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May 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 - Sursurrebuttal Testimony of Gregory W. Said, Dennis E. Peseau, Pete Pengilly, and Keith J. Kolar On Behalf of Idaho Power Company

Dear Sir or Madam:

Enclosed for filing in the above-referenced docket is the original and five copies of Sursurrebuttal Testimony of Gregory W. Said, Dennis E. Peseau, Pete Pengilly, and Keith J. Kolar on behalf of Idaho Power Company. 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 **SURSURREBUTTAL TESTIMONY OF GREGORY W. SAID, DENNIS E. PESEAU, PETE PENGILLY, AND KEITH J. KOLAR ON BEHALF OF IDAHO POWER COMPANY** was served via U.S. Mail on the following parties on May 13, 2005:

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ATER WYNNE LLP

Jessica A. Centeno

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 167

IN THE MATTER OF THE APPLICATION)
OF IDAHO POWER COMPANY FOR)
AUTHORITY TO INCREASE ITS RATES)
AND CHARGES FOR ELECTRIC SERVICE)
TO ELECTRIC CUSTOMERS IN THE STATE)
OF OREGON.)
______________________________________)

IDAHO POWER COMPANY

SURSURREBUTTAL TESTIMONY

OF

GREGORY W. SAID

Q. Please state your name and business address.

A. My name is Gregory W. Said and my business address is 1221 West Idaho Street, Boise, Idaho.

Q. Are you the same Gregory W. Said that presented direct and rebuttal testimony in this case?

A. Yes, I am.

Q. What is the purpose of your sursurrebuttal testimony?

A. I will discuss how Staff surrebuttal testimony, CUB surrebuttal testimony, and Oregon ICIP surrebuttal testimony regarding normalization of power supply expenses do not dispute that their respective proposals do not provide the Company with a reasonable opportunity to recover its revenue requirement. Instead, Staff, CUB, and Oregon ICIP continue to recommend power supply expense proposals that are unrealistically low and are inconsistent with the power supply expense normalization principles that this Commission and the Idaho Commission have directed Idaho Power to follow for over 20 years. I will also respond to Oregon ICIP comments regarding my rebuttal testimony concerning the Company's Danskin plant.

Q. You and Mr. Gale made statements in your respective rebuttal testimonies that Staff, CUB, and Oregon ICIP power supply proposals, if adopted, would not allow the Company a realistic opportunity to recover its reasonably incurred power supply expenses (thus eroding the return component of revenue requirement) during the period of time that new rates will be in effect. Did the Staff, CUB or the Oregon ICIP dispute this aspect of Company testimony?

A. No. None of the parties dispute that current drought conditions will substantially increase power supply expense over the next two years. No party has disputed the Company's current year expectation of $169 million in power supply expenses. Based upon an expectation of $169 million in power supply expenses, if base rates that include negative $15.3 million in actual power supply expenses (as per Staff recommendations) are established, the Company could face a revenue shortfall of $184.4 million ($169 million + $15.3 million) in power supply expenses (not considering Idaho jurisdictional treatment or potential deferrals in Oregon) on a system wide basis. On an Oregon jurisdictional basis, the lack of recovery of power supply expenses would be $9.1 million ($184.4 million * 4.94%). Income after taxes would decline by $5.5 million ($9.1 million / 1.642 where 1.642 is the tax gross-up factor). Considering that the return component of Idaho Power's revenue requirement request in this case amounted to only $6.8 million (Idaho Power/24, Obenchain/1), it is easy to see that $5.5 million of after-tax income erosion would be a significant event for the Company to overcome in order to have a reasonable opportunity to earn its authorized rate of return in its Oregon jurisdiction.

Q. In the next two years, will the Company have difficulty earning its authorized rate of return in the Oregon jurisdiction even under the Company's proposal for test year power supply expenses?

A. Yes, drought conditions make it more difficult for the Company to earn its authorized rate of return even when normalized power supply expenses are set at the average of multiple potential scenarios as per the Company's proposal. Staff's proposal to change Idaho Power's historically approved power supply methodology from one which incorporates multiple scenarios with varying market prices to a methodology that considers only one condition will, in my opinion, only exacerbate the impact on Idaho Power's revenues.

Q. Beginning at page 3 of his surrebutal testimony, Staff witness Mr. Galbraith clarifies the difference between the terms "forecast" and "projection" as used in his testimony. He states that a projection is an attempt to show what "would" happen given certain conditions while a forecast is an attempt to show what "will" happen. Do you agree with his distinction?

A. I believe the terms forecast and projection are often used interchangeably. Based upon Mr. Galbraith's definition of the two terms, a range of future load scenarios represented by a high, expected and low load forecast would be more properly be described as one forecast (expected) and two projections (high and low). However, for the purposes of this proceeding, I will accept his distinction in the hope that it will clarify the various positions of the parties.

Q. Based upon Mr. Galbraith's definition of the terms projection and forecast, has the Oregon Commission historically used projections or forecasts of net power supply expenses for setting Idaho Power rates?

A. As I have stated in my rebuttal testimony and as Mr. Galbraith has confirmed at page 5 of his surrebuttal testimony, the Oregon

Commission has historically utilized the average of multiple (in this case 76) power supply *projections* as the normalizing method of determining Idaho Power's power supply expenses. No single projection nor the average of the multiple projections has been represented as or considered a forecast.

Q. In his recommendations, has Mr. Galbraith utilized multiple projections of what "would" happen given 76 different water conditions and their corresponding electricity market price conditions consistent with current Commission approved methodology?

A. No. Mr. Galbraith has rejected the power supply expense normalizing assumption that electricity market prices will correspond to water conditions. Instead, he has assumed a single electricity market price scenario (a forward market price *forecast*) applied to a single projection of load/resource balance (*not a forecast*).

Q. Why do you consider a forward market price curve to be a forecast rather than a projection?

A. A forward price curve more closely fits the "forecast" definition as provided by Mr. Galbraith. As Mr. Galbraith has stated, a projection can be used as a forecast if all of the underlying assumptions of the projections can realistically be expected to occur. Reiterating my rebuttal testimony, a forward price curve is a representation of the spot market prices various power marketers indicate would be future price for power purchases or sales at the date the forward price estimate is created. In other words, based upon what is known today (underlying assumptions), energy for next December can bought or sold today at a price reflective of what marketers believe prices “will” be in December. A forward price curve represents a current price for a commodity to be delivered in the future based upon a forecast of conditions that will exist at the time of delivery of the commodity.

Q. Do forecasts take into consideration existing conditions such as drought?

A. Of course, and for that matter projections could also take existing conditions into consideration. A near term forecast, such as the April 30, 2004 forward price curves for 2005 power delivery used by Mr. Galbraith would be heavily influenced by then current drought conditions and below normal expectations of future precipitation. The further into the future a forecast predicts, the less current conditions affect the forecast.

Q. Does the Northwest Power and Conservation Council (Council) describe their electricity prices for 2006 as a forecast or a projection?

A. The Council uses both terms to describe future electricity prices in their publications. Although the Council’s forecast of market prices may actually be a projection based upon Mr. Galbraith’s definitions, examination of the Council’s forecast of market prices reveals a five-year decline in market prices occurring from now until 2010 when a steady level of market prices occurs.

Q. In essence, do both Mr. Galbraith and CUB witnesses ignore market price variation impacts that accompany water condition variation and instead apply a single market price forecast to an average of 76 load resource balance projections?

A. Yes, Mr. Galbraith rejects test year power supply expense normalization methodology based upon a range of projections that include matching resource balance assumptions and market price assumptions in favor of a methodology that mixes a single average resource balance projection (not a forecast) with a single and unrelated forecast of market prices. In my rebuttal testimony, I called such mismatching a comparison of apples and bananas. Mr. Galbraith has not addressed this mismatch in his surrebuttal testimony, but does suggest that if the Commission finds my “lack-of-a-price-range” argument persuasive, the Commission could adopt an alternative AURORA run. Similarly, CUB witnesses mix the same average resource balance projection recommended by Mr. Galbraith with a single unrelated projection of market prices presenting the same inconsistency and lack of a price range deficiencies.

Q. Does Mr. Galbraith imply that a power supply expense normalization methodology should include a forecast rather than a range of scenario projections?

A. Yes, on page 4 of his surrebuttal testimony, Mr. Galbraith states “ Using Idaho Power’s projection of NVPC, based upon the water condition 1967 (the hydro condition most representative of average hydro conditions), as a forecast of 2006 NVPC would be an improvement.” He then states “However, as Idaho Power has indicated, both the Public Utility Commission of Oregon and the Idaho Public Utilities Commission have traditionally set normalized NVPC on the mean of the company’s NVPC projections”. The implication is that the

Commission should change power supply expense normalization methodology to be forecast-like rather than an average of expectations under varying scenarios (projections). The problem with Mr. Galbraith's recommendation is that he doesn't really propose a forecast of power supply expenses. Rather, he only forecasts market prices. He then applies his forecast of market prices, which he believes is reasonably expected to occur, to an average water condition which is not reasonably expected to occur creating mismatch of assumptions.

Q. If the Commission knows that market prices in the Northwest vary with water conditions, is it reasonable to ignore that variability and apply a single forecast of market prices instead?

A. No, but that is exactly what Mr. Galbraith and CUB witnesses are recommending.

Q. At page 6 of his surrebuttal testimony, Mr. Galbraith states that your Exhibit No. 201 and Mr. Peseau's Exhibit No. 302 are invalid because the purpose of AURORA modeling is not to replicate past actual results. Please comment.

A. Mr. Galbraith misunderstands the purpose of Exhibit No. 201. As I stated in my rebuttal testimony, my intent in preparing Exhibit No. 201 was to demonstrate that the range of modeled power supply expenses was consistent with power supply expenses that the Company has actually experienced. Projections included in Commission approved power supply normalization methodology include resource balance scenarios represented by historical water conditions and current levels of development. Electricity market prices, which, as I discussed in my direct testimony, have risen in the last 10 years, are also reflected. My conclusion, based upon Exhibit 201, that the range of test year modeled results fall short of what the Company has actually experienced on the high end of power supply expenses and are close to what the Company has actually experienced on the low end of power supply expenses is *not* invalid, it is true.

Q. Mr. Galbraith states that your comparison of the highest modeled projection of power supply expense and the highest actually experienced power supply expense is not meaningful. Please comment.

A. Mr. Galbraith suggests that the totality of circumstances surrounding the 2000-2001 Western Energy Crisis were an aberration not representative of the range of conditions likely to prevail on a going-forward basis. I agree and Company modeling in this case demonstrates that agreement in that the highest modeled projection of power supply costs is $131.7 million below that actual extreme. However, the more interesting question exists at the other extreme. Apparently Mr. Galbraith would not argue the actually experienced low value for power supply expense of –$18.7 million is also an aberration, instead he testifies that this extreme is remarkably close to his expectation of normal. As such, Mr. Galbraith asserts that half of the time the Company should expect to incur lower power supply expenses than it has actually historically experienced half of the time.

Q. Staff counsel's question at page 8 of Mr. Galbraith's surrebuttal testimony suggests that you made a statement that "Idaho Power's

AURORA modeling greatly understates the highest possible NVPC, while only moderately understating the lowest possible NVPC. Please comment.

A. Although my testimony on page 8 could have been more precise, I believe it is still readily apparent that my discussion of "possible" extremes for power supply expenses was, in reality, a reference to actual historical extremes. While I can easily envision circumstances that would result in "possible" extremes greater than or less than actually experienced historical extremes for power supply expenses, I do not believe that it is good rate making to assume that those circumstances that have never occurred are now not only going to occur, but will also become the norm.

Q. At page 9 of his surrebuttal testimony, Mr. Galbraith states comparisons of actual historical transaction rates to projected transaction rate are not valid because loads and resources have changed. Please comment.

A. Regional as well as Company loads (demand) and resources (supply) have definitely changed over time as I discussed in my direct testimony. However, fluctuations in water supply in the Northwest continue to have a huge impact on overall supply and market price. Both Staff and the CUB suggest that a return to normal hydro production cannot produce prices as low or lower than occurred three years ago ($23.65 per MWh in 2001) even though over 80 percent of historical water conditions would produce greater hydro generation than was experienced in 2001. I believe that such a view is very shortsighted. Cost drivers for transaction rates do change, but not as rapidly as suggested by the CUB and Mr. Galbraith. Near term historical actual transaction rates provide the Commission with strong evidence that the Company's modeled transaction rates can reasonably be expected to occur in the future and support the pricing contained in Company modeling.

Q. Please respond to the summary of findings and recommendations contained in Mr. Galbraith's surrebuttal testimony.

A. The Commission should reject the Staff's primary recommendation to utilize a single *forecasted* market price scenario in conjunction with a projection (not a forecast) of an average resource balance condition to arrive at a test year power supply expense. This approach should be rejected because it is inconsistent with Commission approved normalization methodology and fails to recognize the effect of hydro conditions on market prices. Staff methodology effectively ignores the Company's *actual* test year power supply expenses of $149.8 million and reduces the Company's modeled test year power supply expenses of $47.7 million to negative $15.3 million creating a situation where the Company would have no reasonable opportunity to earn its authorized rate of return. Such a recommendation is unreasonable and unrealistic. Likewise, replacing the Staff forecast of market price with a CUB projection of market price applied to a single condition in order to manually override multiple modeled conditions is equally inappropriate. Utilizing any blend of forecasted rather than projected market prices to apply to a single projected resource balance condition should be rejected for failing to utilize reasonable and approved normalizing methodology.

Q. What about Mr. Galbraith's alternative proposal?

A. Mr. Galbraith suggests that if the Commission finds Company arguments persuasive, his alternative proposal should be adopted. Mr. Galbraith ignores the logical conclusion – if the Commission finds the Company's arguments persuasive, the Commission should adopt the Company's recommendations.

Q. Does Mr. Galbraith provide any support for his alternative recommendation?

A. No. As a matter of fact, Mr. Galbraith's first argued against his one attempt to utilize Commission-approved methodology. Now, he suggests that his attempt could be used if his primary recommendation is rejected.

Q. Has Mr. Galbraith describe the range of market prices that are included in his alternative proposal.

A. No. Mr. Galbraith has provided no information as to the range of electricity market prices contained in Staff Exhibit 302 nor has he demonstrated the reasonableness of such a range. In his direct testimony Mr. Galbraith suggested market prices could be as low as $20 per MWh or as high as $50 per MWh depending on water condition. Ultimately, he recommended a single condition with a market price far closer to $50 per MWh than $20 per MWh. He suggests that the Company carries the burden of justifying the AURORA assumptions for the run the Company made with Staff provided inputs.

Q. Is it reasonable to expect the Company to justify AURORA assumptions as specified by the Staff?

A. No. It is reasonable to expect the Company to provide the

Staff with the understanding of how model operates and in this case, how certain inputs influence market-clearing prices. However, it is unreasonable to expect the Company to justify Staff inputs to the model.

Q. Dr. Reading acknowledges that his argument for recommending disallowance of Danskin is the plant's high cost. Are his cost per kilowatt-hour arguments persuasive?

A. No. Peaking units are intended to sit idle in excess of 70% of the time. Based upon a utility's obligation to serve load prudently, the least expensive means of supplying loads under peak summer conditions is to build peaking rather than base load energy resources. As such, peaking units are evaluated on a cost per kW rather than a cost per kWh basis. As the Idaho Public Utilities Commission concluded, when it approved Danskin for inclusion in revenue requirement in Idaho, Danskin's cost per kW was reasonable when compared to other peaking facilities constructed at the time Danskin was built.

Q. Dr. Reading comments on two Company positions: 1) Modeling understates Danskin generation, and 2) Power supply expenses as modeled by the Company should be accepted. He concludes, "The Company can't have it both ways." Please respond.

A. Dr. Reading implies that requesting approval of understated power supply expenses is "having it both ways". I agree with the Idaho Commission Staff testimony that the power supply expenses modeled in this case are appropriate, but potentially lower than a reasonable expectation for normalized power supply expenses.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 167

IN THE MATTER OF THE APPLICATION	)
OF IDAHO POWER COMPANY FOR	)
AUTHORITY TO INCREASE ITS RATES	)
AND CHARGES FOR ELECTRIC	)
SERVICE TO CUSTOMERS IN THE	)
STATE OF OREGON	)
	)

IDAHO POWER COMPANY

SUR-SURREBUTTAL TESTIMONY

OF

DENNIS E. PESEAU

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dennis E. Peseau. My business address is Suite 250, 1500 Liberty Street, S.E., Salem, Oregon 97302.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am President of Utility Resources, Inc. (URI). URI has consulted on a number of economic, financial and engineering matters for various private and public entities for more than twenty years.

Q. ARE YOU THE SAME DENNIS E. PESEAU WHO TESTIFIED PREVIOUSLY IN THESE PROCEEDINGS?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SUR-SURREBUTTAL TESTIMONY?

A. I will address the surrebuttal testimonies of staff witness Mr. Galbraith, CUB witnesses Mr. Jenks and Ms. Brown, and OICIP witness Dr. Reading on the issue of the proper level upon which to base Idaho Power's net variable power supply costs in these proceedings. Before I address the individual issues of each witness, I would like to summarize the single issue, or flaw in my opinion, that continues to run through the testimony of all three parties (Staff, CUB, OICIP) that makes their respective estimates of Idaho Power's test year net power supply costs incorrect, and predictably, low.

Q. PLEASE SUMMARIZE THIS SINGLE NET POWER COST ISSUE.

A. Idaho Power requests a test year level of net power costs in this case of $47.7 million. Staff's surrebuttal testimony continues to urge that this test year level of net power costs be reduced by $63.1 million to the negative value of ($15.3) million. (Staff/300, Galbraith/1). For reasons similar to those espoused by Staff, CUB's surrebuttal testimony continues to argue that Idaho Power's test year net power supply costs should be reduced by $66.2 million to the negative value of ($18.5) million. (CUB/200, Jenks-Brown/1). The greatest difference between Idaho Power's request and CUB and Staff's cases is not in the assumptions used, but in the basic methodology proposed.

To determine its test year net power supply expenses, Idaho Power has employed the same methodology it has used in Oregon and Idaho since the 1970s. Based on my 20+ years of experience in regional utility regulation, I know this is the same basic methodology other commissions in other Northwest states have used since the 1970s as well. This methodology computes the average of net power costs over each of multiple water years. In this case, Idaho Power uses seventy-six historical water years.

Staff and CUB, however, went back to the pre-1970's methodology of computing net power costs as that single year's cost assuming an average water year. As was recognized in the 1970s when the multiple water year methodology was adopted, the single average water year method always underestimates normalized net power costs for reasons I cite below.

Q. PLEASE EXPLAIN WHY THE METHODOLOGY STAFF AND CUB PROPOSE ALWAYS UNDERESTIMATES NET POWER SUPPLY

COSTS.

A. Staff and CUB are of the opinion that Idaho Power's AURORA model underestimates market-clearing prices for surplus power sales and purchases. (Staff/300, Galbraith/7). These market-clearing prices are the result of running the AURORA model over seventy-six historical water or hydro conditions. Rather than re-run the AURORA model over the seventy-six historical hydro conditions with their own independent sets of data and assumptions, Staff and CUB simply use a single average water year and a new estimate of a single year's surplus power sales price. The OICIP witness appears to simply adopt Staff's position.

Q. WHAT, IN YOUR OPINION, IS WRONG WITH STAFF AND CUB'S ESTIMATING NET POWER COSTS BASED UPON THE SINGLE AVERAGE WATER YEAR?

A. I have participated in numerous rate cases in the Pacific Northwest over the past 20+ years. It has been clearly demonstrated to me in multiple rate case proceedings dating back to the early 1970s that use of a net power cost estimate based on a single average water year inevitably underestimates these costs. The reason that the single water condition estimates of net power costs systematically underestimate normalized net power costs is because these estimates ignore the non-proportional relationship between water conditions and resulting power costs. Power costs and different hydro conditions are not proportionally (or linearly) related. In my rebuttal testimony, Page 5, Lines 5-8, I expressed this circumstance as power costs not being symmetric around average water conditions.

In simple terms, all that this means is that, for example, when hydro conditions are, say, 10% below average, net power costs may be 20% above average. Similarly, when hydro conditions are 10% above average, net power costs may only be 5% below average. Unless net power costs vary proportionally, or approximately equally in magnitude with changes in water conditions, the single net power cost estimate evaluated at average hydro will be incorrect, and low.

This basic non-proportional relationship is illustrated in my Exhibit 701. This exhibit reflects past water and net power cost Company data that show that the average of power costs of Idaho Power over multiple hydro conditions is higher than the power cost determined using the average of water conditions. In failing to recognize this fundamental relationship between net power costs and water conditions in their analyses and estimates, Staff and CUB have underestimated net power costs.

In fact, there is really no modeling whatsoever in the analyses of Staff and CUB. As noted in Mr. Galbraith's surrebuttal testimony on pages 7 and 8, Staff disagrees with the surplus prices resulting from Idaho Power's hydro modeling, and rather than identifying a problem with the model, simply adopts a different set of prices equal to those reported in an April 30, 2004 forward price curve.

Similarly, CUB's surrebuttal testimony continues to argue in support of its proposal to substitute a recent set of prices taken from a draft forecast of prices contained in a Northwest Power Planning Council report for the multiple water year projection in Idaho Power's request (CUB 200/Jenks-Brown 2). Because I believe Staff and CUB's approach is fundamentally flawed, I reiterate the proposal I made in my rebuttal testimony. Before changing the water modeling methodology back to the single average water condition method, this Commission should hold a separate, technical case wherein these complicated issues can be thoroughly pursued.

Q. HOW DO YOU RECOMMEND THAT THE COMMISSION ESTABLISH THE AUTHORIZED LEVEL OF NET POWER COSTS USED TO SET RATES IN THESE PROCEEDINGS?

A. I recommend that the Commission adopt a level of net power costs that is consistent with Idaho Power's recent normalized net power costs. This can be accomplished either with the Company's proposed level of net power costs in these proceedings of $47.7 million, or by recognizing and continuing the level of net power costs that are currently in its Oregon rates, $48 million.

Q. WHY DO YOU MAKE THIS RECOMMENDATION?

A. I make this recommendation in light of the utter lack of any plausible explanation by Staff, CUB or the OICIP in either their direct or surrebuttal testimony as to just how, in the past year, in the current electric markets in the Pacific Northwest and WSCC that Idaho Power's net power costs could have taken the precipitous $63-66 million decrease these parties suggest is now the norm. Perhaps in the forum of the technical proceedings that I propose, the merits of such an explanation could be carefully evaluated. To date no such explanation is offered, and I believe that no such explanation exists.

Q. HAVE YOU ATTEMPTED TO DEMONSTRATE THE REASONABLENESS OF THE $47.7 MILLION OF NET POWER COSTS REQUESTED BY IDAHO POWER?

A. Yes. My original Exhibit 302 provides summary and historical net power cost comparisons.

Q. IN THEIR SURREBUTTAL TESTIMONY, DO MR. GALBRAITH AND DR. READING CRITICIZE YOUR EXHIBIT 302?

A. Yes, but only on a single and narrow issue. Staff and OICIP comment that the "modeled" line on Exhibit 302 is not wholly consistent with a "back cast" because the AURORA model used to make the modeled estimates uses current WSCC loads and resources (Galbraith, Page 6, Lines 4-11). This is true, as I specifically note on Page 7, Lines 8-9 of my Exhibit 300.

Q. DO YOU AGREE THAT THE USE OF CURRENT REGIONAL LOADS AND RESOURCES MAKES EXHIBIT 302 "INVALID"?

A. No. I do not dispute that by using more current data the modeled and the actual net power costs shown in Exhibit 302 would be even more highly correlated than they are now, but the present high correlation is no accident.

Q. HOW DO YOU RESPOND TO THE OTHER CRITICISMS OF EXHIBIT 302 EXPRESSED IN MR. GALBRAITH'S AND DR. READINGS' SURREBUTTAL TESTIMONY?

A. To eliminate any argument of the modeling accuracy of

Exhibit 302, I make two modifications and present them as Exhibit 702. First, Exhibit 702 removes the line titled "modeled" in Exhibit 302. Second, I insert a third horizontal line corresponding to CUB's recommended net power cost level of a negative ($18.5) million. Thus Exhibit 702 contains only actual historical net power costs experienced by Idaho Power, 1983-2003, and the three different levels of net power costs proposed by Idaho Power, Staff and CUB. I believe these changes eliminate the dispute on these issues raised in the surrebuttal testimony.

Q. WHAT DOES EXHIBIT 702 SHOW?

A. Exhibit 702 shows that Idaho Power's requested $47.7 million in net power costs is very much in the middle of the actual historical net power costs that it has experienced. Of the twenty-one years of actual annual net power costs shown, eleven of the actual historical net power costs are above the $47.7 million requested, while ten years of actual historical power costs are below the $47.7 million.

Exhibit 702 also shows the horizontal line denoting Staff's proposal of a negative ($15.3) million have been actually incurred in only two water years, 1983 and 1984, which are the two highest water years on record. In my opinion, Staff's and CUB's proposals are so far out of the historical central tendency of net power costs that neither can be considered a reasonable level of normalized net power costs.

Exhibit 702 also shows the horizontal line denoting Staff's secondary proposal (Galbraith, surrebuttal, Page 16, Lines 15-20) and CUB's proposal to set Idaho Power's normalized net powers at a negative ($18.5 million) in these proceedings. Interestingly, the exhibit shows that historically (1983-2003), Idaho Power has never once experienced net power costs as low as CUB's proposed normalized net power costs of a negative ($18.5) million, even under the best water years on record.

Q. WHAT DO YOU CONCLUDE FROM EXHIBIT 702?

A. I conclude that when compared to actual net power costs, both Staff's and CUB's proposed normalized net power costs are such aberrations that they should not be considered in these proceedings.

Q. DO YOU HAVE COMMENTS ON MR. GALBRAITH'S DISCUSSION OF THE FORWARD PRICE CURVE DISCUSSION CONTAINED IN HIS SURREBUTTAL TESTIMONY?

A. Yes. On Pages 12 and 13 of his surrebuttal testimony, Mr. Galbraith indicates that he disagrees with my conclusion that April 30, 2004 forward price curve reflected to some degree an expectation of continued poorer than average hydro conditions. I believe that there may be some confusion as to my position, because both Mr. Galbraith and I reach similar conclusions based on our analysis of forward price curves before and after January 2005.

To verify this, I compare Mr. Galbraith's statement that " . . . The charts for May, June and July of 2005 show a pronounced increase in forward prices beginning in early 2005 . . ." (Galbraith surrebuttal, Page 12, Lines 15-17), with my similar conclusion on Page 13, Lines 16-18 of my rebuttal that " . . . Exhibit 305 shows that the prices reflected in the forward curves were consistent at least until the snowpack reports of January 2005 . . ." Mr. Galbraith and I both conclude that forward price curves prior to January 2005 were relatively consistent, or flat, while a significant shift upward occurred in January 2005. I see no disagreement here, nor would a disagreement on this issue have an impact on the conclusions I have reached regarding the appropriate level upon which to set net power costs in these proceedings.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE

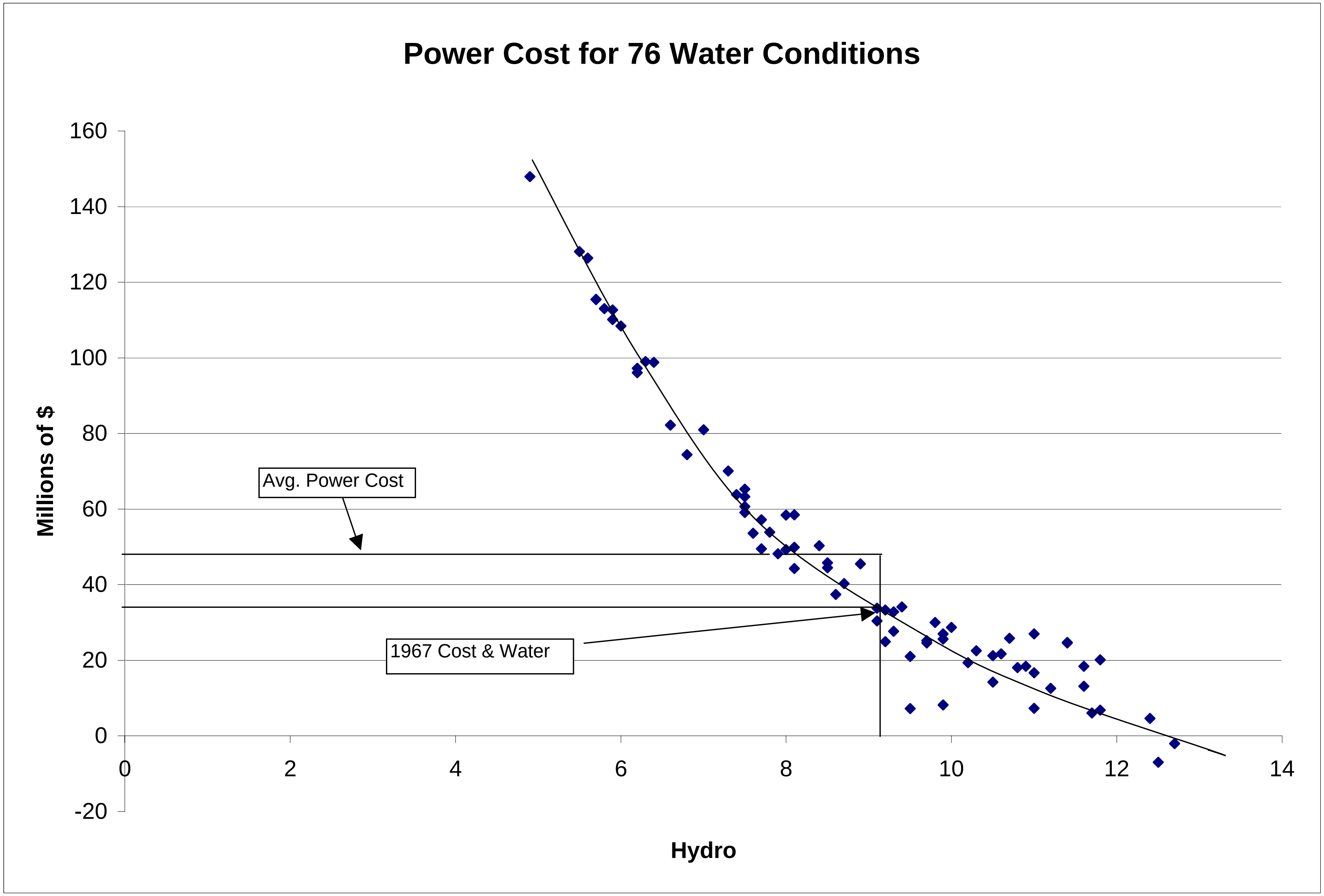
OREGON PUBLIC UTILITIES COMMISSION

CASE NO. UE 167

IDAHO POWER COMPANY

EXHIBIT NO. 701

DENNIS J. PESEAU



Idaho Power/701
Peseau/1

BEFORE THE

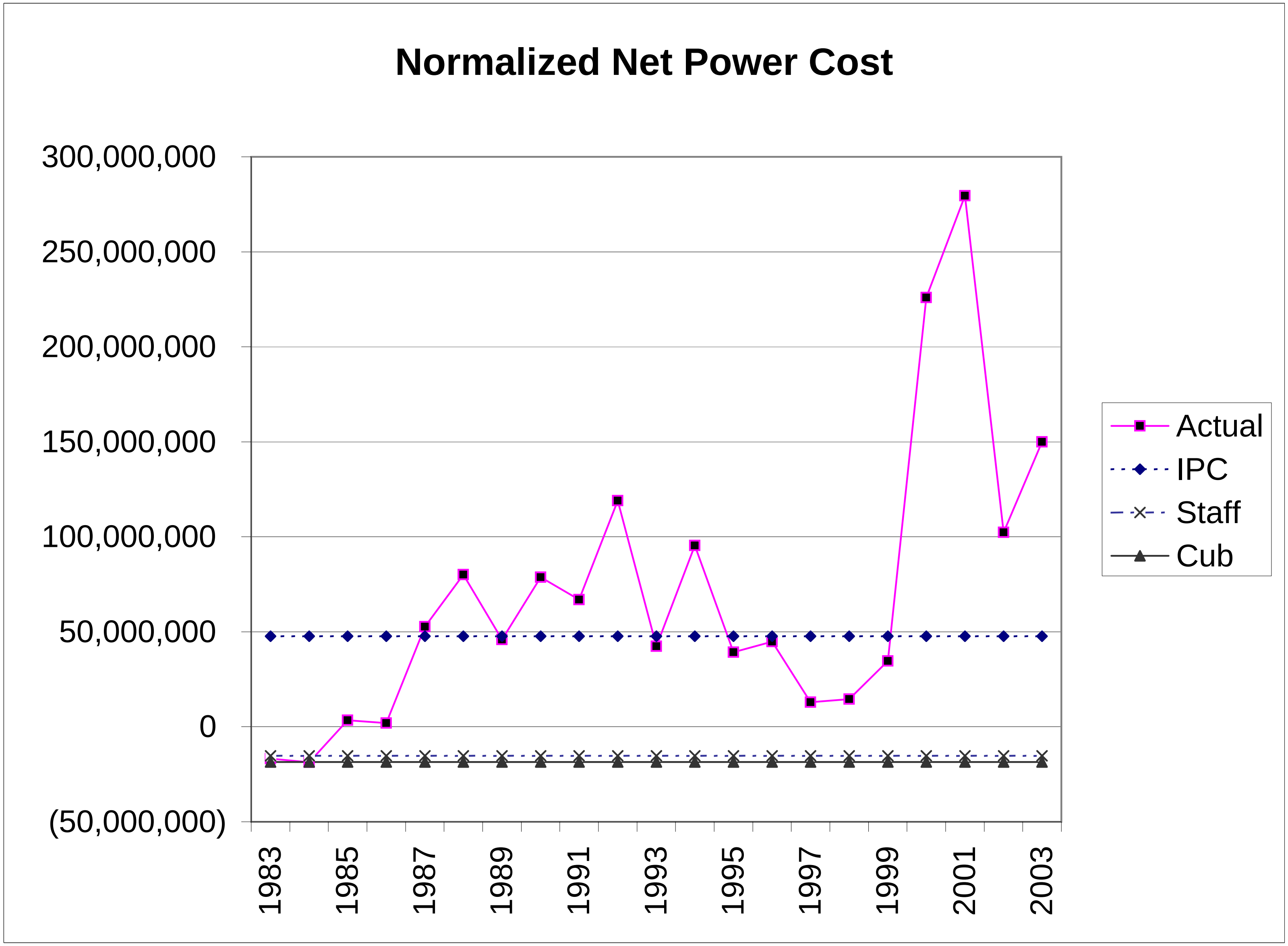
OREGON PUBLIC UTILITIES COMMISSION

CASE NO. UE 167

IDAHO POWER COMPANY

EXHIBIT NO. 702

DENNIS J. PESEAU



Idaho Power/702
Peseau/1

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 167

IN THE MATTER OF THE APPLICATION	)
OF IDAHO POWER COMPANY FOR	)
AUTHORITY TO INCREASE ITS RATES	)
AND CHARGES FOR ELECTRIC	)
SERVICE TO CUSTOMERS IN THE	)
STATE OF OREGON	)
______________________________________	)

IDAHO POWER COMPANY

SURSURREBUTTAL TESTIMONY

OF

PETE PENGILLY

Q. Please state your name, address, and present occupation.

A. My name is Pete Pengilly. I am a Senior Analyst in the Pricing and Regulatory Services Department at Idaho Power Company. My business address is 1221 West Idaho Street, Boise, Idaho.

Q. Are you the same Pete Pengilly that previously presented direct and rebuttal testimony in this case?

A. Yes, I am.

Q. Have you had the opportunity to review the surrebuttal testimony of the Citizen's Utility Board of Oregon (CUB) and the Oregon Industrial Customers of Idaho Power (OICIP) in this case?

A. Yes, I have.

Q. Q. What is the scope of your sursurrebuttal testimony?

A. My testimony will address issues raised by CUB regarding seasonal rates for residential customers and by OICIP regarding time-of-use rates for industrial customers taking service under Schedule 19.

Q. In its surrebuttal testimony, CUB continues to recommend that residential customers not be billed with seasonal rates. Do you agree with this position?

A. No. CUB's surrebuttal testimony fails to address the fundamental premise that rate design should reflect the costs associated with system load and system resource availability as well as specific customer class load characteristics. The Company's need for additional resources is driven primarily by the peak summer usage during summer resource scarcity and only secondarily by peak winter usage. By implementing seasonal rates, the Company is striving to signal customers, whose usage contributes to the summer peak that consumption during the summer months is more costly. Seasonal rates should provide an incentive for these customers to conserve.

Q. Do you believe that under the seasonal rates proposed by the Company the magnitude of the winter peak bill relative to the summer peak bill will be reduced sufficiently as to eliminate an incentive for customers to reduce their winter electrical usage as CUB suggests?

A. No, not to the extent that it lessens the impact of an overall rate increase. CUB asserts that the largest single bill provides the strongest conservation incentive (CUB/200 Jenks-Brown/3). In fact, customers respond to both rate differences and bill differences. The Company's proposed pricing maintains the same price per kWh for the first 300 kWh throughout the year and a price differential of 12.56% between the above 300 kWh Summer and Non-Summer blocks. Although this is a relatively small differential, the Company believes it will send the appropriate price signal to customers. Because a large number of Idaho Power's Oregon residential customers use electric space heat, their winter usage is significantly higher than their summer usage. The higher usage will still cause the majority of the winter bills, particularity for those customers who utilize electric heating, to be greater than the summer bills. Idaho Power's Oregon residential customers' average usage is 56% higher in January than in July. A customer that uses 1,200 kWh in July would be billed $72.12 for electric service under the Company's proposed rates. The same customer with the average 56% higher usage in January would use 1,872 kWh and be billed $102.60. The Company's position is that the overall proposed price increase and seasonal rates for the over-300 kWh price block will provide the Oregon residential customer with a conservation incentive in *both* the summer and the winter.

Q. If Oregon customers use so much more energy in the winter than in the summer why are you proposing seasonal rates?

A. One of Idaho Power's primary goals in rate design is to better match the customers' rate for energy with the Company's cost of energy. System loads and resources drive these costs. Linking the cost of energy with the retail rate of energy sends the appropriate price signal to the customer.

Q. On page 9 of his surrebuttal testimony, Dr. Reading asserts that your rebuttal testimony concludes that customers benefit by paying a price that is reflective of the cost of the energy they consume. Is this assertion an accurate representation of your testimony?

A. No. Both the question and Dr. Reading's answer misstate my testimony. I testified that by better matching the customers' rate for energy with the Company's cost of energy each customer pays a price appropriately reflective of the cost of the energy that they consume. The time-of-use rates proposed in this proceeding are designed to minimize the annual bill impact to customers so that customers are not penalized for not changing their usage patters but do have the opportunity to reduce their bills by shifting energy usage to lower cost time periods.

As previously stated, one of Idaho Power's overall goals in rate design is to better match the customers' rate for energy with the Company's cost of energy. Having each customer pay a price more appropriately reflective of the cost of energy they consume is an equitable method of rate design. Those customers who have lower cost usage patterns benefit by this better matching of price to cost through lower bills under time-of-use rates while customers who have higher cost usage patterns pay more.

The benefit of the proposed time-of-use rate design to the individual industrial customer is an opportunity to pay less for the energy that they consume by shifting usage to lower cost periods.

Q. On page 5 of his surrebuttal testimony, Dr. Reading characterizes Idaho Power's proposed time-of-use rate for industrial customers as "misguided." What is your response?

A. Idaho Power believes time-of-use pricing for industrial customers is good rate design because it provides a better price signal and more appropriately recovers costs from those that impose them.

Q. Do you expect to see immediate changes in usage patterns for industrial customers as a result of time-of-use rates?

A. No, the Company does not believe that a change in usage patterns will necessarily occur in the short term. Over time, however, as customers revise business practices or replace equipment, they can and will respond to price signals. That is why the Company designed the rates to be non-punitive for those customers that do not immediately change their usage patterns.

Q. Do you agree with OICIP's assertion that time-of-use rates have not worked in Idaho?

A. Absolutely not. It is simply too early to determine whether time-of-use rates in Idaho have changed the usage patterns of the Idaho industrial customers. Idaho industrial customers have never been charged Summer time-of-use rates. These rates will begin on June 1, 2005. The Non-Summer time-of-use rates have only been in effect since December 1, 2004. Since the industrial customers' time-of-use rates are new for customers, customers have not had an adequate opportunity to modify usage behavior, change business practices, or change design features with time-of-use rates being considered. Idaho Power maintains that over time the price signals from time-of-use rates will affect industrial customers' energy usage patterns.

Q. Does this conclude your sursurrebuttal testimony?

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 167

IN THE MATTER OF THE APPLICATION OF)
IDAHO POWER COMPANY FOR AUTHORITY)
TO INCREASE ITS RATES AND CHARGES)
FOR ELECTRIC SERVICE TO ELECTRIC)
CUSTOMERS IN THE STATE OF OREGON)
)

IDAHO POWER COMPANY

SURSURREBUTTAL TESTIMONY

OF

KEITH J. KOLAR

Q. Please state your name, address, and present occupation.

A. My name is Keith J. Kolar. My business address is 1550 South Main Street, Payette, Idaho. I am Regional Operations Manager of Delivery in Payette/Canyon Region for Idaho Power Company.

Q. Are you the same Keith J. Kolar that presented direct and rebuttal testimony in this case?

A. Yes, I am.

Q. Have you reviewed the surrebuttal testimony of Dr. Reading of the OICIP?

A. Yes.

Q. In his testimony, Dr. Reading claims that Idaho Power is satisfied with providing service that is “good enough”. Is that a fair characterization of your testimony?

A. No. My legal counsel advises me that Oregon law requires that Idaho Power provide “adequate and safe service at reasonable rates”. My description of Idaho Power’s Oregon service as “generally reliable service” seems to me to be substantially similar to “adequate and safe”. To reiterate, my view on the service we provide in Oregon is that it is as reliable and safe as the service provided throughout Idaho Power’s entire system. I certainly view the Company’s service in Oregon as more than just “good enough”. There is no question in my mind that it meets or exceeds Oregon requirements.

Q. Dr. Reading also questions the accuracy of the outage statistics you presented in your testimony. Do you believe the outage statistics you presented are accurate?

A. I stand by the numbers presented by Idaho Power as both accurate and an actual depiction of service quality from Idaho Power’s perspective.

Q. How do you account for the fact that Ore-Ida’s log of outages is different than Idaho Power's records?

A. I think part of the problem stems from the fact that the word "outage" is being used too broadly to describe two separate types of events. Idaho Power considers an outage to be when power is not supplied to the customer. Dr. Reading uses the word outage to describe an event that causes one of Ore-Ida's production lines to cease operation or shut down. These production shutdowns are typically caused by an anomaly in the supply voltage. These anomalies are called sags or swells. A sag is a momentary lowering of voltage to a value below nominal. A swell is a momentary increase of voltage above nominal. These events are usually associated with an event on the power system, such as a fault or line switching operation. During these events, Idaho Power does not stop delivering power to the customer.

Q. Dr. Reading focuses much of his testimony on a list of "outages" occurring in calendar year 2000. Can you respond to the list of outages described by Dr. Reading?

A. Yes. I have prepared Exhibit 901 that describes system events that occurred on the dates listed in calendar year 2000.

Q. Please elaborate on the relationship between electrical system events and service quality.

A. In 1996, the Computer Based Equipment Manufacturers Association (CBEMA) performance standard was developed to help manufacturers of equipment build systems that would ride through the typical, unavoidable anomalies such as sags and swells that occur on any power system. The performance standards establish a "window" in which manufacturing and processing equipment should be capable of operating during system anomalies. In 1997, Idaho Power installed an ION 7700 meter system at Ore-Ida Substation. This meter system is designed to capture normal telemetry, and is fast enough to report system anomalies such as voltage sags or swells. I have prepared a series of charts for the dates listed in the Ore-Ida report that also show the occurrence of voltage sag or swell. These charts are enclosed as Exhibit 902.

The events listed on the Ore-Ida log that have ION meter data for the same day are included in Exhibit 902. Both Ore-Ida supplied information and Idaho Power supplied information are included in tabular for with each graph. Meter data that is outside of the event window will be displayed in BOLD text in Exhibit 902. Explanations pertaining to each graph are included below the tables.

Date	Exhibit 902 Page	EVENTS INSIDE CBEMA WINDOW	EVENTS OUTSIDE CBEMA WINDOW
Jan 7, 2000	1	1	0
Jan 11, 2000	2	1	1
Feb 1, 2000	3	3	1
Feb 10, 2000	4	1	1
Apr 13, 2000	5	11	1
May 24, 2000	6	3	1
Jun 19, 2000	7	1	0
Sep 5, 2000	8	1	0
Sep 6, 2000	9	1	1
Sep 20, 2000	10	0	2
Oct 16, 2000	11	6	1

The listed dates of February 18, April 18, September 7, and September 21 showed no recorded events on the meter. The ION meter is set to record all events where the voltage sags below 95% of nominal or swells above 105% of nominal. This meter is presently supplying watt and var information to both Idaho Power and Ore-Ida. The sag and swell information now provided to Idaho Power can be shared directly from the meter with Ore-Ida if desired.

Q. What do the ION meter readings tell us about production line interruptions at Ore-Ida?

A. I have reviewed the information on sags and swells on the system as recorded by the ION meter installed at Ore-Ida Substation, for most of the days listed in the Ore-Ida outage log. The graph in Exhibit 902 displays any anomaly recorded by the meter for the date and time listed in the log. The curve in the graph is the CBEMA curve, and Ore-Ida's equipment should not go off line for anomalies within that curve. From the meter information, it appears that production lines are interrupted for events that are both inside and outside of the recommended operating window.

In 1998, Idaho Power and Ore-Ida were working together to solve the loss of production line problem. However, changes in personnel at Ore-Ida and other events seem to have left the project unresolved. Idaho Power would be willing to again work with Ore-Ida at their convenience to find ways to mitigate the problems they are experiencing.

Q. Do you agree with any part of Dr. Reading's surrebuttal testimony related to service quality?

A. Yes, I agree with Dr. Reading that the Company should work proactively with its customers to resolve power quality issues. I do not agree that the Commission needs to order the Company to do so and I believe the Company has demonstrated its willingness to work with its customer, including Ore-Ida, in the past.

Q. Does this conclude your sursurrebuttal testimony?

A. Yes, it does.

BEFORE THE

OREGON PUBLIC UTILITIES COMMISSION

CASE NO. UE 167

IDAHO POWER COMPANY

EXHIBIT NO. 901

KEITH J. KOLAR

reported event	REPORTED EVENT DATE	REPORTED EVENT	SOURCE	FOUND EVENT DATE	FOUND EVENT TIME	Device	FOUND EVENT DESCRIPTION	Result
1	07-Jan-00	distribution disturbance in New Plymouth	DORS/DL	07-Jan-00	22:10	NWPM-013, F16	car pole accident	fuse opened
			DORS/DL	08-Jan-00	1:34	NWPM-013, F16	service restored	fuse closed
			DORS/DL	07-Jan-00	7:10	WESR-013. F4	adverse weather	fuse opened
			DORS/DL	07-Jan-00	7:33	WESR-013. F4	service restored	fuse closed
			DL	07-Jan-00	13:50	HOLY-011, F3	animal in line	fuse opened
			DL	07-Jan-00	14:24	HOLY-013, F3	service restored	fuse closed
2	11-Feb-00	problem with Emmett line	DORS/DL	11-Feb-00	12:58	CARO-013, Ju	general maintainance	jumper opened
			DORS/DL	11-Feb-00	13:48	CARO-013, Ju	service restored	jumper closed
			DL	11-Feb-00	3:00	CNCK T61 Fuse	Fuse operation transformer T-61	fuse open
			DL	11-Feb-00	13:13	CNCK T61 Fuse	Station transformer checked, power restored	fuse closed
			DL	11-Feb-00	13:20	VALE-013	new tap line energized	jumper closed
			DL	11-Feb-00	1:49	EMET-OIDA 69	station breaker 61A operation	trip/close
			DL	11-Feb-00	6:13	EMET-OIDA 69	station breaker 61A operation	trip/close
3	09-Apr-00	problem with Emmett line	DL	09-Apr-00	9:25	CNCK T61	out of service for replacement	Switches opened
4	06-May-00	lost power at Emmett, recloser problems	DORS	06-May-00	18:39	ONTO-020	windy	trip/close
5	05-Jun-00	Emmett line reclosures	DORS	05-Jun-00	10:50	WESR-011, F111	unknown	fuse opened
			DORS	05-Jun-00	11:58	WESR-011, F111	service restored	fuse closed
			DL	05-Jun-00	0:01	HOLY-011, F12	unknown	fuse opened
			DL	05-Jun-00	0:23	HOLY-001, F12	service restored	fuse closed
			DL	05-Jun-00	20:59	CNCK-011, Ju	opened for repairs	Jumper opened
6	28-Sep-00	reclosure problems, Ontario to Emmett	DORS	28-Sep-00	15:11	CNCK-011, Ju	de-energized line	jumper opened
		reclosure problems, Nyssa to Ontario				no outage information available regarding reclosure problems		
7	06-Oct-00	reclosure problems, Ontario to Vale	DORS/DL	06-Oct-00	9:50	CARO-011, Ju	general maintainance	jumper opened
			DORS/DL	06-Oct-00	10:24	CARO-011,Ju	service restored	jumper closed
			DORS/DL	06-Oct-00	11:15	EMET-014. R132	front end loader hit pole	recloser opened
			DORS/DL	06-Oct-00	11:15	EMET-014, Ju	problem isolated, line section off (11:35)	jumper opened
			DORS/DL	06-Oct-00	11:36	EMET-014, R132	partial service restoration	recloser closed
			DORS/DL	06-Oct-00	16:22	EMET-014, Ju	service restored	jumper closed
			DORS/DL	05-Oct-00	16:48	EMET-014, F166	servoce restored	fuse closed
			DORS	Dispatch Outage Reporting System				
			DL	Dispatch Log				

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EXHIBIT NO. 902

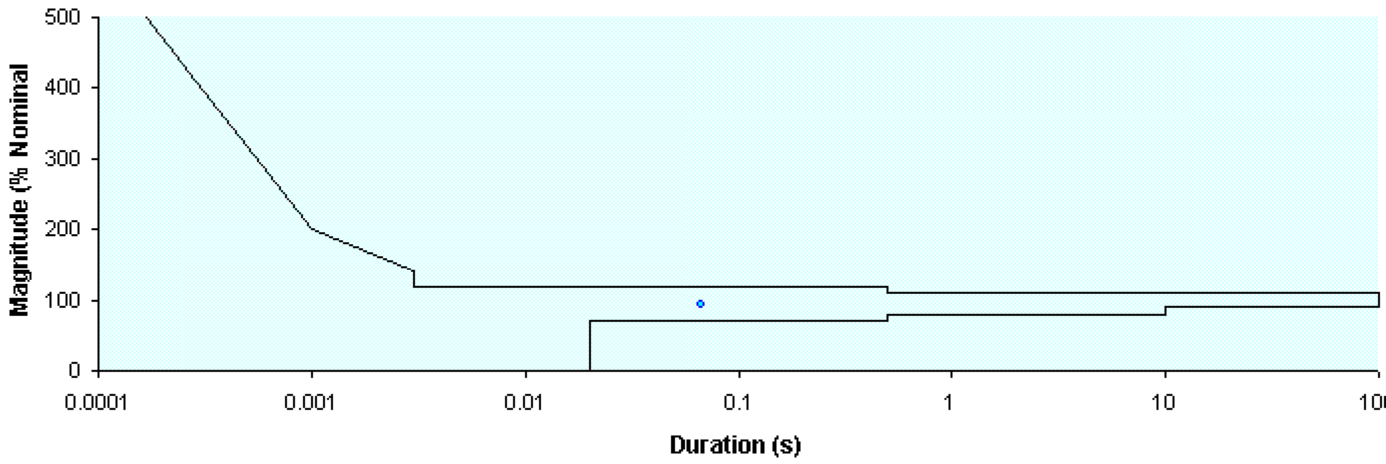
KEITH J. KOLAR

APPENDIX A

Power Measurement Ltd **From: 2000-Jan-07 15:20:51.800**
To: 2000-Jan-07 15:20:51.800

Reporting technology provided by: POWER MEASUREMENT

Disturbances [1996 CBEMA - ITIC]



Ore_Ida.ORID012 - Sags, Swells & Transients

TimeStamp	Type	Phase	Duration (s)	Magnitude (% Nominal)
2000-Jan-07 15:20:51.800	*Sag*	*V2*	*0.067000002*	*93*

Meter Configuration

Meter	Basic Config	Transient Config	Sag/Swell Config
	PT1-PT2 | CT1-CT2 | NomSV	Threshold	Sag Lim | Swell Lim
Ore_Ida.ORID012			0 | 0

ORE-IDA DATA

DATE	TIME	EQUIP#	SHIFT	LINE	MIN	CATG	REASON	DESCRIPTON

IPCO MATCHING DATA

REPORTED EVENT	REPORTED START DATE	REPORTED START TIME	CAUSE	REPORTED END DATE	REPORTED END TIME	DURATION HR:MN	OTHER INFORMATION
NWPM-013,F16	07-Jan-00	22:10	ACCIDENT	08-Jan-00	1:34	3:24	DAMAGED POLE
WESR-013, F4	7-Jan-00	7:10	ADVERSE WEATHER	7-Jan-00	7:33	0:23	FUSE OPENED

There is no matching date on the Ore-Ida log sheet. This date matches one of those listed in the SUBREBUTTAL TESTIMONY, PAGE 7, LINE 24. The recorded event is outside of the CBEMA window.