# UTAH QUALIFYING FACILITIES IN PLACE SINCE PURPA ENACTMENT

1. Sunnyside
2. Thayne Ranch Hydro
3. Davis County Waste Management
4. Whitmore Oxygen

Recently approved QF contracts for pre-existing facilities

Kennecott Utah Copper Company, January 2005

US Magnesium, January 2005

## UTAH QF PROCEEDINGS SINCE 2003

- On February 24, 2003, in Docket 02-035-T11, the Commission directed PacifiCorp to develop an avoided cost methodogy within 90 days. No methodology was provided.
- On September 24, 2003, in Docket 03-035-14, the Commission ordered PacifiCorp to file a revised avoided cost methodology within 60 days. Again, nothing was provided by the utility.
- A working group was established in 2003 and met sporadically to try and resolve the issues. No consensus was reached on a methodology.
- In February of 2004, PacifiCorp finally made a filing with a proposed pricing methodology for the large QFs.
- In April 2004, intervenors filed direct testimony on PacifiCorp’s filing.
- In May 2004, intervenors filed rebuttal and surrebuttal testimony on PacifiCorp’s filing.

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# Research:

## Summary: PacifiCorp

**Publication Date:** 05-Mav-2005
**Primary Credit Analyst(s):** Anne Selling. San Francisco (1) 415-371-5009; anne_setting@standardandpoors.com

**Credit Rating:** A-/Stable/A-

## ■ Rationale

The ratings on PacifiCorp reflect an average business profile, a diversified service territory, a reasonably balanced generation portfolio, and recent favorable regulatory treatment in the six western states it serves. PacifiCorp comprises about 45% of ultimate parent Scottish Power's operating profit. The consolidated Scottish Power financial profile has remained adequate for the rating, despite the fact that the utility's financial profile was until recently strained by significant amounts of deferred power costs.

Since 2002, PacifiCorp has been recovering the sizable power costs it incurred during the western energy crisis in 2000 and 2001. Collection in retail rates of about $303 million of the $537 million that PacifiCorp deferred began in fiscal 2003. But by the end of Dec. 31, 2004, the utility had collected in retail rates all but $26 million in deferred costs, and full recovery is expected to be completed over the next six months.

PacifiCorp faces near-term challenges to its financial performance that are expected to be compensated by the continued strength of Scottish Power consolidated operations. Scottish Power announced last November that collectively PacifiCorp and PacifiCorp Group Holdings Co. (PGHC) would likely fall short of a fiscal 2005 target of $1 billion in earnings before interest and taxes (EBIT, reported on a U.K. GAAP basis), due largely to plant performance and weaker electricity sales at PacifiCorp. (This target excludes the operations of PPM Energy Inc., which is also a subsidiary of PacifiCorp Holdings Inc. [PHI].) The company plans to publish full-year earnings for fiscal 2005 in late May.

Fiscals 2006 and 2007 are forecast to also remain flat on a U.K. GAAP reporting basis. In March, Scottish Power advised that PacifiCorp's first six months of fiscal 2006 performance could be adversely affected by low hydro availability in the Pacific Northwest. About 10% of PacifiCorp's installed capacity is hydro generation, typically supplying between 4% to 8% of the utility's annual generation requirements. Management has estimated that replacement power costs could total about $60 million during calendar 2005. To allow deferred recovery of these expected costs, PacifiCorp recently filed with the Oregon state commission for permission to establish a deferred power account and is expected to do so in Washington.

The absence of a power cost adjustment mechanism in any of the states PacifiCorp serves is an ongoing credit concern because of the uncertainty over the timing and ultimate recovery of potential, new deferred power costs. However, the utility is pursuing adjusters with regulators, and regulatory relationships are stable. In February, the Utah Public Service Commission approved a $51 million rate case settlement, providing a 4% increase that began March 1 and represents a 10.5% return on equity (ROE). In February 2005, the state enacted Senate Bill (SB) 26, which establishes a resource procurement process for PacifiCorp that should substantially increase the utility's prospects for cost recovery. The utility has a pending rate casein Oregon, which is expected to be decided sometime in 2005. Also, four of the six states served by PacifiCorp have approved an agreement for allocating common costs, referred to as the multi-state process, which should streamline recovery of these costs.

Another significant challenge is to effectively manage a $3 billion capital expenditure program. The company is currently building two new gas-fired combined cycle plants. About 280 MW of Currant Creek is expected on line this summer, with 525 MW added by 2006. Lakeside, a 534-MW plant, is expected to be commercial by summer of 2007. Both projects are on time and on budget.

PacifiCorp is headquartered in Portland and serves about 1.6 million retail customers in a 136,000-square-mile service territory in portions of Utah, Oregon, Wyoming, Washington, Idaho, and California. Business is conducted under the legal names of Pacific Power and Utah Power & Light. PacifiCorp is a wholly owned subsidiary of PHI, which in turn is a non-operating, direct, wholly owned subsidiary of U.K. holding company Scottish Power pic.

**Short-term ratings factors.**

The short-term rating on Scottish Power, Scottish Power U.K. PLC, and PacifiCorp is 'A-2'. In the short term, the companies are expected to have ample internal liquidity, owing to a steady, predictable net cash flow stream produced by regulated businesses, minimal debt maturities over the next few years, good credit facility capacity, and more stable pricing in the western U.S. power markets. Scottish Power's discretionary cash flow after dividends and capital expenditure is expected to be negative in 2004, but its sizable unrestricted cash balance should finance any shortfall. Cash balances, amounting to £424 million at Dec. 31, 2004, are held in a variety of quickly accessible funds.

Scottish Power has sufficient liquidity to cover its outstanding debt obligations and good financial flexibility to access funds in the event of unexpected cash flow interruptions. Full capacity exists under a $1 billion revolving credit facility, split between a $625 million facility and a $375 million facility, both due in 2008. Scottish Power U.K. maintains a $2 billion Euro-commercial paper program, which is undrawn. Liquidity was further enhanced by the issuance of $1.5 billion of long-term debt during March 2005.

PacifiCorp provides for its own liquidity needs. PacifiCorp's cash and cash equivalent position was $25 million as of Dec. 31, 2004, down from $59 million as of March 31, 2004. Liquidity is enhanced by the utility's $800 million commercial paper program. As of Dec. 31, 2004, the company had drawn $285 million in commercial paper. An $800 million revolver executed in May 2004 backstops the commercial paper program. There were no borrowings under the facility as of Dec. 31, 2004. Regulatory authorities limit PacifiCorp from issuing more than $1.5 billion in short-term debt.

PacifiCorp's discretionary cash flow after dividends and capital expenditure is expected to be negative in fiscal 2005. PacifiCorp's long-term debt outstanding was $3.7 billion as of Dec. 31,20O4, excluding current maturities. Future maturities of $289 million in fiscal 2006 are in line with historic obligations. Affiliate transaction rules restrict PacifiCorp from lending to any of PHI's subsidiaries or U.K. affiliates.

## ■ Outlook

The stable outlook reflects consolidated Scottish Power's financial ratios that are adequate for the rating and the steady operational and financial performance at the company's regulated subsidiaries. To maintain the rating. Standard & Poor's expects Scottish Power to produce cash flow coverage ratios commensurate with the 'A-' level-adjusted FFO interest coverage of about 4.0x and adjusted FFO to debt of 20%-and to manage its U.K. generation and supply and U.S. unregulated energy management business conservatively. An improvement in the ratings is less likely, given the sizable capital expenditures for both the U.K. and U.S. operations, and management's expectations that PacifiCorp's financial performance over the next few years will remain flat.

## ■ Accounting

PacifiCorp is one of four subsidiaries of PacifiCorp Holdings Inc. (PHI), which is an indirect subsidiary of Scottish Power pic. Other companies under PHI are unregulated and consist of PPM Energy Inc. (PPM), Pacific Klamath Energy Inc. (PKE); and PacifiCorp Group Holdings Co. (PGHC), a holding company for non-regulated companies, including PacifiCorp Financial Services Inc. (PFS).

PacifiCorp's financial statements are prepared under U.S. GAAP standards and are audited by PriceWaterhouseCoopers LLC, which provided an unqualified opinion for fiscal 2004, which ended March 31, 2O04. PacifiCorp's financial statements are also reported as part of its parent, Scottish Power, whose audits are prepared under U.K. GAAP by PWC. PacifiCorp is the only subsidiary under PHI that has issued public debt in the U.S., and as such is the only PHI Company that is required to file before the Securities and Exchange Commission (SEC). Scottish Power's financial segment reporting combines the results of operations for both PacifiCorp and PGHC, whereas U.S. filings reflect the stand-alone results of the utility.

Comparison of PacifiCorp's financial results as filed with the SEC to those reported by Scottish Power's requires making a number of adjustments to reconcile differences between U.S. and U.K. GAAP accounting as well as the inclusion of PGHC. The largest difference is attributable to the differing treatment of PacifiCorp's recovery of sizable power costs incurred several years ago. Under U.K. GAAP, PacifiCorp's replacement power obligations were expensed in full when incurred on Scottish Power's income statement. But under U.S. GAAP FAS 71 allowed the utility to create a regulatory asset on the utility's balance sheet. As PacifiCorp has collected these deferred costs in rates, its income statement has reflected the amortization of deferred power costs as an expense under U.S. GAAP, providing a smoothing effect for PacifiCorp net income. In contrast, as the recovery of deferred costs flows directly into revenues, with no offsetting amortization expense, U.K. GAAP earnings have been boosted over the period of recovery. In fiscal 2004, for example, U.S. GAAP EBIT for PacifiCorp and PGHC was $685 million, but on a U.K. GAAP basis, EBIT was $945 million. Power cost deferrals accounted for $110 million of this difference. With the pending completion of recovery in fiscal 2006, the wedge between U.K. and U.S. GAAP will narrow, but other recurring adjustments to depreciation and other accounts will remain. And, beginning in April 2006, Scottish Power will adopt International Accounting Standards. PGHC is involved in the receipt of revenues under synthetic fuels contract and the leasing of commercial aircraft.

PacifiCorp has sizable power purchase obligations, and as a result, Standard & Poor's Ratings Services has added about $570 million to the utility's balance sheet that predominantly reflects long-term power purchase agreements (PPAs) and about $46 million in operating leases. Standard & Poor's uses a 50% risk factor in calculating off-balance sheet debt associated with these PPAs. The passage of SB 26 implies that a lower risk factor will be utilized for future Utah PPAs that fall under the protection of the new legislation.

UAE Exhibit 1.4 (SAG-4)
Direct Testimony of Scott Gutting
UPSC Docket No. 03-035-14
July 29, 2005
18 Pages

ITEM NO. 2

**PUBLIC UTILITY COMMISSION OF OREGON**
**STAFF REPORT**
**PUBLIC MEETING DATE: February 3, 2004**

**REGULAR** __X__ **CONSENT** ____ **EFFECTIVE DATE** __February 4, 2004__

**DATE:** January 23, 2004

**TO:** Lee Sparling through Ed Busch and Jack Breen

**FROM:** Lisa Schwartz

**SUBJECT:** PACIFIC POWER AND LIGHT: (Docket No. UM 1118) Request for proposals for renewable resources (RFP 2003-B) filed in compliance with Commission Order No. 91-1383.

## STAFF RECOMMENDATION:

Staff recommends the Commission find that PacifiCorp's request for proposals for renewable resources (RFP 2003-B), as filed October 17, 2003, and amended January 27, 2004, is in compliance with bidding guidelines established by Order No. 91-1383, as most recently interpreted in Order No. 03-356 and Order No. 03-387, and is consistent with the company's acknowledged 2003 Integrated Resource Plan. Staff recommends that the Commission approve the RFP to be issued on or after February 4, 2004.

Staff also recommends that the company be directed to submit the following information to the Commission in lieu of using an independent consultant to monitor, validate and audit the RFP process:

a) The detailed scoring criteria and weightings the company will use to decide which projects make the short list – *Before March 9, 2004*

*In the RFP Summary Report within 45 days of completing negotiations*[1]*:*

b) Detailed initial price and non-price scoring results for all bids
c) Detailed price and non-price scoring results for short-listed bids as revised after negotiations, including present value revenue requirements, and any subsequent economic analysis of Financial Accounting Standards Board requirements and credit rating agency considerations
d) The forward price curves used for the cost-effectiveness analysis
e) Further documentation of the RFP process, including:
    - Total number of parties participating

[1]Staff expects that PacifiCorp will seek a protective order and confidential treatment for items (b), (c) and (d).

- Total number of bids
- Number of short-listed bids
- Total MW and total expected aMW for all bids *and* short-listed bids by proposed on-line date and control area to be served (East or West)
- Number of total bids *and* number of short-listed bids by project size (MW and aMW), proposed on-line date, control area to be served, state, fuel source, construction status (existing, construction in progress, or new), contract duration, type of transmission (firm vs. nonfirm), and offer of equity or turnkey ownership

Staff further recommends that in the event PacifiCorp's analysis of bids finds insufficient cost-effective projects to meet the megawatt targets in RFP 2003-B, after including any contributions from the Energy Trust and considering whether the status of the federal Production Tax Credit limits the viability of the bids altogether, the company be required to report in its RFP Summary Report to the Commission whether any of the near cost-effective, short-listed projects would have been considered cost-effective if an additional $5 per MWh value (associated with portfolio risk reduction, for example) could be demonstrated to be associated with the bid proposal.

In addition, staff recommends that if PacifiCorp considers the potential effects of existing and new Financial Accounting Standards Board requirements or rating agency considerations on the cost of a particular power purchase agreement, the company do so only *after* the company performs cost-effectiveness analysis for short-listed proposals. If subsequent economic analysis properly identifies that an adjustment in costs for a short-listed proposal related to these requirements and considerations is appropriate, the company could factor that analysis into its decision-making, provided it retains such analysis for subsequent staff review.

Staff also recommends that PacifiCorp be allowed to use its generic power purchase agreement (PPA) in the bidding process with the following provisos:

a) The company must modify its scoring standard so that a bidder's score is not reduced for modifying the PPA in a manner that benefits or is neutral to the company and its customers; and
b) The company will allow bidders to negotiate final contract terms that are different from the generic PPA so long as the negotiated terms constitute contract provisions that are acceptable to PacifiCorp on a legal, contractual, credit and other business basis.

Finally, staff recommends that the Commission expressly note that, by allowing PacifiCorp's use of a generic PPA, it is neither approving the PPA in its entirety nor endorsing any specific term of the PPA.

**DISCUSSION:**

The Commission acknowledged (in part) on August 25, 2003, PacifiCorp's most recent Integrated Resource Plan (IRP), with agreed-upon modifications (*Order No. 03-508*). Action plan items 18 and 19 call for an RFP for 1,100 megawatts (MW) of wind resources on the East and West sides of the company's system staged from 2005 through 2010[2], with acquisition dates moved up if economic to do so. Action item 20 calls for an RFP for other renewable resources that could be implemented in addition to, or instead of, the wind resources proposed.

PacifiCorp filed its proposed RFP for renewable resources with the Commission on October 17, 2003, to carry out these action plan items, in compliance with bidding guidelines established by Order No. 91-1383. On December 9, 2003, the company requested that the Commission's consideration of the filing be deferred until its meeting on January 6, 2004. On January 2, 2004, the company requested deferral until a later date.

The company amended its filing on January 27, 2004, to:

- Revise the RFP schedule consistent with the delay
  - RFP issue date - February 4, 2004
  - Pre-bid conference – February 11, 2004
  - Intent to bid form due – February 19, 2004
  - Proposals due - March 9, 2004
- Correct an error in the environmental weighting for low-impact hydro resources
- Require bidders to submit bids with — and without — the federal Production Tax Credit for certain renewable energy projects (to recognize that Congress has not yet passed an energy bill that renews and potentially expands the tax credit)
- Change its approach for evaluating cost-effectiveness of short-listed bids from the IRP methodology to an assessment of equivalent-value energy based on a forward price curve analysis
- Address the potential effects of existing and new Financial Accounting Standards Board requirements that require long-term PPAs be fully disclosed as debt on a utility's books under some circumstances, as well as rating agency considerations

The company held a workshop for non-bidder stakeholders on August 29, 2003, to discuss RFP objectives, timeline, bid requirements, points of delivery, transmission issues, bid evaluation factors, and the process for post-bid negotiations and to get feedback on several issues. The company held a workshop for potential bidders on September 10, 2003, to discuss these topics and to provide an opportunity for questions and input. Thirty-five renewable resource industry representatives attended. PacifiCorp

[2]PacifiCorp fiscal years 2006-2011.

posted answers to all subsequent questions from potential bidders on its Web site so everyone would have access to the same information. The company also posted all RFP documents on its Web site at the time it filed them with the Commission.

The Energy Trust of Oregon has indicated that it has approximately $2 million to $4 million to contribute toward any above-market costs of projects that would benefit PacifiCorp's Oregon customers. Bidders must contact the Energy Trust directly to discuss funding possibilities.

The RFP provides a clear synopsis of the solicitation process as required by the Commission's order on PacifiCorp's RFP 2003-A (*Order No. 03-356*). However, the company does not propose to use an independent consultant as required by that order. Staff addresses this issue and others below.

*No independent consultant*
Order No. 03-356 requires that for any future request for proposals PacifiCorp may wish to issue, it "[u]se an independent consultant to administer, validate and audit the RFP process."

The company proposes not to use an independent consultant for this RFP because there is no self-build option, the RFP excludes affiliates from bidding, and, as a result, the company believes the expense is unwarranted. Staff agrees with the company that an independent consultant is not needed under these circumstances.

In lieu of a self-build alternative, the company proposes to use a forward price curve analysis to evaluate the cost-effectiveness of short-listed projects. Staff recommends that the company be required to provide the Commission the forward price curves it uses in its analysis — as well as the initial price and non-price scoring results for all bids and the scoring results for short-listed bids as revised after negotiations, including present value revenue requirements. This information should be part of the company's RFP Summary Report, which staff proposes the company submit to the Commission within 45 days of completing negotiations.

In addition, staff recommends that PacifiCorp be required to include the following information in its Summary Report:

- Total number of parties participating
- Total number of bids
- Number of short-listed bids
- Total MW and total expected aMW for all bids *and* short-listed bids by proposed on-line date and control area to be served (East or West)

- Number of total bids *and* number of short-listed bids by project size (MW and aMW), proposed on-line date, control area to be served, state, fuel source, construction status (existing, construction in progress, or new), contract duration, type of transmission (firm vs. nonfirm), and offer of equity or turnkey ownership

Prior to the deadline for proposals, staff recommends that PacifiCorp be required to provide to the Commission the *detailed* scoring criteria and weightings the company will use to decide which projects make the short list. PacifiCorp originally objected to the mid-process submission of this information on the basis that it exceeds the Commission's role as defined in Order No. 91-1383. The company withdrew this objection with the following understanding: (1) this is the only information being reviewed mid-process; (2) staff will not seek to modify the company's approach to this RFP mid-process; and (3) the Commission will review the competitive bidding process, including the issues implicated by this condition, in an upcoming docket on competitive bidding.

Another alternative for the Commission's consideration, of course, is requiring an independent consultant to monitor, validate and audit the bidding process. One of the roles of the consultant is to review the detailed criteria and weightings and validate that the company applies them in an unbiased manner. The Commission could choose to require an independent consultant to guard against utility bias in favor of turnkey proposals (where the utility assumes ownership of the facility upon completion, puts it in rate base and earns a return) or to guard against the company rejecting some or all bids so it can build its own projects, powered by renewable resources or other fuels.

*Risk analysis*

For its Integrated Resource Plan (IRP), PacifiCorp evaluated both the cost and risk of potential resource portfolios. The company used present value revenue requirements (PVRR) as the main cost metric to rank portfolios. The company performed Monte Carlo simulations to assess the variability of PVRR and portfolio stochastic risks. Using this analysis, PacifiCorp chose the portfolio with the lowest cost and the lowest risk, which included 1,400 MW of renewable resources.

Based on its IRP analysis, the company decided to issue an RFP for renewable resources. In conducting its bidding process, PacifiCorp proposes to evaluate short-listed projects using a least-cost standard. The company also intends to use the generic PPA, submitted with the RFP, and bilateral negotiations to mitigate certain risks associated with a particular proposal.

The IRP did not assess risk for *individual* resource projects; instead, it evaluated risk for an entire *portfolio* of new resources (added to the company's resource base). The IRP also did not determine what cost premium, if any, would be appropriate for the company to pay in the event a portfolio resulted in a higher cost, but lower risk.

PacifiCorp does not have direction from this Commission — or the regulatory authorities in the other five states it serves — on how to make such a cost-risk tradeoff for a portfolio of resources or for individual resource projects. Therefore, the company does not propose for this RFP to assess how an individual renewable resource project (or portfolios of selected projects) could reduce the risk of future revenue requirements being higher than expected. Nor does the company propose to assess any cost-risk tradeoff.

Staff believes resource planning and resource acquisition should be functionally integrated and suggests two ways to maintain an integrated IRP/RFP process:

- The utility could simply acquire the level of renewable resources specified in its IRP action plan, if its analysis of bids shows that the selected projects are cost-effective. In that case, the bid prices validate the assumed costs of renewable resources in the IRP, and the updated forward price curves are close to the curves used for the IRP.
- The utility could calculate both the cost and risk metrics of short-listed resources in the same manner as in the IRP and acquire projects based on the results.

Another option is for the utility to estimate the hedge value of renewable resources — the value of their long-term price stability (avoiding natural-gas price volatility and the risk of further regulation of $CO_2$ and other pollutants).[3] The fuel cost for wind, for example, is always zero, and it is pollution-free. Staff believes the risk analysis PacifiCorp conducted for its IRP is superior to simply assigning an estimated hedge value to short-listed projects. However, staff believes that if the utility does neither during the bidding process, we will not know whether the resulting resource mix represents the best combination of cost and risk.

Staff believes that regulators should provide guidance to the electric utilities on this cost-risk tradeoff in the context of integrated resource planning and competitive bidding. The Oregon Commission already has included in the issues list for its least-cost planning investigation (UM 1056) whether IRPs should explicitly measure and consider the cost-risk tradeoff. That investigation also should explore *how* to do that tradeoff.

Staff expects the Commission to open an investigation into competitive bidding, and we believe the cost-risk tradeoff also should be addressed in that docket. In its 1991 order

[3]Lawrence Berkeley National Laboratory, for example, estimates the fuel-price hedge value of wind resources at $0.40/MMBtu to $0.80/MMBtu, or 0.3¢/kWh to 0.6¢/kWh. (Mark Bolinger, Ryan Wiser, and William Golove, *Accounting for Fuel Price Risk: Using Forward Natural Gas Prices Instead of Gas Price Forecasts to Compare Renewable to Natural Gas-Fired Generation*, August 2003, LBNL-53587, http://eetd.lbl.gov/ea/EMS/reports/53587.pdf)

on competitive bidding, the Commission noted that "[b]idding should be viewed as one of many pathways the utility may follow to achieve the least-cost planning goal of acquiring the resource mix with the *best combination of expected costs and variance of costs*." [Emphasis added.]

Meantime, as a step toward accounting for the hedge value of renewable resources in resource acquisition, the company offered the following condition for RFP approval: In the event PacifiCorp's analysis of bids finds insufficient cost-effective projects to meet the megawatt targets in RFP 2003-B, after including any contributions from the Energy Trust and considering whether the status of the federal Production Tax Credit limits the viability of bids altogether, the company must report in its RFP Summary Report to the Commission whether any of the near cost-effective, short-listed projects would have been considered cost-effective if an additional $5 per MWh value (associated with portfolio risk reduction, for example) could be demonstrated to be associated with the bid proposal. Staff believes that PacifiCorp's proposed condition is an appropriate step at this time toward addressing the cost-risk tradeoff.

*Acquisition schedule*
The RFP calls for the following acquisition schedule:

| Control Area | Size (MW) | Target Delivery Date |
|---|---|---|
| West | 100 | April 2005 |
| | 200 | April 2007 |
| | 200 | April 2009 |
| East | 200 | April 2006 |
| | 200 | April 2008 |
| | 200 | April 2010 |
| **Total** | **1,100 MW** | |

The RFP notes that PacifiCorp will consider acquiring resources ahead of this schedule if economic to do so, consistent with the Commission's order acknowledging the company's IRP.

One of the largest wind developers in the country, FPL Energy, suggests acquiring the 1,100 MW of renewable resources through two RFPs — one RFP to acquire the first 100 MW on the West side and the first 200 MW on the East side, and the second RFP to acquire the remaining 800 MW system-wide. FPL Energy believes there would be fewer bids and they would be less complex, expediting the evaluation process and awarding of projects for the early years. The developer also notes that wind turbine technology is changing rapidly, and beyond 2006, far larger turbines than are used today will be the norm. Their pricing is not yet known. But FPL Energy states that a substantial reduction in capital costs is possible, and PacifiCorp could reduce procurement costs for later delivery dates by issuing an RFP for those resources at a later time.

Staff believes the current RFP structure allows bidders flexibility in its offers to PacifiCorp. They can range from strict adherence to the target delivery schedule, to earlier delivery dates or larger projects in the earlier years. In addition, the company may issue additional solicitations for renewable resources in the future in the event that insufficient economic resources are identified in this RFP.

Further, one of the reasons for moving up the acquisition dates for renewable resources, if economic to do so, was to take advantage of the best sites. Including all of the acquisition targets in a single RFP today is consistent with that goal.

Sizable federal depreciation benefits are scheduled to expire at the end of 2004, and they may make it possible for PacifiCorp to acquire attractive projects by year-end. FPL Energy and Ridgeline Airtricity Energy noted in their comments the importance of a timely RFP schedule for that purpose. Ridgeline further noted that the process should continue at an expeditious pace despite uncertainty over extension of the federal Production Tax Credit. The developer stated that PacifiCorp should award by mid-year any projects for 2004 on-line dates.

*Generic power purchase agreement*
PacifiCorp's RFP includes a generic PPA. Conforming with its provisions — and RFP requirements — counts for up to 15% of the score the company will use to determine the short list.

PacifiCorp states that it will consider conformance with the generic PPA in its evaluation of bids for two reasons: (1) to identify the terms that accompany the bid price and (2) to allow an easier comparison of bids, resulting in a more timely evaluation process. The company included this scoring standard based in part on its recent experience evaluating and negotiating bids for a wind project developed in cooperation with the Energy Trust of Oregon.

In initial comments to staff on the generic PPA, FPL Energy stated that it appeared to be drafted for a gas-fired facility rather than a wind project. The developer also stated that a number of the provisions would preclude projects from being financed on a nonrecourse basis, resulting in fewer bidders and higher prices. FPL Energy submitted a form of PPA that it states has been widely accepted in the marketplace and has proven to be financeable.

Staff requested that FPL Energy state explicitly which provisions would pose difficulties for financing or would unduly increase the cost of projects. The developer subsequently filed specific comments on the generic PPA.

Among the PPA provisions FPL Energy views as inappropriate for a wind farm is a prohibition on maintenance during most hours for seven months of the year. While that provision may be reasonable for a 300 MW natural gas-fired plant, it may not make sense for a wind farm composed of 1 MW turbines. FPL Energy suggests allowing planned maintenance outages any time of the year, so long as the outage accounts for less than 10% of the site capacity. FPL Energy also states that it is customary to consider that the commercial operation date for a wind project has occurred once commissioning certificates have been issued for 90% of the turbines, rather than when the project is 100% complete, as the generic PPA requires.

PPA provisions that FPL Energy believes would affect financing of projects include minimum guaranteed output, termination for failure to meet a milestone by the due date, and termination for the seller being in default under any commercial agreement. In many cases, FPL Energy suggests alternative provisions that it believes reasonably address the intent of the generic PPA terms. For example, it outlines a mechanical availability guarantee in lieu of an output guarantee, as well as provisions for a guaranteed commercial operations date with delay damages, instead of termination for missing a milestone.

FPL Energy also states that the PPA should include certain assignment and notice provisions for lenders, specify that PacifiCorp will provide audited financial statements to lenders, and state that PacifiCorp will post security in the event that its rating is downgraded below investment grade. In addition, FPL Energy notes that the PPA must be changed to comply with the new FERC interconnection agreement for large generators.

Another wind developer, RidgeLine Airtricity Energy, informed staff of two concerns it has with the generic PPA. Of greatest concern is a provision that gives PacifiCorp the right of first offer to purchase the project. As drafted, RidgeLine says the provision gives PacifiCorp the right to match any offer, so other parties will not invest the resources required to evaluate any purchase of the facility. RidgeLine believes the provision severely limits the ability of a project owner to realize the value of its project, and this “option” has a cost to the developer that will result in higher bid prices. Further, RidgeLine believes it will be difficult for PacifiCorp to determine the value of this option and compare it with alternatives.

RidgeLine believes that the developer should realize the value of the project because it is in the best position to maximize that value, and ratepayers would benefit from a lower bid price. RidgeLine therefore requests that the Commission instruct PacifiCorp not to use a developer’s response in agreeing to this provision when the company is evaluating bids.

RidgeLine’s second issue concerns credit requirements in the generic PPA, which require the developer to post substantial security so that PacifiCorp will not face any loss when purchasing replacement power in the event of a prolonged delivery interruption. RidgeLine believes this requirement is an “extremely expensive“ way for PacifiCorp to address these concerns. RidgeLine further comments that the credit requirements favor large developers that will not have to post letters of credit, and that limiting the ability of smaller players to compete would lead to higher bid prices. Therefore, RidgeLine requests that the Commission instruct PacifiCorp to give full consideration to more cost-effective levels of security and mechanisms for achieving them in order to keep bid prices down.

U.S. Geothermal also points out that the security requirements will be difficult for small developers and expensive for all developers. U.S. Geothermal says that a flat cap of some percent of the total initial project value may be more satisfactory. Staff believes another alternative could be a type of liquidated damages in the form of acquiring remaining equity in the project.

U.S. Geothermal further notes that there are substantial penalties for late startup. It suggests reducing the size of the Project Development Security to one year of the project's output times 1/2 cent per kWh and making "unlimited liability" apply only to "willful" breach of contract.

Staff agrees that it may be difficult for developers that are not a subsidiary of a financially secure parent, or whose financial statements do not reflect an entity that would have such a rating, to meet the security requirements in the generic PPA. The security is required only for companies that do not have a credit rating for senior-secured, long-term debt of at least Baa2 (Moody's) or BBB (S&P). But smaller companies and startup ventures may not be rated and may incur significant cost to acquire a rating, if such a rating can be acquired at all. Also, a company’s rating may be linked to the counter-party risk, depending on the concentration of that company’s transactions with a single counter-party. Therefore, any reduction in PacifiCorp’s rating could affect the seller, especially if it owns only a single project that is contracted to

PacifiCorp. Contract language that excludes the potential for a negative impact on a provider may mitigate this concern.

In lieu of a satisfactory credit rating, bidders may meet default security requirements three ways:

*Cash escrow*: Cash can be escrowed on a general basis or maintained on a margining basis, depending on PacifiCorp's exposure to changes in forward power prices should the bidder not fulfill its obligations. Margining on the basis of changes in power prices requires an ongoing assessment of the difference between forward market prices for power and the contract price. If there were spikes in the market price, the required security could change significantly. The seller would have to increase the security within the number of days specified in the contract.

The terms for the margining calculation are unclear in the generic PPA. It appears that forward power prices would need to be calculated constantly. The required amount would be limited only by the following 18-month contract price. Because a falling price structure would require ever-increasing escrow amounts as market prices diverge from contract prices, there would be little incentive for bidders to offer a falling price structure even though it may be economic for the company and its customers. PacifiCorp responds that the actual terms would be set forth in each contract, and that the seller would have the right to the return of the cash collateral upon a drop in forward prices.

*Letter of credit*. Small companies or startup ventures may not have access to a potentially large letter of credit that may be necessary to meet the sum described above.

*Guaranty*. Small companies (without a parent) may not have access to a guaranty.

U.S. Geothermal also questions the termination provisions in the draft PPA, which state that the contract may be ended if the seller fails to substantially perform its obligations for a period exceeding 180 days, even in the case of a force majeure event. U.S. Geothermal states that this could make the contract unfinanceable, or the lender will view this provision as a major risk, significantly increasing financing costs. U.S. Geothermal asks whether a PacifiCorp-owned project that was unable to generate power for six months would be forever removed from the rate base. U.S. Geothermal requests that the termination provision be dropped from the force majeure clause or that termination be allowed for force majeure events after a longer period of nonperformance to make this risk more reasonable for the developer to bear.

With the following reservations, staff does not oppose PacifiCorp's use of a generic PPA in the RFP process:

PacifiCorp should modify the bid scoring standards so that a bidder's score is not penalized or reduced for modifying the generic PPA in a manner that benefits or is neutral to the company and its customers. In other words, the Commission should not allow PacifiCorp to use the perceived value of having a generic PPA to supersede the value to ratepayers of having a bidder submit a modified PPA that has better prices and business terms otherwise acceptable to the company.

Staff also understands that despite the use of a generic PPA in the bidding process, bidders will still be able to negotiate terms with PacifiCorp in arriving at a final contract. Staff believes this is appropriate and urges PacifiCorp to make sure all potential bidders know that the generic PPA terms are ultimately negotiable, as long as such negotiated terms don't reduce value to the company and its customers.

Finally, staff emphasizes that by not opposing PacifiCorp's use of a generic PPA in the bidding process, staff is not recommending approval of the PPA in its entirety nor is it endorsing any particular term of the PPA.

Staff believes that PacifiCorp will work with bidders to reach reasonable contract provisions that meet the requirements of both parties. However, if staff's review of the RFP process finds that PacifiCorp has attempted to impose contract provisions that eliminated cost-effective projects that also were otherwise favorable to the company and its customers, and the company does not meet the acquisition targets in its IRP, that may become a factor in evaluating PacifiCorp's resource decisions in a future rate case. Staff also will recommend that the types of issues raised here by developers be further explored in the Commission's forthcoming investigation into competitive bidding.

*New accounting requirements*
Since its initial filing, PacifiCorp raised two recent actions by the Financial Accounting Standards Board (FASB) that may require long-term PPAs to be included on a utility's accounting books:

1. Modification and Clarification of FASB Interpretation No. 46[4] requires assets and liabilities of a Variable Interest Entity[5] to be consolidated on the purchaser's books (effective March 31, 2004).

[4] Originally issued in January 2003.
[5] Variable interest entities, formerly called special purpose entities, are structured in such a way that (a) the equity investment is not sufficient for the entity to be financed without subordinated support or (b) the direct investors have limited decision-making powers, do not absorb losses and do not receive residual returns.

2. FASB Emerging Issues Task Force Issue No. 01-08, implemented July 1, 2003, affects how companies must review power purchase contracts under lease accounting rules.

The first item could affect PacifiCorp. It appears that it would apply if the company is considered the primary beneficiary of an entity, but it may be inapplicable if the company is not at risk for losses or does not take any residual profits from the project.

The second item provides further guidance on lease accounting. For several decades, FASB has required full disclosure of the material impacts of leasing transactions. The new task force decision affects what types of alternative contracts, such as certain types of PPAs, may be viewed as leases and would need to be disclosed as such. Under certain conditions, the utility would be required to follow specific reporting requirements for a PPA. It is not clear how the increased transparency would affect perceptions of investors or application of credit ratings. Presumably, rating agencies already consider the impact of PPAs on cash flows and will continue to do so, as they have historically. It also is not clear how the development industry will react to the new accounting requirements.

PacifiCorp discussed with staff whether the effects of a long-term PPA on the company's cash flows would be viewed similarly to debt financing. PacifiCorp represents that PPAs may have an implied interest rate higher than the company's cost of debt. However, the effect, if any, is specific to the terms and conditions of the particular PPA. PacifiCorp also represents that the cash flow impacts may affect its cost of certain long-term PPAs, and that it must account for any changes in incremental debt and interest costs in its evaluation of bids for RFPs. (The company says it also must consider this cost for new Qualifying Facility contracts and renegotiation of any existing contracts.)

The company further indicated that having to account for agreements as leases would likely affect the perceived riskiness of the company, and the increased risk would increase its cost of capital, all else being equal. Staff is less sure. The investment community may view favorably the increased transparency associated with the new disclosure requirements.

How a PPA must be included on the utility's books under the new requirements depends on the structure of the contract. Thus, the structure of each proposed transaction must be reviewed separately. One way to avoid the leasing issue altogether is if PacifiCorp assumes ownership of the facility upon completion. However, the company says its ability to take an ownership position at this time is limited by financial constraints and lack of experience in operating renewable energy facilities.

Staff does not believe PacifiCorp has demonstrated that changes in FASB requirements will *necessarily* have a material impact on its costs for long-term PPAs. Staff recommends that if PacifiCorp considers the potential effects of existing and new FASB requirements or rating agency considerations on the cost of a particular PPA, the company do so only *after* the company performs cost-effectiveness analysis for short-listed proposals. If subsequent economic analysis properly identifies that an adjustment in costs for a short-listed proposal related to these requirements and considerations is appropriate, the company could factor that analysis into its decision-making. Staff recommends that any such economic analysis be included in the company's RFP Summary Report to the Commission. It is staff's understanding that PacifiCorp could obtain specific advisory opinions from each rating agency that support the company's assumptions.

Staff's proposal provides for a more disciplined economic analysis — and allows staff in subsequent reviews of the RFP process to examine the company's assumptions and analysis regarding the potential effects of the PPA and the required accounting conventions, credit rating considerations and associated costs. That's especially important because assuming additional costs would be a significant change from the assumptions that formed the basis for PacifiCorp's acknowledged IRP.

Staff also notes that considering the effect of a particular type of resource on the utility's cost of capital would be a change from traditional practice. If PacifiCorp chose to consider the effect of a long-term PPA on its cost of capital, staff would want to discuss how the company will apply this principle to other types of resource decisions — fuel choices, for example. By staff recommending that PacifiCorp may consider the potential effects of FASB requirements and credit rating agency considerations on the cost of long-term PPAs, we are not agreeing at this time that any type of cost recovery in future rate cases or other proceedings would be appropriate.

*Environmental ranking*
PacifiCorp's RFP uses the environmental non-price factor weightings approved by the Commission for PGE's RFP (Order No. 03-387). They will count for up to 10% of the score for deciding which projects are on the short list.

Renewable Northwest Project (RNP) recommends that the Commission further refine the environmental factors for renewable resources. However, it supports PacifiCorp issuing the renewable resources RFP *as is*. RNP will ask the Commission to address this issue in its forthcoming investigation into competitive bidding, rather than take it up in this proceeding and risk delaying the RFP process.

RNP does not believe the factors appropriately reflect their actual environmental impacts, which it describes as “zero or extremely minimal.” Specifically, RNP believes that wind, solar and geothermal resources are assigned damage factors that are inappropriately high, and the damage factors for landfill gas are too low because of air emissions and water use.

RNP further comments that the environmental factors table does not make clear what specific information about a project a utility would consider in order to assign an adjustment factor. For a wind project, for example, will the company consider only wildlife issues, or will it also consider other permitting issues, such as land use, noise, visual impacts and opposition by neighbors?

U.S. Geothermal also believes that the parameters PacifiCorp will use to determine a particular environmental score are unclear and should be more transparent. The developer further believes that all renewable resource technologies should be able to score the full 10% because most, if not all, are far better for the environment than fossil fuels. U.S. Geothermal believes that the adjustment factors do not reflect the "many substantial environmental issues involved with wind." The developer states that geothermal is no less desirable than wind. Geothermal is not an intermittent resource, so it does not require the same level of backup resources, geothermal plants have a far smaller footprint compared to wind projects (mitigating land use and visual impacts), and geothermal plants are quieter. Further, U.S. Geothermal believes animal and crop waste generation technologies should be ranked higher than they currently are because they mitigate other pollution problems.

U.S. Geothermal believes that the environmental scoring method does not need to be finalized prior to PacifiCorp issuing the RFP. The developer recommends that the Commission review the environmental factors while the RFP is out and publish the final scoring method by the due date for bids.

Staff believes this issue should be addressed in the forthcoming competitive bidding investigation. We do not recommend delaying the solicitation or leaving environmental scoring up-in-the-air until the deadline for bid submittal. We also are concerned that the proposed review of environmental factors for this RFP would be rushed, and we would have to address the issue again in the competitive bidding docket.

*Evaluating pricing proposals for the short list*
U.S. Geothermal requests that PacifiCorp publish the discount rate that it will use to determine the levelized price of each bid. For its IRP, the company used a discount rate of 7.5%. Staff agrees that the company should advise bidders whether it plans to use the same discount rate in evaluating proposals for RFP 2003-B. U.S. Geothermal also

requests that PacifiCorp publish any other information affecting how the submitted price will be evaluated to allow bidders to make their cost structure and prices most advantageous to the company.

In addition, U.S. Geothermal requests that the Commission consider requiring the company to use a lower discount rate for PPAs. A lower rate would favor contracts with a higher initial price and a lower price for later years. Staff believes this issue should be addressed in the context of resource planning, and that the Commission could consider this in its UM 1056 investigation.

U.S. Geothermal further requests that the Commission require the company to publish guidelines that will encourage bidders to offer summer or winter peak capacity. Geothermal projects may have the option to use dry cooling or wet cooling, which produce different generation profiles throughout the year. The developer seeks clarification from PacifiCorp on how it will value bids offering more generation during peak months of the year.

Staff understands that PacifiCorp's analysis will assign a higher value to proposed projects that provide generation on-peak and that are dispatchable. Staff believes no further guidance to bidders is required.

*Notice of Intent to Bid Form*
FPL Energy requests that PacifiCorp define the phrases highlighted below (in italics), from the PacifiCorp Affiliate Certification section of the form:

"Bidder does not have an affiliate relationship (whether by ownership, joint venture *or other association*) with PacifiCorp or any PacifiCorp affiliate; and the proposed bid is for power generated by facilities that are not owned by, *or otherwise associated* with PacifiCorp, or any PacifiCorp affiliate."

Staff has discussed this issue with FPL Energy and PacifiCorp and does not believe any changes need to be made to this language to ensure FPL Energy can meet the stated requirements.

**PROPOSED COMMISSION MOTION:**

The Commission find that PacifiCorp's Request for Proposals for Renewable Resources (RFP 2003-B), as filed October 17, 2003, and amended January 27, 2004, is in compliance with bidding guidelines established by Order No. 91-1383, as most recently interpreted in Order No. 03-356 and Order No. 03-387, and is consistent with the company's acknowledged 2003 Integrated Resource Plan. PacifiCorp may issue RFP 2003-B on or after February 4, 2004, subject to the following conditions:

1. PacifiCorp must provide the following information to the Commission in lieu of using an independent consultant to monitor, validate and audit the RFP process:

   a) The detailed scoring criteria and weightings the company will use to decide which projects make the short list – *Before March 9, 2004*

   *In its RFP Summary Report within 45 days of completing negotiations:*

   b) Detailed initial price and non-price scoring results for all bids
   c) Detailed price and non-price scoring results) for short-listed bids as revised after negotiations, including present value revenue requirements, and any subsequent economic analysis of Financial Accounting Standards Board requirements and credit rating agency considerations
   d) The forward price curves used for the cost-effectiveness analysis
   e) Further documentation of the RFP process, including:
      - Total number of parties participating
      - Total number of bids
      - Number of short-listed bids
      - Total MW and total expected aMW for all bids *and* short-listed bids by proposed on-line date and control area to be served (East or West)
      - Number of total bids *and* number of short-listed bids by project size (MW and aMW), proposed on-line date, control area to be served, state, fuel source, construction status (existing, construction in progress, or new), contract duration, type of transmission (firm vs. nonfirm), and offer of equity or turnkey ownership

2. In the event PacifiCorp's analysis of bids finds insufficient cost-effective projects to meet the megawatt targets in RFP 2003-B, after including any contributions from the Energy Trust and considering whether the status of the federal Production Tax Credit limits the viability of bids altogether, the company must report in its RFP Summary Report to the Commission whether any of the near cost-effective, short-listed projects would have been considered cost-effective if

an additional $5 per MWh value (associated with portfolio risk reduction, for example) could be demonstrated to be associated with the bid proposal.

3. PacifiCorp may consider the effect of Financial Accounting Standards Board requirements and credit rating agency considerations on the cost of a proposed power purchase agreement only *after* the company performs cost-effectiveness analysis for short-listed proposals. If subsequent economic analysis properly identifies increased cost for a short-listed proposal related to these requirements and considerations, the company may consider that analysis in its decision-making, provided it retains such analysis for subsequent staff review.

4. PacifiCorp may use its proposed generic power purchase agreement (PPA) in the bidding process with the following provisos:
   a) The company must modify its scoring standard so that a bidder's score is not reduced for modifying the PPA in a manner that benefits or is neutral to the company and its customers; and
   b) The company will allow bidders to negotiate final contract terms that are different from the generic PPA so long as such negotiated terms constitute contract provisions that are acceptable to PacifiCorp on a legal, contractual, credit and other business basis.

Finally, the Commission expressly notes that, by allowing PacifiCorp's use of a generic PPA, it is neither approving the PPA in its entirety nor endorsing any specific term of the PPA.