BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 180/UE 181/UE 184

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision (UE 180),	))))))))
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Annual Adjustments to Schedule 125 (2007 RVM Filing) (UE 181),	)))))))))
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision relating to the Port Westward plant (UE 184).	))))))))))

PRODUCTION REVENUE REQUIREMENT/PARTIAL REQUIREMENTS

DIRECT TESTIMONY OF KATHRYN E. IVERSON AND LINCOLN WOLVERTON

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

August 9, 2006

Q. PLEASE STATE YOUR NAMES AND BUSINESS ADDRESSES.

A. My name is Kathryn E. Iverson, 17244 W. Cordova Court, Surprise, Arizona, 85387. I am employed by the firm of Brubaker & Associates, Inc. ("BAI"), regulatory and economic consultants with corporate headquarters in St. Louis, Missouri. My qualifications are described in Exhibit ICNU/201.

My name is Lincoln Wolverton. My address is East Fork Economics, Post Office Box 620, La Center, WA, 98629. My qualifications also are described in Exhibit ICNU/201.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. We are testifying on behalf of the Industrial Customers of Northwest Utilities ("ICNU"). ICNU is a non-profit trade association, whose members are large industrial customers served by electric utilities throughout the Pacific Northwest, including Portland General Electric Company ("PGE" or the "Company").

Q. WHAT SPECIFIC AREAS DOES YOUR TESTIMONY COVER?

A. Our testimony discusses four issues: 1) the allocation of PGE's production revenue requirement; 2) the Schedule 75 notification conditions; 3) other changes to Schedule 75; and 4) the Schedule 76R replacement power provisions.

Q. ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A. Yes. We are sponsoring Exhibits ICNU/201 through ICNU/205.

Q. CAN YOU SUMMARIZE YOUR RECOMMENDATIONS?

A. Yes.

1. We recommend that the Commission modify the marginal power costs used for the allocation of production revenue requirement to take into account the need for capacity and super-peak energy. PGE's proposed methodology treats all peak hours as equal, but only a limited number of extreme peak hours actually drive the

need for sufficient peaking resources. ICNU recommends a modification to PGE's proposed rate spread that includes marginal costs based on the top 100 hours of peak demand and a reliability component that reflects the stress that such increases in demand place on the system.

2. Partial Requirements customers should not be required to provide two-years notice before changing their Baseline Demand. For changes in Baseline Demand of up to 10 MW, we recommend that Partial Requirements customers be required to provide six-months notice. For changes in Baseline Demand greater than 10 MW, we recommend that Partial Requirements customers be required to provide one-year notice. These notice requirements would apply six-months and one-year in advance of the calendar year in which the change occurred.

3. Partial Requirements customers should be provided the explicit right to enter into simultaneous buy-sell transactions under which they purchase their electric requirements from PGE, and sell part or all of their generator output to PGE or a third party.

4. Partial Requirements customers should be permitted to avoid supplemental reserves charges by entering into a load reduction plan with PGE.

5. Partial Requirements customers should be permitted to change their Baseline Demand, without the notice required above, if they add new equipment, or make permanent or long-term changes in loads or generator operations.

6. PGE should offer more pricing options under Schedule 76R.

I. ALLOCATION OF PRODUCTION COSTS

Q. DO YOU SUPPORT PGE'S COST OF SERVICE STUDY PROVIDED IN THE TESTIMONY AND EXHIBITS OF PGE WITNESSES DOUG KUNS AND MARC CODY?

A. Yes, for the most part, we support the cost study provided by the Company. However, we propose a modification to the marginal costs methodology used for the allocation of PGE's production revenue requirement.

Q. HOW DOES PGE CURRENTLY ALLOCATE PRODUCTION COSTS?

A. PGE's production revenue requirement is currently allocated to customer classes based on a resource stacking methodology that was implemented in 2001 pursuant to a settlement stipulation in Docket No. UE 115. In this docket, PGE proposes to allocate production costs based on each schedule's marginal power costs. Under PGE's proposed method, marginal power costs are based on meeting each schedule's energy requirement with market purchases that are priced at the average on-peak and off-peak forward market price for each month of the test year. The production revenue requirement is then allocated based on test year loads by scaling to the projected market prices.

Q. ARE PGE'S PROPOSED MARGINAL POWER COSTS ACCURATE?

A. No. PGE's proposed marginal cost methodology is not entirely accurate, because it does not take into account the need for capacity and super-peak energy. PGE's proposal treats all peak hours as equal. In reality, however, a limited number of extreme peak hours drive the need for reliable and adequate peaking resources. Using all peak hours as the measure of capacity and standby super-peak energy needs understates the cost of providing such service.

Q. HOW DO YOU PROPOSE TO REMEDY THIS OVERSIGHT?

A. To remedy this problem, ICNU proposes to reflect the additional cost of a reliability/adequacy-related resource by looking at the top 100 hours of peak demand in the marginal cost of power, rather than all the peak hours. A review of the projected system loads in PGE's MONET model reveal that that top 100 hours are spread over five months: January with 36 hours, February with 9 hours, July and August with 5 hours each, and December with 45 hours.

Q. HOW DO YOU PROPOSE TO INCORPORATE THE NEED FOR RELIABILITY IN THE MARGINAL COST OF POWER?

A. To incorporate the additional stress placed on the system during these times of increased need, ICNU proposes to assign a portion of the marginal capacity cost of a simple-cycle combustion turbine ("CT") to the class schedules. The cost of a CT is assumed to be

$64.50 per kW-year based on the average of PGE's estimates of supply side main options.[1/] Since a CT is typically run no more than 1,000 hours per year, a conservative estimate of this capacity cost would be $64.50 per MWh. The $64.50 per MWh is multiplied by each schedule's MWh associated with the top 100 hours. For purposes of coming up with each schedule's MWh, their monthly coincident peak ("CP") is multiplied by the corresponding number of monthly hours in the top 100 hours: January CP x 36 hours, February CP x 9 hours, July CP x 5 hours, and so forth.[2/] This reliability cost is then added to the marginal power costs as proposed in Exhibit PGE/1305, Kuns–Cody/3. This marginal power cost, including the cost of reliability, then forms the basis by which the production revenue requirement is allocated.

Q. IS IT NECESSARY FOR PGE TO BE ACTUALLY CONSTRUCTING OR ACQUIRING A PEAKING UNIT SUCH AS A CT IN ORDER FOR THE MARGINAL POWER COST TO INCLUDE THIS RELIABILITY COST?

A. No. The basis for including a reliability component in marginal power costs is to recognize that generating facilities are necessary to meet the reliability requirements of customers. ICNU's proposal to include the cost of a peaker in the marginal power cost is based on the peaker deferral method, a method commonly used in marginal cost studies in order to determine marginal capacity costs. The peaker deferral method uses the annual cost of a CT as the basis for the reliability component of marginal power costs and is not predicated on whether or not the utility is actually acquiring a peaking resource. This point is highlighted in the National Association of Regulatory Commissioners'

1/ Based on the average of $69 per kW-year (SCCT 47 MW per unit) and $60 per kW-year (SCCT 170 MW per unit), capital cost plus fixed O&M. Stakeholder Dialogue No. 4, PGE's 2006 Integrated Resource Plan, July 25, 2006.

2/ Since hourly load information for all schedules is not available, peak information is used as a reasonable approximation of the energy loads of customers on each schedule during the top 100 hours.

("NARUC") Electric Utility Cost Allocation Manual in its section on Marginal Production Cost:

> 1. Peaker Deferral Method
>
> Peakers are generating units that have relatively low capital cost and relatively high fuel costs and are generally run only a few hours per year. Since peakers are typically added in order to meet capacity requirements, peaker costs provide a measure of the cost of meeting additional capacity needs. If a utility installs a baseload unit to meet capacity requirements, the capital cost of the baseload unit can be viewed as including a reliability component equivalent to the capital cost of a peaker and an additional cost expended to lower operating costs. **Thus, the peaker deferral method can be used even when a utility has no plans to add peakers to meet its reliability needs**.

Electric Utility Cost Allocation Manual, NARUC at 116 (Jan. 1992) (emphasis added).

Q. IS THERE ANOTHER REASON WHY PGE SHOULD INCLUDE THE RELIABILITY COMPONENT OF PRODUCTION IN ITS MARGINAL COST STUDY?

A. Yes. Rates in Oregon are typically based on long-run marginal costs as opposed to short-run costs. See, e.g. Re PGE, OPUC Docket No. UE 88, Order No. 95-322 (March 29, 1995). Long-run marginal costs reflect the cost of serving a change in customer usage when all factors of production – both variable and fixed – can be varied. The market prices used in PGE's cost study are based on expected prices in the near term (2007), and thus do not reflect the long-run marginal cost of adding facilities required to reliably serve customers. By incorporating the cost associated with a CT into the marginal cost of production, the allocation and rate design will better reflect the long-run cost of production.

Q. HAVE YOU PREPARED AN EXHIBIT THAT SHOWS THE MARGINAL POWER COSTS BY SCHEDULE, WHICH INCLUDE THE RELIABILITY COMPONENT?

A. Yes. Exhibit ICNU/202, page 1, provides the details of the additional marginal power costs as well as the allocation percentages used to allocate production costs. The development of each schedule's MWh associated with the top 100 hours is provided on page 2 of this Exhibit.

Q. HOW DOES THE INCORPORATION OF A RELIABILITY COMPONENT IN THE MARGINAL POWER COST IMPACT RATE SPREAD IN THIS DOCKET?

A. Exhibit ICNU/203 provides the rate impact by schedule and compares these proposed changes to those filed by PGE. This exhibit is based on PGE's rate case revenue requirement as filed, before the inclusion of Port Westward.

Q. ARE THE PRODUCTION ALLOCATION PERCENTAGES SHOWN IN EXHIBIT ICNU/203 USED FOR ANY OTHER ALLOCATION?

A. Yes. PGE proposes to allocate the production-related revenue requirements of Port Westward using the same production allocation percentages it has developed in this docket. We would likewise propose that the production allocation percentages shown in Exhibit ICNU/203 be used in the allocation of Port Westward production revenue requirement. Since Port Westward is a long-term resource of PGE, it is important that this resource be allocated to the classes based on their long-run marginal cost of production, which includes the cost of reliability.

II. NOTIFICATION REQUIREMENTS FOR SCHEDULE 75

Q. PGE PROPOSES TO CHANGE THE NOTIFICATION REQUIREMENTS FOR CHANGES IN PARTIAL REQUIREMENTS SERVICE UNDER SCHEDULES 75 AND 575. DO YOU SUPPORT THE CHANGE?

A. No. PGE proposes to require a two-year notice for changes in Baseline Demand under Schedules 75 and 575 to "improve the process for customer-initiated changes to Baseline

Demand." PGE/1300, Kuns-Cody/38. The level of Baseline Demand determines the amount of power that a Partial Requirements customer can purchase at the cost-of-service rate. Electric use in excess of the Baseline Demand is served at market rates or by self-generation. The purported reasoning for PGE's proposed change is that a Partial Requirements customer could "optimize in the short-term at the expense of others by changing its Baseline Demand based on short-term natural gas market conditions." Id. Kuns and Cody then go on to say that their proposal "achieves an equitable balancing" between all customers. Id.

Q. DO YOU AGREE THAT PGE'S PROPOSAL "ACHIEVES AN EQUITABLE BALANCEING?"

A. No. ICNU members are mindful of the risk of adverse impacts from a Partial Requirements customer changing its Baseline Demand in order to "game" the market. ICNU represents customers that are not partial requirements customers, customers that are partial requirements customers, and customers that may in the future become partial requirements customers. To strike a balance between the interests of all these customers, ICNU recognizes that some restrictions against excessive gaming are necessary. However, we do not believe that an equitable balance has been struck in PGE's proposed tariff, because there is no evidence that Partial Requirements customers could or would act in such a short-term manner, assuming the markets for gas and power were predictable enough to take such measures. Similarly, there is no convincing evidence that PGE needs two-years notice to plan to serve changes in Baseline Demand.

Q. PGE CLAIMS THAT THE TWO-YEAR NOTICE REQUIREMENT IS SIMILAR TO THE ADVANCED NOTICE THAT PGE TYPICALLY RECEIVES FOR CUSTOMERS WHO ANTICIPATE THAT THEIR LOAD WILL GROW. SEE ICNU/204, IVERSON-WOLVERTON/1-2 (PGE RESPONSE TO ICNU DR NOS. 4 AND 133). PLEASE RESPOND.

A. PGE stated that two years advance notice is needed "to ensure that PGE is able to install the necessary power delivery infrastructure to support this load growth." Id. at 2. PGE has not provided any support for its claim that existing customers anticipating load growth typically provide PGE with two-years advance knowledge of their load growth. ICNU specifically asked PGE to support its claim, and PGE did not provide any supporting documents or other information. Id.

Since industrial customers do not provide notice of all changes in load, PGE's claims as to the notice it receives is obviously exaggerated. For example, there is a certain amount of load growth that occurs without the customer providing PGE any notice. Although industrial customer load changes are not as variable as residential customers, the loads of industrial customer load can vary for numerous reasons, including economic conditions, seasonal requirements, and production demands.

More importantly, PGE's assertion that existing customers provide advance notice is a red herring. PGE's rationale does not support limiting the ability of a Partial Requirements customer to change its Baseline Demand. PGE's notice requirements are not tied to any infrastructure needs; instead, PGE is seeking to limit the ability of a Partial Requirements customer to change its Baseline Demand, even in those instances where PGE may already have sufficient infrastructure in place to serve the customer's entire load.

Q. DO YOU HAVE AN ALTERNATIVE PROPOSAL?

A. Yes. Exhibit ICNU/205 proposes language for Schedule 75 (which would be mirrored in Schedule 575) that, in ICNU's opinion, strikes a better balance between the needs of a Partial Requirements customer and all other customers.

Specifically, the proposal attempts to strike a balance between PGE's two-year notice proposal and the 30-day notice requirement provided in PacifiCorp's Schedule 47 service agreements. Under ICNU's proposed language, a PGE Partial Requirements customer would be required to give six months notice for a change in Baseline Demand of up to 10 MW for the next calendar year. We propose the 10 MW threshold because all customers experience load changes, and Partial Requirements customers should not have fewer rights to change their load than full requirements industrial customers. For changes in excess of 10 MW, a one-year notice would be required. These notice requirements apply to the calendar year in which the change would take place (i.e., for changes up to 10 MWs, notice must be provided at least six-months prior to the following January 1). While this proposal does not give PGE's Partial Requirements customers the same flexibility as PacifiCorp's customers (i.e., 30 days notice), we believe it is a fair compromise. In addition, it reflects the fact that PGE purchases more of its supply on the market than PacifiCorp, and as a result, it needs more time to adjust its purchases to accommodate changes in load.

Q. AS A POLICY MATTER, WHY SHOULD THE COMMISSION ADOPT THE LEAST RESTRICTIVE NOTICE PROVISIONS THAT ARE NECESSARY?

A. Self-generation typically is both highly efficient and broadly distributed on the utility's system, reducing the need for less efficient generation and new transmission investment. As a result, Partial Requirements customers should be given as much flexibility as possible to encourage development of self-generation. Encouraging self-generation is also consistent with the Commission's objectives, including removing barriers to the development of distributed generation, eliminating barriers to the development of a competitive retail market, mitigating the market power of electric utilities, promoting the efficient use of energy resources, and developing more sustainable energy resources.

III. OTHER CHANGES TO SCHEDULE 75

Q. HAVE YOU PROPOSED CHANGES TO THE DEFINITION OF BASELINE DEMAND?

A. Yes. We propose that Baseline Demand be defined as the amount of demand that PGE normally supplies to the Partial Requirements customer when the customer's generator is operating as planned. Planned generator operations means both the Partial Requirements customer's actual operational plans for the generator and the customer's plans to sell any electricity produced to PGE or to third parties. This proposed language is very similar to the language in PacifiCorp's partial requirements tariff (Schedule 47). PacifiCorp's Schedule 47 was modeled off, and reflects an improvement to, PGE's existing Schedule 75.

Q. PLEASE EXPLAIN HOW THE PACIFICORP LANGUAGE DIFFERS FROM PGE'S PROPOSAL?

A. As written, PGE's proposed tariff language does not address whether a Partial Requirements customer can take service from PGE and sell part or all of its generator output to PGE or a third party. The language we propose makes it clear that a Partial Requirements customer's Baseline Demand should reflect how the customer plans to use its generation resource. Our language would specifically allow the Partial Requirements customer to decide to use its generation resource to serve its own load or to sell the generation to PGE or a third party. If the Partial Requirements customer elects to sell its generator output, then the customer would purchase its electric requirements to serve its load from PGE. These types of arrangements are commonly described as "simultaneous buy-sell" transactions. The Partial Requirements customer should be allowed to make this choice (to serve load or sell its output) at the time it selects or changes its Baseline Demand.

Q. DOES PGE SUPPORT ALLOWING A PARTIAL REQUIREMENTS CUSTOMER TO ENTER INTO A SIMULTANEOUS BUY-SELL CONTRACT?

A. PGE's position on the issue of whether a Partial Requirements customer can enter into a simultaneous buy-sell transaction is convoluted and confusing. We hope that PGE will clarify and simplify its position in rebuttal testimony. Based on PGE's answers to data responses, we will summarize PGE's position, and provide a response.

PGE appears to agree that a Qualifying Facility ("QF") under the Public Utility Regulatory Purposes Act ("PURPA"), or an industrial customer with self-generation resources, but who is not a Partial Requirements customer, can purchase all of its requirements to meet its load, and sell all of its generator output to a third party or PGE. ICNU/204, Iverson-Wolverton/5 (PGE Response to ICNU DR No. 145). We agree that an industrial customer can enter into this type of buy-sell transaction. We also agree that that an industrial customer in that circumstance would not be a Partial Requirements customer, because they would not be supplying any part of their load with their self-generation.

It is unclear whether PGE believes it is appropriate for a Partial Requirements customer to sell part of its generation output to PGE or a third party and purchase its remaining load requirements from PGE. For Partial Requirements customers with metered net requirements service, PGE has stated that a Partial Requirements customer can only sell part of its generator output after meeting all of the energy requirements of its load through self-generation. ICNU/204, Iverson-Wolverton 4, 9-10 (PGE Response to Staff DR No. 407 and PGE Response to ICNU DR No. 143). For Partial Requirements customers with separate utility metering for their generation resource, PGE has agreed that the Partial Requirements customer can sell the output from the generation resource; however, PGE had identified a number of vague and potentially onerous conditions that could prevent the Partial Requirements customer from actually selling its generation output. ICNU/204, Iverson-Wolverton/4 (PGE Response to ICNU DR No. 143).

We have been advised by counsel that customers with self-generation, especially those that qualify as QFs, have a legal right to enter into simultaneous buy-sell transactions, even if they are Partial Requirements customers. The reason for this is that the sale of generation is a FERC regulated wholesale transaction, while the consumption of energy is a state regulated retail transaction. The retail purchase and the wholesale sale are distinct transactions that must be treated separately. Therefore, we recommend that the Commission reject any attempt by PGE to prevent a Partial Requirements customer from entering into a simultaneous buy-sell transaction (other than reasonable notice provisions for changing their Baseline Demand) with PGE or a third party. For example, a Partial Requirements customer should not be required to use its generation resource to serve its own load before selling the generator's output to a third party or PGE.

Similarly, PGE should not be able to impose unjustified barriers on a Partial Requirements customer by making vague allegations regarding the need to impose protections to avoid adverse impacts on retail customers. If PGE believes that other retail customers need to be protected from a Partial Requirements customer entering into a simultaneous buy-sell transaction, then PGE should clearly identify its concerns and proposed conditions in its rebuttal testimony.

Q. YOUR PROPOSED REVISION TO SCHEDULE 75 INCLUDES A SUPPLEMENTAL RESERVES LOAD REDUCTION PLAN. CAN YOU PLEASE EXPLAIN WHY YOU PROPOSE THIS OPTION?

A. Yes. We took this proposed language directly from PacifiCorp's partial requirements tariff (Schedule 47). PGE's existing and proposed Schedule 75 includes an option for a Partial Requirements customer to self supply their Supplemental and Spinning Reserves, if they have a nameplate generation of 15 MW or greater. PGE and the Partial Requirements customer are required to enter into an agreement that specifies, among other things, how the Partial Requirements customer will supply the needed reserves. We support the self supply option in PGE's existing and proposed Schedule 75.

We believe Partial Requirements customers should have an alternative option to avoid unnecessary charges for Supplemental Reserves. This option would only be available if Partial Requirements customer are not self supplying their Supplemental Reserves. We propose that a Partial Requirements customer be permitted to enter into a load reduction plan that demonstrates the customer's ability to reduce load within the first ten minutes of generator failure. If the plan is approved by PGE and adhered to by the Partial Requirements customer, then the customer should not be required to pay for Supplemental Reserves. The actual kW reduction will be specified in the plan and will be credited monthly on the customer's bill. PGE should have the ability to terminate the load reduction plan and recoup some of the kW credits from a Partial Requirements customer that fails to comply with an approved load reduction plan.

Q. YOU HAVE PROPOSED REVISIONS TO SPECIAL CONDITION 8 REGARDING CHANGES TO A CUSTOMER'S BASELINE DEMAND. PLEASE EXPLAIN THESE CHANGES.

A. Special Condition 8 allows a Partial Requirements customer to change its Baseline Demand during the term of their service agreement without providing PGE with the normally required notice. PGE must approve the change to Baseline Demand. Such changes may occur if the Customer removes equipment, installs permanent energy efficiency measures, or sheds load. ICNU believes that the language of Special Condition 8 should be clarified.

First, we propose to clarify that a Partial Requirements customer can increase or decrease its Baseline Demand. We believe this clarification is necessary because of PGE's past positions regarding its current partial requirements tariffs.

Second, we believe that there are additional grounds upon which a Partial Requirements customer should be allowed to change its Baseline Demand, including the addition of equipment, and permanent or long-term changes in loads or generator operations. These are common sense changes that reflect the types of long-term changes that could significantly impact a customer's Baseline Demand. Again, our proposed revisions are similar to the language in PacifiCorp's Partial Requirements tariff.

Q. WHY IS IT IMPORTANT TO CLARIFY SPECIAL CONDITION 8, AS WELL AS THE DEFINITION OF BASELINE DEMAND?

A. PGE's current Schedule 75 is ambiguous regarding when and how a customer can change its Baseline Demand. That ambiguity gave rise to a dispute between PGE and a Partial Requirements customer that was resolved through a settlement in UE 176. The settlement did not resolve the ambiguity in the tariff; thus, it is important to clarify these provisions.

IV. REPLACEMENT POWER UNDER SCHEDULE 76R

Q. PLEASE DESCRIBE THE ISSUE REGARDING SCHEDULE 76R.

A. Schedule 76R is a tariff that allows a Partial Requirements customer to purchase power at market prices when it is more economical than running its generation. Economic Replacement Energy is priced at the Dow Jones Mid-Columbia Hourly Price Index ("Mid-C"), plus a 5% adder, plus wheeling and losses. The hourly index price is a real time price that is not known until after the fact. Use of a real-time price makes it difficult for a Partial Requirements customer to determine whether buying Economic Replacement Energy is an economic option. Since Schedule 76R provides a pass through of market prices, PGE should offer more options consistent with what is available in the market place. Accordingly, we offer the following options for improving Schedule 76R. Offering these options will not adversely impact PGE or its customers, since PGE will recover its costs.

Q. WHAT OPTIONS DO YOU PROPOSE FOR SCHEDULE 76R ECONOMIC REPLACEMENT POWER?

A. We have three alternatives for pricing Economic Replacement Energy under Schedule 76R.

First, we propose to substitute the daily pricing option under proposed Schedules 83/89 for the provisions in 76R. This would allow the customer to make a decision based on a day ahead price Mid-C price. The allowed cost should be composed of the Mid-C Firm Index price plus wheeling and losses. In addition, reasonable scheduling requirements would apply. We propose that the language of proposed schedules 83 and 483 for PGE Mid-C service be adopted as one principal option for Schedule 76R

The second alternative would be to allow Schedule 76R service in the same manner as the buy-through arrangements in Schedule 576R are treated. This would allow the end user to contract with an ESS to provide power to displace its generation.

The third alternative is to allow Schedule 76R customers to use the Schedule 87, Experimental Real Time Pricing Service for their non-Baseline load, subject to the provisions of that experimental tariff—size and limitations on the number of customers. Under Schedule 87, energy is priced based on a day ahead hourly price. Opening Schedule 87 would allow more competition. The Consumer Baseline Load in Schedule 87 for Schedule 76R customers would be the Baseline load under Schedule 75.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

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ICNU/201

IVERSON - WOLVERTON QUALIFICATIONS

August 9, 2006

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Kathryn E. Iverson, 17244 W. Cordova Court, Surprise, Arizona 85387.

Q. PLEASE STATE YOUR OCCUPATION.

A. I am a consultant in the field of public utility regulation with Brubaker & Associates, Inc. (“BAI”), energy, economic and regulatory consultants.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. In 1980 I received a Bachelors of Science Degree in Agricultural Sciences from Colorado State University, and in 1983, I received a Masters of Science Degree in Economics from Colorado State University.

In March of 1984, I accepted a position as Rate Analyst with the consulting firm Browne, Bortz and Coddington in Denver, Colorado. My duties included evaluation of proposed utility projects, benefit-cost analysis of resource decisions, cost of service studies and rate design, and analyses of transmission and substation equipment purchases.

In February 1986, I accepted a position with Applied Economics Group, where I was responsible for utility economic analysis including cogeneration projects, computer modeling of power requirements for an industrial pumping facility, and revenue impacts associated with various proposed utility tariffs. In January of 1989, I was promoted to the position of Vice President. In this position, I assumed the additional responsibilities of project leader on projects, including the analysis of alternative cost recovery methods, pricing, rate design and DSM adjustment clauses, and representation of a group of industrial customers on the Conservation and Least Cost Planning Advisory Committee to Montana Power Company.

In March 1992, I accepted a position with ERG International Consultants, Inc., of Golden, Colorado as Senior Utility Economist. While at ERG, I was responsible for the cost-effectiveness analysis of demand-side programs for Western Area Power Administration customers. I also assisted in the development of a reference manual on the process of Integrated Resource Planning including integration of supply and demand resource, public participation, implementation of the resource plan and elements of writing a plan. I lectured and provided instructional materials on the key concept of life-cycle costing seminars held to provide resource planners and utility decision-makers with a background and basic understanding of the fundamental techniques of economic analysis. My work also included the evaluation of a marginal cost of service study, assessment of avoided cost rates, and computer modeling relating engineering simulation models to weather-normalized loads of schools in California.

In November of 1994, I accepted a position with Drazen-Brubaker & Associates, Inc. ("DBA"). In April, 1995 the firm of BAI was formed. It includes most of the former DBA principals and Staff. Since joining this firm, I have performed various analyses of integrated resource plans, examination of cost of service studies and rate design, fuel cost recovery proceedings, as well as estimates of transition costs and restructuring plans.

In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona; Chicago, Illinois; Corpus Christi, Texas; and Plano, Texas.

Q. HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

A. Yes. I have testified before the regulatory commissions in Colorado, Georgia, Idaho, Michigan, Montana, New Mexico, Oregon, Texas, Washington, and Wyoming.

WITNESS QUALIFICATION STATEMENT

Name:	Lincoln Wolverton
Business Address:	East Fork Economics, PO Box 620, LaCenter, WA 98629
Education:	B.A., 1963, Dartmouth College, English and French M.A., 1971, University of Washington, Economics Ph.D Candidate, 1971, University of Washington, Economics
Work Experience:	Boeing Computer Services, Consulting Division, Seattle, 1973 – 1978 Portland General Electric, 1978 – 1981 Public Power Council, Vancouver, WA, 1981-1986 Resource Management International, Manager, Portland Office, 1986 – 1987 East Fork Economics, Owner, 1987 – present

November 16, 2005

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2/86 - 1/88	Manager, Portland Office Resource Management International Portland, Oregon
1/81 - 2/86	Director of Technical Projects Public Power Council Vancouver, Washington
5/78 - 1/81	Economist Corporate Planning Division Portland General Electric Co. Portland, Oregon
7/73 - 5/78	Project Economist The Consulting Division Boeing Computer Services, Inc. Seattle, Washington
9/71 - 7/73	Research Consultant Institute for Governmental Research University of Washington
1/67 - 9/71	Graduate Student/Research and Teaching Assistant Department of Economics University of Washington
Education:	A.B., English and French Dartmouth College, 1963
	M.A., Economics University of Washington, 1970
	Ph.D. Candidate Economics University of Washington, 1971
	Economic Fields: Natural Resources, Labor

EMPLOYMENT HISTORY

January 1988 - present — Owner, Consultant, East Fork Economics

The firm specializes in litigation support, Pacific Northwest regulated utility rates, forecasting and planning, least cost planning, strategic planning, transmission issues and economic analyses and testimony. Recent work has included:

- Representative of Utah industrial group in PacifiCorp's decision to build its Currant Creek plant, including testimony on its economics and comparisons to alternatives.

- Representative of industrial group in deliberations and development of comments regarding formation of regional transmission organizations, including issues of structure, pricing, reliability and benefits and costs. Organizational deliberations included the Independent Grid Operator (IndeGO), RTO West, Grid West and the Federal Energy Regulatory Commission's Standard Market Design.

- Provision of technical support to deliberations regarding and development of rules to implement open direct access in the state of Oregon. Testimony was prepared and presented regarding rates and structural issues regarding direct access in Oregon proceedings involving PacifiCorp and Portland General Electric.

- Analysis and provision of testimony in merger proceedings involving Scottish Power and PacifiCorp and Portland General Electric and Enron.

- A management audit of the load-forecasting process of the Allegheny Power System's West Penn utility. The audit included examination of the structure of the forecasting group both within the West Penn utility and the Allegheny Power System, evaluation of the process for developing forecasts, including contributions from demand-side resources, and examination of the public-review procedures. Included was a look at the relationship of West Penn and its neighbor utilities to which it sells or for which it transmits power.

- Development of a financial/operating risk analysis model that looks at net revenues to the Bonneville Power Administration given variations in loads, resource performance, markets for sale of surplus power and hydroelectric conditions. The model simulates operations of the BPA system given distributions of weather, economics, hydro conditions and thermal performance in the several markets into which BPA sells its power.

- Development of a 10-year revenue-requirement/financial-results for BPA that looks at the impacts of load growth, resource selection, rates and financing methods. The model produces rate and cash flow impacts over the 10 years and revenue requirements by utility function.

- Assistance to industries in relations with their local utilities on rate matters and potential cogeneration opportunities.

- Analysis of impact of innovative rate design on telephone company revenues, customer acceptance.

- Support of intervention by large industrial firm in rate proceeding of investor-owned utility on revenue-requirements and rate-design issues. Work included analyses of and testimony on rate-design proposals regarding seasonality and capacity/energy proposals.

- As a member of the Northwest Power Planning Council's Scientific and Statistical Advisory Committee on Demand Forecasting, assistance to primary Northwest electricity planning body on load forecasting.

- Service as Technical Director of the Association of Public Agency Customers (APAC), a group of industries that buy substantial quantities of electric power from consumer-owned utilities in the Pacific Northwest.

- Expert testimony in issues of lost income from automobile accident.

- An analysis of the load/resource impact of the February 1989 cold-weather spell.

- Analyses of BPA's budget and revenue outlooks in support of BPA customer positions on the need for rate increases.

- Analyses and negotiation of open-access pilot programs for Puget Sound Energy, Portland General Electric, and PacifiCorp.

- Consultant for Industrial Customers of Northwest Utilities in Enron/Portland General Electric merger.

- Technical expert in negotiations for Puget Sound Energy Schedule 48, a deregulation tariff for industrial customers.

- Industrial representative on City of Seattle's Rate Advisory Committee, looking at revenue requirements, cost of service and industrial margins.

- Analyses of competitive power bids for industrial customer.

EMPLOYMENT HISTORY (Continued)

February 1986 - January 1988	Manager, Portland Office Resource Management International, Inc.

Responsibilities included managing the Portland office of Resource Management International, a Sacramento, California, based energy consulting firm with extensive experience in electric utility rates, load forecasting and strategic planning. Besides management duties, the work involved:

- Service as technical director of the Association of Public Agency Customers (APAC), a group of industries that buy substantial quantities of electric power from consumer-owned utilities in the Pacific Northwest.

- Writing Federal Energy Regulatory Commission license application chapters on Need for Power for a hydroelectric development project on behalf of a Pacific Northwest client.

- Providing expert testimony on rates and revenue requirements in the 1987 Bonneville Power Administration 1987 Rate Proceeding.

- Investigating opportunities for power purchase by California clients from Pacific Northwest utilities.

- Providing analyses and expert testimony on damages for failure to perform under contract in Oregon civil proceeding between resource developer and potential utility purchaser. Analysis including valuation of a business opportunity that was lost.

January 1981 - February 1986	Director of Technical Projects Public Power Council

Responsibilities in this position included direction of the technical effort of the Public Power Council staff and its member committees in matters involving Bonneville Power Administration wholesale rates, resource costs, cost effectiveness and other regional power planning issues. Performance of these tasks involved direction of PPC staff work, hiring and supervision of consultants and communication with PPC's Executive Committee, the Northwest Power Planning Council and senior staff at BPA. The work involved:

- Direction of Public Power Council rate proceedings before BPA, including selection and training of consultants and staff witnesses.

- In conjunction with other customer groups of BPA, direction of PPC's portion of a Joint Customer Proposal in 1982 (along with the Direct Service Industries and private utilities in the region), a Northwest utilities rate proposal in 1983 (along with the private utilities in the region) and a three-party customer proposal in 1985.

- Participation in and (as a staff member) facilitation of a strategic planning exercise for public power in the Northwest that resulted in a redirection of PPC's role.

- Negotiation of a 20-year BPA Power Sales Contract for Residential Exchange energy. Negotiations took place over a one-year period and required analyses of many proposals for contract provisions.

- Participation in marathon negotiations among BPA and all its customers on 20-year power sales contracts to be offered to all BPA's utility and Direct Service Industrial customers.

- Participation in the development of the first two Northwest Energy Plans by the Northwest Power Planning Council as a member of the Scientific and Statistical Advisory Committee on Load Forecasting and Rate Design.

- Direction of PPC's technical effort, participation in legal strategy development and design of PPC's proposal for a rate test (ceiling) to protect BPA's preference customers under the Regional Power Act. The proposal was the result of nearly two years of negotiation, analysis and technical modelling.

- Appearance as an expert witness in BPA rate proceedings and in United States District Court on rate and Rate Ceiling matters.

- Direction of PPC's efforts in response to BPA's analysis of its options for the region's aluminum companies. Analysis involved examination of the economics of aluminum smelting worldwide.

In addition to the above specific tasks, I have acted as an adviser on strategy to public power entities in the Northwest.

May 1978 - January 1981

Economist
Corporate Planning Division
Portland General Electric

Responsibilities while in the Load Planning and Policy Analysis Departments included supervision of the 20-year electric energy consumption forecast and of special studies on energy matters. Preparation of the forecast required projections of the local economy, consideration of the social and political environment in which the company operates, an understanding of the regional electricity generation system of which PGE is a part, and knowledge of the rate-making procedures for a regulated utility. The work involved:

- Development of a multi-sector personal income forecasting model for the seven counties served by PGE.

- Estimation of statistical equations for consumption of electricity in several final-demand sectors.

- Direction of the preparation and publication of the 1978 Electric Energy Consumption Forecast document for PGE.

- Validity testing of an econometric load-forecasting model developed for PGE. The tests included a simulation of history.

- Design and direction of the development of a computer system that integrated the forecasting model with models of the regional electric generation system, the construction program of the company and its rate-making process. In the integrated model, the company's cost structure and capital base were linked to the rate-setting process. The model was designed both as a forecasting and "what if" simulation tool.

- Testimony in proceedings before the Oregon Energy Facility Siting Council.

- Consultation with other PGE divisions on macro- and microeconomic issues arising locally and nationally, including interpretation and analysis of the Wharton Econometric Forecasting Associates models.

- Special studies on the economics of home-weatherization and solar water-heating programs.

- Analysis of termination options for company's nuclear power plants.

July 1973 - May 1978

Project Economist
The Consulting Division

Boeing Computer Services, Inc.

Responsibilities included direction of the Washington State Econometric Model and economic and econometric analyses of a wide variety of topics, such as:

- Development of an econometric forecasting model of the State of Washington containing over 200 equations and identities, with extensive industrial-sector detail.

- Preparation and delivery of a quarterly briefing on the national economy for the Boeing Commercial Airplane Company management.

- Development of a passenger traffic forecasting model for Air Panama.

- Design and development of user documentation for the Wharton Econometric Forecasting Associates econometric software system.

- Internal consulting to the Engineering Division of Boeing Commercial Airplane Company on energy economics.

EMPLOYMENT HISTORY (Continued)

These studies required computer analyses, substantial report writing and supervision of others working on the same project, as well as substantial client contact.

I also assisted in the testing and design of a number of the modules of the Wharton Econometric Forecasting System.

September 1971 - July 1973

Research Consultant
Institute for Governmental Research
University of Washington

Responsibilities included co-direction of a study of the 1970-71 recession in the Seattle area. The study was done under a subcontract to the RAND corporation. It involved an econometric analysis of employment in the Seattle area, preliminary design of a household survey of unemployed persons in the area and selection of a subcontractor to implement the survey. In addition, a major analysis of the preliminary survey results was performed by me before I went to the Boeing Company.

January 1967 - September 1971

Graduate Student/Teaching and Research Assistant
Department of Economics
University of Washington

While a student at the University of Washington, I was a teaching assistant for introductory macroeconomics and elementary price theory for undergraduates. In addition, I was a research assistant in natural-resource economics.

PROFESSIONAL ASSOCIATIONS

Member, Northwest Power Planning Council's Statistical and Scientific Advisory Committee on Demand Forecasting.

PERSONAL

Family status	Married, two grown children
Citizenship	U.S.A.
Health	Excellent
Pastimes	Winemaking Cooking Music appreciation Gardening Computer programming

NON-PROFESSIONAL AFFILIATIONS

Director, Gardner School Board. Owner, Salishan Vineyards, Inc.

MILITARY SERVICE

U.S. Army, October 1964 - October 1966. Service in Germany and France.

LANGUAGE PROFICIENCY

Fluent in reading, writing and speaking French.

Record of Testimony
Submitted by
Lincoln Wolverton

Utility	Proceeding	Subject of Testimony	Before	Client	Date
Portland General Electric Company		Load forecasts	Oregon Public Utility Commission	PGE	1979
Portland General Electric Company		Load forecasts	Energy Facility Siting Council	PGE	1979
Bonneville Power Administration	1981 Rate Case	BPA costs, restructuring	BPA	Public Power Council	1981
Bonneville Power Adminiistration	WP-83	Revenue requirements, DSI rate design, preference customer rate test,	BPA/FERC	Public Power Council	1983
Bonneville Power Adminiistration	WP-85	Preference customer rate test, revenue crediting, cost allocation, DSI industrial margin	BPA/FERC	Public Power Council	1985
Bonneville Power Adminiistration	VI-86	Aluminum company variable rate	BPA/FERC	Public Power Council	1986
Bonneville Power Adminiistration	WP-87	Aluminum company variable rate, preference customer rate test, cost of service, revenue requirements	BPA/FERC	Association of Public Agency Customers	1987
Bonneville Power Adminiistration	WP-91	Preference customer rate test, revenue crediting, cost allocation, financial goals, interruptible rates, unbundling of transmission costs	BPA/FERC	Association of Public Agency Customers	1991
Bonneville Power Adminiistration	WP-93	Vintaged rates, financial risk planning, interim rate adjustments, preference customer rate test, revenue requirements, cost of service, rate design	BPA/FERC	Association of Public Agency Customers	1993
Bonneville Power Administration	WP/TR-96 TC-96	Rate design, revenue requirements, industrial margins, eligible customer under open-access tariff	BPA	Association of Public Agency Customers	1995
Puget Sound Power & Light and Washington Natural Gas	UE-960195 UE-951270	Puget Power/Washington Natural Gas merger support	Washington Public Utilities Commision	Industrial Customers of Northwest Utilities	1996
Puget Sound Power & Light	OA96-161-000 et al	Open access tariff recommendations, load forecasts	FERC	Industrial Customers of Northwest Utilities	1996-98
Generic	UM827	Marginal cost	OPUC	Industrial Customers of Northwest Utilities	1997
Enron/Portland General Electric	UE102	Competitive Choice (upcoming testimony)	OPUC	Industrial Customers of Northwest Utilities	1997

Record of Testimony Submitted by Lincoln Wolverton

Utility	Proceeding	Subject of Testimony	Before	Client	Date
Washington Water Power	UE971422	Banded Rate discrimination, over-earnings	WUTC	Industrial Customers of Northwest Utilities	1997
PacifiCorp	UM918	PacifiCorp / Scottish Power merger	OPUC	Industrial Customers of Northwest Utilities	1999
Bonneville Power Administration	WP-02	BPA general rate case	BPA	Industrial Customers of Northwest Utilities	2000-2001
Bonneville Power Administration	SN-03	Safety Net Cost Recovery Adjustment Clause proceeding	BPA	Industrial Customers of Northwest Utilities	2003
PacifiCorp	UM-1081	Direct Access Transmition	OPUC	Industrial Customers of Northwest Utilities	2004
PacifiCorp	Docket 03-035-29	PacifiCorp Application for Certificate of Convenience for Currant Creek	Utah Public Service Commission	UAE Intevention Group	2004

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 180/UE 181/UE 184

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
Request for a General Rate Revision (UE 180),	)
	)
In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
Annual Adjustments to Schedule 125 (2007 RVM Filing) (UE 181),	)
	)
In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
Request for a General Rate Revision relating to the Port Westward plant (UE 184).	)

ICNU/202

PGE ALLOCATION OF PRODUCTION COSTS TO COS CUSTOMERS 2007

August 9, 2006

PORTLAND GENERAL ELECTRIC
ALLOCATION OF PRODUCTION COSTS TO COS CUSTOMERS
2007

Grouping	Marginal Energy Cost ($000)	Reliability MC Top 100 Hr MWH	Reliability MC Times $64.50 per MWH	Total Marginal Power Costs ($000)	COS Calendar Energy	Marginal Unit Cost $/MWH	Allocation Percent	Allocated Production Costs ($000)	Embedded Unit Cost $/MWH	Cycle Basis Costs ($000)
Schedule 7	$529,616	**191,586**	**$12,357**	$541,973	7,531,917	71.96	39.57%	$429,768	$57.06	$429,341
Schedule 15	$1,563	**378**	**$24**	$1,588	23,509	67.53	0.12%	$1,259	$53.55	$1,258
Schedule 32	$104,473	**31,988**	**$2,063**	$106,536	1,504,143	70.83	7.78%	$84,480	$56.17	$84,419
Schedule 38										
On-peak	$5,224	**634**	**$41**	$5,265	71,092	74.05	0.38%	$4,175	$58.72	$4,170
Off-peak	$2,173			$2,173	34,860	62.34	0.16%	$1,723	$49.44	$1,721
Schedule 47	$1,459	**193**	**$12**	$1,472	23,110	63.69	0.11%	$1,167	$50.50	$1,158
Schedule 49	$4,253	**507**	**$33**	$4,286	67,770	63.24	0.31%	$3,398	$50.15	$3,407
Schedule 83-S	$371,685	**82,974**	**$5,352**	$377,037	5,410,241	69.69	27.53%	$298,979	$55.26	$298,572
Schedule 89-S 1-4 MW										
On-peak	$30,702	**9,912**	**$639**	$31,341	422,835	74.12	2.29%	$24,853	$58.78	$24,809
Off-peak	$13,567			$13,567	220,242	61.60	0.99%	$10,758	$48.85	$10,739
Schedule 89-S GT 4 MW										
On-peak	$1,142	**183**	**$12**	$1,154	15,174	76.03	0.08%	$915	$60.29	$909
Off-peak	$659			$659	10,530	62.62	0.05%	$523	$49.66	$520
Schedule 83-P	$19,797	**3,932**	**$254**	$20,051	298,952	67.07	1.46%	$15,900	$53.18	$15,879
Schedule 89-P 1-4 MW										
On-peak	$37,175	**11,325**	**$730**	$37,905	529,177	71.63	2.77%	$30,058	$56.80	$30,016
Off-peak	$19,529			$19,529	327,814	59.57	1.43%	$15,486	$47.24	$15,464
Schedule 89-P GT 4 MW										
On-peak	$67,628	**18,379**	**$1,185**	$68,814	965,719	71.26	5.02%	$54,567	$56.50	$54,486
Off-peak	$40,022			$40,022	675,187	59.28	2.92%	$31,737	$47.00	$31,689
Schedule 89-T										
On-peak	$53,987	**15,317**	**$988**	$54,975	780,717	70.42	4.01%	$43,594	$55.84	$43,366
Off-peak	$34,183			$34,183	584,632	58.47	2.50%	$27,106	$46.36	$26,964
Schedule 91	$6,496	**1,841**	**$119**	$6,615	97,437	67.89	0.48%	$5,246	$53.84	$5,265
Schedule 92	$403	**70**	**$5**	$408	5,939	68.66	0.03%	$323	$54.45	$323
Schedule 93	$37	**11**	**$1**	$38	565	67.28	0.00%	$30	$53.35	$30
TOTAL	$1,345,774	**369,229**	**$23,815**	$1,369,590	19,601,562	69.87	100.00%	$1,086,044	$55.41	$1,084,506
							TARGET	$1,086,044		

ICNU/202
Iverson - Wolverton/1

PORTLAND GENERAL ELECTRIC
DEVELOPMENT OF TOP 100 HOURS LOAD
2007

	Coincident Peak					MWH					
	Jan	**Feb**	**Jul**	**Aug**	**Dec**	**Jan**	**Feb**	**Jul**	**Aug**	**Dec**	**Total**
Schedule 7	2,104.9	1,848.5	1,233.6	1,288.6	1,923.6	75,776	16,637	6,168	6,443	86,562	191,586
Schedule 15	3.5	3.0	0.0	0.0	5.0	126	27	0	0	225	378
Schedule 32	303.1	302.8	384.2	378.2	323.1	10,912	2,725	1,921	1,891	14,540	31,988
Schedule 38	6.4	8.7	5.5	8.2	5.7	230	78	28	41	257	634
Schedule 47	0.5	0.7	14.4	14.8	0.5	18	6	72	74	23	193
Schedule 49	0.9	1.7	40.3	43.4	0.9	32	15	202	217	41	507
Schedule 83-S	818.2	848.6	1,032.9	1,017.2	791.8	29,455	7,637	5,165	5,086	35,631	82,974
Schedule 89-S 1-4 MW	98.6	98.4	125.0	128.8	93.5	3,550	886	625	644	4,208	9,912
Schedule 89-S GT 4 MW	0.8	0.7	9.9	12.4	0.8	29	6	50	62	36	183
Schedule 83-P	37.8	42.2	49.6	47.5	37.9	1,361	380	248	238	1,706	3,932
Schedule 89-P 1-4 MW	109.6	114.7	144.5	146.7	108.7	3,946	1,032	723	734	4,892	11,325
Schedule 89-P GT 4 MW	182.7	178.3	192.1	211.2	181.8	6,577	1,605	961	1,056	8,181	18,379
Schedule 89-T	148.9	158.8	155.8	166.4	153.7	5,360	1,429	779	832	6,917	15,317
Schedule 91	16.9	15.0	0.0	0.0	24.4	608	135	0	0	1,098	1,841
Schedule 92	0.7	0.7	0.7	0.7	0.7	25	6	4	4	32	70
Schedule 93	0.1	0.1	0.2	0.1	0.1	4	1	1	1	5	11
	3,833.6	**3,622.9**	**3,388.7**	**3,464.2**	**3,652.2**	138,010	32,606	16,944	17,321	164,349	369,229
Hours in top 100	36	9	5	5	45						

ICNU/202
Iverson - Wolverton/2

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 180/UE 181/UE 184

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
Request for a General Rate Revision (UE 180),	)
	)
In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
Annual Adjustments to Schedule 125 (2007 RVM Filing) (UE 181),	)
	)
In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
Request for a General Rate Revision relating to the Port Westward plant (UE 184).	)

ICNU/203

PGE ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS 2007

August 9, 2006

PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2007 COS ONLY -- WITH ICNU'S CHANGE TO GENERATION ALLOCATION

CATEGORY	RATE SCHEDULE	Current	CONSUMERS (Forecast SDEC05E07)	MWH SALES	TOTAL ELECTRIC BILLS: CURRENT with all supplementals except LIA & PPC	TOTAL ELECTRIC BILLS: PGE PROPOSED with all supplementals except LIA & PPC	TOTAL ELECTRIC BILLS: ICNU PROPOSED with all supplementals except LIA & PPC	Change: PGE %	Change: ICNU %
Residential	7	7, 31-1R	702,246	7,524,421	$635,784,749	$671,984,273	$674,316,843	5.7%	6.1%
Employee Discount		& 31-IIR			($684,662)	($725,483)	($728,046)		
Subtotal					$635,100,087	$671,258,789	$673,588,798	5.7%	6.1%
Outdoor Area Lighting	15	14R, 14C	1,351	23,496	$4,133,012	$4,362,657	$4,360,308	5.6%	5.5%
General Service <30 kW	32	31-I, 32-I,	81,581	1,503,045	$129,641,279	$139,753,707	$139,920,796	7.8%	7.9%
Opt. Time-of-Day G.S. >30 kW	38	37* & 38*	1,255	105,829	$9,056,184	$10,023,222	$9,952,031	10.7%	9.9%
Irrig. & Drain. Pump. < 30 kW	47	48* & 49*	3,090	22,922	$1,682,697	$1,910,163	$1,909,934	13.5%	13.5%
Irrig. & Drain. Pump. > 30 kW	49	48* & 49*	1,410	67,951	$3,694,522	$4,205,407	$4,205,407	13.8%	13.8%
General Service >30 kW									
Secondary	83-S	31-II, III,	11,768	5,402,871	$373,803,541	$395,508,412	$394,535,896	5.8%	5.5%
Primary	83-P		143	298,570	$18,760,067	$20,638,575	$20,563,933	10.0%	9.6%
Schedule 89 > 1 MW		82-I,II, 83-I,II							
Secondary	89-S		101	667,477	$46,378,229	$47,032,935	$46,896,777	1.4%	1.1%
Primary	89-P		115	2,494,263	$149,758,830	$156,233,551	$155,435,012	4.3%	3.8%
Subtransmission *	89-T	& 85-P	9	1,358,222	$74,460,512	$78,864,607	$78,392,843	5.9%	5.3%
Street & Highway Lighting	91	91	206	97,806	$14,620,605	$16,365,388	$16,366,366	11.9%	11.9%
Traffic Signals	92	92	14	5,939	$395,062	$441,149	$441,149	11.7%	11.7%
Recreational Field Lighting	93	93	27	565	$80,167	$89,536	$89,536	11.7%	11.7%
TOTAL (CYCLE YEAR BASIS]			803,314	19,573,378	$1,461,564,795	$1,546,688,099	$1,546,658,784	5.8%	5.8%
==========================									
CONVERSION ADJUSTMENT					$2,104,558	$2,227,130	$2,227,088		
===================================									
TOTAL (CALENDAR YEAR BASIS]				19,601,562	**$1,463,669,353**	**$1,548,915,229**	**$1,548,885,872**	5.8%	5.8%

ICNU/203
Iverson - Wolverton/1

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 180/UE 181/UE 184

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision (UE 180),	)
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Annual Adjustments to Schedule 125 (2007 RVM Filing) (UE 181),	)
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision relating to the Port Westward plant (UE 184).	)

ICNU/204

PGE RESPONSES TO DATA REQUESTS

August 9, 2006

May 4, 2006

TO: S. Bradley Van Cleve
ICNU

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to ICNU Data Request 1.4
Dated April 20, 2006
Question No. 004

Request:

Please explain why an increase in baseline demand from a partial requirements customer should be treated differently from a new load.

Response:

A partial requirement customer's contractually specified Baseline Demand may increase as a result of from an increase in either a partial requirements customer's load (that is, on-site energy usage exclusive of generation) or a decrease in on-site generation output, subject to notice requirements as described in Schedule 75, Condition 9. Schedule 75 differentiates between these two reasons for changes to Baseline Demand. The Schedule 75 Baseline Demand establishes the load normally supplied by the Company.

As described in Schedule 75, load is served by the Company up to the Baseline Demand at the Cost of Service prices set out in Schedule 89. Increases in the customer's load net of generation, caused by an increase in energy usage by on-site equipment with no change in generation characteristics, are effectively treated the same as new load and will increase the contractual Baseline Demand (Schedule 75, Special Condition 8). In reality, PGE is generally aware of significant new loads well before they come on line. This is due to our need to adequately plan to meet the load not only from a supply view point but also in terms of delivery of the power. The advance knowledge is often at least two years.

A change in the customer's net load resulting from on-site generation output reduction is not a new load but a shift in generation source initiated by the customer. The customer's Baseline Demand can then be changed with two year notice. As explained in Exhibit 1300, Kuns-Cody/38, the ability of a partial requirements customer to minimize its costs in the short run by changes in the Baseline Demand related to use of on-site generation or utility cost of service supply, does not equitably balance the impact of this optionality with cost impacts on other customers.

August 3, 2006

TO: S. Bradley Van Cleve
ICNU

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to ICNU Data Request 10.133
Dated July 20, 2006
Question No. 133

Request:

Regarding PGE's response to ICNU data request No. 1.4, please provide an explanation and all documents that support the statement that "advance knowledge is often at least two years."

Response:

Existing customers who anticipate load growth typically contact PGE representatives well in advance of this load growth in order to ensure that PGE is able to install the necessary power delivery infrastructure to support this load growth. As stated in the Response to ICNU Data Request No. 004 "advance knowledge is often at least two years."

August 3, 2006

TO: S. Bradley Van Cleve
ICNU

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to ICNU Data Request 10.143
Dated July 20, 2006
Question No. 143

Request:

In reference to PGE's response to Staff data request No. 407, is it PGE's position that a QF must meet its entire energy requirement with self-generation before it can sell any energy to a third party?

Response:

PGE's response to Staff data request No. 407, which relates to partial requirements service provided under Sch. 75 is based on the assumption that the partial requirements service is a metered net requirements service, that is, PGE supplies all power to the customer not otherwise generated on-site and exports from the customer occur only when generation output is in excess of on-site load.

Customers with on-site generation which also has appropriate utility metering for the generation may export output from a metered generator, subject to any FERC and state regulations regarding transmission access and appropriate protections to avoid adverse impacts on retail customers. The partial requirements service provided by the Company must not support arrangements that allow the customer to utilize COS supply in order to effect or support energy sales. In addition, PGE COS should not indirectly provide ancillary services in support of a sale of power resulting from unexpected generator output fluctuations. For example, if the customer's generation decreased unexpectedly, the partial requirements service should not be assumed to be standing by for all generation swings where exports are being made.

August 3, 2006

TO: S. Bradley Van Cleve
ICNU

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to ICNU Data Request 10.145
Dated July 20, 2006
Question No. 145

Request:

Can a customer with self-generation purchase all of its requirements pursuant to Schedule 89 and simultaneously sell all of its output to a third party? Does the answer change if the customer is a QF? Does the answer change if the sale is to PGE?

Response:

A customer (or QF) with self-generation may purchase all of its requirements on Schedule 89 and sell all of its generator output to a third party. A sale of QF power to PGE must meet the requirements of PURPA.

May 16, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated May 3, 2006
Question No. 407

Request:

Please explain whether a Schedule 75 customer can sell all or part of its generator output to a third party. If not, please explain why, including how such a provision could harm other customers or shareholders, and cite the condition in the tariff that PGE believes prohibits such sales.

Response:

Schedule 75 as its name states, is a Partial Requirements Schedule: therefore it is made available to Large Nonresidential Customers *supplying all or some portion of their load by self-generation operating on a regular basis.* If a customer is selling all of its generation output to a third party and purchasing its power requirements from PGE, it is not a partial requirements customer and thus is not served under Schedule 75.

A Schedule 75 customer can sell part of its generator output to a third party provided it has met all of its energy requirements through self-generation and does not take energy from PGE.

A Schedule 75 customer may not sell its generator output while simultaneously receiving energy from PGE because to do so allows the customer to unfairly arbitrage between power markets and the PGE cost of service rate. For example if the Schedule 75 customer were to request an additional 50 MWa (438,000 MWH and market prices were anticipated to be $75 per MWH while PGE's embedded cost of service energy supply was anticipated to be $55 per MWH, other customers would bear the burden of this cost increase in energy supply. If market prices later fell below the PGE rate and assuming that the customer's cost of generation was less, the customer would then stop selling in the market and utilize the power it generated. Again, PGE's other customers would suffer.

OPUC Staff has previously recognized that changes to Schedules 75 and 575 should be considered. Attachment 407-A contains the OPUC Staff memo that states that "...we agree with PGE that changes to Schedules 75 and 575 should be considered to protect other customers from 'precipitous decisions by partial requirements customers to switch from self generation to cost of service'."

Conditions in the tariff that prohibit the Schedule 75 customer from selling its output while simultaneously receiving energy from PGE at a COS energy rate are specified in the following places within the proposed Schedule 75 tariff:

75-1 under Applicability; To Large Nonresidential Customers supplying all or some portion of their load by self-generation operating on a regular basis.

75-2 under Baseline Demand; Baseline Demand is the Demand normally supplied by the Company to the Large Nonresidential Customer when the Customer's generator is operating.

75-3 under Baseline Energy; Unless otherwise agreed to, the Baseline Energy is the Energy normally supplied by the Large Nonresidential Customer when the Customer's generator is operating.

Rule F (E.) Restrictions on Resale.

UE 180
Attachment 407-A

OPUC Staff Memo

10/28/05

Craig Zuck
Senior Key Customer Manager
Portland General Electric
122 SW Salmon Street
1WTC0807
Portland Oregon, 97204

Subject: Request to Increase Baseline Demand from 2000 KW to 20,000 KW

Dear Craig:
Subject to PGE Rate Schedule 75 and Special Condition #9 of Rate Schedule 75, SP Newsprint requests that the Baseline Demand for its Newberg mill be increased from 2,000 kW to 20,000 kW effective January 1, 2006. Rate Schedule 75 defines the Baseline Demand as:

> "the Demand normally supplied by the Company to the Large Nonresidential Consumer when the Consumer's generator is operating. The Consumer's typical peak Demand for the most recent 12 months prior to installing the generator, adjusted for generator operations, shall be used to calculate the Baseline Demand. The Company and Consumer may mutually agree to use an alternate method to determine the Baseline Demand when the Consumer's Demand is highly variable. Any modification to the Baseline Demand must be consistent with the Special Condition."

Special Condition #9 of Rate Schedule 75 further states that:

> "The Consumer's Baseline Demand may be modified as requested by the Consumer upon the addition of permanent energy efficiency measures, load shedding, or the removal of equipment. The Consumer's Baseline Demand may be modified by the Company if the Company determines that the level does not reflect load adjusted for the actual Consumer generation."

During this last year, customer demands required that we develop and offer a lighter weight (27 lbs) newsprint grade in addition to the traditional standard weight (30lbs) to our customers. The demand for the lighter weight product has increased from about 25% of our production at the beginning of 2005 to about 75% today. The reduction in weight has created a corresponding reduction in the amount of pulp (fiber) necessary to supply the same amount of print surface. This has changed our pulp supply mix causing us to use more recycle pulp and less thermal mechanical pulp (TMP). The TMP is extremely energy intensive, all in the form of electricity. Additionally, the TMP pulp presents a quality issue with linting that de-inked pulp does not. Overall we now need less MW's to make a roll of paper.

This reduction in energy demand is being accomplished by:

- De- bottlenecking our recycle Deink Pulp mill.
- Installing more efficient refiner plates

- Operating without No 2 refiner line
- Reduced operations of No. 1 refiner line.

This reduced base load electric energy consumption will render the economic dispatch of our second gas turbine subject to prevailing power and natural gas prices[1]. At projected natural gas and power prices for 2006 it is expected that the second gas turbine will be dispatched only during high system wide demand periods. Due to the permanent energy efficiency measures, and the shutting down of production lines, a Baseline Demand of 20,000 kW is considered more appropriate at this time.

SP requests that PGE increase the Baseline Demand at the Newberg Mill from 2,000 kW to 20. 000 kW effective January 1, 2006 for a period of one year. No decision has been made at this time to permanently remove "refiner lines" or a gas turbine from the Newberg mill, but may be considered in the future.

SP Newsprint understands that Special Condition 10 of Rate Schedule 75 requires that Energy used above the initial Baseline Demand (2,000 kW) and below the revised Baseline Demand will be priced at the Daily Price Option contained in Schedule 83 unless the Consumer has given the required notice to change the applicable Schedule 83 Energy Charge Option.

Sincerely,

C. E. "Ed" Smith
Corporate Energy Manager

cc Lisa Schwartz
Maury Galbraith
Bruce Craig
Ken Li
Randy Blank
Mark Rawlings

[1] The efficiency of the gas turbines at the Newberg mill changes depending upon the prevailing operating conditions and the chosen output level. The effective heat rate (amount of natural gas used per unit of electric output) changes depending upon whether the machine is in start-up, shut-down, fully loaded, or partially loaded. Future operation of the second gas turbine will be more dependent upon the prevailing market heat rate.

ITEM NO. 3A

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: November 8, 2005

REGULAR _X_ CONSENT ____ EFFECTIVE DATE ____November 9, 2005____

DATE: November 3, 2005

TO: Public Utility Commission

FROM: Lisa Schwartz and Maury Galbraith

THROUGH: Lee Sparling, Ed Busch, and Bonnie Tatom

SUBJECT: PORTLAND GENERAL ELECTRIC: (Docket No. UE 176/Advice No. 05-17) Revises Schedules 75 and 575, Partial Requirements Service.

STAFF RECOMMENDATION:

Staff recommends that the Commission deny PGE's request to allow Advice No. 05-17 to go into effect with less than statutory notice, and the question of whether the tariff should be suspended or allowed to go into effect be set over for the public meeting of November 22, 2005.

DISCUSSION:

The Commission approved Schedules 75, 575, 76R and 576R, Portland General Electric (PGE) partial requirements service, on July 19, 2004. The schedules were developed through an investigation (UE 158) and resulting Stipulation filed by staff, PGE, SP Newsprint, Industrial Customers of Northwest Utilities and Oregon Department of Energy. *See* Order No. 04-400.

PGE filed Advice No. 05-17 on November 1, 2005, requesting that the Commission "clarify the process and time frame by which a customer may request modification of its Baseline Demand when the modification relates to changes in generation capacity or generation operations including the mothballing or removal of generating equipment." Baseline Demand represents the self-generating consumer's demand under normal operation of its on-site generation.

SP Newsprint is the sole customer taking service on PGE's partial requirements schedules. PGE's current filing was precipitated by SP Newsprint's request on October 28, 2005, to increase its Baseline Demand for 2006 (Attachment A). As a Schedule 75 customer, SP Newsprint can choose any option in Schedule 83 for Baseline Energy (energy usage up to Baseline Demand), so long as it meets the notification requirements for switching energy options.

PGE requests a waiver of statutory notice so that the filing would take effect November 9, 2005. In its application for the waiver, PGE states that the purpose is to add clarification prior to the company's Resource Valuation Mechanism (RVM) filing on November 15, 2005.

Staff recommends that the Commission reject PGE's request for a waiver of statutory notice. Staff, parties to UE 158, and others that may be affected by the filing should have sufficient opportunity to review the advice filing and provide comments to the Commission.

Unless PGE extends the effective date of the tariff filing beyond December 1, 2005, among staff's options for the public meeting on November 22, 2005, are to recommend that the Commission suspend the filing or allow the filing to go into effect – with or without an investigation under ORS 757.215(4).

While staff takes no position at this time regarding SP Newsprint's request to increase its Baseline Demand, we agree with PGE that changes to Schedules 75 and 575 should be considered to protect other customers from "precipitous decisions by partial requirements customers to switch from self generation to cost of service." At the same time, we believe that some of the proposed tariff changes go beyond clarifying the existing tariffs.

SP Newsprint's request to increase its Baseline Demand should be determined based on Schedule 75 as of the date SP Newsprint made its request, and not the tariff as amended by the Commission after that date.

<u>Implications of SP Newsprint's Baseline Demand Request for PGE's 2006 RVM</u>

PGE's annual RVM sets transition adjustment rates that reflect the costs or benefits to the utility system of customers choosing an alternative electricity supplier.

The schedule in PGE's 2006 RVM proceeding requires the company to make a final MONET filing on November 10, 2005, and to post Schedule 125 transition adjustment rates on November 15, 2005. The appropriate load forecast for PGE's RVM filing is affected by whether SP Newsprint's request to increase Baseline Demand meets the conditions in Schedule 75 for making such a change.

The Schedule 125 Part A adjustment rates are calculated as the difference between PGE's projected forward market prices, adjusted for delivery to the company's system, and the expected cost of power from long-term resources delivered to PGE's system, divided by expected system loads. The Part A adjustment rate for large nonresidential customers is affected by SP Newsprint's request to increase its Baseline Demand. If PGE grants SP Newsprint's request, expected large nonresidential load would increase, and the Part A adjustment credit would decrease for all large nonresidential customers.

A reduced Part A credit would result in higher cost of service rates for large nonresidential customers. It also would affect customers that receive energy service from PGE under a standard offer rate and those that receive service from an alternative electricity supplier (except for those participating in Schedule 483).

If PGE denies SP Newsprint's request to increase Baseline Demand based on PGE's reading of the current tariff language, SP Newsprint may file a complaint under ORS 756.500 and OAR 860-013-0015. If PGE does not include the requested increase in Baseline Demand in its load forecast in the 2006 RVM filing, PGE is at risk of under-recovery if the Commission later determines that the request for a change in Baseline Demand was inappropriately denied. Alternatively, PGE could include SP Newsprint's requested increase in Baseline Demand in its load forecast in the 2006 RVM filing, and set higher large nonresidential rates, subject to refund, that would keep PGE whole in the event that the Commission later determines that the request should have been granted.

The Commission does not need to make a decision at this time about SP Newsprint's request to change its Baseline Demand under the terms of the existing Schedule 75.

PROPOSED COMMISSION MOTION:

Portland General Electric's request to allow Advice No. 05-17 to go into effect with less than statutory notice be denied, and the question of whether the tariff should be suspended or allowed to go into effect be set over for the public meeting of November 22, 2005.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 180/UE 181/UE 184

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision (UE 180),	))))))))
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Annual Adjustments to Schedule 125 (2007 RVM Filing) (UE 181),	)))))))))
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision relating to the Port Westward plant (UE 184).	))))))))))

ICNU/205

PROPOSED REVISIONS TO PGE SCHEDULE 75

August 9, 2006

ICNU/205
Proposed Revisions to PGE Schedule 75

SCHEDULE 75
PARTIAL REQUIREMENTS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers supplying all or some portion of their load by self-generation operating on a regular basis, where the self-generation has a total nameplate rating of 1 MW or greater. A Large Nonresidential Customer is a Customer that has exceeded 30 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 30 kW.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage		
	Secondary	Primary	Subtransmission
Basic Charge	$130.00	$230.00	$1,000.00
Transmission and Related Services Charge			
per kW of monthly On-Peak Demand	$0.66	$0.66	$0.66
Distribution Charges			
The sum of the following:			
per kW of Facility Capacity			
First 1,000 kW	$2.33	$2.17	$2.17
Over 1,000 kW	$0.40	$0.24	$0.24
per kW of monthly On-Peak Demand	$2.45	$2.45	$1.28
Generation Contingency Reserves Charges			
Spinning Reserves			
per kW of Reserved Capacity > 1,000 kW	$0.234	$0.234	$0.234
Supplemental Reserves			
per kW of Reserved Capacity > 1,000 kW	$0.234	$0.234	$0.234
System Usage Charge			
per kWh	0.206 ¢	0.186 ¢	0.178 ¢
Energy Charge			
per kWh	See Energy Charge Below		

* See Schedule 100 for applicable adjustments.

SCHEDULE 75 (Continued)

BASELINE DEMAND

Baseline Demand is the Demand normally supplied by the Company to the Large Nonresidential Customer when the Customer's generator is operating as planned by the Customer. Initially, the Customer's Baseline Demand will be determined as ~~T~~the Customer's typical peak Demand for the most recent 12 months prior to installing the generator, adjusted for planned generator operations.~~,~~ ~~will be used to calculate the Baseline Demand. The Company and Customer may mutually agree to use an alternate method to determine the Baseline Demand when the Customer's Demand is highly variable.~~ Subsequently, Customer shall select its Baseline Demand for the contract term under the service agreement based upon the Customer's peak demand for the most recent 12 months during the times the generator was operating as planned, adjusted for changes in load and planned generator operations. Planned generator operations includes changes in the electricity produced by the generator as well as the Customer's plans to sell any electricity produced by the generator to the Company or third parties. The Company and Customer may mutually agree to use an alternate method to determine the Baseline Demand when the Customer's Demand is highly variable. Any modification to the Baseline Demand must be consistent with the Special Conditions.

For Customers who are also receiving service under Schedule 76R, monthly Demand charges under Schedule 75 will be based on Demand up to the Baseline Demand.

FACILITY CAPACITY

For the first three months of service under this schedule, the Facility Capacity will be equal to the Customer's Baseline Demand. Starting with the fourth month, the Facility Capacity will be the average of the two greatest non-zero monthly Demands established during the 12-month period which includes and ends with the current Billing Period, but will not be less than the Customer's Baseline Demand.

RESERVED CAPACITY

The Reserved Capacity is the lesser of the nameplate rating of the Customer's generation or the maximum kW of Customer load supplied by the Customer's generation. Additionally, upon agreement with the Customer, the Company will reduce the Reserved Capacity by the Customer's demonstrated, instantaneous load reduction capability in kW associated with generation output reductions.

The Customer and Company will enter into a written agreement that specifies the Reserved Capacity in kW, the load reduction capability in kW (if any), the requirements for Customer notification to the Company of any changes in the Reserved Capacity, the Company's ability to request a demonstration of load reduction capability annually, additional metering requirements and any other necessary notification requirements.

SCHEDULE 75 (Continued)

RESERVED CAPACITY (Continued)

Except during the first three months of operation, if the Customer's operations result in an actual Reserve Capacity requirement above the level specified by the agreement, the Reserved Capacity will immediately be adjusted to the actual kW level for that month and the following three months. Thereafter, the Reserved Capacity will remain at that increased kW level until the Customer has demonstrated to the Company's reasonable satisfaction that the Reserved Capacity should be revised.

GENERATION CONTINGENCY RESERVES

Generation Contingency Reserves consist of the following components:

Spinning Reserves

Spinning Reserves provide Electricity immediately after a Customer's generator output falls below the Reserved Capacity. Spinning Reserves in combination with Supplemental Reserves transition a Customer's load to Unscheduled Power. A Customer on Schedule 75 must take Spinning Reserves in all Billing Periods that its generator is expected to operate. Spinning Reserves are not required for a Customer with Reserved Capacity of 1,000 kW or less, or when the Customer's generator is not normally scheduled to operate during an entire Billing Period.

Supplemental Reserves

Supplemental Reserves provide Electricity within the first 10 minutes after a Customer's generator output falls below the Reserved Capacity. In lieu of purchasing Supplemental Reserves, a Customer may choose to reduce load within the 10 minutes of generator failure. The Customer's load reduction plan must be approved by the Company.

Self-Supplied Reserves

Customers with nameplate Generation of 15 MW or greater may self-supply needed Generation Contingency Reserves upon agreement between Customer and the Company. The agreement will specify the kW of Contingency Reserves provided by the Customer at 7% of Reserved Capacity, the notification processes for delivery of reserve Energy, the requirements for Customer delivery of requested reserves, the requirements for Customer notification to the Company of any changes in the ability to self-supply reserves, the settlement process to be used when Contingency Reserves are supplied by the Customer, the provisions for an annual demonstration of such capability, any additional metering requirements and other necessary notification requirements. Customers who self-supply Generation Contingency Reserves will not be charged for Spinning and Supplemental Reserves under this schedule.

SCHEDULE 75 (Continued)

Supplemental Reserves Load Reduction Plan

In lieu of self supplying of Supplemental Reserves through a Self-Supply Agreement, a Customer may provide Supplemental Reserves through the submittal to the Company of a Load Reduction Plan that demonstrates the ability to reduce load within the first ten minutes of generator failure and specifies a kW amount of load reduction equal to 3.5 percent of the Supplemental Reserves Level. The Load Reduction Plan also shall specify the notification processes for delivery of Reserves, the requirements for Customer delivery of requested Reserves, the requirements for Customer notification to Company of any changes in the ability to Supply Supplemental Reserves, the settlement process to be used when Reserves are supplied by the Customer, the provisions for a demonstration of such capability, any additional metering requirements and other necessary notification, plant and financial requirements. The Customer Load Reduction Plan must be approved by the Company. If approved by the Company, and adhered to by the Customer, a Supplemental Reserves kW credit will be applied to Customer's bill based on the Supplemental Reserves Level as specified in the Load Reduction Plan.

If Customer fails to follow the Company-approved Load Reduction Plan, all kW credits for the subsequent three months (Penalty Period) shall be forfeited. If the Customer satisfactorily follows the Company-approved Load Reduction Plan during the second three month Penalty Period, the Load Reduction Plan kW credit will be reinstated at the end of the second three month Penalty Period.

If the Customer fails to follow the Company-approved Load Reduction Plan a second time during the combined six month period, the Load Reduction Plan shall be terminated.

The duration of the Penalty Period shall not be limited by the establishment of a new contract.

Following termination or contract expiration, consumer may submit a new Load Reduction Plan to the Company. Company will approve the new Load Reduction Plan if the Customer is able to demonstrate the load education capability of the Plan to Company's satisfaction.

Notwithstanding the above, Customer may terminate the Company-approved Load Reduction Plan upon giving written notice to Company as provided in the Self-Supply Agreement.

SCHEDULE 75 (Continued)

ENERGY CHARGE

The Energy Charge is comprised of the following:

Baseline Energy

Unless otherwise agreed to, the Baseline Energy is the Energy normally supplied by the Company to the Large Nonresidential Customer when the Customer's generator is operating.

Usage on an hourly basis up to and including the Baseline Demand will be considered Baseline Energy. The Company may, in collaboration with the Customer, develop an alternate method to determine Baseline Energy when the Customer is new to the Company's system or has changed operations from the previous year.

If other than the typical operations are used to determine Baseline Energy, the Customer and the Company must agree on the Baseline Energy before the Customer may take service under this schedule. The Company may require use of an alternate method to determine the Baseline Energy when the Customer's usage not normally supplied by its generator is highly variable. Baseline Energy will be charged at the applicable Energy Charge, including adjustments, under Schedule 89. All Energy Charge options included in Schedule 89 are available to the Customer on Schedule 75 based on the terms and conditions under Schedule 89. For Energy supplied in excess of Baseline Energy, the Scheduled Maintenance Energy and/or Unscheduled Energy charges will apply except for Energy supplied pursuant to Schedule 76R.

Any Energy Charge option for Baseline Energy selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service.

Scheduled Maintenance Energy

Scheduled Maintenance Energy is Energy prescheduled for delivery, up to 744 hours per calendar year, to serve the Customer's load normally served by the Customer's own generation (i.e. above Baseline Energy). Scheduled Maintenance must be prescheduled at least one month (30 days) before delivery for a time period mutually agreeable to the Company and the Customer.

When the Customer preschedules Energy for an entire calendar month, the Customer may choose that the Scheduled Maintenance Energy Charge be either the Monthly Fixed or Daily

SCHEDULE 75 (Continued)

ENERGY CHARGE (Continued)
Scheduled Maintenance Energy (Continued)

Price Energy Charge Option, including adjustments as identified in Schedule 100 and notice requirements as described under Schedule 89. When the Customer preschedules Energy for less than an entire month, the Scheduled Maintenance Energy will be charged at the Daily Price Energy Option, including adjustments, under Schedule 89.

Unscheduled Energy

Any Electricity provided to the Customer that does not qualify as Baseline Energy or Scheduled Maintenance Energy will be Unscheduled Energy and priced at an Hourly Rate consisting of the Dow Jones Mid-Columbia Hourly Firm Electricity Price Index (DJ-Mid-C Hourly Firm Index) plus 0.236¢ per kWh for wheeling, a 0.300¢ per kWh recovery factor, plus losses. If prices are not reported for a particular hour or hours, the average of the immediately preceding and following reported hours' prices within on- or off-peak periods, as applicable, will determine the price for the non-reported period. Prices reported with no transaction volume or as survey-based will be considered reported.

On-peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

The Company may request that a Customer taking Unscheduled Energy during more than 1,000 hours during a calendar year provide information detailing the reasons that the generator was not able to run during those hours in order to determine the appropriate Baseline Demand.

LOSSES

Losses will be included by multiplying the applicable Energy Charge by the following adjustment factors:

Subtransmission Delivery Voltage	1.0337
Primary Delivery Voltage	1.0488
Secondary Delivery Voltage	1.0834

DIRECT ACCESS PARTIAL REQUIREMENTS SERVICE

A Customer served under this schedule may elect to receive Direct Access Partial Requirements Service from an Electricity Service Supplier (ESS) under the terms of Schedule 575 provided it has given notice consistent with any Baseline Energy option requirements. A Customer may return to Schedule 75 provided it has met any term requirements of Schedule 575 and any requirements needed to purchase Baseline Energy if needed.

SCHEDULE 75 (Continued)

MINIMUM CHARGE

The Minimum Charge will be the Basic, Transmission, Distribution, Demand and Generation Contingency Reserves Charges, when applicable. In addition, the Company may require a higher Minimum Charge, if necessary, to justify the Company's investment in service Facilities.

REACTIVE DEMAND CHARGE

In addition to the charges as specified in the Monthly Rate, the Customer will pay 50¢ for each
REACTIVE DEMAND CHARGE (Continued)

kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule will be subject to all adjustments as summarized in Schedule 100. Applicable adjustments will be applied to Baseline Energy and Scheduled Maintenance Energy with the exception of Schedules 108 and 115, which are applied to factors other than usage as required by statute.

SPECIAL CONDITIONS

1. Prior to receiving service under this schedule, the Customer and the Company must enter into a written service agreement specifying the terms and conditions of service, the Customer's Baseline Demand and Energy Pricing Option under Schedule 89, the Customer's Reserved Capacity, the Company's and Customer's contact information, and any other information necessary for implementation of service under this schedule. The term of the service agreement shall be one calendar year (except that the term of the first service agreement shall be the remainder of the year when signed and the next calendar year) and shall renew annually thereafter for successive one year terms, unless the customer gives 90 days prior written notice. These terms and conditions will be consistent with this schedule.

2. A Customer must inform the Company within 30 minutes of taking Unscheduled Energy at a rate of five MW or greater and inform the Company of the anticipated time that the generator will return to normal operations.

3. Customers must have Company approved interval metering and meter communications in place prior to initiation of service under this schedule. The Company requires metering that measures the net quantity and direction of flow at the Point of Delivery and total Generator output.

SCHEDULE 75 (Continued)

SPECIAL CONDITIONS (Continued)

4. If the Customer is served at Primary or Subtransmission Voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and the necessary wiring on both sides of the transformers. All transformers, equipment and wiring will be of types and characteristics approved by the Company and their installation, operation and maintenance will be subject to inspection and approval by the Company.

5. If during a Billing Period the Customer is billed for Transmission and Related Services under this schedule and Transmission Services under the Company's FERC Open Access Transmission Tariff (OATT) for the purpose of effecting a wholesale power sale from the Customer's generator, the payments for OATT charges for Transmission Service (Schedules 7 or 8) and Schedule 3, Regulation and Frequency Response Service will be credited to the Transmission and Related Services Charge under this schedule. The credit will be the actual OATT demand incurred but will not exceed the Monthly Demand for the Schedule 75 monthly Transmission Demand multiplied by the applicable OATT (OATT Schedules 3, 7 or 8) and such credit will not exceed the Transmission and Related Services Charge incurred under this schedule.

6. The Customer will not use Scheduled Maintenance Energy, Unscheduled Energy or Reserved Capacity to directly or indirectly make or continue a delivery of Electricity to another Customer or wholesale power purchaser.

7. A Customer's failure to inform the Company of the use of on-site generation will not relieve the Customer of responsibility for the charges and requirements under this schedule.

8. The Customer's Baseline Demand may be increased or decreased~~modified~~ as requested by the Customer upon the addition of permanent energy efficiency measures, load shedding, or the addition or removal of equipment or permanent or long-term changes in loads or generator operations. The change in Baseline Demand shall be made as soon as such change is verified by the Company. The Customer's Baseline Demand may be modified by the Company if the Company determines that the level does not reflect load adjusted for the actual Customer generation.

9. A change in Baseline Demand related to modifications in generating capacity or planned generation operations may be made provided the Customer provides the following notice: a) for a change in Baseline Demand that is equal to or less than 10 MW, customer shall supply notice by July 1, which will be effective for the following calendar year; and b) for a change in Baseline Demand that is greater than 10 MW, customer shall supply notice by January 1, which will be effective for the following calendar year ~~not less than two calendar years prior notice to the Company of such change~~. Any subsequent notice by the Customer under this

SCHEDULE 75 (Continued)

SPECIAL CONDITIONS (Continued)

special condition must be made consistent with these notice requirements. ~~no earlier than two years from the last notice that resulted in a change to the Customer's Baseline Demand.~~

10. If the Customer's Baseline Demand is increased, any Energy used above the initial Baseline Demand, and below the revised Baseline Demand will be priced at the Daily Price Option contained in Schedule 89 unless the Customer has given the required notice to change the applicable Schedule 89 Energy Charge Option.

11. The Company reserves the right to modify any agreements existing under this schedule as a result of changes in Western Electricity Coordinating Council guidelines.

12. If the Customer is receiving service under this schedule and Schedule 76R, the monthly Basic and Facility Capacity charges may be replaced and billed pursuant to Schedule 76R Special Conditions.

~~**TERM**~~

13. A Customer may not change service options until it has satisfied any Baseline Energy term provisions as established in Schedule 89.