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 TO ELECTRIC CUSTOMERS IN THE STATE OF IDAHO.	)	CASE NO. IPC-E-08-10

DIRECT TESTIMONY OF KEITH HESSING

IDAHO PUBLIC UTILITIES COMMISSION

OCTOBER 24, 2008

Q. Please state your name and business address for the record.
A. My name is Keith D. Hessing and 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 Public Utilities Engineer.
Q. What is your education and experience background?
A. I am a Registered Professional Engineer in the State of Idaho. I received a Bachelor of Science Degree in Civil Engineering from the University of Idaho in 1974. Since then, I worked six years for the Idaho Department of Water Resources, and two years for Morrison-Knudsen. I have been continuously employed at the Commission since August 1983.

As a member of the Commission Staff, my primary areas of responsibility have been electric utility power supply, cost allocation, rate design and power cost adjustment (PCA) mechanisms.
Q. What is the purpose of your testimony in this proceeding?
A. I will address the areas of Jurisdictional Separations, Customer Class Cost of Service, Revenue Allocation and the Power Cost Adjustment (PCA) Mechanism.
Q. Please summarize your testimony.

A. I accept the Company's Jurisdictional Separations methodology and allocators and the results they produce using Staff adjusted accounting information. Those results are presented in Staff witness Cecily Vaughn's testimony.

I accept the Company's proposal to change cost of service methodology to the 3CP/12CP method from the Base Case method that was approved in Case No. IPC-E-03-13. Based on a 1.44 percent overall increase in revenue, I propose that individual class increases be capped at 4.9 percent and that no class receive a decrease. I propose that classes not impacted by the cap or floor be moved to full cost of service.

I propose that PCA computational factors, such as base case power supply costs, energy amounts and the jurisdictional energy allocator used in the Company's Power Cost Adjustment (PCA) mechanism, be updated to reflect Staff's case. I propose that cloud seeding base costs and revenues remain unchanged. I also propose that the load growth adjustment factor used in the PCA remain unchanged while the Commission processes Case No. IPC-E-08-19 which addresses the methodology and proposes a new load growth adjustment factor.

JURISDICTIONAL SEPARATIONS

Q. What is the purpose of Jurisdictional Separations?

A. The Jurisdictional Separations process identifies the Idaho jurisdiction's share of total Company costs and revenues and establishes the Idaho jurisdictional revenue requirement.

Q. What causes the Idaho jurisdictional revenue requirement to change between rate cases?

A. In general there are three items that can cause the revenue requirement to change between rate cases - changes in accounting information, changes in jurisdictional characteristics (demand, energy and customer numbers) and changes in separations methodology. I will briefly discuss each of the three.

Account balances change every year. Some cost categories increase and some decrease. Generally, costs increase, but so do revenues as new customers are added to the system. Other Staff witnesses have testified concerning accounting data and appropriate adjustments. Account balances change between rate cases and those changes appropriately drive changes in the Idaho jurisdictional revenue requirement.

Jurisdictional characteristics also change every year. These are things like coincident peak demands, annual energy use and numbers of customers by jurisdiction. The fact that these characteristics change on a relative basis is important because they are used to separate or allocate total Company costs to the various jurisdictions. Staff Exhibit No. 129 demonstrates the changes that have occurred in these characteristics over the Company's four most recent general rate cases including this one. For demonstration purposes only one demand, one energy and one customer allocator are shown. Each category has one or more other allocators that are also used in the jurisdictional separations study. It is significant that while energy and peak loads have grown along with total system costs, the Idaho jurisdiction's share of the Company's costs has changed very little since the Company's last case. This can be observed by the change from the last rate case to this rate case in the major demand and energy allocators. The D10 allocator has not change from .950 and the E10 allocator grew from .947 to .948. In other words, the Idaho jurisdiction was allocated 95.0% of demand related costs in the last rate case and in this case Idaho ratepayers would again be allocated 95.0% of system demand related costs.

As pointed out in Company testimony, jurisdictional separations methodology has remained largely unchanged for a very long period of time. When Jurisdictional Separations methodology does not change and major allocators change little, the accounting data drives the changes in the Idaho Jurisdictional Revenue

Requirement.

Q. Do you accept Idaho Power's Jurisdictional Separations study?

A. I accept the methodology and allocation factors proposed by the Company; however, other Staff witnesses have proposed adjustments to the accounting data and the Return on Equity. Staff's Jurisdictional Separations results are presented as Staff Exhibit No. 125 to Staff witness Cecily Vaughn's testimony. Staff proposes an Idaho Jurisdictional revenue requirement of $682,850,888 that requires an overall rate increase of $9,681,348 or 1.44 percent

CLASS COST OF SERVICE

Q. What is the purpose of a Customer Class Cost of Service Study?

A. A Customer Class Cost of Service Study divides the Idaho Jurisdictional Revenue Requirement that results from the Jurisdictional Separations Study among the various Idaho rate classes.

The process is generally the same as previously described in the Jurisdictional Separations discussion. Costs are identified as energy, demand or customer related and each rate class's percentage share of energy use, demand use or number of customers is applied to the costs to divide them among the various rate classes or rate schedules.

Q. Is the Company proposing to change the Cost of Service method most recently accepted by the Commission?

A. Yes. In the IPC-E-03-13 general rate case the Commission used a method that the Company calls "Base Case" as a guide in allocating costs to the various rate classes. In this case the Company is proposing a change to a method that the Company calls "3CP/12CP". The IPC-E-05-28 general rate case that followed the IPC-E-03-13 case was a settled case that spread costs to classes on a uniform percentage basis and, therefore, did not use cost of service results. Case No. IPC-E-07-8 that followed the 05-28 case was also a settled case that used no specific cost of service study to allocate the Idaho jurisdictional revenue requirement to customer classes.

Q. What are the differences between the Base Case method and 3CP/12CP method?

A. The differences are in the classification and allocation of Production Plant. The Base Case method classifies all production plant investment, except the Company's gas fired peaking unit investment, as energy and demand related based on the Idaho jurisdictional load factor. The Idaho jurisdictional load factor is 59.38%. Therefore, approximately 59% of these costs were classified as energy related and allocated using an energy allocator, and approximately 41% were classified as demand related and allocated using a demand allocator. Gas fired peaking unit investment was classified as 100% demand related. Both energy and demand allocators were based on twelve months of data weighted by the marginal cost of energy or demand, respectively, from the Company's marginal cost study.

The proposed 3CP/12CP cost of service method classifies base load and intermediate load plant investment, hydro and thermal generating resources, as energy related and demand related based on the Idaho jurisdictional load factor just as the Base Case method does. The Company's peaking resource investment in natural gas fired plant is classified as 100% demand related as in the Base Case study. However, different demand allocators are applied. Demand related peaking unit investment is allocated using an unweighted 3CP allocator based on the Company's three summer peak months of June, July and August. Other demand related production investment associated with serving base and intermediate load is allocated using an unweighted 12CP allocator. The energy related portion of base and intermediate load production plant investment is allocated based on marginal cost weighted class energy use.

Q. What other changes in cost of service methodology from IPC-E-03-13 is the Company proposing?

A. The Company is proposing to classify Account 555 - Purchased Power costs (market purchases and PURPA purchases) as energy and demand related based on the system load factor. The IPC-E-03-13 rate case classified purchased power costs as almost entirely energy related.

Another cost of service change that has occurred since the 03-13 case is a change in the way coincident peak demand allocators are determined. The 03-13 cost of service study used actual test year coincident peak demands to determine the allocation factor. Following that case workshops were held to discuss a number of cost of service issues. As part of that process the parties agreed to use a 5-year median coincident peak demand to normalize the allocation factor. The Company has applied this methodology in all cases since the 03-13 case.

Q. What is the difference in study results between the 03-13 Base Case method and the 3CP/12 CP method proposed by the Company in this case?

A. Company witness Tatum presents the results of three cost of service studies that he prepared in Company Exhibit No. 69. The results of the Base Case study and the 3CP/12CP study are included and show similar trends.

Q. Which method do you propose the Commission accept?

A. I recommend that the Commission accept the

3CP/12CP method proposed by the Company.

Q. Does your testimony include an exhibit showing Cost of Service results using the 3CP/12CP method applied to the Idaho jurisdictional revenue requirement proposed by Staff?

A. Yes. Staff Exhibit No. 130 shows those results.

Q. Do your results show the same general pattern as the results presented by the Company in Exhibit No. 69?

A. Yes. The special contract customers, Micron, Simplot and DOE, along with the Large Power customers served under Schedule 19 and the Irrigation class show a need for a much higher than average increase if their rates are to be set at full cost of service. Residential customers are shown to deserve a decrease.

Q. Are these results similar to cost of service results from the IPC-E-03-13 case?

A. No. Cost of service results did not indicate higher than average cost increases for the high load factor customer classes in that case.

Q. How do you explain the significant changes in cost of service results that have occurred since the IPC-E-03-13 case?

A. There are a number of circumstances that have caused changes in cost of service results. Load growth, substantially in the residential class, has occurred in record amounts. The cost of power supply to meet the growing load, at approximately 6¢/kWh, has been much higher than it used to be. Under cost of service methodology a disproportionately larger share of all costs, old and new, are allocated to the residential class because the residential classes percentage share of energy, peak demand and customers has increased. A mix of old and new costs is also allocated to all other classes even if they experienced no load growth. No customer class is entitled to rates based on a grandfathered share of old costs. In the cost of service model the residential class received credit for all of the revenue from its load growth at near 6¢/kWh and a portion of the production cost increases at about the same rate. In the cost of service study the increased revenues offset the increased costs and the Residential Class is shown to deserve an increase below the Idaho Jurisdictional average, or even a decrease as demonstrated in Staff's results.

High load factor customer groups are situated differently. They are allocated a reduced portion of all costs, old and new, and have little or no new revenue to offset the new costs. The new costs more than offset the cost reduction due to the decrease in the allocation percentages and without additional revenue rates go up. Therefore, cost of service results indicate increases higher than the average.

Even if there were substantial growth in the high load factor classes, their revenue at about 3¢/kWh would not offset marginal power supply costs at about 6¢/kWh. The size of the increase may be decreased, but there would still be an above average increase for high load factor customers.

Q. Does your explanation explain cost of service trends since the IPC-E-03-13 case?

A. There are many moving parts in a cost of service study. The explanation that I have provided addresses the cost trends for the large customer classes. There are many other factors that are also driving changes in cost of service results such as differences in methodology, allocation factors, distribution and transmission costs, etc.

The explanation that I have provided addresses the trend of disproportionate increases to the high load factor classes observed in the Company's three most recent general rate case filings - IPC-E-05-28, IPC-E-07-8 and the current case.

Q. Is there any reason to believe that the trend will not continue?

A. No. It is largely driven by the high marginal power supply cost of serving new load. I expect load to continue to grow and marginal costs to remain significantly higher than high load factor customer rates.

REVENUE ALLOCATION

Q. How do you propose the Commission use the Cost of Service results contained in Staff Exhibit No. 130?

A. In general, I propose that Cost of Service results be used as a guide in establishing class revenue requirements for the various rate classes. I view Cost of Service results as an imprecise science that is appropriately used as a starting point in revenue allocation.

Q. What customer class allocation of the Idaho Jurisdictional revenue requirement do you recommend?

A. Staff's Cost of Service results are based on an average Idaho jurisdictional retail rate increase of 1.44 percent. However, some individual class increases vary substantially from the average. For this reason I recommend that cost of service results not be strictly followed, but that the results be used as a guide in establishing class revenue requirements.

It is my recommendation that no class receive a rate decrease and that increases be capped at 4.9 percent. All customer classes in between would be moved to full cost of service. This approach diminishes rate shock and moves all classes toward cost of service.

Q. Have you prepared an exhibit that shows the results of your proposal?

A. Yes. I have prepared Staff Exhibit No. 131. As you can see, Schedules 19, 24, 42 and the special contract customer schedules would receive the maximum increase of 4.9%. Schedules 1, 7, 15, 40 and 41 would receive no increase or decrease. Schedule 9 would be moved to full cost of service.

Q. Have you prepared an exhibit that compares your Revenue Allocation proposal to Idaho Power's Revenue Allocation proposal?

A. Yes. Staff Exhibit No. 132 makes that comparison.

POWER COST ADJUSTMENT (PCA) MECHANISM

Q. What Power Cost Adjustment (PCA) components are established in a general rate case?

A. Company Exhibit No. 51 identifies most of the "PCA Computational Factors" that are established in a general rate case. The Company proposes that the PCA computational factors be updated to the 2008 test year level.

Q. Have you prepared a similar exhibit that presents your quantification of appropriate PCA computational factors?

A. Yes, I have. Staff Exhibit No. 133 contains the information in the Company's proposal from Company Exhibit No. 51 along with my proposal. My proposal is based on Staff's case.

Q. Please discuss the factors presented in your proposal to the extent that they differ from the Company's proposal.

A. The Company and Staff proposals for Normalized Power Supply Expense differ because the expense amounts come from the AURORA power supply model and Staff assumed a different natural gas price input to that model than the Company did. This difference is discussed in more detail in Staff witness Rick Sterling's testimony. Also the Staff proposes to continue the use of the Commission ordered base revenue and cost amounts for cloud seeding. These differences are also the cause of the difference in the Normalized Base PCA Rate that is calculated using the Normalized Power Supply Expense and Cloud Seeding expense and revenue.

Q. Are there other PCA computational factors that are normally established in a general rate case?

A. Yes. The load growth adjustment rate, also called the Expense Adjustment Rate for Growth (EARG), and the forecast equation.

Q. Please discuss your recommendation for the load growth adjustment rate.

A. In the Company's most recent general rate case, the IPC-E-07-8 case, the Commission accepted a settlement stipulation. In that stipulation, the load growth adjustment rate was based on a 2007 marginal cost calculation of $62.79/MWh and was applied to one-half of the load growth. I propose that the currently approved rate continue to be used and that it continue to be applied to one-half the load growth.

Q. Have the Company and Staff calculated new marginal costs that could be used to update the load growth adjustment rate?

A. Yes. Company Exhibit No. 50 shows a 2008 marginal power supply cost of $56.48 per MWh. Staff Exhibit No. 134 shows a 2008 marginal power supply cost of $54.07 per MWh. The difference is caused by different assumptions in monthly natural gas prices.

Q. Why are you not proposing to update the load growth adjustment rate?

A. The Commission currently has Case No. IPC-E-08-19 before it which contains a stipulated settlement that changes the computational method and the rate. I believe that it is appropriate for load growth adjustment rate changes to be considered in that case.

Q. You said that the PCA Forecast equation is also normally updated in a general rate case. Please discuss the PCA forecast equation.

A. The Company filed an updated PCA forecast equation. The calculations are shown on Company Exhibit No. 49. The Staff has not prepared such a calculation because Case No. IPC-E-08-19 also proposes to change forecast methodology. If the Commission does not accept the settlement proposed in that case, an updated regression formula based on Commission approved power supply costs could be prepared at that time.

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

A. Yes, it does.

Case No. IPC-E-08-10
Comparison of Historic Jurisdictional Allocators

Classification	Allocator	Case No.	Units	Idaho	Oregon & FERC	Total
Demand	D10	IPC-E-03-13	kW	2,076,437	121,967	2,198,404
	D10	IPC-E-05-28	kW	2,102,069	121,411	2,223,480
	D10	IPC-E-07-08	kW	2,281,542	120,809	2,402,351
	D10	IPC-E-08-10	kW	2,335,595	121,919	2,457,514
	D10	IPC-E-03-13	Allocator	0.945	0.055	1.000
	D10	IPC-E-05-28	Allocator	0.945	0.055	1.000
	D10	IPC-E-07-08	Allocator	0.950	0.050	1.000
	D10	IPC-E-08-10	Allocator	0.950	0.050	1.000
Energy	E10	IPC-E-03-13	kWh	13,275,012	832,564	14,107,576
	E10	IPC-E-05-28	kWh	13,950,521	868,631	14,819,152
	E10	IPC-E-07-08	kWh	14,784,934	827,764	15,612,698
	E10	IPC-E-08-10	kWh	15,036,726	826,902	15,863,628
	E10	IPC-E-03-13	Allocator	0.941	0.059	1.000
	E10	IPC-E-05-28	Allocator	0.941	0.059	1.000
	E10	IPC-E-07-08	Allocator	0.947	0.053	1.000
	E10	IPC-E-08-10	Allocator	0.948	0.052	1.000
Customer	CW903	IPC-E-03-13	Weighted Customers	6,581,117	292,716	6,873,833
	CW903	IPC-E-05-28	Weighted Customers	8,910,067	379,961	9,290,028
	CW903	IPC-E-07-08	Weighted Customers	8,910,067	379,961	9,290,028
	CW903	IPC-E-08-10	Weighted Customers	7,873,470	309,347	8,182,817
	CW903	IPC-E-03-13	Allocator	0.957	0.043	1.000
	CW903	IPC-E-05-28	Allocator	0.959	0.041	1.000
	CW903	IPC-E-07-08	Allocator	0.959	0.041	1.000
	CW903	IPC-E-08-10	Allocator	0.962	0.038	1.000

Idaho Power Company
Staff Case
Revenue Allocation Summary
12 Months Ending December 31, 2008
3CP/12CP Cost-of-Service Results

Line No.	Tariff Description	Rate Schedule No.	COS Percent Change	COS Revenue Change	Revenue Allocation at COS	Average ¢/kWH at COS
	Uniform Tariff Schedules					
1	Residential Service	1	-4.51%	$ (14,353,316)	$ 303,603,145	5.99
2	Small General Service	7	-1.02%	(155,331)	$ 15,006,048	7.87
3	Large General Service	9	0.60%	940,798	$ 158,385,063	4.40
4	Dusk/Dawn Lighting	15	-50.19%	(504,206)	$ 500,302	8.40
5	Large Power Service	19	6.77%	4,755,039	$ 75,026,145	3.53
6	Irrigation Service	24	19.74%	15,208,117	$ 92,253,691	5.95
7	Unmetered Service	40	-10.22%	(98,763)	$ 867,728	5.18
8	Municipal Street Lighting	41	-37.87%	(876,389)	$ 1,437,872	6.51
9	Traffic Control Lighting	42	33.68%	52,275	$ 207,478	4.93
10	*Total Idaho Rates*		0.77%	4,968,224	647,287,472	51.45
	Special Contracts					
11	Micron	26	14.51%	$ 2,903,461	$ 22,907,419	3.26
12	J R Simplot	29	17.91%	898,802	$ 5,916,961	3.12
13	DOE/INL	30	15.63%	910,860	$ 6,739,035	3.13
14	*Total Specials*		15.28%	4,713,123	35,563,415	32.10
15	Total Idaho Retail Sales		1.44%	$ 9,681,347	$ 682,850,887	4.99

Exhibit No. 130
Case No. IPC-E-08-10
K. Hessing, Staff
10/24/08

Idaho Power Company
Staff Case
Revenue Allocation Summary
12 Months Ending December 31, 2008

Line No.	Tariff Description	Rate Schedule No.	Percent Change	Revenue Change	Revenue Allocation
	Uniform Tariff Schedules				
1	Residential Service	1	0.00%	$ -	$ 317,956,461
2	Small General Service	7	0.00%	-	15,161,379
3	Large General Service	9	0.60%	940,798	158,385,063
4	Dusk/Dawn Lighting	15	0.00%	-	1,004,508
5	Large Power Service	19	4.90%	3,444,373	73,715,479
6	Irrigation Service	24	4.90%	3,776,427	80,822,001
7	Unmetered Service	40	0.00%	-	966,491
8	Municipal Street Lighting	41	0.00%	-	2,314,261
9	Traffic Control Lighting	42	4.90%	7,607	162,810
10	*Total Idaho Rates*		1.27%	8,169,205	650,488,453
	Special Contracts				
11	Micron	26	4.90%	$ 980,504	$ 20,984,462
12	J R Simplot	29	4.90%	245,968	5,264,127
13	DOE/INL	30	4.90%	285,671	6,113,846
14	*Total Specials*		4.90%	1,512,142	32,362,434
15	Total Idaho Retail Sales		1.44%	$ 9,681,347	$ 682,850,887
16	Revenue Requirement Shortfall				$ 0

Exhibit No. 131
Case No. IPC-E-08-10
K. Hessing, Staff
10/24/08

Comparison of Cost Of Service Results and Revenue Allocation Proposals

Case No. IPC-E-08-10

			Company		Staff	
Line No	Tariff Description	Rate Sch. No.	COS Results 3CP/12CP Percent Change	Company Proposal	COS Results 3CP/12CP Percent Change	Staff Proposal
			%	%	%	%
	Uniform Tariff Rates:					
1	Residential Service	1	3.71	6.31	(4.51)	0.00
2	Small General Service	7	7.91	10.63	(1.02)	0.00
3	Large General Service	9	8.73	11.46	0.60	0.60
4	Dusk to Dawn Lighting	15	(41.85)	2.51	(50.19)	0.00
5	Large Power Service	19	15.87	15.00	6.77	4.90
6	Agricultural Irrigation Service	24	28.54	15.00	19.74	4.90
7	Unmetered General Service	40	(2.57)	2.51	(10.22)	0.00
8	Street Lighting	41	(29.24)	2.51	(37.87)	0.00
9	Traffic Control Lighting	42	44.20	15.00	33.68	4.90
	Special Contracts:					
10	Micron	26	24.41	15.00	14.51	4.90
11	J R Simplot	29	28.14	15.00	17.91	4.90
12	DOE	30	25.37	15.00	15.63	4.90
13	***Total Idaho***		9.89	9.89	1.44	1.44

Exhibit No. 132
Case No. IPC-E-08-10
K. Hessing, Staff
10/24/08

PCA Computational Factors
Case No. IPC-E-08-10

	Units	2007 Settlement	Company Proposal 2008 Test Year	Staff Proposal 2008 Test Year
Normalized PCA Expense				
Normalized Power Supply Expense	$	34,964,670	88,421,246	77,576,480
Normalized CSPP	$	93,080,631	63,269,889	63,269,889
Cloud Seeding Expense	$	892,084	-	892,084
Cloud Seeding Revenue	$	(1,427,334)	-	(1,427,334)
Normalized PCA Expense	$	127,510,051	151,691,135	140,311,119
Normalized Base PCA Rate Computation				
Normalized System Firm Sales	MWh	14,239,222	14,465,151	14,465,151
Normalized Base PCA Rate	¢/kWh	0.8955	1.0487	0.9700
Idaho Jurisdictional Percentage Computation				
Normalized System Firm Load	MWh	15,612,699	15,863,628	15,863,628
Idaho Jurisdictional Firm Load	MWh	14,784,934	15,036,726	15,036,726
Idaho Jurisdictional Percentage	%	94.7%	94.8%	94.8%
Expense Adjustment Rate for Growth				
Applied to one-half of load growth	$/MWh	62.79	-	62.79

Exhibit No. 133
Case No. IPC-E-08-10
K. Hessing, Staff
10/24/08

MARGINAL ENERGY COSTS
SUMMARY TOTAL

BASE CASE

Year	Type	Units	January	February	March	April	May	June	July	August	September	October	November	December	Annual
2008	Energy	MWh	1,284,751	1,113,726	1,106,625	983,300	1,135,254	1,315,055	1,611,826	1,474,185	1,177,299	1,055,375	1,118,368	1,374,258	14,750,022
2008	Cost	($ x 1000)	$ 6,459.7	$ (9,580.1)	$ (8,498.2)	$ (7,204.5)	$ 517.8	$ 8,912.4	$ 25,259.4	$ 18,948.6	$ 11,338.4	$ 5,353.5	$ 12,857.7	$ 13,211.9	$ 77,576.5
2008	Cost/MWh	$/MWh	$ 5.0	$ (8.6)	$ (7.7)	$ (7.3)	$ 0.5	$ 6.8	$ 15.7	$ 12.9	$ 9.6	$ 5.1	$ 11.5	$ 9.6	$ 5.3

BASE CASE PLUS 50 aMW

Year	Type	Units	January	February	March	April	May	June	July	August	September	October	November	December	Annual
2008	Energy	MWh	1,322,179	1,146,507	1,139,382	1,013,124	1,169,995	1,354,840	1,659,836	1,518,307	1,212,802	1,086,893	1,151,110	1,414,224	15,189,199
2008	Cost	($ x 1000)	$ 8,595.4	$ (7,818.5)	$ (6,841.0)	$ (5,861.5)	$ 1,977.6	$ 10,338.8	$ 28,318.6	$ 21,554.0	$ 13,295.2	$ 7,155.1	$ 14,863.9	$ 15,746.0	$101,323.6
2008	Cost/MWh	$/MWh	$ 6.5	$ (6.8)	$ (6.0)	$ (5.8)	$ 1.7	$ 7.6	$ 17.1	$ 14.2	$ 11.0	$ 6.6	$ 12.9	$ 11.1	$ 6.7

MARGINAL COST OF ENERGY

Year	Type	Units	January	February	March	April	May	June	July	August	September	October	November	December	Annual
2008	MEC	$/MWh	$57.06	$53.74	$50.59	$45.03	$42.02	$35.85	$63.72	$59.05	$55.12	$57.16	$61.28	$63.41	$54.07

Exhibit No. 134
Case No. IPC-E-08-10
K. Hessing, Staff
10/24/08

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 24TH DAY OF OCTOBER 2008, SERVED THE FOREGOING **DIRECT TESTIMONY OF KEITH HESSING,** IN CASE NO. IPC-E-08-10, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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