Public Service Commission
RIC CAMPBELL
Chairman
TED BOYER
Commissioner
RON ALLEN
Commissioner

State of Utah

JON M. HUNTSMAN, JR.
Governor

GARY HERBERT
Lieutenant Governor

To: Technical Conference Participants, Docket File

From: Carol Revelt

Date: September 15, 2006

Re: August 30, 2006 Technical Conference on 2005 EPAct Amendments to PURPA Meeting Minutes – Docket 06-999-03

On August 30, 2006, a technical conference was held in room 401 of the Heber Wells building to discuss the five new standards which are amendments to the Public Utility Regulatory Policies Act (PURPA) enacted by the 2005 Energy Policy Act (EPAct). The goal of the technical conference was to familiarize interested parties with the status of regulatory activities associated with the amendments and with PacifiCorp's actions/programs/ processes which may address the new standards. The information presented in the conference provides the basis for a workgroup to further evaluate the issues associated with the amendments. Associated technical conference documents, including the meeting agenda, applicable meeting questions, and a meeting roster can be found in Docket 06-999-03 on the Utah Public Service Commission website.

Conference Format: The conference commenced with a review of the general requirements of the 2005 EPAct relating to PURPA and its applicability to electric utilities followed by a discussion of what PURPA requires of the Commission and electric utilities, PURPA deadlines/procedural requirements, and the issue of prior state actions. Each new standard was then introduced along with a brief presentation of potential prior state actions. Pre-determined questions for each new standard were then answered by PacifiCorp/Rocky Mountain Power (the Company) employees. Questions or comments from the audience associated with the new standards were also addressed or noted.

Applicability: As discussed during the conference PacifiCorp/Rocky Mountain Power is the only electric utility over which the Utah Public Service Commission has ratemaking authority thus the questions posed during the conference were addressed only by the Company.

The following sections provide the wording of the specific PURPA Amendments, a listing of prior state actions, and finally pertinent questions and the Company's responses.

I. Net Metering

A. PURPA Net Metering Standard: Each electric utility shall make available upon request net metering service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term "net metering service" means service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period.

Heber M Wells Building. 160 East 300 South Box 45585, Salt Lake City, UT 84145-0585
telephone (801) 530-6716 • facsimile (801) 530-6796 www.psc.state.ut.us

B. Prior State Actions

- Net Metering Standard enacted by Law in 2002 and became effective on May 6, 2002, pursuant to Utah Const., Art. VI. Sec. 25, requiring electrical corporations to make a net metering program available to their customers.
- Public Utilities Statute: 54-15-101 to 106 – Net Metering of Electricity
- May 2002: PacifiCorp submitted tariff advice letter which was approved by Commission.

C. Discussion Items/Questions for Electric Utilities on Net Metering
Responses provided by Bill Griffith and Les Bahls of PacifiCorp.

1. *Please provide a description and brief history of your net metering program. To what rate schedules does net metering apply and how many customers are currently enrolled in net metering programs?* The Company's Schedule 135 – Net Metering Service became effective on May 6, 2002, as required by Utah statute. It is applicable to customer generation of <25 kilowatts. Currently 81 customers (mostly in two large condominiums) are enrolled in the program – mostly rooftop solar and a few solar/wind.

2. *What are the types and cost of meter technology currently being used for net metering?* The standard solid state meters used by the Company do not run backwards – the Company must install a solid state bi-directional meter – cost is approximately $100 for the meter and $45 for installation labor.

3. *What is the current generating capacity in the net metering program and how is this determined?* 110 kilowatts (vs. program schedule maximum of 3,516 kilowatts).

4. *Have any net-metering credits expired at the end of the year since the program's inception?* No. As specified in Schedule 135, if a generator generates excess electricity the account is credited according to the rates in Schedule 37 in effect at the time that the credit is generated. All credits not used during the calendar year expire at the end of the calendar year.

5. *Are there charges associated with meter installation and interconnection of net-metering facilities?* No, however, customer must pay for the cost of any required modifications to the distribution system.

6. *What is the term of the Interconnection Agreement Contract for net metering? Under what conditions are interconnection agreements required for net meter contracts?* The contract is in effect until it is terminated with change of ownership of the facilities or the premises. Net-metering contracts do not require interconnection agreements.

Comments: Small generators without inverters (i.e. micro-hydro systems) must apply as a QF because the definition of "customer generator" in the Utah net-metering statute requires the generation facility to be controlled by an inverter and micro-hydro systems are not controlled by inverters. There was also some discussion of what is included in the "avoided cost" calculation (i.e., should the avoided costs contain generation, transmission, and distribution elements). There was also discussion regarding the issue of training and qualifications of installation contractors and meeting code requirements as the Company does not monitor the installation. The Company requires an accessible self-disconnect for safety reasons.

II. Interconnection

A. <u>PURPA Interconnection Standard</u>: Each electric utility shall make available, upon request, interconnection service to any electric consumer that the electric utility serves. For purposes of this paragraph, "interconnection service" means service to an electric consumer under which an on-site generating facility on the consumer's premises shall be connected to the local distribution facilities. Interconnection services shall be offered based upon the standards developed by the Institute of Electronics Engineer; IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems, as they may be amended from time to time. In addition, agreements and procedures shall be established whereby the services are offered shall promote current best practices of interconnection for distributed generation, including but not limited to practices stipulated in model codes adopted by associations of state regulatory agencies. All such agreements and procedures shall be just and reasonable, and not unduly discriminatory or preferential.

B. <u>Prior State Actions</u>

- Net metering interconnection addressed in 54-15-106 enacted by Law in 2002 and became effective on May 6, 2002, pursuant to Utah Const., Art. VI. Sec. 25, requiring electrical corporations to allow customer generation systems to be interconnected to their facilities.
- Public Utilities Statute:
- 54-15-106 – Customer to provide equipment necessary to meet applicable code requirements – Commission may adopt additional requirements – Testing and inspection of interconnection

C. <u>Discussion Items/Questions for Electric Utilities on Interconnection</u>
Responses provided by Les Bahls of PacifiCorp

1) *Please describe your current interconnection procedures and agreements for distributed generation.* As specified in Schedule 135, Net Metering customers must provide at their expense all equipment necessary to meet applicable local and national standards regarding electrical and fire safety, power quality, and interconnection requirements established by the National Electrical Code, the Institute of Electrical and Electronics Engineers, and Underwriters laboratory.

   Regarding interconnection requirements in general, the Company provided the following, link http://www.rockymtnpower.net/Article/Article61757.html which specifies:

   > *Customers wishing to connect generators to PacifiCorp (those which do not qualify as net metering) should know that two processes are required for successful interconnection and for the sale of the energy produced.*
   >
   > *Interconnect requests are governed by different federal or state regulations depending on the size of the generator, the voltage of the distribution or transmission line the generator is requesting to connect to, and whether the interconnect customer intends to be a Qualified Facility or not.*
   >
   > *To begin the physical interconnection process to PacifiCorp transmission or distribution lines, please contact the Account Manager Transmission at*

503-813-6102.

To begin the Power Purchase Agreement or other sale of energy produced, contact the Manager of QF Contracts at 503-813-5957.

Net metering rules vary by state. Generally states restrict net metering to 25-kW or smaller customer-owned generation that uses renewable energy to offset electricity purchases from PacifiCorp. PacifiCorp's contact for net metering questions is the Segment Manager at 503-813-5150

For a definition of a Qualified Facility please visit the Federal Energy Regulatory Commission (FERC) Web site at www.ferc.gov .

The large generator (i.e. larger than 20 MW) transmission system interconnection process and agreement (LGIP and LGIA), covered under the Company's Open Access Transmission Tariff (OATT) under the jurisdiction of the FERC, can be viewed at: http://www.oasis.pacificorp.com/oasis/ppw/FIFTHREVISEDVOLUME11.PDF

In addition, the small generator (no larger than 20 MW) transmission system interconnections interconnection process and agreement (SGIP and SGIA), also under the jurisdiction of the FERC, can be found at: http://www.oasis.pacificorp.com/oasis/ppw/ORDER2006_SGIP.PDF and http://www.oasis.pacificorp.com/oasis/ppw/ORDER2006_SGIA.PDF, respectively.

Purchase power agreements and interconnection agreements follow two separate paths. In general for interconnection, once an application is submitted a scoping meeting is held, and various interconnection studies are completed (feasibility study, system impact study, facilities study, optional interconnection study). The facilities study contains specifications and an estimate of the costs, equipment, engineering, and procurement work needed to implement the conclusions of the system impact study, in accordance with good utility practice, to physically and electrically connect the interconnection facility with the transmission system.

2) *What is the average cost of interconnection for the various customer classes and are there any additional insurance requirements specified in the interconnection agreements?* For non-net metering schedules, there is no difference in cost between customer classes. The cost of interconnection studies ranges from $5,000 to $15,000 (some more some less) – depending upon the circuit and location. Factors which increase the cost of the studies include: initially supplied generation data is incorrect and the interconnection will result in two-way traffic when previously the traffic was one way. The Company must analyze many things to ensure the safety and reliability of a given circuit. In addition, many new interconnections will require telemetry on their systems. The Company's methodologies for completing system impact and facilities studies are included as Attachments E and F, respectively, of the Company's OATT. Section 18 of the LGIA addresses insurance requirements for the interconnection agreement for large generators including requirements for $1 million commercial general liability, workers compensation where applicable, automobile, excess public liability insurance, waiver of subrogation, etc. Many of these provisions are not applicable to the SGIA.

3) *Are applicable IEEE standards specifically spelled out in your interconnection agreement(s) or procedures?* Schedule 135 and the SGIA do not spell out specific standards – but generally refers to IEEE standards as indicated in Schedule 135, Special Condition #4 and the SGIA, Section 1.5.4, respectively. For the LGIA, the procedures used to complete the studies are included in Exhibit G of the contract.

4) *For any studies required by the various interconnection agreements who must pay the cost of studies?* No cost for Schedule 135 Customers, otherwise Customer pays for the studies.

5) *Do your company's interconnection agreements comply with the model code adopted by NARUC?* They are somewhat the same. Some differences include the length of time for studies, deposits, and requirements for construction. The company operates in six states and the NARUC model is the third model suggested. There can be super-expedited process for large KW sizes. NARUC agreement is more structured – the Company works back and forth in an iterative process and the NARUC agreement doesn't address this. Also NARUC doesn't contain insurance and indemnification provisions.

Comments: The value of ease of obtaining interconnection is associated with the value of controlling the peak. It appears that the process contains lots of unknowns and disincentives for small generators. It was suggested that maybe some costs should be subsidized. There was a short discussion regarding that if the net-metering generator is at the end of a line some devices (like voltage regulators) may need to be looked as the interconnection will result in power flowing in the opposite direction as previously.

III. Time-Based Metering and Communications

A. <u>PURPA Time-Based Metering and Communications Standard</u>:

(A) Not later than 18 months after the date of enactment each electric utility shall offer each of its customer classes, and provide individual customers upon customer request, a time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's cost of generating and purchasing electricity at the wholesale level. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.

(B) The types of time-based rate schedules that may be offered under the schedule referred to above include, among others –

i) time-of-use pricing whereby electricity prices are set for a specific time period on an advance or forward basis, typically not changing more often than twice a year, based on the utility's cost of generating and/or purchasing such electricity at the wholesale level for the benefit of the consumer. Prices paid for energy consumed during these periods shall be pre-established and known to consumers in advance of such consumption, allowing them to vary their demand and usage in response to such prices and manage their energy costs by shifting usage to a lower cost period or reducing their consumption overall;
ii) critical peak pricing whereby time-of-use prices are in effect except for certain peak days, when prices may reflect the costs of generating and/or purchasing electricity at the wholesale level and when consumers may receive additional discounts for reducing peak period energy consumption;

iii) real-time pricing whereby electricity prices are set for a specific time period on an advanced or forward basis, reflecting the utility's cost of generating and/or purchasing electricity at the wholesale level, and may change as often as hourly; and
iv) credits for consumers with large loads who enter into pre-established peak load reduction agreements that reduce a utility's planned capacity obligations.

(C) Each Electric utility subject to subparagraph (A) shall provide each customer requesting a time-based rate with time-based meter capable of enabling the utility and customer to offer and receive such rate, respectively.

(D) For purposes of implementing this paragraph, any reference contained in this section to the date of enactment of the Public Utility Regulatory Policies Act of 1978 shall be deemed to be a reference to the date of enactment of this paragraph.

B. <u>Prior State Actions</u>

- Commission has approved various time-of-day tariff options submitted by PacifiCorp. More recently, in April 2004 the Commission approved a revised Schedule 2 Residential Time-of-Day tariff.

C. <u>Discussion Items/Questions for Electric Utilities on Time-Based Metering and Communications</u>
Responses provided by Douglas Marx of PacifiCorp.

1. *Please provide a description of your time-based rate program with respect to (B)(i),(ii), (iii) and (iv) above and discuss the types of rate schedules and customers to which these apply*.
Applicable Rate Schedules:
2 – Optional Time-of-Day Residential Service
6A – General Service – Energy Time-of-Day Option
6B – General Service – Demand Time-of-Day Option
8 – Large General Service – 1,000 kW and Over – Distribution Voltage
9 – General Service – High Voltage
9A – General Service High Voltage – Energy Time-of-Day (closed to new service)
10 – Irrigation and Soil Drainage Pumping Power Service Time-of-Day Program
23B – Demand Time-of-Day Option Small Customer
71 – Energy Exchange Pilot Program Rider

All distribution customers with greater than 1MW and high voltage customers are served on time-of-day tariffs (Schedule 8 and Schedule 9). There are currently 11MWs on schedules 6A and B. Currently on Schedule 2 there are 285 customers (plus or minus 50). PacifiCorp has not implemented critical peak pricing (CPP) or real time pricing (RTP) for any rate schedule but does have interruptible contracts (see Schedule 71 – Energy Exchange Program Rider). Currently the Company has 37MW on Schedule 71 (mostly in Utah) for curtailments, which they have utilized this year.

2. *How often does your company replace or upgrade meters for the various customer classes?* Meters are not replaced on a routine bases. Per ANSI standards, a certain number of meters are sample tested per year and those meters found obsolete, with known inaccuracies, or are prone to failure are replaced through a scheduled program.

3. *What type of technology exists to implement smart metering with communications to the various customer classes and what would be the capital cost to install such metering? Please discuss cost differences among metering equipment required to implement time-based rate schedules*. For RTP, meter costs would increase. Significant costs for "smart" meters are associated with the transfer of data/communications technology (i.e. through radio frequencies or telephone lines). Cost depends upon the density of population, how much data are being transferred (i.e. hourly data vs. two blocks per month). For CPP and RTP, existing time-of-use meters would have to be replaced as they are only two block meters. There is a difference between "energy only" vs. "smart meters". It is estimated the there would be a $75 to $150 incremental cost to replace meters but this does not include additional infrastructure plus the cost of installation. A rough guess would be $250 - $300 per meter if the company completed the entire system and the meter met all of the provisions of the 2005 EPAct. This boils down to an issue of where we want to go and the issue of used/useful and prudent costs. While automated meter reading requires a hand held device and a van to collect the data, CPP requires full two-way communication in order to communicate with the meter so that it can be reconfigured/reprogrammed for pricing changes.

4. *Does your company have meters with smart metering capabilities in place? If so, please describe.* Only the very largest customers are equipped with "smart" meters. The data is transferred via cellular or standard telephone lines.

5. *Has your company conducted any studies in Utah to determine if time-based metering programs affect customer behavior and/or if your company's current programs are sending accurate price signals?* The Company submitted its evaluation of Schedule 2 – Optional Time of-Day rates on December 8, 2005, in which it indicated that in October, 2005, there were 325 participants in the program with an average savings of $1.02. Schedule 2 is intended to be revenue neutral. The Company also completed a two-way power line carrier pilot in the Fountain Green area (725 customers) whereby communication through the power lines was achieved by coupling the distribution substation processor unit with the distribution voltage lines. The pilot area, if equipped with the correct meters, could meet criteria listed in the 2005 EPAct. Puget Sound completed a program with a ½ smart meter which doesn't meet all of the criteria of the EPAct.

Comments: It might be worthwhile considering redesigning the Schedule 2 program so that it is more effective. The question was raised as to what society in general wants/responds to – does society want to invest their personal time to monitor prices when it may only impact their bill by $20/month? What is the value/elasticity of electricity and is the installation of smart meters a prudent expense? References were made to the California Public Utilities Commission study and the recently-issued FERC demand response report.

IV. Fuel Sources

A. PURPA Fuel Sources Standard: Each electric utility shall develop a plan to minimize dependence on one fuel source and to ensure that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies.

B. Prior State Actions

- Docket 90-2035-01 – In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp:
- Report and Order on Standards and Guidelines
- Attachment A Standards and Guidelines for Integrated Resource Planning for PacifiCorp, Utah Jurisdiction
- Integrated resource planning is a utility planning process which evaluates all known resources on a consistent and comparable basis, in order to meet current and future customer electric energy services needs at the lowest total cost to the utility and its customers, and in a manner consistent with the long-run public interest. The process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty.

C. Discussion Items/Questions for Electric Utilities on Fuel Sources
Responses provided by Dave Taylor of PacifiCorp.

1) *Please provide a description of the megawatt capacity and fuel sources of your company's current generation and power purchase portfolio.* Please refer to PacifiCorp's recent SEC 10K form which can be found at: http://www.pacificorp.com/File/File65321.pdf

   As of the end of the fiscal year ending March 31, 2006, the Company's system consisted of 69 plants which provide about 9,000MW of nameplate generating capability (8,500 MW net) consisting of about 6,600 MW coal, 1,350MW natural gas/other, 1,100MW hydroelectric, and 33MW wind. The Company has about 2,000 MW long term/front office in its purchase power portfolio (20 to 25% of the total resources). A breakdown of this portfolio in terms of fuel sources was not provided at the meeting.

2) *What changes to this portfolio are anticipated in the next five years?* Please refer to tables within PacifiCorp's most recent Integrated Resource Plan filing and the RFP 2012.

3) *What efforts has your company taken in the past five years to encourage renewable technologies?* Please refer to MEHC commitments #39 – Future Generation Options and #40 – Renewable Energy which deal with renewable resources. For portfolio standards which are enacted, the costs of complying would go to the states in which they are enacted. The Company recently issued an RFP for 1,400MW of renewable resources which would increase the wind component of their portfolio to 7% where currently it is less than 1%. Any new wind and renewable resources percentages will increase with additions because the current amounts are so small (i.e., <1%).

V. Fossil Fuel Generation Efficiency

A. PURPA Fossil Fuel Generation Efficiency Standard: Each electric utility shall develop and implement a 10-year plan to increase the efficiency of its fossil fuel generation.

B. Prior State Actions

- Unknown but possible IRP proceedings -- Docket 90-2035-01 – In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp:

C. Discussion Items/Questions for Electric Utilities on Fossil Fuel Generation Efficiency
Responses provided by Bill Kyle of PacifiCorp.

1) *Does your company currently have a strategic plan for increasing fossil fuel generation efficiency? If so, what is the plan?* No specifically-named plan but actions for improving efficiency of the fossil fuel fleet are embedded in the integrated resource plan. For the existing fleet, they attempt to operate as efficiently as possible and retrofit the unit/plant with new technologies which will help improve overall efficiency.

2) *What sort of measures has your company implemented to track generation efficiency?* Company tracks generation efficiency through heat rate – BTU/KWH – the lower the number the better. Company tracks unit average heat rate monthly and compares it to what was budgeted. Also the Company rolls up heat rate at an annual level. Refer to FERC Form 1 which lists information on unit heat rates. (*PacifiCorp's most recent FERC Form No. 1 can be found on the FERC website using the elibrary general search capability*).

   PacifiCorp focuses on optimizing existing units in terms of reliability, efficiency, and availability. When new units are added to the fleet they utilize new technologies. Retired units are the older and least efficient units.

   Comments: PacifiCorp should attempt to run units at higher capacity levels which would increase efficiency. Also, controlling peak demand would help to increase unit efficiency by not having to run peaking units which are the most inefficient. Combined heat and power may help – referred to Oregon Order.

3) *If a strategic plan for increasing generation efficiency and measures to track generation efficiency both exist, how are they incorporated into the budget process?* The Company has become more sophisticated through time about how to plug heat rate information into the budget which helps estimate costs. A heat rate curve is generated for each unit which plots the efficiency of the unit at different loads. In addition, the Company uses maintenance and overhaul information to help plan which is reflected in the annual budget. Decreasing thermal efficiency won't accelerate overhaul schedule because the dollars saved are small in comparison with the costs associated with an overhaul. Heat rate curves are adjusted with changing efficiencies, however, all coal-fired units are base loaded and changing heat rates doesn't affect the dispatch order.