RECEIVED

2008 DEC -3 PM 3:45

IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE.	)	CASE NO. IPC-E-08-10

IDAHO POWER COMPANY

DIRECT REBUTTAL TESTIMONY

OF

GREGORY W. SAID

1 Q. Please state your name.

2 A. My name is Gregory W. Said.

3 Q. Are you the same Gregory W. Said that

4 previously submitted direct testimony in this proceeding?

5 A. Yes, I am.

6 Q. What is the purpose of your rebuttal

7 testimony?

8 A. My rebuttal testimony will address what I

9 believe are fundamental flaws in the rationale supporting

10 the testimonies of Staff Witness Sterling and Micron

11 Witness Peseau with regard to power supply issues. I will

12 respond to Mr. Sterling's assertion that high gas prices

13 benefit Idaho Power's customers. I will also respond to

14 Mr. Sterling's testimony that focuses exclusively on

15 recommendations minimizing power supply expenses included

16 in base rates while making no effort to identify the

17 appropriate normalized level for power supply expenses. I

18 will address Micron Witness Peseau's apparent lack of

19 understanding regarding the impact of natural gas prices on

20 modeled power supply expenses.

21 Q. Mr. Sterling states on page 4 of his

22 testimony that "High gas prices actually benefit Idaho

23 Power and its ratepayers in most years." Is he correct?

1 A. No. High gas prices will not benefit Idaho
2 Power Company or its customers. Mr. Sterling relies on
3 test-year modeled power supply outcomes to arrive at
4 conclusions that are counter intuitive. Idaho Power's
5 current generating fleet includes 435 MW of simple cycle
6 gas-fired generating plants used primarily for provision of
7 power during peak load periods of time. In addition, the
8 Company is currently reviewing bids for up to 300 MW of
9 baseload gas-fired generation to be available in 2012. It
10 is misleading to suggest that the Company or its customers
11 will benefit from rising gas costs when gas-fired
12 generation will increasingly be required to serve growing
13 customer loads. The only way Mr. Sterling can come to the
14 conclusion that high natural gas prices are good for
15 customers is in the hypothetical world of power supply
16 modeling. In the real world, high natural gas prices will
17 cost customers more money as the Company burns more gas to
18 serve loads.
19 Q. What do you mean when you refer to the
20 hypothetical world of power supply modeling?
21 A. The Company, the Commission Staff, and many
22 other utilities in the Northwest use the AURORA model to
23 simulate power supply costs for ratemaking purposes. Gas
24 price assumptions included in AURORA power supply

1 simulations are a primary driver of modeled market prices
2 for electricity. Over the full range of water conditions
3 the Company has traditionally used to present its power
4 supply expenses on a "normal" basis, the Company's modeling
5 shows it will often have surplus energy to sell. Stated
6 another way, the normalized level of annual surplus sales
7 is 2.4 million MWh while the normalized level of power
8 purchased from the market is 0.5 million MWh. In the
9 modeling world, with a net surplus position, higher
10 electricity market prices will benefit sellers of
11 electricity provided that the surplus is generated by
12 resources modeled at cost less than the gas-fired
13 generation driving the modeled market prices for
14 electricity.
15 In the real world, as the Company's loads grow, less
16 and less surplus will be available from hydro generation
17 and more expensive coal-fired and natural gas-fired
18 resources will be utilized to a greater extent to serve
19 system loads. Short-run modeled surplus sales benefits
20 that result from high gas price-influenced electricity
21 market price will ultimately disappear as loads grow and
22 only the higher cost of fuel used to serve the growing load
23 will remain.

1 Q. Does the AURORA power supply modeling
2 adequately reflect the impacts that Northwest hydro
3 conditions can have on electricity market prices?
4 A. While the AURORA model does many things
5 well, one thing it does not do well is account for the
6 impact of regional hydro conditions when forecasting the
7 market prices Idaho Power will receive for its surplus
8 sales. The Company has repeatedly stated, and the
9 Commission has repeatedly recognized, that within the
10 Northwest, both gas prices and hydro conditions are primary
11 drivers of market prices for electricity.[1] Low water
12 conditions, droughts, tend to drive electricity prices in
13 the Northwest up while abundant water tends to drive
14 electricity prices in the Northwest down. The Company
15 believes that AURORA modeling considers the gas price
16 influence on electricity market prices too heavily and the
17 water condition influence on electricity market price too
18 lightly.
19 Q. What has the Company done within power
20 supply modeling to account for the influence of water
21 conditions on electricity market prices?
22 A. In order to correct for the modeling
23 deficiency in AURORA that fails to adequately reflect the

[1] Order No. 24806 issued in Case No. IPC-E-92-25 and Order No. 30047 issued in Case No. IPC-E-06-07 are two examples.

1 hydro condition influence on electricity market prices, the
2 Company has segmented water condition scenarios into five
3 pentiles. Recognizing that the model primarily uses gas
4 prices to determine electricity prices, the Company adjusts
5 gas prices in each of the pentiles as a surrogate for water
6 condition influences on electricity prices.
7 Q. Mr. Sterling refers to Exhibit No. 102 that
8 he says demonstrates "there appears to be no correlation
9 whatsoever between Northwest hydro conditions and Sumas gas
10 prices on a monthly basis." Is this conclusion misleading?
11 A. Yes. Idaho Power has never contended there
12 is a correlation between Northwest hydro conditions and
13 Sumas gas prices. What Idaho Power has contended, and
14 still believes to be the case, is that Northwest hydro
15 conditions influence electricity market prices. Because
16 the AURORA model does not adequately quantify this
17 influence, Idaho Power has corrected for the modeling
18 deficiency by modifying the model driver, gas price. This
19 modification is not made to suggest a correlation between
20 water condition and gas price, but rather to reflect water
21 condition impacts on electricity market prices. The

1 Company has been open and forthright in stating this
2 position.[2]
3 Q. Does Mr. Sterling suggest that Northwest
4 hydro conditions do not influence electricity market
5 prices?
6 A. No. To the contrary, Mr. Sterling states
7 that gas prices and hydro conditions "both greatly
8 influence market prices." However, even though he
9 recognizes the importance of hydro conditions, Mr. Sterling
10 provides no assessment of the AURORA model capability to
11 quantify the impacts of hydro conditions on electricity
12 market prices. Rather than addressing the issue, he
13 recommends the elimination of the Company's attempt to
14 correct for a modeling deficiency based upon a
15 mischaracterization of the intent of the correction. As a
16 result, he understates the proper level of net power supply
17 expenses.
18 Q. What level of power supply expenses should
19 the Commission approve for inclusion in base rates?
20 A. The Commission should approve power supply
21 expenses as included in the Company's Application and
22 testimony in this case. The customer "benefits" from high
23 gas prices as quantified by Mr. Sterling are, in my

[2] See pages 6 and 7 of Greg Said's direct testimony in Case No. IPC-E-03-13.

1 opinion, an unfair reduction of reasonably expected power
2 supply expenses arising from an AURORA modeling deficiency.
3 I am concerned that Staff may be looking solely for an
4 opportunity to reduce the Company's revenue requirement
5 rather than make the effort needed to address this
6 deficiency in the AURORA model and thereby properly
7 quantify normalized power supply expenses.
8 Q. Did the Commission Staff, in a production
9 request, ask whether the Company had included the cost of
10 integrating wind projects in its power supply expense
11 quantification?
12 A. Yes. The Commission Staff's Production
13 Request No. 9 asked if the Company had included any wind
14 integration costs in this test year. The Company replied
15 that it had not included any wind integration costs in the
16 test year. The Company also stated that including wind
17 integration costs would add nearly $3.5 Million to
18 normalized power supply expenses. While the Staff
19 discovered the additional power supply expense the Company
20 failed to include in its case, Mr. Sterling has not
21 proposed to add the wind integration expense into power
22 supply expenses.
23 Q. Does the Company believe these wind
24 integration costs should be included in base rates?

1 A. Yes. The Company is currently bearing the
2 costs of integrating these projects into the system. The
3 costs of integrating wind projects into the system include
4 hourly operational impacts that are not easily captured in
5 AURORA modeling, such as the need for standby generation
6 from Company resources, increased purchased power expenses,
7 and reduced surplus sales. These costs should
8 appropriately be included in base rates.
9 Q. In addition to mischaracterizing the
10 Company's correction of a modeling deficiency and not
11 adjusting results to include additional power supply
12 expenses identified in discovery, is there anything else in
13 Mr. Sterling's testimony that suggests a goal of
14 understating the appropriate level of power supply expenses
15 to be included in base rates?
16 A. Yes. On page 15 of his testimony, Mr.
17 Sterling was asked "What happens if Idaho Power's actual
18 net power supply costs turn out to be different than those
19 adopted in this general rate case?" In his response, he
20 states "Idaho Power will never be at risk for more than 10
21 percent of the difference between projected power supply
22 costs and the base power supply costs." This response
23 concerns me because Mr. Sterling's statement suggests that
24 it does not matter if the Commission adopts base power

1 supply expenses that are $10 million too low because the
2 Company will get $9 million back through the PCA. Such a
3 position would be inconsistent with the intent of the PCA.
4 The PCA was intended to be symmetrical, with the Company
5 giving back to customers during times of low power supply
6 expenses and recovering additional amounts during times of
7 high power supply expenses. If base power supply expenses
8 are purposely set too low, the symmetry and fundamental
9 fairness of the process is lost. During the last eight
10 years, the Company has had power supply expenses exceed the
11 levels included in base rates seven times. While this is
12 largely a result of prolonged drought, the Commission
13 should be concerned about the integrity of PCA adjustments
14 over time.
15 Q. On page 15, line 7 of Dr. Peseau's
16 testimony, he states "At the time Idaho Power prepared its
17 testimony in this case, it used a March 2008 NYMEX natural
18 gas price forecast averaging about $10/mmbtu." Is this
19 statement accurate?
20 A. No. The Company did develop its natural gas
21 price forecast in March 2008; however, the methodology was
22 based on the inclusion of multiple natural gas price
23 indices, including NYMEX. The average natural gas price

1 used by the Company in the 2008 rate case is $7.74/mmbtu,
2 not the $10/mmbtu implied by Dr. Peseau.
3 Q. What average natural gas price did Mr.
4 Sterling propose?
5 A. Although Mr. Sterling was critical of the
6 Company approach in arriving at $7.74/mmbtu, he proposes
7 using $7.75/mmbtu. Dr. Peseau suggests that current
8 forecasts are for gas prices under $7.00/mmbtu.
9 Q. Dr. Peseau states that a 30 percent
10 reduction in gas prices will "of course, have a significant
11 effect on regional electricity prices and Idaho Power's net
12 power supply expenses for the test year." He goes on to
13 say that "I am sure, however, the use of the current
14 natural gas prices in the net power expense model would
15 eliminate all or a very substantial portion of the
16 forecasted increase in net power supply expenses." (P. 15,
17 ll. 14-17.) Has Dr. Peseau accurately characterized the
18 affect of reduced natural gas prices modeled net power
19 supply expenses?
20 A. No. Dr. Peseau apparently does not
21 understand the current relationship between gas prices and
22 modeled net power expenses that both Mr. Sterling and I
23 discussed in our respective testimonies. Lower gas prices
24 mean lower market prices. In the power supply model, lower

1 market prices increase Idaho Power's net power supply
2 expense on a normalized basis. Higher natural gas price
3 assumptions input to the AURORA model result in higher
4 market surplus sales prices and thereby decrease Idaho
5 Power's net power supply expense on a normalized basis.
6 Q. Did the Company provide NYMEX future natural
7 gas prices to Dr. Peseau in its responses to Micron's
8 Production Requests Nos. 21-23?
9 A Yes.
10 Q. Were these natural gas prices higher or
11 lower than the Company's original natural gas price
12 forecast used in its test year?
13 A. The NYMEX natural gas prices provided to Dr.
14 Peseau based upon his specifications averaged $10.80/mmbtu
15 and $10.41/mmbtu, both higher than the $7.74/mmbtu used by
16 the Company and both higher than the below $7.00/mmbtu
17 stated in Dr. Peseau's testimony.
18 Q. Dr. Peseau states that he requested power
19 supply model runs that would reflect the approximate 25-30
20 percent reduction in natural gas price forecasts. Did
21 Micron request power supply model runs with gas prices 25
22 to 30 percent lower than in the Company's filed case?
23 A. No. Micron requested runs using the NYMEX
24 gas prices provided by Idaho Power in response to Micron

1 production requests that I previously stated were
2 $10.80/mmbtu and $10.41/mmbtu. These runs are contained in
3 Micron's Exhibit No. 704.
4 Q. Dr. Peseau testifies that his Exhibit No.
5 704 supports his argument that the Company's net power
6 supply expenses should be reduced by approximately $25
7 million as shown in his Exhibit No. 704. Is he accurately
8 characterizing what Exhibit No. 704 shows?
9 A. No. Exhibit No. 704 shows the opposite
10 affect I just described. By increasing the natural gas
11 prices to the $10 per mmbtu level as requested by Dr.
12 Peseau, the Company's net power supply expenses went down
13 just as Mr. Sterling and I have testified.
14 Q. Have you prepared an exhibit to quantify a
15 10 percent reduction from the $7.75/mmbtu gas price
16 assumption included in the Company's filing?
17 A. Yes. Exhibit No. 87 is AURORA output based
18 upon a reduction in gas price assumption from $7.75/mmbtu
19 to $6.98/mmbtu. Normalized net power supply expenses rise
20 from $88.4 million to $97.2 million.
21 Q. Dr. Peseau supports his argument for a
22 reduction in the Company's net power supply expenses by
23 comparing the PURPA avoided cost model to the model used to

1 determine the Company's net power supply expense. Is that
2 a valid comparison?
3 A. No. The PURPA model predicts the fully
4 distributed cost of a hypothetical combined cycle
5 combustion turbine. It is intended to model the marginal
6 resource on the Company's system, i.e., the cost it can
7 "avoid." It does not model the Company's net power supply
8 expenses. The 30 percent reduction in natural gas prices
9 cited by Dr. Peseau will reduce the cost of the PURPA
10 surrogate avoided resource. Lower gas prices have the
11 opposite affect on modeled net power supply expenses.
12 Q. Does the Company agree with Mr. Sterling's
13 natural gas price forecast of $7.75/mmbtu, or the natural
14 gas price forecast over $10/mmbtu contained in Dr. Peseau's
15 Exhibit No. 704, but characterized by Dr. Peseau as under
16 $7/mmbtu?
17 A. Dr. Peseau is correct when he states that
18 gas prices have fallen. Both Mr. Sterling's and the
19 Company's natural gas price assumptions may be too high.
20 However, as I have stated earlier in my rebuttal testimony,
21 reducing the natural gas price assumptions would increase
22 the level of net power supply expenses. Dr. Peseau's
23 conclusions regarding the changes in power supply expenses

1 that result from changes in gas prices are incorrect and

2 should be ignored.

3 Q. Does this conclude your rebuttal testimony?

4 A. Yes, it does.

IPCO POWER SUPPLY COSTS FOR 2008 NORMALIZED LOADS OVER 80 WATER YEAR CONDITIONS
10 % Gas Price Reduction
AVERAGE

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	743,548.7	888,803.6	870,114.3	864,268.9	866,449.0	842,395.2	727,873.1	688,036.5	555,471.4	527,759.4	478,321.1	695,521.7	8,748,562.8
Bridger													
Energy (MWh)	455,179.3	425,812.9	422,140.7	330,372.1	330,360.6	427,287.5	455,179.3	455,179.3	440,496.2	455,179.3	440,496.2	455,179.3	5,092,863.0
Cost ($ x 1000)	$ 7,339.2	$ 6,865.7	$ 6,806.5	$ 5,326.8	$ 5,326.6	$ 6,889.6	$ 7,339.2	$ 7,339.2	$ 7,102.4	$ 7,339.2	$ 7,102.4	$ 7,339.2	$ 82,116.0
Boardman													
Energy (MWh)	38,393.2	35,881.8	38,835.9	30,554.3	6,436.2	27,684.6	40,236.1	40,937.3	39,379.8	40,831.1	39,601.2	41,012.9	419,784.5
Cost ($ x 1000)	$ 552.5	$ 516.9	$ 558.1	$ 440.6	$ 94.3	$ 409.5	$ 575.8	$ 584.6	$ 562.8	$ 583.2	$ 565.5	$ 585.5	$ 6,029.3
Valmy													
Energy (MWh)	162,269.2	150,512.6	159,780.5	81,413.7	147,717.1	145,502.9	170,850.9	171,576.8	164,584.2	171,111.6	167,379.5	173,627.8	1,866,326.6
Cost ($ x 1000)	$ 3,919.4	$ 3,637.6	$ 3,863.3	$ 1,976.8	$ 3,578.9	$ 3,532.8	$ 4,112.7	$ 4,129.0	$ 3,963.0	$ 4,118.5	$ 4,025.9	$ 4,175.2	$ 45,033.2
Danskin													
Energy (MWh)	920.3	263.5	26.5	7.9	0.0	88.6	14,663.9	7,181.9	955.4	760.8	3,868.8	2,372.2	31,109.8
Cost ($ x 1000)	$ 82.5	$ 24.3	$ 2.3	$ 0.6	$ 0.0	$ 6.7	$ 1,048.7	$ 500.9	$ 71.2	$ 51.6	$ 279.4	$ 186.8	$ 2,254.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.5	$ 296.9	$ 315.5	$ 306.2	$ 315.5	$ 306.2	$ 315.5	$ 315.5	$ 306.2	$ 315.5	$ 306.2	$ 315.5	$ 3,730.3
Total Cost	$ 398.0	$ 321.2	$ 317.8	$ 306.8	$ 315.5	$ 312.9	$ 1,364.2	$ 816.4	$ 377.4	$ 367.1	$ 585.6	$ 502.3	$ 5,985.0
Bennett Mountain													
Energy (MWh)	56.1	8.6	-	-	-	0.9	5,872.8	2,725.3	65.4	35.6	393.7	184.1	9,342.5
Cost ($ x 1000)	$ 5.2	$ 0.8	$ -	$ -	$ -	$ 0.1	$ 441.1	$ 194.8	$ 5.4	$ 2.3	$ 29.2	$ 14.9	$ 693.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ 5.2	$ 0.8	$ -	$ -	$ -	$ 0.1	$ 441.1	$ 194.8	$ 5.4	$ 2.3	$ 29.2	$ 14.9	$ 693.8
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	37,500.5	591.1	598.3	3,298.9	12,990.3	46,666.9	151,833.2	67,096.3	48,598.6	3,934.6	37,199.7	64,783.3	475,091.7
Contract Energy (MWh)	34,868.2	32,401.5	35,271.0	34,356.0	31,709.3	68,147.5	72,599.6	67,511.3	30,031.7	35,463.4	32,718.0	42,172.0	517,249.4
Total Energy Excl. CSPP (MWh)	72,368.7	32,992.6	35,869.3	37,654.9	44,699.6	114,814.4	224,432.7	134,607.6	78,630.3	39,398.1	69,917.7	106,955.3	992,341.1
Market Cost ($ x 1000)	$ 2,403.3	$ 40.9	$ 34.0	$ 173.2	$ 679.2	$ 2,240.0	$ 9,278.0	$ 4,085.4	$ 3,364.5	$ 279.4	$ 2,617.5	$ 4,451.2	$ 29,646.6
Contract Cost ($ x 1000)	$ 1,764.2	$ 1,639.7	$ 1,311.4	$ 1,277.2	$ 1,182.0	$ 3,250.2	$ 3,841.6	$ 3,560.3	$ 1,523.8	$ 1,793.7	$ 1,988.0	$ 2,550.5	$ 25,682.5
Total Cost Excl. CSPP ($ x 1000)	$ 4,167.5	$ 1,680.6	$ 1,345.4	$ 1,450.3	$ 1,861.2	$ 5,490.2	$ 13,119.7	$ 7,645.7	$ 4,888.3	$ 2,073.1	$ 4,605.4	$ 7,001.6	$ 55,329.0
Surplus Sales													
Energy (MWh)	187,995.7	420,560.4	420,154.0	360,951.9	260,392.0	242,718.3	27,286.0	26,063.6	102,283.2	179,699.1	81,618.1	100,606.4	2,410,328.7
Revenue Including Transmission Costs ($ x 1000)	$ 8,014.4	$ 19,939.0	$ 19,870.6	$ 13,969.1	$ 9,094.6	$ 6,843.7	$ 1,142.3	$ 1,234.1	$ 4,214.7	$ 7,812.3	$ 3,448.5	$ 4,811.0	$ 100,394.3
Transmission Costs ($ x 1000)	$ 188.0	$ 420.6	$ 420.2	$ 361.0	$ 260.4	$ 242.7	$ 27.3	$ 26.1	$ 102.3	$ 179.7	$ 81.6	$ 100.6	$ 2,410.3
Revenue Excluding Transmission Costs ($ x 1000)	$ 7,826.4	$ 19,518.5	$ 19,450.4	$ 13,608.2	$ 8,834.2	$ 6,600.9	$ 1,115.0	$ 1,208.0	$ 4,112.4	$ 7,632.6	$ 3,366.9	$ 4,710.4	$ 97,984.0
Net Power Supply Costs ($ x 1000)	$ 8,555.2	$ (6,495.8)	$ (6,559.3)	$ (4,106.8)	$ 2,342.4	$ 10,034.2	$ 25,837.7	$ 19,501.6	$ 12,786.8	$ 6,850.8	$ 13,547.2	$ 24,908.3	$ 97,202.4
												Original Filing	88,421.2
												Difference	8,781.2

RECEIVED
2008 DEC -3 PM 3:45
IDAHO PUBLIC
UTILITIES COMMISSION

Exhibit No. 87
Case No. IPC-E-08-10
G. Said, IPC
Page 1 of 1