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June 20, 2007

Via Electronic and U.S. 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 PORTLAND GENERAL ELECTRIC COMPANY
Request for a General Rate Revision
Docket No. UE 188

Dear Filing Center:

Enclosed please find the following documents on behalf of the Industrial Customers of Northwest Utilities in the above-captioned docket:

– An original and six copies of the Confidential Direct Testimony and Exhibits of Randall J. Falkenberg; and

– An original and two copies of the Redacted Direct Testimony and Exhibits of Randall J. Falkenberg

Please return one file-stamped copy of each document in the self-addressed stamped envelope provided. 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 the foregoing Redacted Direct Testimony and Exhibits of Randall J. Falkenberg on behalf of the Industrial Customers of Northwest Utilities, upon the parties on the official service list by causing the same to be served via Electronic and US mail. Only those parties, as indicated below, which are qualified under the protective order in this proceeding, will be served the Confidential Version of the foregoing Direct Testimony and Exhibits of Randall J. Falkenberg via US Mail.

Dated at Portland, Oregon, this 20th day of June, 2007.

/s/ Ruth A. Miller
Ruth A. Miller

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(C) = Qualified to Receive Confidential Information

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 188

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
	)
Request for a General Rate Revision.	)
	)

SCHEDULE 120 - BIGLOW CANYON 1 ADJUSTMENT

DIRECT TESTIMONY OF

RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

Redacted Version

June 20, 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 many Portland General Electric Company ("PGE" or the "Company") cases: UE 137 and UE 139 in 2002, UE 149 in 2003, UE 161 in 2004, UE 165/UM 1187, and UE 172 in 2005. In 2006 I filed testimony in Docket Nos. UE 180/181/184 and UM 1234. In those cases, I primarily addressed various issues related to recovery of power costs. I also have filed testimony in several PacifiCorp proceedings in Oregon: UE 111, UE 116, UM 995, UE 134, UM 1050, UE 170, and UE 179. In those cases, I primarily addressed issues related to power cost recovery.

II. INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. ICNU has asked me to examine PGE's proposed Schedule 120 (Biglow Canyon 1 Adjustment) in order to make recommendations concerning the rate treatment of this new facility.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I have concluded as follows:

1. PGE's proposed Schedule 120 will over collect the cost of Biglow Canyon after 2008. The revenue requirements for Biglow Canyon will decline substantially in future years because of the depreciation of the ratebase and the increase in accumulated deferred income taxes. Further, certain tax credits applicable to the project will increase over time, further reducing revenue requirements. While some costs such as property taxes and O&M will likely increase in the years ahead, on net, Biglow Canyon's revenue requirements can be expected to decline substantially.

2. To address this inequity, I propose an annual adjustment be made to Schedule 120, similar to the adjustments made under other PGE rate schedules such as the Annual Update tariff. Whether Biglow Canyon

costs increase or decrease in the years ahead, this approach will provide a much better matching of costs and revenues.

3. As an alternative to an annual update of Schedule 120, the Commission could consider levelizing the cost of the project over a multi-year period. Based on a 5-year levelization, Schedule 120 would be reduced by $5.4 million compared to the PGE proposal.

III. SCHEDULE 120 ISSUES AND ALTERNATIVES

Q. HOW DOES PGE PROPOSE TO COMPUTE THE REVENUE REQUIREMENT UNDERLYING SCHEDULE 120?

A. Exhibit PGE/201 shows the Company's initial calculation of the Biglow Canyon revenue requirement.[1/] Essentially, the Company proposes to use 2008 test year data for the project to compute the Schedule 120 revenue requirement.

Q. DO YOU HAVE ANY OBJECTIONS TO PGE'S CALCULATION OF THE BIGLOW CANYON REVENUE REQUIREMENT?

A. Yes. PGE's calculation might be acceptable if the rate effective period were limited to 2008. However, Schedule 120 will be in effect beyond 2008, likely until the Commission approves new rates in PGE's next general rate case. It may be many years before Schedule 120 is incorporated into permanent rates.

This is important, because, as PGE acknowledged in its response to an ICNU data request, the costs of Biglow Canyon will decline over time:

1/ As a result of the Stipulation among the parties and updated data, PGE has provided a new computation of the Schedule 120 revenue requirement, resulting in a total cost of approximately $9.4 million.

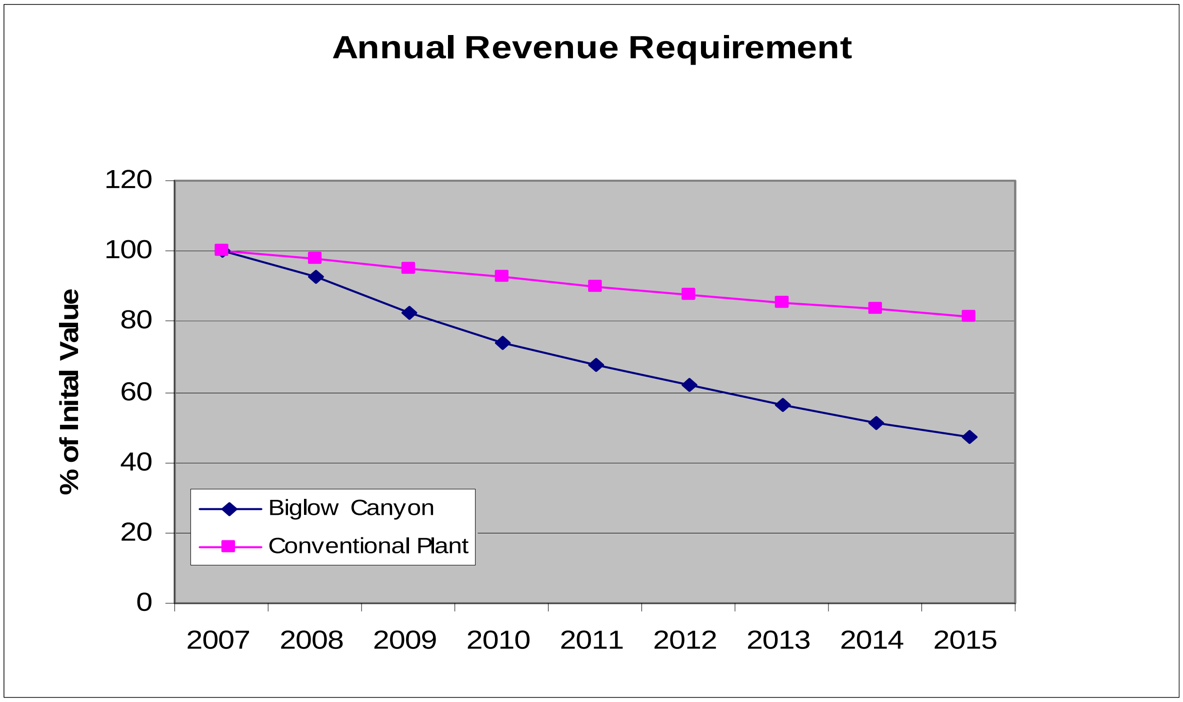
> **<u>Request:</u>**
>
> Please provide a comparison showing the expected cost per MWh for Biglow Canyon as compared to the Klondike purchase. Please provide the comparison for the next five years?
>
> *<u>Response</u>**:***
>
> PGE has not performed this analysis. PGE selected both of these resources 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/102, Falkenberg/1 (emphasis added).

As a result, the Biglow Canyon costs for 2008 likely are higher than the costs for subsequent years.

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

A. No. ICNU requested such an analysis, but PGE objected to providing it and stated that it had not specifically analyzed Biglow Canyon's currently projected costs. ICNU/103, Falkenberg/1. In response to another data request, however, PGE provided a life of the resource analysis that the Company used in the bid evaluation process. 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. ICNU/104, Falkenberg/1. To protect the confidentiality of the data, all figures are indexed to 2008 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.[2] Also shown are results from a more conventional plant, which shows a less significant decline in costs.



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

A. There are a number of reasons. Wind turbines qualify for a very favorable tax treatment that allows a 5-year tax life. Other types of plants generally use a ten or fifteen-year tax life. Also, wind turbines represent a new technology and may 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).

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

Q. WHAT IS THE IMPLICATION OF THESE ISSUES FOR RATE TREAMENT OF BIGLOW CANYON?

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 considered. Approaches that worked for conventional resources in the past are not as appropriate for wind generation.

Q. PLEASE ELABORATE ON THE IMPACT OF THE 5-YEAR TAX LIFE.

A. PGE expects that by the end of 2008, it will have taken slightly more than [redacted] in accelerated depreciation for tax purposes on Biglow Canyon, or [redacted] of the project's tax basis. This results in a substantial accumulated deferred tax balance, [redacted], by December 2008. Because a 13-month average ratebase is used, less than half of this deferred tax balance is deducted from ratebase in the 2008 test year. The same is true, of course, of the depreciation reserve, which amounts to more than [redacted] by year-end 2008. By the end of the year, the total ratebase of Biglow Canyon is only [redacted] as compared to the 2008 average ratebase of approximately [redacted]. This is a substantial reduction from the total project cost of approximately $261 million. The implication of all this is that, starting in 2009, Biglow Canyon would have a much smaller ratebase than for the 2008 Test Year. Thus, for 2009 (and every subsequent year), the revenue requirements for Biglow Canyon will be reduced substantially.

Q. ARE YOU ADVOCATING THAT THE COMMISSION ABANDON ITS TRADITIONAL USE OF THE 13-MONTH AVERAGE RATE BASE?

A. No. I am merely pointing out that using the 2008 Biglow Canyon revenue requirement for 2009 and beyond will result in the Company collecting more than

Biglow Canyon's actual revenue requirement after 2008. As a result, I recommend updating the Schedule 120 charges on an annual basis or developing an alternative approach to deal with this issue.

Q. IS IT LIKELY THAT SOME BIGLOW CANYON COSTS WILL INCREASE OVER TIME?

A. Yes. The Biglow Canyon O&M expense can be expected to increase. Property taxes also will increase in the second year because the Company was only required to pay one-half year of property taxes in 2008. However, these impacts are much smaller than the other sources of negative attrition related to the project.

Q. DO YOU HAVE ANY PROJECTIONS OF THIS PHENOMENON?

A. Yes. As noted above, ICNU requested that PGE provide projections comparable to PGE/201 for future years, and the Company objected to ICNU's request and refused to provide any analysis. ICNU/103, Falkenberg/1. In other discovery, however, the Company provided the model it used for the Orion bid evaluation. Because the assumptions in this model differed from those currently in use,[3/] I performed my own projections with current assumptions based on PGE's model. Exhibit ICNU/105 provides these results.

Q. ARE THERE ANY OTHER ASPECTS OF THIS ISSUE NOT ADDRESSED IN EXHIBIT ICNU/105?

A. Yes. Exhibit ICNU/105 deals only with the Biglow Canyon revenue requirement. However, the Schedule 120 charges are levied on a per kWh basis. To the extent that PGE's kWh sales grow in the years ahead, further over collections of Biglow

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[3/] Many factors differed, notably the overall project was originally much larger. Also, assumptions related to the cost of capital, taxes, NEPA credits, and other issues addressed in the stipulation differed.

Canyon costs will occur. Use of an annual update calculation for Schedule 120 would address this problem as well.

Q. DISCUSS THE RESULTS OF YOUR ANALYSIS.

A. The exhibit shows that, in 2009, Biglow Canyon's revenue requirement can be expected to decline by $3.3 million. By 2010, use of PGE's currently proposed Schedule 120 would result in $9.3 million in overcollections on a cumulative basis. By the end of 2012, the Company would obtain more than $28 million in overcollections. Again, these figures ignore sales growth, which would further increase overcollections. Naturally, if PGE has a rate case before 2012, the Company likely would permanently include the cost of the project in rates using the then current revenue requirement for the project. However, PGE has had many years between rate cases in the past, and the Company's ability to update and true-up power costs each year further decreases the need to file rate cases.

Q. ELABORATE ON YOUR LAST STATEMENT.

A. PGE appears to have embarked on a scheme of "piecemeal" ratemaking. The Company has generally isolated certain cost elements, such as power costs, and sought specific recovery of those costs, in isolation, as opposed to a general rate filing. The Company now has an Annual Update tariff to update its annual net variable power cost forecast each year and an Annual Variance tariff to true-up its annual forecast to actuals. Further, the Company has requested specific recovery mechanisms for hydro deficits, and most recently a major plant outage. In the current case, the Company requests recovery of a specific new resource, Biglow Canyon, through a specific tariff rider.

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) as well as 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. 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. It is a bit ironic that, out of all of PGE's rate adjustment schedules, PGE would believe that the Biglow Canyon tariff should be fixed until the next general rate case, while making provisions for adjustments or true-ups in the great majority of the other schedules.

Q. HOW DO YOU PROPOSE THAT THE COMMISSION IMPLEMENT AN ANNUAL ADJUSTMENT PROCESS FOR SCHEDULE 120?

A. The update could be computed using the revenue requirements methodology shown in PGE/201. The filing could be made once per year, once the data applicable to the next year is available. I believe a filing made each year on September 1 could be implemented by January 1 of the following year. This would afford parties some time to review the filing and verify the projections and calculations. This need not be a time consuming process.

An alternative would be for PGE to specify a formula for computing the Biglow Canyon revenue requirement within schedule 120. This would be what is known as a "formula rate" tariff.

Q. CAN YOU PROVIDE ANY EXAMPLES OF A COMPARABLE FORMULA RATE TARIFF APPROVED BY OTHER REGULATORY COMMISSIONS?

A. Yes. Exhibit ICNU/106 is copy of Service Schedule MSS-4 used in the Entergy System Agreement to price out unit power sales between its operating units. This tariff is approved by FERC and is an example of a formula rate used to recover the cost of a specific generating unit. It is my understanding that the charges computed under this tariff are computed monthly. While I have not conducted a search of all such tariffs, I believe this approach is fairly common at FERC.

Q. IF BIGLOW CANYON'S COSTS WERE RECOVERED IN A GENERAL RATE CASE, IT SEEMS LIKELY 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. 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 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 though 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. I find it a bit ironic that PGE would make this proposal after it argued strenuously in UE 180 in favor of annual updates to power costs along with an annual true up. I would ask "If annual updates for power costs are appropriate, why not for Biglow Canyon?"

Q. THE CURRENT NEPA TAX CREDIT FOR WIND RESOURCES IS SCHEDULED TO EXPIRE IN 2008. IF THIS HAPPENS, ISN'T IT LIKELY THAT THE 2009 COSTS FOR BIGLOW CANYON WILL INCREASE?

A. Yes. Like PGE, I assume this credit will be renewed. However, if it is not renewed, it seems quite likely PGE would make a new filing in 2009 to update Schedule 120. In any case, use of an annual update will provide better assurance that costs and revenues for Biglow Canyon will be in alignment.

Levelization of Biglow Canyon Charges

Q. IS AN ANNUAL UPDATE OF SCHEDULE 120 THE ONLY APPROACH TO ADDRESSING THE PROBLEM OF A DECLINING REVENUE REQUIREMENT FOR BIGLOW CANYON?

A. No. Another option is to use a levelization technique to develop a tariff that would be applicable over a multi-year period. Under this approach, a single revenue requirement is computed, that produces the same net present value of revenue requirements as are currently projected to occur for the period chosen. Exhibit ICNU/105 also shows the levelized revenue requirement for Schedule 120, assuming a five-year levelization period. Under this approach, PGE would be afforded full recovery of the cost of the project (plus carrying charges) by the end of the five-year period. This would provide a much simpler approach, in that annual updates would not be required. Under this methodology, the Biglow Canyon revenue requirement would be reduced by $5.4 million as compared to the PGE proposal.

Q. IF PGE WERE GRANTED A BASE RATE INCREASE BEFORE THE END OF FIVE YEARS, HOW WOULD THE COMMISSION DEAL WITH THE USE OF A FIVE YEAR LEVELIZATION?

A. In that case, a mismatch between the annual costs and revenue costs would occur until the last year of the levelization period. This could be dealt with quite easily by creating a regulatory asset to track the cost differences. If a rate case took place before the end of the levelization period, the uncollected amount would then be included in ratebase, subject to an amortization schedule to be determined by the Commission. I have provided a calculation of this regulatory asset in Exhibit ICNU/105.

Q. IF THESE PROJECTIONS PROVE TO BE INACCURATE, WOULD THAT MEAN THE LEVELIZATION METHOD PRODUCES INCORRECT RATES?

A. Possibly. While use of a five-year levelization may be more subject to forecast error, it is possible that errors in future years may cancel out. In any case, should the rate prove to be much too high or too low, the Commission should expect to revisit this issue in the future.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 188

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	)
PORTLAND GENERAL ELECTRIC COMPANY	)
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EXHIBIT ICNU/101

QUALIFICATIONS OF RANDALL J. FALKENBERG

June 20, 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

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

treatments of new baseload generation. I also assisted in EMA's educational seminars where utility personnel 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

APPEARANCES

3/84	8924	KY	Airco Carbide	Louisville Gas & Electric	CWIP in rate base.

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

Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
12/86	9437/ 613	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-EL-AIR 88-170-EL-AIR	OH OH	Ohio Industrial Energy Consumers	Toledo Edison Co., Cleveland Electric Illuminating Co.	Power system reliability reserve margin.
1/89	I-880052	PA	Philadelphia Area Industrial Energy	Philadelphia Electric Co.	Nuclear plant outage, replacement fuel cost

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
			Users' Group		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 Utility Counsel	El Paso Electric Co.	Power system planning, quantification of damages of imprudence, environmental cost of electricity
8/91	4007-U	GA	Georgia Public Service Commission	Georgia Power Co.	Integrated resource planning, regulatory risk assessment.

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

Date	Case	Jurisdict.	Party	Utility	Subject
			Staff		
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 21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	GSU Merger prodcution cost 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,	KY	Kentucky Industrial Utility Customers	Big Rivers Elec. Corp.	Prudence of fuel procurement decisions.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
	90-360-C		& Attorney General		
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
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

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
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
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

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
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
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

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

Date	Case	Jurisdict.	Party	Utility	Subject
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
2/07	UE-061546	WA	ICNU/Public Counsel	PacifiCorp	Power Cost Modeling, Jurisdictional Allocation, PCA
2/07	32710	TX	OPC	EGSI	Fuel Reconciliation

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 188

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT ICNU/102

PGE RESPONSE TO ICNU DATA REQUEST NO. 037

June 20, 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

UE 188

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT ICNU/103

PGE RESPONSE TO ICNU DATA REQUEST NO. 001

June 20, 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. 001

Request:

Please provide an analysis or projection similar to Exhibit 201, Tooman-Tinker-Schue/1, Column 2 (Biglow Canyon Impact) for the test year and through the expected lifetime of the facility. Please provide supporting workpapers and document all input assumptions.

Response:

PGE objects to this request because it is overly burdensome. PGE has performed an analysis or projection similar to PGE Exhibit 201 only for the test year. We have not made any projections beyond the test year similar to PGE Exhibit 201. For the test year, please see the workpapers provided on March 2, 2007 and the confidential workpapers provided on March 27, 2007.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 188

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC	)
COMPANY	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT ICNU/104

PGE RESPONSE TO ICNU DATA REQUEST NO. 002

June 20, 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. 002

Request:

If the answer to ICNU Data Request No. 1 is that the requested information is not available or PGE does not provide the analysis for any other reason, please provide any and all incremental revenue requirements analyses of Biglow Canyon performed by PGE since the project's initial planning to the present. Include any particular analyses performed by the Company for RFP evaluation purposes.

Response:

PGE objects to this request because it is overly broad and unduly burdensome. Without waiving objection, PGE responds as follows:

Confidential Attachment 002-A is an Excel file, "DR_002_Attach A_CONF.xls." This file is PGE's analysis of the RFP bid submitted by Orion Energy, LLC, which was based on the Biglow Canyon site. Although Orion's original bid was based on more turbines than are in PGE's Phase 1 development, and hence an overall size of 299 MW, the analysis also includes a real-levelized per MWh cost figure.

Attachment 002-A is confidential and subject to Protective Order No. 07-078. It is provided electronically (CD) under separate cover.

		P
Per Biglow BudgetWP - YE 2007 Dep Res		(1,158,257)
	YE 2007 Def Tax re	(3,942,890)

DR 48

	MACRS Life	January-07	February-07	March-07	Q1 Basis	Q1 Rate
Biglow	5	-	-	-	-	0.26000
Biglow Tr	15	-	-	-	-	0.09130

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(124,596)	-1282.9
-76213.41	-4019.1

2008 Tax Depreciation - 2007 Tax Additions

Q1 Depreciatior	April-07	May-07	June-07	Q2 Basis	Q2 Rate	Q2 Depreciat	July-07
-	-	-	-	-	0.30000	-	-
-	-	-	-	-	0.09380	-	-

t1

August-07	September-07	Q3 Basis	Q3 Rate	Q3 Depreciatic	October-07
-	-	-	0.34000	-	54,698,083
-	-	-	0.09630	-	26,721,803

		AFDC	Q4	Q4
November-07	########	Equity	Basis	Rate
179,321,705		4,600,482	229,419,306	0.38000
-		700,083	26,021,720	0.09880
		5 Year	0.90	
		15 Yer	0.10	

Q4 Depreciation	Basis Total 2008	2008 Depreciation
87,179,336	229,419,306	87,179,336
2,570,946	26,021,720	2,570,946

Exhibit ICNU/105

Biglow Canyon Levelized Revenue Requirement

	==Revenue Requirement==		Regulatory
	Annual	Levelized	Asset
2008	33,924	28,564	5,360
2009	30,601	28,564	7,775
2010	27,959	28,564	7,718
2011	25,419	28,564	5,116
2012	23,088	28,564	0
NPVRR	116,968	116,968	
Discount Rate		7.05%	

	ROE	10.10%
	Capital	
PORTLAND GENERAL ELECTRIC COMPANY	Capacity Factor	31%
Orion Energy Sherman County Wind		

21-Jun-07

	Year	Book Deprec.	Return Requirements	Income Taxes	Deferred Inc. Taxes	Property Taxes	Total	Land Lease	A&G, FF, Etc O&M	NEPA Credits	Shaping	Wheeling	Integration
		Fixed Revenue Requirements											
2007	1	$13,208	$19,370	($26,385)	$29,337	$1,047	$36,577	0	6,717	($12,151)	138	$0	$0
2008	2	13,208	16,401	(14,174)	15,873	1,988	33,295	0	6,885	(12,455)	131	$0	$0
2009	3	13,208	14,326	(6,985)	7,765	1,882	30,196	0	7,057	(12,766)	134	$0	$0
2010	4	13,208	12,691	(5,252)	5,275	1,776	27,699	0	7,233	(13,085)	136	$0	$0
2011	5	13,208	11,211	(4,684)	4,008	1,670	25,413	0	7,414	(13,412)	146	$0	$0
2012	6	13,208	10,178	3,263	(4,474)	1,564	23,739	0	7,600	(13,748)	147	$0	$0
2013	7	13,208	9,478	3,439	(5,062)	1,458	22,521	0	7,790	(14,091)	138	$0	$0
2014	8	13,208	8,803	8,395	(5,062)	1,351	26,695	0	7,984	(14,444)	135	$0	$0
2015	9	13,208	8,128	8,139	(5,062)	1,245	25,658	0	8,184	(14,805)	150	$0	$0
2016	10	13,208	7,453	7,884	(5,062)	1,139	24,621	0	8,389	(15,175)	174	$0	$0
2017	11	13,208	6,777	7,628	(5,062)	1,033	23,584	0	8,598	0	169	$0	$0
2018	12	13,208	6,102	7,373	(5,062)	927	22,547	0	8,813	0	168	$0	$0
2019	13	13,208	5,427	7,117	(5,062)	821	21,510	0	9,034	0	161	$0	$0
2020	14	13,208	4,751	6,861	(5,062)	715	20,473	0	9,259	0	181	$0	$0
2021	15	13,208	4,076	6,606	(5,062)	609	19,436	0	9,491	0	176	$0	$0
2022	16	13,208	3,401	6,350	(5,062)	503	18,399	0	9,728	0	193	$0	$0
2023	17	13,208	2,726	6,094	(5,062)	397	17,362	0	9,971	0	197	$0	$0
2024	18	13,208	2,050	5,839	(5,062)	291	16,325	0	10,221	0	205	$0	$0
2025	19	13,208	1,375	5,583	(5,062)	185	15,288	0	10,476	0	195	$0	$0
2026	20	0	1,037	393	0	0	1,430	0	10,738	0	208	$0	$0
2027	21	0	1,037	393	0	0	1,430	0	11,007	0	212	$0	$0
2028	22	0	1,037	393	0	0	1,430	0	11,282	0	235	$0	$0
2029	23	0	1,037	393	0	0	1,430	0	11,564	0	227	$0	$0
2030	24	0	1,037	393	0	0	1,430	0	11,853	0	224	$0	$0
2031	25	0	1,037	393	0	0	1,430	0	12,149	0	226	$0	$0
2032	26	0	1,037	393	0	0	1,430	0	12,453	0	265	$0	$0
2033	27	0	1,037	393	0	0	1,430	0	12,764	0	260	$0	$0
2034	28	0	1,037	393	0	0	1,430	0	13,083	0	258	$0	$0
2035	29	0	1,037	393	0	0	1,430	0	13,410	0	264	$0	$0
2036	30	0	1,037	393	0	0	1,430	0	13,746	0	271	$0	$0
		$250,952											
				30-yr. Real Levelized ($2003)			15,110.95	0.00	6,085.27	(5,324.52)	117.09	0.00	0.00
				Mills per kWh			45.38	$0	18.27	(15.99)	0.35	0.00	0.00
				Present Value ($2003)			$287,567	$0	$115,805	($101,328)	$2,228	$0	$0
				Busbar ($2003)									

Assumptions:

1) Capacity (MW)	125.000
2) Heat Rate (HHV)	0
3) Capacity Factor	31.00%
4) Steam Price (per MMBtu)	$0.00
5) Steam Load (MMBtu/h)	0
6) Fuel prices($1996): Not Applicable	
7) Line losses	1.90%

Energy Shape (MWH)

Peak	25,739	35,612	51,553	42,577	52,701	57,473
Off-peak	13,040	17,993	26,332	22,808	29,772	33,801
Peak	3.12%	4.32%	6.25%	5.16%	6.39%	6.97%
Off-peak	1.58%	2.18%	3.19%	2.76%	3.61%	4.10%

Actual Energy Net of Line L 333,000

Peak Hour	1 Jan	2 Feb	3 Mar	4 Apr	5 May	6 Jun
2007	432	384	432	400	432	416
2008	432	400	416	416	432	400
2009	432	384	416	416	416	416
2010	416	384	432	416	416	416
2011	416	384	432	416	416	416
2012	416	400	432	400	432	416
2013	432	384	416	416	432	400
2014	432	384	416	416	432	400
2015	432	384	416	416	416	416
2016	416	400	432	416	416	416
2017	416	384	432	400	432	416
2018	432	384	432	400	432	416
2019	432	384	416	416	432	400
2020	432	400	416	416	416	416
2021	416	384	432	416	416	416
2022	416	384	432	416	416	416
2023	416	384	432	400	432	416
2024	432	400	416	416	432	400
2025	432	384	416	416	432	400
2026	432	384	416	416	416	416
2027	416	384	432	416	416	416
2028	416	400	432	400	432	416
2029	432	384	432	400	432	416
2030	432	384	416	416	432	400
2031	432	384	416	416	432	400
2032	432	400	432	416	416	416
2033	416	384	432	416	416	416
2034	416	384	432	400	432	416
2035	432	384	432	400	432	416
2036	432	400	416	416	432	400

Differential

2007	(6,033)	(223)	4,387	1,980	4,850	7,384
2008	(5,988)	(790)	5,038	1,415	4,895	8,034
2009	(6,033)	(223)	4,995	1,372	5,458	7,384
2010	(5,424)	(223)	4,387	1,372	5,458	7,384
2011	(5,424)	(223)	4,387	1,372	5,458	7,384
2012	(5,381)	(790)	4,432	2,022	4,895	7,428
2013	(6,033)	(223)	4,995	1,372	4,850	7,993
2014	(6,033)	(223)	4,995	1,372	4,850	7,993
2015	(6,033)	(223)	4,995	1,372	5,458	7,384
2016	(5,381)	(790)	4,432	1,415	5,501	7,428
2017	(5,424)	(223)	4,387	1,980	4,850	7,384
2018	(6,033)	(223)	4,387	1,980	4,850	7,384
2019	(6,033)	(223)	4,995	1,372	4,850	7,993
2020	(5,988)	(790)	5,038	1,415	5,501	7,428

2021	(5,424)	(223)	4,387	1,372	5,458	7,384
2022	(5,424)	(223)	4,387	1,372	5,458	7,384
2023	(5,424)	(223)	4,387	1,980	4,850	7,384
2024	(5,988)	(790)	5,038	1,415	4,895	8,034
2025	(6,033)	(223)	4,995	1,372	4,850	7,993
2026	(6,033)	(223)	4,995	1,372	5,458	7,384
2027	(5,424)	(223)	4,387	1,372	5,458	7,384
2028	(5,381)	(790)	4,432	2,022	4,895	7,428
2029	(6,033)	(223)	4,387	1,980	4,850	7,384
2030	(6,033)	(223)	4,995	1,372	4,850	7,993
2031	(6,033)	(223)	4,995	1,372	4,850	7,993
2032	(5,988)	(790)	4,432	1,415	5,501	7,428
2033	(5,424)	(223)	4,387	1,372	5,458	7,384
2034	(5,424)	(223)	4,387	1,980	4,850	7,384
2035	(6,033)	(223)	4,387	1,980	4,850	7,384
2036	(5,988)	(790)	5,038	1,415	4,895	8,034

Market Price Forecast - Peak

2007	68.43	64.66	56.81	49.56	41.72	45.38
2008	68.48	64.66	57.10	49.29	41.75	46.20
2009	68.80	65.00	57.37	49.52	42.37	45.63
2010	69.67	65.58	57.63	49.96	42.75	46.04
2011	70.41	66.28	58.24	50.49	43.20	46.52
2012	71.20	66.98	58.90	51.38	43.25	47.05
2013	72.91	68.88	60.79	52.47	44.44	49.18
2014	74.92	70.78	62.47	53.92	45.67	50.54
2015	76.98	72.73	64.19	55.40	47.41	51.05
2016	79.26	74.56	65.56	56.83	48.63	52.37
2017	81.30	76.53	67.25	58.67	49.38	53.72
2018	83.09	78.50	68.98	60.18	50.65	55.10
2019	85.35	80.64	71.17	61.43	52.03	57.58
2020	87.66	82.77	73.09	63.09	53.99	58.14
2021	90.47	85.17	74.83	64.87	55.52	59.78
2022	92.73	87.30	76.70	66.50	56.90	61.28
2023	95.05	89.48	78.62	68.59	57.73	62.81
2024	97.43	91.72	80.59	70.31	59.17	64.38
2025	99.86	94.01	82.60	72.06	60.65	65.99
2026	102.36	96.36	84.67	73.87	62.17	67.64
2027	104.92	98.77	86.78	75.71	63.72	69.33
2028	107.54	101.24	88.95	77.61	65.32	71.06
2029	110.23	103.77	91.18	79.55	66.95	72.84
2030	112.99	106.36	93.46	81.53	68.62	74.66
2031	115.81	109.02	95.79	83.57	70.34	76.53
2032	118.71	111.75	98.19	85.66	72.10	78.44
2033	121.67	114.54	100.64	87.80	73.90	80.40
2034	124.72	117.40	103.16	90.00	75.75	82.41
2035	127.83	120.34	105.74	92.25	77.64	84.47
2036	131.03	123.35	108.38	94.56	79.58	86.58

Value of Differential

2007	413	14	(249)	(98)	(202)	(335)
2008	410	51	(288)	(70)	(204)	(371)
2009	415	15	(287)	(68)	(231)	(337)
2010	378	15	(253)	(69)	(233)	(340)
2011	382	15	(255)	(69)	(236)	(344)

2012	383	53	(261)	(104)	(212)	(349)
2013	440	15	(304)	(72)	(216)	(393)
2014	452	16	(312)	(74)	(221)	(404)
2015	464	16	(321)	(76)	(259)	(377)
2016	426	59	(291)	(80)	(268)	(389)
2017	441	17	(295)	(116)	(239)	(397)
2018	501	18	(303)	(119)	(246)	(407)
2019	515	18	(355)	(84)	(252)	(460)
2020	525	65	(368)	(89)	(297)	(432)
2021	491	19	(328)	(89)	(303)	(441)
2022	503	19	(336)	(91)	(311)	(452)
2023	516	20	(345)	(136)	(280)	(464)
2024	583	72	(406)	(99)	(290)	(517)
2025	602	21	(413)	(99)	(294)	(527)
2026	617	22	(423)	(101)	(339)	(499)
2027	569	22	(381)	(104)	(348)	(512)
2028	579	80	(394)	(157)	(320)	(528)
2029	665	23	(400)	(158)	(325)	(538)
2030	682	24	(467)	(112)	(333)	(597)
2031	699	24	(478)	(115)	(341)	(612)
2032	711	88	(435)	(121)	(397)	(583)
2033	660	26	(441)	(120)	(403)	(594)
2034	677	26	(453)	(178)	(367)	(609)
2035	771	27	(464)	(183)	(377)	(624)
2036	785	97	(546)	(134)	(390)	(696)

						Total
63,404	54,171	45,460	48,256	22,465	34,140	#######
38,753	32,991	25,101	23,436	10,583	16,841	#######
7.69%	6.57%	5.51%	5.85%	2.72%	4.14%	
4.70%	4.00%	3.04%	2.84%	1.28%	2.04%	

7	8	9	10	11	12	Off-peak	1
Jul	Aug	Sep	Oct	Nov	Dec		Jan
416	432	400	432	416	416		312
432	416	416	432	400	432		312
432	416	416	432	400	432		312
432	416	416	416	416	432		328
416	432	416	416	416	432		328
416	432	400	432	416	416		328
432	432	400	432	416	416		312
432	416	416	432	400	432		312
432	416	416	432	400	432		312
416	432	416	416	416	432		328
416	432	416	416	416	416		328
416	432	400	432	416	416		312
432	432	400	432	416	416		312
432	416	416	432	400	432		312
432	416	416	416	416	432		328
416	432	416	416	416	432		328
416	432	416	416	416	416		328
432	432	400	432	416	416		312
432	416	416	432	400	432		312
432	416	416	432	400	432		312
432	416	416	416	416	432		328
416	432	416	416	416	416		328
416	432	400	432	416	416		312
432	432	400	432	416	416		312
432	416	416	432	400	432		312
432	416	416	416	416	432		312
416	432	416	416	416	432		328
416	432	416	416	416	416		328
416	432	400	432	416	416		312
432	416	416	432	400	432		312

9,779	5,443	3,144	3,056	(6,746)	(2,034)	(6,597)
9,215	6,095	2,579	3,101	(6,096)	(2,597)	(6,565)
9,170	6,052	2,536	3,056	(6,138)	(2,642)	(6,597)
9,170	6,052	2,536	3,664	(6,746)	(2,642)	(7,205)
9,779	5,443	2,536	3,664	(6,746)	(2,642)	(7,205)
9,822	5,488	3,185	3,101	(6,703)	(1,990)	(7,171)
9,170	5,443	3,144	3,056	(6,746)	(2,034)	(6,597)
9,170	6,052	2,536	3,056	(6,138)	(2,642)	(6,597)
9,170	6,052	2,536	3,056	(6,138)	(2,642)	(6,597)
9,822	5,488	2,579	3,707	(6,703)	(2,597)	(7,171)
9,779	5,443	2,536	3,664	(6,746)	(2,034)	(7,205)
9,779	5,443	3,144	3,056	(6,746)	(2,034)	(6,597)
9,170	5,443	3,144	3,056	(6,746)	(2,034)	(6,597)
9,215	6,095	2,579	3,101	(6,096)	(2,597)	(6,565)

9,170	6,052	2,536	3,664	(6,746)	(2,642)	(7,205)
9,779	5,443	2,536	3,664	(6,746)	(2,642)	(7,205)
9,779	5,443	2,536	3,664	(6,746)	(2,034)	(7,205)
9,215	5,488	3,185	3,101	(6,703)	(1,990)	(6,565)
9,170	6,052	2,536	3,056	(6,138)	(2,642)	(6,597)
9,170	6,052	2,536	3,056	(6,138)	(2,642)	(6,597)
9,170	6,052	2,536	3,664	(6,746)	(2,642)	(7,205)
9,822	5,488	2,579	3,707	(6,703)	(1,990)	(7,171)
9,779	5,443	3,144	3,056	(6,746)	(2,034)	(6,597)
9,170	5,443	3,144	3,056	(6,746)	(2,034)	(6,597)
9,170	6,052	2,536	3,056	(6,138)	(2,642)	(6,597)
9,215	6,095	2,579	3,707	(6,703)	(2,597)	(6,565)
9,779	5,443	2,536	3,664	(6,746)	(2,642)	(7,205)
9,779	5,443	2,536	3,664	(6,746)	(2,034)	(7,205)
9,779	5,443	3,144	3,056	(6,746)	(2,034)	(6,597)
9,215	6,095	2,579	3,101	(6,096)	(2,597)	(6,565)

						Market Price Forec
56.44	70.30	65.70	56.56	57.82	64.43	57.64
56.10	71.13	65.23	56.60	58.01	64.21	57.68
56.37	71.46	65.53	56.86	58.28	64.51	57.95
56.87	72.10	66.12	57.56	58.65	65.08	58.68
57.86	72.07	66.82	58.17	59.27	65.77	59.30
58.51	72.88	68.11	58.64	59.94	66.79	59.97
59.73	74.90	70.00	60.26	61.60	68.64	61.41
61.38	77.81	71.36	61.92	63.46	70.24	63.10
63.07	79.95	73.32	63.62	65.21	72.18	64.84
65.13	81.12	75.21	65.48	66.72	74.04	66.75
66.81	83.21	77.15	67.17	68.44	76.26	68.47
68.53	85.36	79.77	68.67	70.20	78.23	69.98
69.93	87.68	81.95	70.54	72.11	80.36	71.89
71.82	91.05	83.49	72.45	74.25	82.19	73.83
73.85	93.62	85.86	74.75	76.16	84.52	76.20
76.20	94.92	88.00	76.62	78.06	86.63	78.10
78.11	97.29	90.21	78.53	80.02	89.16	80.06
80.06	99.72	92.46	80.49	82.02	91.39	82.06
82.06	102.22	94.77	82.51	84.07	93.68	84.11
84.11	104.77	97.14	84.57	86.17	96.02	86.21
86.22	107.39	99.57	86.68	88.32	98.42	88.37
88.37	110.08	102.06	88.85	90.53	100.88	90.58
90.58	112.83	104.61	91.07	92.79	103.40	92.84
92.84	115.65	107.23	93.35	95.11	105.99	95.16
95.17	118.54	109.91	95.68	97.49	108.64	97.54
97.54	121.50	112.65	98.07	99.93	111.35	99.98
99.98	124.54	115.47	100.53	102.43	114.14	102.48
102.48	127.66	118.36	103.04	104.99	116.99	105.04
105.04	130.85	121.32	105.61	107.61	119.92	107.67
107.67	134.12	124.35	108.26	110.30	122.91	110.36

(552)	(383)	(207)	(173)	390	131	380
(517)	(434)	(168)	(176)	354	167	379
(517)	(432)	(166)	(174)	358	170	382
(521)	(436)	(168)	(211)	396	172	423
(566)	(392)	(169)	(213)	400	174	427

(575)	(400)	(217)	(182)	402	133	430
(548)	(408)	(220)	(184)	416	140	405
(563)	(471)	(181)	(189)	390	186	416
(578)	(484)	(186)	(194)	400	191	428
(640)	(445)	(194)	(243)	447	192	479
(653)	(453)	(196)	(246)	462	155	493
(670)	(465)	(251)	(210)	474	159	462
(641)	(477)	(258)	(216)	486	163	474
(662)	(555)	(215)	(225)	453	213	485
(677)	(567)	(218)	(274)	514	223	549
(745)	(517)	(223)	(281)	527	229	563
(764)	(530)	(229)	(288)	540	181	577
(738)	(547)	(295)	(250)	550	182	539
(753)	(619)	(240)	(252)	516	247	555
(771)	(634)	(246)	(258)	529	254	569
(791)	(650)	(252)	(318)	596	260	637
(868)	(604)	(263)	(329)	607	201	650
(886)	(614)	(329)	(278)	626	210	612
(851)	(630)	(337)	(285)	642	216	628
(873)	(717)	(279)	(292)	598	287	643
(899)	(741)	(291)	(364)	670	289	656
(978)	(678)	(293)	(368)	691	302	738
(1,002)	(695)	(300)	(378)	708	238	757
(1,027)	(712)	(381)	(323)	726	244	710
(992)	(817)	(321)	(336)	672	319	724

2 Feb	3 Mar	4 Apr	5 May	6 Jun	7 Jul	8 Aug	9 Sep	10 Oct
288	312	320	312	304	328	312	320	312
296	328	304	312	320	312	328	304	312
288	328	304	328	304	312	328	304	312
288	312	304	328	304	312	328	304	328
288	312	304	328	304	328	312	304	328
296	312	320	312	304	328	312	320	312
288	328	304	312	320	312	312	320	312
288	328	304	312	320	312	328	304	312
288	328	304	328	304	312	328	304	312
296	312	304	328	304	328	312	304	328
288	312	320	312	304	328	312	304	328
288	312	320	312	304	328	312	320	312
288	328	304	312	320	312	312	320	312
296	328	304	328	304	312	328	304	312
288	312	304	328	304	312	328	304	328
288	312	304	328	304	328	312	304	328
288	312	320	312	304	328	312	304	328
296	328	304	312	320	312	312	320	312
288	328	304	312	320	312	328	304	312
288	328	304	328	304	312	328	304	312
288	312	304	328	304	312	328	304	328
296	312	320	312	304	328	312	304	328
288	312	320	312	304	328	312	320	312
288	328	304	312	320	312	312	320	312
288	328	304	312	320	312	328	304	312
296	312	304	328	304	312	328	304	328
288	312	304	328	304	328	312	304	328
288	312	320	312	304	328	312	304	328
288	312	320	312	304	328	312	320	312
296	328	304	312	320	312	328	304	312

(3,685)	(1,232)	(2,958)	157	2,087	3,173	1,456	(2,033)	(2,401)
(3,959)	(1,806)	(2,319)	189	1,512	3,814	882	(1,393)	(2,368)
(3,685)	(1,840)	(2,350)	(451)	2,087	3,782	848	(1,425)	(2,401)
(3,685)	(1,232)	(2,350)	(451)	2,087	3,782	848	(1,425)	(3,009)
(3,685)	(1,232)	(2,350)	(451)	2,087	3,173	1,456	(1,425)	(3,009)
(3,959)	(1,199)	(2,925)	189	2,119	3,208	1,489	(2,000)	(2,368)
(3,685)	(1,840)	(2,350)	157	1,479	3,782	1,456	(2,033)	(2,401)
(3,685)	(1,840)	(2,350)	157	1,479	3,782	848	(1,425)	(2,401)
(3,685)	(1,840)	(2,350)	(451)	2,087	3,782	848	(1,425)	(2,401)
(3,959)	(1,199)	(2,319)	(417)	2,119	3,208	1,489	(1,393)	(2,975)
(3,685)	(1,232)	(2,958)	157	2,087	3,173	1,456	(1,425)	(3,009)
(3,685)	(1,232)	(2,958)	157	2,087	3,173	1,456	(2,033)	(2,401)
(3,685)	(1,840)	(2,350)	157	1,479	3,782	1,456	(2,033)	(2,401)
(3,959)	(1,806)	(2,319)	(417)	2,119	3,814	882	(1,393)	(2,368)

(3,685)	(1,232)	(2,350)	(451)	2,087	3,782	848	(1,425)	(3,009)
(3,685)	(1,232)	(2,350)	(451)	2,087	3,173	1,456	(1,425)	(3,009)
(3,685)	(1,232)	(2,958)	157	2,087	3,173	1,456	(1,425)	(3,009)
(3,959)	(1,806)	(2,319)	189	1,512	3,814	1,489	(2,000)	(2,368)
(3,685)	(1,840)	(2,350)	157	1,479	3,782	848	(1,425)	(2,401)
(3,685)	(1,840)	(2,350)	(451)	2,087	3,782	848	(1,425)	(2,401)
(3,685)	(1,232)	(2,350)	(451)	2,087	3,782	848	(1,425)	(3,009)
(3,959)	(1,199)	(2,925)	189	2,119	3,208	1,489	(1,393)	(2,975)
(3,685)	(1,232)	(2,958)	157	2,087	3,173	1,456	(2,033)	(2,401)
(3,685)	(1,840)	(2,350)	157	1,479	3,782	1,456	(2,033)	(2,401)
(3,685)	(1,840)	(2,350)	157	1,479	3,782	848	(1,425)	(2,401)
(3,959)	(1,199)	(2,319)	(417)	2,119	3,814	882	(1,393)	(2,975)
(3,685)	(1,232)	(2,350)	(451)	2,087	3,173	1,456	(1,425)	(3,009)
(3,685)	(1,232)	(2,958)	157	2,087	3,173	1,456	(1,425)	(3,009)
(3,685)	(1,232)	(2,958)	157	2,087	3,173	1,456	(2,033)	(2,401)
(3,959)	(1,806)	(2,319)	189	1,512	3,814	882	(1,393)	(2,368)

:ast - Off-peak

52.20	46.17	36.97	25.19	19.27	40.99	40.91	45.36	48.47
52.20	46.41	36.76	25.21	19.61	40.74	41.39	45.04	48.50
52.48	46.63	36.94	25.59	19.37	40.93	41.58	45.25	48.73
52.95	46.83	37.26	25.82	19.54	41.30	41.95	45.65	49.32
53.51	47.33	37.66	26.09	19.75	42.02	41.94	46.13	49.85
54.08	47.87	38.33	26.12	19.98	42.49	42.41	47.03	50.25
55.61	49.41	39.14	26.84	20.88	43.38	43.58	48.33	51.63
57.15	50.77	40.22	27.58	21.46	44.57	45.28	49.27	53.06
58.72	52.17	41.33	28.63	21.67	45.80	46.53	50.62	54.52
60.19	53.28	42.39	29.37	22.23	47.30	47.21	51.93	56.11
61.79	54.65	43.76	29.82	22.81	48.52	48.42	53.27	57.56
63.38	56.06	44.89	30.59	23.39	49.77	49.67	55.08	58.85
65.11	57.84	45.82	31.42	24.44	50.78	51.02	56.58	60.45
66.82	59.41	47.06	32.61	24.68	52.15	52.98	57.65	62.08
68.76	60.82	48.39	33.53	25.38	53.63	54.48	59.28	64.05
70.48	62.34	49.60	34.37	26.02	55.34	55.24	60.76	65.65
72.24	63.90	51.16	34.87	26.67	56.72	56.62	62.28	67.29
74.05	65.50	52.44	35.74	27.33	58.14	58.03	63.84	68.98
75.90	67.13	53.75	36.63	28.02	59.59	59.48	65.43	70.70
77.80	68.81	55.10	37.55	28.72	61.08	60.97	67.07	72.47
79.74	70.53	56.48	38.49	29.43	62.61	62.49	68.75	74.28
81.74	72.30	57.89	39.45	30.17	64.18	64.06	70.46	76.14
83.78	74.10	59.34	40.43	30.92	65.78	65.66	72.23	78.04
85.87	75.96	60.82	41.45	31.70	67.43	67.30	74.03	79.99
88.02	77.85	62.34	42.48	32.49	69.11	68.98	75.88	81.99
90.22	79.80	63.90	43.54	33.30	70.84	70.71	77.78	84.04
92.48	81.80	65.50	44.63	34.13	72.61	72.47	79.72	86.14
94.79	83.84	67.13	45.75	34.99	74.43	74.29	81.72	88.30
97.16	85.94	68.81	46.89	35.86	76.29	76.14	83.76	90.50
99.59	88.09	70.53	48.06	36.76	78.19	78.05	85.85	92.77

192	57	109	(4)	(40)	(130)	(60)	92	116
207	84	85	(5)	(30)	(155)	(37)	63	115
193	86	87	12	(40)	(155)	(35)	64	117
195	58	88	12	(41)	(156)	(36)	65	148
197	58	89	12	(41)	(133)	(61)	66	150

214	57	112	(5)	(42)	(136)	(63)	94	119
205	91	92	(4)	(31)	(164)	(63)	98	124
211	93	95	(4)	(32)	(169)	(38)	70	127
216	96	97	13	(45)	(173)	(39)	72	131
238	64	98	12	(47)	(152)	(70)	72	167
228	67	129	(5)	(48)	(154)	(71)	76	173
234	69	133	(5)	(49)	(158)	(72)	112	141
240	106	108	(5)	(36)	(192)	(74)	115	145
265	107	109	14	(52)	(199)	(47)	80	147
253	75	114	15	(53)	(203)	(46)	84	193
260	77	117	16	(54)	(176)	(80)	87	198
266	79	151	(5)	(56)	(180)	(82)	89	202
293	118	122	(7)	(41)	(222)	(86)	128	163
280	124	126	(6)	(41)	(225)	(50)	93	170
287	127	129	17	(60)	(231)	(52)	96	174
294	87	133	17	(61)	(237)	(53)	98	224
324	87	169	(7)	(64)	(206)	(95)	98	227
309	91	176	(6)	(65)	(209)	(96)	147	187
316	140	143	(7)	(47)	(255)	(98)	150	192
324	143	147	(7)	(48)	(261)	(58)	108	197
357	96	148	18	(71)	(270)	(62)	108	250
341	101	154	20	(71)	(230)	(106)	114	259
349	103	199	(7)	(73)	(236)	(108)	116	266
358	106	204	(7)	(75)	(242)	(111)	170	217
394	159	164	(9)	(56)	(298)	(69)	120	220

11 Nov	12 Dec	Total Hou	1 Jan	2 Feb	3 Mar	4 Apr	5 May
304	328		744	672	744	720	744
320	312		744	696	744	720	744
320	312		744	672	744	720	744
304	312		744	672	744	720	744
304	312		744	672	744	720	744
304	328		744	696	744	720	744
304	328		744	672	744	720	744
320	312		744	672	744	720	744
320	312		744	672	744	720	744
304	312		744	696	744	720	744
304	328		744	672	744	720	744
304	328		744	672	744	720	744
304	328		744	672	744	720	744
320	312		744	696	744	720	744
304	312		744	672	744	720	744
304	312		744	672	744	720	744
304	328		744	672	744	720	744
304	328		744	696	744	720	744
320	312		744	672	744	720	744
320	312		744	672	744	720	744
304	312		744	672	744	720	744
304	328		744	696	744	720	744
304	328		744	672	744	720	744
304	328		744	672	744	720	744
320	312		744	672	744	720	744
304	312		744	696	744	720	744
304	312		744	672	744	720	744
304	328		744	672	744	720	744
304	328		744	672	744	720	744
320	312		744	696	744	720	744

(7,284)	(5,671)
(7,859)	(5,030)
(7,893)	(5,063)
(7,284)	(5,063)
(7,284)	(5,063)
(7,253)	(5,637)
(7,284)	(5,671)
(7,893)	(5,063)
(7,893)	(5,063)
(7,253)	(5,030)
(7,284)	(5,671)
(7,284)	(5,671)
(7,284)	(5,671)
(7,859)	(5,030)

(7,284)	(5,063)
(7,284)	(5,063)
(7,284)	(5,671)
(7,253)	(5,637)
(7,893)	(5,063)
(7,893)	(5,063)
(7,284)	(5,063)
(7,253)	(5,637)
(7,284)	(5,671)
(7,284)	(5,671)
(7,893)	(5,063)
(7,253)	(5,030)
(7,284)	(5,063)
(7,284)	(5,671)
(7,284)	(5,671)
(7,859)	(5,030)

51.41	52.97
51.58	52.79
51.82	53.03
52.15	53.50
52.70	54.07
53.30	54.91
54.77	56.43
56.42	57.74
57.98	59.34
59.32	60.87
60.85	62.69
62.42	64.31
64.12	66.06
66.02	67.57
67.72	69.48
69.41	71.22
71.14	73.30
72.92	75.13
74.75	77.01
76.62	78.94
78.53	80.91
80.49	82.93
82.51	85.01
84.57	87.13
86.68	89.31
88.85	91.54
91.07	93.83
93.35	96.18
95.68	98.58
98.07	101.05

		Total
374	300	138
405	266	131
409	268	134
380	271	136
384	274	146

387	310	147
399	320	138
445	292	135
458	300	150
430	306	174
443	356	169
455	365	168
467	375	161
519	340	181
493	352	176
506	361	193
518	416	197
529	424	205
590	390	195
605	400	208
572	410	212
584	467	235
601	482	227
616	494	224
684	452	226
644	460	265
663	475	260
680	545	258
697	559	264
771	508	271

6	7	8	9	10	11	12	
Jun	Jul	Aug	Sep	Oct	Nov	Dec	
720	744	744	720	744	720	744	8760
720	744	744	720	744	720	744	8784
720	744	744	720	744	720	744	8760
720	744	744	720	744	720	744	8760
720	744	744	720	744	720	744	8760
720	744	744	720	744	720	744	8784
720	744	744	720	744	720	744	8760
720	744	744	720	744	720	744	8760
720	744	744	720	744	720	744	8760
720	744	744	720	744	720	744	8784
720	744	744	720	744	720	744	8760
720	744	744	720	744	720	744	8760
720	744	744	720	744	720	744	8760
720	744	744	720	744	720	744	8784
720	744	744	720	744	720	744	8760
720	744	744	720	744	720	744	8760
720	744	744	720	744	720	744	8760
720	744	744	720	744	720	744	8784
720	744	744	720	744	720	744	8760
720	744	744	720	744	720	744	8760
720	744	744	720	744	720	744	8760
720	744	744	720	744	720	744	8784
720	744	744	720	744	720	744	8760
720	744	744	720	744	720	744	8760
720	744	744	720	744	720	744	8760
720	744	744	720	744	720	744	8784
720	744	744	720	744	720	744	8760
720	744	744	720	744	720	744	8760
720	744	744	720	744	720	744	8760
720	744	744	720	744	720	744	8784

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 188

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC	)
COMPANY	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT ICNU/106

SERVICE SCHEDULE MSS-4

June 20, 2007

SERVICE SCHEDULE MSS-4

UNIT POWER PURCHASE

40.01 Purpose

The purpose of this Service Schedule is to provide the basis for making a unit power purchase between Companies and/or the sale of power purchased by another Company, unless an alternative basis is agreed to by the parties subject to the approval of the Commission and the regulatory agencies of the purchasing and selling Companies under otherwise applicable law and which provides a lower monthly capacity charge than the charge determined pursuant to Section 40.06 or Section 40.09 of this Service Schedule MSS-4.

40.02 Designated Generating Unit

(a) A Designated Generating Unit shall be any generating unit from which the unit power purchase is made under Section 40.01 that is mutually agreed upon by the purchaser and the seller.

(b) Any Company that makes a Unit Power Purchase of a portion of capability shall be entitled to receive each hour, the same portion of the total energy generated by the Designated Generating Unit. Such energy shall be purchased at the cost of fuel consumed per kWh in accordance with Section 30.08(a) and will be treated in the same manner as any other energy available to the purchasing Company.

40.03 Capability Payment

For the capability purchased in accordance with Section 40.02, the Company making the sale shall receive, from the Company making the purchase, a monthly payment determined in accordance with the method described in Section 40.06 hereinafter.

The monthly capability payment to be received by a Company shall be determined by multiplying the kW of capability sold from its Designated Generating Unit by a charge per kW–month as defined below.

40.04 Investment in Designated Generating Unit (DGURB)

For the purpose of calculating the Monthly Charge under Section 40.06, the investment in the Designated Generating Unit (based on the Federal Energy Regulatory Commission's Uniform System of Accounts prescribed for the Public Utilities and Licensees) shall be:

DGURB = Designated Generating Unit Rate Base

DGURB = DGUPTPLT + DGUCME - DGUDR + DGUFINV - DGUADIT + [(GPLT – GDR + IPLT – IAA) * (DGUL / LXAG)] + [(MS + PP) * (DGUPLT / PLT)]

(a) The cost of the Designated Generating Unit included in FERC Plant Accounts 310 through 346; the cost for step-up transformers, circuit breakers, switching equipment, etc. included in FERC Plant Account 353 which are required to connect the Designated Generating Unit to the transmission system (DGUPTPLT),

(b) Plus Coal Mining Equipment in FERC Plant Account 399 directly associated with the Designated Generating Unit (DGUCME),

(c) Less the Accumulated Provision for Depreciation (consistent with the accounting relating to Statement of Financial Accounting Standards (SFAS) 143 approved by the retail regulator having jurisdiction over the Designated Generating Unit, unless the FERC determines otherwise) associated with items (a) and (b) above, as recorded in FERC Account

108, excluding Nuclear Decommissioning Trust Fund Balances, if applicable (DGUDR),

(d) Plus Fuel Inventory for the Designated Generating Unit, if applicable, in FERC Accounts 151 and 152 (DGUFINV),

(e) Less net Accumulated Deferred Income Taxes recorded in FERC Accounts 190, 281, 282 and 283 and Accumulated Deferred Investment Tax Credit – 3% portion only recorded in FERC Account 255 (DGUADIT) directly associated with the Designated Generating Unit if known; otherwise, an allocation of the plant-related balances in FERC Accounts 190, 281, 282 and 283, as reduced by amounts not generally and properly includable for FERC cost of service purposes, including, but not limited to, SFAS 109 ADIT amounts and ADIT amounts arising from retail ratemaking decisions, and Accumulated Deferred Investment Tax Credit – 3% portion only recorded in FERC Account 255 based on the proportion of gross Plant in Service for the Designated Generating Unit (DGUPLT), where DGUPLT is the sum of the investment pursuant to Section 40.04 (a) above plus the calculated General and Intangible plant pursuant to Sections 40.04 (f) and (h) below, to the Company's total gross Plant in Service (PLT), where PLT is the sum of Production, Transmission, Distribution, General and Intangible Plant in Service,

(f) Plus an allocation of General Plant recorded in FERC Plant Accounts 389 through 398 (GPLT) based on the proportion of labor for the Designated Generating Unit (DGUL) to the Company's total Labor charged to O&M Expense excluding Administrative and General ("A&G") Labor (LXAG),

(g) Less an allocation of Accumulated Provision for Depreciation (consistent with the accounting relating to SFAS 143 approved by the retail regulator having jurisdiction over the Designated Generating Unit, unless the FERC determines otherwise) associated with item (f) above as recorded in FERC

Account 108 (GDR) based on the proportion of labor for the Designated Generating Unit (DGUL) to the Company’s total Labor charged to O&M Expense excluding A&G Labor (LXAG),

(h) Plus an allocation of Miscellaneous Intangible Plant recorded in FERC Plant Account 303 (IPLT) based on the proportion of labor for the Designated Generating Unit (DGUL) to the Company's total Labor charged to O&M Expense excluding A&G Labor (LXAG),

(i) Less an allocation of Accumulated Provision for Amortization associated with item (h) above recorded in FERC Account 111 (IAA) based on the proportion of labor for the Designated Generating Unit (DGUL) to the Company's total Labor charged to O&M Expense excluding A&G Labor (LXAG),

(j) Plus an allocation of Materials & Supplies and Stores Expense Undistributed recorded in FERC Accounts 154 and 163, respectively, (MS) based on the proportion of Plant in Service for the Designated Generating Unit (DGUPLT) to the Company’s total Plant in Service (PLT), and

(k) Plus an allocation of Prepayments recorded in FERC Account 165 (PP) based on the proportion of Plant in Service for the Designated Generating Unit (DGUPLT) to the Company’s total Plant in Service (PLT).

The Investment in the Designated Generating Unit (Designated Generating Unit Rate Base) shall be based on the actual balances on the seller’s books as of the end of the month immediately preceding the service month.

If the Designated Generating Unit is one of a multi-unit station, its costs shall include an allocation of the amounts in the above plant accounts, which are allocable to all the generating units in the station, such allocation to be in the ratio of the capability of the Designated Generating Unit to the total capability of all generating units installed in the station for the service month.

40.05 Expenses associated with Designated Generating Unit (OXP)

For the purpose of calculating the Monthly Charge under Section 40.06, expenses associated with Designated Generating Unit shall be the following:

OXP = Operating Expense
OXP = DGUPOM + [SEOM * (DGUSEPLT / SEPLT)] + DGUDE + DGUI + DGUPT + DGUAG + [(GDX + OT + INDX) * (DGUL / LXAG)] + [FT * (DGUPLT / PLT)]

(a) The Designated Generating Unit Production Operation and Maintenance Expense ("O&M") Expense, included in FERC Accounts 500 through 554 excluding fuel in Accounts 501, 518 and 547 (DGUPOM),

(b) Plus an allocation of O&M associated with Designated Generating Unit step-up transformers and related transmission investment recorded in FERC Accounts 562 and 570 (SEOM) based on the proportion of the Designated Generating Unit Step-up Transformer Plant recorded in Plant Account 353 (DGUSEPLT) to the Company's total Transformer Station Equipment Plant recorded in Plant Account 353 (SEPLT),

(c) Plus any Depreciation Expense associated with the plant investment in Designated Generating Unit referred to in Section 40.04 items (a) and (b) (as recorded in Account 403) and Decommissioning Expense, as approved by Retail Regulators, directly assigned to the Designated Generating Unit, if applicable (DGUDE) unless the jurisdiction for determining the depreciation and/or decommissioning rate is vested in the FERC under otherwise applicable law,

(d) Plus Property Insurance Expense recorded in FERC Account 924 directly assigned to the Designated Generating Unit (DGUI),

(e) Plus Ad Valorem Taxes recorded in FERC Account 408 directly assigned to the Designated Generating Unit (DGUPT),

(f) Plus A&G Expense (DGUAG) directly associated with a nuclear-fueled Designated Generating Unit recorded in FERC Accounts 920 through 935, excluding property insurance in Account 924; otherwise, an allocation of A&G Expense recorded in FERC Accounts 920 through 935 excluding property insurance in Account 924 based on the proportion of labor for the Designated Generating Unit (DGUL) to the Company's total labor charged to O&M Expense excluding EOI and A&G labor,

(g) Plus an allocation of General Plant Depreciation Expense recorded in FERC Account 403 (GDX) based on the proportion of labor for the Designated Generating Unit (DGUL) to the Company's total Labor charged to O&M Expense excluding A&G Labor (LXAG),

(h) Plus an allocation of Payroll Taxes recorded in FERC Account 408 (OT) based on the proportion of labor for the Designated Generating Unit (DGUL) to the Company's total Labor charged to O&M Expense excluding A&G Labor (LXAG),

(i) Plus an allocation of Miscellaneous Intangible Plant Amortization Expense recorded in FERC Account 404 (INDX) based on the proportion of labor for the Designated Generating Unit (DGUL) to the Company's total Labor charged to O&M Expense excluding A&G Labor (LXAG), and

(j) Plus an allocation of Corporate Franchise Taxes recorded in FERC Account 408 (FT) based on the proportion of Plant in Service for the Designated Generating Unit (DGUPLT) to the Company's total Plant in Service (PLT).

The expenses shall be based on transactions recorded on the seller's books for the service month.

If the Designated Generating Unit is one of a multi-unit station, expenses relating to the common plant shall be allocated to the Designated Generating Units in the station based on the ratio of the capability of the Designated Generating Unit to the total capability of all generating units installed in the station for the service month.

40.06 Determination of Monthly Capacity Charge

For the purpose of calculating the Monthly Capacity Charge (MC) per kW for billings under Capability Payment for each unit, the following formula shall be followed:

MONTHLY CAPACITY CHARGE

MC = Monthly Capacity Charge ($/kW-Month)

MC = [DGURB * ((CM + F)/12) + OXP - ITC/(1-T)] / CP

Where:

DGURB = Designated Generating Unit Rate Base per Section 40.04

CM = The weighted average cost of capital consistent with the procedures used by each Operating Company to calculate its AFUDC rate, determined as follows:

CM = (DR * i) + (PR * p) + (ER * c), where

DR = Ratio of Debt Capital and Preferred Stock with tax deductible dividends (QUIPS) at the last day of the month immediately preceding the current service month
PR = Ratio of Preferred Stock without tax deductible dividends at the last day of the month immediately preceding the current service month
ER = Ratio of Common Stock at the last day of the month immediately preceding the current service month
i = Average embedded cost of debt capital outstanding at the last day of the month immediately preceding the current service month
p = Average embedded cost of preferred stock outstanding at the last day of the month immediately preceding the current service month
c = Return on common equity at 11.0%
F = Federal and State Income Tax as determined from the following:
F = T /(1 - T)* (CM – DR * i)

Where:

T = f + s – fs when federal tax is not deductible in computing state tax, and
T = (f + s – 2fs) / (1-fs) when federal tax is deductible in computing state tax, and
f = Federal Income Tax Rate
s = State Income Tax Rate

OXP = Operating Expense per Section 40.05
ITC = ITC Amortization recorded in FERC Account 411 directly associated with the Designated Generating Unit if known; otherwise, an allocation of ITC Amortization recorded in FERC Account 411 based on a gross plant-related balance ratio
CP = Capability for the Designated Generating Unit as defined in Section 2.14 of the Entergy System Agreement for the service month

General Notes:

(a) Labor ratios shall be determined based on the sum of the payroll expenses for the owner of the DGU, including those payroll expenses billed to it by EOI and ESI, for the service month.

(b) Plant ratios shall be determined based on plant in service balances as of the end of the month immediately preceding the service month.

40.07 Adjustment for Tax Changes

The Capability Payment as determined above shall be adjusted to reflect the imposition of any applicable new taxes not included in the above formula or for any increase or decrease in taxes included as of the date of this Agreement.

40.08 Billings Procedure

Bills for services rendered under Section 40.06 shall be issued within 45 days following the end of the service month and shall be payable within 10 days of receipt. Five days after such bill is due, interest shall accrue on any balance due at the rate as determined in Section 35.19a(2)iii of the FERC Regulations. The billing provisions under Section 4.14 of the Entergy System Agreement shall not apply to billings under Section 40.06 of this Service Schedule MSS-4.

40.09 Designated Power Purchase

(a) A Designated Power Purchase shall be any portion of a power purchase contract the sale and purchase of which is made pursuant to Section 40.01 hereof, which is mutually agreed upon by the purchaser and the seller. Any resale of a power purchase from the Grand Gulf nuclear unit pursuant to Section 40.09 shall be subject to the approval of the Commission and the regulatory agency of the purchasing company.

(b) Any Company that makes a Designated Power Purchase of a portion of the capability of the power purchase contract from which the sale and purchase is made shall be entitled to receive each hour, the same portion of the total energy purchased pursuant to the Designated Power Purchase subject to review by the FERC.

Issued by: Kimberly Despeaux, Associate General Counsel
Effective: November 21, 2006

Issued on: September 22, 2006

Filed to comply with orders of the Federal Energy Regulatory Commission, Docket No. EC05-112-000, issued September 13, 2005, 112 FERC ¶ 62,209 and Docket No. ER06-559-000, issued March 9, 2006 (unpublished letter order).

(c) Sales to one Company of power purchased by another Company shall be priced at the delivered cost of said purchase incurred by the selling Company as recorded in FERC Accounts 555 and 565, excluding all timing effects on such costs due to retail ratemaking decisions on a monthly basis, and shall be billed pursuant to Section 4.14 of the Entergy System Agreement subject to review by the FERC.

This Service Schedule MSS-4 shall be attached to and become a part of the Agreement dated the 23rd day of April, 1982 and shall be effective with said Agreement or at such later date as may be fixed by any requisite regulatory approval or acceptance for filing.

Attest — ARKANSAS POWER & LIGHT COMPANY

Original signed by R. J. Estrada Assistant Secretary	Original signed by Jerry Maulden President

Attest — LOUISIANA POWER & LIGHT COMPANY

Original signed by W. H. Talbot Secretary	Original signed by J. M. Wyatt President

Attest — MISSISSIPPI POWER & LIGHT COMPANY

Original signed by R. J. Estrada Assistant Secretary	Original signed by D. C. Lutken President

Attest — NEW ORLEANS PUBLIC SERVICE INC.

Original signed by William C. Nelson Secretary	Original signed by James M. Cain President

Issued by: Kimberly Despeaux
Associate General Counsel

Effective: November 21, 2006

Issued on: September 22, 2006

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