BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1330

In the Matter of	)
	)
PUBLIC UTILITY COMMISSION OF OREGON	)
	)
Investigation of Automatic Adjustment Clause pursuant to SB 838.	)

DIRECT TESTIMONY OF

RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

September 28, 2007

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8343 Roswell Road, Sandy Springs, Georgia 30350.

Q. WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A. I am a utility rate and planning consultant holding the position of President and Principal with the firm of RFI Consulting, Inc. ("RFI"). I am appearing in this proceeding as a witness for the Industrial Customers of Northwest Utilities ("ICNU").

Q. PLEASE BRIEFLY DESCRIBE THE NATURE OF THE CONSULTING SERVICES PROVIDED BY RFI.

A. RFI provides consulting services in the electric utility industry. The firm provides expertise in electric restructuring, system planning, load forecasting, financial analysis, cost of service, revenue requirements, rate design, and fuel cost recovery issues.

I. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. Exhibit ICNU/101 describes my education and experience within the utility industry. I have 30 years of experience in the industry. I have worked for utilities, both as an employee and as a consultant, and as a consultant to major corporations, state and federal governmental agencies, and public service commissions. I have been directly involved in a large number of rate cases and regulatory proceedings concerning the economics, rate treatment, and prudence of nuclear and non-nuclear generating plants.

During my employment with EBASCO Services in the late 1970s, I developed probabilistic production cost and reliability models used in studies for 20 utilities. I personally directed a number of marginal and avoided cost studies performed for compliance with the Public Utility Regulatory Policies Act of 1978 ("PURPA"). I also participated in a wide variety of consulting projects in the rate, planning, and forecasting areas.

In 1982, I accepted the position of Senior Consultant with Energy Management Associates ("EMA"). At EMA, I trained and consulted with planners and financial analysts at several utilities using the PROMOD III and PROSCREEN II planning models.

In 1984, I was a founder of J. Kennedy and Associates, Inc. ("Kennedy"). At that firm, I was responsible for consulting engagements in the areas of generation planning, reliability analysis, market price forecasting, stranded cost evaluation, and the rate treatment of new capacity additions. I presented expert testimony on these and other matters in more than 100 cases before the Federal Energy Regulatory Commission ("FERC") and state regulatory commissions and courts in Arkansas, California, Connecticut, Florida, Georgia, Kentucky, Louisiana, Maryland, Michigan, Minnesota, New Mexico, New York, North Carolina, Ohio, Oregon, Pennsylvania, Texas, Utah, Washington, West Virginia, and Wyoming. Included in Exhibit ICNU/101 is a list of my appearances.

In January 2000, I founded RFI Consulting, Inc. with a comparable practice to the one I directed at Kennedy.

Q. HAVE YOU PREVIOUSLY APPEARED IN ANY PROCEEDINGS BEFORE THE OREGON PUBLIC UTILITY COMMISSION?

A. Yes. I filed testimony in numerous Portland General Electric Company ("PGE") and PacifiCorp cases. In those cases, I primarily addressed various issues related to the recovery of power costs. Exhibit ICNU/101 presents these appearances and the topics I testified about.

Q. YOUR TESTIMONY IN THIS CASE CONCERNS COST ALLOCATION, MARGINAL COST PRICING AND ITS IMPLICATIONS FOR RATE DESIGN. HAVE YOU PREVIOUSLY TESTIFIED BEFORE REGULATORY COMMISSIONS REGARDING SUCH MATTERS?

A. Yes. While I have not testified on these issues in Oregon, I have been involved in rate design and rate spread matters since the start of my career in the utility industry. I have previously testified regarding these issues in cases in Arkansas, Kentucky, Florida, Iowa, Maryland, Minnesota, New York, Ohio, and Pennsylvania. Exhibit ICNU/101 provides a list of these appearances.

II. INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. ICNU has asked me to examine PGE's proposed Schedule 122 and PacifiCorp's Schedule 202 and to make recommendations concerning these tariffs and other policy issues surrounding the recovery of costs of renewable resources acquired by PGE and PacifiCorp in compliance with Senate Bill ("SB") 838.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I have concluded as follows:

1. An earnings test should be applied to the Commission-approved recovery mechanisms. This kind of test is necessary to ensure that PGE and PacifiCorp properly collect the costs of new renewable resources acquired pursuant to SB 838.

2. The Commission should not approve either PGE Schedule 122 or PacifiCorp schedule 202 unless substantial modifications are made to these schedules.

3. PGE's proposed Schedule 122 will overcollect the cost of new renewable resources, such as wind turbines, after their initial year of operation. Revenue requirements for new wind generators will decline substantially after the initial year because of negative attrition due to the growth of accumulated depreciation and deferred income taxes.

4. PacifiCorp's Schedule 202 does not suffer from the same infirmity as PGE's Schedule 122. PacifiCorp's proposal acknowledges that cost and revenues will not match unless all cost elements are updated annually.

5. To address this problem, I propose an annual adjustment be made to PGE's proposed Schedule 122, similar to the adjustments made under other PGE rate schedules such as the Annual Update Tariff ("AUT"). Whether compliance costs increase or decrease in the years ahead, this approach will provide a much better matching of costs and revenues.

6. Both PGE and PacifiCorp have ignored proper costing and pricing principles by allocating the costs of renewable resources on a simple per kWh basis.[1/] These schedules should be modified to reflect the OPUC's marginal cost allocation factors approved in each utility's last general rate case.

7. PGE and PacifiCorp provide no cost justification for their proposals in their testimony or discovery responses. Both companies attempt to justify their proposals on a non-cost basis, such as regulatory simplicity or consistency with other tariffs. These justifications are not well-founded and should be rejected.

8. For both PacifiCorp and PGE, I propose annual filings made pursuant to SB 838 be included with the annual Transmission Adjustment Mechanism ("TAM") or AUT filings. The broadened scope of these proceedings should also include a longer procedural schedule and more rounds of testimony. This will enable a fair review of the costs collected under SB 838, as well as resolve certain procedural problems that have become apparent in recent proceedings.

9. There should also be an annual true-up to ensure that the revenues collected under the schedules approved in this proceeding match the actual

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[1/] PGE proposes a voltage level differential in its Schedule 122, but no other type of class differentiation would apply. PacifiCorp's Schedule 202 does not provide for class differentiation, not even voltage level differentials.

> costs approved. Differences in sales growth rates can cause mismatches, and should be avoided.

III. RENEWABLE COST RECOVERY ISSUES AND ALTERNATIVES

Q. PLEASE DISCUSS SB 838.

A. This legislation was intended to promote utility acquisition of renewable resources. It sets rather ambitious targets for utilities to meet, requiring that qualifying renewable resources provide up to 25% of the utilities' energy by the year 2025. Under the bill, the Oregon Public Utilities Commission ("OPUC" or the "Commission") is directed to establish a mechanism for the recovery of prudently incurred compliance costs:

> The Public Utility Commission *shall establish an automatic adjustment clause as defined in ORS 757.210 or another method that allows timely recovery of cost*s prudently incurred by an electric company to construct or otherwise acquire facilities that generate electricity from renewable energy sources and for associated electricity transmission.

SB 838, Section 13(3) (emphasis added).

Q. IS AN AUTOMATIC ADJUSTMENT CLAUSE SPECIFICALLY REQUIRED UNDER THE ACT?

A. No. As the plain language of the act shows, the Commission is required to develop *a mechanism that allows timely recovery of prudently incurred compliance costs.* This provides the Commission with a certain degree of latitude in structuring a recovery mechanism that is just and reasonable, while still satisfying the requirements of the statute.

Q. IS THE USE OF AN AUTOMATIC ADJUSTMENT CLAUSE THE ONLY MECHANISM BY WHICH A UTILITY COULD RECOVER ITS ELIGIBLE RENEWABLE RESOURCE COSTS?

A. No. The Commission has a wide range of procedural options available. The Commission should naturally be wary of frustrating the intent of the legislation.

ICNU's proposals in this proceeding are intended to meet the goals of SB 838 in a fair and equitable manner.

Q. WHAT POLICY GOALS SHOULD GUIDE THE COMMISSION IN DEVELOPING A RECOVERY MECHANISM?

A. The Commission should evaluate any proposed recovery mechanism in terms of how it meets the four following goals:

1. Full and timely recovery of prudently incurred qualifying costs must be allowed, pursuant to statute.
2. Equity vis-à-vis utilities and ratepayers should be maintained. The recovery mechanism should not unduly favor utilities or consumers.
3. Equity between customer classes should be maintained. Commission-approved allocation methods should be utilized to prevent class subsidies from forming or growing.
4. All parties to the process should be afforded a full and fair opportunity to examine and address the costs to be recovered. This is a nothing more than the fundamental requirement of "due process."

To achieve these goals, ICNU proposes that the Commission adopt an annual process to include prudently incurred eligible costs in a separate rate schedule for both PGE and PacifiCorp. ICNU also proposes some important modifications to the proposals made by PGE and PacifiCorp.

Timely and Equitable Recovery

Q. WHAT ARE THE PROBLEMS TYPICALLY ASSOCIATED WITH THE USE OF AUTOMATIC ADJUSTMENT CLAUSES?

A. When an automatic adjustment clause is present, cost discipline is not rewarded, and perverse incentives are created. If a utility knows that it will automatically recover 100% of all costs invested in wind generation, for example, it may not be as diligent in controlling the costs of such resources and could conceivably construct more such resources than required under the least cost expansion plan or for compliance with SB 838. Indeed, I believe this is a real possibility, because utilities seek first to minimize risk to investors, and only second to minimize cost for ratepayers. If a new steam plant is not afforded pass-through recovery, while a wind resource is, certainly it would be expected that a utility may develop a bias in favor of wind generation. However, given the ambitious targets set forth under SB 838, it appears that it will be a challenge for PGE and PacifiCorp to meet those goals.

A second problem with automatic adjustment clauses is that they can create an inequitable shifting of costs between ratepayers and the utility due to regulatory lag. Utilities face a wide range of costs, covering everything from administrative costs to generating plants and their associated fuels. Over time, some of these costs (fuels and purchased power) may increase, while other cost elements (a depreciating rate base) decline. Due to regulatory lag, utilities will never exactly recover their costs to the last penny. However, under a reasonable and equitable form of regulation, the utility will have a *fair opportunity* to recover its costs. This can only occur if sources of declining costs and sources of increasing costs are treated on an equal footing when it comes to regulatory lag.

If, however, increasing costs are afforded automatic pass-through recovery, while declining costs are not, it stands to reason that utilities will have an opportunity to over collect. Absent a full blown rate case every year, an earnings test is a reasonable means of avoiding this problem when implementing a new recovery mechanism.

Q. DOES SB 838 PRECLUDE THE USE OF AN EARNINGS TEST?

A. SB 838 does not address the subject of an earnings test. There is no language prohibiting the Commission from adopting one as part of its approved recovery method. Given that PGE and PacifiCorp both now have annual rate recovery mechanisms for dealing with their largest and most uncertain cost elements (the TAM for PacifiCorp and the AUT and Annual Variance Tariff ("AVT") for PGE), introduction of yet another automatic adjustment clause without imposition of an earnings test would not promote efficiency nor would it be equitable.

Q. HOW WOULD AN EARNINGS TEST HELP PROMOTE THE GOALS OF ACHIEVING EFFICIENCY AND MAINTAINING EQUITY BETWEEN RATEPAYERS AND UTILITIES?

A. An earnings test is an important tool for addressing the second goal discussed above – maintaining equity vis-à-vis customers and investors. While imperfect, an earnings test would provide some incentive for cost control. If a utility expects that every dollar of expenditures will be matched with a dollar of revenues, incentives for cost control may be absent. However, with an earnings test, the direct linkage between expenditures and cost recovery is broken. The utility, therefore, has a greater incentive to control costs. This is particularly true in the case of an over-earning utility, because it would recognize that some of its earnings would be used to defray the cost of additional spending. Therefore, unnecessary spending would be discouraged. In the case of an under-earning utility, the ordinary pressures of business should provide some impetus for cost control.

Of course, an earnings test is not perfect, because it is not as precise as a full blown general rate case. Nonetheless, it is a tool the Commission has already approved, and it is much easier to implement than an annual rate case filing.

Q. DESCRIBE THE COMMISSION'S APPROVED EARNINGS TEST.

A. The Commission adopted a simple earnings test in UE 180 for application to PGE's AVT:

> We establish an earnings deadband of ± 100 basis points around the company's allowed ROE, for two reasons. First, although we use a specific ROE to set rates, there is a range of acceptable returns on equity. *See Duquesne Light Co. v. Barasch*, 488 US 299, 312 (1989). Second, an earnings review does not determine a company's actual ROE with the same accuracy as a full rate case, because the company's costs are not examined as thoroughly in the earnings review. If PGE is earning within +/-100 basis points of this authorized rate of return, there will be no power cost adjustment for that year. If the Company's earnings are more than 100 basis points below its authorized ROE, it will be allowed to recover excess power costs, after application of the deadband and 90-10 sharing described below, up to an earnings level that is 100 basis points less than its authorized ROE. If the Company's earnings are more than 100 basis points above its authorized ROE, it will be required to refund to customers power cost savings, after application of the deadband and sharing, down to the ROE plus 100 basis points threshold. We will apply the earnings test to PGE's authorized ROE, and decline to accept its suggestion that the return should be updated annually. We find that using PGE's authorized ROE for the earnings review is reasonable, and the Company has discretion to propose an updated ROE in [a] general rate filing.

<u>Re PGE</u>, Docket Nos. UE 180, UE 181, and UE 184, Order No. 07-015 at 26 (Jan. 12, 2007). There is no reason to depart from this standard for recovery of renewable energy costs.

Q. CLARIFY THE APPLICATION OF THIS EARNINGS TEST TO THE RECOVERY OF PRUDENTLY INCURRED COMPLIANCE COSTS.

A. The initial application of any schedule designed to collect compliance costs will be a positive number. However, as I will discuss shortly, subsequent changes to a schedule may result in increases or decreases. Once the amount to be recovered under the schedule is determined (using the Commission's approved formula), the earnings test should be applied to determine whether the rate change should actually be implemented.

In the event of a prospective *increase* in the charges, no rate change would occur if the earnings test shows that the utility's ROE is less than 100 basis points below its most recently authorized return. In the event of a prospective *decrease* in the charges, no rate change would occur if the utility's ROE is less than 100 basis points above its most recently authorized return. In this manner, rates would not increase if the utility's earnings are already adequate (i.e., only modestly below the authorized rate of return) or above the authorized return. Conversely, no rate reduction would occur if the utility's earnings are only marginally above or below the allowed return. In this way, some incentive features will be present in the renewable cost recovery mechanism, and the utility will have a fair opportunity to recover compliance costs.

Q. WOULD APPLICATION OF THIS EARNINGS TEST INHIBIT TIMELY RECOVERY OF PRUDENTLY INCURRED COMPLIANCE COSTS?

A. No. The earnings test described above would ensure that the utility is earning within 100 basis points of its allowed return and, if not, than appropriate rate adjustments would be made to allow for full cost recovery of the eligible compliance costs. As long as earnings fall within the 100 basis point deadband, it is reasonable to assume all costs are being recovered. Because the test is applied in conjunction with an automatic adjustment process, recovery is timely. In the end, it is not a tracking of a specific cost on a dollar for dollar basis that the Commission should strive for. Rather, the Commission should consider cost recovery to be effectuated if earnings of the utilities are adequate.

Q. THE COMMISSION'S EARNINGS TEST DISCUSSED ABOVE IS APPLIED IN CONNECTION WITH A SHARING MECHANISM. IS THAT APPROPRIATE IN THIS CASE?

A. Absent the directives of SB 838, a sharing mechanism would have merit. However, if a sharing approach were used, then arguably the utility could recover more or less than the full amount of prudently incurred compliance costs when earnings fall outside of the ROE deadband. As a result, ICNU is not recommending a sharing deadband be used.

<u>PGE's Proposed Schedule 122</u>

Q. IS THERE ANY DETAIL REGARDING HOW PGE PROPOSES TO COMPUTE THE REVENUE REQUIREMENT UNDERLYING SCHEDULE 122?

A. PGE objected to providing any projection of costs to be recovered under Schedule 122. ICNU/102, Falkenberg/1. However, PGE did provide an example using Biglow Canyon revenue requirements from UE 188. Presumably, it would not object to using the same approach for other compliance costs.

Based on PGE's Schedule 122, the Company will implement a charge for new renewable projects at the time they enter service. Initially, this charge will credit net dispatch benefits against fixed costs. With the filing of the next AUT (in April of the following year), PGE will reflect the net dispatch benefits in the MONET model and remove those credits from fixed costs collected under

Schedule 122. After that time, PGE will not make any revisions to the fixed costs collected under Schedule 122, unless there is a full general rate case when PGE will roll the charges into base rates. Once the initial fixed cost revenue requirement of the new resource is determined, PGE will never reduce that amount unless it has a general rate case.[2/]

Q. DO YOU HAVE ANY OBJECTIONS TO PGE'S PROPOSAL?

A. Yes. PGE's calculation might be acceptable if the rate effective period were limited to only the first year of operation of a new renewable resource. However, Schedule 122 will be in effect beyond that time, and would remain in effect until the Commission approves new rates in PGE's next general rate case. It may be many years before Schedule 122 fixed costs are incorporated into permanent rates. Under PGE's proposed Schedule 122, this need only happen once every five years. While PGE would add new resources to Schedule 122 from time to time, it would apparently not change the charges for resources already included in the tariff, no matter what their costs might be.[3/]

This is significant because, as PGE acknowledged in its response to an ICNU data request in the Biglow Canyon case (UE 188), the costs of new renewable resources such as Biglow Canyon will decline over time:

2/ PGE indicates it will not change the fixed costs collected under Schedule 122 for a new resource after it enters service. However, I suspect PGE might decide to petition for a change in the rate if costs were increasing.

3/ I suspect PGE would depart from this in the event of unexpected cost increases, such as termination of the NEPA credits.

> **<u>Request:</u>**
>
> Please provide a comparison showing the expected cost per MWh for Biglow Canyon as compared to the Klondike purchase. Please provide the comparison for the next five years?
>
> *<u>Response</u>**<u>:</u>***
>
> PGE has not performed this analysis. PGE selected both of these resources through its 2003 Request for Proposals and related evaluation process. The analysis considered all years of projected resource life, not simply a subset. In the cases of Biglow and the Klondike II purchase, analyzing only the first five years would be misleading. Under the relevant contractual terms, payments for Klondike are approximately flat in real terms, whereas *Biglow has a rate base component, whose related costs are higher in early years, but lower in later years. Focusing only on the early years would make Biglow look more expensive than it really is over its life cycle*.

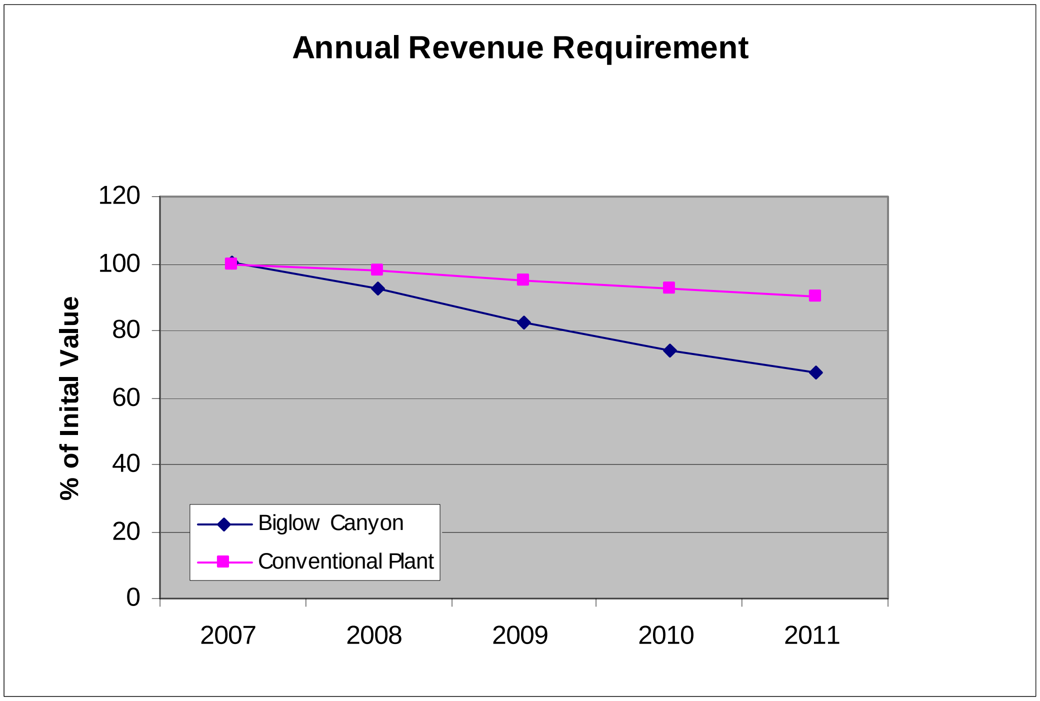
ICNU/103, Falkenberg/1 (emphasis added). There is no reason why the above admission would not be true for any new renewable resource.

Q. HAVE YOU PERFORMED ANY ANALYSIS OF BIGLOW CANYON THAT ILLUSTRATES THE TREND OF DECLINING COSTS OVER TIME?

A. Yes. The chart below shows the decline in costs for Biglow Canyon computed by PGE as part of the evaluation of the Orion Energy LLC bid. To protect the confidentiality of the data, all figures are indexed to 2007 levels (which is set equal to 100). As the figure shows, by the end of the first five years, the revenue requirement for the facility is only 67% of its initial year value.[4/] Also shown are results from a more conventional plant, which shows a less significant decline in costs. While this analysis used Biglow Canyon costs, they are illustrative of any

[4/] Originally assumed to be 2007 by PGE in this bid evaluation.

new wind turbine project. Based on current economic considerations, wind turbines are likely to be the most common form of compliance capacity.



Q. WHY WOULD COSTS FOR A WIND TURBINE DECLINE MORE QUICKLY THAN FOR A CONVENTIONAL PLANT?

A. There are a number of reasons. Wind turbines qualify for a very favorable tax treatment that allows a five-year tax life. Other types of plants generally use a ten- or fifteen-year tax life. Also, wind turbines represent a new technology and are assumed to have a shorter book life than conventional plants. Further, wind generation is eligible for the NEPA tax credit, which is indexed to inflation. Finally, wind turbines use no fuel as compared to a conventional fossil fuel power plant (although these costs are not shown on the above chart).

Q. WHAT ARE THE IMPLICATIONS OF THIS FOR THE RATE TREAMENT OF NEW WIND RESOURCES?

A. The cost profile for wind resources shows a steeper downward slope than would be the case for conventional resources. As a result, rate treatment specific to this type of resource should be reflected in the Commission's approved compliance cost recovery mechanism.

Q. PLEASE ELABORATE ON THE IMPACT OF THE FIVE-YEAR TAX LIFE.

A. A five-year tax life for a long-term asset like a wind turbine is an exceptionally favorable tax treatment. This results in a rapid increase in accumulated deferred taxes of the new wind resource and a concomitant reduction in rate base. For property placed into service in the fourth quarter of any year, the first- and second-year tax depreciation for the asset is 43% of the total tax basis.[5/] All of this contributes to the rapid decline in revenue requirements for wind generators that would not be fully captured in a test year based on the first twelve months of service. Under PGE's proposal, the Company would retain many of the benefits of these federal incentives for its shareholders.

Q. IS IT LIKELY THAT SOME WIND TURBINE COSTS WILL INCREASE OVER TIME?

A. Yes. The O&M expense can be expected to increase. However, these impacts are much smaller than the other sources of negative attrition related to the project.

Q. DISCUSS THE IMPLICATIONS OF YOUR ANALYSIS.

A. Any rate treatment tied to the first-year fixed cost of a new wind resource will likely result in substantial over-collection of prudently incurred compliance costs.

5/ IRS Publication 946, page 74.

This would be highly inequitable and a poor policy for the Commission to adopt, particularly if the Commission does not implement an earnings test. In this proposal, PGE seeks to totally eliminate the detrimental effects of regulatory lag when a new renewable resource comes on line, but once it is included in rates, PGE seeks to retain the subsequent benefits of regulatory lag. Once a cost is included in Schedule 122, there would be no adjustment made, despite the clear evidence that the cost of the resource would decline over time. This is a highly inequitable proposal.

In this regard, PGE's proposed Schedule 122 would be unique. PGE now has the AUT (Schedule 125) and AVT (Schedule 126) to address year to year power cost variations. PGE also has several other rate adjustment schedules to recover other types of costs: Schedule 102 (Regional Power Act Exchange Credit), Schedule 105 (Regulatory Adjustments), Schedule 106 (Multnomah County Business Income Tax Recovery), Schedule 107 (Demand Side Management Investment Financing Adjustment), Schedule 108 (Public Purpose Charge), Schedule 115 (Low-Income Assistance), in addition to the Power Cost/Transition Credit related tariffs - Schedules 125, 126, and 128-130.

Q. DO ANY OF THE SCHEDULES LISTED ABOVE CONTAIN A PROVISION FOR PERIODIC ADJUSTMENT?

A. Yes. Schedules 102, 105, 106, 125, 126, 128, and 130 are all subject to periodic adjustment. Schedule 107 apparently is not, but it recovers a fixed amount of financing costs over a ten-year period and is subject to a balancing account. Thus, no such periodic adjustment is needed. Collections pursuant to Schedules 108 and 115 are simply passed on to other organizations, so there is apparently no need for any adjustment to these tariffs either. It is a bit ironic that, out of all of PGE's rate adjustment schedules, PGE would believe that the tariff designed to recover new wind resource costs should be fixed until the next general rate case, while making provisions for adjustments or true-ups in its other schedules. It appears also that, unlike the other costs recovered under PGE's special tariffs, only the cost of wind generation can be expected to decline over time.

Q. DOES PACIFICORP PROPOSE A SIMILAR TREATMENT IN ITS SCHEDULE 202?

A. No. PacifiCorp witness Ms. Andrea Kelly proposes that once per year PacifiCorp would adjust Schedule 202:

> "(3) recalculate the revenue requirement of any resources already approved for recovery in the RCAC, which have not yet been incorporated into rates through a general rate case. *This third step will ensure that customers' rates reflect the reduction in rate base due to depreciation as well as provide a current forecast of all costs within the upcoming calendar year*."

PPL/100, Kelly/6 (emphasis added). PacifiCorp also stated in response to ICNU's discovery that it would update all cost elements, including deferred income taxes, on an annual basis. ICNU/104, Falkenberg/4. PacifiCorp contends it has formed no opinion (and does not intend to form one) regarding PGE's proposal. Id. at Falkenberg/9. Nonetheless, if PacifiCorp believed the PGE methodology had merit, I presume it would have proposed it. In any case, the PacifiCorp proposal is more balanced and equitable than the PGE proposal. The Commission should not adopt two such divergent approaches for its approved recovery mechanism. As was seen in the case of PGE's RVM, once PGE was allowed this form of cost recovery, PacifiCorp requested it as well.

Q. HOW DO YOU PROPOSE THAT THE COMMISSION IMPLEMENT AN ANNUAL ADJUSTMENT PROCESS FOR SCHEDULE 122?

A. As with PacifiCorp's proposal, the filing should be made once per year. I will discuss this aspect of my proposal later in this testimony.

Q. IF QUALIFYING COSTS WERE RECOVERED IN A GENERAL RATE CASE, IT SEEMS LIKELY THAT THE ISSUE OF NEGATIVE ATTRITION WOULD NOT BE ADDRESSED. WHY IS IT IMPORTANT TO ADDRESS THE ISSUE IF THE COST OF THE RESOURCE IS RECOVERED THROUGH A SEPARATE RIDER?

A. The premise of this question is not completely accurate. In a number of cases, regulators have set up adjustment mechanisms to deal with negative attrition. The Arkansas commission has used such a method in the past, and it is implementing a new one at this time.

In any case, base rates recover many costs, some that increase and others that decline. The premise underlying conventional ratemaking is that (until proven otherwise) such conflicting trends cancel each other out. Over time, a utility may over or under recover, and it is up to either the company (or the opposing parties) to address mismatches should they become too extreme.

In the case where specific costs are collected through a special recovery mechanism, the above-stated paradigm is broken. When a specific schedule is used to recover a specific type of cost, every effort should be made to recover those costs as accurately as possible. In nearly all of the PGE riders discussed above, there is some provision for periodic adjustment or to track cost variances through a balancing account. Unless this is done, the temptation for the utility would be to promulgate a plethora of special rates and riders for new costs or increasing costs, while reserving conventional rate recovery for declining costs.

In the end, each specific rate schedule charged by the utility must meet the "fair, just and reasonable" standard. This cannot be done if revenues collected under a specific schedule are known to be out of line with costs. As PacifiCorp's proposal shows, PGE's proposal to retain the benefits of negative attrition is not even considered valid by another utility.

Q. IS THERE EVIDENCE THAT THE UTILITIES WILL SEEK TO PROMULGATE MORE SINGLE COST RIDERS AS A PART OF THEIR BUSINESS STRATEGY?

A. Certainly. As shown above, PGE already has many single cost riders. In PacifiCorp's Response to ICNU's DR to No.1.31, we find that the company stated at its April 2007 Investor's Conference that its regulatory strategy would focus on the use of single cost trackers. ICNU/109, Falkenberg/14. Clearly, this is a strategy that should not be taken lightly by the Commission, nor rewarded by allowing an inequitable cost recovery approach.

<u>Rate Design Issues</u>

Q. THE THIRD GOAL ARTICULATED ABOVE SUGGESTS THAT THE PROPOSED SCHEDULES MAINTAIN EQUITY BETWEEN CUSTOMER CLASSES. DO THE PROPOSALS OF PGE AND PACIFICORP FURTHER THAT GOAL?

A. No, both would frustrate it. The proposals of both companies would unfairly collect a disproportionate amount of qualifying costs from larger customers. In this regard, both companies' proposals fail to follow the OPUC's longstanding cost allocation procedures**.**

Q. HOW DO PGE AND PACIFICORP PROPOSE TO ALLOCATE THE COSTS RECOVERED UNDER THEIR PROPOSED SCHEDULES?

A. Both Companies propose to allocate the charges on a pure per kWh basis, with no class differentiation, other than a minor loss factor adjustment in PGE's proposal.

These proposals run contrary to Oregon's longstanding treatment for allocation of generation costs. In my thirty years of experience in utility ratemaking matters, I do not recall ever seeing a case where a utility proposed to allocate and collect the costs for new generating units on an equal cents per kWh basis. This is far outside of standard industry practice and follows no recognized concept of cost causation. There is no basis in any recognized ratemaking theory, whether it be embedded cost or marginal cost, that would support such proposals.[6/]

Q. THAT'S A PROVOCATIVE STATEMENT. PLEASE EXPLAIN.

A. Since the time of the first NARUC Cost Allocation Manual in 1973 (and, I believe, long before), it has been recognized that utility generation costs are comprised of two types of costs: fixed and variable costs. Often these are called demand or capacity related, and energy related costs.[7/] Each type of cost is allocated to customer classes on a different measure of consumption by customer classes.

Q. PLEASE DISTINGUISH BETWEEN "CAPACITY" AND "ENERGY" COSTS IN THIS CONTEXT.

A. Energy costs are incurred in the conversion of fuel inputs into the performance of useful work over time. Capacity costs are related to the infrastructure needed to obtain that energy at any time desired. This is much like the difference between the miles driven by a car (which requires fuel costs) and the availability of the car

6/ In the case of PacifiCorp, that company's proposal is at odds with the methodology it proposes to use to allocate costs between jurisdictions. This will be discussed shortly.

7/ National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual* 31 (1973).

(which requires an investment or lease payment). Energy costs are analogous to fuel costs for a car, while capacity costs are analogous to the cost of owning a car.

Q. HOW ARE CAPACITY AND ENERGY RELATED COSTS NORMALLY TREATED IN CLASS COST ALLOCATION PROCEDURES?

A. Ordinarily, energy related costs are allocated to classes on the basis of energy consumption, while capacity related costs are allocated on the basis of some measure of peak demand (or sometimes peak and average demands). For jurisdictional allocations, PacifiCorp has long followed a practice that allocates demand related costs 75% on the basis of the 12 coincident monthly peaks ("CP"), and 25% on the basis of average demand (or energy).

Q. DOES PACIFICORP PLAN TO FOLLOW THIS INDUSTRY STANDARD APPROACH IN ITS ALLOCATION OF WIND RESOURCE COSTS TO THE OREGON JURISDICTON?

A. Yes. Referring to Exhibit PPL/101, Kelly/1, we see PacifiCorp's proposal for the deferral of costs of the Leaning Juniper project. In this analysis, PacifiCorp proposes to allocate all of the fixed costs of the project to Oregon on the basis of the SG ("System Generation") factor. Further, in PacifiCorp's response to ICNU DR 1.01, it shows that it also proposes to use the same SG factor to allocate fixed costs of wind generation to Oregon in the development of the Schedule 202 revenue requirement. ICNU/104, Falkenberg/3. The SG factor allocates costs on the basis of 75% 12 CP and 25% average demand, as discussed above. Use of this factor provides clear evidence that the Company recognizes that the fixed cost components of wind resources are, indeed capacity or demand related, not purely energy related.

Q. WOULD PACIFICORP COLLECT LESS FROM OREGON IF IT ASSUMED A PURE ENERGY ALLOCATION METHOD FOR WIND RESOURCES, RATHER THAN THE DEMAND ALLOCATION METHOD?

A. Certainly. Allocation of the Leaning Juniper project fixed costs on a demand basis produces an Oregon allocation of $4,705,259 per year, based on PPL/101. Using a pure energy allocation method would produce an annual Oregon revenue requirement of $4,615,102. While this amount is not substantial, it is merely one year's cost for one wind resource. Over the years, when many wind resources will be built, the total cost differential will become much larger.

Q. SO FAR YOU HAVE DISCUSSED JURISDICTIONAL ALLOCATION METHODS. ARE THE SAME METHODS USED BY THE OPUC FOR DETERMININING CLASS REVENUE REQUIREMENTS?

A. No. The OPUC has a longstanding practice of using *marginal* cost studies for the allocation of costs within classes of service. Nonetheless, the OPUC-approved methodology still recognizes the difference between demand and energy related costs. For example, Exhibit ICNU/105 is an excerpt of PacifiCorp's Marginal Cost study used in Docket No. UE 179. The OPUC-approved methodology differentiates marginal production costs between capacity and energy costs. These costs are then used in the class allocation process. <u>See</u> ICNU/106. As the figures show, while the Large Power Service Class consumes 23.54% of the system kWh, it is allocated 22.59% of the generation related revenue requirements under PacifiCorp's OPUC approved marginal cost methodology.

Q. IS THERE ANY REASON WHY WIND OR OTHER RENEWABLE RESOURCES SHOULD NOT FOLLOW THE TRADITIONAL MARGINAL COST ALLOCATION METHOD USED IN OREGON?

A. No.[8] The one way in which wind resources are unique is in the fact that wind resources are comprised of virtually 100% fixed costs. Once the initial capital investment is made, there are no variable fuel or operating costs that one would typically assume to be energy related. Thus, the argument could be made that such costs should be allocated to customer classes on a 100% capacity basis. Because the proposed riders will collect nothing but the incremental costs of new resources, application of a pure capacity (rather than energy) allocation factor across customer classes would be consistent with Oregon's marginal cost based ratemaking paradigm. (In this case, the costs to be recovered are essentially marginal costs.) However, I am not advocating such an approach. Rather, I would simply use the production demand allocation factors from PGE and PacifiCorp's most recent rate cases, which would include both an energy and capacity allocation element.

Q. IS IT POSSIBLE THAT THE MERCURIAL NATURE OF WIND RELEGATES THIS RESOURCE TO BEING NOTHING MORE THAN A NON-FIRM SOURCE OF ENERGY?

A. If so, then perhaps the utilities should reconsider the place wind has in their expansion plans. However, SB 838 and PacifiCorp's and PGE's IRPs place a strong emphasis on wind generation. Both companies assume, on statistical

[8] In this discussion, I am putting aside my view that marginal cost is a flawed allocation methodology. Though use of marginal cost as an embedded cost allocation method enjoys little currency in other states where I have practiced, given its longstanding acceptance in Oregon I will not challenge it.

grounds, that wind generation will provide useful capacity to meet system peak demands. ICNU/102, Falkenberg/8; ICNU/104, Falkenberg/10.

Q. IS THERE AN ANALAGOUS RESOURCE ALREADY INCLUDED IN RATEBASE THAT IS SIMILAR TO WIND?

A. Yes. Wind generation might be considered to be quite comparable to run of river hydro, another resource dependent on the vagaries of weather. Both PGE and PacifiCorp have this type of resource in their generation portfolio. Though PGE objected to answering this question, it appears that both companies treat run of river hydro the same as any other kind of resource in their cost allocation procedures. ICNU/104, Falkenberg/7. Further, it appears both companies already have some wind generation resources collected in base rates, and both companies use the same marginal cost pricing methodology for allocation of these costs to customer classes. ICNU/102, Falkenberg/2-5, 7; ICNU/104, Falkenberg/6. Thus, there is no suggestion on the part of either company that the Commission-approved cost allocation technique is not valid or applicable to wind generation.

Q. UNDER THE THEORY OF MARGINAL COST PRICING, DOES IT EVEN MATTER WHAT KIND OF RESOURCE IS BEING USED TO PRODUCE THE ENERGY AS FAR AS CLASS COST ALLOCATION PROCEDURES ARE CONCERNED?

A. Not really. The underlying premise of marginal cost pricing is that ratepayers will make more intelligent (and presumably more efficient) consumption choices if they are provided price signals that convey information about the incremental costs of their consumption decisions.[9/] The Long Run Marginal Cost of new resources remains the cost of combined cycle generation. Consequently, the price signals provided to customers should reflect the cost of new combined cycle generation, not the specific resource that is used to generate the power being consumed at the moment. Again, this is the process used for *all* of the resources used by PacifiCorp and PGE customers. There is simply no basis for departing from this standard in the case of wind generation or other renewable resources.

Q. DO EITHER PACIFICORP OR PGE PROVIDE ANY COST JUSTIFICATION FOR THEIR PROPOSALS?

A. Neither company provides any cost justification in its initial testimony. ICNU explored this issue in discovery requests. PacifiCorp justifies its proposal on the basis that it was a simplified and generally appropriate method. PacifiCorp would wait until a general rate case to do a proper cost allocation study. ICNU/104, Falkenberg/8. In the end, PacifiCorp believes it is just simpler to use a pure kWh basis to allocate and collect these charges, and apparently does not regard it as important to maintain equity among customer groups.

PGE likewise provides no cost justification. PGE's argument is basically that its other charges (for other single item rate schedules) are collected on a volumetric basis. ICNU/102, Falkenberg/6. In this case, PGE is correct. All of its special charges are levied and collected on a kWh basis. However, the allocation of costs to classes is not. PGE's response to ICNU DR No. 1.6 shows

[9/] This is a simplification that ignores decades of debate over such issues as whether conforming a marginal cost based price to embedded revenue requirements accomplishes anything at all, or whether use of long run marginal costs instead of short-run marginal negates efficiency gains. Again, this is the process Oregon uses, presumably for its assumed economic efficiency benefits, as there is no other basis for adoption of marginal cost based pricing.

the cost allocation method used in UE 180. Id. At Falkenberg/3-5. Review of the attachment shows that a pure kWh method is not used for class allocation purposes. Id. At Falkenberg/5. In the end, PGE simply fails to provide any cost justification for its proposed allocation method. Again, one must presume PGE is more concerned about collecting its compliance costs than maintaining equity among customer classes.

Q. PACIFICORP DOES NOT EVEN PROPOSE TO REFLECT VOLTAGE LEVEL DIFFERENCES IN SCHEDULE 202. PLEASE COMMENT.

A. Again, this is completely contrary to any recognized concept of cost allocation. Customers taking service at higher voltages impose less cost on the system. A residential customer consumes approximately 110 kWh at production to obtain 100 kWh at meter. An industrial customer taking service at transmission voltage may only consume 104.5 kWh at production to obtain 100 kWh at meter. ICNU/105, Falkenberg/2. There is no justification for ignoring this fact in the allocation and collection of costs resulting from new renewable resources. The base rate schedules of PacifiCorp clearly recognize voltage differentials. There is no explanation from PacifiCorp as to why this is appropriate. In this regard, PGE’s proposal is slightly more equitable, as it does at least recognize voltage differentials.

Q. IS IT POSSIBLE THAT PGE AND PACIFICORP WILL ATTEMPT TO JUSTIFY THEIR PROPOSALS ON THE BASIS THAT THE AMOUNT OF MONEY TO BE COLLECTED IS SMALL, THEREFORE, JUSTIFIED ON THE BASIS OF SIMPLICITY?

A. While this is a possible argument, it is not justified. SB 838 establishes rather aggressive goals for utilities to meet. The total cost of compliance will become quite significant in the years ahead. These proposed schedules will likely become a major new source of revenue for both companies, and the dollars collected thereunder will be substantial. For 2009 alone, PacifiCorp projects collections of more than $10 million. ICNU/104, Falkenberg/3. As noted above, PGE objected to providing any projections of collections under their proposed schedule. ICNU/102, Falkenberg/1. In any case, the size of the charges is not really a valid basis for ignoring proper cost allocation methods.

Q. WOULD IT COMPLICATE THE PROSPECTIVE PROCEEDINGS IF A PROPER COST ALLOCATION METHOD WERE EMPLOYED?

A. No. If both companies merely used the cost allocation factors approved by the Commission in their last general rate case, it would require virtually no additional effort on the part of the utilities. Ironically, both companies propose to use the rate of return from their most recent rate case, but would ignore the most recent cost allocation study. Given the recent variability in interest rates,[10/] it seems puzzling that they would think the rate of return would be the more robust variable.

Q. HAS PACIFICORP RECOGNIZED IN OTHER STATES THAT THERE SHOULD BE A DEMAND AND ENERGY ALLOCATION IN A PROPOSED RIDER FOR RECOVERY OF RENEWABLE RESOURCE COSTS?

A. Yes. In the currently pending Wyoming general rate case (Wyoming Public Service Commission Docket No. 20000-277-ER-07), PacifiCorp's Rocky Mountain Power affiliate has proposed a "New Renewable Resource Mechanism" ("NRRM"). PacifiCorp considers this to be a "similar mechanism" to its

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10/ At the time of this writing, the Federal Reserve Board has just taken steps that reduce short-term interest rates by 50 basis points in one day.

Schedule 202. ICNU/104, Falkenberg/5. I have attached a copy of the proposed Wyoming tariff for purposes of illustration. ICNU/107.

There are some striking differences between the Wyoming and Oregon presentations on this matter, though the underlying costs to be recovered of both tariffs appear to be the same. Most significantly, in Wyoming, Rocky Mountain Power proposes to allocate the NRRM charges to customer classes on the basis of the demand and energy allocation factors approved for each class in the most recent general rate case:

> Deferred New Renewable Resource Adjustment shall be the allocated Wyoming New Renewable Resource Revenue Requirement during the Comparison Period allocated to all applicable retail tariff rate schedules and where appropriate to the demand and energy rate components within each schedule based on the applicable allocation factors and cost of service study relationships established in the Company's last general rate case.

ICNU/107, Falkenberg/8. I find it curious that PacifiCorp would propose to honor preexisting cost allocation relationships in Wyoming, but would prefer to abandon them in Oregon.[11/] I urge the Commission to reject this aspect of PacifiCorp's and PGE's proposals.

Q. WHAT ARE OTHER DIFFERENCES IN THE PRESENTATIONS MADE IN WYOMING AND OREGON?

A. The Wyoming tariff proposal is quite detailed and the Wyoming testimony provides numerical examples of how the revenue requirements would be computed. The Oregon tariff proposal (Schedule 202) provides few of the

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[11/] Nothing herein should be read as an endorsement for adoption of the NRRM in Wyoming or all of the terms and conditions included in the proposed Schedule 96. This tariff is included solely for the purpose of demonstrating the cost allocation proposal filed by PacifiCorp in Wyoming and to illustrate the level of detail included in the tariff in that state.

important details of the underlying proposal. PacifiCorp justifies this disparity on the basis that Wyoming regulators require more detailed information than the OPUC. ICNU/104, Falkenberg/15. In the end, PacifiCorp would object to the OPUC's adoption of the proposed Wyoming tariff, though it provides no explanation as to why. Id. at Falkenberg/16. I question why PacifiCorp would propose a tariff in one state that it would find objectionable in another, but provide no basis supporting that position.

Q. HOW DO YOU PROPOSE THE COMMISSION ADDRESS THIS ISSUE?

A. There are two logical approaches that could be followed. First, the Commission could simply use the allocation factors for production related costs from the most recently completed general rate case for each company for class allocation purposes. Exhibit ICNU/108 shows how this would work in the case of PacifiCorp for 2009. Exhibit ICNU/109 provides a similar presentation for PGE using Biglow Canyon costs as a basis for the example.

Another alternative, however, would be to expand the current definition of recoverable costs under PGE's AUT and PacifiCorp's TAM to include the compliance costs of qualifying resources. This approach would require that PGE and PacifiCorp re-compute their respective AUT and TAM schedules using the same revenue allocation and rate design methodologies as applied in the last general rate case. Ultimately, either approach should result in the same class allocation results. Use of the latter approach, however, would reduce the number of adjustable rate schedules applied to customers' bills.

Procedural Considerations

Q. WHY ARE PROCEDURAL ISSUES IMPORTANT?

A. As discussed above, for a regulatory process to be fair, it must afford parties due process. This was the last of the four goals I discussed above. Because adjustment clause cases deal with only a narrowly defined scope of costs, they generally provide for shorter procedural schedules. If the schedule provided is too short, however, then parties are not afforded the full protection of due process. This is a due process right, and not merely a "good idea."

Q. WHAT IS YOUR PROPOSAL?

A. The current TAM and AUT procedures should be expanded to include both the SB 838 cost recovery computations and the compliance cost limitation tests,[12] as well as the NVPC updates. Further, the procedural schedules should be expanded to include an earlier filing date by the utilities, more rounds of testimony and a continuous review process for new contracts. Rather than having multiple proceedings for the testing of compliance limitations, recovery of compliance costs, and net power cost updates, a single, albeit longer schedule should be utilized. Use of multiple proceedings would increase the cost of participation in these activities, particularly for intervenors, and reduce the efficiency of the process.[13] Further, application of an earnings test should be common to both the

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[12] SB 838, Section 12(1) states: "Electric utilities are not required to comply with a renewable portfolio standard during a compliance year to the extent that the incremental cost of compliance, the cost of unbundled renewable energy certificates and the cost of alternative compliance payments under section 20 of this 2007 Act exceeds four percent of the utility's annual revenue requirement for the compliance year. "

[13] If nothing else, three cases may require three sets of hearings, three testimony filings and up to six briefs. One larger case would require only one hearing, perhaps two testimony filings per party, and two briefs.

compliance cost filing and PGE's AVT filing, and combining these filings will create a more efficient process.

Q. IT APPEARS THEN THAT YOU OPPOSE PGE'S PROPOSAL TO FILE UPDATES TO ITS SCHEDULE 122 ONLY WHEN COMPLETION OF A NEW RESOURCE IS EMINENT.

A. Yes. There is no reason why PGE cannot perform a forecast of the costs of compliance a year in advance, as PacifiCorp proposes (even though PGE objected to making such projections in this case). Further, for the reasons discussed above, the Commission should reject PGE's proposal to be allowed to collect compliance costs based solely on the elevated first year cost of a new resource. PacifiCorp does not propose that for Oregon (or Wyoming, for that matter) and the Commission should not impose such a proposal on PGE's customers.

Q. ARE THERE ANY OTHER PROBLEMS WITH THE PGE AND PACFICORP PROPOSALS?

A. Yes. Neither company proposes a true-up to test whether the revenues actually collected under their proposed schedules match cost recovery allowed. Unlike the situation with variable power costs, compliance costs are largely fixed (and therefore independent of sales levels). Therefore, forecast errors will produce more serious problems.

Further, compliance costs collected in these tariffs will invariably rely upon cost estimates. The true-up procedure should also ensure that actual costs match actual recoveries. PGE's Biglow Canyon proceeding revealed a number of problems with its Schedule 202 proposal. In that case, PGE originally filed a forecasted Biglow Canyon cost of $13 million. It became apparent during the course of that case that many of the cost items (particularly the various incentives) were unknown at the time of the filing. In the end, PGE's request was reduced to less than $8 million, a reduction of close to 40%, as more accurate information became available. There is no reason to expect that future cases will be any different. The Biglow Canyon case was filed using approximately the same time frame as PGE proposes to use for future Schedule 202 proceedings. This suggests that it would be unwise to rely exclusively on projections for setting the compliance rates, even when those projections are prepared just months before the on-line date of new resources. It is also important to realize that Biglow Canyon was filed as a full general rate case by PGE, rather than a simple adjustment clause with an expedited procedural schedule. Had parties been limited to an artificially compressed schedule in the Biglow Canyon case, it is possible that the final result may have been much closer to PGE's original request.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1330

In the Matter of	)
	)
PUBLIC UTILITY COMMISSION OF OREGON	)
	)
Investigation of Automatic Adjustment Clause pursuant to SB 838.	)

EXHIBIT ICNU/101

QUALIFICATIONS OF RANDALL J. FALKENBERG

September 28, 2007

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

EDUCATIONAL BACKGROUND

I received my Bachelor of Science degree with Honors in Physics and a minor in mathematics from Indiana University. I received a Master of Science degree in Physics from the University of Minnesota. My thesis research was in nuclear theory. At Minnesota I also did graduate work in engineering economics and econometrics. I have completed advanced study in power system reliability analysis.

PROFESSIONAL EXPERIENCE

After graduating from the University of Minnesota in 1977, I was employed by Minnesota Power as a Rate Engineer. I designed and coordinated the Company's first load research program. I also performed load studies used in cost-of-service studies and assisted in rate design activities.

In 1978, I accepted the position of Research Analyst in the Marketing and Rates department of Puget Sound Power and Light Company. In that position, I prepared the two-year sales and revenue forecasts used in the Company's budgeting activities and developed methods to perform both near- and long-term load forecasting studies.

In 1979, I accepted the position of Consultant in the Utility Rate Department of Ebasco Service Inc. In 1980, I was promoted to Senior Consultant in the Energy Management Services Department. At Ebasco I performed and assisted in numerous studies in the areas of cost of service, load research, and utility planning. In particular, I was involved in studies concerning analysis of excess capacity, evaluation of the planning activities of a major utility on behalf of its public service commission, development of a methodology for computing avoided costs and cogeneration rates, long-term electricity price forecasts, and cost allocation studies.

At Ebasco, I specialized in the development of computer models used to simulate utility production costs, system reliability, and load patterns. I was the principal author of production costing software used by eighteen utility clients and public service commissions for evaluation of marginal costs, avoided costs and production costing analysis. I assisted over a dozen utilities in the performance of marginal and avoided cost studies related to the PURPA of 1978. In this capacity, I worked with utility planners and rate specialists in quantifying the rate and cost impact of generation expansion alternatives. This activity included estimating carrying costs, O&M expenses, and capital cost estimates for future generation.

In 1982 I accepted the position of Senior Consultant with Energy Management Associates, Inc. and was promoted to Lead Consultant in June 1983. At EMA I trained and consulted with planners and financial analysts at several utilities in applications of the PROMOD and PROSCREEN planning models. I assisted planners in applications of these models to the preparation of studies evaluating the revenue requirements and financial impact of generation expansion alternatives, alternate load growth patterns and alternate regulatory treatments of new baseload generation. I also assisted in EMA's educational seminars where utility personnel

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

were trained in aspects of production cost modeling and other modern techniques of generation planning.

I became a Principal in Kennedy and Associates in 1984. Since then I have performed numerous economic studies and analyses of the expansion plans of several utilities. I have testified on several occasions regarding plant cancellation, power system reliability, phase-in of new generating plants, and the proper rate treatment of new generating capacity. In addition, I have been involved in many projects over the past several years concerning the modeling of market prices in various regional power markets.

In January 2000, I founded RFI Consulting, Inc. whose practice is comparable to that of my former firm, J. Kennedy and Associates, Inc.

The testimony that I present is based on widely accepted industry standard techniques and methodologies, and unless otherwise noted relies upon information obtained in discovery or other publicly available information sources of the type frequently cited and relied upon by electric utility industry experts. All of the analyses that I perform are consistent with my education, training and experience in the utility industry. Should the source of any information presented in my testimony be unclear to the reader, it will be provided it upon request by calling me at 770-379-0505.

PAPERS AND PRESENTATIONS

Mid-America Regulatory Commissioners Conference - June 1984: "Nuclear Plant Rate Shock - Is Phase-In the Answer"

Electric Consumers Resource Council - Annual Seminar, September 1986: "Rate Shock, Excess Capacity and Phase-in"

The Metallurgical Society - Annual Convention, February 1987: "The Impact of Electric Pricing Trends on the Aluminum Industry"

Public Utilities Fortnightly - "Future Electricity Supply Adequacy: The Sky Is Not Falling" What Others Think, January 5, 1989 Issue

Public Utilities Fortnightly - "PoolCo and Market Dominance", December 1995 Issue

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject

APPEARANCES

3/84	8924	KY	Airco Carbide	Louisville Gas & Electric	CWIP in rate base.
5/84	830470- EI	FL	Florida Industrial Power Users Group	Fla. Power Corp.	Phase-in of coal unit, fuel savings basis, cost allocation.
10/84	89-07-R	CT	Connecticut Ind. Energy Consumers	Connecticut Light & Power	Excess capacity.
11/84	R-842651	PA	Lehigh Valley	Pennsylvania Power Committee	Phase-in of nuclear unit. Power & Light Co.
2/85 cancellation of	I-840381	PA	Phila. Area Ind. Energy Users' Group	Electric Co.	Philadelphia Economics of nuclear generating units.
3/85	Case No. 9243	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Economics of cancelling fossil generating units.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Economics of pumped storage generating units, optimal res. margin, excess capacity.
3/85 cancellation, forecasting,	3498-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear unit load and energy generation economics.
5/85	84-768- E-42T	WV	West Virginia Multiple Intervenors	Monongahela Power Co.	Economics - pumped storage generating units, reserve margin, excess capacity.
7/85	E-7, SUB 391	NC	Carolina Industrial Group for Fair Utility Rates	Duke Power Co.	Nuclear economics, fuel cost projections.
7/85	9299	KY	Kentucky Industrial Utility Consumers	Union Light, Heat & Power Co.	Interruptible rate design.
8/85	84-249-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Prudence review.
1/86	85-09-12	CT	Connecticut Ind. Energy Consumers	Connecticut Light & Power Co.	Excess capacity, financial impact of phase-in nuclear plant.
1/86	R-850152	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Phase-in and economics of nuclear plant.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power	Optimal reserve margins, prudence, off-system sales guarantee plan.
5/86	86-081- E-GI	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Generation planning study , economics prudence of a pumped storage hydroelectric unit.
5/86	3554-U	GA	Attorney General & Georgia Public Service Commission Staff	Georgia Power Co.	Cancellation of nuclear plant.

**Expert Testimony Appearances
of
Randall J. Falkenberg**

Date	Case	Jurisdict.	Party	Utility	Subject
9/86	29327/28	NY	Occidental Chemical Corp.	Niagara Mohawk Power Co.	Avoided cost, production cost models.
9/86	E7- Sub 408	NC	NC Industrial Energy Committee	Duke Power Co.	Incentive fuel adjustment clause.
12/86 613	9437/	KY	Attorney General of Kentucky	Big Rivers Elect. Corp.	Power system reliability analysis, rate treatment of excess capacity.
5/87	86-524- E-SC	WV	West Virginia Energy Users' Group	Monongahela Power	Economics and rate treatment of Bath County pumped storage County Pumped Storage Plant.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
6/87	PUC-87- 013-RD E002/E-015 -PA-86-722	MN	Eveleth Mines & USX Corp.	Minnesota Power/ Northern States	Sale of generating unit and reliability Power requirements.
7/87	Docket 9885	KY	Attorney General of Kentucky	Big Rivers Elec. Corp.	Financial workout plan for Big Rivers.
8/87	3673-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear plant prudence audit, Vogtle buyback expenses.
10/87	R-850220	PA	WPP Industrial Intervenors	West Penn Power	Need for power and economics, County Pumped Storage Plant
10/87	870220-EI	FL	Occidental Chemical	Fla. Power Corp.	Cost allocation methods and interruptible rate design.
10/87	870220-EI	FL	Occidental Chemical	Fla. Power Corp.	Nuclear plant performance.
1/88	Case No. 9934	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Review of the current status of Trimble County Unit 1.
3/88	870189-EI	FL	Occidental Chemical Corp.	Fla. Power Corp.	Methodology for evaluating interruptible load.
5/88	Case No. 10217	KY	National Southwire Aluminum Co., ALCAN Alum Co.	Big Rivers Elec. Corp.	Debt restructuring agreement.
7/88	Case No. 325224	LA Div. I 19th Judicial District	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Weather normalization gas sales and revenues.
10/88	3799-U	GA	Georgia Public Service Commission Staff	United Cities Gas Co.	Weather normalization of gas sales and revenues.
12/88	88-171-	OH	Ohio Industrial	Toledo Edison Co.,	Power system reliability

**Expert Testimony Appearances
of
Randall J. Falkenberg**

Date	Case	Jurisdict.	Party	Utility	Subject
	EL-AIR 88-170- EL-AIR	OH	Energy Consumers	Cleveland Electric Illuminating Co.	reserve margin.
1/89	I-880052	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Nuclear plant outage, replacement fuel cost recovery.
2/89	10300	KY	Green River Steel K	Kentucky Util.	Contract termination clause and interruptible rates.
3/89	P-870216 283/284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power	Reserve margin, avoided costs.
5/89	3741-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Prudence of fuel procurement.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Need and economics coal & nuclear capacity, power system planning.
10/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Power system planning, economic and reliability analysis, nuclear planning, prudence.
10/89	89-128-U	AR	Arkansas Electric Energy Consumers	Arkansas Power Light Co.	Economic impact of asset transfer and stipulation and settlement agreement.
11/89	R-891364	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Sale/leaseback nuclear plant, excess capacity, phase-in delay imprudence.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Sale/leaseback nuclear power plant.
4/90	89-1001-EL-AIR	OH	Industrial Energy Consumers	Ohio Edison Co.	Power supply reliability, excess capacity adjustment.
4/90	N/A	N.O.	New Orleans Business Counsel	New Orleans Public Service Co.	Municipalization of investor-owned utility, generation planning & reliability
7/90	3723-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Weather normalization adjustment rider.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirements gas & electric, CWIP in rate base.
9/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Power system planning study.
12/90	U-9346	MI	Association of Businesses Advocating Tariff Equity (ABATE)	Consumers Power	DSM Policy Issues.
5/91	3979-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	DSM, load forecasting and IRP.
7/91	9945	TX	Office of Public	El Paso Electric	Power system planning,

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
			Utility Counsel	Co.	quantification of damages of imprudence, environmental cost of electricity
8/91	4007-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Integrated resource planning, regulatory risk assessment.
11/91	10200	TX	Office of Public	Texas-New Mexico Utility Counsel	Imprudence disallowance. Power Co.
12/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Year-end sales and customer adjustment, jurisdictional allocation.
1/92	89-783-E-C	WVA	West Virginia Energy Users Group	Monongahela Power Co.	Avoided cost, reserve margin, power plant economics.
3/92	91-370	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Interruptible rates, design, cost allocation.
5/92	91890	FL	Occidental Chemical Corp.	Fla. Power Corp.	Incentive regulation, jurisdictional separation, interruptible rate design.
6/92	4131-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Integrated resource planning, DSM.
9/92	920324	FL	Florida Industrial Power Users Group	Tampa Electric Co.	Cost allocation, interruptible rates decoupling and DSM.
10/92	4132-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Residential conservation program certification.
10/92	11000	TX	Office of Public Utility Counsel	Houston Lighting and Power Co.	Certification of utility cogeneration project.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Entergy/Gulf States Utilities (Direct)	Production cost savings from merger.
11/92	8469	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, revenue distribution.
11/92	920606	FL	Florida Industrial Power Users Group	Statewide Rulemaking	Decoupling, demand-side management, conservation, Performance incentives.
12/92	R-009 22378	PA	Armco Advanced Materials	West Penn Power	Energy allocation of production costs.
1/93	8179	MD	Eastalco Aluminum/ Westvaco Corp.	Potomac Edison Co.	Economics of QF vs. combined cycle power plant.
2/93	92-E-0814 88-E-081	NY	Occidental Chemical Corp.	Niagara Mohawk Power Corp.	Special rates, wheeling.
3/93	U-19904	LA	Louisiana Public Service Commission Staff	Entergy/Gulf States Utilities (Surrebuttal)	Production cost savings from merger.
4/93	EC92	FERC	Louisiana Public	Gulf States	GSU Merger prodcution cost

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
	21000 ER92-806-000		Service Commission Staff	Utilities/Entergy	savings
6/93	930055-EU	FL	Florida Industrial Power Users' Group	Statewide Rulemaking	Stockholder incentives for off-system sales.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers & Attorney General	Big Rivers Elec. Corp.	Prudence of fuel procurement decisions.
9/93	4152-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Cost allocation of pollution control equipment.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minn. Power Co.	Analysis of revenue req. and cost allocation issues.
4/94	93-465	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Review and critique proposed environmental surcharge.
4/94	4895-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co	Purchased power agreement and fuel adjustment clause.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Light Co.	Rev. requirements, incentive compensation.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue annualization, ROE performance bonus, and cost allocation.
8/94	8652	MD	Westvaco Corp.	Potomac Edison Co.	Revenue requirements, ROE performance bonus, and revenue distribution.
1/95	94-332	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Company	Environmental surcharge.
1/95	94-996-EL-AIR	OH	Industrial Energy Users of Ohio	Ohio Power Company	Cost-of-service, rate design, demand allocation of power
3/95	E999-CI	MN	Large Power Intervenor	Minnesota Public Utilities Comm.	Environmental Costs Of electricity
4/95	95-060	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Company	Six month review of CAAA surcharge.
11/95	I-940032	PA	The Industrial Energy Consumers of Pennsylvania	Statewide - all utilities	Direct Access vs. Poolco, market power.
11/95	95-455	KY	Kentucky Industrial	Kentucky Utilities	Clean Air Act Surcharge,
12/95	95-455	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Company	Clean Air Act Compliance Surcharge.
6/96	960409-EI	FL	Florida Industrial Power Users Group	Tampa Electric Co.	Polk County Power Plant Rate Treatment Issues.
3/97	R-973877	PA	PAIEUG.	PECO Energy	Stranded Costs & Market Prices.
3/97	970096-EQ	FL	FIPUG	Fla. Power Corp.	Buyout of QF Contract
6/97	R-973593	PA	PAIEUG	PECO Energy	Market Prices, Stranded Cost

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
7/97	R-973594	PA	PPLICA	PP&L	Market Prices, Stranded Cost
8/97	96-360-U	AR	AEEC	Entergy Ark. Inc.	Market Prices and Stranded Costs, Cost Allocation, Rate Design
10/97	6739-U	GA	GPSC Staff	Georgia Power	Planning Prudence of Pumped Storage Power Plant
10/97	R-974008 R-974009	PA	MIEUG PICA	Metropolitan Ed. PENELEC	Market Prices, Stranded Costs
11/97	R-973981	PA	WPII	West Penn Power	Market Prices, Stranded Costs
11/97	R-974104	PA	DII	Duquesne Light Co.	Market Prices, Stranded Costs
2/98	APSC 97451 97452 97454	AR	AEEC	Generic Docket	Regulated vs. Market Rates, Rate Unbundling, Timetable for Competition.
7/98	APSC 87-166	AR	AEEC	Entergy Ark. Inc.	Nuclear decommissioning cost estimates & rate treatment.
9/98	97-035-01	UT	DPS and CCS	PacifiCorp	Net Power Cost Stipulation, Production Cost Model Audit
12/98	19270	TX	OPC	HL&P	Reliability, Load Forecasting
4/99	19512	TX	OPC	SPS	Fuel Reconciliation
4/99	99-02-05	CT	CIEC	CL&P	Stranded Costs, Market Prices
4/99	99-03-04	CT	CIEC	UI	Stranded Costs, Market Prices
6/99	20290	TX	OPC	CP&L	Fuel Reconciliation
7/99	99-03-36	CT	CIEC	CL&P	Interim Nuclear Recovery
7/99	98-0453	WV	WVEUG	AEP & APS	Stranded Costs, Market Prices
12/99	21111	TX	OPC	EGSI	Fuel Reconciliation
2/00	99-035-01	UT	CCS	PacifiCorp	Net Power Costs, Production Cost Modeling Issues
5/00	99-1658	OH	AK Steel	CG&E	Stranded Costs, Market Prices
6/00	UE-111	OR	ICNU	PacifiCorp	Net Power Costs, Production Cost Modeling Issues
9/00	22355	TX	OPC	Reliant Energy	Stranded cost
10/00	22350	TX	OPC	TXU Electric	Stranded cost
10/00	99-263-U	AR	Tyson Foods	SW Elec. Coop	Cost of Service
12/00	99-250-U	AR	Tyson Foods	Ozarks Elec. Coop	Cost of Service
01/01	00-099-U	AR	Tyson Foods	SWEPCO	Rate Unbundling
02/01	99-255-U	AR	Tyson Foods	Ark. Valley Coop	Rate Unbundling

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
03/01	UE-116	OR	ICNU	PacifiCorp	Net Power Costs
6/01	01-035-01	UT	DPS and CCS	PacifiCorp	Net Power Costs
7/01	A.01-03-026	CA	Roseburg FP	PacifiCorp	Net Power Costs
7/01	23550	TX	OPC	EGSI	Fuel Reconciliation
7/01	23950	TX	OPC	Reliant Energy	Price to beat fuel factor
8/01	24195	TX	OPC	CP&L	Price to beat fuel factor
8/01	24335	TX	OPC	WTU	Price to beat fuel factor
9/01	24449	TX	OPC	SWEPCO	Price to beat fuel factor
10/01	20000-EP 01-167	WY	WIEC	PacifiCorp	Power Cost Adjustment Excess Power Costs
2/02	UM-995	OR	ICNU	PacifiCorp	Cost of Hydro Deficit
2/02	00-01-37	UT Plant	CCS	PacifiCorp	Certification of Peaking
4/02	00-035-23	UT	CCS	PacifiCorp	Cost of Plant Outage, Excess Power Cost Stipulation.
4/02	01-084/296	AR	AEEC	Entergy Arkansas	Recovery of Ice Storm Costs
5/02	25802	TX	OPC	TXU Energy	Escalation of Fuel Factor
5/02	25840	TX	OPC	Reliant Energy	Escalation of Fuel Factor
5/02	25873	TX	OPC	Mutual Energy CPL	Escalation of Fuel Factor
5/02	25874	TX	OPC	Mutual Energy WTU	Escalation of Fuel Factor
5/02	25885	TX	OPC	First Choice	Escalation of Fuel Factor
7/02	UE-139	OR	ICNU	Portland General	Power Cost Modeling
8/02	UE-137	OP	ICNU	Portland General	Power Cost Adjustment Clause
10/02	RPU-02-03	IA	Maytag, et al	Interstate P&L	Hourly Cost of Service Model
11/02	20000-Er 02-184	WY	WIEC	PacifiCorp	Net Power Costs, Deferred Excess Power Cost
12/02	26933	TX	OPC	Reliant Energy	Escalation of Fuel Factor
12/02	26195	TX	OPC	Centerpoint Energy	Fuel Reconciliation
1/03	27167	TX	OPC	First Choice	Escalation of Fuel Factor
1/03	UE-134	OR	ICNU	PacifiCorp	West Valley CT Lease payment
1/03	27167	TX	OPC	First Choice	Escalation of Fuel Factor
1/03	26186	TX	OPC	SPS	Fuel Reconciliation
2/03	UE-02417	WA	ICNU	PacifiCorp	Rate Plan Stipulation, Deferred Power Costs
2/03	27320	TX	OPC	Reliant Energy	Escalation of Fuel Factor
2/03	27281	TX	OPC	TXU Energy	Escalation of Fuel Factor

**Expert Testimony Appearances
of
Randall J. Falkenberg**

Date	Case	Jurisdict.	Party	Utility	Subject
2/03	27376	TX	OPC	CPL Retail Energy	Escalation of Fuel Factor
2/03	27377	TX	OPC	WTU Retail Energy	Escalation of Fuel Factor
3/03	27390	TX	OPC	First Choice	Escalation of Fuel Factor
4/03	27511	TX	OPC	First Choice	Escalation of Fuel Factor
4/03	27035	TX	OPC	AEP Texas Central	Fuel Reconciliation
05/03	03-028-U	AR	AEEC	Entergy Ark., Inc.	Power Sales Transaction
7/03	UE-149	OR	ICNU	Portland General	Power Cost Modeling
8/03	28191	TX	OPC	TXU Energy	Escalation of Fuel Factor
11/03	20000-ER -03-198	WY	WIEC	PacifiCorp	Net Power Costs
2/04	03-035-29	UT	CCS	PacifiCorp	Certification of CCCT Power Plant, RFP and Bid Evaluation
6/04	29526	TX	OPC	Centerpoint	Stranded cost true-up.
6/04	UE-161	OR	ICNU	Portland General	Power Cost Modeling
7/04	UM-1050	OR	ICNU	PacifiCorp	Jurisdictional Allocation
10/04	15392-U 15392-U	GA	Calpine	Georgia Power/ SEPCO	Fair Market Value of Combined Cycle Power Plant
12/04	04-035-42	UT	CCS		PacifiCorp Net power costs
02/05	UE-165	OP	ICNU	Portland General	Hydro Adjustment Clause
05/05	UE-170	OR	ICNU	PacifiCorp	Power Cost Modeling
7/05	UE-172	OR	ICNU	Portland General	Power Cost Modeling
08/05	UE-173	OR	ICNU	PacifiCorp	Power Cost Adjustment
8/05	UE-050482	WA	ICNU	Avista	Power Cost modeling, Energy Recovery Mechanism
8/05	31056	TX	OPC	AEP Texas Central	Stranded cost true-up.
11/05	UE-05684	WA	ICNU	PacifiCorp	Power Cost modeling, Jurisdictional Allocation, PCA
2/06	05-116-U	AR	AEEC	Entergy Arkansas	Fuel Cost Recovery
4/06	UE-060181	WA	ICNU	Avista	Energy Cost Recovery Mechanism
5/06	22403-U	GA	GPSC Staff	Georgia Power	Fuel Cost Recovery Audit
6/06	UM 1234	OR	ICNU	Portland General	Deferral of outage costs
6/06	UE 179	OR	ICNU	PacifiCorp	Power Costs, PCAM
7/06	UE 180	OR	ICNU	Portland General	Power Cost Modeling, PCAM
12/06	32766	TX	OPC	SPS	Fuel Reconciliation
1/07	23540-U	GA	GPSC Staff	Georgia Power	Fuel Cost Recovery Audit
2/07	06-101-U	AR	AEEC	Entergy Arkansas	Cost Allocation and Recovery

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
2/07	UE-061546	WA	ICNU/Public Counsel	PacifiCorp	Power Cost Modeling, Jurisdictional Allocation, PCA
2/07	32710	TX	OPC	EGSI	Fuel Reconciliation
6/07	UE 188	OR	ICNU	Portland General	Wind Generator Rate Surcharge
6/07	UE 191	OR	ICNU	PacifiCorp	Power Cost Modeling
6/07	UE 192	OR	ICNU	Portland General	Power Cost Modeling

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1330

In the Matter of	)
	)
PUBLIC UTILITY COMMISSION OF OREGON	)
	)
Investigation of Automatic Adjustment Clause pursuant to SB 838.	)

EXHIBIT ICNU/102

EXCERPTS OF PORTLAND GENERAL ELECTRIC COMPANY'S

RESPONSES TO ICNU'S FIRST SET OF DATA REQUESTS

September 28, 2007

September 14, 2007

TO: Brad Van Cleve
Industrial Customers of Northwest Utilities

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UM 1330
PGE Response to ICNU Data Request 1.1
Dated September 5, 2007
Question No. 001

Request:

Provide any projections of the costs and charges expected to be recovered under Schedule 122, if approved as requested by the Company.

Response:

PGE objects to this request because it is speculative and unduly burdensome. Without waiving its objections, PGE states the following:

PGE cannot provide such projections because a related study has not been conducted.

September 14, 2007

TO: Brad Van Cleve
Industrial Customers of Northwest Utilities

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UM 1330
PGE Response to ICNU Data Request 1.5
Dated September 5, 2007
Question No. 005

Request:

Explain the process the Company used in UE 180 to allocate cost responsibility of any existing wind resources to customer classes. Provide a calculation showing the existing wind related costs recovered from each customer class. Explain whether the proposed recovery method in this case is consistent with that method.

Response:

Within the UE 180 test year PGE did not own any wind resources. However, PGE included the cost of two wind-related purchase power contracts, Klondike II and Vansycle Ridge.

Please see the PGE Response to ICNU Data Request No. 006 for how the costs of these two contracts were allocated.

PGE believes that the proposed cost recovery method contained in its proposed Schedule 122 approximates the method used to allocate generation revenue requirements in UE 180.

September 14, 2007

TO: Brad Van Cleve
Industrial Customers of Northwest Utilities

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UM 1330
PGE Response to ICNU Data Request 1.6
Dated September 5, 2007
Question No. 006

Request:

Explain the process the Company used in UE 180 to allocate cost responsibility of existing run of river hydro resources to customer classes.

Response:

PGE objects to this request because it is not relevant to the current docket. Without waiving objection, PGE responds with the following:

Attachment 006-A provides a summary of the approved cost allocation of the UE 180 generation revenue requirement.

UM 1330
Attachment 006-A

Summary of the approved cost allocation of the UE 180 generation revenue requirement.

PORTLAND GENERAL ELECTRIC
ALLOCATION OF PRODUCTION COSTS TO COS CUSTOMERS
2007

Grouping	Marginal Power Costs ($000)	COS Calendar Energy	Marginal Unit Cost $/MWH	Allocation Percent	Allocated Production Costs ($000)	Cycle Basis Costs ($000)
Schedule 7	$502,085	7,581,941	66.22	42.26%	$417,693	$417,397
Schedule 15	$1,444	23,293	61.98	0.12%	$1,201	$1,201
Schedule 32	$99,246	1,498,106	66.25	8.35%	$82,564	$82,518
Schedule 38						
On-peak	$5,142	72,812	70.61	0.43%	$4,277	$4,272
Off-peak	$1,963	33,854	57.98	0.17%	$1,633	$1,631
Schedule 47	$1,428	21,921	65.12	0.12%	$1,188	$1,173
Schedule 49	$4,141	63,321	65.40	0.35%	$3,445	$3,459
Schedule 83-S	$351,476	5,365,999	65.50	29.58%	$292,398	$292,042
Schedule 89-S 1-4 MW						
On-peak	$28,285	403,621	70.08	2.38%	$23,531	$23,500
Off-peak	$12,446	215,862	57.66	1.05%	$10,354	$10,340
Schedule 89-S GT 4 MW						
On-peak	$1,913	25,595	74.76	0.16%	$1,592	$1,595
Off-peak	$747	12,521	59.68	0.06%	$622	$623
Schedule 83-P	$18,940	300,371	63.05	1.59%	$15,756	$15,730
Schedule 89-P 1-4 MW						
On-peak	$33,201	491,421	67.56	2.79%	$27,620	$27,576
Off-peak	$16,787	301,958	55.59	1.41%	$13,965	$13,943
Schedule 89-P GT 4 MW						
On-peak	$35,380	522,906	67.66	2.98%	$29,434	$29,385
Off-peak	$19,760	355,256	55.62	1.66%	$16,439	$16,412
Schedule 89-T						
On-peak	$29,126	438,200	66.47	2.45%	$24,230	$24,274
Off-peak	$17,987	328,735	54.72	1.51%	$14,964	$14,991
Schedule 91	$6,273	101,213	61.98	0.53%	$5,219	$5,219
Schedule 92	$370	5,748	64.42	0.03%	$308	$308
Schedule 93	$36	554	65.15	0.00%	$30	$30
TOTAL	$1,188,176	18,165,207	65.41	100.00%	$988,463	$987,618
				TARGET	$988,463	

September 14, 2007

TO: Brad Van Cleve
Industrial Customers of Northwest Utilities

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UM 1330
PGE Response to ICNU Data Request 1.7
Dated September 5, 2007
Question No. 007

Request:

What cost justification supports the collection of the Schedule 122 charge on a pure cost per kWh basis for all customer classes? Explain.

Response:

Schedule 122 recovers the costs of new renewable resources on a volumetric basis adjusted for delivery voltage. The Schedule 122 volumetric charge is consistent with how PGE recovers the costs of all its generation resources including company-owned resources, purchased power contracts, capacity contracts, and wheeling contracts. Using volumetric charges in Schedule 122 ensures consistency with the Cost of Service Energy Charge for Standard Service Schedules as well as related schedules such as Schedule 125 Annual Power Cost Update, Schedule 126, Annual Power Cost Variance Mechanism, Schedule 128 Short-Term Transition Adjustment, and Schedule 129 Long-Term Transition Adjustment. PGE further believes that the volumetric charge maintains consistency with the direct access options made available to nonresidential customers through Energy Service Suppliers.

September 14, 2007

TO: Brad Van Cleve
Industrial Customers of Northwest Utilities

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UM 1330
PGE Response to ICNU Data Request 1.8
Dated September 5, 2007
Question No. 008

Request:

Are the costs of any existing wind resources recovered in PGE's rates at present?

Response:

Please see PGE's response to ICNU's Data Request No. 005.

September 14, 2007

TO: Brad Van Cleve
Industrial Customers of Northwest Utilities

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UM 1330
PGE Response to ICNU Data Request 1.13
Dated September 5, 2007
Question No. 013

Request:

Are any wind resources included in the current IRP? If so, does the Company assume that these resources will provide useful capacity for reliability purposes, such as meeting peak demands?

Response:

Yes, there are wind resources in PGE's current IRP. Please see PGE's 2007 Integrated Resource Plan (pages 10 and 11, chapters 11 and 13) for a description of proposed acquisitions of wind resources, which can be viewed at http://edocs.puc.state.or.us/efdocs/HAA/lc43haa105740.pdf.

Regarding their capacity contribution, for planning purposes in PGE's 2007 IRP, we assumed that wind would bring a statistical capacity contribution of 15% of the nameplate capability.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1330

In the Matter of	)
	)
PUBLIC UTILITY COMMISSION OF	)
OREGON	)
	)
Investigation of Automatic Adjustment Clause	)
pursuant to SB 838.	)

EXHIBIT ICNU/103

PORTLAND GENERAL ELECTRIC COMPANY'S RESPONSE

TO ICNU DATA REQUEST NO. 1.37 IN DOCKET NO. UE 188

September 28, 2007

April 16, 2007

TO: Brad Van Cleve
Industrial Customers of Northwest Utilities

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 188
PGE Response to ICNU Data Request
Dated April 2, 2007
Question No. 037

Request:

Please provide a comparison showing the expected cost per MWh for Biglow Canyon as compared to the Klondike purchase. Please provide the comparison for the next five years?

Response:

PGE has not performed this analysis. PGE selected both of these resources through its 2003 Request for Proposals and related evaluation process. The analysis considered all years of projected resource life, not simply a subset. In the cases of Biglow and the Klondike II purchase, analyzing only the first five years would be misleading. Under the relevant contractual terms, payments for Klondike are approximately flat in real terms, whereas Biglow has a rate base component, whose related costs are higher in early years, but lower in later years. Focusing only on the early years would make Biglow look more expensive than it really is over its life cycle.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1330

In the Matter of	)
	)
PUBLIC UTILITY COMMISSION OF OREGON	)
	)
Investigation of Automatic Adjustment Clause pursuant to SB 838.	)

EXHIBIT ICNU/104

EXCERPTS OF PACIFICORP'S RESPONSES TO

ICNU'S FIRST SET OF DATA REQUESTS

September 28, 2007

UM-1330/PacifiCorp
September 14, 2007
ICNU Data Request 1.1

ICNU Data Request 1.1

Provide any projections of the costs and charges expected to be recovered under Schedule 202, if approved as requested by the Company.

Response to ICNU Data Request 1.1

The requested information is provided as Attachment ICNU 1.1.

OREGON

UM-1330

PACIFICORP

ICNU DATA REQUEST SET 1 (1-35)

ATTACHMENT ICNU 1.1

ON THE ENCLOSED CD

Pacific Power
Oregon
Renewable Resource Filing
Total Revenue Requirement

	CY 2009					
In-Service Date:	Sep-06	Aug-08				
	Leaning Juniper	**Marengo**	**Total**	**Factor**	**Factor %**	**Oregon Allocated**
Capital Investment	175,472,668	246,626,769	422,099,437	SG	25.9774%	109,650,566
Depreciation Reserve	(19,594,448)	(18,497,008)	(38,091,456)	SG	25.9774%	(9,895,179)
Accumulated DIT Balance	(43,814,171)	(50,636,153)	(94,450,323)	SG	25.9774%	(24,535,762)
Net Rate Base	112,064,050	177,493,608	289,557,658			75,219,624
	11.26%	11.26%	11.26%			11.26%
Pre-Tax Return on Rate Base	12,614,468	19,979,533	32,594,001			8,467,082
Operation & Maintenance	4,080,997	4,952,418	9,033,415	SG	25.9774%	2,346,649
Depreciation	7,018,907	9,865,071	16,883,977	SG	25.9774%	4,386,023
Property Taxes	978,848	1,550,357	2,529,205	GPS	28.4450%	719,432
Renewable Energy Tax Credit	(9,559,856)	(13,528,424)	(23,088,279)	SE	25.4654%	(5,879,520)
Oregon Business Energy Tax Credit (BETC)	(805,815)	-	(805,815)	IBT	30.0233%	(241,932)
Rev. Reqt. Before Franchise Tax & Bad Debt	14,327,549	22,818,954	37,146,504			9,797,733
Franchise Taxes						229,267
Bad Debt Expense						60,152
Total Revenue Requirement						**10,087,152**

Notes:
The following items shown above are in 2008 figures:
1) Oregon allocation factors from the 2008 TAM filing.
2) Operations and Maintenance Expenses
3) The Renewable Energy Tax Credit

UM-1330/PacifiCorp
September 14, 2007
ICNU Data Request 1.4

ICNU Data Request 1.4

At PPL/100, Kelly/6, Ms. Kelly states that the Company will update depreciation each year in its computation of Schedule 202. Does PacifiCorp also expect to update the annual deferred taxes for each new renewable resource whose costs are recovered under Schedule 202?

Response to ICNU Data Request 1.4

Yes, the Company will update all components of revenue requirement including the accumulated deferred income tax balance.

UM-1330/PacifiCorp
September 14, 2007
ICNU Data Request 1.7

ICNU Data Request 1.7

Has the Company requested a tariff similar to Schedule 202 in other states, or does it expect to do so in the near future? If the latter, explain the tariff details and the expected timing of these requests.

Response to ICNU Data Request 1.7

PacifiCorp has proposed a similar mechanism—the New Renewable Resource Mechanism (NRRM), Schedule 96—in its current Wyoming general rate case, Docket No. 20000-277-ER-07.

UM-1330/PacifiCorp
September 14, 2007
ICNU Data Request 1.10

ICNU Data Request 1.10

Explain the process the Company used in UE 179 to allocate cost responsibility of existing wind resources to customer classes. Provide a calculation showing costs related to existing wind resources recovered from each customer class. Explain whether the proposed recovery method in this case is consistent with that method.

Response to ICNU Data Request 1.10

In UE 179, rate base items and O&M expenses associated with all power generating resources, including wind resources, were functionalized to Production. Production costs were allocated to customer classes based on marginal generation cost of service allocation factors. Generation costs were recovered from each class through Schedule 200, Cost-Based Supply Service. A calculation showing wind resource costs collected by each class separate from other generation costs is not available.

The proposed recovery method in this case is an equal cents per kilowatt-hour rate applicable to all customers. This proposal is intended to simplify the rate design for this streamlined proceeding while still generally recovering costs from the appropriate customers. The Schedule 202 rate is also proposed as a temporary rate which will be set to zero during a general rate case where renewable resource costs are rolled into the Company's full revenue requirement.

UM-1330/PacifiCorp
September 14, 2007
ICNU Data Request 1.11

ICNU Data Request 1.11

Explain the process the Company used in UE 179 to allocate cost responsibility of existing run of river hydro resources to customer classes.

Response to ICNU Data Request 1.11

Please see the response to ICNU Data Request 1.10. Run of river hydro resource costs were allocated to customer classes in the same manner as all other generation resource costs.

UM-1330/PacifiCorp
September 14, 2007
ICNU Data Request 1.12

ICNU Data Request 1.12

What cost justification supports the collection of the Schedule 202 charge on a pure cost per kWh basis for all customer classes? Explain.

Response to ICNU Data Request 1.12

The collection of the Schedule 202 charge through a single rate per kWh for all kWh is intended as a simplified method of collection which generally collects costs from the appropriate customers. This streamlined proceeding is not intended to review renewable costs on a full cost of service basis but rather to collect costs in a timely manner without added complexity. A detailed cost of service study would be undertaken in the next rate case where new renewable resource costs would be rolled in to the Company's full revenue requirement.

UM-1330/PacifiCorp
September 14, 2007
ICNU Data Request 1.17

ICNU Data Request 1.17

Does PacifiCorp agree or disagree that PGE's proposal for recovery of renewable resource costs is appropriate and reasonable in light of the fact that PGE does not propose to update cost changes on an annual basis?

Response to ICNU Data Request 1.17

PacifiCorp has not formed an opinion and does not plan to form an opinion on PGE's proposal.

UM-1330/PacifiCorp
September 14, 2007
ICNU Data Request 1.23

ICNU Data Request 1.23

Are any wind resources included in PacifiCorp's current Integrated Resource Plan? If so, does the Company assume that these resources will provide useful capacity for reliability purposes, such as meeting peak demands?

Response to ICNU Data Request 1.23

Yes, the 2007 Integrated Resource Plan includes 2,000 MW of nameplate renewable capacity, the majority of which is expected to be wind resources. The Company assigns a capacity contribution to wind resources using stochastic modeling and a statistical approach that determines the effective load carrying capability for each 100 MW increment of additional wind capacity at a site.

UM-1330/PacifiCorp
September 14, 2007
ICNU Data Request 1.31

ICNU Data Request 1.31

Provide a copy of any presentations made by PacifiCorp (or its parent on behalf of PacifiCorp) to financial analysts in the past two years.

Response to ICNU Data Request 1.31

Please refer to Attachment ICNU 1.31.

OREGON

UM-1330

PACIFICORP

ICNU DATA REQUEST SET 1 (1-35)

ATTACHMENT ICNU 1.31

ON THE ENCLOSED CD

PACIFIC POWER
A DIVISION OF PACIFICORP

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

Patrick Reiten

President

Richard Walje

President

PACIFICORP

Regulatory Strategy & Challenges

- Recovering levels of investment which exceed depreciation and sales growth will require rate increases
  - Frequent large rate increases are not compatible with customer satisfaction goals
  - Low embedded generation cost compared to marginal generation cost, coupled with significant load growth, results in the need for more frequent rate increases
- Implement effective relationship management
  - Communications plan
  - Relationship management plans for regulators, consumer groups and industrial consumer associations
- Pursue alternative cost recovery mechanisms
  - Power cost adjustment mechanisms
  - Single item cost trackers (e.g., renewable investment)
  - Alternate forms of regulation
  - Implement use of future test periods in all states
- Review and implement innovative cost-of-service and rate design methodologies
  - Alternatives to embedded cost rate-making for generation costs

UM-1330/PacifiCorp
September 14, 2007
ICNU Data Request 1.32

ICNU Data Request 1.32

Explain why the proposed Schedule 202 differs so substantially in terms of structure and detail from the Schedule 96 proposed by Rocky Mountain Power in its current general rate case.

Response to ICNU Data Request 1.32

The different states in which PacifiCorp serves have different requirements for what is included in tariff schedules. Schedule 96 proposed by Rocky Mountain Power in Wyoming is consistent with the tariff schedule implementing the power cost adjustment mechanism in that state. The proposed Schedule 202 in Oregon is consistent with the level of detail for Schedule 200 in Oregon.

UM-1330/PacifiCorp
September 14, 2007
ICNU Data Request 1.34

ICNU Data Request 1.34

Would the Company object to the use of a tariff substantially similar to Rocky Mountain Power's proposed Schedule 96 for purposes of meeting the requirements of SB 838?

Response to ICNU Data Request 1.34

Yes. Please see the Company's response to ICNU Data Request 1.32.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1330

In the Matter of	)
	)
PUBLIC UTILITY COMMISSION OF OREGON	)
	)
	)
Investigation of Automatic Adjustment Clause pursuant to SB 838.	)

EXHIBIT ICNU/105

EXCERPTS OF PACIFICORP MARGINAL COST STUDY

IN DOCKET NO. UE 179

September 28, 2007

Table 5

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Generation Costs
In Nominal Dollars

Year			(A) Resource Cost (Mills / kWh) (B) + (C)	(B) Energy Only (Mills / kWh)	(C) Capacity Only (Mills / kWh)	(D) Capacity Only ($ / kW)
2007			70.54	52.56	17.98	$75.60
2008			67.11	48.77	18.34	$77.13
2009			64.54	45.83	18.71	$78.68
2010			62.12	43.03	19.09	$80.27
2011			65.37	45.72	19.65	$82.63
2012			71.30	51.07	20.23	$85.06
2013			74.27	53.45	20.82	$87.56
2014			75.15	53.71	21.44	$90.14
2015			76.57	54.50	22.07	$92.79
2016			78.62	55.90	22.72	$95.52
2017			80.69	57.30	23.39	$98.33
2018			82.70	58.63	24.07	$101.22
2019			84.96	60.18	24.78	$104.19
2020			87.25	61.74	25.51	$107.26
2021			89.70	63.30	26.40	$110.99
2022			92.25	64.94	27.31	$114.85
2023			94.84	66.58	28.26	$118.85
2024			97.48	68.23	29.25	$122.98
2025			100.30	70.03	30.27	$127.26
2026			103.14	71.82	31.32	$131.69
2007	**1 year -**					
|	Sum of PV Costs	@ 9.08%	70.54	52.56	17.98	$75.60
2007 - 2011	**5 year -**					
|	Sum of PV Costs	@ 9.08%	280.35	201.24	79.11	$332.66
|	Annual Cost of R/E	@ 22.39%	62.77	45.06		
|	Annual Cost of Capacity	@ 22.39%			17.71	$74.48
2007 - 2016	**10 years -**					
|	Sum of PV Costs	@ 9.08%	485.70	348.06	137.64	$578.78
|	Annual Cost of R/E	@ 12.81%	62.22	44.59		
|	Annual Cost of Capacity	@ 12.81%			17.63	$74.14
2007 - 2026	**20 years -**					
|	Sum of PV Costs	@ 9.08%	747.77	532.79	214.98	$904.00
|	Annual Cost of R/E	@ 8.22%	61.47	43.80		
|	Annual Cost of Capacity	@ 8.22%			17.67	$74.31

Footnotes:
(B) Tab 5.1 (Energy:) 'Marginal Generation Energy Costs'
(C) Tab 4.1 (Capacity:) 'Marginal Capacity Costs Based on Avoided Capacity Costs'
(D) Tab 4.1 (Capacity:) 'Marginal Capacity Costs Based on Avoided Capacity Costs'

PacifiCorp
Oregon Marginal Cost Study
1 Year Marginal Costs by Load Class
December 2007 Dollars
(Dollars in 000's)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
			Residential	General Service - Schedule 23			General Service - Schedule 28							Large Power Service - Schedule 48T					Irrg
				0-15 kW	15+ kW		0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW		Sch 41
Line		Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)
	Billing Units																		
	Energy																		
1	Energy - Annual Mwh @ Meter	13,212,328	5,423,448	690,926	464,307	914	448,761	677,247	923,634	26,705	213,932	1,033,484	84,717	763,022	469,149	35,807	1,287,407	560,680	108,189
2	Energy Loss Factor		1.0995	1.0995	1.0995	1.0691	1.0995	1.0995	1.0995	1.0691	1.0995	1.0995	1.0691	1.0995	1.0691	1.0995	1.0691	1.0454	1.0995
3	Energy - Annual Mwh @ Generator	14,439,787	5,963,081	759,673	510,505	977	493,412	744,633	1,015,535	28,550	235,218	1,136,315	90,569	838,943	501,557	39,370	1,376,341	586,152	118,954
4																			
5	Customer																		
6	Average Customers	555,012	467,946	61,630	8,518	37	4,312	3,351	1,903	56	229	523	45	130	57	1	33	1	6,240
7																			2,767
8	Unit Costs																		
9																			
10	Energy @ Generator $ / Kwh		$0.05256	$0.05256	$0.05256	$0.05256	$0.05256	$0.05256	$0.05256	$0.05256	$0.05256	$0.05256	$0.05256	$0.05256	$0.05256	$0.05256	$0.05256	$0.05256	$0.05256
11																			
12	Billing Related Costs		$134.19	$148.05	$266.43	1,172.78	$315.40	324.24	$687.36	$1,215.41	$885.92	$885.98	$1,413.41	$2,628.53	$2,717.06	$2,628.53	$2,717.06	$25,829.01	$34.69
13																			$81.62
14																			
15	Marginal Costs $000																		
16																			
17	Total Energy Related	$758,883	$313,390	$39,925	$26,830	$51	$25,931	$39,134	$53,371	$1,500	$12,362	$59,719	$4,760	$44,091	$26,359	$2,069	$72,334	$30,805	$6,252
18																			
19	Billing Related Costs	$79,842	$62,795	$9,124	$2,269	$43	$1,360	$1,087	$1,308	$68	$203	$463	$64	$342	$155	$3	$90	$26	$442
20																			
21																			
22	Total Revenue @ Full MC	$838,726	$376,185	$49,049	$29,099	$94	$27,291	$40,221	$54,679	$1,568	$12,565	$60,182	$4,824	$44,433	$26,514	$2,072	$72,424	$30,831	$6,694

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1330

In the Matter of	)
	)
PUBLIC UTILITY COMMISSION OF OREGON	)
	)
	)
Investigation of Automatic Adjustment Clause pursuant to SB 838.	)

EXHIBIT ICNU/106

EXCERPT OF PACIFICORP EXHIBIT PPL/1005

IN DOCKET NO. UE 179

September 28, 2007

ICNU/106
Falkenberg/1

Pac.
State of Oregon
December 31, 2007 Unbundled Revenue Requirement Allocation by Rate Schedule

Line	Description	Total	(A) Residential	(B) General Service Sch 23	(C) General Service Sch 23	(D) General Service Sch 28	(E) General Service Sch 28	(F) General Service Sch 30	(G) General Service Sch 30	(H) Large Power Service Sch 48T	(I) Large Power Service Sch 48T	(J) Large Power Service Sch 48T	(K) Irrigation Sch 41	(L) Street Lgt. Sch 51, 53, 54
			(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)		
1	**Total Operating Revenues**	$832,085	$422,917	$90,049	$73	$109,586	$1,396	$61,619	$4,069	$37,072	$71,702	$20,081	$10,468	$3,053
2	**MWH**	13,237,198	5,423,448	1,155,232	914	2,049,642	26,705	$1,247,416	84,717	798,829	1,756,556	560,680	108,189	$24,870
3														
4	**Functionalized 20 Year Full Marginal Costs - Class $**													
5	Generation	$795,020	$327,215	$72,507	$56	$125,480	$1,590	$75,674	$5,004	$48,186	$100,821	$30,593	$6,696	$1,198
6	Transmission	$45,174	$18,533	$4,460	$3	$7,336	$93	$4,338	$287	$2,728	$5,430	$1,535	$400	$30
7	Distribution	$277,137	$175,465	$39,530	$20	$24,765	$247	$12,809	$794	$7,001	$7,011	$0	$6,598	$2,895
8	Customer - Billing	$14,163	$12,092	$1,658	$1	$253	$1	$20	$1	$20	$14	$0	$79	$25
9	Customer - Metering	$16,196	$12,109	$2,415	$42	$855	$64	$162	$52	$47	$112	$24	$312	$2
10	Customer - Other	$7,445	$6,260	$853	$0	$180	$1	$38	$2	$33	$23	$0	$45	$9
11	Total	$1,155,136	$551,674	$121,423	$123	$158,869	$1,997	$93,041	$6,141	$58,016	$113,410	$32,154	$14,131	$4,158
12														
13	**Functional Revenue Requirement Allocation Factors**													
14	**Functionalized 20 Year Full Marginal Costs - Class % of Total**													
15	Generation	100.00%	41.16%	9.12%	0.01%	15.78%	0.20%	9.52%	0.63%	6.06%	12.68%	3.85%	0.84%	0.15%
16	Transmission	100.00%	41.03%	9.87%	0.01%	16.24%	0.21%	9.60%	0.64%	6.04%	12.02%	3.40%	0.89%	0.07%
17	Distribution	100.00%	63.31%	14.26%	0.01%	8.94%	0.09%	4.62%	0.29%	2.53%	2.53%	0.00%	2.38%	1.04%
18	Ancillary Service	100.00%	41.16%	9.12%	0.01%	15.78%	0.20%	9.52%	0.63%	6.06%	12.68%	3.85%	0.84%	0.15%
19	Customer - Billing	100.00%	85.37%	11.71%	0.01%	1.78%	0.01%	0.14%	0.01%	0.14%	0.10%	0.00%	0.56%	0.18%
20	Customer - Metering	100.00%	74.76%	14.91%	0.26%	5.28%	0.40%	1.00%	0.32%	0.29%	0.69%	0.15%	1.93%	0.01%
21	Customer - Other	100.00%	84.08%	11.45%	0.01%	2.42%	0.01%	0.50%	0.03%	0.45%	0.31%	0.00%	0.61%	0.13%
22	Embedded DSM - (mWh)	100.00%	40.97%	8.73%	0.01%	15.48%	0.20%	9.42%	0.64%	6.03%	13.27%	4.24%	0.82%	0.19%
23	Regulatory & Franchise	100.00%	50.83%	10.82%	0.01%	13.17%	0.17%	7.41%	0.49%	4.46%	8.62%	2.41%	1.26%	0.37%
24	Taxes (Revenue)													
25														
26	**Functionalized Class Revenue Requirement - (Target)**													
27	Generation	$536,454	$220,794	$48,925	$38	$84,670	$1,073	$51,063	$3,376	$32,514	$68,031	$20,643	$4,518	$808
28	Transmission	$61,845	$25,372	$6,106	$4	$10,043	$127	$5,939	$393	$3,734	$7,434	$2,102	$548	$41
29	Distribution	$254,191	$160,937	$36,257	$19	$22,714	$227	$11,749	$729	$6,422	$6,430	$0	$6,052	$2,655
30	Ancillary Services	$10,228	$4,210	$933	$1	$1,614	$20	$974	$64	$620	$1,297	$394	$86	$15
31	Customer - Billing	$18,504	$15,797	$2,166	$1	$330	$2	$26	$2	$26	$18	$0	$103	$33
32	Customer - Metering	$20,374	$15,233	$3,038	$53	$1,076	$81	$203	$65	$60	$140	$31	$393	$2
33	Customer - Other	$17,786	$14,954	$2,037	$1	$431	$3	$90	$5	$80	$55	$1	$108	$23
34	Embedded DSM - (mWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
35	Regulatory & Franchise T	$22,398	$11,384	$2,424	$2	$2,950	$38	$1,659	$110	$998	$1,930	$541	$282	$82
36	Total	$941,779	$468,681	$101,887	$118	$123,828	$1,570	$71,702	$4,744	$44,453	$85,335	$23,711	$12,090	$3,659
37														
38	**Ratio of Operating Revn to Revenue Requirement-(Target)**	88.35%	90.24%	88.38%	61.72%	88.50%	88.91%	85.94%	85.77%	83.40%	84.02%	84.69%	86.58%	83.43%
39	(Line 1 / Line 36)													
40														
41	**Increase or (Decrease)**	$109,694	$45,764	$11,838	$45	$14,242	$174	$10,083	$675	$7,381	$13,633	$3,630	$1,622	$606
42	(Line 36 - Line 1)													
43														
44														
45	**Percent Increase (Decrease)**	13.18%	10.82%	13.15%	62.01%	13.00%	12.47%	16.36%	16.59%	19.91%	19.01%	18.08%	15.50%	19.86%
46	(Line 41 / Line 1)													

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1330

In the Matter of	)
	)
PUBLIC UTILITY COMMISSION OF OREGON	)
	)
Investigation of Automatic Adjustment Clause pursuant to SB 838.	)

EXHIBIT ICNU/107

ROCKY MOUNTAIN POWER PROPOSED TARIFF SCHEDULE 96

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

September 28, 2007

Rocky Mountain Power
Exhibit RMP___.4(DMM-4)
Docket No. 20000-___-ER-07
Witness: David M. Mosier

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of David M. Mosier

NRRM Tariff – Schedule 96

June 2007

ROCKY MOUNTAIN POWER

Original Sheet No. 96-1

P.S.C. Wyoming No. 10

New Renewable Resource Mechanism
Schedule 96

Available

In all territory served by the Company in the State of Wyoming.

Applicable

All retail tariff rate schedules identified below shall be subject to a rate surcharge for the recovery of plant investment, operations and maintenance costs related to new renewable resources which are not fully included in retail rates established in the most recent general rate case.

Definitions

Rate Effective Period: April 1 through March 31.

Comparison Period: the historic 12-month period beginning December 1 and extending through November 30 preceding the Rate Effective Period.

Base Renewable Resource Costs: costs for existing renewable resources, including return on rate base; expenses for operations, maintenance, depreciation and deferred income tax; applicable tax credits and other costs approved by the Commission and included in Wyoming rates in the most recent general rate case.

New Renewable Resource Costs: costs for new renewable resources including return on rate base; expenses for operations, maintenance, depreciation and deferred income tax; applicable tax credits and other costs for new renewable resources in service during the Comparison Period, but not included in Wyoming rates, and that have an impact on power costs included in the calculation of the Deferred NPC Adjustment defined in Schedule 94.

Pre-Tax Return on Rate Base shall be computed using the weighted after-tax Cost of Capital approved by the Commission in the most recent general rate case. Preferred and Common stock components shall be grossed-up for taxes utilizing tax rates and other relevant factors included in the most recent general rate case.

(continued)

Definitions (continued)

Depreciation Expense shall be computed for the specific new renewable resource using the book depreciation rate approved by the Commission in the most recent depreciation study.

Total Company New Renewable Resource Revenue Requirement: The Company shall maintain a monthly account of total Company New Renewable Resource Revenue Requirements beginning the day a renewable resource commences commercial operation. The account shall compute the revenue requirement on a total Company basis, prorated if necessary for partial month operations, for each individual resource in the following manner: 1] Compute Net Rate Base beginning with the resource Gross Capital Cost, less Accumulated Depreciation and less Deferred Income Tax. 2] Compute the Return on Rate Base by multiplying the pre-tax Return on Rate Base times Net Rate Base. 3] Add the Operation and Maintenance expense for the new renewable resource based on budgeted O&M expense specific to each renewable resource. 4] Add Depreciation Expense. 5] Add applicable state or federal tax credits.

Allocated Wyoming New Renewable Resource Revenue Requirement shall be calculated using Wyoming interjurisdictional allocation factors. Wyoming interjurisdictional allocation factors are Wyoming's percent of total system factors prescribed for allocation of plant investment, operations, maintenance, depreciation and tax expenses pursuant to the Revised Protocol or current Commission approved interjurisdictional allocation methodology and consistent with the allocation factors used in the PCAM for the allocation of net power costs.

Deferred New Renewable Resource Adjustment shall be the allocated Wyoming New Renewable Resource Revenue Requirement during the Comparison Period allocated to all applicable retail tariff rate schedules and where appropriate to the demand and energy rate components within each schedule based on the applicable allocation factors and cost of service study relationships established in the Company's last general rate case. The allocated and classified costs shall then be divided by appropriate billing determinants consistent with those used to calculate

(continued)

ROCKY MOUNTAIN POWER

Original Sheet No. 96-3

P.S.C. Wyoming No. 10

New Renewable Resource Mechanism
Schedule 96

Definitions (continued)

Deferred New Renewable Resource Adjustment (continued)

the Deferred NPC Adjustment in Schedule 94. The Deferred New Renewable Resource Adjustment shall be applicable during the Rate Effective Period.

Timing

The Company shall file Deferred New Renewable Resource Adjustment applications on or before February 1st of each year under normal circumstances coincident with applications for a Deferred NPC Adjustment in Schedule 94. The implementation and effective date of the Deferred New Renewable Resource Adjustment shall be April 1st of each year under normal circumstances.

Monthly Billing

All charges and provisions of the applicable rate schedule will be applied in determining a Customer's bill except that the Customer's total electric bill, excluding surcharges or credits pursuant to Schedule 94, will be adjusted by an amount equal to the product of all kilowatt demand multiplied by the following dollar per kilowatt rate plus all kilowatt-hours of energy use multiplied by the following cents per kilowatt-hour:

Schedule	Delivery Voltage	Billing Units	Deferred Renewable Resource Adjustment
2	**	Demand per kWh	0.000¢
		Energy per kWh	0.000¢
15	**	Demand per kWh	0.000¢
		Energy per kWh	0.000¢
25	Secondary	Demand per kW	$0.00
		Energy per kWh	0.000¢
	Primary	Demand per kW	$0.00
		Energy per kWh	0.000¢

(continued)

Issued by
Jeffrey K. Larsen, Vice President, Regulation

Issued: June 29, 2007

Effective: With service rendered on and after

ROCKY MOUNTAIN POWER

New Renewable Resource Mechanism
Schedule 96

Monthly Billing (continued)

Schedule	Delivery Voltage	Billing Units	Deferred Renewable Resource Adjustment
33	Primary	Demand per kW	$0.00
		Energy per kWh	0.000¢
	Transmission	Demand per kW	$0.00
		Energy per kWh	0.000¢
40	**	Demand per kW	$0.00
		Energy per kWh	0.000¢
46	Secondary	Demand per kW	$0.00
		Energy per kWh	0.000¢
	Primary	Demand per kW	$0.00
		Energy per kWh	0.000¢
48T	Transmission	Demand per kW	$0.00
		Energy per kWh	0.000¢
51	**	Demand per kWh	0.000¢
		Energy per kWh	0.000¢
53	**	Demand per kWh	0.000¢
		Energy per kWh	0.000¢
54	**	Demand per kWh	0.000¢
		Energy per kWh	0.000¢
57	**	Demand per kWh	0.000¢
		Energy per kWh	0.000¢

(continued)

ROCKY MOUNTAIN POWER

Original Sheet No. 96-5

P.S.C. Wyoming No. 10

New Renewable Resource Mechanism
Schedule 96

Monthly Billing (continued)

Schedule	Delivery Voltage	Billing Units	Deferred Renewable Resource Adjustment
58	**	Demand per kWh	0.000¢
		Energy per kWh	0.000¢
207	**	Demand per kWh	0.000¢
		Energy per kWh	0.000¢
210	**	Demand per kW	0.000¢
		Energy per kWh	0.000¢
211	**	Demand per kWh	0.000¢
		Energy per kWh	0.000¢
212-1	**	Demand per kWh	0.000¢
		Energy per kWh	0.000¢
212-2	**	Demand per kWh	0.000¢
		Energy per kWh	0.000¢
212-3	**	Demand per kWh	0.000¢
		Energy per kWh	0.000¢

** Rates will be applicable for all Delivery Voltage levels.

Rules

Service under this Schedule is subject to the General Rules contained in the tariff of which this Schedule is a part, and to those prescribed by regulatory authorities.

Issued by
Jeffrey K. Larsen, Vice President, Regulation

Issued: June 29, 2007

Effective: With service rendered on and after

ROCKY MOUNTAIN POWER

Original Sheet No. 96-1

P.S.C. Wyoming No. 10

New Renewable Resource Mechanism
Schedule 96

Available

In all territory served by the Company in the State of Wyoming.

Applicable

All retail tariff rate schedules identified below shall be subject to a rate surcharge for the recovery of plant investment, operations and maintenance costs related to new renewable resources which are not fully included in retail rates established in the most recent general rate case.

Definitions

Rate Effective Period: April 1 through March 31.

Comparison Period: the historic 12-month period beginning December 1 and extending through November 30 preceding the Rate Effective Period.

Base Renewable Resource Costs: costs for existing renewable resources, including return on rate base; expenses for operations, maintenance, depreciation and deferred income tax; applicable tax credits and other costs approved by the Commission and included in Wyoming rates in the most recent general rate case.

New Renewable Resource Costs: costs for new renewable resources including return on rate base; expenses for operations, maintenance, depreciation and deferred income tax; applicable tax credits and other costs for new renewable resources in service during the Comparison Period, but not included in Wyoming rates, and that have an impact on power costs included in the calculation of the Deferred NPC Adjustment defined in Schedule 94.

Pre-Tax Return on Rate Base shall be computed using the weighted after-tax Cost of Capital approved by the Commission in the most recent general rate case. Preferred and Common stock components shall be grossed-up for taxes utilizing tax rates and other relevant factors included in the most recent general rate case.

(continued)

**New Renewable Resource Mechanism
Schedule 96**

Definitions (continued)

Depreciation Expense shall be computed for the specific new renewable resource using the book depreciation rate approved by the Commission in the most recent depreciation study.

Total Company New Renewable Resource Revenue Requirement: The Company shall maintain a monthly account of total Company New Renewable Resource Revenue Requirements beginning the day a renewable resource commences commercial operation. The account shall compute the revenue requirement on a total Company basis, prorated if necessary for partial month operations, for each individual resource in the following manner: 1] Compute Net Rate Base beginning with the resource Gross Capital Cost, less Accumulated Depreciation and less Deferred Income Tax. 2] Compute the Return on Rate Base by multiplying the pre-tax Return on Rate Base times Net Rate Base. 3] Add the Operation and Maintenance expense for the new renewable resource based on budgeted O&M expense specific to each renewable resource. 4] Add Depreciation Expense. 5] Add applicable state or federal tax credits.

Allocated Wyoming New Renewable Resource Revenue Requirement shall be calculated using Wyoming interjurisdictional allocation factors. Wyoming interjurisdictional allocation factors are Wyoming's percent of total system factors prescribed for allocation of plant investment, operations, maintenance, depreciation and tax expenses pursuant to the Revised Protocol or current Commission approved interjurisdictional allocation methodology and consistent with the allocation factors used in the PCAM for the allocation of net power costs.

Deferred New Renewable Resource Adjustment shall be the allocated Wyoming New Renewable Resource Revenue Requirement during the Comparison Period allocated to all applicable retail tariff rate schedules and where appropriate to the demand and energy rate components within each schedule based on the applicable allocation factors and cost of service study relationships established in the Company's last general rate case. The allocated and classified costs shall then be divided by appropriate billing determinants consistent with those used to calculate

(continued)

ROCKY MOUNTAIN POWER

Original Sheet No. 96-3

P.S.C. Wyoming No. 10

New Renewable Resource Mechanism
Schedule 96

Definitions (continued)

Deferred New Renewable Resource Adjustment (continued)

the Deferred NPC Adjustment in Schedule 94. The Deferred New Renewable Resource Adjustment shall be applicable during the Rate Effective Period.

Timing

The Company shall file Deferred New Renewable Resource Adjustment applications on or before February 1st of each year under normal circumstances coincident with applications for a Deferred NPC Adjustment in Schedule 94. The implementation and effective date of the Deferred New Renewable Resource Adjustment shall be April 1st of each year under normal circumstances.

Monthly Billing

All charges and provisions of the applicable rate schedule will be applied in determining a Customer's bill except that the Customer's total electric bill, excluding surcharges or credits pursuant to Schedule 94, will be adjusted by an amount equal to the product of all kilowatt demand multiplied by the following dollar per kilowatt rate plus all kilowatt-hours of energy use multiplied by the following cents per kilowatt-hour:

Schedule	Delivery Voltage	Billing Units	Deferred Renewable Resource Adjustment
2	**	Demand per kWh	0.000¢
		Energy per kWh	0.000¢
15	**	Demand per kWh	0.000¢
		Energy per kWh	0.000¢
25	Secondary	Demand per kW	$0.00
		Energy per kWh	0.000¢
	Primary	Demand per kW	$0.00
		Energy per kWh	0.000¢

(continued)

ROCKY MOUNTAIN POWER

Original Sheet No. 96-4

P.S.C. Wyoming No. 10

New Renewable Resource Mechanism
Schedule 96

Monthly Billing (continued)

Schedule	Delivery Voltage	Billing Units	Deferred Renewable Resource Adjustment
33	Primary	Demand per kW	$0.00
		Energy per kWh	0.000¢
	Transmission	Demand per kW	$0.00
		Energy per kWh	0.000¢
40	**	Demand per kW	$0.00
		Energy per kWh	0.000¢
46	Secondary	Demand per kW	$0.00
		Energy per kWh	0.000¢
	Primary	Demand per kW	$0.00
		Energy per kWh	0.000¢
48T	Transmission	Demand per kW	$0.00
		Energy per kWh	0.000¢
51	**	Demand per kWh	0.000¢
		Energy per kWh	0.000¢
53	**	Demand per kWh	0.000¢
		Energy per kWh	0.000¢
54	**	Demand per kWh	0.000¢
		Energy per kWh	0.000¢
57	**	Demand per kWh	0.000¢
		Energy per kWh	0.000¢

(continued)

ROCKY MOUNTAIN POWER

Original Sheet No. 96-5

P.S.C. Wyoming No. 10

New Renewable Resource Mechanism
Schedule 96

Monthly Billing (continued)

Schedule	Delivery Voltage	Billing Units	Deferred Renewable Resource Adjustment
58	**	Demand per kWh	0.000¢
		Energy per kWh	0.000¢
207	**	Demand per kWh	0.000¢
		Energy per kWh	0.000¢
210	**	Demand per kW	0.000¢
		Energy per kWh	0.000¢
211	**	Demand per kWh	0.000¢
		Energy per kWh	0.000¢
212-1	**	Demand per kWh	0.000¢
		Energy per kWh	0.000¢
212-2	**	Demand per kWh	0.000¢
		Energy per kWh	0.000¢
212-3	**	Demand per kWh	0.000¢
		Energy per kWh	0.000¢

** Rates will be applicable for all Delivery Voltage levels.

Rules

Service under this Schedule is subject to the General Rules contained in the tariff of which this Schedule is a part, and to those prescribed by regulatory authorities.

Issued by
Jeffrey K. Larsen, Vice President, Regulation

Issued: June 29, 2007

Effective: With service rendered on and after

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1330

In the Matter of	)
	)
PUBLIC UTILITY COMMISSION OF OREGON	)
	)
	)
Investigation of Automatic Adjustment Clause pursuant to SB 838.	)

EXHIBIT ICNU/108

CALCULATION OF PACIFICORP 2009 USE OF ALLOCATION FACTORS

FOR PRODUCTION RELATED COSTS FOR CLASS ALLOCATION PURPOSES

September 28, 2007

Exhibit ICNU/108
Proposed Revenue Allocation Methodology

Class of Service	Total	----Res.----	----General Service----		----General Service----		----General Service----		--------Large Power Service--------			Irrigation	Street Light
Schedule			23		28		30			48T		41	51, 53, 54
Voltage		Secondary	Secondary	Primary	Secondary	Primary	Secondary	Primary	Secondary	Primary	Transm.		
Ue 179 Generation $	795020	327215	72507	56	125480	1590	75674	5004	48186	100821	30593	6696	1198
Allocation Factor	100.000%	41.158%	9.120%	0.007%	15.783%	0.200%	9.519%	0.629%	6.061%	12.682%	3.848%	0.842%	0.151%
UE 179 Allocation Factors													
2009 Revenue Rqmt.	$10,087,152	4,151,679	919,963	711	1,592,080	20,174	960,146	63,490	611,380	1,279,209	388,162	84,958	15,200

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1330

In the Matter of	)
	)
PUBLIC UTILITY COMMISSION OF OREGON	)
	)
	)
Investigation of Automatic Adjustment Clause pursuant to SB 838.	)

EXHIBIT ICNU/109

CALCULATION OF PGE 2009 USE OF ALLOCATION FACTORS

FOR PRODUCTION RELATED COSTS FOR CLASS ALLOCATION PURPOSES

September 28, 2007

EXHIBIT ICNU//109
UE 180 ALLOCATION OF BIGLOW FIXED COSTS TO COS CUSTOMERS
2008

Grouping	COS Calendar Energy	COS Busbar Energy	UE 180 Allocation Percent	Allocated Biglow Costs ($000)	Biglow Price mills/kWh	Cycle Energy	Cycle Basis Revenues ($000)
Schedule 7	7,648,767	8,286,674	42.26%	$14,452	1.89	7,643,451	$14,446
Schedule 15	23,746	25,726	0.12%	$41	1.73	23,746	$41
Schedule 32	1,517,848	1,644,437	8.35%	$2,856	1.88	1,516,483	$2,851
Schedule 38							
On-peak	49,048	53,139	0.43%	$147	3.00	49,022	$147
Off-peak	54,466	59,008	0.17%	$58	1.07	54,437	$58
Schedule 47	21,961	23,792	0.12%	$41	1.87	21,742	$41
Schedule 49	65,852	71,344	0.35%	$120	1.82	66,065	$120
Schedule 83-S	5,507,328	5,966,639	29.58%	$10,116	1.84	5,499,638	$10,119
Schedule 89-S							
On-peak	448,346	485,738	2.54%	$869	1.94	447,696	$869
Off-peak	243,845	264,181	1.11%	$380	1.56	243,492	$380
Schedule 83-P	278,283	291,863	1.59%	$544	1.95	278,446	$543
Schedule 89-P							
On-peak	1,170,606	1,227,731	5.77%	$1,973	1.69	1,163,133	$1,966
Off-peak	767,968	805,444	3.07%	$1,050	1.37	763,065	$1,045
Schedule 89-T							
On-peak	445,496	460,509	2.45%	$838	1.88	445,053	$837
Off-peak	333,419	344,655	1.51%	$516	1.55	333,087	$516
Schedule 91	103,260	111,872	0.53%	$181	1.76	103,260	$182
Schedule 92	5,612	6,080	0.03%	$10	1.83	5,612	$10
Schedule 93	562	609	0.00%	$0	0.00	562	$0
Schedule 94	241	261	0.00%	$0	1.84	241	$0
TOTAL	18,686,653	20,129,704	99.98%	$34,192		18,658,231	$34,172
			TARGET	$34,192			

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September 28, 2007

Via Electronically and US Mail

Public Utility Commission
Attn: Filing Center
550 Capitol St. NE #215
P.O. Box 2148
Salem OR 97308-2148

Re: In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Investigation of Automatic Adjustment Clause pursuant to SB 838.
Docket No. UM 1330

Dear Filing Center:

Enclosed please find an original and five copies of the Direct Testimony of Randall J. Falkenberg on behalf of the Industrial Customers of Northwest Utilities in the above-captioned Docket.

Thank you for your assistance.

Sincerely yours,

/s/ Ruth A. Miller
Ruth A. Miller

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served a copy of the foregoing Direct Testimony of Randall J. Falkenberg on behalf of the Industrial Customers of Northwest Utilities, upon the parties, on the official service list for UM 1330, by causing the same to be electronically served to those parties who waived paper service, as well as mailed, postage-prepaid, through the U.S. Mail to all other parties.

Dated at Portland, Oregon, this 28th day of September, 2007.

/s/ Ruth A. Miller
Ruth A. Miller

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