

2006 IRP Public Input Meeting

Wednesday, June 7, 2006
9:00 am – 3:30 pm (Pacific)

Meeting Summary and Parking Lot Responses

Idaho	Terri Carlock (ID-PUC), Rick Sterling (ID-PUC), Dan Pfeiffer (ID-PUC)
Oregon	Lisa Schwartz (OPUC), Phil Carver (ODOE), Hossein Haeri & Lauren Miller Gage (Quantec)
Utah	Thomas Brill (DPU), Andrea Coon (DPU), Elizabeth Brereton (DPU), Sam Liu (DPU), Joni Zenger (DPU), Cheryl Murray (CCS), Charles Peterson (DPU), Gary Dodge (Hatch, James & Dodge), Becky Wilson (UT-PSC), John Harvey (UT-PSC), Carol Revelt (UT-PSC), Jim Logan (UT-PSC), Nancy Kelly (CCS), Betsy Wolf (SLCAP), Kathy Van Dame (WCAC), Glade Sowards (UDAQ), Ron Slusher (DPU)
Washington	Yohannes Mariam (WUTC), Hank McIntosh (WUTC), Joelle Steward (WUTC), John Klingele
Wyoming	Denise Parrish (OCA), Walter Eggers (Holland and Hart)
Regional	Massoud Jourabch (NWPCC), Eric Guidry (WRA), Lowrey Brown (CUB), Steve Weiss (NVEC), Don Hendrickson (Energy Strategies),
PacifiCorp	<u>In Portland:</u> Greg Duvall, Michael Liljenwall, Dan Swan, Stan Williams, Ken Dragoon, Teri Ikeda, Mike Rife, Irene Heng, Stacey Kusters, Jeff Bumgarner, Don Jones Jr., Cathie Allen, Dina Thompson, Melissa Seymour, Elaine Biggs <u>In Salt Lake City:</u> Pete Warnken, Bill Whitney, Jim Lacey, Ian Andrews <u>In Cheyenne:</u> David Mosier, Bob Tarantola

INTRODUCTION

The main objective for PacifiCorp's sixth Public Input Meeting was to explain, and seek feedback on, the company's proposed scenario modeling and risk analysis approach for evaluating resource portfolios. Other topics covered in the meeting included a consultant project to estimate demand-side management resource supply curves, procurement activity update, selection and derivation of IRP resource options, and overview of modeling approaches for transmission resource and resource adequacy/planning reserve margin analysis.

Prior to the start of presentations, Pete Warnken announced that the company decided to use the June 30, 2006 official forward price curves rather than the March 31 curves as the

basis for fuel and wholesale electricity price forecast assumptions. He noted that the June 30 forecast incorporated some of the suggestions raised by participants at the prior public meeting (May 10, 2006). PacifiCorp agreed to provide participants with a summary of major methodological changes between price curve forecasts. A participant also asked when the most recent PIRA long term gas price forecast was issued.

PacifiCorp noted a public meeting schedule change: the tentatively scheduled July 19 meeting is postponed until September to accommodate the current modeling schedule. Participants raised concerns about the meeting date change, and the impact on participants' ability to review modeling results and provide comments on a timely basis. PacifiCorp agreed to revisit the meeting dates and consider an earlier meeting if it can be accommodated.

Participants also raised the issue of how to best respond with comments on the scenario analysis information provided at this meeting. PacifiCorp responded that it would be best to send written comments to PacifiCorp's IRP mailbox, and gave a target deadline of two weeks to provide comments. The company also suggested that a follow-up conference call or meeting could be arranged if necessary to address comments.

DEMAND-SIDE MANAGEMENT: CLASS I & III RESOURCE ASSESSMENT UPDATE

Quantec LLC, represented by Hossein Haeri and Lauren Miller Gage, presented an update on an IRP project to develop proxy supply curves for PacifiCorp's dispatchable/firm schedulable load control (Class 1) and price-responsive load reduction (Class 3) programs. From these supply curves, PacifiCorp will develop DSM resources to be modeled among with supply-side alternatives using the company's capacity expansion optimization and detailed simulation models.

Quantec first described the project scope, deliverables, and schedule. The basis of the study was a set of five Class 1 program profiles (small thermal energy storage and fully dispatchable direct load control for winter, summer, large commercial/industrial, and irrigation loads) and three Class 3 profiles (interruptible pricing, critical peak pricing, and demand buyback). The program profiles reflect PacifiCorp's proposed program types presented at the February 10, 2006 Technical Workshop on DSM and comments received by participants at that meeting. Quantec also explained that an additional objective of the project was to assess DSM valuation methods used by other organizations and determine what constituted best practices.

Quantec next described their proxy supply curve development methodology. After describing key value factors for customers and utilities and citing the challenges associated with obtaining sufficient customer end-use data, participants discussed the impact of advanced metering on DSM program implementation. Some suggested that PacifiCorp look into the price and timing impacts on DSM programs. Another participant suggested that additional environmental externalities besides criteria pollutants and Green

House Gases should be considered in evaluating DSM program benefits, such as water supply impacts.

Quantec then summarized the supply curve development steps, characterized as a bottom-up approach, and described the primary data sources to be used. These sources consist chiefly of PacifiCorp and U.S. Energy Information Administration survey data as well as various industry studies. Next, Quantec described how PacifiCorp's 2005 load data and Quantec's derived end-use load shapes were used to estimate technical and achievable DSM market potentials (Quantec noted that street lighting and "plug" loads—total of 800 MW—were excluded from the load shapes). Quantec then described two key parameters used to estimate achievable market potential: program and event participation rates. These rates were derived by considering PacifiCorp program experience as well experience from other utilities and Regional Transmission Organizations that have offered similar programs. Participants discussed specific attributes of those DSM programs selected by PacifiCorp for supply curve analysis. Participants questioned the assumption regarding dispatchable load control program availability, stating that PacifiCorp's assumed 87-hour annual limit was too short a time because of opportunities to shave daily afternoon peaks. Quantec responded that the supply curves were developed by looking at maximum program potential; specifically, end use demand during the highest one-percent of peak load.

Quantec staff concluded their presentation by discussing distinguishing characteristics of demand response programs, categorizing them as meeting reliability or economic objectives. Quantec made the point that programs need to be properly accounted for in the IRP based on the planning objective for which they are designed. As an example, programs designed to provide emergency reserves should not also be counted on as firm resources for long-term capacity planning. PacifiCorp emphasized that this example highlighted the problem of ensuring that DSM is not double-counted in the IRP models.

PROCUREMENT UPDATE: DEMAND-SIDE MANAGEMENT AND SUPPLY-SIDE RESOURCES

Jeff Bumgarner summarized the status of PacifiCorp's DSM Request for Proposals (RFP) issued in 2005. Profiles of new programs and program concepts proposed by bidders for Class 1 and Class 2 (energy conservation/efficiency) were provided, followed by a status report on bid evaluation progress. PacifiCorp reported that the company was continuing to evaluate programs. The current focus is to look at additional tools, methodologies, and data for incorporating various system benefits into the proposal economics. The company noted that most proposals were not judged as cost-effective based on the limited assumptions presented in PacifiCorp's 2004 IRP. The Quantec survey of electric utility valuation methods, to be included in Quantec's final report, will be used to support this additional valuation effort, along with the IRP modeling effort itself. PacifiCorp also noted the challenges associated with DSM valuation, including data availability and accuracy, as well as the difficulty in calibrating value estimates to specific bid prices.

One participant mentioned that PacifiCorp should still aggressively pursue load control programs as insurance against uncertainty in load growth.

Participants asked for information concerning PacifiCorp's current coordination activities with respect to Utah gas companies on residential DSM programs. PacifiCorp stated that it is optimistic with regard to partnership opportunities, and is exploring initiatives with Questar.

Stacey Kusters next provided an update on PacifiCorp's two currently active Supply-side Requests for Proposals, RFP 2003B and RFP 2012. PacifiCorp outlined milestone/schedule dates for both RFPs. The company noted that the states have different procurement requirements, and that PacifiCorp will follow all applicable rules for each state.

The company issued an amendment to the Renewables RFP 2003 B—which was due on March 24, 2006—for up to 400 MW to be installed by December 31, 2007. The proposals received contained a mix of purchase power agreements, build-own-transfers, and site sales. The shortlist consists of multiple projects with adequate resource opportunity to meet the 400 MW target by 2007 as specified in the MidAmerican commitment. A participant asked if more than 400 MW would be acquired. PacifiCorp replied that it is interested in all opportunities; however, they would need to be cost-effective.

PacifiCorp summarized the issuance of the schedule for the Draft 2012 Request for Proposal, highlighting the July 11, 2006 filing date for the 2012 Final Draft RFP. Stakeholders were advised they would have an opportunity to submit written comments after the Draft RFP 2012 was issued. One participant sought clarification on the differences between the 2012 Final Draft RFP and the 2004 IRP Update report with respect to the number of coal plants. PacifiCorp replied that background on the 2012 Final Draft RFP coal benchmarks would be addressed in the 2012 Final Draft RFP document and regulatory review process.

IRP RESOURCE ALTERNATIVES

Jim Lacey (PacifiCorp Resource Development & Construction Department) provided an overview of the resource supply options to be evaluated in the 2006 IRP. PacifiCorp recently purchased a license to access technology reference data from the Electric Power Research Institute (EPRI) Technical Assessment Guide (TAG) database. PacifiCorp cited the reasons for using the TAG database, which include consistency in the cost-estimation basis and objectivity of an outside source. The company noted that TAG capital cost and emissions estimates were adjusted to make them more in line with recent company project experience. In response to a participant's question on the extent and consistency of data differences between TAG and PacifiCorp, PacifiCorp noted that the major difference was with coal capital costs; TAG coal plant capital costs were believed to be on the low side based on current construction market trends.

PacifiCorp reviewed the new Integrated Gasification Combined Cycle (IGCC) options added to the IRP resource list, which include (1) IGCC with minimum carbon-capture-ready provisions (both west and east-side resources), (2) IGCC without a spare gasifier, and (3) IGCC with full carbon-capture and CO₂ sequestration. Participants discussed cost differences attributable to the different configurations. One participant noted that the definition of “carbon-capture-ready” is fluid and that PacifiCorp should consider the option value of building extra gasifier and Air Separation Unit capacity up-front versus when sequestration capability is added later. Participants also raised the issue of capturing additional revenue streams from selling gasification byproducts (hydrogen, methanol, clean distillates, etc.) and whether PacifiCorp has investigated partnerships to offset initial construction costs with byproduct revenues. PacifiCorp mentioned that it has discussed partnership opportunities with such companies as Energy Northwest, but noted the regulatory hurdles and core business implications of engaging in byproduct sales.

PacifiCorp noted some additional resource changes for the 2006 IRP, including the addition of a “G” class Combined Cycle Combustion Turbine (CCCT). Participants asked about the treatment of solar and nuclear technologies in the IRP. Regarding solar, PacifiCorp will not model a central station technology because it is not currently cost-effective. For nuclear plants, PacifiCorp responded that such a resource could not be placed in service probably any earlier than 2020, and the current lack of suitable sites is a barrier. Participants asked that PacifiCorp nevertheless address nuclear in the IRP. One participant cited the possibility of combining Compressed Air Energy Storage with wind or a simple cycle gas turbine to level out the capacity factor. PacifiCorp responded that there are sites in Wyoming that may be suitable for such a hybrid project.

PacifiCorp next provided observations concerning capital and operations and maintenance (O&M) cost changes with respect to the 2004 IRP Update. The company noted that many of the cost estimates have increased due to material cost increases and developing shortages of experienced contractors and engineering support. Consequently, the company has decided to develop and report capital cost ranges to reflect price volatility. PacifiCorp also noted that coal resource costs have out-paced gas resource costs in both capital and O&M cost categories. Participants then discussed coal liquids markets and the impact on coal prices.

IRP TRANSMISSION ANALYSIS APPROACH

Ken Dragoon provided a description of the approach for evaluating additional transmission resource options in the 2006 IRP. PacifiCorp first reviewed the updated IRP topology and then summarized seven transmission options that the CEM will evaluate along with generation and demand-side options. These transmission options include (1) “Walla Walla to Mid-C, (2) Bridger to Ben Lomond, (3) Mona to Utah North, (4) additional Path C upgrade, (5) Miners to Ben Lomond, (6) Southwest Wyoming wind to Utah North, and (7) Montana Yellowtail to Bridger (to access south central Montana wind). PacifiCorp explained that these options stemmed primarily from MidAmerican Energy Holding Company transmission analysis commitments and transmission needed

to support wind development. Participants sought additional clarification on what criteria were used to select resources for modeling, as well as specific attributes of the resources (size, engineering, and cost assumptions) and whether a resource is tied to a generation plant or not. Participants then focused on how PacifiCorp will address transmission options for accessing market hubs and regional resources. Oregon Public Utility Commission staff noted the Commission's IRP acknowledgement requirement to analyze such regional transmission projects, and recommended that PacifiCorp identify in the IRP those resource options that address state IRP acknowledgement orders.

PORTFOLIO ANALYSIS SCENARIOS AND RISK ANALYSIS

Pete Warnken described the scenario and risk analysis approach that will be used for the 2006 IRP. Two scenario types were outlined: *Alternative Futures*, which consist of a combination of variable values reflecting different future states, and *Sensitivity Analysis*, which consist of changes to a single variable or resource to determine the effect on portfolio costs. Alternative Future scenarios will be analyzed using the CEM, while sets of Sensitivity Analysis scenarios have been developed for analysis by both the CEM and the Planning and Risk module.

PacifiCorp next outlined the portfolio variables used to define scenarios. The key variables, which will be modeled as “low”, “base”, or “high” values, include CO₂ adder amount, wholesale natural gas prices, wholesale electricity prices, retail load growth, and resource adequacy level (capacity planning reserve margin). Other risk variables include the start of CO₂ regulations, scope of Renewable Portfolio Standards, coal prices, IGCC and wind capital costs, demand-side management program potential, renewable Production Tax Credit availability, and existence of regional transmission projects.

Next, the process flow for deriving a “preferred portfolio” was presented. This process flow consists of (1) CEM portfolio optimization runs to use as a guide for manually selecting candidate portfolios for further analysis (four to five is the target number of candidate portfolios), (2) detailed stochastic analysis of candidate portfolios, and (3) derivation of the preferred portfolio by considering risk-adjusted portfolio costs and non-modeling aspects. PacifiCorp stated that the expected outcome of the CEM optimization studies was four or five candidate portfolios that would be tested

PacifiCorp then reviewed the sets of scenarios and asked for participant comments. Recommendations included adding Oregon to the list of states that are expected to have a Renewable Portfolio Standard, include some variations of the low/high portfolio cost bookend scenarios, and revisit the assumption of a 2010 start date for CO₂ regulations. Oregon Public Utility Commission staff also stated that a separate scenario to study the impact of Class 3 DSM on unserved energy¹ was not necessary; rather, incorporating Class 3 DSM into the 12% planning margin scenario (for detailed stochastic simulation) would meet the Oregon Commission's analysis requirement.

¹ “Energy Not Served” represents kilowatt-hours required by customers that cannot be supplied.

PacifiCorp also asked participants' opinions regarding an appropriate "high" CO₂ adder value, suggesting that either a \$25/ton or \$40/ton value (in 1990 dollars) could be used. A participant stated that a \$25/ton value would be adequate.

RESOURCE ADEQUACY/CAPACITY PLANNING MARGIN

Ken Dragoon described PacifiCorp's approach for analyzing resource adequacy using the capacity planning reserve margin (PRM). PacifiCorp will continue to use a 15% planning reserve margin as a base assumption, but will test alternative margin levels (12% and 18%) using both the CEM and Planning and Risk module. As part of this approach, the company will construct a scenario composed of base forecast assumptions and run the CEM at 12%, 15%, and 18% planning reserve margin levels. To address an Oregon Public Utility Commission IRP analysis requirement, PacifiCorp will perform stochastic modeling of the resource portfolios resulting from the three CEM runs. Participants recommended more extensive testing by either modeling with more planning reserve margin levels or applying a single level (such as 12%) to more than one scenario. PacifiCorp expressed concern over expanding the number of scenarios given time limitations.

In concluding the meeting, PacifiCorp reemphasized that additional time to review the scenarios and provide written comments would be provided. Participants also requested that future meetings be established to correspond to the key portfolio analysis milestones, such as selection of candidate portfolios for stochastic analysis.