small QFs. Based on that inquiry, the Company performed a number of analyses of the potential additional power supply expense associated with purchases from such a large generating facility.

Q. Can you summarize the results of those analyses?

A. The Company first looked at the CHP project from the standpoint of the additional revenue requirement associated with purchasing energy from the 111 MW facility at prices equivalent to the Option 1 standard rates (fixed rates) in Idaho Power's Oregon Schedule 85 beginning in 2008. This review did not reflect any adjustment for dispatchability, reliability, or other criteria to be considered in negotiating long-term non-standard contracts with large QFs. It assumed a take-and-pay contract at a 100% capacity factor. That analysis showed that the CHP project would trigger a cumulative revenue requirement over a 20-year contract term of approximately $1.128 billion.

The Company then looked at the cost of its total IRP resource portfolio, including the 111 MW CHP project and compared it to the cost of the Company's IRP resource portfolio without the CHP. Using Idaho Power's 2004 IRP resource stack and running the Company's dispatching and pricing model with Schedule 85 Option 1 (fixed rate) prices showed that the project would produce a total of approximately 1.9 million MWh of economic energy **over a** ~~each year for~~ 20 year~~s~~ **term**. Economic energy is energy Idaho Power would need to meet its customers' loads at a price that is equal to or less than estimated market prices and less costly than other resources available to Idaho Power at the time. Using the Oregon Schedule 85 Option 1 pricing, the total cost to Idaho Power customers of this economic energy over the 20-year term of the contract would be approximately $140 million.

The Company then looked at the approximate quantity of excess energy the CHP would produce. Excess energy is energy generated at times when customer needs are low and/or the CHP generation would be more expensive than both the least-cost resource available or market prices. This analysis showed that the 111 MW project would produce 15.1 MWh of excess energy **over a** ~~each year for~~ 20 year~~s~~ **term**. The cost of the 15.1 MWh of excess energy

Schedule 86, which governs purchases and sales of non-firm energy from QFs. Non-firm energy is defined in Schedule 86 as energy sold by the QF to the Company on a "non-firm, if, as and when available basis." (Idaho Power Company, IPUC No. ~~26~~ 27, Tariff No. 101, ~~3rd Revised~~ **Original** Sheet No. 86-1.) A QF seller of non-firm energy can increase or curtail its energy deliveries to Idaho Power at any time without prior notice and without any economic consequence. A copy of Idaho Power's Rate Schedule 86 is enclosed with my testimony as Exhibit 302.

Q. Is Idaho Power recommending that the Oregon Commission allow Idaho Power to file a similar tariff in Oregon?

A. Yes. In Idaho, several QF projects have opted for the Schedule 86 non-firm agreement to better match their planned operations. These QF projects recognized that, due to the uncertainty of their resource or operating plans, they were unable to commit to any level of energy output to the utility. In some circumstances, this was the case in the early start-up phase of a project; once they gained experience with their operations, they opted to terminate the non-firm agreement (with no penalty) and transition into a firm QF agreement in accordance with the applicable rules and regulations at that time. In addition, having an approved tariff such as Idaho's Schedule 86 draws a clear distinction between firm and non-firm energy purchased from QFs.

Q. Please describe what you mean by firm energy purchases.

A. Idaho Power purchases hundreds of thousands of MWh of firm energy each year. Sellers under these firm energy purchases contractually commit to deliver energy at the times and in the amounts specified in the contract. In these non-QF firm energy contracts, failure to provide the specified amount of energy at the agreed-upon time results in the payment of damages, either actual damages or liquidated damages. Firm energy purchases for larger amounts of energy also require a more rigorous analysis of the creditworthiness of the Seller to provide assurance that the Seller has the financial strength to perform its obligations.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1129

PHASE II -- TRACK 2

In the Matter of

PUBLIC UTILITY COMMISSION OF OREGON

Staff's Investigation Relating to Electric Utility Purchases From Qualifying Facilities.

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

JOHN R. GALE

February 27, 2006

Q. Please state your name and business address for the record.

A. My name is John R. Gale and my business address is 1221 West Idaho Street, Boise, Idaho.

Q. By whom are you employed and in what capacity?

A. I am employed by Idaho Power Company ("Idaho Power" or the "Company") as the Vice President of Regulatory Affairs.

Q. Are you the same John R. Gale who has previously provided rebuttal testimony in Phase I and Phase II – Track 1 of this proceeding?

A. Yes, I am.

Q. What is the purpose of your direct testimony in this Track 2 of Phase II?

A. The principal focus of my testimony is to address issues associated with negotiating the purchase prices, terms and conditions to be included in non-standard contracts with large qualifying facilities ("QFs"). I will also address a number of the issues relating to both large and small QFs identified in Judge Kirkpatrick's November 17, 2005 Order establishing issues for resolution in this Track 2.

Q. When you refer to large QFs, what do you mean?

A. I am referring to QFs with a nameplate capacity larger than the 10 MW cap for entitlement to standard rates and standard contracts the Public Utility Commission of Oregon (the "Commission") set in Order No. 05-584.

Q. In its testimony in Phase I, Weyerhaeuser proposed that large QFs should have the option to require utilities to purchase their generation at prices that vary monthly based on an index of delivered natural gas prices. What is Idaho Power's response to this proposal?

A. Weyerhaeuser's proposal would require Idaho Power to depart from the energy acquisition framework laid out in its Integrated Resource Plan ("IRP") and would subject customers to an unacceptable level of price volatility risk. For these reasons, Idaho Power opposes Weyerhaeuser's proposal.

Q. Please explain.

A. In accordance with orders issued by both this Commission and the Idaho Public Utilities Commission, Idaho Power prepares a biennial IRP which is filed and acknowledged by both the Idaho and Oregon Commissions. Idaho Power believes that all resource acquisitions, including the acquisition of large QF resources, should be consistent with the risk and cost profiles of the portfolio resources identified in the acknowledged IRPs. Idaho Power does not currently have a base-load natural gas-fired generating resource in its resource portfolio. Idaho Power's most recent IRP, the 2004 IRP, does not include the construction or acquisition of a base-load generating resource fueled by natural gas. The decision *not* to include a base-load natural gas-fired generating resource in the IRP resource portfolio was based, in part, on the potential for increased customer cost due to the volatility of natural gas prices. Idaho Power believes that recent upward spikes in natural gas prices validates that decision. However, if the Company is required to enter into contracts with large QFs that include energy purchase prices that vary based on monthly spot market gas prices, the Company's integrated resource planning process will have been subverted and the Company and its customers will become subject to the very price volatility the Company sought to avoid in its long-term resource planning process.

Q. Has the Company performed any analysis of the potential costs associated with the purchase of energy from a large QF utilizing a contract in which the purchase price varies with monthly changes in the spot price for natural gas?

A. Yes. Recently a well-known developer of natural gas-fired power plants contacted the Company and advised the Company that it intended to pursue construction of a 111 MW natural gas-fired combined heat and power ("CHP") plant at an industrial facility located in Idaho Power's Oregon service area. The developer indicated it intended to require Idaho Power to purchase the energy generated by this large CHP for 20 years using purchase prices computed in a manner similar to the Option 3 (Gas Market) standard rate methodology that is available to small QFs. Based on that inquiry, the Company performed a number of analyses of the potential additional power supply expense associated with purchases from such a large generating facility.

Q. Can you summarize the results of those analyses?

A. The Company first looked at the CHP project from the standpoint of the additional revenue requirement associated with purchasing energy from the 111 MW facility at prices equivalent to the Option 1 standard rates (fixed rates) in Idaho Power's Oregon Schedule 85 beginning in 2008. This review did not reflect any adjustment for dispatchability, reliability, or other criteria to be considered in negotiating long-term non-standard contracts with large QFs. It assumed a take-and-pay contract at a 100% capacity factor. That analysis showed that the CHP project would trigger a cumulative revenue requirement over a 20-year contract term of approximately $1.128 billion.

The Company then looked at the cost of its total IRP resource portfolio, including the 111 MW CHP project and compared it to the cost of the Company's IRP resource portfolio without the CHP. Using Idaho Power's 2004 IRP resource stack and running the Company's dispatching and pricing model with Schedule 85 Option 1 (fixed rate) prices showed that the project would produce a total of approximately 1.9 million MWh of economic energy over a 20 year term. Economic energy is energy Idaho Power would need to meet its customers' loads at a price that is equal to or less than estimated market prices and less costly than other resources available to Idaho Power at the time. Using the Oregon Schedule 85 Option 1 pricing, the total cost to Idaho Power customers of this economic energy over the 20-year term of the contract would be approximately $140 million.

The Company then looked at the approximate quantity of excess energy the CHP would produce. Excess energy is energy generated at times when customer needs are low and/or the CHP generation would be more expensive than both the least-cost resource available or market prices. This analysis showed that the 111 MW project would produce 15.1 MWh of excess energy over a 20 year term. The cost of the 15.1 MWh of excess energy using Oregon's Schedule 85 Option 1 prices is approximately $989 million over the term of the 20-year contract.

Of course, excess energy could be sold at the prevailing market prices. Again, using the Company's economic dispatch model, Idaho Power estimates the revenue from sales of this excess energy would be approximately $759 million. Based on this analysis, when compared to the cost of Idaho Power's current IRP resource portfolio, the extra cost to Idaho Power's customers of the CHP purchase is estimated to be approximately $230 million (excess energy cost less estimated market sales of excess energy) over the 20-year term of the CHP project's contract.

Q. Did the Company analyze the relative impact on customers if it were required to purchase the QF's output at a price varying with monthly changes in the spot market price for natural gas, as Weyerhaeuser argues it should be required to do?

A. Yes. In the case of the 111 MW QF, the developer indicates that it wishes to negotiate a contract including purchase prices that would vary based on a monthly index of delivered natural gas prices similar to the Option 3 (Gas Index) standard rate methodology in Idaho Power's Oregon Schedule 85, which is available to small QFs. Pricing the above-described purchase using the Option 3 (Gas Index) standard rate methodology for the period January 2005 through January 2006, using a 90% capacity factor for all hours in the day, indicated that using an Option 3-like pricing arrangement would have resulted in an additional annual revenue requirement in 2005 of approximately $8.3 million when compared to purchase prices based on Oregon Schedule 85 Option 1 (fixed-price) method. This represents a 14% increase in customer costs that would have been incurred during the 13-month January 2005 – January 2006 period. Exhibit 301 shows the computation of that comparison. Again, this analysis does not attempt to include any adjustment for dispatchability, reliability, or other factors that would be subject to negotiation in the development of a long-term, non-standard contract to purchase energy from a large QF.

Q. Did Idaho Power also analyze the purchase from the 111 MW project utilizing Option 2, the gas dead-band methodology and comparing it to Option 1 prices?

A. Yes. Pricing the same purchase using the Option 2 (gas dead-band method) standard rate methodology for the period January 2005 through January 2006 using a 90% capacity factor for all hours in the day shows that using an Option 2 pricing arrangement would have resulted in an additional annual revenue requirement in 2005 of approximately $1 million when compared to purchase prices based on Oregon's Schedule 85 Option 1 (fixed price) method. Exhibit 301 shows the computation of that comparison.

Q. Please summarize Idaho Power's position on pricing energy purchases from large QFs using monthly spot-market gas prices?

A. Idaho Power is opposed to using monthly natural gas price indices to set purchase prices for energy generated by large QFs. That includes using either Option 2 or Option 3 of the standard rates for small QFs as the starting point for negotiation. Idaho Power is willing to negotiate purchase prices for energy generated by large QFs based on Idaho Power's approved avoided costs. Idaho Power's approved avoided costs utilize the Northwest Power and Conservation Council's most recent long-term forecast for the price of natural gas as the fuel component. Idaho Power's approved avoided costs are not based on an index of monthly prices for natural gas. Requiring Idaho Power to purchase energy from a large QF using prices that vary monthly based on an index of delivered natural gas prices would transfer all of the risk of natural gas price volatility from the QF developer to Idaho Power's customers. Both the Oregon Commission and the Idaho Commission have acknowledged Idaho Power's resource plan as contained in its 2004 IRP. That plan does not include building or acquiring a base-load natural gas-fired generation resource, thereby providing some protection for Idaho Power's customers from price risk associated with volatile gas prices. That price risk should properly be assumed by the QF developer.

Q. Small QFs desiring to sell energy to Idaho Power can select Option 3 standard rates and receive purchase prices that vary monthly based on an index of delivered natural gas prices. Why is Idaho Power opposed to offering a similar pricing arrangement to large QFs?

A. There are several reasons. First, small combined heat and power projects that use natural gas as a fuel may not have the economic resources or economies of scale that would allow them to negotiate fixed-price contracts with gas suppliers or to hedge their purchases of natural gas. Because of their small size, they may have no choice but to be price takers.

Large CHP QFs, on the other hand, have a much greater ability to control their natural gas costs by the use of longer term contracts and more sophisticated physical and financial hedging techniques.

Finally, and probably most importantly, a large QF, whether it is actually fired by natural gas or not, can have a substantial effect on the Company's resource planning process and on its revenue requirement. Idaho Power's Oregon jurisdictional system peak load is approximately 110 MW. The 111 MW CHP project I discussed previously in my testimony would overwhelm the Company's total load in the state of Oregon.

Simply put, while Idaho Power questions whether standard rate Option 3 is representative of costs Idaho Power can actually avoid by purchasing from small QFs, Idaho Power can probably tolerate the increased revenue requirement associated with a small QF utilizing the Option 3 standard rate. But it is a totally different story when the Company and its customers are asked to absorb the increased costs and volatility associated with large QFs being paid purchase prices based on fluctuating monthly spot-market gas prices.

Q. Several of the issues on the adopted issue list, including issues 1(b) and 1(c), relate to the "firmness" of QF power supply commitments. Please describe the difference between firm and non-firm energy purchases.

A. Because a number of QFs over the years have desired to sell energy to Idaho Power on a non-firm basis, Idaho Power has an approved rate schedule in the state of Idaho, Schedule 86, which governs purchases and sales of non-firm energy from QFs. Non-firm energy is defined in Schedule 86 as energy sold by the QF to the Company on a "non-firm, if, as and when available basis." (Idaho Power Company, IPUC No. 27, Tariff No. 101, Original Sheet No. 86-1.) A QF seller of non-firm energy can increase or curtail its energy deliveries to Idaho Power at any time without prior notice and without any economic consequence. A copy of Idaho Power's Rate Schedule 86 is enclosed with my testimony as Exhibit 302.

Q. Is Idaho Power recommending that the Oregon Commission allow Idaho Power to file a similar tariff in Oregon?

A. Yes. In Idaho, several QF projects have opted for the Schedule 86 non-firm agreement to better match their planned operations. These QF projects recognized that, due to the uncertainty of their resource or operating plans, they were unable to commit to any level of energy output to the utility. In some circumstances, this was the case in the early start-up phase of a project; once they gained experience with their operations, they opted to terminate the non-firm agreement (with no penalty) and transition into a firm QF agreement in accordance with the applicable rules and regulations at that time. In addition, having an approved tariff such as Idaho's Schedule 86 draws a clear distinction between firm and non-firm energy purchased from QFs.

Q. Please describe what you mean by firm energy purchases.

A. Idaho Power purchases hundreds of thousands of MWh of firm energy each year. Sellers under these firm energy purchases contractually commit to deliver energy at the times and in the amounts specified in the contract. In these non-QF firm energy contracts, failure to provide the specified amount of energy at the agreed-upon time results in the payment of damages, either actual damages or liquidated damages. Firm energy purchases for larger amounts of energy also require a more rigorous analysis of the creditworthiness of the Seller to provide assurance that the Seller has the financial strength to perform its obligations.

Q. Aren't most of the 87 contracts Idaho Power has signed with both Oregon and Idaho QFs "firm" energy contracts?

A. The contracts Idaho Power signed with QF developers prior to 2003 describe the energy deliveries as "firm." In actual practice, the amount of energy delivered under these earlier contracts can fluctuate from 0 MW to 10 MW, hour to hour, day to day, or month to month, completely at the discretion of the QF. As a result, Idaho Power only has a general idea of how much energy it can expect to receive from any QF at any time. As a result, the actual firmness of the energy deliveries under these pre-2003 contracts more closely resembles non-firm energy deliveries than firm energy deliveries.

Q. Is the same true for standard contracts in Oregon?

A. The answer to that question depends to some extent on the outcome of the Phase I proceedings in that case. Idaho Power is requesting that the QFs be required to provide monthly commitments as to the amount of energy they will deliver. Staff and ODOE are recommending that the commitment only be annual. If the commitment is annual, then it is difficult to characterize the Oregon standard QF contracts as providing firm energy.

Q. How does Idaho Power recommend that non-standard contracts with large QFs be structured to address firmness?

A. Idaho Power recommends that the Commission not restrict Idaho Power's ability to negotiate reasonable terms and conditions that require large QFs to make firm commitments as to the amounts of energy they will deliver and when they will deliver it. The contracts should include standard industry liquidated damage provisions for a failure to perform in accordance with the agreement and reasonable credit provisions to ensure that the large QF can actually pay damages to customers if the large QF fails to perform. Purchase prices should be negotiated to reflect the attributes, including reliability and dispatchability, as described in 18 CFR § 292.304, for the specific large QF resource just like other wholesale purchases the Company makes from other wholesale market participants. This is critical because, as demonstrated by the potential purchase from the 111 MW CHP I discussed earlier in my testimony, even a single large QF can have a material impact on Idaho Power's resource planning and customer rates.

Q. What about large intermittent QF resources, such as wind farms?

A. Idaho Power acknowledges that the intermittent nature of wind or solar resources will require that contracts for those resources include some additional flexibility in determining the "firmness" of the commitment to qualify for a firm energy purchase price. Idaho Power is currently undertaking a comprehensive study of the costs that the Company will incur to integrate increasingly greater levels of wind resources into its resource portfolio. That study is expected to be completed by the end of June. The wind integration study will give the Company much needed data to accurately assess the dispatchability and reliability of wind resources and assist in the negotiation of reasonable rates, terms and conditions for inclusion in contracts with large wind QF resources.

Q. Should purchase prices for energy purchased from large QF resources be based on the market prices obtained in competitive bidding programs undertaken by Idaho Power?

A. There is no question that competitive bidding programs yield the best indication of the costs Idaho Power can avoid by acquiring energy from a particular generation technology.

Q. Has Idaho Power obtained recent experience with competitive bid pricing for renewable resources?

A. Yes. In 2005 Idaho Power issued a request for proposals ("RFP") for the acquisition of up to 200 MW of wind resources. Idaho Power expects to announce the results of that RFP in the very near future. Idaho Power also plans to issue an RFP for up to 100 MW of geothermal generating resources in the next month. As a result of the RFPs, Idaho Power will have current information on what costs it can avoid by purchasing wind resources and geothermal resources at market prices as compared to the cost of acquiring wind and geothermal resources from QFs at administratively determined prices. I can see no reason why customers should be expected to pay purchase prices for energy from large QFs that exceed the cost the utility would incur if it purchased the same resources with identical attributes by means of a competitive bid. In developing contracts for purchase from large QFs, the Company should be able to use the results of that bidding process in the negotiation process.

Q. Does the Company have any preliminary results from its wind resources RFP?

A. All indications suggest that purchasing wind resources via the RFP will be less expensive than purchasing wind resources from QFs utilizing administratively determined avoided-cost rates.

Unfortunately, if the Company continues to purchase additional amounts of wind resource from small QFs at higher, administratively determined avoided cost prices, it probably will be forced to cut back on the amount of wind resources purchased by competitive bid. Based on the Company's recent experience, that means that customers will probably pay more for wind resources than they otherwise would need to pay.

Q. One of the issues identified for resolution in this Phase 2 is the need for liability insurance for QFs with a design capacity at or under 200 kW. Does Idaho Power's experience with QFs in Idaho provide any guidance on this issue?

A. I believe it does. First, it should be stated that the size of a QF facility has nothing to do with the exposure that a utility has in the case of an electrical contact or other incident in which liability insurance would come into play. The need for liability insurance is just as serious for a 200 kW facility as it is for a 20 MW facility. That being said, Idaho Power currently has contracts with 11 QFs whose design capacity is 200 kW or less. Each one of those QFs maintains $1,000,000 of liability insurance. There is no indication that these small QFs are having any difficulty obtaining and paying for liability insurance. It is important to remember that a 200 kW facility operating at an 85% capacity factor using Oregon Schedule 85, Option 1 pricing would have been paid approximately $100,000 during calendar year 2005. Idaho Power's experience in Idaho demonstrates that requiring reasonable levels of liability insurance is not a barrier to the development and ongoing operation of very small QF projects.

Q. One of the issues to be determined in this proceeding is the impact on utility costs from imputed debt arising from QF contracts. What is imputed debt?

A. Like other electric utilities, when Idaho Power adds to its rate base, it must use some portion of shareholder equity to fund the investment. The Company must maintain its equity component above a certain level as it continues this investment process. If it does not, the debt level increases and the Company will face the threat of a bond-rating downgrade. Conversely, when the Company enters into a QF contract for purchased power, an obligation not reflected in its financial statements, an increase in equity is needed to maintain credit quality. Unless an equity component is provided to offset the debt-like obligation of long-term QF purchase power contracts, the Company faces off-balance sheet financial risk. For financial commitments that do not appear on the balance sheet, credit rating analysts impute the debt and interest equivalents on the financial statements of the Company to achieve a more accurate picture of the risk associated with their investment. The added equity needed to offset this imputed debt and interest represents the effect that long-term purchased power commitments have on the cost of capital. Any increase in the long-term obligation of a utility related to its capacity and energy resources will have to be backed by an appropriate amount of equity in the eyes of the investment community.

In reviewing its evaluation of the credit implications of QF related expenditures, S&P recently affirmed its position that such agreements are "debt-like in nature" and that the increased financial risk must be considered in evaluating a utility's credit risks. As the rating agency explained in its publication, Utilities & Perspectives, May 12, 2003:

"[P]urchased power agreements typically result in the assumption of fixed costs representing the portion of the purchase price that is linked to the capacity component of the total payment. These fixed capacity payments are similar to debt service payments incurred by a utility that constructs debt-like financed power generation facilities. Therefore, whether a utility builds its own generation plants, or enters into a long-term power purchase agreement with a fixed-cost component, that utility is taking on financial risk."

Q. How does Idaho Power suggest that the Commission address imputed debt arising out of an increasing level of QF contract activity?

A. There is really nothing the Commission can do to prevent the additional cost associated with added equity required by increasing levels of imputed debt due to QF purchases. The only real issue is who will bear that additional cost? Unless avoided costs are adjusted to reflect the additional cost-of-capital expense associated with imputed debt, those higher costs will be passed on to the entire body of Idaho Power's customers. It seems equitable to Idaho Power that QF developers at least share some of the additional cost created by imputed debt by means of a reduction in the utility's avoided cost purchase prices.

Q. Does that complete your direct testimony?

A. Yes, it does.

PUBLIC UTILITY COMMISSION
OF
OREGON

CASE: UM 1129
WITNESS: John R. Gale

IDAHO POWER EXHIBIT 301

February, 2006

Idaho Power Company

Estimated Oregon Schedule 85 Energy Payments

Nameplate of proposed Project	111.00 MW
Capacity Factor	90.00%

	Energy			Option 1 -Fixed Prices			Option 2 - Gas Deadband			Option 3 - Gas Index		
Total	533,866	417,982	951,847	$36,090,273	$18,287,929	$54,378,202	$36,533,747	$18,646,835	$55,180,581	$40,307,039	$21,687,552	$61,994,591
						$57.13			$57.97			$65.13
	On-Peak	Off-Peak	Total	On-Peak	Off-Peak	Total	On-Peak	Off-Peak	Total	On-Peak	Off-Peak	Total
Jan-05	41,558	32,767	74,326	$2,810,595	$1,430,944	$4,241,538	$2,748,423	$1,381,924	$4,130,347	$2,748,423	$1,381,924	$4,130,347
Feb-05	39,960	29,570	69,530	$2,702,495	$1,291,339	$3,993,834	$2,546,251	$1,175,719	$3,721,970	$2,546,251	$1,175,719	$3,721,970
Mar-05	41,558	32,767	74,326	$2,065,787	$1,051,744	$3,117,531	$1,932,304	$946,497	$2,878,800	$1,924,667	$940,476	$2,865,143
Apr-05	41,558	30,370	71,928	$2,065,787	$974,787	$3,040,574	$2,122,021	$1,015,881	$3,137,902	$2,122,021	$1,015,881	$3,137,902
May-05	41,558	32,767	74,326	$2,065,787	$1,051,744	$3,117,531	$2,109,009	$1,085,822	$3,194,831	$2,109,009	$1,085,822	$3,194,831
Jun-05	39,960	31,968	71,928	$2,702,495	$1,396,043	$4,098,537	$2,527,870	$1,256,342	$3,784,212	$2,523,554	$1,252,890	$3,776,444
Jul-05	41,558	32,767	74,326	$3,372,714	$1,717,132	$5,089,846	$3,337,056	$1,689,018	$5,026,074	$3,337,056	$1,689,018	$5,026,074
Aug-05	41,558	32,767	74,326	$3,372,714	$1,717,132	$5,089,846	$3,315,812	$1,672,267	$4,988,079	$3,315,812	$1,672,267	$4,988,079
Sep-05	39,960	31,968	71,928	$2,702,495	$1,396,043	$4,098,537	$2,877,120	$1,535,743	$4,412,863	$3,204,472	$1,797,625	$5,002,097
Oct-05	43,157	31,169	74,326	$2,918,694	$1,361,141	$4,279,836	$3,107,290	$1,497,349	$4,604,639	$4,027,695	$2,162,086	$6,189,781
Nov-05	38,362	33,566	71,928	$3,113,274	$1,759,014	$4,872,288	$3,314,442	$1,935,036	$5,249,478	$4,734,174	$3,177,301	$7,911,476
Dec-05	41,558	32,767	74,326	$3,372,714	$1,717,132	$5,089,846	$3,590,646	$1,888,964	$5,479,609	$4,594,032	$2,680,095	$7,274,127
Jan-06	41,558	32,767	74,326	$2,824,724	$1,423,735	$4,248,459	$3,005,503	$1,566,272	$4,571,776	$3,119,872	$1,656,447	$4,776,320
Feb-06												
Mar-06												
Apr-06												
May-06												
Jun-06												
Jul-06												
Aug-06												
Sep-06												
Oct-06												
Nov-06												
Dec-06												

PUBLIC UTILITY COMMISSION
OF
OREGON

CASE: UM 1129
WITNESS: John R. Gale

IDAHO POWER EXHIBIT 302

February, 2006

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
June 1, 2004 June 1, 2004
Jean D. Jewell Secretary

SCHEDULE 86
COGENERATION AND SMALL POWER PRODUCTION NON-FIRM ENERGY

AVAILABILITY

Service under this schedule is available throughout the Company's service territory within the State of Idaho.

APPLICABILITY

Service under this schedule is applicable to any Seller that:

1. Owns or operates a Qualifying Facility with a nameplate capacity rating of less than 10 MW and desires to sell Energy generated by the Qualifying Facility to the Company on a non-firm, if, as, and when available basis;

2. Meets all applicable requirements of the Company's Schedule 72 and the Generation Interconnection Process.

DEFINITIONS

Avoided Energy Cost is the weighted average of the daily on-peak and off-peak Dow Jones Mid-Columbia Electricity Price Index (Dow Jones Mid-C Index) prices for nonfirm energy published in the Wall Street Journal. If the Dow Jones Mid-C Index prices are not reported for a particular day or days, the average of the immediately preceding and following reporting periods or days will be used.

Designated Dispatch Facility is the Company's Boise Bench Dispatch Center.

Energy means the non-firm electric energy, expressed in kWh, generated by the Qualifying Facility and delivered by the Seller to the Company in accordance with the conditions of this schedule. Energy is measured net of Losses and Station Use.

Generation Facility means equipment used to produce electric energy at a specific physical location, which meets the requirements to be a Qualifying Facility.

Generation Interconnection Process is the Company's generation interconnection application and engineering review process developed to ensure a safe and reliable generation interconnection.

Interconnection Facilities are all facilities reasonably required by Prudent Electrical Practices and the National Electric Safety Code to interconnect and safely deliver Energy from the Qualifying Facility to the Company's system, including, but not limited to, connection, transformation, switching, metering, relaying, communications, disconnection, and safety equipment.

Losses are the loss of electric energy occurring as a result of the transformation and transmission of electric energy from the Qualifying Facility to the Point of Delivery.

IDAHO PUBLIC UTILITIES COMMISSION
Approved **Effective**
June 1, 2004 **June 1, 2004**
Jean D. Jewell Secretary

SCHEDULE 86
COGENERATION AND SMALL
POWER PRODUCTION NON-FIRM
ENERGY
(Continued)

DEFINITIONS (Continued)

Point of Delivery is the location where the Company's and the Seller's electrical facilities are interconnected.

Prudent Electrical Practices are those practices, methods and equipment that are commonly used in prudent electrical engineering and operations to operate electric equipment lawfully and with safety, dependability, efficiency and economy.

PURPA means the Public Utility Regulatory Policies Act of 1978.

Qualifying Facility is a cogeneration facility or a small power production facility which meets the PURPA criteria for qualification set forth in Subpart B of Part 292, Subchapter K, Chapter I, Title 18, of the Code of Federal Regulations.

Schedule 72 is the Company's service schedule which provides for interconnection to non-utility generation or its successor schedule(s) as approved by the Commission.

Seller is any entity that owns or operates a Qualifying Facility and desires to sell Energy to the Company.

Standby Power is electrical energy or capacity supplied by the Company during an unscheduled outage of a Qualifying Facility to replace energy consumed by the seller which is ordinarily supplied by the Seller's Qualifying Facility.

Station Use is electric energy used to operate the Qualifying Facility which is auxiliary to or directly related to the generation of electricity and which, but for the generation of electricity, would not be consumed by the Seller.

Supplementary Power is electric energy or capacity supplied by the Company which is regularly used by a Seller in addition to the Energy and capacity which the Qualifying Facility usually supplies to the Seller.

PURCHASE PRICE

The Company will pay the Seller monthly, for each kWh of Energy delivered and accepted at the Point of Delivery during the preceding calendar month, an amount equal to 85 percent of the monthly Avoided Energy Cost.

IDAHO PUBLIC UTILITIES COMMISSION
Approved **Effective**
June 1, 2004 **June 1, 2004**
Jean D. Jewell Secretary

SCHEDULE 86
COGENERATION AND SMALL
POWER PRODUCTION NON-FIRM
ENERGY
(Continued)

CONDITIONS OF PURCHASE AND SALE

The conditions listed below shall apply to all transactions under this schedule.

1. The Company shall purchase Energy from any Seller that offers to sell Energy to the Company.

2. As a condition of interconnection with the Company, the Seller shall:

a. Complete and maintain all requirements of interconnection in accordance with Schedule 72.

b. Complete and maintain all requirements of the Company's Generation Interconnection Process.

c. Submit proof to the Company of all insurance required by paragraph 12.

d. Obtain written confirmation from the Company that all conditions to interconnection have been fulfilled prior to operation of the Generation Facility. Such confirmation shall not be unreasonably withheld by the Company.

3. The Seller shall never deliver or attempt to deliver energy to the Company's system when the Company's system serving the Seller's Generation Facility is de-energized for any reason.

4. The Seller and the Company shall each indemnify the other, their respective officers, agents, and employees against all loss, damage, expense, and liability to third persons for injury to or death of persons or injury to property, proximately caused by the indemnifying party's construction, ownership, operation or maintenance of, or by failure of, any of such party's works or facilities used in connection with purchases under this schedule. The indemnifying party shall, on the other party's request, defend any suit asserting a claim covered by this indemnity. The indemnifying party shall pay all costs that may be incurred by the other party in enforcing this indemnity.

5. The Company shall offer to provide Standby Power and Supplementary Power to the Seller. Charges for Supplementary and Standby Power will be in accordance with the Company's Schedule 7 as that schedule is modified from time to time by the Commission.

6. The Seller shall maintain voltage levels acceptable to the Company.

7. The Seller shall maintain at the Qualifying Facility or such other location mutually acceptable to the Company and Seller, adequate metering and related power production records, in a form and content recommended by the Company.

SCHEDULE 86
COGENERATION AND SMALL
POWER PRODUCTION NON-FIRM
ENERGY
(Continued)

CONDITIONS OF PURCHASE AND SALE (Continued)

Either the Seller or the Company after reasonable notice to the other party, shall have the right, during normal business hours, to inspect and audit any or all such metering and related power production records pertaining to the Seller's account.

8. During a period of shortage of energy on the Company's system, the Seller shall, at the Company's request and within the limits of reasonable safety requirements as determined by the Seller, use its best efforts to provide requested Energy, and shall, if necessary, delay any scheduled shutdown of the Qualifying Facility.

9. The Company and the Seller shall maintain appropriate operating communications through the Designated Dispatch Facility.

10. The Company shall not be obligated to accept, and the Company may require the Seller to curtail, interrupt or reduce deliveries of Energy if the Company, consistent with Prudent Electrical Practices, determines that curtailment, interruption or reduction is necessary because of line construction or maintenance requirements, emergencies, or other critical operating conditions on its system.

11. If the Company is required by the Commission to institute curtailment of deliveries of electricity to its Customers, the Company may require the Seller to curtail its consumption of electricity in the same manner and to the same degree as other Customers within the same Customer class who do not own Generation Facilities.

12. The Seller shall secure and continuously carry liability insurance coverage for both bodily injury and property damage liability in the amount of not less than $1,000,000 each occurrence combined single limit.

Such insurance shall include an endorsement naming the Company as an additional insured insofar as liability arising out of operations under this schedule and a provision that such liability policies shall not be canceled or their limits of liability reduced without 30 days' written notice to the Company. The Seller shall furnish the Company with certificates of insurance together with the endorsements required herein. The Company shall have the right to inspect the original policies of such insurance.

13. The Seller shall grant to the Company all necessary rights of way and easements to install, operate, maintain, replace, and remove the Company's metering and other Interconnection Facilities including adequate and continuing access rights to the property of the Seller. The Seller warrants that it has procured sufficient easements and rights of way from third parties as are necessary to provide the Company with the access described above. The Seller shall execute such other grants, deeds, or documents as the Company may require to enable it to record such rights of way and easements.

IDAHO PUBLIC UTILITIES COMMISSION
Approved **Effective**
June 1, 2004 **June 1, 2004**
Jean D. Jewell Secretary

SCHEDULE 86
COGENERATION AND SMALL
POWER PRODUCTION NON-FIRM
ENERGY
(Continued)

CONDITIONS OF PURCHASE AND SALE (Continued)

14. Depending on the size and location of the Seller's Qualifying Facility, it may be necessary for the Company to establish additional requirements for operation of the Qualifying Facility. These requirements may include, but are not limited to, voltage, reactive, or operating requirements.

IDAHO PUBLIC UTILITIES COMMISSION
Approved **Effective**
June 1, 2004 **June 1, 2004**
Jean D. Jewell Secretary

SCHEDULE 86
UNIFORM AGREEMENT

Idaho Power Company
For the Purchase of Non-Firm
Energy From Qualifying Facilities

THIS AGREEMENT Made this _______ day of __________________________, 20 _______, between ____whose mailing address is ____________________________hereinafter called Seller and Idaho Power Company, a corporation with its principal office located at 1221 West Idaho Street, Boise, Idaho hereinafter called "Company".

NOW, THEREFORE, The parties agree as follows:

1. Company shall purchase Energy produced by the Seller's Qualifying Facility located at or near,___________________County of_____________________________, State of Idaho, located in the _________ of Section ________, Township, _______ Range _________, BM, in the form of three phase 60 Hz and at a nominal phase to phase potential of __________ volts, subject to emergency operating conditions of the Company. Purchases under this Agreement are subject to the Company's applicable Tariff provisions, including but not limited to Schedules 86 and 72 approved by and as may be hereafter modified by the Idaho Public Utilities Commission ("Commission") and the provisions of this Agreement.

2. Seller shall pay Company for all costs of Interconnection Facilities as provided for in Exhibit A of this Agreement and Schedule 72.

3. In addition to the charges provided under Paragraph 2, Seller shall pay to the Company the monthly Operation & Maintenance Charge specified in Schedule 72 on the investment by the Company in Interconnection Facilities which investment is set forth in Exhibit A, attached hereto and made a part hereof. As such investment changes, in order to provide facilities to serve Seller's requirements, Company shall notify Seller in writing of additions or deletions of facilities by forwarding a dated revised Exhibit A, which shall become part of this Agreement. The monthly Operation & Maintenance Charge will be adjusted to correspond to the Revised Exhibit A.

4. The initial date of acceptance of Energy under this Agreement is subject to the Company's ability to obtain required labor, materials, equipment, satisfactory rights of way, and comply with governmental regulations.

5. The term of this Agreement shall become effective on the date first above written, and shall continue to full force and effect until canceled by Seller upon sixty (60) days prior written notice.

6. This Agreement and the rates, terms, and conditions of service set forth or incorporated herein, and the respective rights and obligations of the parties hereunder, shall be subject to valid laws and to the regulatory authority and orders, rules, and regulations of the Commission and such other administrative bodies having jurisdiction.

SCHEDULE 86
COGENERATION AND SMALL POWER PRODUCTION NON-FIRM ENERGY

Idaho Power Company
For the Purchase of Non-Firm
Energy From Qualifying Facilities
(Continued)

7. Nothing herein shall be construed as limiting the Commission from changing any rates, charges, classification or service, or any rules, regulation or conditions relating to service under this Agreement, or construed as affecting the right of the Company or the Seller to unilaterally make application to the Commission for any such change.

8. This Agreement shall not become effective until the Commission approves all terms and provisions hereof without change or condition and declares that all payments to be made hereunder shall be allowed as prudently incurred expenses for rate making purposes.

(APPROPRIATE SIGNATURES)

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March 16, 2006

VIA ELECTRONIC MAIL AND US MAIL

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

Re: UM 1129 (Track II, Phase II) – Idaho Power's Errata to Direct Testimony of John R. Gale

Dear Sir or Madam:

Idaho Power has identified some errors in its Direct Testimony filed on February 27, 2006 that require correction as follows:

1. Idaho Power/300, Gale/3, lines 16-17 have been changed from "each year for 20 years" to "over a 20 year term."

2. Idaho Power/300, Gale/3, line 26 has been changed from "each year for 20 years" to "over a 20 year term."

3. Idaho Power/300, Gale/7, line 3 has been changed from "IPUC No. 26, Tariff No. 101, 3rd Revised Sheet" to "IPUC No. 27, Tariff No. 101, Original Sheet."

4. Idaho Power/302, Gale/1-7, referred to at Idaho Power/300, Gale/7 is updated to reflect the change.

Enclosed are redline versions of changes 1-3, as well as a clean version of the entire Testimony, which will reflect any line numbering changes. Please discard the previous Testimony and replace it with the attached.

Please contact this office with any questions.

Very truly yours,

Jessica A. Gorham

Enclosures
cc: UM 1129 Service List

CERTIFICATE OF SERVICE
UM 1129 (Phase II, Track II)

I hereby certify that a true and correct copy of **IDAHO POWER COMPANY'S ERRATA TO DIRECT TESTIMONY OF JOHN R. GALE** was served via U.S. Mail on the following parties on March 16, 2006:

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