BEFORE THE

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IDAHO PUBLIC
UTILITIES COMMISSION

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 IN THE STATE OF IDAHO.	)	**CASE NO. IPC-E-07-8**

DIRECT TESTIMONY OF RICK STERLING

IDAHO PUBLIC UTILITIES COMMISSION

DECEMBER 10, 2007

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

A. My name is Rick Sterling. My business address is 472 West Washington Street, Boise, Idaho.

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

A. I am employed by the Idaho Public Utilities Commission as a Staff engineer.

Q. What is your educational and professional background?

A. I received a Bachelor of Science degree in Civil Engineering from the University of Idaho in 1981 and a Master of Science degree in Civil Engineering from the University of Idaho in 1983. I worked for the Idaho Department of Water Resources from 1983 to 1994. In 1988, I received my Idaho license as a registered professional Civil Engineer. I began working at the Idaho Public Utilities Commission in 1994. During my employment at the IPUC, I have attended the annual regulatory studies program sponsored by the National Association of Regulatory Commissioners (NARUC) at Michigan State University, as well as numerous other seminars and short courses.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to discuss the

net power supply cost recommendation of Idaho Power, to explain why I believe it is too high, and to make an alternative recommendation that I believe fairly and reasonably represents the Company's normalized net power supply cost for the 2007 test year.

Q. Please briefly summarize your proposed net power supply cost adjustments.

A. I am proposing a net power supply cost of $34.9 million, which is approximately $6 million less than Idaho Power's proposed net power supply cost. My net power supply cost recommendation is based on the use of a natural gas price of $7.62 per MMBtu in the AURORA model.

Q. Have you reviewed the work done by Idaho Power to develop a net power supply cost recommendation for this case?

A. Yes, I have reviewed the Company's testimony and recommendations related to net power supply cost, and have also reviewed all of the supporting exhibits and workpapers prepared by the Company as well as all of the power supply cost simulations made using AURORA.

Q. What is Idaho Power recommending as the net power supply cost to be included in its revenue requirement?

A. Idaho Power is recommending a net power supply cost of $41.0 million in addition to PURPA costs of $93.1

million, for a total power supply cost of $134.1 million.

Q. Do you agree with the net power supply cost recommendations contained in the testimony of Idaho Power witness Greg Said?

A. No, I do not. I believe that the net power supply cost recommendations of the Company are too high. I do accept the Company's estimate of PURPA costs, however.

Q. Why do you believe that the net power supply cost recommendations of the Company are too high?

A. I believe that Idaho Power's net power supply cost recommendations are too high because of incorrect assumptions made by the Company regarding natural gas fuel prices used in AURORA, the model used for computing net power supply costs.

Q. Are natural gas price assumptions crucial in the determination of net power supply costs, even though Idaho Power has a relatively small amount of natural gas fired generation on its system?

A. Yes, Idaho Power's net power supply costs are not only a function of the costs of fueling and operating its own generating resources, but are also a function of the costs of its off-system purchases and its secondary sales. During the majority of the year, gas-fired generation is the marginal resource in the region;

consequently, it tends to set the market price for all market purchases and sales. Obviously, higher gas prices drive electric market prices up and lower gas prices drive market prices down.

Q. How do high gas prices affect Idaho Power and its ratepayers?

A. High gas prices actually benefit Idaho Power and its ratepayers in most years. Because Idaho Power is a net energy seller over the course of the year, high gas prices and high electric market prices allow the Company to sell its surplus low-cost hydro and coal generation at those higher market prices, substantially reducing its net power supply costs.

Q. What assumptions about gas price did Idaho Power make for purposes of its AURORA power supply cost simulations?

A. Idaho Power's derivation of the gas prices it used in AURORA is shown on Staff Exhibit No. 106. Idaho Power obtained 10-year gas price forecasts from three different sources—PIRA, DOE-EIA, and Global Insight—and five-year forecasts from two sources—NYMEX and IGI. Idaho Power computed a weighted average price using each of the ten years from 2007-2016, then made other adjustments to prepare the prices for input into the AURORA model. Idaho Power generated upper and lower

limits for gas prices to be used in AURORA by applying the standard deviation in actual prices at Sumas from 2001 through 2006. The result of this exercise was an average gas price of $7.93/MMBtu with upper and lower limits of $9.99/MMBtu and $5.87/MMBtu.

Q. How was this range of assumed gas prices used by Idaho Power in the AURORA model?

A. Idaho Power assumed that high gas prices are associated with low water conditions and that low gas prices occur when water conditions are high. For the 79 water years of record used in the power supply analysis, the Company created an algorithm that assigned the highest gas price ($9.99) to the lowest water year on record and assigned the lowest gas price ($5.87) to the highest water year on record. Gas prices were then assigned to all of the years in between based on their relative water condition.

Q. What is wrong with this approach in your opinion?

A. I believe that Idaho Power's approach is wrong for two reasons. First, I do not believe it is appropriate to use 10, or even five years of gas price forecasts when we are really only trying to establish power supply costs between now and when Idaho Power files its next general rate case. Company witness Gale states

on page 17 of his testimony that the Company intends to make more frequent rate case filings in the future. Informally, Idaho Power has told Staff that its future rate case filings could be made as often as annually. With the new Evander Andrews plant yet to be included in rate base, and with hydro relicensing costs quickly growing, Staff believes another general rate case filing is likely very soon. Therefore, because we are likely only setting rates to be effective for approximately the next year, it seems logical that we should only be using gas price forecasts representative of the same time frame. Gas price forecasts five or ten years into the future have no relevance whatsoever when we are only setting rates one year into the future.

Q. What is your other primary objection to the method used by Idaho Power?

A. My second objection relates to Idaho Power's assumption that gas prices are directly related to hydro conditions. I do not believe that gas prices are correlated with hydro conditions on Idaho Power's system, or for that matter, even with Northwest hydro conditions. I believe that natural gas prices are influenced by numerous factors, most of which have nothing to do with water conditions in the Northwest. Because pipelines allow natural gas to be transported throughout North

America, gas prices now tend to rise or fall in unison. Prices in the Northwest can be affected by a prolonged cold snap in the Northeast, for example, by tropical storms and hurricanes in the Gulf, or by unusual demand in California. Underground gas storage levels, drilling activity and market speculation also significantly affect prices. Gas demand, wherever it occurs in the country, can affect prices nationally. Regional supply interruptions seem to be one of the few factors that can still significantly affect regional gas prices.

Q. Have you examined any data or performed any analysis to support your conclusion that gas prices and Northwest hydro conditions are not related?

A. Yes, I have. I performed regression analysis using historical Henry Hub and Sumas gas prices as reported by the Intercontinental Exchange and historical water conditions represented by hydro shaping factors used in AURORA. The hydro shaping factors used in AURORA reflect monthly and annual scaling factors used to accurately replicate historic hydro conditions in areas throughout the Northwest. The source for the hydro data used in AURORA is the Northwest Power Pool. Staff Exhibit No. 107 shows the results of the correlation analysis on a monthly basis for hydro conditions since 2001 at Hells Canyon, Southern Idaho, run-of-river plants

on Idaho Power's system, the Oregon-Washington-Northern Idaho area, British Columbia and Montana. As shown by the exhibit, there appears to be no correlation whatsoever between Northwest hydro conditions and Sumas gas prices on a monthly basis. The results are similar for Henry Hub gas prices.

Q. Are you saying that neither gas prices nor hydro conditions affect power supply costs?

A. No, I am not suggesting that gas prices and hydro conditions do not affect power supply costs. Clearly, both greatly affect power supply costs. They do so independently, however. What I am saying is that gas prices are unrelated to Northwest hydro conditions.

Q. What gas prices did you consider using for the power supply analysis in AURORA?

A. I believe it is reasonable to simply use gas prices representative of the 2007 test year. To obtain prices representative of 2007, I considered several forecasts available to Staff. One forecast I considered was the May 2007 forecast prepared by Global Insight. Idaho Power used Global Insight's 2006 forecast in developing the Company's gas price forecast. I also considered the Department of Energy/Energy Information Administration forecast that was released in February 2007, and the Northwest Power and Conservation Council's

fuel price forecast approved on September 11, 2007. In addition to these forecasts, I considered the most recent 12 months of NYMEX spot market prices and NYMEX futures prices for 2008. I also reviewed recent forecasts made by gas industry experts as reported quarterly in the publication *Natural Gas Week*.

Q. Do you consider these sources to be superior to those used by Idaho Power?

A. All of the forecasts I considered were more recent than the forecast information used by Idaho Power. I had an advantage in my analysis because all of the gas price information I considered was simply not yet available at the time the Company prepared its case.

Q. What gas prices do you believe should be used for power supply modeling in AURORA?

A. My recommendation is to use a gas price of $7.62 per MMBtu for all 79 water years based on the natural gas price forecast contained in the Energy Information Administration's 2007 Annual Energy Outlook. That is the forecasted price for 2007 (in year 2007 dollars).

Q. Why do you propose to use the same gas price for all 79 water years?

A. I believe it is appropriate to use the same gas price for all 79 water years because I have found no

evidence to suggest that gas prices vary based on water conditions. The purpose of using 79 different water years is to simulate normal water conditions during the test year. Normal gas prices for the test year can be simulated with only a single estimate because gas prices are unrelated to water conditions.

Q. What net power supply cost do you calculate using AURORA with the $7.62 per MMBtu gas price you believe should be used?

A. Using a gas price of $7.62 per MMBtu for all water years, AURORA calculated a net power supply cost of $34.9 million. Net power supply costs are comprised of four accounts: 447 System Opportunity Sales; 501 Fuel (Coal); 547 Fuel (Gas); and 555.1 Purchased Power. Staff's proposed totals for each account are shown on Exhibit No. 108, and are also compared to Idaho Power's proposed amounts. Staff's most significant adjustment is a $5.3 million reduction in account 555.1 Purchased Power.

Except for the change in gas price, I used all of Idaho Power's other assumptions in AURORA. A summary of the results of this AURORA simulation is presented in Staff Exhibit No. 109.

Q. Have you prepared an exhibit comparing your net power supply cost recommendations to Idaho Power's?

A. Yes, Staff Exhibit No. 110 compares my recommendation for net power supply cost to Idaho Power's. The exhibit also shows the PURPA costs that are added to get total power supply cost, as well as the normalized power supply costs adopted in the Company's last general rate case.

Q. Did you make any AURORA runs using gas prices from Idaho Power's own gas forecast?

A. Yes, I did. I used Idaho Power's own forecasted gas prices for 2007 and 2008 to compute net power supply costs. Using Idaho Power's own gas price forecast for 2007 ($8.20 per MMBtu) for all 79 water years, I computed a net power supply cost of $ 21.8 million. If I used Idaho Power's 2007 gas price as an average for the 79 water years and assigned higher and lower prices to the years based on water condition using Idaho Power's method, a net power supply cost of $33.7 million was computed.

Q. Why are you not recommending simply using Idaho Power's own gas price forecast for the years when rates will be in effect to establish net power supply costs?

A. I am not recommending that Idaho Power's own gas price forecasts for 2007 or 2008 be used because I believe that the gas prices are too high. Such high gas prices produce net power supply cost results that are

unrealistically low.

Q. Why did you choose to not use gas prices from the Northwest Power and Conservation Council? Isn't the Council's forecast the most recent publicly available forecast?

A. The Council's September 11, 2007 gas price forecast is the most recent publicly available forecast, so in that respect it may be superior to other forecasts that could be used. Using the Council's forecasted gas price for 2007, AURORA calculates a net power supply cost of $ 27.8 million. I chose to not recommend using the Council's gas price forecast because I believe the Council's estimated price for 2007 is too high. Despite the forecast being the most recently released, it is actually several months older than it appears due to the public review process it must go through. In addition, I do not believe that the Council focused much on 2007 since the year would be three-fourths over by the time the forecast was released and the price forecast for 2007 would be of limited use to users of the forecast.

Q. Have you prepared an exhibit to compare Idaho Power's net power supply recommendation, your recommendation, and other net power supply results obtained using other possible gas price assumptions?

A. Yes, I have. Staff Exhibit No. 111 shows the

effect of various gas price assumptions on net power supply costs and compares my recommended result to the Company's. As the results show, my recommended net power supply cost is below the Company's recommendation, but higher than it would be if several other gas forecasts were used, including the Company's own forecasted prices for 2007 and 2008. Compared to the results obtained using other possible gas prices, I believe my recommendation is conservative.

Q. What happens if Idaho Power's actual net power supply costs turn out to be different than those adopted in this general rate case?

A. If actual power supply costs in the future are different than those adopted in this general rate case, then the difference will be considered in the annual Power Cost Adjustment (PCA) until the Company's next general rate case. Under the PCA, 90 percent of the difference between the annual projected power cost and the Commission approved base power cost as established in this case will be credited to or collected from customers. Consequently, Idaho Power will never be at risk for more than 10 percent of the difference between projected power supply costs and the base power supply costs.

Q. Can you validate the AURORA model by comparing

predicted results to actual net power supply costs from prior years, say for 2006?

A. Although it is possible to compare simulated results to actual historical results, the two will probably never be equal even if historical gas prices and hydro conditions are replicated. Actual electric market prices are affected by many things besides just hydro conditions and natural gas prices. Many factors that affect actual power supply costs simply cannot easily be replicated on an actual basis in AURORA, such as weather, plant outages, fuel supply interruptions, and market speculation. The 2006 water year results from the "base case" used to determine power supply costs in this case will not match actual 2006 power supply costs because the "base case" for 2006 only differs from the other 78 years used in the analysis by the hydro conditions. The base case for 2006 does not use actual gas prices in 2006, actual demand in 2006, or any other actual data from 2006. The 2006 results only reflect 2006 water conditions and nothing more.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes, it does.

IDAHO POWER COMPANY
GAS PRICE FORECAST
2007 $/MMBTU

2007 dollars

Year	PIRA Sumas	PIRA Wgt	NYMEX Sumas	NYMEX Wgt	IGI Sumas	IGI Wgt	EIA Sumas	EIA Wgt	Global Insight Sumas	Global Insight Wgt	Total Wgts	Sumas $/MMBtu	Transport $/MMBtu Fixed	Transport $/MMBtu Volumetric	Transport $/MMBtu Fuel Gas-2.01%	DELIVERED $/MMBtu	Basis Adj $/MMBTu	W/ Basis/Transport Adj $/MMBtu
2007	$ 6.86	14%	$ 7.54	29%	$ 7.50	29%	$ 8.48	14%	$ 8.69	14%	100%	$ 7.72	$ 0.3798	$ 0.0300	$ 0.16	$ 8.29	$ (0.48)	$ 8.20
2008	$ 6.94	14%	$ 7.69	29%	$ 7.65	29%	$ 8.12	14%	$ 9.24	14%	100%	$ 7.85	$ 0.3798	$ 0.0300	$ 0.16	$ 8.42	$ (0.31)	$ 8.16
2009	$ 6.74	14%	$ 8.15	29%	$ 7.99	29%	$ 7.52	14%	$ 8.89	14%	100%	$ 7.92	$ 0.3798	$ 0.0300	$ 0.16	$ 8.49	$ (0.23)	$ 8.15
2010	$ 6.74	14%	$ 8.63	29%	$ 8.67	29%	$ 7.26	14%	$ 8.29	14%	100%	$ 8.14	$ 0.3798	$ 0.0300	$ 0.16	$ 8.71	$ (0.25)	$ 8.39
2011	$ 6.74	14%	$ 9.43	29%	$ 9.42	29%	$ 6.88	14%	$ 8.06	14%	100%	$ 8.50	$ 0.3798	$ 0.0300	$ 0.17	$ 9.08	$ (0.25)	$ 8.75
2012	$ 7.08	54%					$ 6.69	23%	$ 7.85	23%	100%	$ 7.17	$ 0.3798	$ 0.0300	$ 0.14	$ 7.72	$ (0.25)	$ 7.42
2013	$ 7.27	54%					$ 6.74	23%	$ 7.64	23%	100%	$ 7.23	$ 0.3798	$ 0.0300	$ 0.15	$ 7.79	$ (0.25)	$ 7.48
2014	$ 7.42	54%					$ 6.65	23%	$ 7.43	23%	100%	$ 7.25	$ 0.3798	$ 0.0300	$ 0.15	$ 7.80	$ (0.25)	$ 7.50
2015	$ 7.73	54%					$ 6.41	23%	$ 7.23	23%	100%	$ 7.31	$ 0.3798	$ 0.0300	$ 0.15	$ 7.87	$ (0.25)	$ 7.56
2016	$ 7.90	54%					$ 6.35	23%	$ 7.24	23%	100%	$ 7.39	$ 0.3798	$ 0.0300	$ 0.15	$ 7.95	$ (0.25)	$ 7.64
AVERAGE 2007 to 2016	$ 7.14		$ 8.29		$ 8.25		$ 7.11		$ 8.06			$ 7.65					$ (0.28)	$ 7.93
	$ (0.28)		$ (0.28)		$ (0.28)		$(0.28)		$ (0.28)									
	$ 7.42	HH	$ 8.56	HH	$ 8.52	HH	$ 7.39	HH	$ 8.33	HH								

$ 7.93

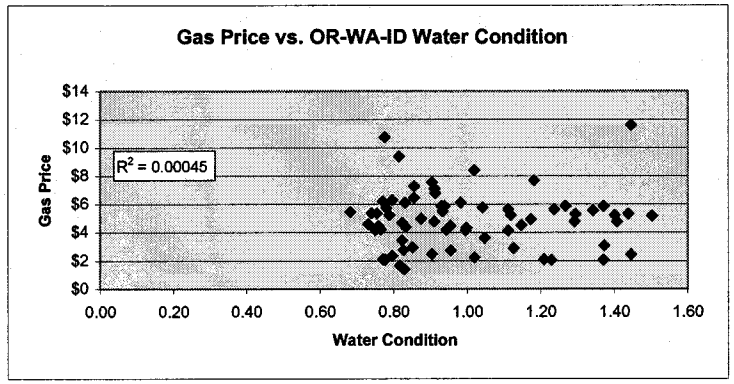
Standard Deviation in actual prices at Sumas from January 1, 2001 to December 31, 2006: $ 2.05

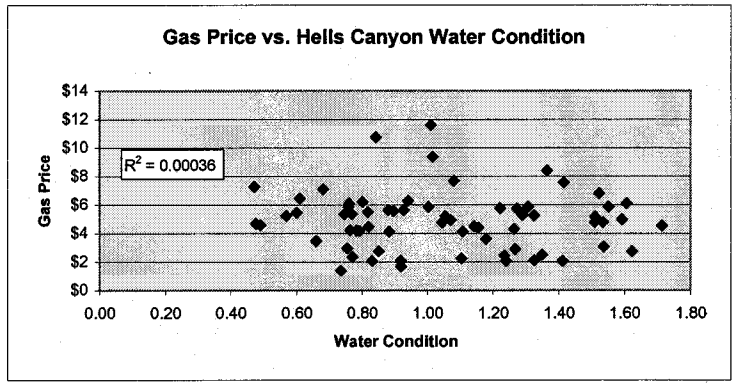
25.86%

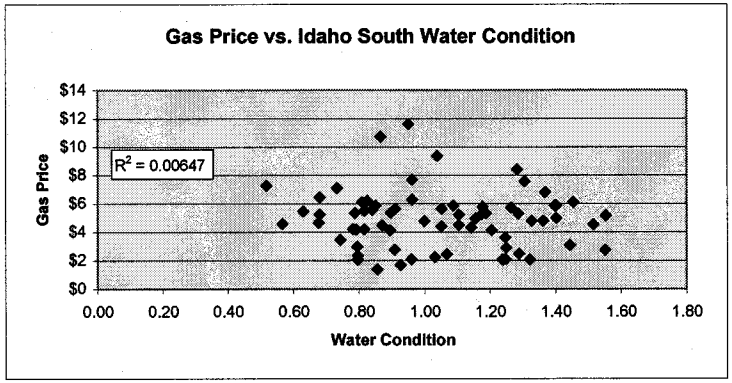
High:	$ 7.93	x	1.26	=	$	9.99
Low:	$ 7.93	x	0.74	=	$	5.87

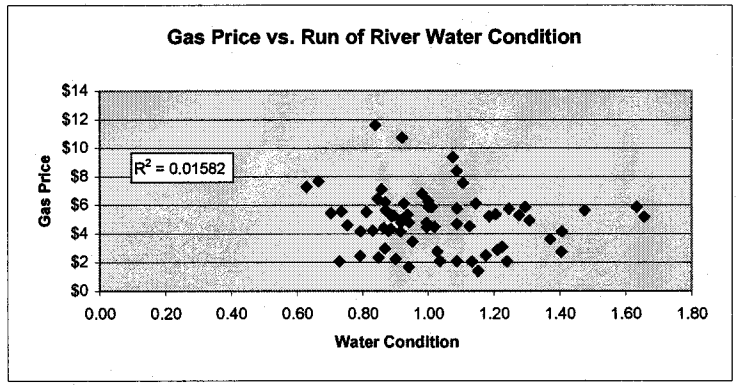
Exhibit No. 106
Case No. IPC-E-07-8
R. Sterling, Staff
12/10/07

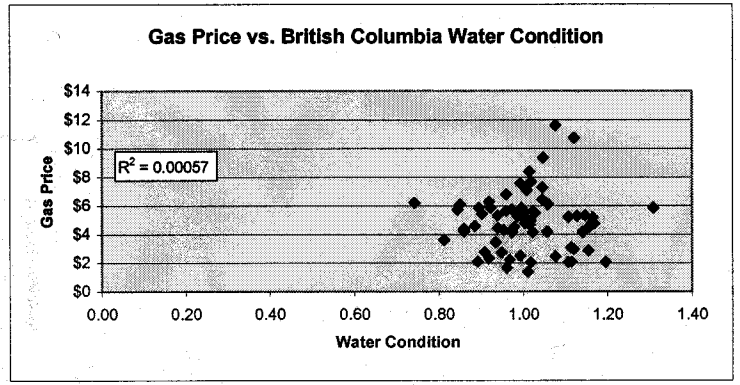
Correlations Between Monthly Northwest Water Conditions and Gas Prices at Sumas
May 2001- December 2006











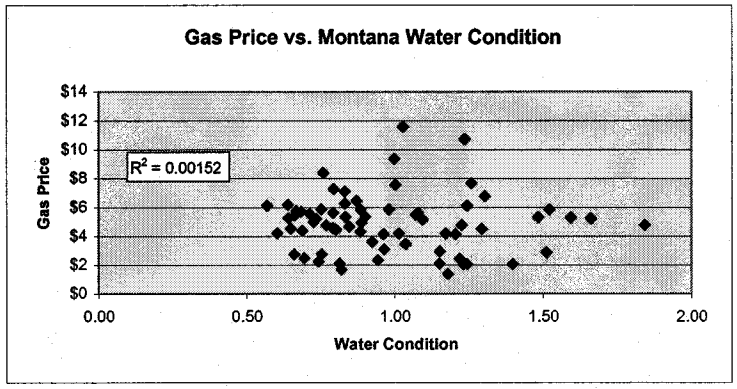
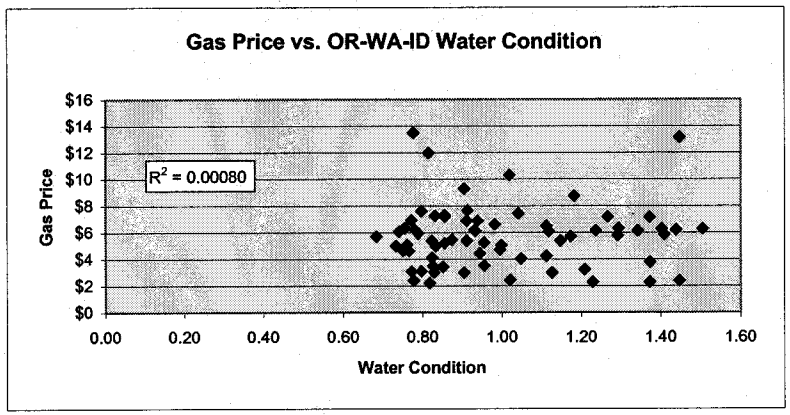
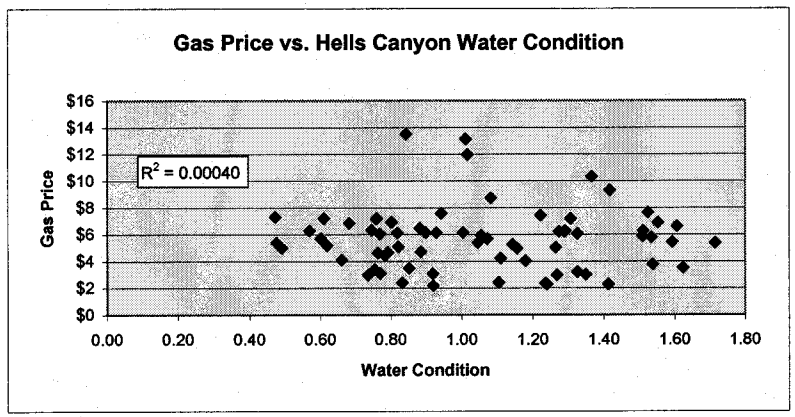
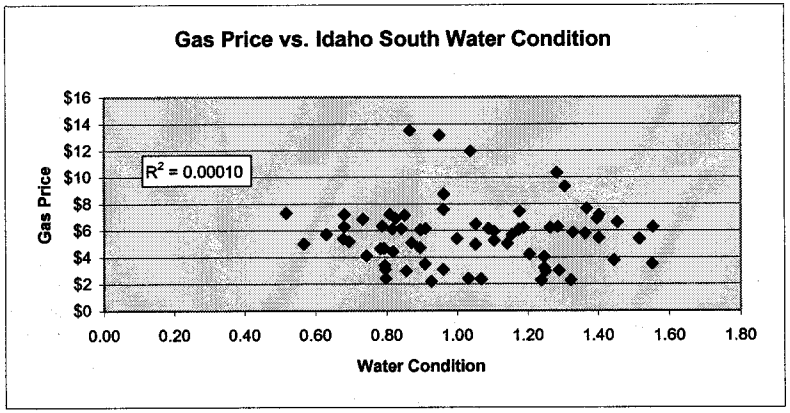


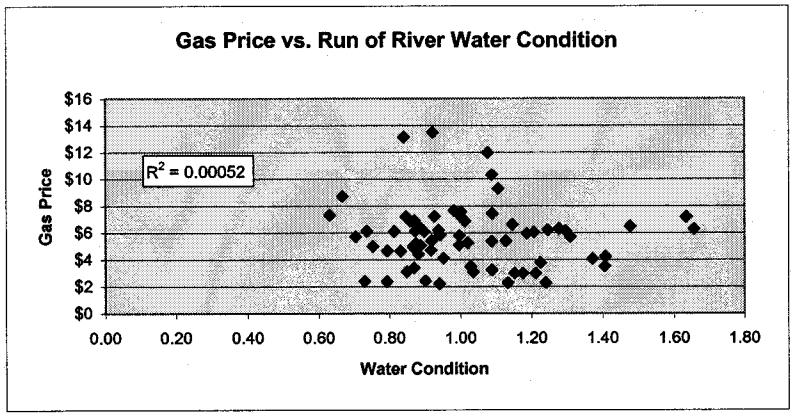
Exhibit No. 107
Case No. IPC-E-07-8
R. Sterling, Staff
12/10/07 Page 1 of 2

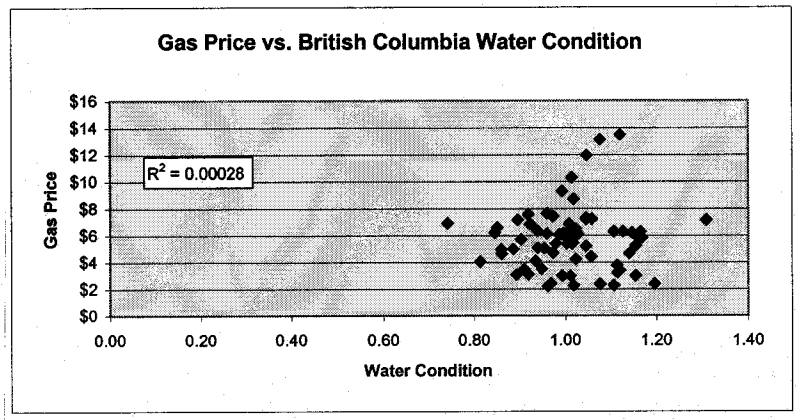
Correlations Between Monthly Northwest Water Conditions and Gas Prices at Henry Hub
April 2001- December 2006

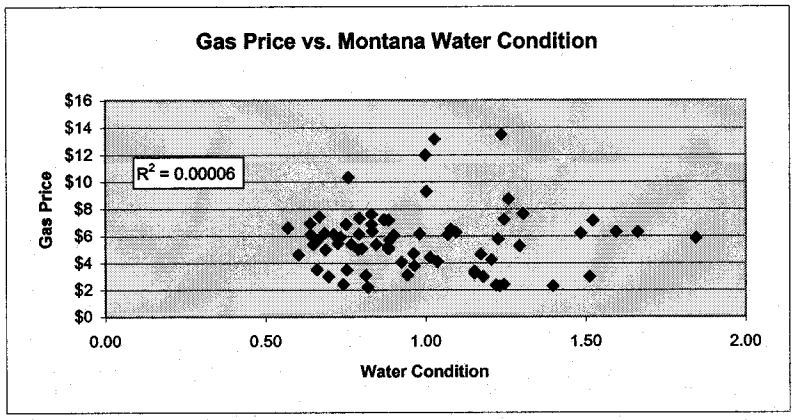












Summary of Net Power Supply Cost Adjustments to Specific Accounts

Account	Description	IPCo Proposal	Staff Proposal	Adjustment
447	System Opportunity Sales	$ 142,883,600	$ 142,875,579	$ 8,021
	System Opp. Sales Trans & Wheeling Revenue	$ 6,426,777	$ 6,426,777	$ -
	Subtotal	$ 149,310,377	$ 149,302,356	$ 8,021
501	Fuel (Coal)	$ (119,484,800)	$ (119,480,735)	$ (4,065)
547	Fuel (Gas)	$ (7,085,900)	$ (6,416,597)	$ (669,303)
555.1	Purchased Power	$ (57,283,900)	$ (51,942,918)	$ (5,340,982)
	Purchased Power Trans & Wheeling Cost	$ (1,270,606)	$ (1,270,606)	$ -
	Subtotal	$ (58,554,506)	$ (53,213,524)	$ (5,340,982)
	Total Net Power Supply Cost (excluding Trans & Wheeling)	$ (40,971,000)	$ (34,964,671)	$ (6,006,329)

Exhibit No. 108
Case No. IPC-E-07-8
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12/10/07

2007 NORMALIZED NET POWER SUPPLY COSTS Scenario 2; DOE AEO Avg Gas 2007$; Every Hour; Every Day; Every Week

Scenario 1

Thermal Generation (MWh) (Br, Bo, V)		7,346,837	
Hydro Generation (MWh)		6,179,840	
Combustion Turbine (MWh)		82,639	
Total Market Purchases (MWh)		921,242	
Total Market Sales (MWh)		981,354	
Total Thermal Unit Fuel Costs ($000)*	1/	126,548	
Total Market Purchases ($000)		77,861	$84.52
Total Market Sales ($000)		50,896	$51.86
Net Power Supply Costs ($000)		153,513	

* Bridger, Boardman, Valmy, Danskin, Bennett Mt

2007 Normalized Thermal Output (MWh)		aMW
Jim Bridger	5,056,012	577
Valmy	1,857,497	212
Boardman	433,328	49
Danskin	5,343	1
Bennett Mt	77,296	9
2007 Normalized Cost ($000)		**$/MWh**
Jim Bridger	73,364	$14.51
Valmy	40,915	$22.03
Boardman	6,014	$13.88
Danskin	451	$84.45
Bennett Mt	5,804	$75.08

Scenario 2

Thermal Generation (MWh) (Br, Bo, V)		7,328,182	
Hydro Generation (MWh)		7,615,503	
Combustion Turbine (MWh)		57,396	
Total Market Purchases (MWh)		538,198	
Total Market Sales (MWh)		1,989,883	
Total Thermal Unit Fuel Costs ($000)*		124,320	
Total Market Purchases ($000)		42,796	$79.52
Total Market Sales ($000)		102,880	$51.70
Net Power Supply Costs ($000)		64,236	

* Bridger, Boardman, Valmy, Danskin, Bennett Mt

2007 Normalized Thermal Output (MWh)		aMW
Jim Bridger	5,055,557	577
Valmy	1,849,467	211
Boardman	431,012	49
Danskin	3,463	0
Bennett Mt	54,209	6
2007 Normalized Cost ($000)		**$/MWh**
Jim Bridger	73,358	$14.51
Valmy	40,752	$22.03
Boardman	5,986	$13.89
Danskin 1/	293	$84.56
Bennett Mt	4,083	$75.33

Scenario 3

Thermal Generation (MWh) (Br, Bo, V)		7,316,972	
Hydro Generation (MWh)		8,618,509	
Combustion Turbine (MWh)		42,852	
Total Market Purchases (MWh)		304,535	
Total Market Sales (MWh)		2,733,316	
Total Thermal Unit Fuel Costs ($000)*		122,981	
Total Market Purchases ($000)		23,365	$76.72
Total Market Sales ($000)		141,234	$51.67
Net Power Supply Costs ($000)		5,112	

* Bridger, Boardman, Valmy, Danskin, Bennett Mt

2007 Normalized Thermal Output (MWh)		aMW
Jim Bridger	5,053,280	577
Valmy	1,835,518	210
Boardman	428,175	49
Danskin	2,577	0
Bennett Mt	40,275	5
2007 Normalized Cost ($000)		**$/MWh**
Jim Bridger	73,325	$14.51
Valmy	40,421	$22.02
Boardman	5,933	$13.86
Danskin 1/	214	$82.98
Bennett Mt	2,966	$73.66

Scenario 4

Thermal Generation (MWh) (Br, Bo, V)		7,290,572	
Hydro Generation (MWh)		9,950,676	
Combustion Turbine (MWh)		35,501	
Total Market Purchases (MWh)		182,796	
Total Market Sales (MWh)		3,909,803	
Total Thermal Unit Fuel Costs ($000)*		121,969	
Total Market Purchases ($000)		14,021	$76.70
Total Market Sales ($000)		193,910	$49.60
Net Power Supply Costs ($000)		(57,920)	

* Bridger, Boardman, Valmy, Danskin, Bennett Mt

2007 Normalized Thermal Output (MWh)		aMW
Jim Bridger	5,051,003	577
Valmy	1,818,266	208
Boardman	421,304	48
Danskin	2,116	0
Bennett Mt	33,385	4
2007 Normalized Cost ($000)		**$/MWh**
Jim Bridger	73,292	$14.51
Valmy	40,121	$22.07
Boardman	5,865	$13.92
Danskin 1/	179	$84.66
Bennett Mt	2,512	$75.25

Scenario 5

Thermal Generation (MWh) (Br, Bo, V)		7,213,469	
Hydro Generation (MWh)		11,609,792	
Combustion Turbine (MWh)		18,200	
Total Market Purchases (MWh)		45,777	
Total Market Sales (MWh)		5,337,060	
Total Thermal Unit Fuel Costs ($000)*		119,338	
Total Market Purchases ($000)		3,200	$69.91
Total Market Sales ($000)		247,967	$46.46
Net Power Supply Costs ($000)		(125,429)	

* Bridger, Boardman, Valmy, Danskin, Bennett Mt

2007 Normalized Thermal Output (MWh)		aMW
Jim Bridger	5,042,897	576
Valmy	1,775,050	203
Boardman	395,523	45
Danskin	748	0
Bennett Mt	17,452	2
2007 Normalized Cost ($000)		**$/MWh**
Jim Bridger	73,174	$14.51
Valmy	39,246	$22.11
Boardman	5,538	$14.00
Danskin 1/	63	$84.85
Bennett Mt	1,317	$75.45

AVERAGE OF ALL YEARS

Thermal Generation (MWh) (Br, Bo, V)		7,301,247	
Hydro Generation (MWh)		8,748,180	998.7
Combustion Turbine (MWh)		47,390	
Total Market Purchases (MWh)		403,134	
Total Market Sales (MWh)		2,950,346	
Total Thermal Unit Fuel Costs ($000)*		123,071	
Total Market Purchases ($000)		32,644	$80.97
Total Market Sales ($000)		145,826	$49.43
Net Power Supply Costs ($000)		9,888	
* Bridger,Boardman,Valmy,Danskin(excl fixed)	Danskin-Fixed	2,840	
and Bennett Mountain	PPL	19,230	
1/ Excludes Danskin Fixed	Wheeling	2,950	
	Avg NPSC	34,909	

2007 Normalized Thermal Output (MWh)		aMW
Jim Bridger	5,051,862	577
Valmy	1,827,301	209
Boardman	422,085	48
Danskin	2,859	0
Bennett Mt	44,531	5
2007 Normalized Cost ($000)		**$/MWh**
Jim Bridger	73,304	$14.51
Valmy	40,304	$22.06
Boardman	5,873	$13.91
Danskin 1/	242	$84.56
Bennett Mt	3,348	$75.19

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IPCO POWER SUPPLY COSTS FOR 2007 NORMALIZED LOADS OVER 79 WATER YEAR CONDITIONS
SUBSEQUENT TO ADDITION OF 2007 PURPA AND HORIZON CONTRACTS

AVERAGE

DOE AEO Avg Gas 2007$; Every Hour; Every Day; Every Week

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	744,476.8	861,560.3	873,104.2	868,348.4	868,539.4	846,701.3	728,299.1	687,593.1	560,309.5	531,854.7	479,344.3	698,048.6	8,748,179.7
Bridger													
Energy (MWh)	451,689.8	407,977.9	389,764.6	327,839.4	360,623.3	432,969.0	451,689.8	451,689.8	437,119.2	451,689.8	437,119.2	451,689.8	5,051,861.6
Cost ($ x 1000)	$ 6,554.2	$ 5,919.9	$ 5,655.6	$ 4,757.1	$ 5,232.8	$ 6,282.5	$ 6,554.2	$ 6,554.2	$ 6,342.7	$ 6,554.2	$ 6,342.7	$ 6,554.2	$ 73,304.1
Boardman													
Energy (MWh)	38,764.2	35,218.8	39,611.1	24,737.1	11,701.2	27,595.4	40,381.5	41,304.3	39,837.9	41,337.1	40,102.6	41,493.5	422,084.7
Cost ($ x 1000)	$ 540.2	$ 490.6	$ 550.7	$ 345.3	$ 166.7	$ 397.8	$ 560.0	$ 571.2	$ 551.1	$ 571.6	$ 554.3	$ 573.5	$ 5,873.0
Valmy													
Energy (MWh)	163,209.4	148,112.9	161,111.1	72,487.8	123,508.1	147,849.0	169,662.0	170,429.7	163,450.5	170,343.1	165,675.4	171,462.0	1,827,300.9
Cost ($ x 1000)	$ 3,603.8	$ 3,269.2	$ 3,556.4	$ 1,608.9	$ 2,735.6	$ 3,283.1	$ 3,734.4	$ 3,750.0	$ 3,599.0	$ 3,748.2	$ 3,644.1	$ 3,770.9	$ 40,303.7
Danskin													
Energy (MWh)	-	-	-	0.0	0.1	16.7	1,497.3	1,293.6	46.5	0.1	2.1	2.5	2,858.9
Cost ($ x 1000)	$ -	$ -	$ -	$ 0.0	$ 0.0	$ 1.4	$ 125.7	$ 110.3	$ 4.0	$ 0.0	$ 0.2	$ 0.3	$ 241.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 220.8	$ 220.8	$ 241.2	$ 234.4	$ 241.2	$ 234.4	$ 241.2	$ 241.2	$ 234.4	$ 241.2	$ 234.4	$ 241.2	$ 2,826.5
Total Cost	$ 220.8	$ 220.8	$ 241.2	$ 234.4	$ 241.2	$ 235.8	$ 366.9	$ 351.5	$ 238.4	$ 241.2	$ 234.6	$ 241.5	$ 3,068.3
Bennett Mountain													
Energy (MWh)	-	17.0	9.4	227.2	53.6	766.8	19,106.9	17,331.0	4,217.7	643.1	1,269.8	888.4	44,531.1
Cost ($ x 1000)	$ -	$ 1.4	$ 0.7	$ 16.0	$ 3.8	$ 55.1	$ 1,411.7	$ 1,300.4	$ 319.2	$ 50.0	$ 108.7	$ 81.3	$ 3,348.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ 1.4	$ 0.7	$ 16.0	$ 3.8	$ 55.1	$ 1,411.7	$ 1,300.4	$ 319.2	$ 50.0	$ 108.7	$ 81.3	$ 3,348.3
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	21,339.2	2,653.6	988.4	5,981.6	20,396.1	35,708.4	114,775.3	60,233.3	40,721.5	5,395.0	50,592.4	44,349.0	403,133.8
Contract Energy (MWh)	25,445.2	22,770.8	25,852.5	25,243.7	22,251.8	60,334.8	62,247.7	59,361.3	20,872.0	26,047.0	23,587.8	32,829.1	406,843.9
Total Energy Excl. CSPP (MWh)	46,784.4	25,424.4	26,840.9	31,225.3	42,647.9	96,043.3	177,023.0	119,594.6	61,593.5	31,442.1	74,180.2	77,178.1	809,977.7
Market Cost ($ x 1000)	$ 951.4	$ 161.9	$ 64.2	$ 359.2	$ 1,281.8	$ 2,316.6	$ 10,247.9	$ 5,622.7	$ 3,167.0	$ 422.1	$ 4,227.9	$ 3,820.8	$ 32,643.5
Contract Cost ($ x 1000)	$ 1,221.4	$ 1,093.0	$ 912.1	$ 890.6	$ 785.0	$ 2,779.6	$ 3,149.5	$ 2,966.5	$ 1,001.9	$ 1,250.3	$ 1,358.7	$ 1,891.0	$ 19,299.4
Total Cost Excl. CSPP ($ x 1000)	$ 2,172.8	$ 1,254.9	$ 976.3	$ 1,249.8	$ 2,066.9	$ 5,096.2	$ 13,397.4	$ 8,589.2	$ 4,168.9	$ 1,672.4	$ 5,586.5	$ 5,711.7	$ 51,942.918
Surplus Sales													
Energy (MWh)	229,889.1	408,808.1	480,322.7	367,878.1	346,821.1	293,417.2	45,766.3	55,484.9	166,469.2	228,945.2	134,952.1	191,592.0	2,950,346.1
Revenue Including Transmission Costs ($ x 1000)	$ 8,928.3	$ 21,001.6	$ 23,420.9	$ 17,361.9	$ 14,886.4	$ 10,858.0	$ 2,841.1	$ 3,776.8	$ 9,573.8	$ 12,737.4	$ 7,518.3	$ 12,921.4	$ 145,825.9
Transmission Costs ($ x 1000)	$ 229.9	$ 408.8	$ 480.3	$ 367.9	$ 346.8	$ 293.4	$ 45.8	$ 55.5	$ 166.5	$ 228.9	$ 135.0	$ 191.6	$ 2,950.3
Revenue Excluding Transmission Costs ($ x 1000)	$ 8,698.4	$ 20,592.8	$ 22,940.6	$ 16,994.1	$ 14,539.5	$ 10,564.6	$ 2,795.3	$ 3,721.3	$ 9,407.3	$ 12,508.5	$ 7,383.4	$ 12,729.9	$ 142,875.579
Net Power Supply Costs ($ x 1000)	$ 4,393.4	$ (9,436.0)	$ (11,959.7)	$ (8,782.7)	$ (4,092.5)	$ 4,785.8	$ 23,229.3	$ 17,395.1	$ 5,812.1	$ 329.1	$ 9,087.6	$ 4,203.2	$ 34,964.7
Total Energy (MWh)	1,215,035.5	1,069,503.3	1,010,118.5	956,987.1	1,060,252.5	1,258,524.2	1,541,893.2	1,433,751.2	1,100,105.7	998,364.8	1,062,741.5	1,249,171.0	13,956,448.5

Thermal Generation (MWh) (Br, Bo, V)	7,301,247
Hydro Generation (MWh)	8,748,180
Combustion Turbine (MWh)	47,390
Total Market Purchases (MWh)	403,134
Total Market Sales (MWh)	2,950,346
Total Thermal Unit Fuel Costs ($000)	123,071
Total Market Purchases ($000)	32,644
Total Market Sales ($000)	145,826
Net Power Supply Costs ($000)	9,888

Jim Bridger	5,051,862
Valmy	1,827,301
Boardman	422,085
Danskin	2,859
Bennett Mt	44,531
2003 Normalized Cost ($000)	
Jim Bridger	73,304
Valmy	40,304
Boardman	5,873
Danskin	242
Bennett Mt	3,348

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Summary Comparison of Net Power Supply Costs

	Idaho Power Case			Staff Case		
	NPSC	PURPA	Total	NPSC	PURPA	Total
Scenario 1 Before 88 MW New PURPA and Horizon	$ 91.8	$ 52.4	$144.2	**$ 99.2**	$ 52.4	$151.6
Scenario 2 After 88 MW New PURPA and Horizon	$ 41.0	$ 93.1	$134.1	**$ 34.9**	$ 93.1	$128.0
Difference			$ 10.1			$ 23.6
2005 Normalized Adopted Costs	$ 47.2	$ 54.6	$101.8			

All costs shown are in million $

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Summary of AURORA Net Power Supply Cost Results

AVERAGE OF ALL YEARS		Scenario 2				
	Run ID	IPCo Case	AEO 2007 Gas $7.62	NPCC 2007 Gas	IRP 2007 Gas	IRP 2007 Gas Range
	Run Year	2007	2007	2007	2007	2007
	Run Condition	Every Hour; Every Day; Every Week	Every Hour; Every Day; Every Week	Every Hour; Every Day; Every Week	Every Hour; Every Day; Every Week	Every Hour; Every Day; Every Week
Thermal Generation (MWh) (Br, Bo, V)		7,301,793	7,301,247	7,414,447	7,417,702	7,416,132
Hydro Generation (MWh)		8,748,180	8,748,180	8,748,180	8,748,180	8,748,180
Combustion Turbine (MWh)		48,861	47,390	47,511	47,967	49,743
Total Market Purchases (MWh)		401,368	403,134	458,141	457,563	455,611
Total Market Sales (MWh)		2,950,604	2,950,346	3,123,267	3,126,402	3,124,887
Total Thermal Unit Fuel Costs ($000)*		123,744	123,071	124,796	125,085	125,622
Total Market Purchases ($000)		37,984	32,644	37,518	39,040	44,430
Total Market Sales ($000)		145,834	145,826	159,742	167,513	161,517
Net Power Supply Costs ($000)		15,894	9,888	2,573	(3,388)	8,535
* Bridger,Boardman,Valmy,Danskin(excl fixed)	Danskin-Fixed	2,840	2,840	2,840	2,840	2,840
and Bennett Mountain	PPL	19,230	19,230	19,230	19,230	19,230
1/ Excludes Danskin Fixed	Wheeling	2,951	2,950	3,123	3,126	3,125
	Avg NPSC	**40,915**	**34,909**	**27,766**	**21,808**	**33,730**
Avg Market Purchase Price ($/MWh)		$94.64	$80.97	$81.89	$85.32	$97.52
Avg Market Sales Price ($/MWh)		$49.43	$49.43	$51.15	$53.58	$51.69

Gas Price	Hi	$9.99	$7.62	$7.81	$8.20	$10.33
	Lo	$5.87	$7.62	$7.81	$8.20	$6.07
	Avg	$7.93	$7.62	$7.81	$8.20	$8.20

STAFF RECOMMENDATION

Exhibit No. 111
Case No. IPC-E-07-8
R. Sterling, Staff
12/10/07

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 10TH DAY OF DECEMBER 2007, SERVED THE FOREGOING **DIRECT TESTIMONY OF RICK STERLING,** IN CASE NO. IPC-E-07-8, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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SECRETARY

CERTIFICATE OF SERVICE