comment on April 20, 2007.

Guideline 3: Plan Filing, Review, and Updates

a. *Timeliness of IRP filing*

The company filed its 2007 IRP timely, less than 1-1/2 years after acknowledgment of the last plan.

b. *Timely presentation of the results of the filed plan at a Commission public meeting*

The company presented the results of its plan to the Commission at a special public meeting on September 5, 2007.

---

[20] *See* Regular Agenda Item 5, November 21, 2006, public meeting.
[21] Based on the average adder level evaluated.

c.-g. *N/A*

Guideline 4: Plan Components

At a minimum, the plan must include the following elements:

a. An explanation of how the utility met each of the substantive and procedural requirements

Appendix I of the IRP provides this explanation.

b. Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions

The company included high and low growth scenarios in its Alternative Future scenarios. *See* Table 7.1, IRP at 141. The company included loads among its stochastic risk parameters in testing all its Risk Analysis portfolios.

Staff is concerned about the load forecasting risk associated with electrifying the oil and gas fields in Wyoming, given the uncertainty that such loads will in fact materialize and continue as projected. PacifiCorp states that it addressed the risk by assigning probabilities to these loads based on its belief that the loads will materialize, by slipping the projected start dates for the new loads based on the company's experience, and including load forecasts among the stochastic modeling variables. *See* PacifiCorp's response to Staff Data Request No. 6.

The company further states that it addresses this issue through analyzing Risk Analysis (RA) portfolios 14 (preferred portfolio) through 17, all of which include resources with shorter lead times: market purchases, natural gas resources and renewable resources. If the company acquires a gas plant and the expected loads do not materialize, the company states that it can defer other resources. *See* PacifiCorp's response to Staff Data Request No. 7.

Similar to direct access loads, staff's concern about the projected growth in oil and gas field loads is that costs of stranded generating facilities can be shifted to remaining customers. Staff notes that customer-sited resources, such as CHP facilities, can be a good match for uncertain loads because if the load goes away, so does the need for power. The company states that the need for useful thermal output in oil and gas exploration and development is very limited. The load is primarily pumping and compression. Thus, the company finds only marginal potential for CHP in this area. Due to the need to keep the pipelines running, the company also sees little potential for interruptible contracts except for system reliability and emergency conditions. *See* PacifiCorp's responses to Staff Data Request Nos. 8 and 9.

Staff further discusses the issue of projected Wyoming load growth under guideline 4c, immediately below.

c. *For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested*

Chapter 4 provides a resource needs assessment based on existing resources, contract expirations and plant retirements, projected load growth and planning reserve margin. *See* IRP at 61-87.

PacifiCorp estimates that it will become energy deficit on an average annual basis system-wide by 2009. The company projects it will become capacity deficit in 2010, based on the single peak hour of the year and a 12 percent capacity reserve margin. The company estimates the deficit will grow from 791 MW in 2010 to 2,400 MW in 2012, and to nearly 3,200 MW in 2016. *See* IRP at 82 and 87.

Accurate load growth forecasts are important because of the lengthy planning and development cycle for new resources and because subsequent net power cost updates rely on forecasts of load from the resource planning process. The company provides load projections based on its March 2007 forecast for two timeframes — the first 10 years (2007 to 2016) and the latter half of the study period (2016 to 2026).

Energy Needs. PacifiCorp projects energy consumption to grow system-wide at an average annual rate of 2.4 percent from 2007 through 2016. This rate is higher than the 10-year average rate of 2.1 percent in the company's 2004 IRP, as well as the actual average rate of 1.6 percent during the period 1995-2005. The growth rate represents an average increase of some 1.4 million MWh per year. For the second half of the study period, the company projects a 2.0 percent system-wide growth rate.

Energy consumption in the east is expected to grow four times faster than in the west — 3.2 percent versus 0.8 percent per year, respectively. The company expects Wyoming to grow at a faster rate than any other state — 5.6 percent per year on average. However, the company expects Utah, with its larger customer base, to have the largest increase in annual loads (in megawatt-hours). In the west, Washington's load is forecast to grow at 1.3 percent per year on average, leading California and Oregon. With its larger customer base, Oregon represents the bulk of the annual growth on the west side (in megawatt-hours), but has the lowest average energy growth rate (0.6 percent).

Capacity Needs. PacifiCorp forecasts coincident peak loads to grow by 2.6 percent system-wide from 2007-2016.[22] For comparison, historical peak load growth in summer (1995-2007) has been 2.2 percent on average. By control area, the company expects peak loads to grow by 3.2 percent in the east and 1.2 percent in the west. Total peak load growth is forecast to be 240 MW annually. Oregon is expected to contribute only 25 MW, or about 10 percent.

Staff's Analysis of Load Forecasts. Overall, the company projects both energy and capacity to grow faster than historical averages. These growth rates also are higher than the company forecast in its 2004 IRP. The company explains that Wyoming industrial growth — in particular, oil and gas extraction, along with associated residential and commercial growth, is driving the higher growth rates for energy consumption. The company also projects a modest overall rate increase for Oregon. Washington, Idaho, California and Utah are all predicted to grow at a slower rate than they have historically.

Curiously, on the basis of a tepid 0.6 percent forecast increase in Oregon load growth, and a robust 5.6 percent increase in Wyoming load growth,[23] the company predicts loads to grow 50 percent faster than the average historical growth rate. Staff is skeptical that the company has made a sufficient case to substantiate that increases in these two economic hot spots justify an overall increase of 2.4 percent in energy consumption. The 2.1 percent load growth the company predicted in the 2004 IRP was optimistic. Further, according to the Northwest Power and Conservation Council's "Biennial Monitoring Report on the 5th Power Plan," growth in the Northwest has remained sluggish primarily due to high energy prices and the lingering effects of the 2000-2001 energy crisis.

Staff has concerns about the validity of the Wyoming energy growth forecasts and whether this represents long-term growth or a short-term spike that will not be sustained over time. In the absence of the Wyoming anomaly, overall growth in energy and capacity would be more modest — around 2 percent — and closer to growth from 1995 to 2005.

Projected peak growth also is skewed by the abnormal growth rate in Wyoming. If Wyoming peak growth instead is consistent with the system average, again the result would be near 2.1 percent overall and more consistent with historical peak load growth of 2.2 percent. Staff finds that the company's load forecasts require further scrutiny.

Natural Gas Growth Stations. PacifiCorp changed its approach for modeling how the company will meet loads in the second half of the study period (years 11 through 20). In previous plans, the company modeled market purchases for this period. Staff far prefers this method to the one used in the current plan, where natural gas-fired plants are used as "growth stations" to meet loads in later years.

[22] Coincident peak load occurs in summer driven by air conditioning.
[23] Wyoming comprises only 15 percent of the total load.

Such a method may skew the analysis — for example, when comparing portfolios where the timing of "growth stations" differs in the second half of the study period. Indeed, the timing and size of growth stations vary by portfolio. *See* PacifiCorp's response to Staff Data Request No. 69. Staff finds the best way to consistently compare portfolios, and not inappropriately weight far-off resource decisions, is to model market purchases for the out-years of the plan. Further, the addition of growth stations creates CO_2 allowance credits that skew results. *See* PacifiCorp's responses to Utah DPU Data Request No. 1.22.

Transmission. The company modeled existing transmission rights and future transmission additions associated with the portfolios tested. *See* IRP at 113-114 and IRP Technical Appendices at 31.

d. *N/A*

e. *Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology*

   See Tables 5.1 through 5.4, IRP at 93-96, as well as resource descriptions at 97-116.

f. *Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs*

   The IRP meets this requirement. *See* the discussion under guideline 11.

g. *Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered*

   The IRP meets this requirement by stating the base case assumptions (Appendix A) and testing a range of alternative scenarios addressing key variables such as load growth, natural gas and electricity prices, and regulatory compliance costs for CO_2 emissions.

   PacifiCorp established the forward price curves for gas and electricity using the same methodology as in previous IRPs. The company used a third party (PIRA) forecast for natural gas forward price curves, translated to western delivery points. Electricity forward prices are a blend of market forecast calculations from a "fundamentals-based" price forecasting model called MIDAS, which relies in part on the PIRA natural gas forward price curves. These price curves are comparable to independent, third party price curves evaluated by staff.

h. *Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system*

The IRP generally meets this requirement, with exceptions noted under guideline 1a. In all, the company evaluated 56 portfolios in the IRP and additional portfolios in response to data requests.

i. Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties

The IRP meets this requirement. Chapter 7 presents the results of deterministic and stochastic analyses. Staff discusses elsewhere treatment of risks and uncertainties as they apply to specific areas.

j. Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results

The IRP meets this requirement. *See* Chapter 7.

k. Analysis of the uncertainties associated with each portfolio evaluated

The IRP meets this requirement. *See* Chapters 6 and 7.

l. Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers

PacifiCorp estimates future revenue requirements over a 20-year study period to compare the costs and risks of candidate portfolios. The company considers both stochastic and scenario risks. Stochastic risk applies when probability distribution functions can be estimated. Such is the case with fuel and electricity market prices, hydro conditions, loads and thermal availability. Scenario risks represent abrupt changes in risk factors, such as sudden changes in natural gas prices, regulatory compliance costs and capital costs.

PacifiCorp conducts stochastic analyses to arrive at both its cost and risk determinations. One hundred stochastic runs over the 20-year study period are conducted for each of five modeled levels of CO_2 adders, ranging from zero to $61 per ton (levelized, in 2008 dollars). The company calculates present value of revenue requirements (PVRR) assuming a *direct* tax adder and a cap-and-trade compliance strategy whose trading values are equivalent to the tax adders. The cap-and-trade results generally yield the same cost and risk rankings as the direct tax adder cases.[24] Stochastic Mean PVRR, the average of 100 modeled PVRR outcomes, is the company's primary cost metric.

Stochastic Risk Analysis - The company's favored risk metric, "Risk Exposure," is defined as the Upper-Tail PVRR minus the mean PVRR. The Upper-Tail PVRR is the mean of the worst 5 percent of the model PVRR outcomes. Other risk measures

[24] For the balance of this discussion, mean PVRR and other stochastic elements refer to the outcomes under a cap-and-trade environment with a particular CO_2 adder equivalent.

displayed in the IRP are the Upper-Tail PVRR by itself and the 95th Percentile, which is the 95th highest PVRR out of the 100 runs. *See* IRP Table 7.39 at 190.

Staff disagrees with the company's contention that the "risk analysis portfolio rankings are generally invariant with respect to the stochastic risk measures." *See* IRP Technical Appendices at 148. In fact, Table 7.39 shows major disparities in outcomes. For example, portfolio RA13 is ranked first or second for every CO_2 adder level using the Risk Exposure measure, but is ranked last for every adder using 95th Percentile and between second and fourth based on Upper-Tail PVRR.

More fundamental, staff does not agree with PacifiCorp that "Risk Exposure" (Upper-Tail PVRR minus mean PVRR) constitutes the best risk measure. The Risk Exposure metric is more a measure of variability than either the probability of having a bad outcome or the degree of a bad outcome that might occur.[25]

By focusing on variability, the Risk Exposure ranking of a portfolio can be excellent even though the portfolio's mean PVRR is so high that its 95th Percentile and Upper-Tail PVRR values are, unsatisfactorily, very high. Such is the case with portfolio RA13. Its mean PVRR is the highest across all CO_2 adder levels. So even though its variability is the lowest (translating to a first or second ranking for "Risk Exposure"), its 95th Percentile PVRR is higher than every other portfolio. That means that while all the other portfolios generally have greater variability, their average PVRR was low enough relative to RA13 that they have a lower probability of having a PVRR equal to RA13's 95th Percentile value.

Ratepayers should be interested in minimizing the probability that the 20-year PVRR exceeds a certain amount using a high percentile value (e.g., the 95th). Therefore, the 95th percentile constitutes a superior risk metric than the company's Risk Exposure metric, which simply focuses on variability and ignores the potentially offsetting benefits of a low mean.

Upper-Tail PVRR also is superior to the company's Risk Exposure metric. PGE uses Upper-Tail PVRR as its key stochastic risk measure.[26] *See* PGE's 2007 IRP at 177. Upper-Tail PVRR indicates how portfolios rank in terms of the expected value, or mean, among the worst set of outcomes.[27] The objective is to minimize the average of the <u>*set*</u> of worst outcomes. Even if a portfolio has a relatively high level of variability, its mean value can be low enough to result in a relatively low Upper-

[25] Note that by "variability" staff does not mean year-to-year volatility. The 100 stochastic outcomes are 100 different sets of 20-year PVRR. The observed variability of 20-year PVRR comes more from the modeled disparities in long run trends for the driving stochastic factors (especially loads and prices) than from year-to-year disturbances.

[26] PGE uses the term "TailVaR95" to denote the mean of the worst 5 percent of outcomes, which translates to the "Value at Risk" at the upper 95 percent tail level. Staff notes that, unlike PacifiCorp, PGE separately evaluates year-to-year PVRR volatility.

[27] The average of the X percent of worst outcomes is a simple average rather than one where each PVRR is weighted by the probability of occurrence of a PVRR so high.

Tail PVRR. Again, the concern is with a low Upper-Tail PVRR value *per se* rather than how far above the overall mean it is.

As noted above, PacifiCorp calculates Upper-Tail PVRR for the worst 5 percent of outcomes. PGE's calculations are for the worst 10 percent. The 10 percent figures would be less "distorted" by the extremely high PVRR values (because they'd be part of a 10-item mean rather than a five-item mean). On the other hand, having Upper-Tail PVRR values based on the 5 percent worst outcomes provides some perspective to the 95th Percentile values.

For future resource plans, staff recommends PacifiCorp rank portfolios using both the 95th Percentile and Upper-Tail PVRR, instead of the company's Risk Exposure metric. This latter metric can be dropped altogether as long as the standard deviation values continue to be shown, which give a sense of a portfolio's PVRR variability.

Economic Life of Coal Plants – Oregon parties criticize PacifiCorp for not taking into account that high CO_2 adders may substantially shorten the economic lives of pulverized coal plants. With that in mind, staff requested that the company conduct a number of its stochastic studies with economic lives of new supercritical pulverized coal plants reduced from 40 years to 25 years.

Study results with the abbreviated economic lives are available for PacifiCorp's preferred portfolio (RA14) and for two cases of a portfolio (RA12[28]) which staff had previously requested the company investigate in detail. *See* PacifiCorp's responses to Staff Data Request Nos. 65-67.[29] In both RA12 cases staff asked the company to use the same forecasted loads, fuel prices, etc. as were used in RA14 to enable direct comparisons. The second RA12 case went beyond these modifications and substituted two 1,000 MW nuclear plants (post-2017) for the coal resources in the original RA12 portfolio.

Not surprisingly, the advantages of RA14 shrink, or even disappear, if the 40-year economic life assumption does not hold. In the case where nuclear power was introduced into the RA12 portfolio, it achieved Stochastic Mean PVRR values that were lower than RA14 for the \$38 and \$61 CO_2 adder scenarios. This case also achieved lower Upper-Tail PVRR values than RA14 for all reported CO_2 adder scenarios. Compared to the modified RA14, the non-nuclear modification of portfolio RA12 had slightly higher Stochastic Mean PVRR values than portfolio RA14 (averaging \$1.8 billion, or about 8 percent higher), but slightly lower Upper-Tail PVRR values than portfolio RA14 (averaging \$4.68 billion, or about 6 percent less).

---

[28] RA12 has three pulverized coal plants, but as befits a "bridging" strategy, they come later than in the other portfolios.

[29] To minimize the study burden, the data requests limited the CO_2 adder conditions to \$8, \$38 and \$61 per ton. The studies employed a cap-and-trade regime.

Capital Cost Risk - The company used low and high values of capital cost risk of 5 percent and 10 percent, respectively, for all generating resources. The company also built in US Energy Information Agency contingency factors which capture differences among technologies. The company used its "high" case capital costs to analyze construction cost risk for the 17 risk analysis portfolios. *See* IRP at 91, 189; PacifiCorp's response to Staff Data Request No. 44. Staff notes that the "high" case estimates appear to be quite low, particularly for long lead-time resources. RNP points out that the high case does not even encompass actual prices for recent coal plants. *See* RNP Opening Comments at 5. CUB states that it is getting more difficult, and therefore costly, to build coal plants. Staff agrees with RNP and CUB that the capital cost risk of new coal plants has not been addressed adequately in the IRP. *See* CUB's Opening Comments at 7-8.

The company states that capital cost volatility is best addressed through the resource procurement process. *See* PacifiCorp's Reply Comments, October 12, 2007, at 6. Evaluating capital cost risk in the RFP process should not be a substitute for evaluating this risk in the resource planning process. Staff also notes that the company's current RFP for 2012 base load resources allows bidders (and the company) to index a sizable portion of their bid (or benchmark cost estimates) to specific market indices. Further, the company is not committing to be held to its cost estimates for its benchmark resources when it comes time to put any such resource into rates. [30] *See* PacifiCorp's 2012 RFP for Base Load Resources, issued April 5, 2007, at 6, 27-28.[31]

m. *Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation*

The IRP was filed before Oregon adopted a Renewable Portfolio Standard (RPS, SB 838) and emissions reduction goals for greenhouse gases (HB 3543). The IRP also was filed before the U.S. House of Representatives passed a federal RPS bill for the first time. Staff is satisfied at this time with the company's responses to our requests for more information on meeting state and potential federal renewable energy standards. However, staff recommends the Commission require the company to develop a plan to meet the emissions reduction goals in HB 3543:

> <u>For the 2007 IRP update and next planning cycle, develop a plan to meet the CO_2 emissions reduction goals in Oregon HB 3543, including development of a compliant portfolio that meets the Commission's best cost/risk standard.</u>

n. *An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the*

[30] "[T]he Company does not intend for the Benchmark Resources to be treated like market bids for purposes of subsequent ratemaking treatment." RFP at 6.
[31] PacifiCorp's RFP as issued to the market is at http://www.pacificorp.com/Article/Article62879.html.

activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing

Table 8.2 (IRP at 224-227) provides the company's action plan.

Guideline 5: Transmission

The IRP meets this guideline. The analysis of transmission options in the current planning cycle is an improvement on previous plans. Rather than simply including transmission to bring electricity from new proxy plants to loads, the company allowed its capacity optimization model (CEM) to select among 10 transmission resources to enhance transfer capability and reliability and increase access to markets. The projects included those targeted for evaluation under MEHC commitments. All portfolios included the 300 MW Path C upgrade and the 176 MW Craig-Hayden project, both with an in-service date of 2010. Transmission associated with wind resources located in southwest and southeast Wyoming, as well as eastern Nevada, was included in the capital costs of those wind resource options; they were not modeled as transmission paths. *See* IRP at 113-114.

Based on initial modeling results, eight transmission projects were part of all Group 2 risk analysis portfolios, including the preferred portfolio (RA 14). *See* Table 7.36, IRP at 186.

The company also performed a CEM sensitivity study on a regional transmission project similar to the Frontier Line project, which would connect Wyoming generation with load centers in Utah, California and Nevada. The proxy transmission resource consisted of 1,500 MW lines from Wyoming to the SP15 transmission zone in southern California, and from Utah to the NP15 transmission zone in northern California. The project decreased PVRR by $424 million compared to the base case portfolio. The CEM's optimized portfolio in this study included an IGCC plant, more wind, a slight increase in front office transactions and elimination of all simple-cycle combustion turbines. *See* IRP at 124-125, 148-149.

Guideline 6: Conservation

a. Periodic conservation potential study for the entire service territory

Under the Commission's updated planning guidelines, the utility should analyze potential conservation resources regardless of any limits on funding. The IRP as filed did not include any review of conservation potential in Oregon, beyond what the Energy Trust of Oregon expects to acquire with public purpose funds.

The company completed a six-state assessment of demand-side management (DSM) potential shortly after filing the 2007 IRP. The company's DSM study excluded conservation in Oregon, despite the Commission's planning guidelines being adopted in January 2007 and the MEHC commitment for a *system-wide* study.

In response to staff's concern that incremental Oregon was not considered in the IRP or system-wide study, the company provided an assessment of additional conservation potential in its Oregon service area, based on Energy Trust of Oregon estimates. The company plans to make a supplemental filing to amend its IRP action plan to include 50 MWa of additional conservation in Oregon.[32] The company states that the increase would affect only the level of short-term market purchases in the Western control area, and not the size or timing of the proposed natural gas-fired power plant planned for 2011 or 2012 in the west. *See* PacifiCorp's supplemental response to Staff Data Request No. 4. The company further explains that 50 MWa of conservation is the forecasted total in 2016; in 2011, the estimate is 23 MWa. In addition, the company believes reducing front office transactions rather than the size of the gas plant would achieve better results on a cost, risk and reliability basis. *See* PacifiCorp's response to Staff Data Request No. 58.

b. *To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.*

c. *To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should:*

- *Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and*
- *Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.*

Staff finds the company's evaluation of conservation resources flawed. The company did not conduct a meaningful analysis of varying amounts of conservation, or its potential risk reduction benefits. Instead, the company performed a stochastic analysis on the preferred portfolio with, and without, 12 conservation peak load "decrements" of 100 MW each of various shapes, such as residential cooling, to determine whether they would lower the cost of market purchases (by reducing spot market purchases) and operating power plants (by optimizing operation of existing and new resources in the portfolio).

PacifiCorp states that resource deferral benefits associated with conservation in the action plan are reflected in its modeling to the extent that the conservation is reflected in the retail load forecast. *See* IRP at 136-137; PacifiCorp Reply Comments, October

[32] With the passage of SB 838, the company can request to include in rates cost-effective conservation beyond what can be acquired through the public purpose charge. The company intends to file such a request with the Commission soon. Following up on a question from staff, the company clarified that the estimated incremental conservation from the industrial sector included only customers with loads less than 1 MWa.

12, 2007 (at 5). That's the case for the 141 MWa of "base" conservation included in the system load forecast by 2012, growing to 227 MWa by 2016.[33] *See* IRP Technical Appendices at 5-6. However, to determine the 200 MWa of "planned" conservation, the company did not consider any benefit for deferring or avoiding new power plants and transmission. Nor did the company address how new conservation programs might change the resource makeup of the portfolio. Therefore, staff does not find that the company included in its preferred portfolio all best cost/risk conservation resources.

The company agreed in the last planning cycle to evaluate whether it was preferable to use supply curves for various types of conservation resources, model them as portfolio options that compete with supply-side options, and analyze cost and risk reduction benefits. The company did not use this method in the 2007 IRP because the company did not complete its multi-state conservation assessment until after the IRP was filed.[34] *See* PacifiCorp's response to Staff Data Request No. 24.

For a 2007 IRP update and the next planning cycle, the company plans to use its Capacity Expansion Module to perform an initial economic analysis on the conservation potential identified in the system-wide study. The company will then perform detailed analysis using the Planning and Risk module on the screened resources. The company also will assess how its base and planned conservation and demand response programs compare with the cost-effective amounts determined in the system-wide study as required by Order No. 06-029. *See* PacifiCorp's responses to Staff Data Request Nos. 18 and 23.

OAR 860-030-0010(6) requires the utilities to use a 10 percent discount for conservation resources when determining cost-effectiveness. The Commission explicitly recognized that the 10 percent discount accounts for the value of conservation in reducing risk and uncertainty.[35] Staff notes that PGE's 2007 IRP uses this value in determining the cost-effectiveness of conservation resources.

Staff recognizes that PacifiCorp is a multi-state utility, and other states may not apply a 10 percent discount when determining program cost-effectiveness. However, PacifiCorp has not provided analysis that reasonably approximates Oregon's requirement.

The Northwest Power and Conservation Council demonstrates that conservation performs better than simple-cycle combustion turbines, the traditional solution for risk management, because conservation provides value when market prices are low and is not subject to forced outages. Conservation also out-performs wind resources in this

---

[33] These "identified and budgeted" amounts include Energy Trust of Oregon projections, but do not include the incremental conservation PacifiCorp now plans to pursue in Oregon.
[34] PacifiCorp advised staff and parties early in the IRP process that this would be the case. Staff did not object given agreement by the states on a multi-state DSM study, a commitment under MEHC's acquisition.
[35] *See* Order No. 94-590 (UM 551) at 14.

latter respect. Ultimately, the Council concludes that utilities may be overlooking the capacity benefits of conservation.[36]

PacifiCorp notes there are about 250 MWa of conservation resources in the preferred portfolio, not including the additional 50 MWa Oregon increment recently proposed. The company plans to analyze another 200 MWa of conservation using the methodology from the 2007 IRP. In November 2007, the company plans to issue an RFP for conservation (outside Oregon), along with demand response and dispatchable customer standby generation. It expects to execute contracts in June 2008 and have programs running in October 2008.[37] *See* PacifiCorp's response to Staff Data Request No. 19.

Staff proposes the amendment below to IRP action item 2 to address the following:

- Remove the reference to using a flawed methodology for determining cost-effectiveness of new program proposals
- Address conservation analysis in the IRP update and the next planning cycle
- Incorporate the company's proposed amendment to add 50 MWa of incremental conservation in Oregon
- Remove the limit on the amount of conservation the company may acquire that meets the Commission's cost/risk standards
- Consider how conservation can reduce the costs of complying with Renewable Portfolio Standards, given that mandated levels of renewable resources are based on load served in the compliance year (conservation reduces load)

Proposed modification to action item 2:

> ~~Use decrement values to assess cost-effectiveness of new program proposals.~~ Acquire the base Class 2 DSM (PacifiCorp and ETO combined, including energy savings in Oregon beyond that funded by the ETO) of ~~250~~ 300 MWa and ~~up to an additional~~ 200 MWa or more of additional Class 2 DSM if risk-adjusted cost-effective initiatives can be identified. Will work with the ETO to identify such new energy efficiency initiatives and file the necessary tariffs with the Oregon Public Utility Commission. Will reassess Class 2 objectives upon completion of system-wide DSM potential study ~~to be completed by June 2007~~. Will incorporate potentials study findings into the 2007 update and 2008 integrated resource planning processes, including developing supply curves, modeling them as portfolio options that compete with supply-side options, and analyzing cost and risk reduction benefits. Modeling also will take into account the benefits of conservation in reducing the costs of complying with Renewable Portfolio Standards.

---

[36] *See* Michael Schilmoeller, Northwest Power and Conservation Council, "Enhanced Value of Conservation for Addressing Risk," presentation to the Power Committee, March 13, 2007 (http://www.nwcouncil.org/news/2007_03/p4.pdf).
[37] Milestones are tentative.

Guideline 7: Demand Response

PacifiCorp categorizes demand response into two types: Class 1 DSM includes dispatchable load control, scheduled irrigation and thermal energy storage; Class 3 DSM includes curtailable rates, critical peak pricing and demand buyback.

In the 2004 IRP, the company took its first step toward comparable treatment of demand response and supply-side resources by allowing the CEM to choose Class 1 DSM and displace supply-side resources in the preferred portfolio. Staff recommended that in future planning cycles the company test various *amounts and types* of both Class 1 and Class 3 DSM within modeling of *all* portfolios.

In the current IRP, the company provided "proxy" values to a third party for initial program screening for Class 1 DSM. The proxy values of $58 per kW-year on the west side and $98 per kW-year on the east side were based on the demand response resources the CEM selected — and did not select — in each control area. *See* PacifiCorp's response to Staff Data Request No. 20 and IRP Technical Appendix B. Staff finds this methodology severely flawed. However, the company states that it did not use these costs in the IRP for evaluating demand response resources.

The company used the CEM to evaluate Class 1 and Class 3 DSM resources starting in 2009 using a set of alternative future scenarios — low, medium and high achievable DSM potential. These scenarios reflect on-peak market electricity prices of $40, $60 and $100 per megawatt-hour, respectively, as well as incrementally higher marketing and program costs as the company moves its way up the DSM supply curve. Pursuant to a requirement from the last planning cycle, the company included supply curves for curtailable rates, demand buyback and critical peak pricing in its CEM modeling. However, only Class 1 resources were included in the development of risk analysis portfolios. In other words, Class 3 programs were pre-screened out of the risk analysis (final) portfolios, prior to reviewing their potential value for mitigating risk.[38] Further, PacifiCorp's proxy values pre-screened out Class 1 DSM resources in the third-party potential study. Therefore, the amounts and types of resources that the model was permitted to choose did not comprise all of the resources that otherwise might be selected for the best cost/risk portfolio.

Fundamentally, the analysis of demand response resources suffers from the same problem as conservation, described above. The company's six-state DSM assessment addressed demand response resources system-wide, including in Oregon. However, the results were not finalized until after the company filed its resource plan. In lieu of having these results, demand response potentials were estimated for each control area

[38] However, the company conducted a sensitivity analysis of Class 3 DSM by adding 106 MW (total available based on proxy supply curves developed by a third party) of such resources to the RA8 portfolio in 2009. PacifiCorp found that there was little impact on portfolio risk performance, including cost and reliability. For example, energy not served decreased by 0.1 percent. Given the fuel price, capital cost and regulatory risks of other resource options, staff finds the results supportive of including Class 3 DSM resources in risk analysis portfolios.

based on the proxy values described above. Staff finds the result gives short-shrift to demand response resources, particularly on the west side of the company's system.

The company will use the results of the six-state DSM report to analyze demand response resources in the next IRP. In doing so, staff is cautious of certain findings in the report. For example, the report says that over the next 20 years, there is only 20 MW of achievable potential in the west from so-called "firm" demand response – all of it in controlling irrigation loads. The company also found just 20 MW from programs like demand buyback, curtailable tariffs and other pricing options in the west. On the east side, the estimated achievable potential is more than 10 times higher. That's due in large part to the higher proxy values for avoided capacity costs — $98 vs. $58 per kilowatt-year. The company does not plan to use these values in assessing demand response proposals through its forthcoming DSM RFP. *See* PacifiCorp's response to Staff Data Request No. 22.

Staff recommends the following modifications to the action plan to memorialize PacifiCorp's commitments:

> Action Item 3 (New Class 1 Programs): Targets were established through potential study work performed for the 2007 IRP. Acquire 100 MW or more of additional Class 1 resources if risk-adjusted cost-effective initiatives can be identified. A new potential study is expected to be completed by June 2007, and associated findings will be incorporated into the 2007 update and the 2008 integrated resource planning processes, including developing supply curves, modeling them as portfolio options that compete with supply-side options, and analyzing cost and risk reduction benefits.
>
> Action Item 4 (Existing and New Class 3 Programs): Although not currently in the base resource stack, the company will seek to leverage Class 3 and 4 resources to improve system reliability during peak load hours. Will incorporate potential study findings into the 2007 update and~~/or~~ the 2008 integrated resource planning processes, including developing supply curves for Class 3 resources, modeling them as portfolio options that compete with supply-side options, and analyzing cost and risk reduction benefits.

Pursuant to an agreed-upon modification to PacifiCorp's last resource plan, in the 2004 IRP update and the 2007 IRP the company assumed existing interruptible contracts are extended beyond the end of the 20-year study period.

Guideline 8: Environmental Costs

The company met the Commission's current guidelines for analyzing portfolios at the specified CO_2 adder levels. The Commission is reviewing guideline 8 in Docket UM 1302.

The company used a new approach for considering (in part) the results of the required CO_2 adder analysis — averaging them. This effectively assumes that all adder levels are equally likely. Staff notes RNP's criticism that the company should have used a *median* value, rather than an average that skews results toward a lower adder level. Further, RNP notes that the median value of current policy proposals would be $55 per ton. *See* RNP's Opening Comments at 11-12. Staff continues to find valuable the individual adder level analyses, particularly worst case (higher adder level) results.

Staff also finds trigger point analysis of value. For example, the company's breakeven analysis for supercritical pulverized coal vs. a gas-fired combined-cycle plant yielded a breakeven CO_2 adder level of $38 per ton CO_2 (2008 dollars). *See* IRP at 193. At staff's request, the company determined a similar breakeven adder level for supercritical pulverized coal vs. an IGCC plant *with* CO_2 capture and sequestration (CCS) — $39 per ton CO_2. The company states that a similar analysis for supercritical pulverized coal vs. IGCC technology, both *with* CCS, would not be meaningful because of uncertainty in the CCS costs for supercritical pulverized coal plants. *See* PacifiCorp's response to Staff Data Request No. 3.

PacifiCorp also conducted such trigger point analysis under the "high" gas and electricity prices used in the company's sensitivity analyses. Under that scenario, the gas-fired CCCT plant replaced the supercritical pulverized coal plant at a CO_2 cost adder of $97 per ton. PacifiCorp also ran the study with "low" gas and electricity prices. In that case, the model picked the CCCT at a carbon tax adder of *zero* — i.e., under all CO_2 cost scenarios. *See* PacifiCorp's response to Utah CCS Data Request No. 1.4.

In addition, the company developed and evaluated a portfolio that would comply with a regional performance standard for greenhouse gas emissions; pulverized coal and unsequestered IGCC plants were excluded. The company's capacity optimization model did *not* select a sequestered IGCC plant.[39] Instead, the model selected additional natural gas-fired plants, renewable resources, short-term market purchases and demand response resources. Under high CO_2 adders, the compliant portfolio performs better than the preferred portfolio based on Stochastic Mean PVRR (the company's primary cost metric). On average across all adders studied, the Stochastic Mean PVRR for the compliant portfolio is in the middle of the pack for the final risk analysis portfolios (RA13 to RA17). The 95th Percentile values are comparable to RA14. *See* IRP at 213-219. Staff finds these results compelling.

The company tested the resource mix impacts of increasing the CO_2 adder by $5 increments.[40] Moving from $8 (base case) to $15 per ton CO_2, the CEM removed the 2012 Utah supercritical coal plant and added another gas-fired CCCT and 700 MW more wind. When the adder was increased to $20 per ton CO_2, the model removed the 750 MW Wyoming supercritical coal plant and added 600 MW more wind and

[39] The CEM selected the resources in the portfolio based on a carbon adder of $8 per ton.
[40] Analysis was performed on the initial (CAF) portfolios.

additional demand response and short-term market purchases. At $25 per ton CO_2, the model removed the Utah coal plant and the west-side IGCC plant and added another combined-cycle gas plant as well as a peaking plant on the east side. *See* IRP at 149.

For mercury from existing coal plants and coal proxy resources, the company included in variable operating and maintenance costs the cost of complying with the federal Clean Air Mercury Rule. The company also accounted for mercury allowances under a federal cap and trade program expected to begin in 2010. *See* PacifiCorp's response to Staff Data Request No. 50.

The company adjusted natural gas and market price forecasts, and SO_2 and NO_x allowance prices, to reflect the CO_2 adder levels. *See* IRP at 133. The company did a similar adjustment for the 2004 IRP. In Docket UM 1302, staff recommends such logical consistency in modeling inputs.

Guideline 9: Direct Access Loads

PacifiCorp complies with this guideline. The company does not offer a permanent opt-out program. Therefore, it plans for all Oregon loads, including those customers who have selected direct access or standard offer service.

Guideline 10: Multi-state Utilities

The company planned on a system-wide basis, as specified under this guideline. However, as detailed elsewhere, staff questions whether PacifiCorp's preferred portfolio represents the best cost/risk portfolio for all its retail customers.

Guideline 11: Reliability

PacifiCorp significantly improved its reliability analysis in the 2007 IRP, responsive to this guideline and the Commission's directives from the last planning cycle. The company analyzed reliability within the risk modeling of the actual portfolios being considered by evaluating a subset of portfolios at both a 12 percent and a 15 percent planning reserve margin,[41] and one portfolio at an 18 percent planning margin, and then evaluating loss of load probability and average and worst-case energy not served (ENS). Ultimately, the company selected a portfolio with a 12 percent planning reserve margin (RA14). The company concludes: "PacifiCorp's view is that supply reliability is not materially impacted by a swing in the margin from 15 to 12 percent." *See* IRP at 203.

Also pursuant to a requirement from the last IRP, the company conducted an analysis of planning to the average of the (system) eight-hour super-peak period using the base case portfolio (CAF 11 — "medium" values for input assumptions and a *15 percent*

[41] Comparing portfolio pairs to test a 15 percent margin against a 12 percent margin (RA1 vs. RA8, RA10 vs. RA9, RA11 vs. RA12, and RA16 vs. RA 14) yielded small differences in average energy not served of between 1.2 MWa to 3.9 MWa.

planning margin), rather than the single peak hour of the year.[42] PVRR decreased by $194 million as a result of removal of a 302 MW peaking plant, a 100 MW decrease in wind resources, and a reduction in front office transactions. *See* IRP at 150.

Following are the reliability metrics under the eight-hour super-peak period planning scenario:

- Expected ENS – 149 GWh
- Worst-case ENS (upper-tail mean) – 1,609 GWh
- Average LOLP in July (ENS event > 25,000 MWh[43]) – 13 percent (first 10 years)
- Average LOLP in July (ENS event > 25,000 MWh) – 19 percent (entire study period)
- Probability of an ENS event > 25,000 MWh in July – 9 percent in 2012, 19 percent in 2013, and 16 percent in 2014

See PacifiCorp's response to Staff Data Request No. 33.

In comparison, the values for the preferred portfolio[44] (with a *12 percent* planning margin), based on the single peak hour of the year, are as follows (IRP at 198-200):

- Expected ENS – 144 GWh
- Worst-case ENS – 1,299 GWh
- Average LOLP in July (ENS event > 25,000 MWh) – 11 percent (first 10 years)
- Average LOLP in July (ENS event > 25,000 MWh) – 18 percent (entire study period)
- Probability of ENS event (> 25,000 MWh in July) – 7 percent in 2012, 12 percent in 2013, and 10 percent in 2014

After seeing the results of this analysis, as well as other reliability data in the IRP, staff remains skeptical of a planning reserve margin based on the single peak hour of the year as the preferred reliability metric. We note that LOLP analysis accounts for all hours where resources are insufficient to meet loads. Staff recommends the following modification to the company's action plan to further address the use of LOLP as a reliability metric and consideration of the cost/risk tradeoff:

> <u>For the next planning cycle, further develop with stakeholders use of loss of load probability (LOLP) and energy not served (ENS) in lieu of a reserve margin based on the single peak hour. Fully develop cost and risk metrics of various LOLP and ENS criteria.</u>

Pursuant to the requirement from the last planning cycle that the company include Class 3 DSM alternatives for meeting unserved energy, the company included the

---

[42] The eight-hour peak period is on the same day as the single peak hour.

[43] Equivalent to 2,500 MW for 10 hours.

[44] Wind and DSM resources are treated differently in the Risk Analysis (RA) portfolios, including the preferred portfolio (RA 14), relative to the initial CEM "Alternative Future" (CAF) portfolios.

maximum available amount of such DSM based on the proxy supply curves developed by a third party.

Guideline 12: Distributed Generation

PacifiCorp evaluated combined heat and power (CHP, or cogeneration) and dispatchable customer standby (diesel) generation resources. The company's preferred portfolio includes 100 MW of CHP resources.

Pursuant to a requirement from the last planning cycle, the company conducted a sensitivity analysis on the potential of CHP to reduce generation and transmission costs. The company found that for a 5 MW customer load located on a typical 12.5 kilovolt feeder in Oregon, a 5 MW CHP unit can potentially offset connection costs of $50,000 to $150,000 and avoid infrastructure costs of $500,000 to $2.5 million, so long as the customer agreed to be interrupted if the CHP unit is off-line at a time where the distribution system cannot serve the load. *See* Appendix H.

Although the preferred portfolio does not include dispatchable standby generation, the company plans to include this resource in its fall 2007 RFP for DSM resources. The company has discussed such a program with PGE, which has one of the largest dispatchable standby generation programs in the country.

PacifiCorp included CHP, solar and dispatchable standby generation resources in the six-state DSM report completed after the IRP was filed. The report shows achievable potential in the west from *all* of these sources at only 79 MW over the next *20* years. Staff is skeptical about these findings.

Guideline 13: Resource Acquisition

a. An electric utility should, in its IRP:

- *Identify its proposed acquisition strategy for each resource in its action plan.*
- *Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.*
- *Identify any Benchmark Resources it plans to consider in competitive bidding.*

The company complied with these requirements. The company provided its acquisition strategy for its action plan and a brief assessment of the advantages and disadvantages of owning vs. purchasing resources. *See* IRP at 229-233. The company identified its benchmark resources for the current 2012 RFP for base load resources. *See* IRP at 57.

b. N/A

III. Initial Recommendations for Acknowledgment of Major Thermal Resources in the Action Plan

Staff provides the following initial comments and recommendations for acknowledgment of action plan items 7, 8, 9 and 11. To the extent PacifiCorp does not agree to staff's proposed modifications to these action items, staff recommends at this time that any Commission acknowledgment of the IRP provide an explicit exception for these items.

Action Item 7: Procure a 550 MW[45] base load/intermediate load resource in the east by the summer of 2012, modeled as a Wet "F" 2X1 CCCT with duct firing
Action Item 8: Procure a 350 MW base load/intermediate load resource in the east by the summer of 2012, modeled as a 340 MW supercritical pulverized coal unit in Utah

The company's load and resource balances under a 12 percent planning margin demonstrate that the company is capacity deficit system-wide beginning in 2010. The company expects the deficit to grow to 2,446 MW in 2012. The eastern portion of the system accounts for most of the capacity needed. *See* IRP at 81-84. Staff finds reasonable that the company plans to acquire a thermal resource on the east side of its system in 2012.

PacifiCorp provides analysis that demonstrates it would have a planning reserve margin of only 9 percent in 2012 if the company acquires the proposed gas plant (action item 7), but does not acquire the 340 MW proxy coal plant (action item 8). The company estimates that Energy Not Served would increase by 24 percent over the 20-year study period without the coal plant. *See* PacifiCorp's response to Staff Data Request No. 48.

However, staff is not convinced that the company should acquire two base load/ intermediate load resources in the east to meet its resource needs. As was the case with the company's 2004 IRP and current RFP, the company has not demonstrated that base load resources are the appropriate strategy for meeting the highly seasonal, peak-hour needs on the east side of its system.

Assuming economic dispatch, the company's energy balance shows its *annual system energy surplus would double* under the preferred portfolio,[46] rising to some 2,000 MWa in 2012 after introduction of the proxy coal (340 MW) and natural gas-fired (548 MW) resources to go into service that year, as well as the west-side gas plant (600 MW) in 2011. *See* PacifiCorp's response to Staff Data Request No. 47. Staff shares CUB's concerns about captive customers paying for new coal plants whose economics rely on sales of CO_2-heavy electricity into the market. *See* CUB's Opening Comments at 5-6.

Additional conservation, demand response and market purchases targeting summer on-peak hours, as well as natural gas-fired peaking plants, may be a better solution for at

---

[45] The action plan rounds size to the nearest 50 MW for generation resources.
[46] Under average hydro conditions.

least one of these proxy resources. Further, staff is skeptical of the high energy growth rates the company is projecting. *See* the discussion under guideline 4c.

On October 2, 2007, the company filed a motion with the Public Service Commission of Utah, requesting approval of proposed amendments to the company's 2012 RFP for base load resources. Among the proposed amendments is adding two natural gas-fired benchmarks for 2012 due to problems with its planned Intermountain Power Project 3 (IPP 3) coal plant. PacifiCorp states: "Since the Company's submission of IPP 3 as a 2012 benchmark resource, actions and statements have been made by Intermountain Power Agency and Los Angeles Department of Water and Power indicating that they would no longer support the development of IPP 3.... [Such public statements and actions] puts at risk the timeliness and viability of the construction of this 2012 benchmark." The company further states: "The existing company Benchmark for 2012 ... may be delayed or ultimately determined to not be viable for circumstances outside of the company's control." *See* *http://www.psc.utah.gov/elec/Indexes/0503547indx.htm*.

Such a development may make moot the question of whether the Commission should acknowledge a proxy coal plant for 2012. However, staff notes that: 1) the company has not filed an update to the 2007 IRP related to this 2012 proxy resource, 2) the IPP 3 plant remains a utility benchmark resource in the RFP, and 3) coal plants can bid into the RFP. Therefore, staff addresses the issue below.

First, PacifiCorp did not conduct an analysis for the 2007 IRP of the impacts of new coal plant development on potential forced retirement of existing coal plants. *See* PacifiCorp's response to Staff Data Request No. 14. Under forthcoming CO_2 regulation, if new coal plants are not banned outright, CO_2 cost adders (under a tax or a cap-and-trade regime) may cause such retirements as new coal plants operate and emit large quantities of CO_2. Such displacement should be considered when evaluating coal plants as a resource option.

Second, staff shares other parties' concerns regarding the risk to ratepayers of pulverized coal resources due to future carbon regulation, particularly considering the company's existing carbon exposure and rising CO_2 emissions under the preferred portfolio. *See* discussion under guideline 1d.

As CUB points out, the company's cap-and-trade assumptions simply cap CO_2 emission at 2000 levels. CUB notes that serious proposals to address climate change include a *declining* cap on emissions over time. *See* CUB's Opening Comments at 3. PacifiCorp acknowledges that the cap level used in the IRP is lower than some recent regulatory proposals. However, the tax scenario included in the IRP is equivalent to no cap at all. *See* PacifiCorp's Reply Comments, October 12, 2007, at 8.

CUB and other parties find other key IRP assumptions unrealistic, including the $8 per ton base-case CO_2 adder, accumulation and sale of emissions allowance credits (in cap-and-trade scenarios), and buyers willing and able to take the carbon burden associated with sales from PacifiCorp's unsequestered coal plants – with no consequences for the sale price. Because of these assumptions, the models produce results that appear unlikely in the real world – in particular, that the cost of portfolios with two new, unsequestered coal plants goes down as CO_2 regulatory costs go up. *See* CUB's Opening Comments at 4-6.

PacifiCorp explains that neither of its IRP models was capable of modeling CO_2 emissions externality costs other than as a dispatch cost adder (i.e., tax). However, the models perform expansion and dispatch functions identically under both cap-and-trade and CO_2 tax scenarios. The models also do not have the capability to track CO_2 emissions associated with non-firm imports and exports. The company therefore estimated offline the CO_2 footprint of generation used to serve load, by applying system emissions factors to aggregated wholesale purchases and sales. *See* PacifiCorp's Reply Comments, October 12, 2007, at 7-8.

Parties raise concerns about PacifiCorp's modeling of CO_2 emissions for short-term market transactions. For wholesale *purchases*, the company used an emissions rate of 0.565 tons per MWh, based on a detailed review of its 2005 purchases, offset by emissions deemed to go with wholesale sales at the average system emission rate. For wholesale *sales*, the company used its average system emission rate of 0.822 tons per MWh, based on 2007 as the representative year. Included in that rate were wholesale purchases (short- or long-term); wholesale sales were excluded in order to represent emissions associated with serving retail loads. In reporting cumulative CO_2 emissions for the portfolios, the company summed direct (generator) emissions and emissions from market purchases, *net* of CO_2 emissions from wholesale sales. *See* IRP at 134; PacifiCorp's responses to Northwest Energy Coalition Data Request Nos. 9 and 10.

Staff finds it unlikely that the market — including price — will be the same for power with widely differing CO_2 content. However, this dubious assumption helps make portfolios with coal plants appear to have favorable cost and risk metrics.

The company states that it has acquired an add-on component for modeling emissions compliance and is discussing with its model vendor ways to address assignment of emissions rates to short-term market transactions. *See* PacifiCorp's Reply Comments, October 12, 2007, at 7.

Staff finds reasonable ODOE's position that future CO_2 regulations are unlikely to give PacifiCorp free allowances to cover the emissions of any new coal resources, which will not be on line until 2012 at the earliest. In fact, to meet future carbon regulation, ODOE states that PacifiCorp will likely be required to replace the output of existing coal-fired plants with low or zero carbon resources. Staff also takes note of ODOE's arguments regarding higher borrowing costs that may result from investments in new coal plants. *See* ODOE's Opening Comments at 10-12.

Pursuant to the Commission's order on the last resource plan (at 51), PacifiCorp evaluated a portfolio that excludes pulverized coal plants (RA6). The company found that this strategy increased average Risk Exposure (across all CO_2 adders) by $5.7

billion, compared to the CEM deterministic solution (RA1, the portfolio optimized for expected cost under base-case assumptions). *See* IRP at 169. The company also analyzed two of the portfolios requested by Oregon staff. These portfolios: 1) deferred pulverized coal plants until 2015; 2) included an unsequestered IGCC plant in 2014, and 3) included 600 MW of additional wind resources tested as a resource strategy in the Group 1 analysis (2,000 MW total wind). One portfolio had a 15 percent planning reserve margin (RA11); the other had a 12 percent margin (RA12). Compared to RA1, these portfolios increased average stochastic mean PVRR (cost) by about $350 million. However, portfolio RA11 performed well in the risk analysis, including the 95th Percentile and Upper-Tail PVRR values. *See* IRP at 162, 166-168.

Staff is particularly concerned about pulverized coal plants, because the technology to capture CO_2 emissions is less advanced compared to IGCC facilities. Staff agrees with parties' criticism that the IRP did not fully evaluate IGCC plants with CCS technology.

PacifiCorp cites 2014 as the earliest in-service date for an IGCC plant. *See* Table 5.1, IRP at 93. An IGCC plant is the company's alternative 2014 benchmark resource in its current RFP process.[47] Until such time as the technology is further commercialized, the Commission directed the company to fully explore other types of resources in line with its seasonal, peak-hour needs, including natural gas-fired peakers, additional market purchases, demand response, conservation and distributed generation. *See* Order No. 06-029 at 51; Order No. 07-018 at 8.

In lieu of action items 7 and 8, which address east-side resources with the same in-service date, staff recommends the following consolidated action item:

> Procure flexible resources in the east (other than coal plants) by the summer of 2012. Refine the size and type (base load vs. peaking) of resources needed after updating DSM and renewable resource analyses, accounting for changes in resources, and refining load forecasts.

Staff also recommends two additional action items:

> For the next planning cycle, model the impact of forced early retirements of existing coal plants, or retrofits necessary to reduce their CO_2 emissions, under stringent carbon regulation scenarios.
>
> Refine CO_2 emissions modeling to improve treatment of compliance under various regulatory schemes, including assignment of emissions rates to short-term market transactions.

Action Item 9: Procure a 550 MW base load/intermediate load resource in the east by the summer of 2014, modeled as a 527 MW supercritical pulverized coal unit in Wyoming

[47] The company's base benchmark resource in 2014 is the pulverized Wyoming coal plant that serves as the proxy resource for action item 9 in the 2007 IRP.

Staff has the same concerns regarding this action item as stated above for action items 7 and 8. Staff therefore recommends the following modification to action item 9:

> Procure ~~a 550 MW base load/intermediate load~~ resources in the east by the summer of 2014 other than pulverized coal plants. Refine the size and type (base load vs. peaking) of resources needed after updating DSM and renewable resource analyses, accounting for changes in resources, and refining load forecasts.

Action Item 11: Procure a 600 MW base load/intermediate load resource in the west by the summer of 2011-2012, modeled as a Wet "F" 2X1 CCCT with duct firing

Under *critical* hydro conditions, and before adding any resources, on an average annual basis the company already is energy-deficit in the *west*, and becomes slightly energy-deficit *system-wide* in 2009. *See* IRP at 85-86. Under *average* hydro conditions, used in portfolio analysis and selection, the company becomes slightly energy-deficit system-wide in 2010. *See* PacifiCorp's response to ODOE Request No. 17.

By 2012, after adding the west-side proxy CCCT and the east-side proxy plants in the preferred portfolio, the company expects its system to be energy surplus by 2,000 MWa under average hydro conditions. *See* PacifiCorp's response to Staff Data Request No. 47. *Also see* discussion on page 31.

PacifiCorp states that the west-side CCCT is needed regardless of the renewable resources required under the Oregon RPS. The company projects a sizable capacity deficit system-wide in 2012 caused in part by expiration of west-side wholesale purchase contracts. The company also points out the dispatch flexibility benefits of a natural gas-fired plant in integrating the renewable resources that are part of the preferred portfolio. *See* PacifiCorp's response to Staff Data Request No. 12.

Further, the company states that the incremental Oregon conservation it plans to add to its action plan (50 MWa) would reduce market purchases, rather than affect the size of the proposed natural gas-fired plant. *See* PacifiCorp's response to Staff Data Request No. 30. *Also see* the discussion under guideline 6.

Staff is not convinced that the company needs a 600 MW base load plant in the west given the projected system-wide energy surpluses that would result from implementation of the preferred portfolio. We also are not convinced that the company selected the appropriate amounts of market purchases, both short- and intermediate-term. Further, the company did not appropriately evaluate DSM resources that may economically reduce the size of any thermal resource needed, or sufficiently account for the on-peak capacity value of renewable resources other than wind.

Staff also is not convinced that a CCCT is a better choice than a peaking plant (simple-cycle combustion turbine), given transfer capability to the west and integration needs for renewable resources that will be required by law.

Staff is further analyzing whether it makes sense to place cheaper, peaking units in the east, where most of the load growth is projected, rather than install a large CCCT in the west. Under a cap-and-trade CO_2 adder of $8 per ton, substituting intercooled aeroderivative simple-cycle combustion turbines in the east, in lieu of the proposed western CCCT, added only $161 million, or 0.75%, to RA14's projected PVRR. The impact under a straight carbon tax strategy was even smaller. *See* PacifiCorp's response to Staff Data Request No. 54.

Staff recommends the following modification to action item 11 to address these issues:

> Procure ~~a 600 MW base load/intermediate~~ resources in the west (other than coal plants) by the summer of 2011-2012 <u>to address contract expirations and load growth and integrate renewable resources. Refine the size and type (base load vs. peaking) after updating DSM and renewable resource analyses, accounting for changes in resources, and refining load forecasts.</u>

Appendix A

OPUC Data Request 39

Please refer to PacifiCorp's response to Staff Data Request No. 26. Please explain whether any renewable energy resources other than wind — i.e., renewable energy resources with higher capacity factors — are included in the "Planned Resources" for the Preferred Portfolio Capacity Load and Resource Balance (page 204). For example, is the capacity value associated with potential additional development of Oregon biomass resources described in the Renewable Energy Action Plan filed May 30, 2007, accounted for in these "Planned Resources"?

Response to OPUC Data Request 39

The planned renewable resources identified in Table 7.46 (page 204) are represented by the wind proxies both East and West. These proxies have capacity factors consistent with wind resources.

However, the renewable line items in the category referred to as "existing resources" include some planned biomass projects as well as planned geothermal expansions; covering a portion of the alternatives to wind.

OPUC Data Request 31

The company states, "As demonstrated by comparing risk analysis portfolios with differing front office transactions assumptions, less reliance on front office transactions tends to reduce market price risk exposure, but can increase or decrease mean stochastic cost depending on the make-up of the portfolio…. [T]he company is concerned about long-term reliance on the market and exposure to market price risk, and therefore seeks to reduce that reliance as part of its overall resource management strategy. " (IRP at 205.) The company then cites sources of market price risk and uncertainty.

a. Please explain how an "extensive expansion" of renewable energy capacity in the Western Interconnection increases market price risk and uncertainty and how that position is consistent with the following statement by the company: "In MIDAS, renewable resources are low- to no-cost resources. The impact of adding renewable resources in MIDAS is to decrease average market prices." (PacifiCorp IRP public input meeting handout, May 10, 2006, page 34.)

b. Please provide the documents and analysis that are the basis for PacifiCorp's statement regarding potential tightening of regional capacity in the next decade "as more utilities rely on the market to meet their future needs."

Response to OPUC Data Request 31

a. Regarding the cited text on page 205 of the 2007 IRP, PacifiCorp does not imply that "extensive expansion" of renewable energy capacity itself increases market prices, but rather that such expansion is one element of a shifting resource mix that introduces planning uncertainty and market risk. As part of this shifting resource mix, the Company identified the expansion of gas-fired capacity and reduction in coal capacity development, which has implications for natural gas and electricity price levels and volatility. Additionally, a large expansion of renewable capacity increases the possibility of having to rely on market purchases given the intermittency of renewable resources such as wind, which could also impact market price risk and uncertainty due to the increased volatility in electricity prices.

b. This statement stems from PacifiCorp's view on future market activity given WECC resource assessments that point to a declining region-wide capacity margin, as well as utilities stepping up their acquisition of wind resources and natural gas-fired generating capacity (documented in several recent IRPs). Based on these resource acquisition trends, PacifiCorp expects that utilities will rely on increased market purchases for renewables integration, and as a resource bridging strategy until CO2 regulatory uncertainty is reduced and alternative generation technologies that meet state resource acquisition rules become commercially proven. For example, in their 2007 IRP, Portland

General Electric Company looks to medium-term power agreements as part of their bridging strategy, and states that "[p]ower purchase agreements for various amounts and durations could take place at any time, but will likely become more extensive after the expiration of existing resources, shortly after the end of this decade."

OPUC Data Request 46

Please explain how the IRP considered the potential value of intermediate-term power purchase agreements – e.g., contracts with a term longer than Front Office Transactions and up to 10 years.

Response to OPUC Data Request 46

The Company's approach to evaluating intermediate-term power purchase agreements was to use the base load Request for Proposal (RFP) for Eastern Control Area resources to determine their potential volume and cost. (The RFP included PPAs of a minimum of 5 years and 100 MW as an eligible resource.)

OPUC Data Request 11

Please provide an electronic spreadsheet with formula intact demonstrating whether renewable resources included in the Action Plan are sufficient to accommodate RPS requirements in Oregon, California and Washington through 2014. For the purpose of this analysis, assume a first banking date of January 1, 2008, for Oregon RPS-eligible Renewable Energy Certificates.

Response to OPUC Data Request 11

The response is provided as Attachment OPUC 11, which illustrates a scenario where the Company's existing renewable resources and the 1,600 megawatts included in the Action Plan are sufficient to meet the renewable portfolio standard requirements for Oregon, Washington, and California through 2014. The allocation is based upon the Revised Protocol System Energy allocation factor. The MSP Workgroup is analyzing the appropriate allocation factor.

In California, the Company may not be able to meet the renewable portfolio standard requirements however; the Company is awaiting the final rules from the California Public Utility Commission in California's renewable portfolio standard compliance proceeding for small, multi-jurisdictional utilities.

OREGON

PACIFICORP IRP

LC-42

PACIFICORP

OPUC DATA REQUEST 5-33

ATTACHMENT OPUC 11

	Projected Retail Sales				RPS % Targets			Req'd Renewable MWhs			Cumulative Annual Requirement	Estimated Capability (MW)
	CA	WA	OR	Total	CA	WA	OR	CA	WA	OR		
2007	862,536	4,159,881	13,571,089	51,980,340	17.00%	0.00%	0.00%	146,631			146,631	56
2008	871,805	4,178,558	13,597,725	53,599,783	18.00%	0.00%	0.00%	156,925			156,925	60
2009	881,415	4,207,435	13,633,728	55,300,432	19.00%	0.00%	0.00%	167,469			167,469	64
2010	889,652	4,401,046	13,764,301	57,239,924	20.00%	0.00%	0.00%	177,930			177,930	68
2011	898,093	4,473,671	13,845,614	58,774,217	20.00%	0.00%	5.00%	179,619		692,281	871,899	332
2012	906,772	4,513,397	13,942,493	60,031,769	20.00%	3.00%	5.00%	181,354	135,402	697,125	1,013,881	386
2013	915,690	4,554,343	14,049,711	61,203,595	20.00%	3.00%	5.00%	183,138	136,630	702,486	1,022,254	389
2014	924,789	4,594,798	14,157,025	62,312,823	20.00%	3.00%	5.00%	184,958	137,844	707,851	1,030,653	392

California and PacifiCorp Total System Retail MWH Sales Projections[1]

Year	Projected California Retail MWH Sales	Assumed California RPS % Targets	California Required Renewable MWH	Projected Total System Retail MWH Sales	Projected California Energy Consumption Allocation Share[2]
2007	**862,536**	**17.00%**	**146,631**	**51,980,340**	**1.6850%**
2008	871,805	18.00%	156,925	53,599,783	1.6524%
2009	881,415	19.00%	167,469	55,300,432	1.6217%
2010	889,652	20.00%	177,930	57,239,924	1.5819%
2011	**898,093**	**20.00%**	**179,619**	**58,774,217**	**1.5547%**
2012	906,772	20.00%	181,354	60,031,769	1.5367%
2013	915,690	20.00%	183,138	61,203,595	1.5222%
2014	924,789	20.00%	184,958	62,312,823	1.5099%

Eligible Renewable Resources to Meet California RPS Requirements

California Total Eligible[3] Renewable Resources (MWh)	California Allocated Share of Renewable Resources	California Surplus / (Deficit)
3,285,888	**55,369**	**(91,263)**
4,579,740	75,674	(81,251)
4,877,580	79,098	(88,371)
5,876,220	92,954	(84,976)
6,577,020	**102,256**	**(77,363)**
6,874,860	105,648	(75,706)
7,926,060	120,649	(62,489)
7,926,060	119,678	(65,280)

(1) 2007 IRP Load Forecast
(2) System Energy (SE) Factor
(3) Includes Existing Renewable Resources and Additions per Action Plan

Oregon and PacifiCorp Total System Retail MWH Sales Projections[1]

Eligible Renewable Resources to Meet Oregon RPS Requirements

Year	Projected Oregon Retail MWH Sales	Assumed Oregon RPS % Targets	Oregon Required Renewable MWH	Projected Total System Retail MWH Sales	Projected Oregon Energy Consumption Allocation Share[2]	Oregon Total Eligible[3] Renewable Resources (MWh)	Oregon Allocated Share of Renewable Resources	Oregon Surplus / (Deficit)
2007	**13,571,089**	**0.00%**	**-**	**51,980,340**	**26.1964%**	**2,128,754**	**557,656**	**557,656**
2008	13,597,725	0.00%	-	53,599,783	25.4624%	3,422,606	871,479	871,479
2009	13,633,728	0.00%	-	55,300,432	24.7523%	3,720,446	920,898	920,898
2010	13,764,301	0.00%	-	57,239,924	24.1066%	4,719,086	1,137,612	1,137,612
2011	**13,845,614**	**5.00%**	**692,281**	**58,774,217**	**23.6510%**	**5,419,886**	**1,281,856**	**589,575**
2012	13,942,493	5.00%	697,125	60,031,769	23.3314%	5,717,726	1,334,025	636,900
2013	14,049,711	5.00%	702,486	61,203,595	23.0614%	6,768,926	1,561,010	858,525
2014	14,157,025	5.00%	707,851	62,312,823	22.8250%	6,768,926	1,545,008	837,157

(1) 2007 IRP Load Forecast
(2) System Energy (SE) Factor
(3) Includes Existing Renewable Resources and Additions per Action Plan

Washington and PacifiCorp Total System Retail MWH Sales Projections[1]

Eligible Renewable Resources to Meet Washington RPS Requirements

Year	Projected Washington Retail MWH Sales	Assumed Washington RPS % Targets	Washington Required Renewable MWH	Projected Total System Retail MWH Sales	Projected Washington Energy Consumption Allocation Share[2]	Washington Total Eligible[3] Renewable Resources (MWh)	Washington Allocated Share of Renewable Resources	Washington Surplus / (Deficit)
2007	**4,159,881**	**0.00%**	**-**	**51,980,340**	**8.0958%**	**1,832,750**	**148,375**	**148,375**
2008	4,178,558	0.00%	-	53,599,783	7.8888%	2,113,070	166,696	166,696
2009	4,207,435	0.00%	-	55,300,432	7.7014%	2,410,910	185,674	185,674
2010	4,401,046	0.00%	-	57,239,924	7.7857%	2,708,750	210,896	210,896
2011	**4,473,671**	**0.00%**	**-**	**58,774,217**	**7.7053%**	**2,708,750**	**208,719**	**208,719**
2012	4,513,397	3.00%	135,402	60,031,769	7.6102%	3,006,590	228,807	93,405
2013	4,554,343	3.00%	136,630	61,203,595	7.5324%	3,006,590	226,469	89,838
2014	4,594,798	3.00%	137,844	62,312,823	7.4640%	3,006,590	224,411	86,568

(1) 2007 IRP Load Forecast
(2) System Energy (SE) Factor
(3) Includes Existing Renewable Resources and Additions per Action Plan

OPUC Data Request 27

Please describe the potential impact of a 15% federal RPS on the company's preferred portfolio, and how the company considered the adaptability of the preferred portfolio in this regard. Include in the response the company's assumptions on whether Renewable Energy Certificates acquired through the Action Plan could count toward compliance for both a state and federal RPS.

Response to OPUC Data Request 27

PacifiCorp considered a 15% federal RPS in the context of its alternative future scenario analysis; specifically, CAF8, "Favorable Wind Environment", and SAS16, "Favorable wind environment combined with expiration of the renewable production tax credit." The results of these capacity expansion optimization studies are presented on pages 150-151 of the 2007 IRP report. Looking at the 10-year investment horizon (2007-2016), the 2,000 MW of renewable resources is in line with the cumulative renewables capacity additions by 2016 for the federal RPS/no production tax credit scenario, which assumes a system-wide 15% RPS requirement by 2020. PacifiCorp will enhance its future portfolio evaluation appropriately as RPS formulation at the state and federal levels advance.

PacifiCorp also has performed some preliminary analysis on the renewables capacity necessary to generate enough megawatt-hours to satisfy two proposed federal RPS targets, one of which has passed a floor vote. The megawatt-hour targets, expressed as a percent of retail load, for each proposal are shown in the table below for 2010 through 2016.

	Rep. Udall RPS % Targets (H.R. 3221, Subtitle G)*	Sen. Bingaman proposed RPS % Targets
2005	0.00%	0.00%
2006	0.00%	0.00%
2007	0.00%	0.00%
2008	0.00%	0.00%
2009	0.00%	0.00%
2010	2.75%	3.75%
2011	2.75%	3.75%
2012	3.75%	3.75%
2013	4.50%	7.50%
2014	5.50%	7.50%
2015	6.50%	7.50%
2016	7.50%	7.50%

* Passed by the House of Representatives on August 4, 2007; vote was 241-172.

In setting up the assumptions for its analysis, PacifiCorp assumed that the more stringent state RPS targets are not pre-empted by federal RPS targets. However, during years when a proposed federal RPS target was more stringent than a state RPS target, the federal RPS target was assumed (i.e., under either federal RPS proposal, this approach affected the Oregon and Washington 2010 targets, and under the Bingaman proposal, it also affected the Washington 2011 target).

The results, assuming utility-scale wind projects with a 30% capacity factor, are as follows:

	Rep. Udall (H.R. 3221, Subtitle G) scenario	Sen. Bingaman scenario
2005		
2006	29	29
2007	56	56
2008	60	60
2009	64	64
2010	657	872
2011	797	960
2012	966	979
2013	1,314	1,790
2014	1,498	1,822
2015	2,097	2,263
2016	2,333	2,333

Both the IRP analysis and this preliminary analysis demonstrate that the preferred portfolio is well-positioned to meet general RPS requirements for this timeframe.

In both analyses, Renewable Energy Certificates acquired through the Action Plan derived from projects that satisfy both a state and federal RPS eligibility criteria would count toward compliance for both the state and federal RPS. Note, both the Bingaman and Udall federal RPS proposals contained provisions which would reconcile compliance with the federal targets with compliance with state RPS targets (i.e., no compounding of targets).

OPUC Data Request 6

Please explain how the 2007 Integrated Resource Plan (IRP) addresses risk and uncertainty related to forecasted Wyoming loads, given the strong influence of the boom-and-bust oil and gas industry on the projected high rate of load growth during the study period.

Response to OPUC Data Request 6

The Company addressed this by assigning the customer requested loads to categories of probability based on the Company's belief of the load materializing. These categories are High, Medium, and Low. The customer load is then discounted based on the assignment to the category. Those in the high category are discounted by 0.95, those in the medium by 0.7, and those in the low by 0.25. Further, in assigning the start date of the load, the date is slipped from the customer requested date accounting for frequently experienced complications in starting operations. These adjusted loads are then used in further modeling activities that include the stochastic process to further model uncertainty in the forecasting process.

OPUC Data Request 7

Please describe how the company considered adaptability in choosing its preferred portfolio, given the issues raised in Staff Data Request No. 6.

Response to OPUC Data Request 7

As demonstrated by the range of Group 2 risk analysis portfolios (RA14 through RA17), portfolio adaptability for meeting Wyoming load growth is realized through a combination of shorter acquisition-lead-time resources: gas turbines, front office transactions, and renewables. PacifiCorp can adopt any of these variations of the preferred portfolio as needed to address changing conditions. In the event that a CCCT is acquired and loads fail to materialize as expected, other resources can be displaced or delayed to offset the lower loads.

OPUC Data Request 8

Please explain whether there are potential opportunities for power purchase agreements with combined heat and power facilities associated with electrification of the oil and gas fields in Wyoming. Include in your response an analysis of the potential amounts (MW and MWa) by year and documentation for estimating those amounts. Explain whether the company believes any such opportunities could mitigate the risk and uncertainty addressed in Staff Data Request No. 6. Describe what actions the company plans to take to pursue such opportunities, if they exist.

Response to OPUC Data Request 8

PacifiCorp conducted an assessment of combined heat and power (CHP) potential in 2006-07. Results are published in the report "Assessment of Long-term System-wide Potential for Demand-side and Other Supplemental Resources" dated July 11, 2007. The report outlines the potential for CHP across PacifiCorp's system and suggests 150 average megawatts of CHP generation could be acquired by 2027. Those opportunities are being pursued with specific market segments and customers through power purchase agreements. The potential for CHP, regardless of the technology, is based on the need for useful thermal output from the CHP plant. The electrification in the oil and gas field exploration and development in Wyoming has very limited opportunity for using the thermal output from the CHP. Therefore, the Company sees marginal potential for CHP in this specific market segment.

OPUC Data Request 9

Please explain whether there are potential new opportunities for interruptible contracts with industrial customers associated with projected load growth in Wyoming and other states served. Include in your response how the company considered such opportunities in developing its preferred portfolio. Include in your response an analysis of the potential amounts (MW and MWa) by year and documentation for estimating those amounts. Describe what actions the company plans to take to pursue such opportunities, if they exist.

Response to OPUC Data Request 9

The interruptible contract resources reflected in the 2007 IRP load and resource balance represents the Company's assessment of the potential for such contracts. The ability to increase the number or the amount of interruptible contracts is dependent on the types of industrial customer load on PacifiCorp's system and the willingness of industrial customers to curtail load in such a manner as to bring measurable value to PacifiCorp's system. The majority of the projected load growth in Wyoming is in the oil and gas field exploration and development. The load is primarily pumping and compression. Historically, PacifiCorp has worked with the oil and gas industry on interruptible options for the pumping and compression load; however, due to the nature of the load and requirement to keep product moving in the pipelines, the ability to interrupt is physically limited to system reliability and emergency conditions only. Therefore, the Company does not see high potential for interruptibility in this specific market segment.

OPUC Data Request 69

Please provide in tabular format a schedule of "growth stations" by year for each portfolio studied in the 2007 IRP, specifying sizes (in MW).

Response to OPUC Data Request 69

Please refer to Attachment OPUC 69. Growth station megawatt capacity by year is listed for the Capacity Expansion Module alternative future scenarios (CAF00 through CAF15) as well as all the risk analysis portfolios simulated using the Planning and Risk production cost model (RA1 through RA17, and the greenhouse gas emission performance standard portfolio documented on page 215 of the 2007 IRP report).

OREGON

PACIFICORP IRP

LC-42

PACIFICORP

OPUC DATA REQUEST 68-71

ATTACHMENT OPUC 69

OPUC 69
Table of Growth Stations by year for each portfolio studied in the 2007 IRP

MW		2019	2020	2021	2022	2023	2024	2025	2026
CAF01	West Growth Station - CCCT F 2x1		602		602			602	602
CAF01	East Growth Station - CCCT F 2x1					548			
CAF02	West Growth Station - CCCT F 2x1								602
CAF02	East Growth Station - CCCT F 2x1								
CAF03	West Growth Station - CCCT F 2x1	602	1,204		602	1,204			
CAF03	East Growth Station - CCCT F 2x1	548		548	548			1,096	548
CAF04	West Growth Station - CCCT F 2x1					602		602	
CAF04	East Growth Station - CCCT F 2x1	1,644	548		548				1,096
CAF05	West Growth Station - CCCT F 2x1								
CAF05	East Growth Station - CCCT F 2x1	1,644						548	
CAF06	West Growth Station - CCCT F 2x1	602			1,204	1,204		602	602
CAF06	East Growth Station - CCCT F 2x1	1,644	1,096				1,096	548	
CAF07	West Growth Station - CCCT F 2x1		602		602	602			
CAF07	East Growth Station - CCCT F 2x1	548						548	548
CAF08	West Growth Station - CCCT F 2x1	602	602					602	
CAF08	East Growth Station - CCCT F 2x1	1,096			548	548		548	548
CAF09	West Growth Station - CCCT F 2x1		602		602	602			
CAF09	East Growth Station - CCCT F 2x1	548						548	548
CAF10	West Growth Station - CCCT F 2x1	1,204						602	
CAF10	East Growth Station - CCCT F 2x1	548	548		548	548		548	548
CAF11	West Growth Station - CCCT F 2x1		602		602				602
CAF11	East Growth Station - CCCT F 2x1	548				548		548	
CAF12	West Growth Station - CCCT F 2x1		602						
CAF12	East Growth Station - CCCT F 2x1							548	
CAF13	West Growth Station - CCCT F 2x1	602	602		1,204			1,204	
CAF13	East Growth Station - CCCT F 2x1	548	548	548		548	548	548	1,096
CAF14	West Growth Station - CCCT F 2x1	602							
CAF14	East Growth Station - CCCT F 2x1	548	548					548	
CAF15	West Growth Station - CCCT F 2x1					602		1,204	602
CAF15	East Growth Station - CCCT F 2x1	548					548		548

OPUC 69

Table of Growth Stations by year for each portfolio studied in the 2007 IRP

MW		2019	2020	2021	2022	2023	2024	2025	2026
RA1	West Growth Station - CCCT F 2x1	602	602						
RA1	East Growth Station - CCCT F 2x1	548			548	548		548	548
RA2	West Growth Station - CCCT F 2x1				602				
RA2	East Growth Station - CCCT F 2x1					548		1,096	
RA3	West Growth Station - CCCT F 2x1		602		602				
RA3	East Growth Station - CCCT F 2x1	548				548		548	548
RA4	West Growth Station - CCCT F 2x1				602				
RA4	East Growth Station - CCCT F 2x1					548		548	548
RA5	West Growth Station - CCCT F 2x1								602
RA5	East Growth Station - CCCT F 2x1					548		548	
RA6	West Growth Station - CCCT F 2x1		602		602	602			
RA6	East Growth Station - CCCT F 2x1	548						548	548
RA7	West Growth Station - CCCT F 2x1				602				
RA7	East Growth Station - CCCT F 2x1					548		1,096	
RA8	West Growth Station - CCCT F 2x1	602			602				
RA8	East Growth Station - CCCT F 2x1	548				548		548	548
RA9	West Growth Station - CCCT F 2x1	602			602				602
RA9	East Growth Station - CCCT F 2x1	548				548		548	
RA10	West Growth Station - CCCT F 2x1	602			602				
RA10	East Growth Station - CCCT F 2x1	548				548		1,096	
RA11	West Growth Station - CCCT F 2x1		602		602				602
RA11	East Growth Station - CCCT F 2x1					548		548	
RA12	West Growth Station - CCCT F 2x1		602		602				602
RA12	East Growth Station - CCCT F 2x1					548		548	

OPUC 69

Table of Growth Stations by year for each portfolio studied in the 2007 IRP

MW		2019	2020	2021	2022	2023	2024	2025	2026
RA13	West Growth Station - CCCT F 2x1	1,806							602
RA13	East Growth Station - CCCT F 2x1	1,096			548		548		
RA14	West Growth Station - CCCT F 2x1	602	602						
RA14	East Growth Station - CCCT F 2x1	1,644				548		548	548
RA15	West Growth Station - CCCT F 2x1	1,204							
RA15	East Growth Station - CCCT F 2x1	1,644			548		548	548	
RA16	West Growth Station - CCCT F 2x1	1,204						602	
RA16	East Growth Station - CCCT F 2x1	1,096	548			548			548
RA17	West Growth Station - CCCT F 2x1	1,204							
RA17	East Growth Station - CCCT F 2x1	2,192			548		548	548	
GHG	West Growth Station - CCCT F 2x1	602				602		602	
GHG	East Growth Station - CCCT F 2x1	1,096			548				548

(from Table 7.5)

07-2035-01 /Rocky Mountain Power
May 10, 2007
DPU 1st Set Data Request 1.22

DPU Data Request 1.22

The following Questions relate to the Feb Update (February 5, 2007):

a On P.7, Why are all portfolios less expensive with a $61 adder than with a $38 adder? Also on this page, why is the portfolio RA7 at its lowest stochastic mean cost when there is a $61 carbon adder?

b On P. 16, why does RA3 (RA1 with an extra 600 MW wind) produce more carbon emissions than RA1? Similar question re RA11 (which is highest at the end of the time series).

c On page 7 of the October 31, 2006, Presentation, the Company indicates 336 MW of added DSM, 308 MW of added Load Control, 1,000 MW of added renewable resources, 399 MW of added DG (distributed generation), and 1,086 of front office transactions in Candidate Portfolio 1. Please provide a table of the annual additions of these resources (by type of renewable energy resource) for each RA portfolio. Please identify the source document or analysis that is the basis for each one of these assumed resource amounts.

Response to DPU Data Request 1.22

a These stochastic cost results reflect a CO_2 cap-and-trade strategy. The cost behavior at the $61 CO_2 adder case is driven by the accrual of sizable annual CO_2 allowance credits resulting from a large shift from coal to market purchases and gas-fired generation. Additionally, in the out-years of the study period, only CCCT growth stations are added to the resource mix, which enables accrual of allowance credits given the assumed year-2000 baseline emission quantity. RA7 is at its lowest stochastic mean cost when there is a $61 carbon adder because it has a combination of additional wind resources and gas-fired resources that yields the largest allowance credit accruals.

b From a cumulative emissions standpoint, RA3 does not produce more CO_2 emissions than RA1. See Chapter 7, pages 171-173, of the 2007 IRP document draft. The increase relative to RA1 in later years (particularly 2018) is driven by the mix of other resources added to meet the load obligation, including the impact of deferring pulverized coal by a few years.

c The 2007 IRP document draft describes how these values were derived from load and resource balance assumptions and CEM modeling results.

- DSM – The preferred portfolio resource investment schedule (for example, on page 8) lists the Class 1 DSM resource additions by year. Derivation of these amounts is described on pages 154-6 of Chapter 7. Table A.8 in Appendix A lists the annual Class 2 DSM amounts decremented from PacifiCorp's load forecast.

- Load Control – Load control refers to curtailment contracts, and reflects extension of all non-spin operating reserve contracts that expire during the IRP study period. All risk analysis portfolios have the same annual amounts, which are documented in the initial load and resource balance (see Table 4.10 of Chapter 4).
- Renewables – Annual renewable quantities included in the risk analysis portfolios are documented on pages 154, 179, and 182-4 of Chapter 7. Wind was chosen as the proxy resource to represent all renewables.
- Distributed Generation – All risk analysis portfolios have the same annual amounts, which consist of existing Qualifying Facility contracts and Combined Heat and Power as determined by CEM portfolio results. The annual capacities for existing Qualifying Facility contracts are documented in the initial load and resource balance (see Table 4.10 of Chapter 4). The CHP amounts, which total 100 MW, are documented on pages 156-7 of Chapter 7.
- Front Office Transactions – The table below reports the annual FOT amounts for risk analysis portfolios RA1 through RA12. Annual front office transactions for risk analysis portfolios RA13 through RA17 are documented on pages 182-4 of Chapter 7.

	Capacity (MW)								
Portfolio	2008	2009	2010	2011	2012	2013	2014	2015	2016
RA01	345	273	708	964	1,200	901	1,138	989	1,086
RA02	345	273	708	964					
RA03	345	273	708	954	921	993	1,200	965	947
RA04	112	39	476	730					
RA05	345	273	708	964					
RA06	345	273	708	964	1,069	863	1,099	1,198	891
RA07	345	273	708	954					
RA08	112	39	476	730	1,001	1,081	901	1,001	1,018
RA09	112	39	476	730	1,200	935	1,171	1,200	1,069
RA10	345	273	708	964	1,200	901	1,137	1,200	1,048
RA11	345	273	708	954	1,200	1,200	1,160	541	811
RA12	112	39	476	719	967	1,036	898	998	530

OPUC Data Request 65

Please replicate the RA14 expected PVRR, 95th percentile, and upper-tail mean PVRR figures, employing the \$8, \$38, and \$61 CO_2 adders, but assume an economic life of 25 years for new supercritical pulverized coal plants.

Response to OPUC Data Request 65

The RA14 preferred portfolio was updated to reflect the economic life of 25 years for new supercritical pulverized coal plants. These plants are the Utah Pulverized Coal plant added in 2012 and Wyoming pulverized coal added in 2014. The costs were estimated using a CO_2 cap-and-trade regulatory scenario.

		PVRR (Million $)		
RA14	Economic Life Assumption	Stochastic Mean	95th Percentile	Upper-Tail Mean
$8 CO2 - Cap & Trade	25 Year Coal	21,765	37,272	69,288
$38 CO2 - Cap & Trade	25 Year Coal	21,727	41,633	77,985
$61 CO2 - Cap & Trade	25 Year Coal	21,189	45,081	85,803
$8 CO2 - Cap & Trade	40 Year Coal	21,559	37,066	69,082
$38 CO2 - Cap & Trade	40 Year Coal	21,521	41,426	77,779
$61 CO2 - Cap & Trade	40 Year Coal	20,983	44,875	85,596

OPUC Data Request 66

Please replicate the RA12 expected PVRR, 95th percentile, and upper-tail mean PVRR figures, employing the $8, $38, and $61 CO_2 adders, but use the same forecasted loads, fuel prices and other modeling inputs used for RA14, and assume an economic life of 25 years for new supercritical pulverized coal plants.

Response to OPUC Data Request 66

	Stochastic PVRR, Million$			
RA12 with RA14 Assumptions and 25-year economic life	**Stochastic Average**	**5th Percentile**	**95th Percentile**	**Upper Tail (mean of 5 Highest)**
$8 Ton CO2 - Cap & Trade	22,820	13,590	39,326	64,514
$38 Ton CO2 Cap & Trade	23,602	11,454	44,610	73,426
$61 Ton CO2 - Cap & Trade	23,669	7,633	48,657	81,101

The following table shows the stochastic PVRR values for the original RA12 portfolio for comparison purposes.

	Stochastic PVRR, Million$			
Original RA12	**Stochastic Average**	**5th Percentile**	**95th Percentile**	**Upper Tail (mean of 5 Highest)**
$8 Ton CO2 - Cap & Trade	21,754	13,001	37,029	60,391
$38 Ton CO2 - Cap & Trade	22,143	10,586	41,935	68,561
$61 Ton CO2 - Cap & Trade	21,881	6,559	45,628	75,597

OPUC Data Request 67

Please replicate the RA12 expected PVRR, 95th percentile, and upper-tail mean PVRR figures, employing the \$8, \$38, and \$61 CO_2 adders, but with the following departures from the published IRP studies:

a. Place a constraint on the CEM that prohibits all new coal plants on or after 2018, and appropriately introduces in their places nuclear facilities with 40-year economic lives (*see* pages 93 and 103).
b. Substitute alternatives to the coal plants that the original RA12 proposes for 2014 and 2016 if a superior least cost/risk outcome would be achieved thereby.
c. Use the same forecasted loads, fuel prices and other modeling inputs used for RA 14, but assume an economic life of 25 years for new supercritical pulverized coal plants.

Response to OPUC Data Request 67

	Stochastic PVRR, Million$			
RA12 Modified	**Stochastic Average**	**5th Percentile**	**95th Percentile**	**Upper Tail (mean of 5 Highest)**
$8 Ton CO2 - Cap & Trade	22,328	13,196	38,682	64,223
$38 Ton CO2 - Cap & Trade	21,550	9,548	42,342	71,399
$61 Ton CO2 - Cap & Trade	20,004	4,277	44,737	77,342

The following table shows the stochastic PVRR values for the original RA12 portfolio for comparison purposes.

	Stochastic PVRR, Million$			
RA12 Original	**Stochastic Average**	**5th Percentile**	**95th Percentile**	**Upper Tail (mean of 5 Highest)**
$8 Ton CO2 - Cap & Trade	21,754	13,001	37,029	60,391
$38 Ton CO2 Cap & Trade	22,143	10,586	41,935	68,561
$61 Ton CO2 - Cap & Trade	21,881	6,559	45,628	75,597

The portfolio solution resulting from the execution of the Capacity Expansion Module is shown in the following table. (Resources are only reported through 2020.)

		Nameplate Capacity, MW													
	Resource	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
East	WY coal	-	-	-	-	-	-	-	-	-	750	-	-	-	-
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	1,000	-	1,000
	CCCT F 2x1	-	-	-	-	-	548	-	-	-	-	-	-	548	-
	SCCT Frame	-	-	-	-	-	302	-	-	-	-	-	-	-	-
	CHP	-	-	-	-	-	25	-	-	-	-	-	-	-	-
	DSM	-	-	-	-	-	15	48	-	-	-	-	-	-	-
	Wind East	-	100	100	100	-	600	400	-	-	-	-	-	-	-
	FOT F. Corners	-	-	-	458	489	500	500	500	500	500	500	500	-	-
	FOT Mona	-	-	-	-	-	99	125	152	195	30	200	-	-	-
West	IGCC 200	-	-	-	-	-	-	-	200	-	-	-	-	-	-
	CCCT F 2x1	-	-	-	-	-	-	-	-	-	-	-	-	548	-
	CHP	-	-	-	-	-	75	-	-	-	-	-	-	-	-
	DSM	-	-	-	-	-	32	-	-	-	-	-	-	-	-
	Wind NC OR	-	100	100	-	-	-	-	-	-	-	-	-	-	-
	Wind SE WA	-	-	-	-	100	-	-	-	-	-	-	-	-	-
	FOT Mid-C	-	-	-	-	-	250	250	250	250	250	250	89	-	-
	FOT West Main	-	-	-	148	327	250	250	250	250	176	197	-	-	-

LC-42/PacifiCorp
October 11, 2007
OPUC Data Request 44

OPUC Data Request 44

Please explain how the IRP took into account the capital cost risk of coal plants vs. other generating plants and demand-side options.

Response to OPUC Data Request 44

The capital cost values for Utah and Wyoming supercritical coal resource options were developed using the EPRI Tag software as adjusted by PacifiCorp based on coal project estimates available to PacifiCorp in the spring of 2006. Project estimates used by PacifiCorp included costs for Hunter unit 4 and IPP3 as well as engineering estimates for Jim Bridger unit 5. The same adjustments were made to all capital cost estimates to derive the Low and High estimates. Sources and the derivation of low and high capital cost adjustments are described on page 91 of the 2007 IRP report. The 5-percent (low-end) and 10-percent (high-end) capital cost adjustments were developed internally. The U.S. Energy Information Administration technology contingency factors applied in the calculations are shown in the table below.

Technology	Project Contingency	Technology Optimism	Combined
Conventional Coal	1.070	1.000	1.070
CCCT/CT	1.050	1.000	1.050
IGCC	1.070	1.030	1.102
Wind	1.070	1.000	1.070
Solar Thermal	1.070	1.100	1.177
Advanced Nuclear	1.100	1.050	1.155
Fuel Cell	1.050	1.100	1.155
Geothermal	1.050	1.000	1.050

These factors were used to capture contingency cost differences between technologies. For example, the high capital cost for coal plants included an upward adjustment of one percent while the CCCT/CT plants included a downward adjustment of one percent. This percentage represents one-half of the difference between the conventional coal and CCCT/CT combined contingency percentages in the table above, or (0.07-0.05)/2. Demand Side Management programs do not have capital costs, just fixed and variable expenses expressed as $/kW-year values.

PacifiCorp used the high-end capital cost values to conduct a portfolio construction cost risk assessment, which is described on page 189 of the 2007 IRP report.

OPUC Data Request 4

Please explain how the company plans to address in <u>this</u> IRP cycle the requirement in Order No. 07-002 "…to include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets," given that there is no analysis in the 2007 IRP that addresses conservation resources in Oregon above that funded by the Energy Trust of Oregon. For example, how will the Commission be able to determine whether incremental conservation measures could change the timing or size of the West-side combined-cycle combustion turbine proposed for 2011?[1]

Response to OPUC Data Request 4

PacifiCorp worked with Energy Trust of Oregon (ETO) staff to obtain annual forecasts of Oregon energy efficiency program megawatt-hour savings beyond what is currently funded through the ETO. These incremental savings forecasts were then evaluated from a capacity position standpoint to determine how they would impact PacifiCorp's resource selection decisions as reflected in the 2007 IRP preferred portfolio and action plan.[2] Specifically, the company revised its preferred portfolio capacity balance by removing the 2011 combined cycle combustion turbine (CCCT) in conjunction with adding annual peak load contributions attributable to the incremental ETO energy savings.

Table 1 provides the annual incremental energy savings forecasts from the ETO by end-use sector for 2008 through 2016, grossed up to generator-level reporting by adjusting for line losses. The total cumulative savings for this period is 56.6 average megawatts, corresponding to an average annual increase of 6.3 average megawatts. The ETO used the same economic screen, based on avoided costs, that was used to forecast their base savings covered by public purpose funding. The average measure life for the residential sector is assumed to be 14.4 years, while the lives for the commercial and industrial sectors are assumed to be 16 and 10.6 years, respectively.

Table 1 – ETO Annual Incremental Energy Savings Forecasts by End-Use Sector

End-Use Sector	Average Megawatts*									
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**Cumulative Totals**
Residential	0.21	0.35	0.42	0.42	0.42	0.42	0.42	0.42	0.42	3.53
Commercial	2.20	3.67	4.40	4.40	4.40	4.40	4.40	4.40	4.40	36.66
Industrial	0.98	1.64	1.96	1.96	1.96	1.96	1.96	1.96	1.96	16.37
TOTAL	3.39	5.66	6.79	6.79	6.79	6.79	6.79	6.79	6.79	56.56

* Adjusted to reflect average megawatts at the generator, accounting for line losses as reported in PacifiCorp's 2004 Line Loss Study.

To determine the capacity position impact of replacing the west-side CCCT resource with the ETO energy savings, PacifiCorp started with the preferred portfolio capacity balance as reported

---

[1] Oregon Public Utility Commission staff data request 4, Docket LC 42, August 2, 2007.

[2] Note that while PacifiCorp's response to OPUC staff's data request indicated that optimization modeling would be performed, the magnitude of the ETO energy savings was subsequently found to be too small to necessitate a capacity expansion optimization study.

in Chapter 7 of the 2007 IRP report (see page 204). This capacity balance is presented as Table 2, with just the values for the west control area and system shown.

Table 2 – 2007 IRP Preferred Portfolio Capacity Balance (West and System)

Table 3 displays the 2007 IRP preferred portfolio load and resource balance, accounting for removal of the west CCCT in 2011 and the addition of the ETO incremental peak load contributions starting in that year. As can be seen, the replacement of the CCCT capacity with the DSM peak load contributions creates a sizable resource deficit assuming a 12 percent target planning reserve margin. This deficit ranges from 455 megawatts to 514 megawatts for the system, corresponding to an effective planning reserve margin of seven to eight percent for the 10-year period.

Table 3 – 2007 IRP Preferred Portfolio Capacity Balance, with Incremental ETO Class 2 DSM and no West CCCT

Planning Reserve Margin = 12%										
Calendar Year	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
West										
Thermal	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046
Hydro	1,421	1,421	1,414	1,328	1,357	1,225	1,249	1,243	1,244	1,242
DSM	0	0	0	0	0	0	0	0	0	0
Renewable	108	108	108	108	108	84	84	84	84	84
Purchase	786	800	800	799	749	112	141	107	107	107
QF	40	40	40	40	40	40	38	38	38	38
Transfers	(542)	(804)	(741)	(907)	(1,170)	(964)	(1,120)	(606)	(708)	(786)
West Existing Resources	3,859	3,611	3,667	3,414	3,130	2,542	2,438	2,913	2,811	2,732
Wind	14	14	51	79	79	98	98	98	98	98
DSM (Class 1)	0	0	0	0	0	32	32	32	32	32
Incremental ETO Class 2 DSM	0	0	0	0	29	37	45	53	61	75
CHP	0	0	0	0	0	75	75	75	75	75
Front Office Transactions	0	0	0	219	64	555	657	247	246	249
Thermal	0	0	0	0	0	0	0	0	0	0
West Planned Resources	14	14	51	298	172	797	907	505	512	529
West Total Resources	3,873	3,625	3,718	3,712	3,302	3,339	3,345	3,418	3,324	3,261
Load	2,922	2,924	3,095	3,124	3,199	3,240	3,251	3,262	3,271	3,252
Sale	299	299	299	290	290	258	258	258	158	108
West Obligation	3,221	3,223	3,394	3,414	3,489	3,498	3,509	3,520	3,429	3,360
Planning reserves (12%)	292	291	311	287	321	336	322	376	365	357
Non-owned reserves	7	7	7	7	7	7	7	7	7	7
West Reserves	299	297	318	294	328	342	328	383	372	363
West Obligation + Reserves	3,513	3,514	3,705	3,701	3,810	3,834	3,831	3,896	3,794	3,716
West Position	360	111	12	11	(508)	(495)	(486)	(478)	(470)	(455)
West Reserve Margin	23%	15%	12%	12%	-3%	-2%	-2%	-2%	-2%	-2%
System										
Total Resources	12,137	11,811	12,013	12,353	12,088	12,472	12,649	12,881	12,930	13,252
Obligation	10,391	10,549	10,753	11,217	11,409	11,688	11,842	12,010	12,050	12,321
Reserves	1,075	1,118	1,122	1,131	1,194	1,285	1,293	1,349	1,348	1,386
Obligation + Reserves	11,466	11,667	11,874	12,348	12,603	12,973	13,135	13,359	13,398	13,707
System Position	671	144	138	5	(514)	(501)	(486)	(478)	(469)	(455)
Reserve Margin	18%	13%	13%	12%	7%	8%	8%	8%	8%	8%

The quantity and timing of the ETO's forecasted incremental energy savings was found to not be sufficient to defer the west CCCT resource on the basis of the capacity balance impact. From a resource planning perspective, the impact of the incremental ETO savings amounts would be to offset the acquisition of front office transactions and thereby slightly reduce portfolio risk as measured by PacifiCorp's stochastic risk metrics (e.g., upper-tail mean and risk exposure).

To address the incremental Class 2 DSM in the 2007 IRP, PacifiCorp would propose to amend Action Item 2 in the action plan (page 224 of the 2007 IRP report) to include acquisition of cost-effective energy efficiency programs beyond the base amount funded by the ETO. The proposed amended action item language is identified below.

> Use decrement values to assess cost-effectiveness of new program proposals. Acquire the base DSM (PacifiCorp and ETO combined, **including energy savings in Oregon beyond that funded by the ETO**) of ~~250~~**300** MWa and up to an additional 200 MWa if cost-effective initiatives can be identified. **Will work with the ETO to identify such new energy efficiency initiatives and file the necessary tariffs with the Oregon Public Utility Commission.** Will reassess Class 2 objectives upon completion of system-wide DSM potential study to be completed by June 2007. Will incorporate potentials study findings into the 2007 update and 2008 integrated resource planning processes.

OPUC Data Request 58

Please refer to PacifiCorp's supplemental response to Staff Data Request No. 4. Please provide all analysis documenting how the company determined that reducing short-term purchases is the best strategy in response to a 50 average megawatt increase in conservation in Oregon, considering other options such as reducing the size of the planned natural gas-fired facility in the west, increasing demand response, increasing the level of renewable resources, or a combination of these and other strategies.

Response to OPUC Data Request 58

A comparison of the stochastic simulation results for the preferred portfolio (RA14) and risk analysis portfolio (RA15), for which a combined cycle gas turbine is replaced with front office transactions in 2016, indicates that substituting gas-fired capacity with front office transactions increases cost, risk, and Energy Not Served. (See Table 7.37, Table 7.39, Figure 7.30, and Figure 7.31 of the 2007 IRP report for the relevant stochastic performance comparisons.) Consequently, planning for reduced front office transactions as a response to greater conservation energy savings in Oregon yields a better cost, risk, and reliability outcome than planning for a smaller gas-fired facility, holding other factors constant. The Company is not aware of gains to be made by increasing demand response or renewable resources in reaction to higher conservation savings.

Also, the 50 average megawatt conservation savings is the Energy Trust of Oregon's forecasted cumulative total as of 2016, not 2011. The ETO forecasts about 23 average megawatts in savings by 2011. Given such a small resource amount, it should be noted that PacifiCorp's IRP uses proxy resources based on representative resource characteristics, including average capacity sizes. Attempting to precisely size a thermal resource to be acquired in 2011 given estimates of conservation program savings obtained over several years is ascribing a level of planning precision not warranted for the IRP.

OPUC Data Request 24

Please explain how and when PacifiCorp plans to evaluate whether the current decrement approach for modeling conservation resources is preferable to an alternative approach – using supply curves, modeling them as portfolio options that compete with supply-side options, and analyzing cost and risk reduction benefits. This was an agreed-upon modification to the 2004 IRP Action Plan.

Response to OPUC Data Request 24

PacifiCorp already performed this evaluation for the 2007 IRP, and as documented at the February 10, 2006 public meeting, chose to continue to use the decrement approach for this IRP because of the lack of adequate supply curve information for Class 2 DSM programs at the time the IRP modeling plan was being developed and executed. At this public meeting, PacifiCorp also stated that stochastic simulation would be performed to capture the risk reduction value of these programs. See Appendix I, page 165. Finally, PacifiCorp indicated its intent to model Class 2 DSM using supply curves obtained from the results of the multi-state DSM potentials study.

OPUC Data Request 18

Please explain how the company plans to use the July 2007 six-state demand-side management (DSM) assessment to determine how much conservation outside Oregon and demand response and distributed generation resources to acquire system-wide, including determination of achievable potential and economic screening, accounting for the Commission's best cost/risk standard.

Response to OPUC Data Request 18

PacifiCorp plans to use the IRP capacity expansion tool to perform the initial economic evaluation for DSM and distributed resources identified in the July 2007 DSM potentials study. These resources will be assessed on a comparable basis against supply-side and transmission alternatives for developing potential portfolios; however, details on the methodology have not been determined yet. Detailed portfolio analysis with the screened DSM and distributed resource options, including stochastic and scenario cost/risk evaluation, will be performed using the Planning and Risk module. The Company is currently working with members of the study team at Quantec, LLC to develop appropriate IRP model inputs using the resource supply and cost information developed for the study.

OPUC Data Request 23

Please explain how and when PacifiCorp proposes to "assess how the Company's base and planned [Class 1 and Class 2 DSM] programs compare with the cost-effective amounts determined in the [system-wide economic assessment] study," as required by Order No. 06-029.

Response to OPUC Data Request 23

The assessment will be performed in 2008 for either a 2007 IRP Update or the 2008 IRP.

OPUC Data Request 19

Please explain whether the company plans to issue RFPs or operate in-house programs (absent an RFP or in the event an RFP elicits insufficient economic bids from creditworthy parties) to acquire additional conservation outside Oregon and demand response and dispatchable standby generation resources system-wide. Please include in your response the anticipated timelines for RFP issuance, bid selection, in-house program development, and implementation of bid or in-house programs. Include in your response a summary of acquisitions from the company's RFP for DSM resources following the 2004 IRP (DSM RFP 2005), including the amounts of conservation and demand response resources acquired (MWa and MW, by resource type and state).

Response to OPUC Data Request 19

The Company is planning to issue an RFP for demand side resources, including for energy efficiency outside of Oregon, as well as demand response and dispatchable stand-by generation resources system wide. Proposed milestones for the RFP are as follows:

- November 2007 – issue
- June 2008 – contracts for selected programs
- October 2008 – programs available

These milestones are subject to revision as the schedule is more fully developed.

The Company contracted for the following Class 2 (energy efficiency) resources from the DSM RFP 2005.

- Home Energy Savings program:
  - 7.44 MWa – all states (except Oregon) savings target
  - 2006 – 2009 performance period
  - Actual performance depends in part on approval dates in California and Wyoming
- Energy FinAnswer Design assistance program track
  - 1.99 MWa – all (except Oregon and Wyoming) savings target
  - 2007 – 2011 performance period
  - Actual performance depends on approval dates in California and Idaho

Energy efficiency acquired under the DSM RFP 2005 supplements other Class 2 resources acquired by the Company.

OPUC Data Request 20

Please provide a detailed description of the methodology the company used to determine the avoided capacity cost on the west and east sides of the system at $58/kW and $98/kW, respectively, for evaluating demand response resources in the IRP, as well as DSM and "supplemental resources" (dispatchable standby generation, combined heat and power, and solar) in the six-state assessment. Provide any documentation or white paper describing the methodology.

Response to OPUC Data Request 20

The $98/kW-yr east region value and $58/kW-yr west region value were developed by the Company for Quantec's initial program screening purposes as part of the DSM potentials study, and were not used in the 2007 IRP for evaluating demand resource resources. These values are proxy values used for screening purposes, and are not intended to represent a precise measure of avoided cost. For the next IRP, PacifiCorp will use its IRP models and DSM technical potential supply curves (adjusted for market penetration rates) to screen for cost-effective DSM amounts.

The east and west-side DSM capacity costs were derived from results obtained by running PacifiCorp's capacity expansion optimization tool (the Capacity Expansion Module, or CEM). Based on these results for east-side resources, PacifiCorp assumed the value of the resources to be greater than $82/kw/yr (given that the CEM selected the fully dispatchable large commercial and industrial resources) but less than $119/kw/yr (the cost for the thermal energy storage resources that were not selected). The $98/kw/yr was selected as a proxy value within the potential study for the initial screening of these types of resources in the east region. The value is only used as an estimate at this time as it ignores unique resource characteristics such as dispatchability, hours of availability, etc. after which load management resources may become uneconomic in relation to other resource alternatives. The analysis approach for the $58/kw-yr used for the Pacific Power territory was similar to that described for the $98/kw-yr analysis in the Rocky Mountain Power territory.

LC-42/PacifiCorp
September 21, 2007
OPUC Data Request 22

OPUC Data Request 22

Please refer to Staff Data Request No. 20. Please explain how the company plans to use these avoided capacity costs in economic screening of DSM and supplemental resources acquired through RFPs and in-house programs.

Response to OPUC Data Request 22

The capacity costs used by Quantec as proxy values within the DSM potentials study will not be used to determine the value of the proposals submitted through the RFP process.

OPUC Data Request 3

For the following resource options, please provide results of a study similar to the "CO_2 Adder Breakeven Analysis for Coal versus Gas Combined Cycle" (text box on page 193 of the 2007 IRP), using the same study inputs and assumptions, including forward natural gas and wholesale electricity prices that are adjusted to account for the effect of the CO_2 adder level tested.

a. Integrated Gasification Combined Cycle (IGCC) coal plant without carbon capture and sequestration
b. IGCC coal plant with carbon capture and sequestration
c. Supercritical coal plant with carbon capture and sequestration

Response to OPUC Data Request 3

a. An IGCC plant without carbon capture and sequestration is assumed to have the same CO_2 emission rate as a supercritical pulverized coal plant (205.35 lbs/MMBtu). Therefore, a CO_2 breakeven analysis is not applicable for these two resource types.
b. The CO_2 adder breakeven point for an IGCC coal plant with carbon capture and sequestration, relative to a supercritical pulverized coal plant, is $39/ton. Note that the assumed carbon sequestration cost is highly uncertain; consequently, this breakeven result is subject to change as the feasibility and cost of sequestration technologies becomes better understood.
c. The answer depends on the assumed carbon capture technology used for pulverized coal plants and the expected future cost relative to IGCC with CO_2 removal. While the cost of conventional CO_2 separation technology (using amines) is somewhat higher than the cost for an IGCC facility, new carbon capture technologies, such as chilled ammonia and/or oxyfuel, have the potential to enable carbon capture from coal boiler facilities (including existing pulverized coal plants) at costs competitive to or lower than IGCC. Because of the unknown future costs of carbon capture and sequestration from supercritical pulverized coal plants, determining a difference in the CO_2 cost breakeven point relative to IGCC is not meaningful at this time.

07-2035-01/Rocky Mountain Power
August 7, 2007
CCS 1st Set Data Request 1.4

CCS Data Request 1.4

DPU 1.25 noted that in the medium electricity/gas price CEM scenarios, pulverized coal is squeezed out as the carbon tax increases but that this pattern does not hold in the high bookend case. Please recreate the C02 Adder Breakeven analysis as discussed on page 193 of the final report, but replace medium gas and electricity prices with high gas and electricity prices. Keep the medium load growth assumption. With high gas and electricity prices and medium load growth, at what carbon tax adder would a CCCT replace a SCPC plant?

Response to CCS Data Request 1.4

Under the requested high gas and electricity price assumptions, the CCCT replaced the supercritical pulverized coal plant with a CO2 cost adder of $97/ton (in 2008 dollars).

In addition, the same study was rerun using low gas and electricity prices. In this case, the CCCT was picked with a carbon tax adder of $0/ton.

LC-42/PacifiCorp
October 11, 2007
OPUC Data Request 50

OPUC Data Request 50

Please explain how the IRP addresses the cost of forthcoming mercury emission control requirements for existing and planned coal resources.

Response to OPUC Data Request 50

For existing coal plants and IRP coal plant proxy resource options, the costs of complying with new mercury emission control requirements (i.e., U.S. Environmental Protection Agency's Clean Air Mercury Rule) are factored into the variable operating and maintenance cost values used in the IRP models. The EPA's mercury cap-and-trade scheme, expected to go into effect in 2010, is handled with a spreadsheet tool that estimates the value of mercury allowances acquired and sold. The mercury prices used in the spreadsheet are documented on Page 21 of the 2007 IRP Appendix volume.

OPUC Data Request 33

Please provide the following for the portfolio analysis described on page 150 of the IRP, planning to the average of the eight-hour super-peak period (CAF11):

a. Loss of load probability

b. Expected unserved energy

c. Worst-case unserved energy

1st Supplemental Response to OPUC Data Request 33

PacifiCorp conducted a stochastic simulation of the portfolio resources resulting from the Capacity Expansion Module solution for Sensitivity Analysis Study 15 ("SAS15"). Please note that the stochastic reliability values for portfolio SAS15 are not comparable to those for the risk analysis portfolios reported in the 2007 IRP due to differences in the treatment of wind and demand-side management resources.

a. Loss of load probability:

Probability of ENS Event > 25,000 MWh in July	
2007	1%
2008	3%
2009	11%
2010	12%
2011	13%
2012	9%
2013	19%
2014	16%
2015	23%
2016	24%
2017	23%
2018	21%
2019	13%
2020	23%
2021	23%
2022	26%
2023	22%
2024	31%
2025	31%
2026	28%

Probability of Loss of Load during the Summer Peak (Average for operating years 2007 through 2016)	
Event Size (MWh)	**SAS 15**
> 0	36%
> 1,000	30%
> 10,000	18%
> 25,000	13%
> 50,000	10%
> 100,000	8%
> 500,000	1%
> 1,000,000	0%

Probability of Loss of Load during the Summer Peak (Average for operating years 2007 through 2026)	
Event Size (MWh)	**SAS 15**
> 0	39%
> 1,000	34%
> 10,000	23%
> 25,000	19%
> 50,000	15%
> 100,000	11%
> 500,000	4%
> 1,000,000	2%

b. Expected unserved energy (annual average, 100 iterations):
149 GWh

c. Worst-case unserved energy (annual average, highest five iterations):
1,609 GWh

LC-42/PacifiCorp
October 11, 2007
OPUC Data Request 48

OPUC Data Request 48

Please provide the Preferred Portfolio load and resource capacity balance, in tabular form similar to Table 7.46 (page 204), assuming the following:

a. The company does not acquire the 2012 coal resource in the Action Plan
b. The company does not acquire the 2014 coal resource in the Action Plan
c. The company does not acquire either the 2012 or the 2014 coal resources in the Action Plan

Include the associated electronic spreadsheets with formula intact.

Response to OPUC Data Request 48

For responses a through c, please refer to Attachment OPUC 48.

Note that the suggested resource assumptions a-c would result in significant energy not served (ENS). Please refer to tab "ENS" in Attachment OPUC 48 to see the magnitude of these ENS impacts. Assumptions a, b and c result in increased ENS over the preferred portfolio by 24, 30 and 63 percent, respectively.

OREGON

PACIFICORP IRP

LC-42

PACIFICORP

OPUC DATA REQUEST 37-51

ATTACHMENT OPUC 48

Preferred Portfolio L&R Balance minus 2012 coal

Planning Reserve Margin = 12%

Calendar Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
East										
Thermal	6,134	5,941	5,941	5,941	5,941	5,941	5,941	5,941	5,941	5,941
Hydro	135	135	135	135	135	135	135	135	135	135
DSM	153	163	163	163	163	163	163	163	163	163
Renewable	65	109	109	109	109	109	109	109	105	105
Purchase	904	679	778	548	543	343	343	343	343	322
QF	106	106	106	106	106	106	106	106	106	106
Interruptible	233	233	308	308	308	308	308	308	308	308
Transfers	534	797	731	898	1,162	955	1,111	597	701	777
East Existing Resources	8,264	8,163	8,271	8,208	8,467	8,060	8,216	7,702	7,802	7,857
Wind	0	24	24	40	48	48	109	109	109	109
DSM	0	0	0	0	0	15	63	63	63	63
CHP	0	0	0	0	0	25	25	25	25	25
Front Office Transactions	0	0	0	393	272	97	3	149	192	165
Thermal	0	0	0	0	0	548	548	1,075	1,075	1,432
East Planned Resources	0	24	24	433	320	733	748	1,421	1,464	1,794
East Total Resources	8,264	8,187	8,295	8,641	8,787	8,793	8,964	9,123	9,266	9,651
Load	6,321	6,515	6,657	7,137	7,289	7,595	7,738	7,895	8,026	8,366
Sale	849	811	702	666	631	595	595	595	595	595
East Obligation	7,170	7,326	7,359	7,803	7,920	8,190	8,333	8,490	8,621	8,961
Planning reserves (12%)	706	750	733	767	796	872	894	896	906	953
Non-owned reserves	71	71	71	71	71	71	71	71	71	71
East Reserves	776	821	804	837	867	942	965	966	977	1,023
East Obligation + Reserves	7,946	8,147	8,163	8,641	8,787	9,132	9,298	9,456	9,598	9,984
East Position	317	40	132	0	0	(339)	(334)	(333)	(332)	(334)
East Reserve Margin	16%	13%	14%	12%	12%	8%	8%	8%	8%	8%
West										
Thermal	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046
Hydro	1,421	1,421	1,414	1,328	1,357	1,225	1,249	1,243	1,244	1,242
DSM	0	0	0	0	0	0	0	0	0	0
Renewable	108	108	108	108	108	84	84	84	84	84
Purchase	786	800	800	799	749	112	141	107	107	107
QF	40	40	40	40	40	40	38	38	38	38
Transfers	(542)	(804)	(741)	(907)	(1,170)	(964)	(1,120)	(606)	(708)	(786)
West Existing Resources	3,859	3,611	3,667	3,414	3,130	2,542	2,438	2,913	2,811	2,732
Wind	14	14	51	79	79	98	98	98	98	98
DSM	0	0	0	0	0	32	32	32	32	32
CHP	0	0	0	0	0	75	75	75	75	75
Front Office Transactions	0	0	0	219	64	555	657	247	246	249
Thermal	0	0	0	0	548	548	548	548	548	548
West Planned Resources	14	14	51	298	691	1,308	1,410	1,000	999	1,002
West Total Resources	3,873	3,625	3,718	3,712	3,821	3,850	3,848	3,913	3,810	3,734
Load	2,922	2,924	3,095	3,124	3,199	3,240	3,251	3,262	3,271	3,252
Sale	299	299	299	290	290	258	258	258	158	108
West Obligation	3,221	3,223	3,394	3,414	3,489	3,498	3,509	3,520	3,429	3,360
Planning reserves (12%)	292	291	311	287	321	336	322	376	365	357
Non-owned reserves	7	7	7	7	7	7	7	7	7	7
West Reserves	299	297	318	294	328	342	328	383	372	363
West Obligation + Reserves	3,513	3,514	3,705	3,701	3,810	3,834	3,831	3,896	3,794	3,716
West Position	360	111	12	11	11	16	17	17	16	18
West Reserve Margin	23%	15%	12%	12%	12%	12%	12%	12%	12%	12%
System										
Total Resources	12,137	11,811	12,013	12,353	12,608	12,643	12,812	13,036	13,076	13,385
Obligation	10,391	10,549	10,753	11,217	11,409	11,688	11,842	12,010	12,050	12,321
Reserves	1,075	1,118	1,122	1,131	1,194	1,285	1,293	1,349	1,348	1,386
Obligation + Reserves	11,466	11,667	11,874	12,348	12,603	12,973	13,135	13,359	13,398	13,707
System Position	671	144	138	5	5	(330)	(323)	(323)	(322)	(322)
Reserve Margin	18%	13%	13%	12%	12%	9%	9%	9%	9%	9%
Asset RM	18%	13%	13%	6%	9%	3%	3%	6%	5%	6%
FOT RM Contribution	0%	0%	0%	6%	3%	6%	6%	4%	4%	4%

Preferred Portfolio L&R Balance minus 2014 coal

Planning Reserve Margin = 12%

Calendar Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
East										
Thermal	6,134	5,941	5,941	5,941	5,941	5,941	5,941	5,941	5,941	5,941
Hydro	135	135	135	135	135	135	135	135	135	135
DSM	153	163	163	163	163	163	163	163	163	163
Renewable	65	109	109	109	109	109	109	109	105	105
Purchase	904	679	778	548	543	343	343	343	343	322
QF	106	106	106	106	106	106	106	106	106	106
Interruptible	233	233	308	308	308	308	308	308	308	308
Transfers	534	797	731	898	1,162	955	1,111	597	701	777
East Existing Resources	8,264	8,163	8,271	8,208	8,467	8,060	8,216	7,702	7,802	7,857
Wind	0	24	24	40	48	48	109	109	109	109
DSM	0	0	0	0	0	15	63	63	63	63
CHP	0	0	0	0	0	25	25	25	25	25
Front Office Transactions	0	0	0	393	272	97	3	149	192	165
Thermal	0	0	0	0	0	888	888	888	888	1,245
East Planned Resources	0	24	24	433	320	1,073	1,088	1,234	1,277	1,607
East Total Resources	8,264	8,187	8,295	8,641	8,787	9,133	9,304	8,936	9,079	9,464
Load	6,321	6,515	6,657	7,137	7,289	7,595	7,738	7,895	8,026	8,366
Sale	849	811	702	666	631	595	595	595	595	595
East Obligation	7,170	7,326	7,359	7,803	7,920	8,190	8,333	8,490	8,621	8,961
Planning reserves (12%)	706	750	733	767	796	872	894	896	906	953
Non-owned reserves	71	71	71	71	71	71	71	71	71	71
East Reserves	776	821	804	837	867	942	965	966	977	1,023
East Obligation + Reserves	7,946	8,147	8,163	8,641	8,787	9,132	9,298	9,456	9,598	9,984
East Position	317	40	132	0	0	1	6	(520)	(519)	(521)
East Reserve Margin	16%	13%	14%	12%	12%	12%	12%	6%	6%	6%
West										
Thermal	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046
Hydro	1,421	1,421	1,414	1,328	1,357	1,225	1,249	1,243	1,244	1,242
DSM	0	0	0	0	0	0	0	0	0	0
Renewable	108	108	108	108	108	84	84	84	84	84
Purchase	786	800	800	799	749	112	141	107	107	107
QF	40	40	40	40	40	40	38	38	38	38
Transfers	(542)	(804)	(741)	(907)	(1,170)	(964)	(1,120)	(606)	(708)	(786)
West Existing Resources	3,859	3,611	3,667	3,414	3,130	2,542	2,438	2,913	2,811	2,732
Wind	14	14	51	79	79	98	98	98	98	98
DSM	0	0	0	0	0	32	32	32	32	32
CHP	0	0	0	0	0	75	75	75	75	75
Front Office Transactions	0	0	0	219	64	555	657	247	246	249
Thermal	0	0	0	0	548	548	548	548	548	548
West Planned Resources	14	14	51	298	691	1,308	1,410	1,000	999	1,002
West Total Resources	3,873	3,625	3,718	3,712	3,821	3,850	3,848	3,913	3,810	3,734
Load	2,922	2,924	3,095	3,124	3,199	3,240	3,251	3,262	3,271	3,252
Sale	299	299	299	290	290	258	258	258	158	108
West Obligation	3,221	3,223	3,394	3,414	3,489	3,498	3,509	3,520	3,429	3,360
Planning reserves (12%)	292	291	311	287	321	336	322	376	365	357
Non-owned reserves	7	7	7	7	7	7	7	7	7	7
West Reserves	299	297	318	294	328	342	328	383	372	363
West Obligation + Reserves	3,513	3,514	3,705	3,701	3,810	3,834	3,831	3,896	3,794	3,716
West Position	360	111	12	11	11	16	17	17	16	18
West Reserve Margin	23%	15%	12%	12%	12%	12%	12%	12%	12%	12%
System										
Total Resources	12,137	11,811	12,013	12,353	12,608	12,983	13,152	12,849	12,889	13,198
Obligation	10,391	10,549	10,753	11,217	11,409	11,688	11,842	12,010	12,050	12,321
Reserves	1,075	1,118	1,122	1,131	1,194	1,285	1,293	1,349	1,348	1,386
Obligation + Reserves	11,466	11,667	11,874	12,348	12,603	12,973	13,135	13,359	13,398	13,707
System Position	671	144	138	5	5	10	17	(510)	(509)	(509)
Reserve Margin	18%	13%	13%	12%	12%	12%	12%	8%	8%	8%
Asset RM	18%	13%	13%	6%	9%	6%	6%	4%	4%	4%
FOT RM Contribution	0%	0%	0%	6%	3%	6%	6%	4%	4%	4%

Preferred Portfolio L&R Balance minus 2012 & 2014 coal

Planning Reserve Margin = 12%

Calendar Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
East										
Thermal	6,134	5,941	5,941	5,941	5,941	5,941	5,941	5,941	5,941	5,941
Hydro	135	135	135	135	135	135	135	135	135	135
DSM	153	163	163	163	163	163	163	163	163	163
Renewable	65	109	109	109	109	109	109	109	105	105
Purchase	904	679	778	548	543	343	343	343	343	322
QF	106	106	106	106	106	106	106	106	106	106
Interruptible	233	233	308	308	308	308	308	308	308	308
Transfers	534	797	731	898	1,162	955	1,111	597	701	777
East Existing Resources	8,264	8,163	8,271	8,208	8,467	8,060	8,216	7,702	7,802	7,857
Wind	0	24	24	40	48	48	109	109	109	109
DSM	0	0	0	0	0	15	63	63	63	63
CHP	0	0	0	0	0	25	25	25	25	25
Front Office Transactions	0	0	0	393	272	97	3	149	192	165
Thermal	0	0	0	0	0	548	548	548	548	905
East Planned Resources	0	24	24	433	320	733	748	894	937	1,267
East Total Resources	8,264	8,187	8,295	8,641	8,787	8,793	8,964	8,596	8,739	9,124
Load	6,321	6,515	6,657	7,137	7,289	7,595	7,738	7,895	8,026	8,366
Sale	849	811	702	666	631	595	595	595	595	595
East Obligation	7,170	7,326	7,359	7,803	7,920	8,190	8,333	8,490	8,621	8,961
Planning reserves (12%)	706	750	733	767	796	872	894	896	906	953
Non-owned reserves	71	71	71	71	71	71	71	71	71	71
East Reserves	776	821	804	837	867	942	965	966	977	1,023
East Obligation + Reserves	7,946	8,147	8,163	8,641	8,787	9,132	9,298	9,456	9,598	9,984
East Position	317	40	132	0	0	(339)	(334)	(860)	(859)	(861)
East Reserve Margin	16%	13%	14%	12%	12%	8%	8%	2%	2%	2%
West										
Thermal	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046
Hydro	1,421	1,421	1,414	1,328	1,357	1,225	1,249	1,243	1,244	1,242
DSM	0	0	0	0	0	0	0	0	0	0
Renewable	108	108	108	108	108	84	84	84	84	84
Purchase	786	800	800	799	749	112	141	107	107	107
QF	40	40	40	40	40	40	38	38	38	38
Transfers	(542)	(804)	(741)	(907)	(1,170)	(964)	(1,120)	(606)	(708)	(786)
West Existing Resources	3,859	3,611	3,667	3,414	3,130	2,542	2,438	2,913	2,811	2,732
Wind	14	14	51	79	79	98	98	98	98	98
DSM	0	0	0	0	0	32	32	32	32	32
CHP	0	0	0	0	0	75	75	75	75	75
Front Office Transactions	0	0	0	219	64	555	657	247	246	249
Thermal	0	0	0	0	548	548	548	548	548	548
West Planned Resources	14	14	51	298	691	1,308	1,410	1,000	999	1,002
West Total Resources	3,873	3,625	3,718	3,712	3,821	3,850	3,848	3,913	3,810	3,734
Load	2,922	2,924	3,095	3,124	3,199	3,240	3,251	3,262	3,271	3,252
Sale	299	299	299	290	290	258	258	258	158	108
West Obligation	3,221	3,223	3,394	3,414	3,489	3,498	3,509	3,520	3,429	3,360
Planning reserves (12%)	292	291	311	287	321	336	322	376	365	357
Non-owned reserves	7	7	7	7	7	7	7	7	7	7
West Reserves	299	297	318	294	328	342	328	383	372	363
West Obligation + Reserves	3,513	3,514	3,705	3,701	3,810	3,834	3,831	3,896	3,794	3,716
West Position	360	111	12	11	11	16	17	17	16	18
West Reserve Margin	23%	15%	12%	12%	12%	12%	12%	12%	12%	12%
System										
Total Resources	12,137	11,811	12,013	12,353	12,608	12,643	12,812	12,509	12,549	12,858
Obligation	10,391	10,549	10,753	11,217	11,409	11,688	11,842	12,010	12,050	12,321
Reserves	1,075	1,118	1,122	1,131	1,194	1,285	1,293	1,349	1,348	1,386
Obligation + Reserves	11,466	11,667	11,874	12,348	12,603	12,973	13,135	13,359	13,398	13,707
System Position	671	144	138	5	5	(330)	(323)	(850)	(849)	(849)
Reserve Margin	18%	13%	13%	12%	12%	9%	9%	5%	5%	5%
Asset RM	18%	13%	13%	6%	9%	3%	3%	1%	1%	1%
FOT RM Contribution	0%	0%	0%	6%	3%	6%	6%	4%	4%	4%

Energy not served (GWh)

	Total	2007	2008	2009	2010	2011	2012	2013	2014	2015
Preferred Portfolio	2,873	3	7	32	59	52	9	41	34	47
Pref Port minus 2012 coal	3,570	3	7	32	59	52	17	61	49	66
Increase from Pref Port	24%									
Pref Port minus 2014 coal	3,735	3	7	32	59	52	9	41	55	74
Increase from Pref Port	30%									
Pref Port minus all coal	4,673	3	7	32	59	52	17	61	82	110
Increase from Pref Port	63%									

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
84	137	255	98	164	182	236	307	322	368	436
111	176	323	123	199	225	300	377	397	451	541
126	196	356	139	219	245	333	384	404	473	526
168	250	451	176	270	306	422	474	507	581	645

LC-42/PacifiCorp
October 11, 2007
OPUC Data Request 47

OPUC Data Request 47

Please provide in graph format (similar to Figures 4.6 through 4.8, pages 86-87) and tabular format the average monthly and annual energy balances for the Preferred Portfolio under *average* hydro conditions, for the period 2007-2016. Include the associated electronic spreadsheets with formula intact. Provide these energy balances for the following:

a. System
b. West control area
c. East control area

Response to OPUC Data Request 47

Please refer to Attachment OPUC 47 for the requested energy balances. The energy balance reflects the economic decision criteria employed by the IRP models when adding new resources to create the best cost / risk portfolio. Lower cost energy from non-firm hydro and new, more efficient resources are used to make economic wholesale sales and to displace less economic energy of the existing fleet. The energy balances shown in the attachment represent a static view of the energy balance which has not been reduced to reflect the economic wholesale sales or displacement, therefore it is an incomplete analysis. The added resources of the preferred portfolio are proxy resources. Actual resources will be procured through the company's resource procurement processes consistent with laws, rules and regulations in each state. Thus, the resulting energy profiles will vary depending on the types of resources that are ultimately procured.

OREGON

PACIFICORP IRP

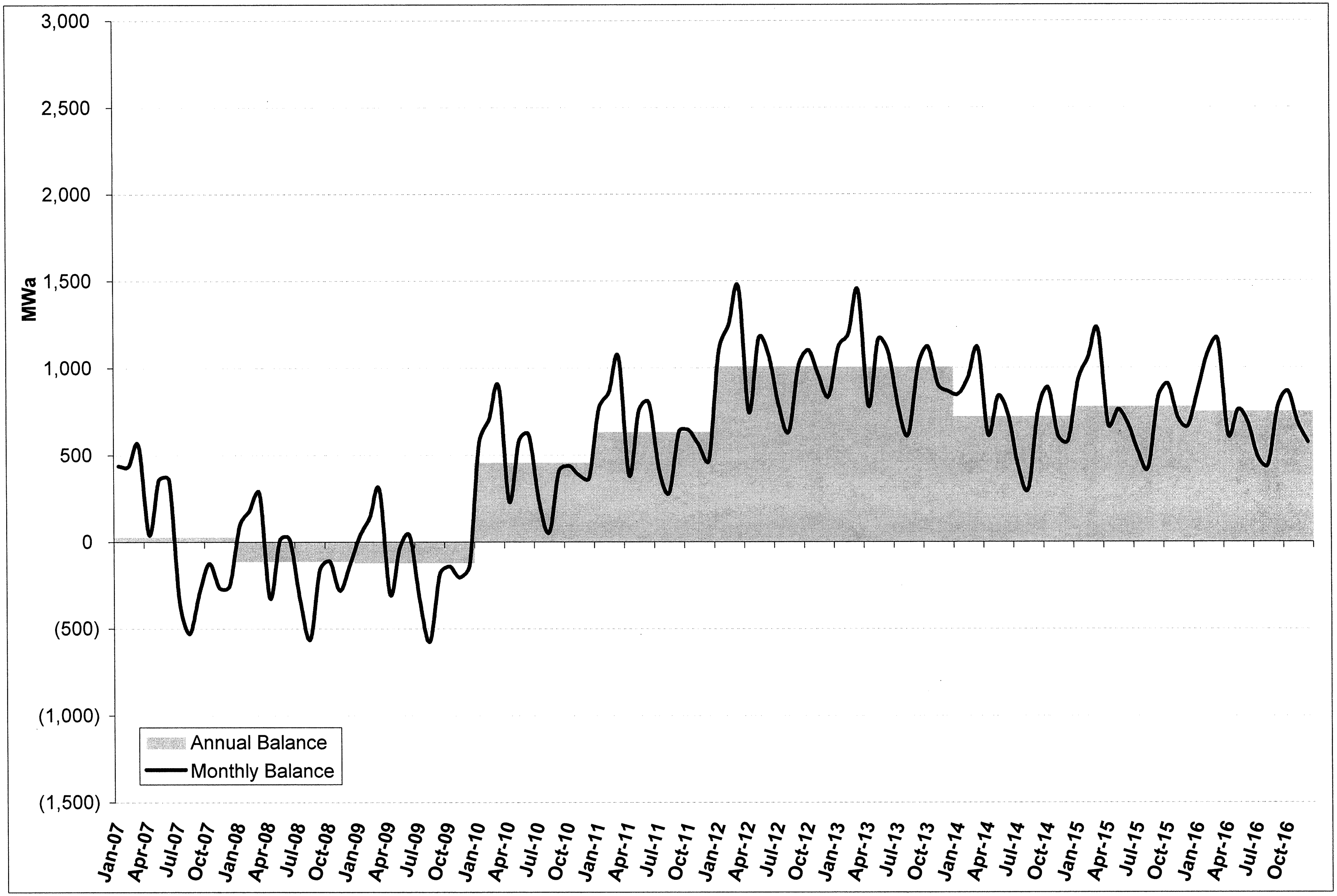
LC-42

PACIFICORP

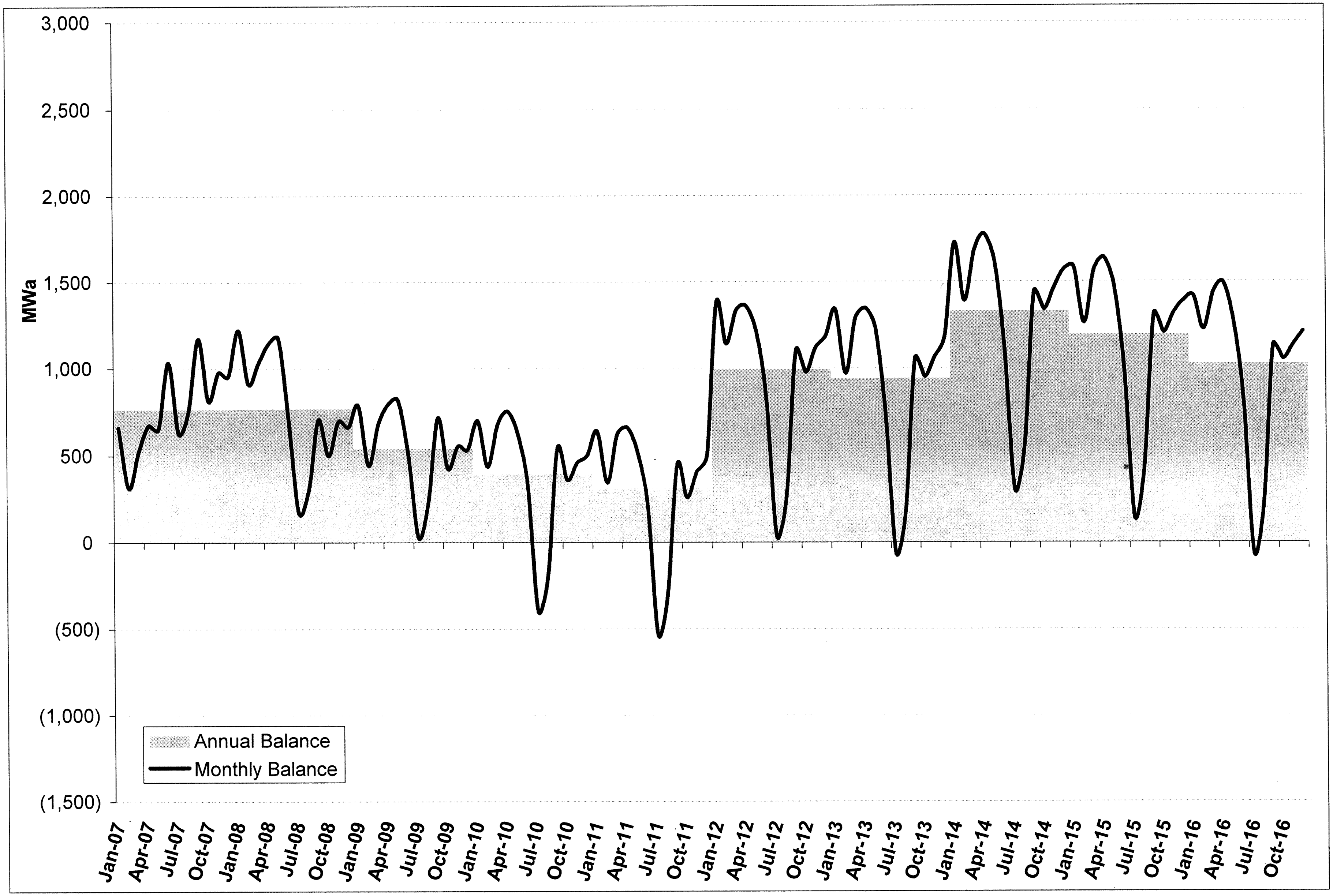
OPUC DATA REQUEST 37-51

ATTACHMENT OPUC 47

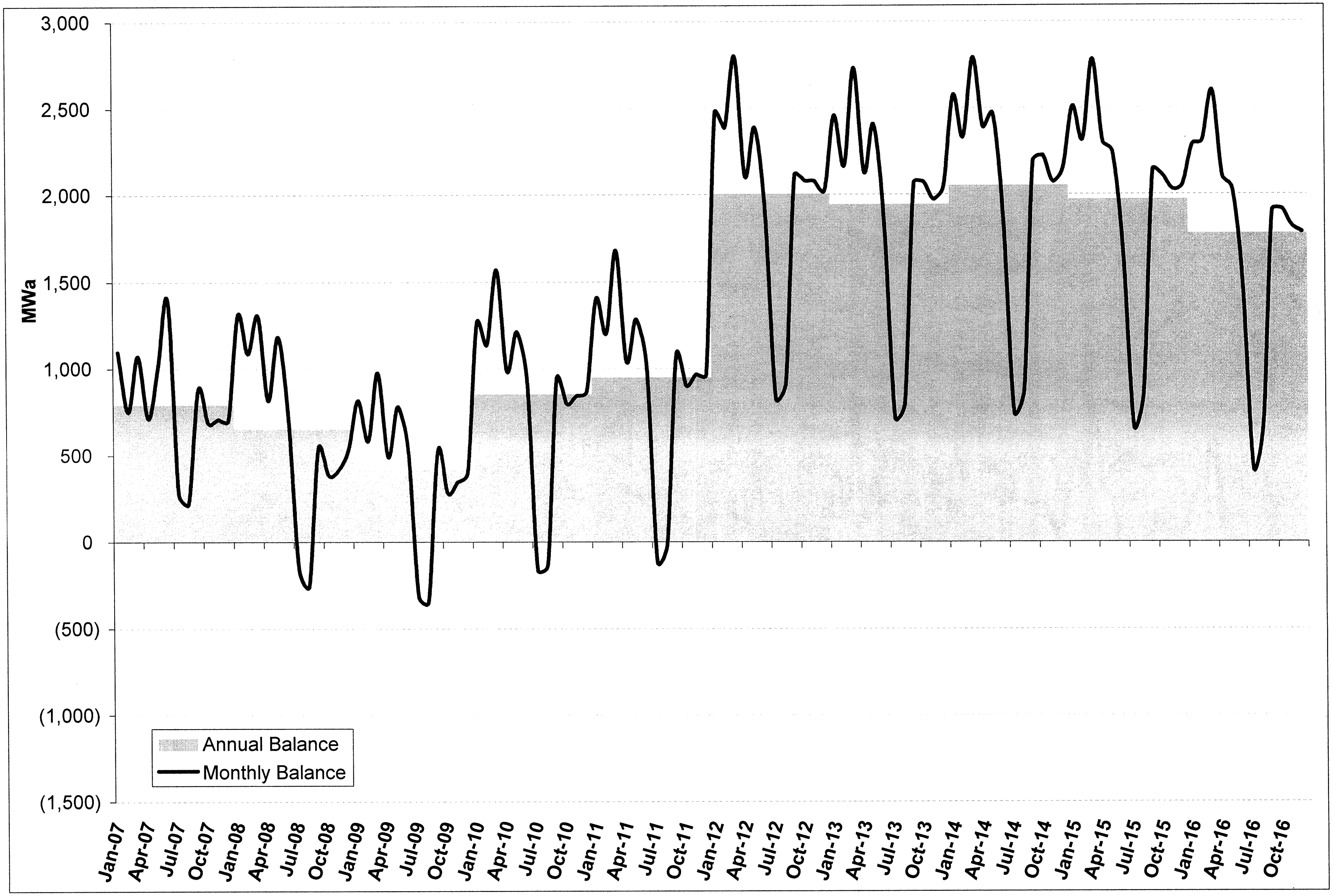
Draft: 2006 IRP West Energy Chart



Draft: 2006 IRP East Energy Chart



Draft: 2006 IRP System Energy Chart



OPUC Data Request 14

Please explain how the IRP considered potential impacts of new coal plant development on Retirement Dates of the generating plants in Table A.12. For example, under a regional cap and trade regime that meets Oregon's newly enacted goals for reducing greenhouse gas emissions (HB 3543), could the coal plants in Table A.12 be forced into early retirement due to emissions from coal plants in the preferred portfolio? Provide documentation supporting your analysis.

Response to OPUC Data Request 14

PacifiCorp did not conduct an analysis of the impact of new coal plant development on retirement dates of existing generating plants for the 2007 IRP. The impacts of Oregon's greenhouse gas emission goals and other regulatory initiatives on the Company's resource portfolio, including those to existing plants, will be analyzed as specific information becomes available as to how these regulatory initiatives apply to the electric industry.

LC-42/PacifiCorp
September 21, 2007
ODOE Data Request 17

ODOE Data Request 17

Please provide slide 7 of your presentation to the Commission on Sept. 5, 2007 under average water conditions.

Response to ODOE Data Request 17

The requested slide is provided as Attachment ODOE 17.

OREGON

PACIFICORP IRP

LC-42

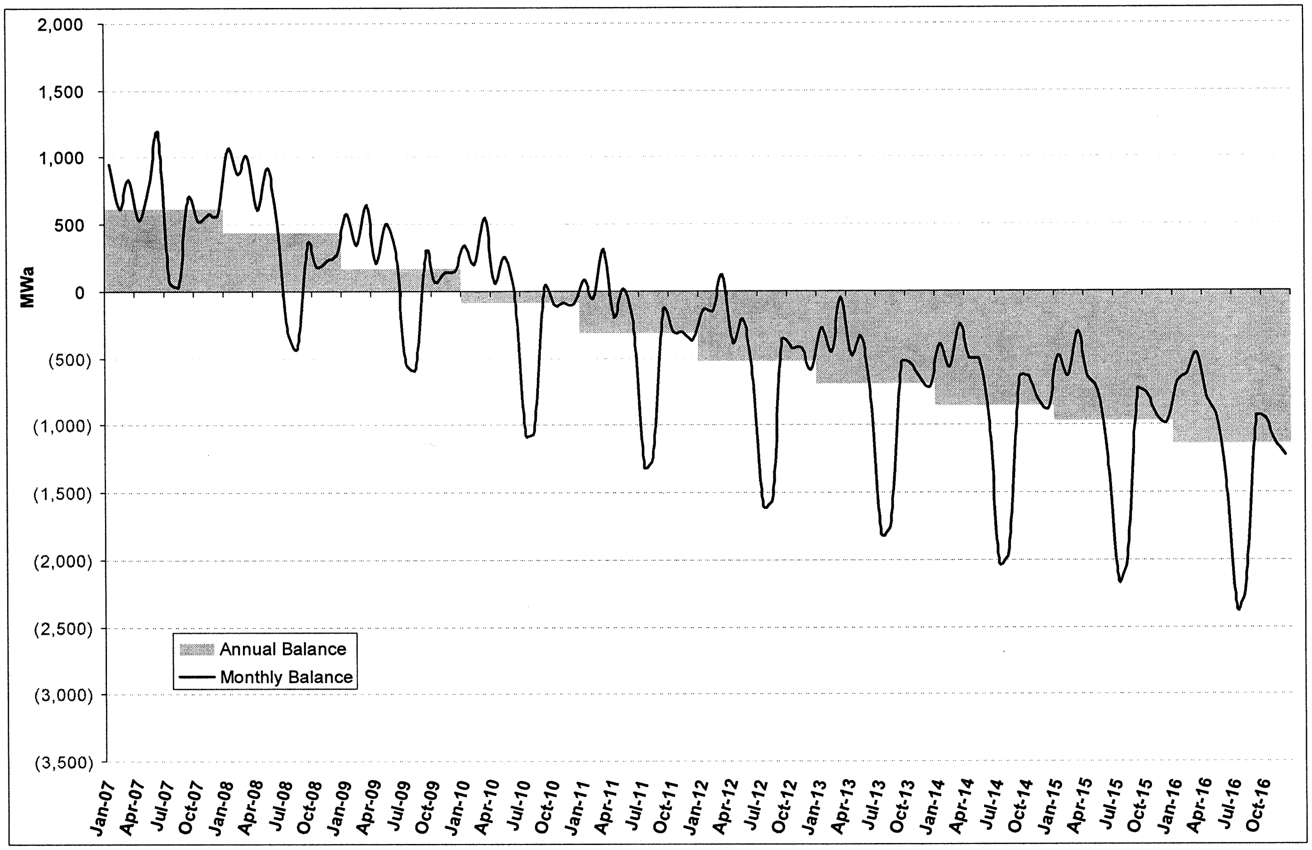
PACIFICORP

ODOE DATA REQUEST 4-19

ATTACHMENT ODOE 17

Energy Balance

- Chart shows annual and monthly average energy assuming median hydro conditions



Note: This chart was prepared for ODOE Request 17, and is not part of any presentation given by PacifiCorp for the 2007 IRP

OPUC Data Request 12

Please explain the impacts of Oregon's RPS on the need for the 600 MW natural gas plant on the west side in the company's Action Plan for 2011. For example, will the projected amounts of renewable resources required under the Act meet forecasted load growth in Oregon?

Response to OPUC Data Request 12

PacifiCorp projects a system capacity deficit of 2,446 MW for 2012, which includes the expiration of sizable west-side wholesale purchase contracts. The 600 MW natural gas plant is needed regardless of the forecasted Oregon load growth and renewable generation requirements stemming from the Oregon RPS. Additionally, a natural gas plant will benefit customers by providing dispatch flexibility for integrating wind resources obtained to meet regional RPS requirements and the Company's overall renewable energy acquisition goals.

OPUC Data Request 30

Please refer to the company's response to Staff Data Request No. 4. How does the incremental conservation the company will pursue in Oregon change the proposed Action Plan and load-resource balance? Specifically, how does it change the amount of front office transactions, renewable resources, and other resources the company will acquire in each year? Include in your response an update to Table 7.46 (IRP at 204) to reflect the incremental Oregon conservation, any changes to other resources in the Action Plan as a result of the incremental conservation, and the planning reserve margin.

Response to OPUC Data Request 30

In PacifiCorp's supplemental response to OPUC Data Request 4 (see pages 3-4), the Company proposed to amend Action Item 2 of the Action Plan to increase the base conservation program amount from 250 MWa to 300 MWa; also, acquired amounts are expected to offset the procurement of front office transactions.

Refer to Attachment OPUC 30 for the load-resource balance that includes the incremental Oregon conservation. Note that the west-side front office transactions decreased by the amounts of the DSM additions. There was no change to the planning reserve margin.

OREGON

PACIFICORP IRP

LC-42

PACIFICORP

OPUC DATA REQUEST 5-33

ATTACHMENT OPUC 30

2007 IRP Preferred Portfolio L&R Balance with ETO Class 2 DSM

Planning Reserve Margin = 12%

Calendar Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
East										
Thermal	6,134	5,941	5,941	5,941	5,941	5,941	5,941	5,941	5,941	5,941
Hydro	135	135	135	135	135	135	135	135	135	135
DSM	153	163	163	163	163	163	163	163	163	163
Renewable	65	109	109	109	109	109	109	109	105	105
Purchase	904	679	778	548	543	343	343	343	343	322
QF	106	106	106	106	106	106	106	106	106	106
Interruptible	233	233	308	308	308	308	308	308	308	308
Transfers	534	797	731	898	1,162	955	1,111	597	701	777
East Existing Resources	8,264	8,163	8,271	8,208	8,467	8,060	8,216	7,702	7,802	7,857
Wind	0	24	24	40	48	48	109	109	109	109
DSM	0	0	0	0	0	15	63	63	63	63
CHP	0	0	0	0	0	25	25	25	25	25
Front Office Transactions	0	0	0	393	272	97	3	149	192	165
Thermal	0	0	0	0	0	888	888	1,415	1,415	1,772
East Planned Resources	0	24	24	433	320	1,073	1,088	1,761	1,804	2,134
East Total Resources	8,264	8,187	8,295	8,641	8,787	9,133	9,304	9,463	9,606	9,991
Load	6,321	6,515	6,657	7,137	7,289	7,595	7,738	7,895	8,026	8,366
Sale	849	811	702	666	631	595	595	595	595	595
East Obligation	7,170	7,326	7,359	7,803	7,920	8,190	8,333	8,490	8,621	8,961
Planning reserves (12%)	706	750	733	767	796	872	894	896	906	953
Non-owned reserves	71	71	71	71	71	71	71	71	71	71
East Reserves	776	821	804	837	867	942	965	966	977	1,023
East Obligation + Reserves	7,946	8,147	8,163	8,641	8,787	9,132	9,298	9,456	9,598	9,984
East Position	317	40	132	0	0	1	6	7	8	6
East Reserve Margin	16%	13%	14%	12%	12%	12%	12%	12%	12%	12%
West										
Thermal	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046
Hydro	1,421	1,421	1,414	1,328	1,357	1,225	1,249	1,243	1,244	1,242
DSM	0	0	0	0	0	0	0	0	0	0
Renewable	108	108	108	108	108	84	84	84	84	84
Purchase	786	800	800	799	749	112	141	107	107	107
QF	40	40	40	40	40	40	38	38	38	38
Transfers	(542)	(804)	(741)	(907)	(1,170)	(964)	(1,120)	(606)	(708)	(786)
West Existing Resources	3,859	3,611	3,667	3,414	3,130	2,542	2,438	2,913	2,811	2,732
Wind	14	14	51	79	79	98	98	98	98	98
DSM (Class 1)	0	0	0	0	0	32	32	32	32	32
ETO Class 2 DSM	0	0	0	0	29	37	45	53	61	75
CHP	0	0	0	0	0	75	75	75	75	75
Front Office Transactions	0	0	0	219	35	518	612	194	185	174
Thermal	0	0	0	0	548	548	548	548	548	548
West Planned Resources	14	14	51	298	691	1,308	1,410	1,000	999	1,002
West Total Resources	3,873	3,625	3,718	3,712	3,821	3,850	3,848	3,913	3,810	3,734
Load	2,922	2,924	3,095	3,124	3,199	3,240	3,251	3,262	3,271	3,252
Sale	299	299	299	290	290	258	258	258	158	108
West Obligation	3,221	3,223	3,394	3,414	3,489	3,498	3,509	3,520	3,429	3,360
Planning reserves (12%)	292	291	311	287	321	336	322	376	365	357
Non-owned reserves	7	7	7	7	7	7	7	7	7	7
West Reserves	299	297	318	294	328	342	328	383	372	363
West Obligation + Reserves	3,513	3,514	3,705	3,701	3,810	3,834	3,831	3,896	3,794	3,716
West Position	360	111	12	11	11	16	17	17	16	18
West Reserve Margin	23%	15%	12%	12%	12%	12%	12%	12%	12%	12%
System										
Total Resources	12,137	11,811	12,013	12,353	12,608	12,983	13,152	13,376	13,416	13,725
Obligation	10,391	10,549	10,753	11,217	11,409	11,688	11,842	12,010	12,050	12,321
Reserves	1,075	1,118	1,122	1,131	1,194	1,285	1,293	1,349	1,348	1,386
Obligation + Reserves	11,466	11,667	11,874	12,348	12,603	12,973	13,135	13,359	13,398	13,707
System Position	671	144	138	5	5	10	17	17	18	18
Reserve Margin	18%	13%	13%	12%	12%	12%	12%	12%	12%	12%
Asset RM	18%	13%	13%	6%	9%	6%	6%	9%	9%	9%
FOT RM Contribution	0%	0%	0%	6%	3%	6%	6%	3%	4%	3%

OPUC Data Request 54

Please refer to Staff Data Request No. 53. What would be the additional economic cost of substituting more peaking-appropriate SCCT capacity for the posited eastern control area 602 MW CCCT? Denote all economic costs as changes in the study period PVRR.

Response to OPUC Data Request 54

Please refer to Attachment OPUC 53. This spreadsheet itemizes, by cost category, economic impact of alternately building SCCT frames or intercooled aeroderivative SCCT units in the East. The attachment shows two different studies prepared to respond to this data request:

- One study, labeled "OPUC 54 SCCT," assumes the addition of 602 MW of SCCT capacity in the East
- The second study, labeled "OPUC 54 Aeros" assumes the addition of 602 MW of intercooled aeroderivative SCCT capacity in the East

Results for the two studies are shown for both a cap-and-trade and tax strategy.

Summary of Portfolios
CO2 Cap & Trade
$8 CO2

		Data Request Study Results			Differences from RA14		
Cost Component (1000 $)	**RA14**	**OPUC 53**	**OPUC 54 SCCT**	**OPUC 54 Aeros**	**OPUC 53**	**OPUC 54 SCCT**	**OPUC 54 Aeros**
Variable Cost							
Total Fuel Cost	12,740,475	12,646,690	12,457,263	12,495,274	(93,785)	(283,212)	(245,201)
Variable O&M Cost	1,688,639	1,678,412	1,699,515	1,675,692	(10,227)	10,876	(12,947)
Total Emission Cost	(686,096)	(712,250)	(694,973)	(736,131)	(26,154)	(8,877)	(50,035)
LT Contracts and FOTs	3,381,073	3,467,328	3,614,723	3,471,341	86,255	233,650	90,268
Spot Market Balancing					0	0	0
Sales	(8,139,526)	(8,069,374)	(7,886,328)	(7,908,720)	70,152	253,199	230,806
Purchases	4,781,176	4,942,074	5,102,339	4,947,122	160,898	321,162	165,946
Energy Not Served	546,119	541,285	533,081	463,167	(4,833)	(13,038)	(82,952)
Total Variable Net Power Costs	14,311,859	14,494,166	14,825,619	14,407,745	182,306	513,760	95,886
Real Levelized Fixed Costs	7,247,005	7,217,220	7,057,823	7,312,152	(29,785)	(189,183)	65,147
Total PVRR	21,558,864	21,711,386	21,883,441	21,719,897	152,522	324,577	161,033

Summary of Portfolios
CO2 Tax Strategy
$8 CO2

		Data Request Study Results			Differences from RA14		
Cost Component (1000 $)	**RA14**	**OPUC 53**	**OPUC 54 SCCT**	**OPUC 54 Aeros**	**OPUC 53**	**OPUC 54 SCCT**	**OPUC 54 Aeros**
Variable Cost							
Total Fuel Cost	12,740,475	12,646,690	12,457,263	12,495,274	(93,785)	(283,212)	(245,201)
Variable O&M Cost	1,688,639	1,678,412	1,699,515	1,675,692	(10,227)	10,876	(12,947)
Total Emission Cost	4,232,883	4,206,572	4,223,998	4,182,659	(26,310)	(8,885)	(50,224)
LT Contracts and FOTs	3,381,073	3,467,328	3,614,723	3,471,341	86,255	233,650	90,268
Spot Market Balancing					0	0	0
Sales	(8,139,526)	(8,069,374)	(7,886,328)	(7,908,720)	70,152	253,199	230,806
Purchases	4,781,176	4,942,074	5,102,339	4,947,122	160,898	321,162	165,946
Energy Not Served	546,119	541,285	533,081	463,167	(4,833)	(13,038)	(82,952)
Total Variable Net Power Costs	19,230,838	19,412,988	19,744,590	19,326,535	182,150	513,752	95,697
Real Levelized Fixed Costs	7,247,005	7,217,220	7,057,823	7,312,152	(29,785)	(189,183)	65,147
Total PVRR	26,477,843	26,630,208	26,802,413	26,638,687	152,365	324,570	160,844

CERTIFICATE OF SERVICE

LC 42

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 860-13-0070, to the following parties or attorneys of parties.

Dated at Salem, Oregon, this 31st day of October, 2007.

Kay Barnes

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

LC 42
Service List (Parties)

CITIZENS' UTILITY BOARD OF OREGON	
LOWREY R BROWN UTILITY ANALYST	610 SW BROADWAY - STE 308 PORTLAND OR 97205 lowrey@oregoncub.org
JASON EISDORFER ENERGY PROGRAM DIRECTOR	610 SW BROADWAY STE 308 PORTLAND OR 97205 jason@oregoncub.org
ROBERT JENKS	610 SW BROADWAY STE 308 PORTLAND OR 97205 bob@oregoncub.org
DAVISON VAN CLEVE	
IRION A SANGER ASSOCIATE ATTORNEY	333 SW TAYLOR - STE 400 PORTLAND OR 97204 ias@dvclaw.com
DAVISON VAN CLEVE PC	
MELINDA J DAVISON	333 SW TAYLOR - STE 400 PORTLAND OR 97204 mail@dvclaw.com
DEPARTMENT OF JUSTICE	
DAVID HATTON ASSISTANT ATTORNEY GENERAL	REGULATED UTILITY & BUSINESS SECTION 1162 COURT ST NE SALEM OR 97301-4096 david.hatton@state.or.us
JANET L PREWITT ASST AG	1162 COURT ST NE SALEM OR 97301-4096 janet.prewitt@doj.state.or.us
EAST FORK ECONOMICS	
LINCOLN WOLVERTON	PO BOX 620 LA CENTER WA 98629 lwolv@tds.net
ESLER STEPHENS & BUCKLEY	
JOHN W STEPHENS	888 SW FIFTH AVE STE 700 PORTLAND OR 97204-2021 stephens@eslerstephens.com
NORTHWEST ENERGY COALITION	
STEVEN WEISS SR POLICY ASSOCIATE	4422 OREGON TRAIL CT NE SALEM OR 97305 steve@nwenergy.org

OREGON DEPARTMENT OF ENERGY PHILIP H CARVER SENIOR POLICY ANALYST	 625 MARION ST NE STE 1 SALEM OR 97301-3742 philip.h.carver@state.or.us
OREGON PUBLIC UTILITY COMMISSION LISA C SCHWARTZ SENIOR ANALYST	 PO BOX 2148 SALEM OR 97308-2148 lisa.c.schwartz@state.or.us
PACIFICORP NATALIE HOCKEN VICE PRESIDENT & GENERAL COUNSEL	 825 NE MULTNOMAH SUITE 2000 PORTLAND OR 97232 natalie.hocken@pacificorp.com
PETE WARNKEN MANAGER, IRP	825 NE MULTNOMAH - STE 600 PORTLAND OR 97232 pete.warnken@pacificorp.com
PACIFICORP OREGON DOCKETS OREGON DOCKETS	 825 NE MULTNOMAH ST STE 2000 PORTLAND OR 97232 oregondockets@pacificorp.com
PORTLAND GENERAL ELECTRIC PATRICK HAGER RATES & REGULATORY AFFAIRS	 121 SW SALMON ST 1WTC0702 PORTLAND OR 97204 pge.opuc.filings@pgn.com
PORTLAND GENERAL ELECTRIC COMPANY J RICHARD GEORGE	 121 SW SALMON ST 1WTC1301 PORTLAND OR 97204 richard.george@pgn.com
RENEWABLE NORTHWEST PROJECT ANN ENGLISH GRAVATT	 917 SW OAK - STE 303 PORTLAND OR 97205 ann@rnp.org
JESSE JENKINS	917 SW OAK ST STE 303 PORTLAND OR 97205 jesse@rnp.org