ATERWYNNE LLP
ATTORNEYS AT LAW

Suite 1800
222 S.W. Columbia
Portland, OR 97201-6618
503-226-1191
Fax 503-226-0079
www.aterwynne.com

June 13, 2005

VIA EMAIL AND US MAIL

Filing Center
Oregon Public Utility Commission
550 Capitol Street NE #215
PO Box 2148
Salem, OR 97308-2148

Re: UE 167 – Idaho Power Company's Opening Brief

Dear Sir or Madam:

Enclosed for filing in the above-referenced docket is the original and five copies of Idaho Power Company's Opening Brief. Please contact me with any questions.

Very truly yours,

Jessica A. Centeno

Enclosures
cc: UE 167 Service List
Bart Kline

CERTIFICATE OF SERVICE
UE 167

I hereby certify that a true and correct copy of **IDAHO POWER COMPANY'S OPENING BRIEF** was served via U.S. Mail on the following parties on June 13, 2005:

Ms. Stephanie S. Andrus
Oregon Department of Justice
General Counsel Division
100 Justice Building
1162 Court Street NE
Salem OR 97301

Lowrey R. Brown
Citizens' Utility Board of Oregon
Suite 308
610 SW Broadway
Portland OR 97205

Jason Eisdorfer
Citizens' Utility Board of Oregon
Suite 308
610 SW Broadway
Portland OR 97205

Ric Gale
Idaho Power Company
PO Box 70
Boise ID 83707

Rates & Regulatory Affairs Rates & Regulatory Affairs
Portland General Electric
121 SW Salmon Street
Portland OR 97204

Don Reading
Ben Johnson Associates
6070 Hill Road
Boise ID 83703

Peter J. Richardson
Richardson & O'Leary
515 North 27th Street
Boise ID 83702

Douglas C. Tingey
Portland General Electric
121 SW Salmon Street
Portland OR 97204

Robert Valdez
PO Box 2148
Salem OR 97308-2148

ATER WYNNE LLP

Jessica A. Centeno

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 167

In the Matter of IDAHO POWER COMPANY Application for General Rate Increase in the Company's Oregon Annual Revenues of $4,418,908, or 17.52 Percent Overall	**IDAHO POWER COMPANY'S OPENING BRIEF**

INTRODUCTION

Idaho Power Company ("Idaho Power" or the "Company") has filed an application with the Public Utility Commission of Oregon ("OPUC" or the "Commission") for authority to raise its rates in the approximate amount of $4,418,908, a 17.52% increase over its current base rates ("Application"). Idaho Power last filed for general rate relief in the State of Oregon based upon a 1993 test year. With the passage of approximately ten years, the company has experienced numerous changes associated with the expenses of providing electric service, primarily due to: (1) overall increases in the Company's operating expenses due to load expansion; (2) substantial additional investment in transmission and distribution plant needed to continue to supply reliable service to customers; and (3) the addition of plant investment and operating expenses associated with the commercial operation of the Danskin combustion turbine generating plant.

The parties have settled most of issues presented by this case, resulting in an agreement for an overall reduction in the requested increase to 12.09%.[1] The major issue remaining in dispute is the appropriate normalized power supply expenses ("NPSE") to be included in the test year expenses. On this point the issue presented to the Commission is straightforward: What expenses associated with power supply can Idaho Power reasonably expect to incur during the

[1] Idaho Power/Staff/CUB/Industrial Customers/100, Owings/Reading/Brown/Jenks/Gale/3 ("Joint Testimony")

ATER WYNNE LLP
222 SW COLUMBIA, SUITE 1800
PORTLAND, OR 97201-6618
(503) 226-1191

period the rates adopted in this case will be in effect? Idaho Power has recommended NPSE of $47.7 million, while Commission Staff ("Staff") contends that the number should be a *negative* $15.3 million. Similarly, Citizens Utility Board ("CUB") has recommended NPSE of *negative* $18.6 million, and the Oregon Industrial Customers of Idaho Power ("OICIP") has generally joined Staff's recommendation.

The basis of the divergent estimates is the parties' differing methodologies for normalizing power expenses. Idaho Power's NPSE estimates are based upon a normalization methodology approved and relied upon by this Commission and the Idaho Public Utilities Commission ("IPUC") to set Idaho Power's rates for over twenty years. This methodology is consistent with sound ratemaking principles and has produced estimates in this case that are reasonable and consistent with historical experience. In contrast, Staff, CUB, and OICIP recommendations represent a complete departure from Commission-approved power supply expense normalization principles. Significantly, the methodologies employed by Staff and the other parties result in the unreasonable assumption that during the period the rates will be in effect Idaho Power will actually make more money selling excess power than it will incur producing and purchasing power for its customers benefit—a situation that has occurred in only two of the past twenty-one years. History, along with knowledge of current drought conditions, demonstrates that the projections of NPSE proposed by Staff, CUB, and OICIP cannot reasonably be expected to occur during the period of time rates will be in effect. As a result, if Staff, CUB, or OICIP's recommendations for net power supply expenses are adopted by this Commission, Idaho Power will have no realistic opportunity to recover its reasonably incurred power expenses or earn its rate of return. For these reasons, this Commission should reject the recommendations for NPSE made by Staff, CUB, and OICIP. Instead, Idaho Power's recommended NPSE should be adopted for inclusion in rates by this Commission.

ATER WYNNE LLP
222 SW COLUMBIA, SUITE 1800
PORTLAND, OR 97201-6618
(503) 226-1191

In addition to their arguments regarding power supply expenses, CUB and OICIP take issue with the Company's filing in several other respects. Specifically, OICIP recommends that the Commission disallow expenses associated with Idaho Power's Danskin Power Plant and reject Idaho Power's proposed time-of-use rates for its industrial customers taking service under Schedule 19. CUB asks that the Commission reject Idaho Power's proposed seasonal rates for residential customers taking service under Schedule 1. Idaho Power requests that the Commission reject these arguments and affirm and adopt the rates proposed by Idaho Power in its Application, as modified by the Stipulation, and adopt the rate design proposed by Idaho Power in its entirety.

BACKGROUND

Idaho Power filed its Application requesting a general rate increase and revised tariff schedules on September 21, 2004. In support of its request, the Company filed the testimony of ten witnesses and supporting exhibits. The Commission suspended the tariff schedules for nine months to allow for an investigation into the reasonableness of the filing.[2] CUB and OICIP have intervened and fully participated in the case.

On February 2, 2005, Staff, CUB, and OICIP circulated settlement proposals to all parties, and the parties met for settlement negotiations on February 14 and 24. As a result of those settlement negotiations, the Parties entered into a Stipulation to resolve most of the issues raised.[3] Among the issues settled were numerous revenue requirement issues including rate of return, net to gross factors, and various expenses, including those related to employee incentive pension, pay and salary structure expenses, legal expenses, and nonlabor and A&G expenses. The parties also settled various non-revenue requirement issues, including marginal expense

---

[2] On June 6, 2005, Idaho Power agreed to extend this suspension until July 29, 2005. *See Idaho Power's Revised Statement Agreeing to Extend Tariff Suspension Period*, filed June 6, 2005.
[3] *See Stipulation*, filed May 20, 2005.

ATER WYNNE LLP
222 SW COLUMBIA, SUITE 1800
PORTLAND, OR 97201-6618
(503) 226-1191

adjustment, service establishment charge, audit recommendations, and conservation. The only issues identified as not settled were the following:

1. *Idaho Power's normalized power supply expenses.* Staff, OICIP, and CUB all take issue with Idaho Power's proposed NPSE to be included in rates;
2. *Seasonal rates for residential customers.* CUB does not agree to the seasonal rates proposed by the Company for residential customers taking service under Schedule 1; and
3. *Time-of-use rates for industrial customers.* OICIP does not agree to the time-of-use rates proposed for customers taking service under Schedule 19.[4]

In addition, OICIP raises three issues that were not initially addressed by Idaho Power's Application and continue to be at issue. Specifically, OICIP contends that: (1) Idaho Power's power quality in its Oregon service territory is insufficient; (2) the Commission should order Idaho Power to work with interested parties to investigate the potential of integrating emergency generators into Idaho Power's system for additional generating capacity; and (3) expenses for the Danskin generating plant should be excluded from rate base.[5]

Staff, CUB, and OICIP filed direct testimony on March 15, 2005. Idaho Power filed its rebuttal testimony on April 8, 2005. Staff, CUB, and OICIP filed surrebuttal on April 29, 2005, and the Company filed sursurrebuttal on May 13, 2005. The hearing was held on May 12, 2005.

LEGAL STANDARD

The Commission's function is a rate case involves two primary steps: (1) determining the amount of revenue that the utility is entitled to receive (the utility's "revenue requirement"); and (2) allocating the revenue requirement among the utility's customer classes and designing rates within classes.[6] The utility's revenue requirement is determined on the basis of the utility's

---

[4] *Joint Testimony* at 2.
[5] *Id.* at 2.
[6] *In the Matter of the PacifiCorp's Proposal to Restructure and Reprice its Services in Accordance with the Provisions of SB 1149*, OPUC Docket No. UE 116, Order No. 01-787 at 5.

ATER WYNNE LLP
222 SW COLUMBIA, SUITE 1800
PORTLAND, OR 97201-6618
(503) 226-1191

investment and expenses.[7] The purpose of a test year is to provide a basis for determining the revenue requirement. When, as in this case, the test year is based on a historical period, that period is only a starting point for determining the revenue requirement. To ensure that the historical period is reasonably representative of the period during which rates will be in effect, adjustments are made to the test year to include recurring increase in revenues and expenses that are reasonably certain to occur. The same standard is used to exclude nonrecurring revenues and expenses.[8]

ARGUMENT

A. Idaho Power's Normalized Power Supply Expenses (NPSE) Should be Accepted

"Power supply expenses" or normalized power supply expenses ("NPSE") refers to the sum of fuel expenses and purchased power expenses[9], *minus* the revenue generated from surplus power sales to other entities.[10] In its filing, Idaho Power has included $47.7 million for power supply expenses. This represents a one percent decrease in power supply expenses from those accepted in 1995 in the Company's last rate case—UE 92. In contrast, Staff has recommended negative $15.3 million for power expenses, which represents a 132% decrease, while CUB has recommended negative $18.6 million, which represents a 139% decrease. Fundamentally, Staff and CUB are contending that over the period of time that rates adopted in this case will be in effect, Idaho Power will actually make more money from excess power sales than it will expend producing and purchasing power. This position is completely at odds with historical experience and expected water conditions, and is the result of flawed normalization methodologies.

---

[7] *Id.*

[8] *In the Matter of the Application of US West Communications, Inc., for an Increase in Revenue*, OPUC Docket No. UT 125/UT 80, Order No. 00-191 at 14-15.

[9] Power supply expenses exclude purchased power expenses associated with PURPA qualifying facilities ("QFs"), which for ratemaking purposes are quantified separately from other power supply expenses and are treated as fixed inputs to power supply modeling rather than variable outputs. Idaho Power/121, Said/4.

[10] Idaho Power/12T, Said/4.

ATER WYNNE LLP
222 SW COLUMBIA, SUITE 1800
PORTLAND, OR 97201-6618
(503) 226-1191

1. Idaho Power's Normalization Methodology is Consistent with this Commission's Accepted Ratemaking Policies and Produces Reasonable Results.

In order to determine its NPSE, Idaho Power utilized a normalization methodology that it has successfully employed in Oregon since 1982. The Company established a representative distribution of annual power expenses by examining 76 hydro supply scenarios (based on water years from 1928-2003) that could occur given 2003 test year loads. The Company then used the mean of that distribution as the NPSE representative of the "normal" central tendency for power supply expenses. The average power supply expense developed through this analysis should be representative of what the company will experience over time.[11]

The market prices for the 76 hydro scenarios were produced by the AURORA model, which incorporates basic economic principles governing the effect of hydro conditions on market prices.[12] Sound economic principles and historical data dictate that there is a close relationship between hydro conditions and the market price of energy in the Pacific Northwest region. When the region – and the Company – have abundant water, higher cost generating plants are not required to satisfy loads. The marginal resource at such times is likely a lower cost coal-fired unit, or even occasionally hydro generation. As a result, the market price for energy will fall to the incremental cost of the marginal resource. Conversely, when the region is in a drought condition, as it is currently, higher cost coal-fired units and gas-fired units will be the marginal resources influencing market prices.[13]

It is worth noting that prior to 1982, both the Oregon and Idaho Commissions evaluated a single supply-side scenario assuming a median water condition and a corresponding median water market price curve in order to determine power supply expenses. If power expense variations associated with drought and high water conditions produced symmetrical expense

[11] Idaho Power/12T, Said/16.
[12] Idaho Power/200, Said/3; Idaho Power/700, Peseau/3.
[13] Idaho Power/200, Said/5.

ATER WYNNE LLP
222 SW COLUMBIA, SUITE 1800
PORTLAND, OR 97201-6618
(503) 226-1191

impacts, such a methodology could be successfully employed. However, drought conditions in the 1970s demonstrated power expenses and different hydro conditions are not symmetric or linearly related.[14] Instead, expense variations associated with drought conditions varied from the median to a greater extent than expense variations associated with abundant water. That is to say, the expense associated with multiple conditions was different and higher than the average expense associated with a single median condition.[15] It is for precisely this reason that both Commissions rejected the "single supply-side scenario" (such as the method proposed by Staff in this case) and instead adopted the methodology proposed by Idaho Power.

It is significant that the Company's use of the AURORA model produced modeled power supply expenses that are generally consistent with actual power supply expenses the Company has experienced in the past. In fact, the model is conservative in its results. For example, the lowest modeled annual net power supply expense of negative $7.0 million is within $13.6 million of the amount actually experienced by the Company. On the other end, the highest annual net power supply expense the Company has experienced is $279.5 million, which is $131.7 million above the modeled extreme.[16]

Near-term historical data provides strong evidence that rates modeled by the Company can reasonably be expected to occur in the future. The data shows that the range of modeled power supply expenses is consistent with power supply expenses the Company has actually experienced.[17]

///

///

///

///

---

[14] Idaho Power/700, Peseau/3.
[15] Idaho Power/200, Said/4.
[16] Idaho Power/200, Said/8; Idaho Power /201, Said/1.
[17] Idaho Power/600, Said/7-8; Idaho Power/702, Peseau/1.

ATER WYNNE LLP
222 SW COLUMBIA, SUITE 1800
PORTLAND, OR 97201-6618
(503) 226-1191

2. Staff's and Intervenors' Proposed Normalization Methods are Inconsistent with this Commission's Approved Methodology and Produce Unreasonable Results.

Staff proposes to decrease the Company's overall NPSE by $63.0 million, which would result in a normalized NPSE of negative $15.3 million.[18] CUB recommends a reduction of $66 million, with pricing based on NWPPC's projections for the Southern Idaho Region.[19] OICIP recommends rejection of power supply modeling, but proposed repricing as per conversations with Staff.[20] The positions of these parties should be rejected.[21]

Rather than use the Commission-approved methodology for computing the Company's normalized NPSE, Staff urges the Commission to return to a pre-1982 approach to compute variable power expenses using a single average water year. In addition, Staff recommends that, instead of using the AURORA model to compute power supply expenses for a range of conditions, the Commission should use a single "average" water year scenario using April 30, 2004 forward price curves for the year 2005.

The so-called average transaction prices produced by Staff's methodology are much higher than those produced by AURORA and, more significantly, are at the extreme of historical experience, excluding 2000-2001 when market prices were distorted in California and the western United States. Using the Company's modeling over the full range of water conditions, the annual transaction rate was $22.90 per MWh. The annual modeled transaction rate for a single median water year (the 1967 water condition) was $23.85 per MWh. In contrast, Staff's forward price curves for the calendar year 2005 use average on-peak prices of $47.33 per MWh and off-peak prices of $39.72 per MWh.[22] Staff's forward transaction price assumptions result in

---

[18] Staff/200, Galbraith/15.
[19] CUB/100, Jenks-Brown/3-4.
[20] Idaho Power/200, Said/18; OICIP/Direct1, Reading/24.
[21] Because the positions of CUB, OICIP, and Staff on normalized net power supply expenses do not materially differ, Idaho Power's arguments with regard to Staff's proposals apply equally to CUB and OICIP. Idaho Power/200, Said/18.
[22] Idaho Power/200, Said/12-13.

ATER WYNNE LLP
222 SW COLUMBIA, SUITE 1800
PORTLAND, OR 97201-6618
(503) 226-1191

a level of net power expenses that has only been experienced by the Company twice in the past 21 years, the two highest water years on record.[23]

Staff's methodology also yields a result that is inconsistent with Staff's stated goal. In the 2003 test year, the actual annual transaction price for purchases and sales was $41.18 per MWh.[24] Notably, this test year was a drought year, and one of the primary goals of Staff's normalization analysis was to move from these drought conditions to an average water year.[25] But in fact, the annual transaction rate for purchases and sales under Staff's normalization scenario was $42.21 per MWh, $1.03 more per MWh than the actual.[26] In other words, Staff's analysis does not result in a test year that is representative of an "average" water year, but rather results in a test year that assumes higher transaction rates than those actually experienced by Idaho Power during a drought year.

These anomalous results are the product of two basic flaws in Staff's normalization methodology. First, Staff's proposed methodology ignores the asymmetric nature of the relationship between hydro expenses and water supplies, and would return the Commission to a means of computing power expenses rejected more than twenty years ago as not representative of actual power expenses. Second, Staff's proposal uses a single market price derived from forward price curves in the place of modeled market prices. This approach fundamentally mismatches a single projected hydro supply scenario's "average" that is unlikely to occur during the period in which the rates will be in effect with a price forecast based upon current hydro conditions that are not average. A number of problems flow from this apples-to-oranges comparison that are described in more detail below.

---

[23] Idaho Power/300, Peseau/8.
[24] Idaho Power/203, Said/1; Hearing Tr. at 17.
[25] Hearing Tr. at 17.
[26] Hearing Tr. at 17.

ATER WYNNE LLP
222 SW COLUMBIA, SUITE 1800
PORTLAND, OR 97201-6618
(503) 226-1191

a. Staff's Single Average Water Year Analysis Underestimates Power Supply Expenses

Staff proposes to use a single average water year, rather than multiple water year scenarios, to compute NPSE. This methodology will always underestimate power expenses because of asymmetric distribution of expenses associated with drought conditions. As described above, power expenses and hydro conditions are not linearly related.[27] The average expense associated with multiple water scenarios is, in fact, different and *higher* than the expenses associated with a single average water year. This is precisely the reason that the Company and OPUC rejected the use of a single median water supply scenario in favor of a multiple water year scenario analysis.[28]

Staff admits that the use of a single scenario reduces the impact of variability of water conditions on a load resource balance computation.[29] Staff further admits that it would be preferable to take into account multiple water year scenarios than to use a simple average scenario to compute NPSE.[30] To address these flaws in its analysis, Staff proposes the use of Staff's inputs to the AURORA model in the 76 scenarios developed by the Company as an alternative to its use of a single average water year.[31] Significantly, this change would result in an almost $40 million dollar difference in Staff's proposed adjustment to the Company's NPSE, to a decrease of $23.2 million. The Company believes that Staff's inputs to the model are themselves flawed, and Staff has made no attempt to justify the accuracy of its inputs.[32] However, the nearly $40 million dollar adjustment to Staff's proposed adjustment does demonstrate that importance of the use of a multiple-year scenario analysis to capture the impact of the asymmetric distribution of expenses associated with variable hydro supplies.

---

[27] Idaho Power/700, Peseau/3.
[28] Idaho Power/200, Said/4-6; Idaho Power/700, Peseau/4.
[29] Hearing Tr. at 11.
[30] *Id.*
[31] Staff/300, Galbraith/15.
[32] Idaho Power/600, Said/11-12; Staff/300, Galbraith/15.

ATER WYNNE LLP
222 SW COLUMBIA, SUITE 1800
PORTLAND, OR 97201-6618
(503) 226-1191

b. Actual Forward Price Curves Cannot be Accurately Applied to an Average Water Year Scenario

Staff proposes to use as cost inputs to its average water year scenario forward price curves for the Mid-C Hub from April 30, 2004, for the calendar year 2005. Staff suggests that forward price curves should be used because they are representative of the power market's expectation of average monthly spot market prices during 2005 under normal hydro conditions. This assumption is significantly flawed. Current forward price curves represent the current drought condition pricing, not average water conditions.[33] As a result, the use of an April 30, 2004 forward price curve significantly overestimates the price Idaho Power would receive for the sale of surplus power, which would be lower in an average or high water year.

Idaho Power has shown that the April 30, 2004 forward price curves reflected the influence of continued drought conditions. First, the Company demonstrated that if forward price curves reflected average water conditions, then those curves would show a pronounced increase towards higher prices as information about the severity of actual 2005 drought conditions became known. In fact, subsequent months' forward price curves were consistent with the April 30, 2004 price curves, which is evidence that drought conditions were already considered in the April 30 price curves.[34] Second, hydro conditions tend to remain below and above historical means for periods of more than a year at a time. This prior-year impact, known as "autocorrelation," indicates that there is a high probability that an extremely low water year (like 2004) will be followed by another low water year.[35] It is unlikely that power marketers would have ignored autocorrelation would have been ignored in determining the April 30, 2004 forward price curves.

[33] Idaho Power/300, Peseau/12-16.
[34] Idaho Power/300, Peseau/12-13.
[35] Idaho Power/300, Peseau 16.

ATER WYNNE LLP
222 SW COLUMBIA, SUITE 1800
PORTLAND, OR 97201-6618
(503) 226-1191

Another problem with the use of forward price curves is that this "flat" pricing (the average of on- and off-peak pricing) does not reflect that surplus would likely be sold off-peak, where pricing is lower.[36]

Finally, the use of forward curves represents a mismatching of types of data. Price curves are best understood as a forecast of pricing that can realistically be expected to occur in the near-term.[37] However, Staff applies this forecast data to a single, average water year that is not likely to occur in the near-term.[38] This mismatching of data results in inaccurate results which cannot be realistically used as a normalization of the test year.

3. Staff's Adjustment to the Company's NPSE Should be Rejected Because it Results in Expenses that are Unreasonable and Unlikely to Occur During the Period in which Rates Will be in Effect.

Clearly, as shown above, Staff's (and CUB's) proposed NPSE should be rejected as the product of a faulty methodology. In addition, a realistic assessment of the region's current drought conditions underscores the unreasonableness of Staff's recommendation. In 2003, the Company incurred actual power expenses of approximately $150 million; 2004 actual power expenses were $141.8. No party has disputed the Company's current year power expense estimate of $169 million.[39] Moreover, none of the parties dispute that current drought conditions will substantially *increase* power supply expenses over the next two years. In fact, Staff admits that it does not expect the Company to achieve in 2005 or 2006 the level of surplus sales that would be necessary to achieve the level of NPSE Staff recommends.[40]

Moreover, the Company has stated its intention, both in this case and in its application for deferred accounting (UM 1198), to file a new rate case in 2005.[41] Therefore, the rates adopted in

---

[36] Idaho Power/300, Peseau/17-18.
[37] Idaho Power/600, Said/4-5.
[38] Idaho Power/600, Said/7.
[39] Idaho Power/600, Said/2.
[40] Hearing Tr. at 24-27.
[41] *In the Matter of Idaho Power Company Authorization to Defer for Future Rate Recovery of Certain Net Excess Power Supply Expenses*, OPUC Docket No. UM 1198, Testimony of Michael J. Youngblood, Idaho Power/1, Youngblood/1-9 (filed March 2, 2005).

ATER WYNNE LLP
222 SW COLUMBIA, SUITE 1800
PORTLAND, OR 97201-6618
(503) 226-1191

this case are likely to be in effect only during 2005 and 2006. And yet remarkably, even though actual power expenses are expected to be in excess of this year's $169 million, Staff recommends a normalized NPSE of negative $15.3 million. Power expenses at this level have actually been incurred by Idaho Power in only two of the past twenty-one years, 1983 and 1984, which are the two highest water years on record.[42] Clearly, then, Staff's theoretical objections to the Company's AURORA model have resulted in Staff proposing an adjustment to the Company's NPSE that is completely out of line with realistic projections of actual power expenses the Company is likely to incur. Quite simply, Staff's proposal would create a situation where the Company would have no reasonable opportunity to recover its power supply expense or earn its authorized rate of return.[43]

Staff's "alternative recommendations," offered in its surrebuttal testimony, highlight the flaws in Staff's suggested methodology. First, Staff suggests the Commission use *Staff's* AURORA projections to normalize NPSE to address Staff's failure to recognize the effect of variations in market pricing. As noted in Section A(2)(a) above, making this adjustment would reduce Staff's recommended decrease to NPSE from $63.0 million to $23.2 million.[44] Second, Staff makes two suggestions to address problems with its use of forward price curves. One would be to reprice project power sales by pricing purchases at on-peak pricing and sales at off-peak pricing. This change would decrease Staff's recommended change to NPSE by $13.5 million (from $63 to $49.5). The other would be to use an average of three months of forward price curves instead of a single day's curve. This change would decrease Staff's recommended change to NPSE by $27.7 million (from $63 to $35.3 million).

Importantly, each attempt by Staff to "fix" the problems associated with its methodology results in a significant decrease to Staff's recommended change to NPSE. Thus, Staff's

---

[42] Idaho Power/700, Peseau/7; Idaho Power/702, Peseau/1.
[43] Idaho Power/600, Said/10.
[44] Staff/300, Galbraith/13-14.

ATER WYNNE LLP
222 SW COLUMBIA, SUITE 1800
PORTLAND, OR 97201-6618
(503) 226-1191

alternative recommendations actually bolster the Company's arguments by illustrating the fact that Staff's own methodology consistently underestimates NPSE. For these reasons, Staff's proposed NPSE should be rejected.

B. The Danskin Plant Should be Included in the Company's Rate Base

The Danskin Power Plant ("Danskin") is a gas-fired peaking facility that was built by the Company to respond to increasing system peaks and reliability concerns.[45] Danskin is typically operated only as a "resource of last resort," meaning that it is operated when there is no transmission available or when the market prices are high enough to justify its use.[46] The Company built the plant after its 2000 and 2002 Integrated Resource Plans ("IRPs") identified the need for a simple-cycle natural gas-fired combustion turbine as a expense-effective means of meeting summer peaks. These IRPs were acknowledged by the Idaho and Oregon Commissions, and the Idaho Commission granted a Certificate of Public Convenience and Necessity for Danskin in 2001. More recently the Idaho Commission approved the inclusion of the plant in the Company's rate base.[47]

Danskin provides a variety of benefits to the Company's customers. As a peaking resource, it enables the Company to meet loads and provides the capacity margin necessary to avoid outages and interruptions during high summer peaks.[48] Because Danskin is close in proximity to the Company's load center, it provides voltage support, which is important to prevent voltage collapse (a situation that may lead to customer outages).[49] Danskin also serves as a hedge against extremes of wholesale prices, such as those seen during the Western Power Market crisis in 2000 and 2001.[50] Finally, even though the Company expects that Danskin will

---

[45] Idaho Power/12T, Said/7-14; Idaho Power/200, Said/22.
[46] Idaho Power/12T, Said/7-14.
[47] *In the Matter of the Application of Idaho Power Company for Authorization to Increase its Interim and Base Rates and Charges for Electric Service,* IPUC Docket No. IPC-E-03-13, Order No. 29505.
[48] Idaho Power/12T, Said/16-17; Idaho Power/200, Said/20, 24-25.
[49] Idaho Power/200, Said/25.
[50] Idaho Power/200, Said/25.

ATER WYNNE LLP
222 SW COLUMBIA, SUITE 1800
PORTLAND, OR 97201-6618
(503) 226-1191

be operated less frequently when the new Bennett Mountain Plant becomes operational, it will still dispatch during peak times, particularly because of increasing summer peaks.[51]

Danskin should be added to Idaho Power's rate base because it is a used and useful facility that continues to provide important peak power supplies.[52] A plant should be considered useful if it provides current benefits and there is an expectation that the plant's output will be necessary within a reasonable period of time. The plant should be considered used if it has been connected to the utility's system and has transmitted power to the utility.[53] Danskin is clearly both used and useful. It has been a key peaking resource for Idaho Power in prior years and has enabled the company to meet loads and prevent outages. The company expects that it will continue to supply power in this manner.

OICIP argues that Danskin should not be included in rate base because of the expense associated with the facility. This argument fails for a number of reasons. First, as a peaking facility, the expenses associated with Danskin cannot appropriately be compared with a base-loaded generation plant. Second, the Danskin plant provides a number of important benefits to customers, including necessary capacity margin and voltage support. Depending on the hydro supplies for summer 2005, the capacity margin provided by Danskin may be necessary to avoid outages or interruptions of service.[54] Finally, it is important to note that the Idaho Commission, which had an in-depth understanding of the Danskin plant and the events leading up to the decision to develop the plant, rejected OICIP's identical arguments in the Company's last rate case.[55]

It is also important to keep in mind that the decision to develop Danskin must be assessed according to the facts that were known at the time. In 2000 and 2001, the price for wholesale

---

[51] Idaho Power/200, Said/25.
[52] ORS 757.355 (2005); *see In re Portland General Electric Co.*, UE 47, Order 87-1017, 86 PUR 4th 463 (page numbers not available) (Sept. 30, 1987) (discussing used and useful standard).
[53] *Id.*
[54] Idaho Power/200, Said/20.
[55] Idaho Power/200, Said/20-21.

ATER WYNNE LLP
222 SW COLUMBIA, SUITE 1800
PORTLAND, OR 97201-6618
(503) 226-1191

power was extremely high. Though we may now consider those prices to be aberrations, in 2001, when the decision to proceed with the plant was finalized, there was no certainty that the prices would retreat significantly, particularly given the uncertainty over the future of FERC-imposed market price caps and the adverse impact of low water conditions.[56] A decision to stop work on the plant in 2001, as OICIP argues the Company should have made,[57] would have been imprudent and unreasonable given the remaining uncertainties in the market, continued high forward prices, and the considerable amount of expenses already incurred.[58]

C. Proposed Changes in Rate Design

The Company proposes two changes to its rate design intended to further the general goal of more closely matching rates with the expenses incurred to provide the services: (1) the Company proposes to move certain customer classes (Schedules 1, 7, 9, 19) to a seasonal rate design; and (2) the Company proposes to implement time-of-use rates for all Schedule 19 industrial customers.[59] These changes should give customers clearer price signals, reduce subsidies within customer classes, and result in a more equitable recovery of the expenses incurred to provide the services.[60]

1. Seasonal Rate Design

Idaho Power faces its greatest load peaks during the months of June, July, and August. Load demands during these months are driving the Company's efforts to seek new peaking resources and try to reduce usage at peak times by implementing more demand-side management programs.[61] Peaking resources, such as the Danskin Plant discussed in Section B, are generally

---

[56] Idaho Power/200, Said/21, 23.
[57] OICIP/Direct1, Reading/11.
[58] Idaho Power/200, Said/22-24.
[59] Idaho Power/29T, Pengilly/4-7.
[60] Idaho Power/29T, Pengilly/4.
[61] Idaho Power/29T, Pengilly/5; Idaho Power/400, Pengilly/1-2.

ATER WYNNE LLP
222 SW COLUMBIA, SUITE 1800
PORTLAND, OR 97201-6618
(503) 226-1191

more expensive than the Company's base load resources. For this reason, power supply expenses are also highest for the Company during these three summer months.[62]

The proposed seasonal rate would raise rates during the summer months to reflect these higher expenses. By raising prices during June, July, and August, the Company hopes to send more accurate price signals to its customers that illustrate, quite simply, that electricity expenses are higher during the summer. The Company intends for these price signals to encourage conservation of electricity during high peak months and to further the Company's overall rate design goals of more closely matching rates and expenses.[63]

CUB argues against the proposed seasonal rate because CUB "believes" that the seasonal rate will not prompt greater conservation among Oregon residential customers.[64] CUB's intuitive theory is that it is only the amount of the bill that matters, not the amount of the rate.[65] Because Oregon residential customers' load peaks in the winter, CUB thinks that the large size of the winter bills will overshadow any price signals stimulated by higher summer bills. In addition, CUB posits that raising the rates in summer bills could undermine price signals sent by winter bills, because a reduction in the difference between the bills would lessen the impact of the winter bill.[66] CUB is also concerned that introducing a seasonal rate would complicate bills and confuse customers.[67]

The Company has seen no evidence to suggest that customers focus exclusively on the size of their bill and ignore changes in rates, or that higher summer rates will lessen the impact of winter bills. Rather, the Company's experience is that customers respond to both bills *and* rates.[68] The Company's experience with seasonal rates in Idaho also contradicts CUB's

[62] Idaho Power/29T, Pengilly/5.
[63] Idaho Power/800, Pengilly/2.
[64] CUB/200, Jenks-Brown/3.
[65] CUB/100, Jenks-Brown/5-6.
[66] CUB/200, Jenks-Brown/3.
[67] CUB/100, Jenks-Brown/6.
[68] Idaho Power/800, Pengilly/2.

ATER WYNNE LLP
222 SW COLUMBIA, SUITE 1800
PORTLAND, OR 97201-6618
(503) 226-1191

contention that customers will find seasonal rates confusing.[69] Moreover, CUB's intuitive arguments do not address the Company's essential premise that rate design should strive to more closely link rates and expenses. Conservation is not the only reason to implement a seasonal rate. The seasonal rate furthers the goal of creating rates that are more closely linked with expenses, which in turn reduces subsidies within classes and provides for more equitable recovery of expenses over time.[70] These goals are independent of whether more accurate price signals result in greater conservation.

CUB's arguments against the proposed seasonal rates are unsupported and should be rejected.

2. Time-of-Use Rates

The Company proposes to implement seasonal time-of-use rates for Schedule 19 customers that will more accurately reflect the fact that expenses to provide energy vary during the day and from season to season. The time-of-use rates will be higher during the summer than during the rest of the year and will be higher during the peak time of day to reflect that Idaho Power incurs higher expenses to provide the service during these times. Seasonal time-of-use rates have been in place for Schedule 19 customers in Idaho since December 1, 2004. However, this rate design has not been in place in Idaho long enough to draw conclusions about the effect of the new rate on customers' usage patterns.[71]

OICIP argues that the purpose of the time-of-use rates is to cause customers to curtail consumption during on-peak hours and that the rate is ineffective for this purpose. OICIP contends that Schedule 19 customers are unlikely to respond to price signals because they are high-load customers who operate around the clock. Like CUB's arguments with regard to seasonal rates, this argument fundamentally misunderstands the purpose of implementing this

---

[69] Idaho Power/400, Pengilly/3.
[70] Idaho Power/29T, Pengilly/4.
[71] Idaho Power/400, Pengilly/4.

ATER WYNNE LLP
222 SW COLUMBIA, SUITE 1800
PORTLAND, OR 97201-6618
(503) 226-1191

new rate design. Like the Company's proposed seasonal rate, the proposed time-of-use rates are intended to more closely match the prices customers pay with the expenses incurred by the Company to provide the service, thereby improving equitable distribution of expenses over time.[72] One consequence of time-of-use rates is that they will provide more accurate price signals to customers. However, this does not mean the purpose of implementing the rate is to curtail use. In fact, the rate has been designed not to penalize customers who do not alter their patterns of use, but instead to offer an incentive to customers who do change.

In Idaho, "dummy" bills with a comparison between flat seasonal rates and seasonal time-of-use rates were in place for Idaho Schedule 19 customers from June 1 to December 1, 2004, as a phase-in to the implementation of actual time-of-use pricing. OICIP contends that the "dummy" billing in place in Idaho demonstrated that time-of-use rates will not be effective in curtailing load.[73] The Company has seen no evidence that time-of-use rates will not be effective in influencing customers' usage patterns. The primary purpose of time-of-use rates is to provide a more accurate match between price and expense with the expectation that the better matching may lead to changes in usage over time.[74] Even if curtailing load at peak times was the primary purpose of time-of-use rates, the "dummy" billing process simply cannot be used to draw conclusions. While the "dummy" bills informed customers what the time-of-use rates would be, the customers were not billed actual time-of-use rates. Therefore, the "dummy" bills did not send a true price signal.[75]

The Company does not intend or expect that time-of-use rates will produce changes in customers' usage patterns in the short term. The hope is that over the long term, customers that are able will make changes in their business to take advantage of the price incentives.[76] This

---

[72] Idaho Power/800, Pengilly/4.
[73] OICIP/Direct1, Reading/17-19
[74] Idaho Power/19T, Pengilly/4
[75] Idaho Power/800, Pengilly/5.
[76] Idaho Power/400, Pengilly/3.

ATER WYNNE LLP
222 SW COLUMBIA, SUITE 1800
PORTLAND, OR 97201-6618
(503) 226-1191

goal is consistent with the Company's long-range planning objectives. The time-of-use rates should therefore be adopted.

D. Power Quality in Idaho Power Service Territory

OICIP claims Schedule 19 customers have experienced "poor power quality" and that the Commission should work with Idaho Power to address this issue.[77] Idaho Power believes that it supplies service that meets or exceeds Oregon requirements and believes that the circumstances described by OICIP can best be handled by direct communication between the Company and any concerned customers.[78]

In support of its claim, OICIP provides "outage" data from one customer, Ore-Ida Frozen Foods ("Ore-Ida"), which is difficult to reconcile with data assembled by the Company. Part of the problem is that the term "outage" is used differently by OICIP and the Company. The Company uses "outage" to describe a situation in which power is not supplied to a customer. In the case of Ore-Ida, OICIP uses the term much more broadly to apply to an event that causes Ore-Ida's production lines to cease operation or shut down. Production line shut-downs such as this may be caused by events both internal and external to Ore-Ida's facility, including anomalies in supply voltage delivered by Idaho Power. However, according to standards developed by the Computer Based Equipment Manufacturers Association (CBEMA) and measured by the ION meter at the Ore-Ida Substation, many of the "outages" described by OICIP occurred while the voltage supplied by Idaho Power was within the range at which Ore-Ida's equipment should not have gone off-line. That said, the Company has previously expressed a willingness to work with Ore-Ida to rectify production line problems and is committed to continuing its ongoing program of working proactively with Ore-Ida, and its other customers, to resolve power quality problems in the future.[79]

---

[77] OICIP/Direct 1, Reading/25.
[78] Idaho Power/900, Kolar/1.
[79] Idaho Power/900, Kolar/4.

ATER WYNNE LLP
222 SW COLUMBIA, SUITE 1800
PORTLAND, OR 97201-6618
(503) 226-1191

For these reasons, the Commission should reject OICIP's arguments regarding service quality.

CONCLUSION

Respectfully submitted this 13th day of June, 2005.

ATER WYNNE, LLP

By: [signature]

Lisa F. Rackner, OSB #87384
Ater Wynne, LLP
222 SW Columbia Street, Suite 1800
Portland, OR 97201
E-mail: lfr@aterwynne.com

IDAHO POWER COMPANY

By: Barton L. Kline, ISB #1526
Senior Attorney
P.O. Box 70
Boise, Idaho 83707
E-mail: bkline@idahopower.com

Attorneys for Idaho Power Company