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December 9, 2005

Via Electronic 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 Staff's Investigation Related to Electric Utility Purchases from Qualifying Facilities.
Docket No. UM 1129

Dear Filing Center:

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

Please return one file-stamped copy of the document in the self-addressed, stamped envelope provided. Thank you for your assistance.

Sincerely yours,

/s/ Christian Griffen
Christian W. Griffen

Enclosures
cc: Service List

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1129

In the Matter of the	)
	)
PUBLIC UTILITY COMMISSION OF OREGON	)
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Staff's Investigation Related to Electric Utility Purchases from Qualifying Facilities.	)
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DIRECT TESTIMONY OF

RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

December 9, 2005

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8351 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/201 describes my education and experience within the utility industry. I have more than 25 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, West Virginia, and Wyoming. Included in Exhibit ICNU/201 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 FILED TESTIMONY IN ANY OREGON PUBLIC UTILITY COMMISSION PROCEEDINGS?

A. Yes. I have filed testimony in seven PacifiCorp proceedings in Oregon: UE 111 in 2000, UE 116 in 2001, UE 134 in 2002 and 2003, UM 995 in 2002, UM 1050 in 2004, and UE 170 and UE 173 in 2005. In those cases, I addressed issues related to power cost modeling, power cost deferrals, prudence of new resources, multi-state jurisdictional allocation and a Power Cost Adjustment Mechanism ("PCAM"). I also filed testimony in six Portland General Electric Company ("PGE") cases: UE 137 and UE 139 in 2002, UE 149 in 2003, UE 161 in 2004, and UE 165/UM 1187 and UE 172 in 2005. In those cases I addressed PGE's Resource Valuation Mechanism ("RVM"), PGE's request for a PCAM, and PGE's proposed Hydro Generation Adjustment ("HGA") tariff.

II. INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. I address PacifiCorp's compliance filing. Specifically, I discuss issues related to PacifiCorp's proposed avoided costs tariffs and the calculation of the deficiency/sufficiency period.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My recommendations are as follows:

1. PacifiCorp's deficiency/sufficiency calculation is overly complex, and does not reflect the methodologies employed by the Company in its Integrated Resource Plan ("IRP"). The calculation should only consider the annual summer peak, not average energy or the winter peak. The decision to add capacity in the IRP is driven by meeting the annual peak. Based on the summer peak demand, PacifiCorp is deficient in 2005 and beyond. Consequently, prices in Schedule 37 should be based on the cost of a combined cycle plant starting in 2005.

2. I propose that PacifiCorp's gas-indexed pricing option for Schedule 37 be modified to include an indexed price during the sufficiency period. I propose to specify a Non-Index Cost ("NIC") representing capacity and market based heat rates applied to the actual Opal gas index prices to determine the avoided cost payment rate for Qualifying Facilities ("QFs") that opt for the gas-index options. This approach provides a gas indexed rate and identifies the market value of capacity during the sufficiency period, in accordance with Commission Order No. 05-584.

3. I present exhibits that detail the specific cost components of PacifiCorp's avoided costs. This information is necessary for large QFs that are required to negotiate specific QF contracts with the utilities.

Sufficiency/Deficiency Period

Q. EXPLAIN HOW PACIFICORP DETERMINES WHETHER IT IS IN A RESOURCE SUFFICIENT OR RESOURCE DEFICIENT PERIOD.

A. Exhibit ICNU/202 is a copy of PacifiCorp's load and resource balance calculation. In this analysis, the Company compares available resources to load requirements for average megawatts (i.e., energy), and during the winter and summer peak period. If the Company is sufficient (i.e., if resources exceed loads) for two of the three periods, then the Company considers itself resource sufficient. Currently, the Company's calculation shows that it is deficient for the summer peak, but sufficient for the winter peak and for energy. Consequently, the Company does not consider itself deficient until 2010. For this reason, the Company proposes to offer only the fixed "market based" rates until the end of 2009. In 2010, the Company proposes to begin paying QFs avoided costs based on the proxy cost of a new combined cycle plant.

Q. WHAT IS THE BASIS FOR THESE CALCULATIONS?

A. The loads and resource data is taken from PacifiCorp's GRID model runs used to develop avoided costs. For the summer peak, for example, the Company computes available resources based on GRID model simulations of capacity available at the time of the summer peak. The Company also includes requirements for long-term and short-term purchases and sales and for operating reserves in these calculations.

For average energy, the model determines whether a surplus or deficit exists based on comparison of the annual energy requirement to the GRID simulation of energy production for its various resources.

Q. IS THIS A REASONABLE METHOD FOR DETERMINING THE LOAD AND RESOURCE BALANCE OF THE COMPANY?

A. This approach bears little resemblance to standard industry practice, is inconsistent with the IRP, and differs substantially from the method used by the Company in its last avoided cost determination.

Q. DO THE RESULTS OF THIS APPROACH SEEM REASONABLE?

A. No. At a very high level, it seems counter intuitive that the Company can be capacity sufficient when its own figures show it is unable to cover the summer peak demand for the next five years. Further, the Company is actively building new capacity, acquiring new resources, engaging in substantial short-term purchases, and has been doing so for some time. This is not the picture of a company that has a five-year surplus of capacity. Rather, these are all indicators of a company that is short on capacity resources.

A major part of the problem is that the Company really considers it irrelevant whether it can meet the summer peak, so long as it can meet the winter peak and annual energy requirements. However, it is generally a fact that a utility that can meet its annual (summer) peak, will also have enough capacity to meet its lesser seasonal (winter) peaks and annual energy requirements.

Generally capacity ratings of units are lower in the summer than in the winter, and seasonal peaks, or average energy requirements, are much lower than annual peak requirements. In effect, PacifiCorp requires a dire capacity shortfall to exist (such that it cannot meet peak demands in the both the summer and winter) before it considers itself "deficient."

Q. WHAT IS STANDARD INDUSTRY PRACTICE?

A. Typically utilities determine capacity adequacy by examination of the annual system peak, ensuring a reasonable provision for reserves. As a general rule, utilities require sufficient capacity to meet the annual peak demand plus a reserve margin of 15%. This is the approach used by PacifiCorp in its IRP, as is shown on Exhibit ICNU/203 at Falkenberg/3.

Q. HOW DOES THIS DIFFER FROM PACIFICORP'S AVOIDED COST APPROACH?

A. Aside from ignoring the summer peak, the Company also uses a non-standard approach to compute reserves and capacity available from its resources. In using the GRID model results for available capacity, the Company is using capacity derated for forced outages, and would even exclude capacity on planned maintenance, should any be expected to occur at that time. The Company adds to that amount of operating reserve and load regulation requirements based on GRID's simulation of North American Electric Reliability Council ("NERC") requirements.

This approach confuses planning reserves with operating reserves. Planning reserve requirements encompass not only the need to cover capacity on outages and operating reserves, but also a component for load forecast uncertainty over a period of years. Operating reserves normally encompass only enough load uncertainty for operations during a typical day, and thus provide a much lower provision for load uncertainty.

Q. ARE THERE ANY OTHER PROBLEMS ASSOCIATED WITH THE COMPANY'S USE OF GRID?

A. Yes. For the average energy calculation, GRID is completely unsuitable. The reason is that GRID simulates the operation of units based on projected market conditions. Gas-fired units do not run fully loaded throughout the year in GRID, so the amount of energy produced by such units may greatly understate the amount of energy potentially available. Ironically, if market prices were projected to drop, the amount of energy available from gas units would decline in GRID. Thus, a drop in market prices could paradoxically result in the appearance of an energy deficiency in the GRID model because balancing energy would be lower in cost than running its own gas units. While I do not believe energy sufficiency is a major issue for the Company, the method used to perform the calculation is highly suspect.[1/]

Q. ARE THERE OTHER PROBLEMS WITH THE PACIFICORP ANALYSIS?

A. The Company also includes short-term firm purchases and sales in the analysis. This is troubling for two reasons. First, the Company has no obligation to make

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1/ For a utility with a more substantial reliance on hydro, or very high load factors, energy sufficiency may be an issue that should be considered. However, PacifiCorp obtains a very small amount of its annual requirements from hydro and does not have high annual load factors.

short-term firm sales. Thus, short-term firm sales do not represent load requirements that the Company has a long-term obligation to plan for. Second, PacifiCorp is constantly changing its short-term firm position. Thus, the forecast of short-term contracts is likely to be very unrealistic and unsuitable for planning purposes.

Q. EARLIER YOU MENTIONED THAT PACIFICORP DID NOT USE THE SAME METHODOLOGY FOR DETERMING ITS SUFFICIENCY OR DEFICIENCY AS WHEN IT SET ITS AVOIDED COSTS IN 2001. HOW DOES THE 2005 METHOD DIFFER FROM THE 2001 METHOD?

A. There are two important differences. First, PacifiCorp used a 12% planning reserve margin, rather than its operating reserve and regulation requirements in its 2001 calculation. Second, the Company did not include short-term firm purchases or sales in 2001.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission determine that based on the summer peak, PacifiCorp is not resource sufficient in 2005, and as a result, use proxy pricing based on the avoided Combined Cycle Combustion Turbine instead of the fixed price option. Note that if the Commission adopts this proposal it would moot ICNU's proposal related to gas market pricing during the sufficiency period, discussed above. Should the Commission adopt a later deficiency date, the gas market pricing option discussed earlier should be implemented during the sufficiency period.

Gas Index Pricing

Q. DID THE COMMISSION REQUIRE UTILITIES TO OFFER A GAS INDEXED RATE IN ORDER NO. 05-584?

A. Yes. The Commission stated as follows:

> All three electric utilities shall offer the same three pricing options, as follows: (1) the Fixed Price Method; (2) the Deadband Method; and (3) the Gas Market Method. We adopt each of these methodologies, as defined by Staff. We delegate implementation decisions to each utility but direct each utility to work with Staff, as appropriate, to develop implementation tariffs and standard contract rates, terms and conditions.

Re Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities, OPUC Docket No. UM 1129, Order No. 05-584 at 34-35 (May 13, 2005) ("Order No. 05-584").

Q. HAS PACIFICORP OFFERED THE GAS MARKET METHOD AND DEADBAND PRICING OPTIONS IN SCHEDULE 37?

A. Yes. PacifiCorp has offered both options. However, these rate options are not indexed to gas prices during the sufficiency period (2005 to 2009). Consequently, QFs have only the fixed price option for the first five years. ICNU believes it would be appropriate to also offer the gas market indexed rates during the sufficiency period.

Q. DID STAFF DEFINE THE GAS MARKET INDEX PRICING METHODS TO APPLY ONLY DURING THE DEFICIENCY PERIOD?

A. That is not obvious from the Staff testimony filed in Phase 1. In reviewing the testimony of Staff witness Steve Chriss earlier in this proceeding, I did not find any discussion indicating that the gas indexed option should apply *only* during the deficiency period. Thus, Staff's intentions on this matter in Phase I were not completely clear from the filed testimony. Consequently, I believe the Commission should decide this issue in this phase of the proceeding. Based on the above-quoted passage, it is clear that the Commission's intention was to provide QFs gas market pricing options. If the rates are only indexed to gas during the deficiency period, then PacifiCorp's rates approved by the Commission in this proceeding may not have an effective gas index pricing option for five years.

Q. ARE THERE OTHER REASONS WHY THE COMMISSION SHOULD ADDRESS THIS ISSUE?

A. Yes. The Commission left two issues open for further review in this phase of the proceeding. First, the Commission invited parties to further elucidate the issue of the market value of capacity during the sufficiency period.[2/] Second, the Commission encouraged the parties to develop a market indexed pricing option for PacifiCorp.[3/] Both of these areas of inquiry can be further developed through proper development of a gas indexed rate. Finally, the Commission directed that the details of the gas-indexed rate would be a subject for this phase of the proceeding.

Q. EXPLAIN HOW THE GAS MARKET INDEX ISSUE IS TIED TO THE ISSUE OF THE MARKET VALUE OF CAPACITY.

A. The wholesale market price for power is largely determined by two factors: the underlying market value of capacity and the price of natural gas. This occurs because natural gas is frequently the marginal fuel during the High Load Hour ("HLH") period. Thus, variations in gas prices will naturally result in increases in wholesale power prices. Further, the market places a premium upon capacity as it becomes deficit, increasing its cost over the value of marginal gas-fired

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[2/] "To the extent that a party can provide evidence regarding the market pricing of capacity, however, we remain open to reconsideration of this decision in the next phase of this proceeding." Order No. 05-584 at 28.

[3/] "We direct PacifiCorp, however, to work with Staff to evaluate whether it would be appropriate to develop an indexed pricing option and encourage either Staff or PacifiCorp to offer an indexed pricing option for PacifiCorp in the second phase of this proceeding." Id. at 35.

generation in the market. Conversely, if capacity is surplus, then the marginal cost of generation will track gas prices more closely. When capacity is short, then the cost of power in the market will increase well above the variable cost of marginal gas-fired energy.

Q. DO YOU HAVE ANY EVIDENCE THAT DEMONSTRATES THIS POINT?

A. Yes. Exhibit ICNU/204 presents a graph showing the comparison of market prices for power (HLH) based on PacifiCorp's CG27 forward curve, and the cost of natural gas, translated to cents per kilowatt hour ("kWh") by use of a market heat rate. The heat rate was determined based on the average cost of energy during the Low Load Hour ("LLH"). This was chosen because it is unlikely that LLH power would contain a substantial capacity component.

The chart shows that the market price for HLH power tracks gas prices. The correlation coefficient p=.66. This is substantial and indicates statistically significant correlation of electric prices and the gas market index. However, during the summer peak months (July through September) and during the winter peak months (December through February) a premium over the underlying gas price is present in the HLH power price. During the late spring "fish flush" month (which generally occurs in May and June), hydro generation is maximized, thus resulting in a negative capacity premium. As a result, the difference between monthly HLH power prices and the underlying cost of marginal gas-fired generation can be seen to follow a predictable seasonal pattern that follows the need for capacity in the market place.

Q. HOW DOES DEVELOPMENT OF A GAS MARKET INDEX DURING THE SUFFICIENCY PERIOD FURTHER THE COMMISSION'S GOAL OF DEVELOPING A MARKET INDEXED RATE FOR PACIFICORP?

A. While a gas market index rate is not exactly the same as a wholesale power market index type rate, it would be a means of addressing the same concerns as those that might motivate the Commission to propose a wholesale market index. One problem with fixed price rates is that underlying gas and power prices can move substantially in a very short period of time. Recent experience concerning the hurricanes in the Gulf of Mexico shows that short-term effects can be substantial. Regulators would understandably be reluctant to update forecasts in response to such events. Then again, ignoring such substantial price movements may also result in inequitable and inefficient rates. Thus, a fixed price rate leaves the Commission with the dilemma of when to update rates, and when to leave them alone. Because gas and electric prices generally move in tandem, use of a gas market index rate would provide a means of avoiding the need for updates to avoided costs between the Commission's ordinary two-year cycle when economic conditions change.

Further, a gas price index could give gas-fired QFs a better price signal, as they would have a better sense of their prospects for supplying generation to PacifiCorp, irrespective of the movements in gas prices.

Q. WHAT ARE THE SPECIFICS OF ICNU'S GAS MARKET RATE PROPOSAL?

A. Exhibit ICNU/205 presents the specifics of this proposal. ICNU proposes to develop the Actual Gas Price Used ("AGPU") as the actual gas market index price (Opal) times an annual heat rate, as shown on the table. The Non-Index

Costs ("NIC") is also shown on the table. Over the 5 year sufficiency period, the market heat rate would average 7,849 btu/kWh, while the NIC would average $1.04 cents per kWh.

Q. HOW WERE THE PRICE COMPONENTS DEVELOPED?

A. These price components were developed directly from PacifiCorp's fixed prices during the sufficiency period and the Company CG27 gas price forecast. The LLH market price was assumed to have no capacity component, and was used to calibrate the annual market heat rate. The NIC, computed as the difference between the LLH and HLH fixed prices, can reasonably be assumed to represent the market value of capacity during the sufficiency period. The NIC would only apply to HLH kWhs actually generated. Thus, this pricing method would compensate QFs for generation based on energy provided during the HLH via the NIC, and gas-fired generation during all hours based on the implicit market heat rate. If PacifiCorp's gas price forecast is perfectly realized, the prices developed under this option will equal PacifiCorp's fixed prices for the period 2005 to 2009.

Q. WOULD IT BE POSSIBLE TO DEVELOP A PRICING FORMAT THAT PROVIDED MORE TARGETED PRICE SIGNALS?

A. Certainly, and ICNU would not object to a reasonable refinement of this analysis. However, PacifiCorp's fixed prices are not differentiated by month or season. For that reason I do not further differentiate these rates either. ICNU is willing to explore other options on this issue, so long as a gas market based rate is available during the sufficiency period.

Q. ASIDE FROM REDUCING THE NEED FOR INTERIM UPDATES, ARE THERE OTHER ADVANTAGES TO THIS PROPOSAL?

A. Certainly. A gas market based rate will provide a more equitable result between customers and QFs. It should be fairly clear by now that gas and electric prices are quite volatile. Forecasts can easily become "obsolete" just a few months after they have been prepared. By offering a price that indexes to natural gas, the Commission can be more confident that customers will not be overcharged if gas prices drop, nor will QFs be underpaid if gas prices go up.

Avoided Cost Components

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section I present certain exhibits to document the methodology and assumptions used by PacifiCorp in computing the avoided cost based prices for Schedule 37. This information is important for large QFs that will be required to negotiate specific QF contracts with the Company. The starting point for these negotiations is always the Commission's published tariff. In the past, there has been a lack of clarity concerning the actual assumptions and method used by the Company to compute avoided costs, which has created problems in the negotiations for large QFs. The exhibits I present are intended to address this problem.

Q. DESCRIBE THESE EXHIBITS.

A. Exhibit ICNU/206 presents a series of data request answers (ICNU Set 6, Data Request Nos. 1-4 and 8-15) that document some of PacifiCorp's basic assumptions concerning avoided costs. These responses show how the Company defines the inputs for natural gas and wholesale power prices, points of delivery and other assumptions. Exhibit ICNU/207 documents the assumptions used by the Company in the deficiency period, while Exhibit ICNU/208 provides the same for the sufficiency period.

Q. DO YOU PROPOSE SIMILAR EXHIBITS FOR IDAHO POWER AND PORTLAND GENERAL ELECTRIC COMPANY ("PGE")?

A. No. I did not perform the analysis. However, such information may be necessary for large QFs that wish to enter into QF contracts with Idaho Power or PGE. I recommend that both Idaho Power and PGE file such information in their rebuttal testimony.

Revised Protocol

Q. ICNU AND WEYERHAEUSER RAISED THE ISSUE OF WHETHER PACIFICORP'S AVOIDED COST FILING WAS CONSISTENT WITH THE REVISED PROTOCOL. DOES YOUR TESTIMONY ADDRESS THIS ISSUE?

A. Yes. Under the Revised Protocol, costs associated with payments to QFs that exceed the cost of a comparable market resource are allocated on a situs rather than system basis. Because avoided costs are determined in each state at a different time, there may be a disparity in each state's avoided cost rates. To ensure that these differences are not confused as being due to Oregon paying above avoided costs, the Commission should find that the prices determined in this proceeding are equal to those of a comparable market resource, as defined in the Revised Protocol. As a result, there should be no basis for a situs allocation of QF costs for rates based on Oregon's standard tariff. The Commission's finding should not impact its review of the prudence of any specific resource acquisitions.

Q. PACIFICORP HAS PROPOSED DEFERRING THIS ISSUE UNTIL THE TIME THE COMPANY SEEKS COST RECOVERY. DO YOU THINK IT IS APPROPRIATE TO POSTPONE CONSIDERATION OF THIS ISSUE?

A. No. ICNU continues to believe that it would be more appropriate to address this issue outside of a rate proceeding in which the revenue requirement impacts regarding the cost recovery of the QF resources may guide some parties' positions on this issue. In addition, ICNU believes that all the parties will benefit from an expedited resolution of this issue.

Q. DO YOU HAVE ANYTHING ELSE TO ADD?

A. Yes. My testimony only addresses a limited number of issues. However, silence on any particular issue does not imply ICNU is in agreement with the utility proposals. ICNU may address additional issues in its post-hearing brief or in rebuttal testimony.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

ICNU/201

Randall Falkenberg Qualifications

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

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

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 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

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

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	3498-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear unit cancellation, load and energy forecasting, 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	Georgia Power Co.	Cancellation of nuclear plant.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
			Service Commission Staff		
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	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.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
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 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	Georgia Power Co.	DSM, load forecasting and IRP.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
			Staff		
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 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.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
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, 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

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
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
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

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
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
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

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
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
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

ICNU/202

PacifiCorp's Load and Resource
Balance Calculation

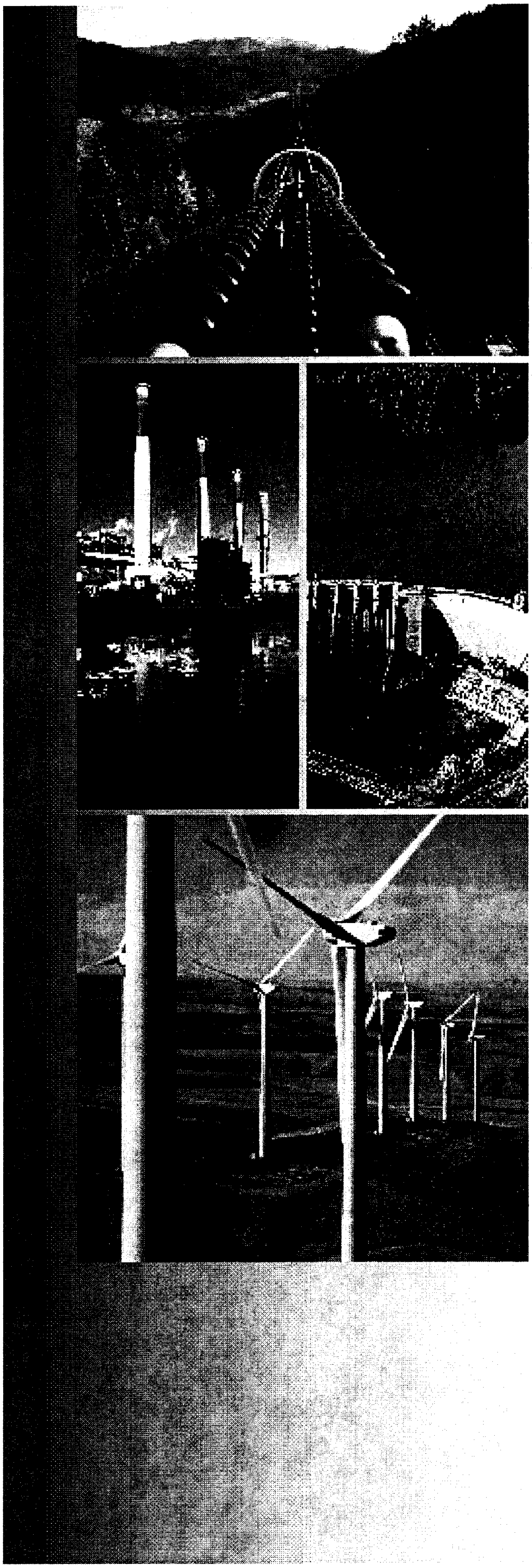
Exhibit ICNU/202
PacifiCorp Load and Resource Balance

Loads and Resources
Calendar Years 2005 through 2010

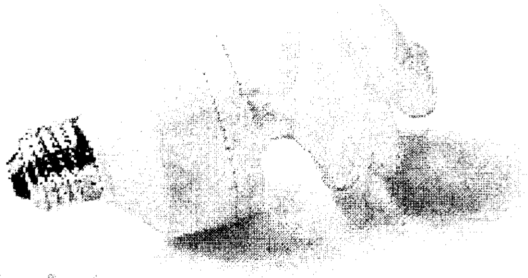
	2005	2006	2007	2008	2009	2010
aMW						
Net Load	6,324	6,509	6,669	6,827	6,991	7,129
Long Term Sales	562	498	359	331	261	226
Short Term Firm Sales	1,536	819	556	37	-	-
Total Requirements	8,422	7,827	7,585	7,195	7,252	7,355
Long Term Purchases	1,483	1,493	1,346	933	923	837
Short Term Firm Purchase	1,066	225	28	-	14	-
Thermal Generation	5,563	5,779	6,003	6,102	6,087	6,008
Other Generation	502	536	541	536	528	526
Reserves	(163)	(136)	(238)	(231)	(233)	(331)
Total Resources after Reserves	8,451	7,898	7,680	7,340	7,319	7,040
Surplus / (Deficit)	29	71	95	146	66	(315)
Percent Surplus / (Deficit)	0.3%	0.9%	1.2%	2.0%	0.9%	-4.3%
Peak (Summer)	August	July	July	July	July	July
Net Load	8,430	8,841	9,094	9,424	9,718	10,072
Long Term Sales	844	839	556	518	409	373
Short Term Firm Sales	969	475	312	37	-	-
Total Requirements	10,244	10,154	9,962	9,979	10,127	10,445
Long Term Purchases	2,089	1,957	1,648	1,473	1,482	1,391
Short Term Firm Purchase	1,025	575	200	-	100	-
Thermal Generation	6,478	6,697	7,193	7,009	7,009	7,009
Other Generation	645	639	639	630	621	616
Reserves	(553)	(577)	(935)	(889)	(889)	(977)
Total Resources after Reserves	9,683	9,290	8,745	8,223	8,323	8,039
Surplus / (Deficit)	(561)	(864)	(1,217)	(1,756)	(1,804)	(2,406)
Percent Surplus / (Deficit)	-5.5%	-8.5%	-12.2%	-17.6%	-17.8%	-23.0%
Peak (December)						
Net Load	7,771	8,027	8,247	8,457	8,651	8,909
Long Term Sales	817	503	500	465	356	320
Short Term Firm Sales	944	1,100	312	37	-	-
Total Requirements	9,532	9,630	9,060	8,960	9,007	9,230
Long Term Purchases	2,516	2,542	2,149	2,370	2,317	2,284
Short Term Firm Purchase	513	300	-	-	-	-
Thermal Generation	6,537	6,768	7,303	7,113	7,113	7,113
Other Generation	880	857	893	885	885	879
Reserves	(523)	(576)	(937)	(895)	(891)	(982)
Total Resources after Reserves	9,923	9,892	9,408	9,473	9,424	9,294
Surplus / (Deficit)	391	261	349	513	416	65
Percent Surplus / (Deficit)	4.1%	2.7%	3.8%	5.7%	4.6%	0.7%

ICNU/203

Excerpt of PacifiCorp's
Integrated Resource Plan



Integrated Resource Plan



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or more in advance. The terms, points of delivery, and products will all vary by individual market point.

The Front Office Transactions used as a Planned Resource in the 2004 IRP are fundamentally different from Structured contracts. Structured contracts tend to be complex, non-standard, highly negotiated agreements tailored to all parties involved. A Structured contract may have a number of pricing components including a "fixed" component, such as a demand or capacity charge, and a variable component, which may vary with index or pricing tier or both. However, this does not preclude a Front Office Transaction from having a complex pricing structure or a Structured contract from having a simple pricing structure. One example of a Structured contract is the TransAlta contract.

As a base planning assumption, 1,200 MW of Front Office Transactions were assumed based on past experience with products and with delivery points. These amounts were modeled as Planned Resources under the criteria described earlier in this chapter, and were incorporated directly into the capacity charts that will be discussed in the next section. As with other Front Office Transactions, absent a Power Cost Adjustment Mechanism, these transactions would be reviewed during the process of a rate case. A more detailed description of these Front Office Transactions can be found in Appendix C.

Qualifying Facilities (QFs)
The Qualifying Facility contracts included as Planned Resources were being negotiated during the IRP analysis. PacifiCorp just recently executed contracts with Kennecott, US Magnesium and Tesoro. The Desert Power contract was included as an Existing Resource. Because the process to acquire these resources was in place at the time of the IRP process, and there was a high level of confidence and consensus that the acquisitions would be successful, they were included as Planned Resources.

The IRP assumed that these resources would deliver approximately 100 MW to northern Utah and would be derived from a combination of new QFs or CHPs (like those described above) that are proposed over the next ten years, and additional QFs procured under the current Utah stipulated cap.

PLANNING MARGIN

Planning margin is the amount of resources above the peak system obligation necessary to reliably meet load. The planning margin is intended to provide sufficient future resources to meet requirements in the event of unplanned outages, meet WECC operating reserve requirements and regulating margin (load following), as well as respond to unanticipated levels of demand growth and weather-related events that vary from normal.

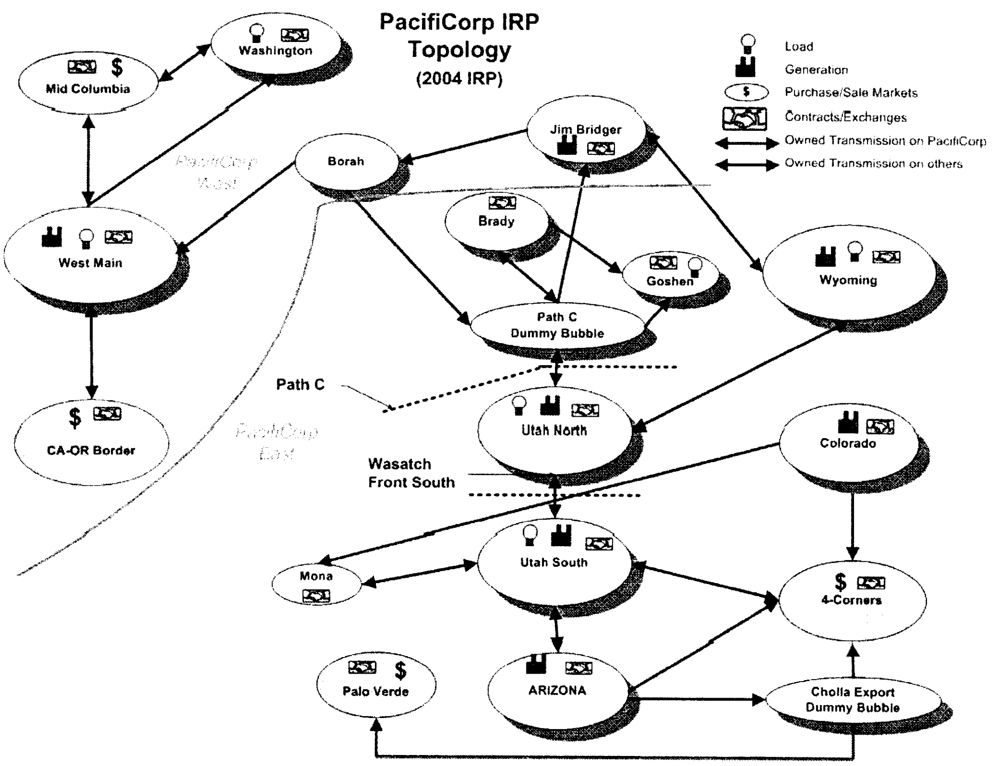
Most Regional Planning Councils across the country have set planning margin and reliability targets. WECC and SERC are the only Councils without either specified resource adequacy criteria or planning reserve margin. The most common resource adequacy criteria are the 1-in-10 year Loss of Load Probability (LOLP) or 1-in-10 Loss of Load Expectation (LOLE), which are seen as industry standard reliability thresholds. Although there are multiple regional efforts underway to define resource adequacy within WECC, utilities must currently plan to meet a level of adequacy specific to their system. PacifiCorp's neighboring utilities have defined their planning margin levels within their IRPs ranging from 12% to 17%.

For the 2004 IRP, PacifiCorp worked with Henwood Energy Services (currently Global Energy Decisions, LLC) to produce a planning margin study for the PacifiCorp system that included an LOLP analysis. The study looked at system reliability over a range of planning margins. Henwood conducted an LOLP analysis in line with the methodology used by several Regional Planning Councils across the country to determine their resource adequacy criteria. The study results showed that an 18% planning reserve margin on the system peak obligation hour provided a 1 in 10 LOLP for the system. Although a 1 in 10 year LOLP is a commonly used reliability standard, the optimum balance between cost of expected unserved energy (EUE) and additional capital investment needed to reduce EUE lies at the 2 in 10 year LOLP or 15% planning margin reserve level for the system. Therefore PacifiCorp concluded that a 15% planning margin level ensured adequate resources will be procured to meet load requirements with a high level of reliability, avoiding physical short exposure to markets, and providing for safe, reliable, low cost energy for the consumer. Refer to Appendix N for details related to the planning margin study.

PACIFICORP SYSTEM TOPOLOGY

The fundamental assumption underlying the load and resource balance is the model topology. Shown in Figure 3.2, this topology was constructed to accurately depict the PacifiCorp system with a moderate level of detail.

Figure 3.2 – PacifiCorp System Topology



for either a build or purchase option. The actual decision to build or buy a particular resource is made during the procurement process.

Timing of Resource Additions

The load and resource balance described in Chapter 3 revealed a resource deficit that requires the addition of large resource blocks in various years of the planning horizon. As indicated in Table 7.1, total system resource additions of approximately 2,800 MW are required in the next ten years (see Chapter 3 and Appendix F for more detailed load and resource balance information).

Table 7.1 – Annual Resource Deficits

Fiscal Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Obligation x PM	11,485	11,701	11,988	11,639	11,916	12,177	12,478	12,650	13,035	13,434
Existing Resources	11,064	11,004	11,163	10,226	10,146	10,126	9,977	9,317	9,315	9,077
Planned Resources	420	710	850	1,340	1,380	1,420	1,560	1,580	1,580	1,580
Deficit	(1)	13	25	(73)	(390)	(631)	(941)	(1,753)	(2,140)	(2,777)

Additions are required on both the eastern and western sides of PacifiCorp's system. The eastern side of the PacifiCorp system requires large resource additions in FY 2009, FY 2011, FY 2014 and FY 2015. The western side of the PacifiCorp system requires a large addition in FY 2013. This pattern of resource addition requirements was the basis for the development of the portfolios discussed in this chapter.

Portfolio Categories

There were numerous portfolios developed to be candidates for the Preferred Portfolio. To explore a broad range of possible resource mixes, candidate portfolios were developed according to the following seven categories:

1. Reference Portfolio
2. Fuel Type Change
3. Technology Change
4. Sequencing of Plants
5. Location Change
6. Storage Technologies
7. Capacity Expansion Model (CEM)

CANDIDATE PORTFOLIOS

The following section discusses each category and the various candidate portfolios in detail. The portfolio names are always preceded with a letter which reflects the chronological order in which the portfolios were developed. All portfolio tables use fiscal years.

Portfolio Category: Reference Portfolio

This category is comprised of one portfolio which is the Reference Portfolio. It serves as the benchmark for the development and evaluation of other portfolios.

This topology consists of 18 bubbles which are designed to describe major load and generation centers, regional transmission congestion impacts, import/export availability, and external market dynamics. Bubbles are linked by firm transmission paths. The development of this topology involved defining the loads associated with each bubble, the existing resources located in each bubble, the characteristics of each resource, and transfer capability of the links between the bubbles.

PacifiCorp's service territory is part of a highly interconnected transmission grid in the WECC and adjoined to multiple external markets. These markets serve both as energy sources and receipts of energy, at differing times, and at market determined prices. PacifiCorp relies on these markets to provide physical balancing. Additionally, interaction with these markets allows for a more accurate reflection of marginal operating costs because plant operations are based on incremental cost decisions. Market activity is a necessary and significant part of our portfolio costs and revenues. In order to model the interaction between the PacifiCorp system and the WECC markets, the topology captures interactions at the following trading points:

- Mid-Columbia (Mid-C)
- California/Oregon Border (COB)
- Four Corners (FC)
- Palo Verde (PV)

Firm transmission rights to the markets serve as PacifiCorp's primary constraint to market size. This is a conservative approach because it does not take into account non-firm transmission or opportunities to make additional sales to, or purchases from, the market.

LOAD AND RESOURCE BALANCE

The difference between the load forecast plus sales and the existing and planned PacifiCorp resources define the shortfall, or gap, in supply. This section presents the load and resource balance for the PacifiCorp system, as well as for each control area.

Capacity Charts

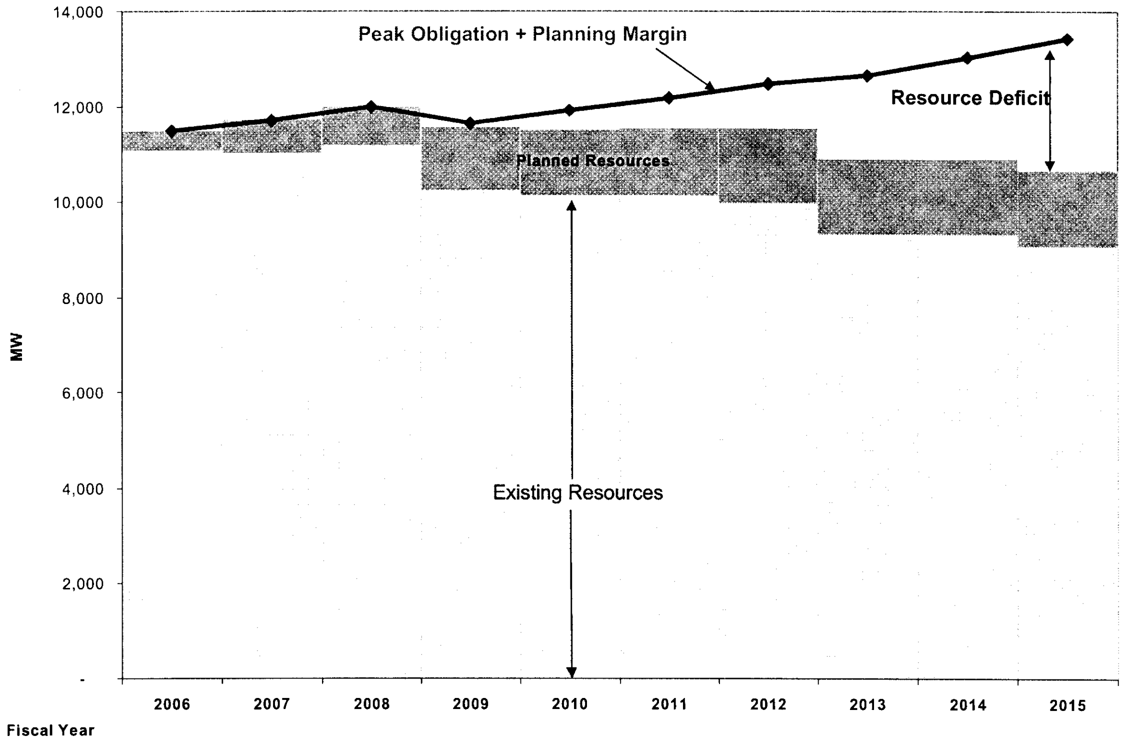
Capacity Charts show the peak obligation (load plus sales) plus the planning margin requirement as compared to the available resources for the peak load hour. They were constructed by determining the system coincident peak hour for each of the first ten years of the planning horizon (FY 2006-2015), and determining the available resources for those hours. Existing resources are computed as follows:

Existing Resources = Thermal + Hydro + Purchases + Interruptible + Class 1 DSM

Thermal and Interruptible resources are measured according to maximum capacity. Hydro, Purchases and Class 1 DSM are measured by model dispatch. The peak obligation is equal to load plus sales. All of the charts assume a coincident peak planning margin of 15%. The Planned Resources which includes RFP wind, Front Office Transactions and some QF contracts are shown above the Existing Resources at the top of each chart. The gap between the peak obligation and PacifiCorp's total available resources is the annual capacity deficit.

Figures 3.3 through 3.5 present the various capacity charts developed for the Load & Resource Balance. In the System and West Capacity Charts there are a few noticeable declines in resources and loads in the 10-year period mostly caused by the expiration of existing contracts. For example in FY 2008 and FY 2012, two large contracts expire – the TransAlta purchase contract and the BPA Peaking Contract, respectively. The expiration of the Clark County Load Service contract causes the drop in capacity and obligation in FY 2009.

Figure 3.3 – System Coincident Peak Capacity Chart



Resources	11,484	11,714	12,013	11,566	11,526	11,546	11,537	10,897	10,895	10,657
Obligation+15%	11,485	11,701	11,988	11,639	11,916	12,177	12,478	12,650	13,035	13,434

ICNU/204

Comparison of Market Gas and
Electric Prices

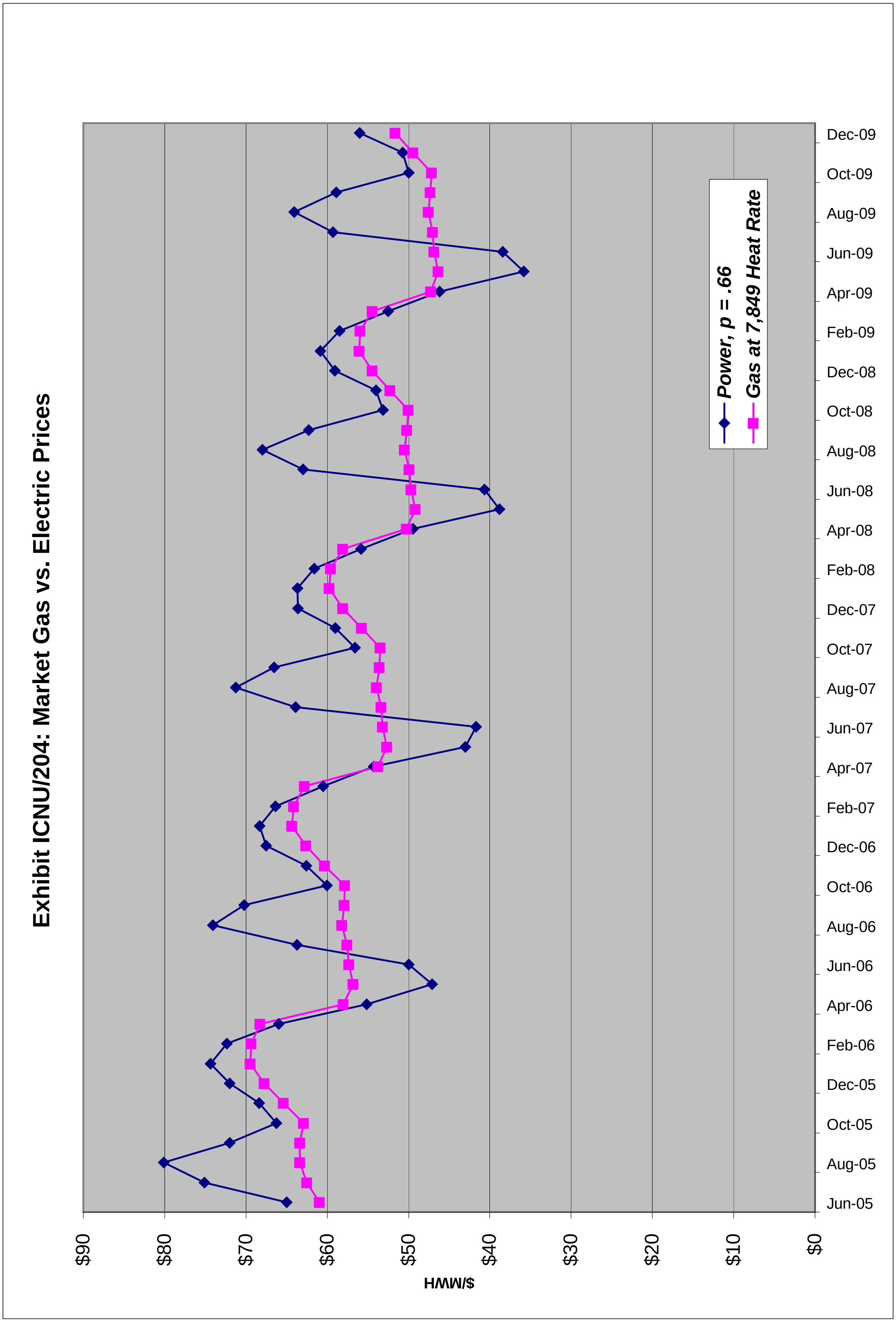


Exhibit ICNU/204: Market Gas vs. Electric Prices
Power, p = .66
Gas at 7,849 Heat Rate
$/MWH
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
Jun-05
Aug-05
Oct-05
Dec-05
Feb-06
Apr-06
Jun-06
Aug-06
Oct-06
Dec-06
Feb-07
Apr-07
Jun-07
Aug-07
Oct-07
Dec-07
Feb-08
Apr-08
Jun-08
Aug-08
Oct-08
Dec-08
Feb-09
Apr-09
Jun-09
Aug-09
Oct-09
Dec-09

ICNU/205

Gas Index Avoided Cost Rate

Exhibit ICNU/205
Gas Index Avoided Cost Rate
Heat Rate in BTU/KWH

	=============$/MWH==========			Opal Index	Heat
Year	HLH	LLH	Capacity (NIC)	$/MMBTU	Rate
2005	71.27	59.81	11.45	7.18	8,326
2006	63.58	52.69	10.89	6.96	7,571
2007	59.59	48.73	10.86	6.38	7,636
2008	55.79	46.34	9.45	5.90	7,853
2009	52.60	43.31	9.29	5.51	7,859
Avg.	60.57	50.18	10.39	6.39	7,849

ICNU/206

Excerpt of PacifiCorp's Response to
ICNU's Sixth Set of Data Requests

ICNU Data Request 6.1

What are the assumed delivery points for power from PacifiCorp's avoided resource during: 1) the sufficiency period; and 2) the deficiency period?

Response to ICNU Data Request 6.1

During the sufficiency period, avoided costs are priced on a system weighted market price. The price is weighted based on expected transactions at COB, Palo Verde and Mid-C from a GRID run, with points of delivery into PacifiCorp's system established accordingly.

During the deficiency period, the avoided resource is a Brownfield CCCT (Dry Cooling 2x1) with Duct Firing located near Mona, Utah, with Mona serving as the point of delivery into the Company's system. The resource is a system resource and could be delivered across the Company's system subject to transmission constraints.

UM-1129/PacifiCorp
November 21, 2005
ICNU 6th Set Data Request 6.2

ICNU Data Request 6.2

Please specify the geographic point(s) and voltage level(s) on PacifiCorp's transmission/distribution system at which the avoided resources are assumed to be delivered.

Response to ICNU Data Request 6.2

Please see the Company's response to ICNU Data Request 6.1 for the geographic location of the avoided resource.

All deliveries are assumed to be made at transmission levels.

UM-1129/PacifiCorp
November 21, 2005
ICNU 6th Set Data Request 6.3

ICNU Data Request 6.3

What is PacifiCorp's assumption, if any, in its proposed avoided costs for the imputation of debt costs to QF contracts?

Response to ICNU Data Request 6.3

The Company does not include any assumptions on the cost of imputed debt in its proposed avoided costs in Schedule 37.

UM-1129/PacifiCorp
November 21, 2005
ICNU 6th Set Data Request 6.4

ICNU Data Request 6.4

Please provide a complete description of the power products that PacifiCorp's avoided cost prices are based on (e.g., 7x24 pre-scheduled firm energy, or unit-contingent energy and capacity).

Response to ICNU Data Request 6.4

Avoided costs during the sufficiency period are based upon an assumed market purchase (short term firm) at the prices set forth in the Company's Official Price Projections. The market purchase does not assume a specific power product.

UM-1129/PacifiCorp
November 21, 2005
ICNU 6th Set Data Request 6.8

ICNU Data Request 6.8

Please describe how PacifiCorp assures that wholesale market purchases from the wholesale market at Mid-C, COB, Palo Verde, or Four Corners are deliverable to PacifiCorp's loads in Oregon.

Response to ICNU Data Request 6.8

Market purchases are system resources and power generated by all system resources, taken as a whole is used to meet system load, including Oregon load. The company has sufficient transmission and transmission rights to deliver from those receipt points.

UM-1129/PacifiCorp
November 21, 2005
ICNU 6th Set Data Request 6.9

ICNU Data Request 6.9

Please specify any transmission costs that PacifiCorp expects to incur from 2005 - 2010 to assure the deliverability of market resources to PacifiCorp's loads in Oregon.

Response to ICNU Data Request 6.9

The Company does not expect to incur any specific transmission costs from 2005-2010 to assure the deliverability of market resources to PacifiCorp's loads in Oregon. To the extent the Company does incur additional transmission expense; it will be at the provider's tariff rate.

UM-1129/PacifiCorp
November 21, 2005
ICNU 6th Set Data Request 6.10

ICNU Data Request 6.10

Please describe how PacifiCorp assures that power from the avoided combined cycle combustion turbine ("CCCT") resource is deliverable to PacifiCorp's loads in Oregon.

Response to ICNU Data Request 6.10

The avoided CCCT is a system resource and power generated by all system resources, taken as a whole, is used to meet system load, including Oregon load.

UM-1129/PacifiCorp
November 21, 2005
ICNU 6th Set Data Request 6.11

ICNU Data Request 6.11

Please specify any transmission costs that PacifiCorp expects to incur from 2005 - 2010 to assure the deliverability of new CCCT resources to PacifiCorp's loads in Oregon.

Response to ICNU Data Request 6.11

No new CCCT will be in service until late in the sufficiency period. The Company does not expect to incur any specific transmission costs from 2005-2010 to assure the deliverability of a new CCCT resource to PacifiCorp's loads in Oregon.

UM-1129/PacifiCorp
November 21, 2005
ICNU 6th Set Data Request 6.12

ICNU Data Request 6.12

Please provide the transportation and distribution tariffs or other cost basis that are the source for the "Transport" and "Distribution" gas costs shown in Table 9 of PacifiCorp's avoided cost workpapers.

Response to ICNU Data Request 6.12

Information responsive to this request contains information that is HIGHLY CONFIDENTIAL and will be made available for inspection at PacifiCorp's offices in Portland. Please contact Laura Beane at PacifiCorp, (503) 813-5542, to make arrangements for such inspection.

UM-1129/PacifiCorp
November 21, 2005
ICNU 6th Set Data Request 6.13

ICNU Data Request 6.13

Please provide PacifiCorp's gas price forecast for 2005 – 2009 that is consistent with the 2005 – 2009 wholesale market prices shown in Table 2. If that gas price forecast is the one in Table 9, please so specify.

Response to ICNU Data Request 6.13

The commodity portion of gas prices in Table 9 are consistent with the wholesale market prices provided in Table 2, both come from the Company's March 2005 Official Price Projection. Please see Response to ICNU Data Request 6.12 regarding the transportation portion.

ICNU Data Request 6.14

Please provide PacifiCorp's Sumas, Washington gas price forecast for 2005 – 2009 that is consistent with the 2005 – 2009 gas price forecast for Opal shown in Table 9.

Response to ICNU Data Request 6.14

For projected gas index prices, the requested information was provided in response to ICNU 5.1. See the Company's response to ICNU 6.15 for the adjustment factors from pipeline to burner-tip prices.

UM-1129/PacifiCorp
November 21, 2005
ICNU 6th Set Data Request 6.15

ICNU Data Request 6.15

If the avoided CCCT resource was located in Oregon, what would be the comparable gas transportation and distribution tariffs that would apply to that resource, comparable to the tariffs that are the source for the "Transport" and "Distribution" gas costs shown in Table 9 of PacifiCorp's avoided cost workpapers?

Response to ICNU Data Request 6.15

Assuming the avoided CCCT were located on the west side, the applicable gas tariff adders for a CCCT resource located in Oregon are provided in the table below. The adders include a 1.41% fuel reimbursement (NW Pipeline Fuel Reimbursement Rate) applied to the average of Sumas, Stanfield, Opal hub prices, and $0.03/MMBtu (NW Pipeline Commodity Rate) for the variable transportation cost.

CY	1.41% Fuel Reimbursement Cost	Variable Transport Cost
2006	$0.10	$0.03
2007	$0.09	$0.03
2008	$0.09	$0.03
2009	$0.08	$0.03
2010	$0.07	$0.03
2011	$0.08	$0.03
2012	$0.09	$0.03
2013	$0.09	$0.03
2014	$0.10	$0.03
2015	$0.10	$0.03
2016	$0.10	$0.03
2017	$0.10	$0.03
2018	$0.10	$0.03
2019	$0.11	$0.03
2020	$0.11	$0.03
2021	$0.11	$0.03
2022	$0.12	$0.03
2023	$0.12	$0.03
2024	$0.12	$0.03
2025	$0.12	$0.03
2026	$0.13	$0.03
2027	$0.13	$0.03
2028	$0.13	$0.03

ICNU/207

PacifiCorp Pricing Methodology and Input

Brief Explanation of PacifiCorp's Avoided Cost Rates

Sufficiency Period: 2005-2009; Deficiency Period : Post 2009
During the sufficiency period, avoided costs are the hub weighted average market price.
In the deficiency period, avoided costs equal the capital and energy cost of a new (Eastern) CCCT.
= (CC Capital Cost)* Payment Factor + O&M+ Heat Rate* Gas Price
Capital Costs are largely allocated to the on peak period. Set to be recoverable if the QF has the same Capacity Factor (CF) as the PacifiCorp plant. The capital and O&M costs are indexed with inflation. The fixed rate uses PacifiCorp's gas forecast, while the indexed rate uses the actual gas market index. The banded indexed rate is designed to vary with market but has ceilings and floors within 10% of PacifiCorp's forecast.

Sources, Inputs and Assumptions

SCCT Statistics	MW	Percent	Cap Cost	Fixed	Var	Heat Rate
Greenfield Intercooled Aero SCCT	87	100%	590	8.11	7.21	8,907

(Used only for split between on and off peak capacity rate. Very little is off peak.)

CCCT Statistics (Utah S Mona)	MW	Percent	Cap Cost	Fixed
Brownfield CCCT (Dry Cooling 2x1	420	80%	682	6.01
Brownfield CCCT Duct Firing for D	105	20%	207	4.28
Capacity Weighted	525	100%	587	5.66

(Used to establish capacity payment in deficiency period.)

CCCT Statistics (Utah S Mona)	MW	CF	aMW	Percent	Var	Heat Rate
Brownfield CCCT (Dry Cooling 2x1	420	56%	235	93%	5.50	7,462
Brownfield CCCT Duct Firing for D	105	16%	17	7%	3.06	9,512
Energy Weighted	525	48%	252	100%	5.34	7,599
(Used to establish energy rate in deficiency period.)					Rounded	7,600

SCCT	CCCT	
8.98%	7.93%	Payment Factor - IRP Table C.28 (January 2005)
16%	48%	Capacity Factor - IRP Table C.28 (January 2005)
	84.2%	Capacity Factor - On-peak 48% / 57% (percent of hours on-peak)
8,907	7,600	Heat Rate in btu/kWh - IRP Table C.27 (January 2005)

2.02%	2004-2010 Inflation Rate - 2004 IRP, Appendix C, Table C.1
2.94%	2011-2020 Inflation Rate - 2004 IRP, Appendix C, Table C.1
3.48%	2021-2030 Inflation Rate - 2004 IRP, Appendix C, Table C.1

(Used to index rate components to inflation.)

ICNU/208

PacifiCorp Sufficiency Period Fixed Prices

Exhibit ICNU/208
Documentation of PacifiCorp Sufficiency Period Fixed Prices

Sufficiency Period Fixed Rate Calculation

The fixed price during the sufficiency period equals the hub-weighted average price for each month based on PacifiCorp's forward curves for three hubs - Mid Columbia, COB and Palo Verde. The hub weights vary monthly based on PacifiCorp's GRID model study, which increases supply in Oregon by 50 MW around the clock. The weights are computed by the Company based on the differences in purchases and sales at each market "bubble" modeled in GRID. The forward prices are defined by the Company as shown in the attached data responses. Annual fixed prices are the average of the monthly hub weighted prices. These prices do not include or provide any allowance for losses, transmission costs or other factors. The prices used are based on PacifiCorp's March 31, 2005 forward price curve CG27 as documented in the IRP. The forward prices used and the montly weighted average are shown below.

This curve represents PacifiCorp's Official Base Case Market Curve CG27. It is a blend of the 03-31-05 forward market curve and Midas curve CG27, which was completed on 03-18-05.

		FPC ELEC COB N-S	FPC ELEC COB N-S	FPC ELEC PV	FPC ELEC PV	FPC ELEC MID-C	FPC ELEC MID-C	Weighted average Weighted by the Difference in system balancing transactions Between GRID runs	
		COB		Palo Verde		Mid-Columbia		Wtd Average	
		Forward Prices		Forward Prices		Forward Prices		Forward Prices	
Start	End	HLH	LLH	HLH	LLH	HLH	LLH	HLH	LLH
06/01/05	07/01/05	$68.25	$55.50	$73.25	$47.00	$63.25	$54.25	$64.99	$53.90
07/01/05	08/01/05	$79.75	$64.10	$87.00	$55.34	$74.25	$63.75	$75.11	$62.99
08/01/05	09/01/05	$83.74	$66.69	$88.00	$55.88	$79.00	$65.25	$80.09	$64.86
09/01/05	10/01/05	$75.76	$63.46	$77.00	$51.54	$71.00	$60.75	$72.03	$60.61
10/01/05	11/01/05	$69.60	$57.34	$68.60	$51.39	$66.00	$55.34	$66.26	$55.57
11/01/05	12/01/05	$71.78	$60.39	$69.30	$53.25	$67.50	$58.91	$68.40	$58.87
12/01/05	01/01/06	$76.85	$65.27	$72.10	$55.11	$72.00	$64.26	$72.02	$61.90
01/01/06	02/01/06	$77.48	$68.58	$75.71	$55.64	$74.03	$66.07	$74.38	$62.14
02/01/06	03/01/06	$76.74	$63.50	$74.24	$54.04	$71.91	$63.60	$72.37	$60.44
03/01/06	04/01/06	$69.29	$58.42	$70.56	$51.36	$65.57	$55.58	$65.95	$55.07
04/01/06	05/01/06	$59.40	$50.00	$58.59	$41.90	$54.88	$47.60	$55.13	$47.08
05/01/06	06/01/06	$53.35	$41.15	$60.48	$42.75	$47.04	$40.08	$47.07	$40.66
06/01/06	07/01/06	$52.25	$41.60	$68.67	$43.61	$46.06	$37.58	$49.97	$38.92
07/01/06	08/01/06	$71.05	$55.58	$84.09	$52.28	$61.20	$53.91	$63.70	$54.45
08/01/06	09/01/06	$76.18	$61.43	$85.31	$52.79	$73.44	$58.45	$74.07	$58.95
09/01/06	10/01/06	$72.52	$58.50	$74.34	$48.69	$69.36	$57.89	$70.21	$58.01
10/01/06	11/01/06	$64.44	$51.00	$64.19	$46.80	$59.97	$49.06	$60.02	$49.16
11/01/06	12/01/06	$66.45	$53.71	$64.85	$49.24	$61.86	$52.22	$62.60	$52.28
12/01/06	01/01/07	$71.15	$58.05	$67.47	$50.70	$67.54	$56.97	$67.53	$55.16
01/01/07	02/01/07	$71.76	$61.83	$71.59	$50.96	$67.99	$59.12	$68.30	$55.41
02/01/07	03/01/07	$71.07	$57.25	$70.20	$49.49	$66.05	$56.91	$66.35	$54.33
03/01/07	04/01/07	$64.17	$52.67	$66.72	$47.04	$60.22	$49.73	$60.51	$49.63
04/01/07	05/01/07	$56.43	$48.31	$56.73	$41.72	$53.99	$45.89	$54.29	$45.58
05/01/07	06/01/07	$50.68	$39.76	$58.56	$39.29	$42.09	$38.64	$43.00	$38.96
06/01/07	07/01/07	$49.64	$40.19	$66.49	$40.50	$41.18	$36.23	$41.72	$37.35
07/01/07	08/01/07	$67.66	$51.08	$80.47	$49.28	$57.83	$48.69	$63.91	$49.68
08/01/07	09/01/07	$72.54	$56.93	$81.64	$49.79	$69.39	$52.79	$71.28	$54.20
09/01/07	10/01/07	$69.05	$54.00	$71.14	$45.69	$65.54	$52.28	$66.53	$52.97
10/01/07	11/01/07	$60.96	$46.50	$61.86	$43.80	$56.29	$45.80	$56.57	$45.87
11/01/07	12/01/07	$62.87	$49.21	$62.49	$46.24	$58.07	$48.76	$59.01	$48.80
12/01/07	01/01/08	$67.31	$53.55	$65.02	$47.70	$63.40	$53.19	$63.58	$51.98

Exhibit ICNU/208
Documentation of PacifiCorp Sufficiency Period Fixed Prices

01/01/08	02/01/08	$66.76	$59.08	$67.84	$47.71	$63.24	$56.12	$63.68	$53.67
02/01/08	03/01/08	$66.07	$54.50	$66.45	$46.24	$61.30	$53.91	$61.58	$52.94
03/01/08	04/01/08	$59.17	$49.92	$62.97	$43.79	$55.47	$46.73	$55.86	$48.13
04/01/08	05/01/08	$51.43	$45.56	$52.98	$38.47	$49.24	$42.89	$49.47	$43.89
05/01/08	06/01/08	$45.68	$37.01	$54.81	$36.04	$37.34	$35.64	$38.83	$36.44
06/01/08	07/01/08	$44.64	$37.44	$62.74	$37.25	$36.43	$33.23	$40.64	$34.56
07/01/08	08/01/08	$62.66	$48.33	$76.72	$46.03	$53.08	$45.69	$62.96	$46.63
08/01/08	09/01/08	$67.54	$54.18	$77.89	$46.54	$64.64	$49.79	$67.95	$51.54
09/01/08	10/01/08	$64.05	$51.25	$67.39	$42.44	$60.79	$49.28	$62.27	$50.11
10/01/08	11/01/08	$55.96	$43.75	$58.11	$40.55	$51.54	$42.80	$53.14	$43.18
11/01/08	12/01/08	$57.87	$46.46	$58.74	$42.99	$53.32	$45.76	$54.02	$46.03
12/01/08	01/01/09	$62.31	$50.80	$61.27	$44.45	$58.65	$50.19	$59.09	$48.94
01/01/09	02/01/09	$63.26	$55.83	$64.59	$45.46	$59.99	$53.12	$60.84	$50.79
02/01/09	03/01/09	$62.57	$51.25	$63.20	$43.99	$58.05	$50.91	$58.48	$49.77
03/01/09	04/01/09	$55.67	$46.67	$59.72	$41.54	$52.22	$43.73	$52.51	$44.94
04/01/09	05/01/09	$47.93	$42.31	$49.73	$36.22	$45.99	$39.89	$46.19	$40.85
05/01/09	06/01/09	$42.18	$33.76	$51.56	$33.79	$34.09	$32.64	$35.82	$33.18
06/01/09	07/01/09	$41.14	$34.19	$59.49	$35.00	$33.18	$30.23	$38.40	$31.91
07/01/09	08/01/09	$59.16	$45.08	$73.47	$43.78	$49.83	$42.69	$59.32	$43.74
08/01/09	09/01/09	$64.04	$50.93	$74.64	$44.29	$61.39	$46.79	$64.04	$48.45
09/01/09	10/01/09	$60.55	$48.00	$64.14	$40.19	$57.54	$46.28	$58.91	$46.99
10/01/09	11/01/09	$52.46	$40.50	$54.86	$38.30	$48.29	$39.80	$49.99	$40.14
11/01/09	12/01/09	$54.37	$43.21	$55.49	$40.74	$50.07	$42.76	$50.70	$42.91
12/01/09	01/01/10	$58.81	$47.55	$58.02	$42.20	$55.40	$47.19	$55.99	$46.05

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the Direct Testimony of Randall Falkenberg on behalf of the Industrial Customers of Northwest Utilities upon the parties, shown below, on the official service list by causing the foregoing document to be deposited, postage-prepaid, in the U.S. Mail, or by service via electronic mail to those parties who waived paper service.

DATED at Portland, Oregon, this 9th day of December, 2005.

DAVISON VAN CLEVE, P.C.

/s/ Christian Griffen
Christian W. Griffen

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