ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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IDAHO PUBLIC
UTILITIES COMMISSION

August 25, 2006

Idaho Public Utilities Commission
472 West Washington
Boise, ID 83702-5983

Attention: Jean D. Jewell
Commission Secretary

Re: Comments of PacifiCorp in Case No. GNR-E-06-2

PacifiCorp (d.b.a. Rocky Mountain Power) hereby submits for filing an original and seven (7) copies of its comments in Case No. GNR-E-06-2 In The Matter of the Commission's Consideration of the Five Amendments to Section 111 of the Public Utility Regulatory Policies Act of 1978 (PURPA) Contained in the Energy Policy Act of 2005.

Service of pleadings, exhibits, orders and other documents relating to this proceeding should be served on the following:

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It is respectfully requested that all formal correspondence and Staff requests regarding this material be addressed to:

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By regular mail: Data Request Response Center
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Sincerely,

D Douglas Larson

D. Douglas Larson
Vice President, Regulation
Enclosures

cc: Service List

PROOF OF SERVICE

I hereby certify that on this 25th day of August 2006 I caused to be served, via E-mail, a true and correct copy of the foregoing COMMENTS OF PACIFICORP in Case No. GNR-E-06-02 to the following parties as shown:

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE COMMISSION'S CONSIDERATION OF THE FIVE AMENDMENTS TO SECTION 111 OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978 (PURPA) CONTAINED IN THE ENERGY POLICY ACT OF 2005	**CASE NO. GNR-E-06-2** **COMMENTS OF PACIFICORP**

PacifiCorp dba Rocky Mountain Power ("PacifiCorp" or the "Company"), by and through its attorneys of record, respectfully submits the following comments in response to the Idaho Public Utilities Commission ("Commission") inquiry into the five new PURPA standards set forth in Title XII of the Energy Policy Act of 2005.

Net Metering

1) Briefly describe your net metering program.

PacifiCorp's net metering program is implemented through tariff Schedule 135 approved by the Commission on June 20, 2003[1]. The program allows participating customers to offset their electric requirements by installing small generation systems on their property and generating all or a portion of their electric needs. Residential and

[1] Case No. PAC-E-03-4, Order No. 29260

small general service customers (those taking service on Schedules 1, 36, 23 or 23A) may net meter generation with capacity of 25 kW or less. Customers taking service on any other Schedule may net meter generation with capacity of 100 kW or less. In each billing period, the customer's generation is used to offset consumption from PacifiCorp on a kilowatt hour for kilowatt hour basis. In any month where the customer's generation exceeds consumption from PacifiCorp, the excess kilowatt hours generated are assigned a monetary value that is carried forward to the following month. Customers taking retail service under Schedules 1, 36, 23 or 23A are financially credited for such excess generation at the customer's standard service schedule rate. Customers taking retail service under all other Schedules are financially credited for such excess generation at 85 percent of a market index as detailed in Schedule 135. In addition, net energy and the excess generation financial credit for customers taking service under any time of day Schedule is calculated separately for on-peak and off-peak usage.

2) Are all customers eligible to participate in your net metering program? If not, why not? Are there limitations on the number of participating customers or the amount of net metering generation? Are there restrictions regarding the type of net metering generation?

All customers are eligible to participate in PacifiCorp's net metering program. The total amount of generation allowed under the program is limited to 714 kilowatts (representing one-tenth of one percent of the Company's retail peak demand in Idaho during 2002). In addition, no single customer may connect more than 20 percent of the cumulative generation nameplate capacity connected under this Schedule. Generation facilities eligible for net metering must use energy derived from the sun, wind, water, biomass or fuel cell technology to generate electricity.

3) State the number of net metering customers by customer class.
4) State the amount of net metering generation by customer class.

The following table details the number of PacifiCorp net metering customers by customer class and the corresponding amount of net metering generation:

Customer Class	Net Metering Customers	Net Metering Generation (kW)
Residential	1	2
Commercial	0	0
Irrigation	0	0
Industrial	0	0
Other	0	0

PacifiCorp's current net metering customer takes retail service under Schedule 36, Optional Time of Day – Residential Service, and has 2 kW of solar-powered generation interconnected. Two additional residential customer interconnection requests are in process.

5) Does your current or proposed net metering tariff/schedule meet the federal net metering standard set out above? If not, should the Commission adopt this standard or a comparable standard?

PacifiCorp's Schedule 135 net metering program meets the new PURPA net metering standard set forth in the Energy Policy Act of 2005 and as described in Case No. GNR-E-06-02, Order No. 30108.

Fuel Sources

1) We direct the utilities to comment on whether this standard has already been implemented by the Commission as part of the IRP process.

PacifiCorp believes that this standard has already been implemented by the Commission as part of the Integrated Resource Plan ("IRP") process. The Company believes that the standard to minimize dependence on a single fuel or technology type is successfully being met as a consequence of IPUC Order No. 22299 as well as IRP standards and guidelines in other states in which PacifiCorp serves load. While Order No. 22299 does not dictate that a diverse resource mix must be the outcome of the IRP process, it does provide the framework to ensure that utilities comprehensively evaluate resource alternatives on a comparable basis and select a resource mix that minimizes costs after considering uncertainty and risk. This framework, which includes scenario analysis to help identify the optimal resource mix given a range of possible future conditions, promotes resource diversification to mitigate risks associated with particular resource types.

Fossil Fuel Generation Efficiency

1) We solicit the utilities to comment on whether increasing fuel efficiency is already a part of their respective IRPs. If not, should the Commission require that the issue of fossil fuel efficiency be included in the bi-annual IRPs?

Improving the efficiency of PacifiCorp's fossil fuel generation is embedded in the Company's bi-annual IRP as explained below. Fossil fuel generation efficiency is typically reported using average heat rate, measured in British Thermal Units (BTU) per kilowatt hour (KWh). The efficiency of a generating unit is improved when the heat rate is decreased, and the efficiency of the Company's fossil fuel generation is improved when the weighted average heat rate for the fleet is decreased. Fuel efficiency is improved by 1) emphasizing continuous improvement in the operation of existing generating units, 2) adding new fossil fuel generation with improved efficiency, and 3) in the long term, retiring old, less efficient fossil fuel units. The following comments explain how these factors are reflected in PacifiCorp's IRP process.

Planning Process With Regard to Existing Generating Units

PacifiCorp's IRP process uses the most recent four year historic average of heat rates for existing units. As such, efficiency improvements made to the existing fossil generating fleet are captured as the IRP is updated.

The efficiency of existing generating units is improved by operating as near to design efficiency as is economically practical and by improving the design efficiency of operating units. The efficiency of generating units degrades gradually as components wear overtime. Generating units are overhauled periodically to maintain reliability and to regain lost efficiency. Efficiency improvements are also made to the design of units when economically justified. Opportunities for improving plant reliability and efficiency are analyzed on a case by case basis and upgrades are made to generating units when economically justified.

Prudent management of the existing generating units requires optimizing the generating output, reliability, efficiency, and production cost of each unit. PacifiCorp maintains an emphasis on continuous improvement of efficiency and, in general, annual improvement in the heat rate for existing fossil fuel generation is measured in tenths of a percent.

Planning Process With Regard to New Generating Units

New generation is added to the fleet using the latest technology with improved heat rates. Existing coal-fired generating units have full load heat rates in the range of 9,980 – 12,062 BTU/KWh. New coal-fired generation will operate at higher pressures and temperatures and will have full load heat rates in the range of 8,900 – 9,300 BTU/KWh. Future integrated gasification combined cycle (IGCC) units will have heat rates in the range of 8,500 – 9,000 BTU/KWh. These expected achievable heat rates become part of the Integrated Resource Plan as new fossil-fueled generating units are incorporated in the IRP. As the new, more efficient generating units identified in the IRP are added to the company's resources, average efficiency of the fleet improves.

Planning Process With Regard to Retirement of Existing Units

The oldest generating units have the poorest efficiency because the units were designed to operate at lower pressures and temperatures. As the oldest units in the fleet retire, the average efficiency of the fleet improves. Retirement of existing units is included in the IRP.

Smart Metering

1) Briefly describe your Smart Metering programs previously implemented. For each program indicate the number of customers by class eligible to participate in the program and the number of customers actually participating in each program. What are the differences between your programs and the federal standard, including costs and benefits?

PacifiCorp's Smart Metering program in Idaho consists of offering optional time-of-day service with prices set differentially for on-peak versus off-peak periods. The Company has offered optional time-of-use schedules for all residential and all distribution voltage general service customers since the mid-1980s. In addition, some special contracts have contained time-of-use pricing. Standard time-of-use meters are used and read monthly using a hand-held electronic device on customary meter reading routes. Presently, 16,482, or 31% of PacifiCorp's Idaho residential customers and two general service customers are served on time-of-use schedules. The Company also offers Energy Exchange, Schedule 71, for targeted instances of load curtailment throughout much of PacifiCorp's service territory, although no Idaho customers have chosen to participate at this time.

PacifiCorp's time-of-use program satisfies the requirements of the standard outlined in PURPA Section 2621(d)(14)(B)(i) in that the on- and off-peak pricing is set in advance and changes only with Commission approval through a general rate case or other ratemaking alternative based on the utility's cost of service. The Company's program differs from the standard in that participation includes only residential and distribution voltage general service customers, along with some special contracts. Another difference is that PacifiCorp does not offer critical peak or real-time pricing to its customers in Idaho.

Costs allocated to PacifiCorp's time-based rate programs are available in the Company's filed class cost of service studies; however, as historical cost studies, the class cost of service studies do not purport to measure incremental costs or benefits of time-based rate programs. The Company's approximate per-customer cost for metering the time-of-use program in Idaho is $125 for residential customers and $400 for commercial customers. However, the cost of Smart Metering varies widely given customer density and customer mix within geographic areas. PacifiCorp has no reasonably current financial analysis of incremental benefits of its time-based rate programs.

2) Should the Commission adopt the Smart Metering standard by requiring each utility to offer by February 8, 2007, a time-based rate to each customer class and the necessary time-based metering to individual customers upon request? Why, or why not?

PacifiCorp believes that it may not be achievable or appropriate for each utility in Idaho to offer a time-based rate to each customer class by February 8, 2007. PacifiCorp agrees with the Commission's statement that implementation of time of use programs should be prudent and cost effective. Adopting an implementation deadline of February

8, 2007 could cause the utilities to expend capital hastily to upgrade metering, data collection, and billing infrastructure; such expenditures may or may not prove to be cost effective unless done with appropriate planning and budgeting. In addition, adopting uniform requirements now could ignore the differences between utilities, customer classes, and cost of service within customer classes.

In the historical absence of uniform requirements in Idaho, PacifiCorp has had success with its current residential time of use schedule in Idaho, and it believes that this type of utility-specific implementation is appropriate. Differences between each utility's customer base and rate structure make uniform application problematic. Customer usage patterns may differ between utility service territories, influencing a utility's rate structure and impacting the financial viability of any time-based rate program.

PacifiCorp recommends that targeted use of time-based rate programs should be approved on a case-by-case basis. Time-based rate programs can be an effective way to address peak load concerns, but only where there is a nexus between consumer habits and the time-based rate program. For example, PacifiCorp offers the Energy Exchange program (Schedule 71) which is a demand response program for large customers. It has been available to all PacifiCorp customers with demand over 1MW, except for California, since 2001. There are currently 37 MW available in PacifiCorp's Eastern System and 61 MW available in its Western System as identified by customers. Should market prices climb, these loads may be curtailed if economic for the participating customers. This program was called upon during the recent extreme heat of summer 2006. This type of strategic program can provide value to the Company and its customers in a cost effective manner.

3) Should the Commission adopt the time-based metering and communications standard by applying the same requirements to all utilities?

No. Rather, the Commission should examine the applicability of the time-based metering and communication standard requirements separately for each utility. As previously mentioned, each utility has different rate structures and serves customers in distinct geographic regions throughout the state. Both of these factors will impact the cost effectiveness of time-based rate options.

4) Which, if any, of the four listed types of time-based rate schedules should the Commission require? Should the same types of rate schedules be required of all utilities and for all customer classes?

If the Commission adopts the Time-Based Metering and Communications Standard, it should adopt the standard outlined in PURPA Section 2621(d)(14)(B)(i), Section 1252(a) of the Energy Policy Act of 2005. This schedule would provide time-of-use pricing whereby electricity prices are set for a specific time period on an advance or forward basis and be based on the utility's cost of generating or purchasing electricity on the wholesale market. The relative simplicity of this option would facilitate implementation, provide known upfront costs, and be more easily understood by customers.

5) Are there other issues the Commission should consider in reviewing this standard?

PacifiCorp has not identified any additional issues.

Interconnection

1) Should the Commission adopt this standard for interconnecting a customer's on-site generating facility to local distribution facilities?

It is not necessary for the Commission to mandate either the IEEE 1547 standard or the National Association of Regulatory Utility Commissioners ("NARUC")

Interconnection Model for all distribution level interconnections of on-site generating facilities. PacifiCorp already applies the IEEE Standard 1547 standards to interconnection engineering studies to determine safety and reliability of the proposed generation. Those standards, however, may not be applicable to all interconnections and specific deviations may be required due to specific circumstances surrounding the generator design or local system. Additionally, the NARUC Interconnection Model may be too rigid for smaller developers. Furthermore, PacifiCorp is concerned about the regional implications of adopting the NARUC model without regional coordination.

With these concerns in mind, PacifiCorp believes that the Commission can still properly balance the needs of customers with electric utilities' obligations to maintain safe and reliable service on the distribution systems. This balance can be achieved by the adoption of general guidelines that each electric utility must adhere to when establishing its interconnection requirements, procedures, and agreements. PacifiCorp suggests that the Commission consider adopting the following guidelines in any regulations, rather than mandating a particular process or set of agreements:

1. All interconnection customers shall be treated in a non-discriminatory and non-preferential manner.
2. The utility shall review all interconnection with the goal to maintain safe, adequate and reliable electric service to its retail electric customers.
3. The utility shall evaluate the cumulative effect on circuits and load pockets.
4. Interconnection customers shall bear the costs of interconnection, operation and maintenance.
5. Interconnection service does not include retail electric or other services.
6. The electric utility shall establish, and amend as necessary to maintain the safe and reliable operation of its system, operating, system design, and maintenance requirements.
7. Technical requirements for all interconnections shall comply with IEEE, NESC, NEC and other safety and reliability standards.

2) Do the utilities currently have tariffs, agreements, procedures or schedules delineating interconnection standards of customer-owned generating facilities? If yes, where are they located (e.g., tariffs, schedules, websites, etc.)? Are there limitations on the per customer capacity or total system capacity of customer-owned generation facilities? What are the limits?

PacifiCorp has a tariff for net metering customer-owned generation, Schedule 135. PacifiCorp has established procedures for state-jurisdictional interconnections to its transmission and distribution systems. PacifiCorp follows the procedures outlined in its Open Access Transmission Tariff on file with the Federal Energy Regulatory Commission for any interconnection to its transmission system, regardless of whether the developer is a Qualifying Facility ("QF") under PURPA or an independent power producer selling on the market. For distribution level interconnections, PacifiCorp has developed a process to address the unique difficulties associated with interconnection generation to systems designed for load service. Past experience has indicated that the majority of small generation projects qualify as QFs and sell their generation to the local electric utility at the established avoided cost pricing under PURPA. Those interconnection customers have varying levels of sophistication regarding electrical engineering requirements because a QF developer is generally not engaged in the generation of electricity as its primary business.

To assist interconnection customers, PacifiCorp posts contact information for distributed generation interconnections on its website. The web site contains contract information for beginning the physical interconnection process, as well as the power purchase agreement process. The Company's Electric Service Requirements manual also contains interconnection compliance information.

While PacifiCorp does not have specific limits on per customer on generation capacity connected to its distribution system, the capacity of each individual project is limited by the necessary upgrades required to the system to accommodate the proposed generator and maintain safe and reliable service to retail customers. The interconnection study that PacifiCorp performs for each potential interconnecting generation source identifies the upgrades necessary to comply with applicable engineering technical standards and prudent system operations.

3) Should the Commission adopt or consider separate interconnection standards for smaller and larger generating facilities (e.g., <25 kW up to 100 kW, <1MW, >1MW, or some other limitation)?

Yes, for net metering facilities. The Commission should distinguish between net metering and non-net metering generation. Net metering interconnections have specific concerns that can be adequately addressed in most situations through the adoption of uniform standards and regulations up to 100 KW. Net metering generation also minimizes its own system impact because the amount of energy coming onto the system is small and generally offsets customer usage. Non-net metering generation, however, introduces specific concerns related to the amount of energy injected into a electric distribution system for the purpose of a power sale.

PacifiCorp recommends that the Commission maintain the current upper limit on capacity of 100 KW for net metering and the associated interconnection standards for net metering. PacifiCorp has experience developing a field review process to handle net metering interconnections up to 100 KW, and adherence to IEEE 1547 and other national or local electrical codes will prevent major issues related to safety and reliability. Beyond 100 KW, however, additional protections may be needed.

Non-net metering generator interconnections raise additional concerns no matter what size. These projects can include self-supply generators that will not sell power, QF generators that will sell their entire output to PacifiCorp, and wholesale generators that plan to sell power on the market. IEEE 1547 alone does not adequately reflect the planning requirements and system impacts of these interconnections. In many cases, these interconnections require specialized engineering analysis. The engineering analysis may require the individual design of interconnection facilities to maintain reliable electric service to retail customers. Consequently, PacifiCorp may need to require additional installation of equipment not contemplated in any general regulations.

4) Should the Commission adopt IEEE Standard 1547?

PacifiCorp currently uses IEEE Standard 1547 in its study process to protect the safety and reliability of the generator, other customers attached to the local network, utility workers and the public. PacifiCorp has no concerns regarding the adoption by reference to generally applicable industry standards.

5) Should the Commission adopt the NARUC Model Interconnection Procedures and Agreement?

No. PacifiCorp believes that the NARUC Model Interconnection Procedures and Agreement (NARUC) rules will introduce unnecessary and unjustified complexity into the Company's planning and operation. The NARUC rules will be counterproductive in certain circumstances when working with unsophisticated developers and may reduce the number of small facilities that can be successfully interconnected.

PacifiCorp has several concerns regarding the October 2003 edition of the NARUC Model Interconnection Procedures and Agreement for Small Distributed

Generation Resources. First, the Company is concerned that the NARUC Model tends to limit the flexibility in the due diligence engineering approach to each unique generator application. Distribution systems are built and operated for one direction of current flow, and the introduction of a generator on a distribution line creates engineering and operating challenges to the utility. When considering workable standards for interconnection of generators, PacifiCorp is concerned about the safety of its employees and the public, unintended effects to neighboring customers, and undue wear and tear on utility infrastructure serving multiple customers. To alleviate those concerns, the Company would have to have sufficient staffing to address surges in interconnection activity in order to meet the deadlines established in the NARUC model for engineering, operations, construction, commissioning and contract drafting tasks. PacifiCorp is concerned that those staffing increases would drive operation costs up, and shift costs to retail ratepayers.

Second, developers of distributed generation projects benefit from a process with some flexibility. Many small interconnection customers have business not related to the development of electric generation, but have the ability to use byproducts from their operations to generate electricity. Those customers are not power development professionals and do not have experience with the design and operation of a generating facility. Some of those customers may not hire qualified consultants until after their initial contact with the electric utility. The NARUC timeline, and associated consequences for failure to meet those deadlines, would likely be excessively restrictive to an unsophisticated developer. For example, the NARUC Model's "super-expedited process" would limit both the interconnection customer's and the utility's flexibility to achieve the best, safest, and most reliable solution for interconnection of a facility that will operate on a common circuit with other customers.

Furthermore, PacifiCorp is concerned that provisions of the NARUC model limiting generator liability, indemnification and requirements for general liability insurance will result in an unjustified shift of risk from the developer to the Company and its customers.

Finally, PacifiCorp seeks similar rules in each of the six states in which it operates. Idaho is the first state of the six served by PacifiCorp to seek comment on rules based on the NARUC model. PacifiCorp is concerned that adoption of the NARUC rules in Idaho would introduce regional variation that would be detrimental to the development of distributed generation and increases the Company's cost to administer the interconnection process.

6) Are there other issues the Commission should consider regarding this standard?

No. PacifiCorp believes the above five questions and responses are adequate to begin the process leading to just and reasonable interconnection procedures and agreements for small generators on distribution lines.

It is respectfully requested that all communications regarding these comments be directed to Brian Dickman at (801) 220-4975.

Respectfully submitted this 25th day of August, 2006.

Dean Brockbank / p.n.

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