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August 11, 2006

VIA ELECTRONIC FILING

Ms. Carole J. Washburn
Executive Secretary
Washington Utilities and Transportation Commission
1300 S. Evergreen Park Drive SW
Olympia, WA 98504-7250

RE: Docket No. UE-060649
Comments on Public Utility Regulatory Policies Act Standards

Dear Ms. Washburn:

In response to the Commission's June 9, 2006 Notice of Opportunity to File Written Comments, PacifiCorp dba Pacific Power & Light Company ("PacifiCorp") hereby submits written comments in response to questions posed by the Commission regarding whether new regulations are needed to govern smart metering and interconnections standards based on the new federal standards from the Energy Policy Act of 2005.

According to the CR-101 Statement, the review in this proceeding will examine "whether new or modified regulations are needed to govern aspects of investor-owned electric utility operations for which new federal standards are included in the Energy Policy Act of 2005. These new federal standards address: 1) net-metering, 2) fuel sources, 3) fossil fuel generation efficiency, 4) smart metering, and 5) interconnection." The Washington Commission has already established standards comparable to the net-metering, fuel source, and fossil fuel generation efficiency standards set out in Section 1251(a) of the Energy Policy Act, therefore the focus of the comments are on smart metering and interconnection standards.

Smart Metering

PacifiCorp will respond to each Commission request regarding smart metering below:

1) Should the Commission, by rule, adopt PURPA Standard 14 – Time-Based Metering and Communications – to apply uniformly to PSE, Avista Utilities, and PacifiCorp 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's Comments: The Commission should not adopt PURPA Standard 14 uniformly to PSE, Avista Utilities, and PacifiCorp. PacifiCorp has had limited success implementing time-based rates and believes that application of these rates is currently only effective in limited circumstances. Uniform requirements would ignore the differences between customer groups and the costs of service specific to each electric utility.

PacifiCorp's experience implementing a mandatory time-based rate program in Oregon has not proven to be either cost-effective or successful. PacifiCorp's Oregon program is an optional time of use tariff, which has received very little customer interest. The program has not been cost effective due to the low rate of participation and the high cost of metering installation and promotions. In March 2005, PacifiCorp hired an outside consultant, Quantec, to evaluate its Oregon time of use tariff. Quantec determined that at the time of its study, only 1,600 customers were participating in the program. The total program costs over three years since implementation were estimated to be $961,557. The study estimated that only 226 kilowatts were shifted at peak times and at least 10,000 customers were needed before the program broke even. Currently, PacifiCorp has only 1,215 residential customers participating in the program, out of 460,012 eligible residential customers, indicating a 0.26% participation rate. Similarly, only 395 non-residential customers participated, out of a potential 72,384, for a 0.55% participation rate.

PacifiCorp's implementation of a similar program in Utah met with a comparable response. A pilot time of use tariff was implemented in Utah in April 2004. Currently, there are only 292 residential customers participating in that program out of 665,645 eligible residential customers. This translates to a 0.04% participation rate in Utah.

Furthermore, differences between each utility's customer base and rate structure make uniform application problematic. The geographic dispersion of PacifiCorp's customers in its Washington service territory increases the costs associated with installation of meters, increasing the cost of the program. Customer usage patterns may also differ between rural service territories and urban service territories. These factors define a utility's rate structure and impact the financial viability of any time-based rate program.

PacifiCorp believes implementing a mandatory time-based rate option in Washington to all customer classes would not be appropriate due to lack of customer interest and the costs of providing that option. Instead, PacifiCorp believes 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 the curtailment is economic for the participating customers. This type of strategic program can provide value to the company and our customers in a more cost effective manner.

2) Should the Commission examine and determine whether to adopt the Time-Based Metering and Communications Standard on a generic basis (*i.e.*, applying the same requirements to all utilities), or should it consider the standard within separate proceedings specific to the circumstances of each utility?

PacifiCorp's Comments: The commission should examine the applicability of the Time-Based Metering and Communication Standard requirements separately for each utility. Each utility has different rate structures and serves customers in distinct geographic regions throughout the state. Both of those factors will impact the cost-effectiveness of time-based rate options. For example, customers served by PacifiCorp in Yakima and Walla Walla may have different usage patterns than customers in Puget Sound Energy's service territory. Also, because of the rural nature of much of PacifiCorp's Washington service territory, the installation costs may be different for PacifiCorp than those electric utilities with an urban customer base.

3) Should the Commission reject, reiterate or modify its policy enunciated in Cause U-78-05 that time-of-day rates are appropriate so long as they are cost-effective?

PacifiCorp's Comments: The commission should reiterate its policy enunciated in Cause U-78-05. While time-of-day rates may not be cost effective for Washington at this time, they may be in the future depending on the individual utility and its customers.

4) What factors should the Commission consider in determining whether time-based rates and metering are cost-effective?

PacifiCorp's Comments: The cost-effectiveness of any time-based rate and metering options should be evaluated through a comparison of long-run benefits and the total costs program. The determination of benefits and costs should, at a minimum, include:

Costs:

- Meter and installation costs
- Administration costs
- Communication and marketing costs
- Costs of potential revenue erosion due to the participation of free riders in an optional time of use offering, discussed further in response to Question No. 5.

Benefits:

- System capacity and energy benefits: Value of operational changes in utilization of generation, transmission and distribution resources as a result of load impacts of time-of-use programs.
- Potential customer bill savings: Whether customers would be paying more or less under time-of-use rates option compared to standard tariff.

5) If the Commission adopts the Time-Based Metering and Communications Standard, which, if any, of the 4 listed types of time-based rate schedules should be required? Should the same type of rate schedule be required of all utilities and for all rate classes?

   PacifiCorp's Comments: 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 a 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, and be based on the utility's cost of generating or purchasing electricity on the wholesale market. This option would provide known upfront costs and be more easily understood by customers.

   Additionally, the Commission should set participation limits on any time-of-use offerings, to mitigate the effects of revenue erosion that may occur due to the participation of free riders. Free riders occur when individual customers can take advantage of an optional rate structure to obtain bill savings without changing their usage characteristics. Thus, the Company's cost of service remains the same despite a decline in revenues. Consequently, participation levels must be capped, or mandatory time-of-use rates for a customer class should be implemented to assure actual system benefits.

6) What, if any, relationship should there be between a utility's integrated resource plan and its use of time-based metering, time-of-use rates and demand management programs?

   PacifiCorp's Comments: Time-of-use programs cannot be reliably incorporated into PacifiCorp's Integrated Resource Planning. PacifiCorp currently has a number of demand response and pricing options in its portfolio of programs to address peak loads. These programs include Energy Exchange, time of use rates, tiered rates, and interruptible tariffs. These time-dependent pricing options cannot be modeled as long-term resources in the same manner as other demand management programs because the load reduction potential of such programs, although real, is not dispatchable or reliable. Instead, PacifiCorp includes the impact of such pricing programs in its price elasticity analysis in the load forecast used in its integrated resource plan. PacifiCorp believes this is the appropriate way to handle these types of programs in planning.

7) Are there other issues the Commission should consider in this Inquiry?

PacifiCorp's Comments: PacifiCorp has identified no further issues to consider at this time.

Interconnection

Below are PacifiCorp's reply comments on the Commission questions regarding interconnection.

1) Should WAC 480-108 be amended to include customer-owned facilities up to 100 kW? If so, would the increase to facility size necessitate any other changes to the rule?

PacifiCorp's Comments: The Commission should amend WAC 480-108 to apply to net metering facilities with generating capacity up to 100 kW. WAC 480-108 is "intended to be consistent with the requirements of chapter 80.60 RCW, Net metering of electricity..." RCW 80.60.010(9) was recently amended by the Washington Legislature to define a net metering system as having a generating capacity of up to 100 kW. The current provisions of WAC 480-108 adequately address net metering issues for the preponderance of anticipated net metering installations up to 100 kW. Applying the provisions of WAC 480-108 for all net metering installations up to 100 kW will be most easily understood and administered for customers, equipment vendors, local codes officials and utilities in Washington.

WAC 480-108, however, should not apply to non-net metering facilities of any size. The planning requirements and system impacts of QF interconnections are not adequately recognized by WAC 480-108. Neither are the system requirements for parallel no-sale arrangements. In many cases QF 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 cannot complete required reliability studies and meet the timing requirements in WAC 480-108-030(3) and may need to require additional installation of equipment not contemplated in the regulations. Similarly, parallel no-sale interconnections may require specific equipment or upgrades to protect system reliability and address safety requirements.

2) Is there another "break-point" to which it would be appropriate for practical reasons to increase the scope of WAC 480-108 (e.g., 300 kW, 500 kW)? If so, would the increase in facility size necessitate any other changes to the rule?

PacifiCorp's Comments: The Commission should limit its application of net metering requirements to the 100 kW limit identified in RCW 80.060.010. Beyond 100 kW the provisions of WAC 480-108 do not adequately address interconnection issues and the potential system requirements. Furthermore, WAC 480-108-040(15) allows generator disconnection at the discretion of the customer. This could conflict with the requirements of power purchase contracts executed when customer generation of any size is connected as a QF. WAC 480-108 is a well drafted regulation that appropriately addresses net metering circumstances up to 100 kW.

3) Should interconnection of facilities larger than those covered currently by WAC 480-108 be governed by a standard rule? If so, would the Federal Energy Regulatory Commission's (FERC) Small Generator Interconnection Rule serve as a good model?[1] If so, how should the FERC rule be adapted to Washington circumstances?

   PacifiCorp's Comments: A 2 MW generator interconnecting to a 12 kV distribution line will have significantly more impact on reliability to the local network then the same generator interconnecting to a 230 kV transmission line. Therefore, rather than adopting the federal regulations governing small generator interconnections to transmission systems, the Commission should adopt a set of guidelines governing state-jurisdictional interconnections not addressed under WAC 408-108. By adopting guidelines, the Commission can establish general requirements for electric utilities, such as consistent electrical standards and the establishment of a formalized process, while allowing electric utilities the opportunity to develop an efficient process that fits the needs of its unique system. This approach will balance the interests of safe and reliable electric service with the needs of Qualifying Facilities and other small generators. It will also minimize the implementation costs of these programs, keeping rate impact to a minimum.

   FERC's Small Generator Interconnection Procedures are appropriate for evaluating interconnections to PacifiCorp's transmission system because generators can convert to a FERC-jurisdictional interconnection upon request and often choose this option. Consistency between the processes at this level becomes highly desirable to avoid duplication of efforts or cost. After all, FERC developed its Small Generator Interconnection Procedures within the scope of FERC's jurisdiction – facilities used in the interstate transmission of electricity. Consequently, PacifiCorp currently requires all Qualifying Facilities interconnection to its transmission system to enter its interconnection queue under its Open Access Transmission Tariff to provide comparability and consistency for all generators.

[1] Standardization of Small Generator Interconnection Agreements and Procedures, Order No. 2006, 70 FR 34190-01 (June 13, 2005), 2005 WL 1382263 (F.R.), order on reh'g, Order No. 2006-A, 70 FR 71760-01 (November 22, 2005), 2005 WL 3171564 (F.R.).

Distribution systems, however, are built and operated for one direction current flow. The introduction of a generator creates engineering and operating challenges to the utility. When considering workable standards for interconnection of generators, PacifiCorp is concerned about the safety of our employees and the public; unintended effects to neighboring customers, undue wear and tear on utility infrastructure serving multiple customers and avoiding costs driven by surges in demand or arbitrarily short timeframes for our engineering, operations, construction, commissioning and contract crafting tasks. In PacifiCorp's experience, many customers and developers of distributed generation projects benefit from a flexible approach of give and take with the utility. They are not power development professionals and often do not engage professional design and operations experts before approaching the utility. The timelines, and associated consequences for failure to meet those deadlines, may be excessively restrictive to a developer or a 2 MW Qualifying Facility.

4) If interconnection of facilities larger than those covered currently under WAC 480-108 should not be governed by a standard rule, what principles should apply to such interconnections?

PacifiCorp's Comments: As discussed above, the Commission can adopt guidelines that contain specific requirements that must be met, while allowing individual utilities to create their own specific procedures. PacifiCorp suggests the following guidelines for the Commission's consideration:

1. All interconnection customers shall be treated in a non-discriminatory and non-preferential manner.
2. The utility shall review all interconnections 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. Any requirements should not restrict utilities from developing timelines that allow the utility and interconnection customer to engage in discussions regarding study results and design options.
8. Technical requirements for all interconnections shall comply with IEEE, NESC, NEC and other safety and reliability standards.

Please direct any questions regarding these comments to Melissa Seymour at (503) 813-6711.

Thank you.

Respectfully,

Andrea Kelly /MAS

Andrea L. Kelly
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