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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO IMPLEMENT POWER COST ADJUSTMENT ("PCA") RATES FOR ELECTRIC SERVICE FROM JUNE 1, 2011, THROUGH MAY 31, 2012.	)	CASE NO. IPC-E-11-06

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

MATTHEW T. LARKIN

1 Q. Please state your name and business address.

2 A. My name is Matthew T. Larkin. My business

3 address is 1221 West Idaho Street, Boise, Idaho.

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

5 A. I am employed by Idaho Power Company ("Idaho

6 Power" or "Company") as a Regulatory Analyst in the

7 Regulatory Affairs Department.

8 Q. Please describe your educational background.

9 A. I received a Bachelor of Business

10 Administration degree in Finance from the University of

11 Oregon in 2007. In 2008, I earned a Master of Business

12 Administration degree from the University of Oregon. I

13 have also attended electric utility ratemaking courses

14 including *The Basics: Practical Regulatory Training for the*

15 *Electric Industry*, a course offered through New Mexico

16 State University's Center for Public Utilities, and

17 *Introduction to Rate Design and Cost of Service Concepts*

18 *and Techniques*, presented by Electric Utilities

19 Consultants, Inc.

20 Q. Please describe your work experience.

21 A. I began employment with Idaho Power as a

22 Regulatory Analyst in January 2009. As a Regulatory

23 Analyst, I provide support for the Company's various

24 regulatory activities, including regulatory reporting,

1 financial analysis, and the development of various cost-
2 related studies. During my time with the Company, I have
3 assisted in the preparation of the Company's Oregon Results
4 of Operations Report, retail revenue forecasts for
5 regulatory filings, and a number of cost-of-service
6 studies.
7 Q. What is the scope of your testimony in this
8 proceeding?
9 A. My testimony is divided into several sections.
10 In the first section, I will provide my determination of
11 the PCA forecast rate using the 2010 PCA base components
12 that were approved in Order No. 31042 in Case No. IPC-E-10-
13 01. In the next section of my testimony, I will quantify
14 the True-Up and the True-Up of the True-Up. The third
15 section of my testimony will address the inclusion of the
16 recovery of $10 million of the Energy Efficiency Rider
17 ("Rider") deferral balance pursuant to Order No. 32217 in
18 Case No. IPC-E-10-27. The fourth section of my testimony
19 will detail the summation of the various PCA components and
20 the determination of the final PCA rates for each rate
21 class. The fifth section of my testimony will address the
22 revised Load Change Adjustment Rate ("LCAR") as approved in
23 Order No. 32206 in Case No. GNR-E-10-03. Finally, my
24 testimony concludes with a description of the 2010 Idaho

1 jurisdictional return on equity ("ROE") determination
2 pursuant to the settlement stipulation ("Stipulation")
3 approved in Order No. 30978 in Case No. IPC-E-09-30.
4 Q. Please describe the components of the PCA
5 base.
6 A. The PCA base is comprised of the following
7 FERC Accounts: FERC Account 501, fuel (coal); FERC Account
8 536, water for power; FERC Account 547, fuel (gas); FERC
9 Account 555, purchased power (both Public Utility
10 Regulatory Policies Act of 1978 ("PURPA") and non-PURPA
11 purchases); FERC Account 565, transmission of electricity
12 by others; and FERC Account 447, sales for resale
13 (typically referred to as surplus sales).
14 **I. PCA FORECAST**
15 Q. Please quantify the PCA component amounts
16 described above that are included in the PCA base from
17 which deviations are to be tracked based on customers
18 receiving a 95 percent share.
19 A. Order No. 31042 approved the Company's 2010
20 base level PCA component amounts from which deviations are
21 to be tracked at 95 percent for customer responsibility as
22 follows:
23 Account 501, coal $167,718,084
24 Account 536, water for power $1,828,640

Account 547, gas	$6,062,472
Account 555, non-PURPA	$66,689,601
Account 565, transmission	$8,262,000
Account 447, surplus sales	($92,642,114)
Net of 95 percent accounts	$157,918,683

Q. Please quantify the PCA component amounts included in the PCA base from which deviations are to be tracked based upon a 100 percent customer sharing percentage.

A. Order No. 31042 approved PCA base component amounts from which deviations are to be tracked at 100 percent for customer responsibility as follows:

Account 555, PURPA	$62,851,454

Q. Please detail the amounts included in the PCA projection for which deviations from base are to be tracked based upon a 95 percent customer sharing percentage.

A. Based upon the Company's March 31, 2011, Operating Plan, the PCA projection of amounts for which deviations from base are to be tracked at 95 percent for customer responsibility is as follows:

Account 501, coal	$153,268,673
Account 536, water for power	$2,291,000
Account 547, gas	$8,971,778
Account 555, non-PURPA	$62,308,530

Account 565, transmission	$7,897,586
Account 447, surplus sales	($79,083,135)
Net of 95 percent accounts	$155,654,432

Q. Does the recently approved special contract with Hoku Materials, Inc. ("Hoku") impact PCA computations?

A. Yes. Order No. 30748 approved the Energy Sales Agreement ("ESA") between Idaho Power and Hoku, which provides that Hoku first block energy revenues are to be reflected in PCA computations as if they were surplus sales. For the 2011/2012 PCA year, the Hoku contract suggests that the Company will collect $22,196,712 in revenues associated with Hoku first block energy. Subtracting this amount from the $155,654,432 projection results in an adjusted net of $133,457,720.

Q. How were Hoku first block energy revenues derived?

A. Expected revenues from Hoku first block energy sales were derived using Hoku's forecasted energy consumption and expected minimum energy payments required under the minimum billed energy clause of the ESA when energy consumption falls below minimum contract levels. The Company expects to receive minimum energy payments in the months of April, May, June, and August of the 2011/2012

1 PCA year, resulting in a customer benefit that will flow
2 through the PCA in the same manner as surplus sales.
3 Q. Are there any other adjustments that impact
4 PCA computations?
5 A. Yes. For the 2011/2012 PCA year, the Company
6 forecasts $7,813,887 of revenues resulting from the sale of
7 Renewable Energy Credits ("REC") and Sulfur Dioxide ("SO_2")
8 benefits, which further reduce this year's PCA forecast.
9 The actual REC benefits are tracked in the PCA deferral
10 report. Subtracting the REC benefits of $7,767,137
11 combined with the SO_2 benefits of $46,750 results in an
12 adjusted PCA forecast amount of $125,643,833.
13 Q. What is the difference between the PCA
14 forecast amount of $125,643,833 and the $157,918,683 PCA
15 base amount approved in Order No. 31042?
16 A. The PCA forecast amount of $125,643,833 is
17 $32,274,850 less than the PCA base amount of $157,918,683.
18 Q. What is the Operating Plan quantification of
19 PURPA expenses anticipated from April 2011 through March
20 2012?
21 A. The March 31, 2011, Operating Plan anticipates
22 $99,801,054 of PURPA expenses during the April 2011 through
23 March 2012 time period.

Q. How does this amount compare to the base level of PURPA expenses quantified in Order No. 31042?

A. The Operating Plan quantification of PURPA expenses is $36,949,600 greater than the $62,851,454 quantified in the Company's update of power supply expenses approved in Order No. 31042.

Q. What is the rate for the projection portion of the PCA for April 2011 through March 2012?

A. The rate for the projection portion of the PCA is equal to the sum of (1) 95 percent of the difference between the non-PURPA expenses quantified in the Operating Plan and those quantified in the Company's last approved update of power supply expenses and (2) 100 percent of the difference between PURPA-related expenses quantified in the Operating Plan and those quantified in the Company's last approved update of power supply expenses, divided by (3) the Company's normalized system firm sales.

The rate for non-PURPA expenses is negative 0.2167 cents per kilowatt-hour ("kWh"), which is calculated by multiplying negative $32,274,850 by 95 percent and then dividing it by the normalized system firm sales of 14,147,195 megawatt-hour ("MWh") ((-$32,274,850 * .95) / 14,147,195). The rate for PURPA expenses is 0.2612 cents per kWh, which is calculated by dividing $36,949,600 by the

normalized system firm sales of 14,147,195 MWh. The projection portion of the PCA rate is 0.0445 cents per kWh, which is calculated by adding negative 0.2167 cents per kWh to 0.2612 cents per kWh.

II. TRUE-UP AND TRUE-UP OF THE TRUE-UP

Q. Please describe the True-Up portion of the PCA rate.

A. The True-Up portion of the PCA rate starts with the *Deferral Expense Report*, attached as Exhibit No. 1. This Report compares actual PCA account results to last year's PCA account projections on a monthly basis, with the differences accumulated as the deferral balance. The balance at the end of March 2011, with interest applied, was $4,181,114, as shown on row 78 of Exhibit No. 1.

Q. Has the Company made any adjustments to the calculation of the True-Up?

A. Yes. Pursuant to the Idaho Public Utilities Commission's ("Commission") findings in Order No. 31093, the Company has modified the calculation of interest on the PCA deferral balance. For the 2010/2011 PCA deferral, interest was calculated according to base net power supply expenses distributed to monthly values utilizing an AURORA-based distribution shape, which is detailed on page 3 of Exhibit No. 1. Once calculated, this interest was applied

1 to base net power supply expenses distributed to monthly
2 values utilizing a revenue-based distribution shape as
3 shown on page 2 of Exhibit No. 1.
4 Q. Were there any one-time adjustments to the PCA
5 True-Up balances in the April 2010 through March 2011 time
6 frame?
7 A. Yes. There was an adjustment for the sale of
8 SO_2 credits, which reduces the True-Up amount by $491,740.
9 Q. Please describe the computation of this year's
10 True-Up rate.
11 A. This year's True-Up component of the PCA is
12 $3,689,374, which was computed by reducing the deferral
13 balance of $4,181,114 by the proceeds from the sale of SO_2
14 credits of $491,740. The revised deferral balance of
15 $3,689,374 divided by the Company's projected Idaho
16 jurisdictional sales of 13,478,411 MWh results in a rate of
17 0.0273 cents per kWh.
18 Q. What is this year's True-Up of the True-Up
19 rate?
20 A. The Company over collected this year's PCA
21 True-Up balance by $18,152,666, as shown on row 97 of the
22 *Deferral Expense Report*. The True-Up of the True-Up rate
23 is calculated by dividing $18,152,666 by the projected 2011

1 Idaho jurisdictional sales of 13,478,411 MWh, which results
2 in a rate of negative 0.1347 cents per kWh.

3 **III. RECOVERY OF RIDER DEFERRAL BALANCE**

4 Q. Please provide a description of Order No.
5 32217 in Case No. IPC-E-10-27 as it pertains to the PCA.
6 A. Order No. 32217 authorized the Company to
7 recover $10 million of the Rider deferral balance through
8 the PCA beginning June 1, 2011.
9 Q. How has the Company incorporated this recovery
10 into the PCA rate?
11 A. As mandated in Order No. 32217, the recovery
12 of the Rider deferral amount through the PCA is not to
13 result in cost shifting between customer classes. To
14 comply with this directive, the Company has allocated the
15 $10 million Rider deferral amount to individual rate
16 classes based on each class's proportion of total base
17 revenues for the test year June 1, 2011, through May 31,
18 2012. As detailed in Exhibit No. 2, this allocation method
19 prevents the shifting of costs between customer classes due
20 to recovery of the Rider deferral amount through the PCA.

21 **IV. FINAL PCA RATE CALCULATION**

22 Q. What is the resulting PCA rate when you
23 combine all of the described components?

A. The Company's PCA rate for the 2011/2012 PCA year is detailed in Exhibit No. 2. The uniform PCA rate is comprised of: (1) the 0.0445 cents per kWh adjustment for the 2011/2012 projected power cost of serving firm loads under the current PCA methodology and 95 percent sharing, (2) the 0.0273 cents per kWh for the 2010/2011 True-Up portion of the PCA, and (3) the negative 0.1347 cents per kWh for the True-Up of the True-Up. The sum of these three components results in a negative 0.0629 cents per kWh charge for all rate classes.

In addition to the uniform PCA rate, each rate class is allocated a portion of the $10 million Rider deferral balance authorized for recovery in Order No. 32217. When this additional charge is added to the uniform PCA components, the result is a different PCA rate for each rate class. The final combined PCA rates are listed by class in column 6 of Exhibit No. 2.

Q. Have you calculated expected PCA revenue using the PCA rates described above?

A. Yes. The Company would expect to credit $8,477,921 (-.000629 * 13,478,411,203 kWh = -$8,477,921) through the uniform PCA rate using the approved base power supply expenses approved in Order No. 31042. The additional $10 million authorized recovery of the Rider

1 deferral balance results in an overall expected collection
2 of $1,522,079 through the final combined PCA rates.
3 Q. What is the revenue impact of the requested
4 rates when compared to the PCA rate currently in effect?
5 A. Exhibit No. 3 provides a detailed description
6 of the overall revenue impact of this filing on each
7 customer class. As shown in Exhibit No. 3, applying the
8 requested PCA rates to expected customer loads for the June
9 2011 through May 2012 test year results in a net PCA
10 reduction of $40,449,693.
11 Q. Should the Commission approve the Company's
12 computation of the PCA rates?
13 A. Yes. The Commission should approve the
14 Company's computation of the PCA rates. The calculation of
15 the PCA rates follows the methodology that was approved in
16 Order Nos. 30715, 30978, 31042, and 32217.
17 **V. LOAD CHANGE ADJUSTMENT RATE**
18 Q. Please provide a brief explanation of the
19 LCAR.
20 A. The LCAR (formerly referred to as the "Load
21 Growth Adjustment Rate" or "LGAR") is part of the PCA
22 mechanism intended to eliminate recovery of power supply
23 expenses associated with load deviations due to weather,
24 growing customer totals, or changing customer usage

1 patterns. Since the PCA was first introduced in 1992, the
2 LCAR calculation has been the subject of extensive debate,
3 resulting in a number of modifications. Most recently the
4 Commission ordered the Company, Avista Corporation
5 ("Avista"), Rocky Mountain Power, Commission Staff, and
6 other interested parties to review the LCAR methodology in
7 Case No. GNR-E-10-03.
8 Q. Please describe the outcome of Case No. GNR-E-
9 10-03.
10 A. On March 15, 2011, the Commission issued Order
11 No. 32206 adopting a revised LCAR methodology proposed by
12 Avista. Through this proposal, Avista recommended a
13 methodology that "calculates the adjusted rate based upon
14 the energy classified portion of embedded production
15 revenue requirement as established in the cost of service
16 for each utility." Order No. 32206, p. 2. The Commission
17 approved this revised methodology with an effective date of
18 April 1, 2011.
19 Q. Has the Company calculated a revised LCAR
20 pursuant to the methodology outlined in Order No. 32206?
21 A. Yes. Pursuant to Order No. 32206, the Company
22 has calculated a revised LCAR of $19.36 per MWh. This rate
23 will be effective April 1, 2011.
24 Q. How was the $19.36 per MWh rate derived?

A. To comply with Commission Order No. 32206, the Company first identified the fixed amount of the Idaho jurisdictional energy classified portion of the embedded production revenue requirement from its most recently approved cost-of-service study in Case No. IPC-E-08-10. However, because base net power supply expenses were updated on June 1, 2010, per Order No. 31093, the Company updated the variable portion of production revenue requirement to align the LCAR with net power supply expenses currently in base rates. After combining the fixed amount from Case No. IPC-E-08-10 with the variable amount reflecting base net power supply expenses currently in rates, the Company derived an overall energy classified embedded production revenue requirement of $286,698,607. The Company then identified the Idaho jurisdictional firm load used to develop current base rates as 14,812,596 MWh. The final rate was calculated by dividing the $286,698,607 by 14,812,596 MWh to arrive at an updated LCAR of $19.36 per MWh.

VI. 2010 IDAHO JURISDICTIONAL ROE

Q. Please provide a brief explanation of the Stipulation approved in Order No. 30978.

A. The Stipulation approved in Order No. 30978 allows for the Company to accelerate amortization of

1 accumulated deferred investment tax credits ("ADITC") for
2 the years 2009 through 2011 should the Company's Idaho
3 jurisdictional ROE fall below 9.5 percent. The Stipulation
4 also outlines a revenue sharing provision should the
5 Company's Idaho jurisdictional ROE exceed 10.5 percent. In
6 addition to authorizing the accelerated amortization of
7 ADITC, the Stipulation states that the Company is not
8 allowed to file a general rate case with rates to become
9 effective prior to January 1, 2012. The stipulation also
10 allowed the Company to update base rate components for its
11 2010 PCA filing.
12 Q. Has the Company calculated the Idaho
13 jurisdictional ROE for the 2010 reporting year?
14 A. Yes. The Idaho jurisdictional ROE was
15 calculated at 10.37 percent for the twelve months ended
16 December 31, 2010.
17 Q. Does the 10.37 percent ROE require the
18 acceleration of the amortization of any ADITC or revenue
19 sharing pursuant to the Stipulation approved in Order No.
20 30978?
21 A. No. The 10.37 percent ROE is between 9.5
22 percent and 10.5 percent resulting in no further action.
23 Q. Does this conclude your testimony?
24 A. Yes.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-11-06

IDAHO POWER COMPANY

LARKIN, DI
TESTIMONY

EXHIBIT NO. 1

Power Cost Adjustment
April 2010 thru March 2011

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Power Cost Adjustment**														
2	**April 2010 thru March 2011**		April	May	June	July	August	September	October	November	December	January	February	March	Totals
3															
4	**PCA Revenue**														
5	Normalized Idaho Jurisdictional Sales		968,949	998,195	1,123,624	1,316,280	1,400,447	1,280,168	1,033,366	958,498	1,074,126	1,193,372	1,115,947	1,029,368	13,492,340
6	PCA Component Rate	$	4.967	4.967	1.404	1.404	1.404	1.404	1.404	1.404	1.404	1.404	1.404	1.404	
7	Revenue	$	4,812,769.68	4,958,034.57	1,577,568.10	1,848,057.12	1,966,227.59	1,797,355.87	1,450,845.86	1,345,731.19	1,508,072.90	1,675,494.29	1,566,789.59	1,445,232.67	25,952,179.43
8															
9	**Load Change Adjustment**														
10	Actual Firm Load - Adjusted	Mwh	1,038,330	1,127,939	1,260,708	1,676,222	1,518,959	1,232,322	1,053,647	1,134,671	1,264,561	1,295,294	1,105,065	1,117,888	14,825,606
11	Normalized Firm Load	Mwh	1,077,297	1,254,940	1,412,842	1,685,870	1,594,331	1,225,589	1,100,776	1,130,765	1,380,118	1,356,320	1,177,732	1,160,140	15,556,720
12	Load Change	Mwh	(38,967)	(127,001)	(152,134)	(9,648)	(75,372)	6,733	(47,129)	3,906	(115,557)	(61,026)	(72,667)	(42,252)	(731,114)
13	Expense Adjustment (@ $26.63)		1,037,691.21	3,382,036.63	4,051,328.42	256,926.24	2,007,156.36	(179,299.79)	1,255,045.27	(104,016.78)	3,077,282.91	1,625,122.38	1,935,122.21	1,125,170.76	19,469,565.82
14															
15	**Actual Non-QF PCA**														
16	Expense Adjustment	$	1,037,691.21	3,382,036.63	4,051,328.42	256,926.24	2,007,156.36	(179,299.79)	1,255,045.27	(104,016.78)	3,077,282.91	1,625,122.38	1,935,122.21	1,125,170.76	19,469,565.82
17	Water for Power (Leases)	$	0.00	0.00	0.00	0.00	914,320.00	457,160.00	0.00	0.00	0.00	215,600.00	(46,200.00)	514,305.00	2,055,185.00
18	Fuel Expense-Coal	$	9,388,937.51	9,136,221.71	7,240,469.21	14,273,343.92	14,070,545.49	15,073,997.60	12,759,450.01	13,666,801.92	15,252,102.81	12,440,920.75	8,622,590.28	6,942,649.02	138,868,030.23
19	Fuel Expense-Gas	$	570,931.13	456,001.76	633,253.82	2,365,212.17	4,670,666.35	730,456.56	340,715.88	972,483.64	441,023.55	665,501.08	546,640.00	528,630.31	12,921,516.25
20	Non-Firm Purchases	$	3,057,226.56	2,261,340.91	8,319,121.12	18,739,777.48	15,878,714.12	3,809,004.44	1,801,892.16	6,229,166.97	7,855,057.23	4,865,362.41	2,104,562.47	2,163,843.76	77,085,069.63
21	Third Party Transmission	$	371,978.28	322,544.48	1,029,307.20	1,122,875.44	978,682.44	325,744.11	347,500.02	206,219.73	243,883.78	286,977.48	251,820.66	324,477.28	5,812,010.90
22	Surplus Sales	$	(4,452,277.35)	(8,213,149.29)	(4,500,060.30)	(2,908,249.71)	(2,977,705.82)	(5,109,309.86)	(3,670,472.37)	(3,097,567.96)	(6,214,673.29)	(12,245,789.97)	(7,129,493.70)	(9,558,816.59)	(70,077,566.21)
23	Hoku 1st Block Energy	$	(25,732.27)	(1,229.06)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	Total Non-QF	$	9,948,755.07	7,343,767.14	16,773,419.47	33,849,885.54	35,542,378.94	15,107,753.06	12,834,130.97	17,873,087.52	20,654,676.99	7,853,694.13	6,285,041.92	2,040,259.54	186,106,850.29
25															
26	**BASE**														
27	Water for Power (Leases)	$	4,734.00	4,664.00	153,090.00	190,953.00	204,643.00	179,325.00	133,942.00	125,889.00	145,752.00	160,237.00	149,325.00	135,069.00	1,587,623.00
28	Fuel Expense-Coal	$	9,357,518.00	9,219,352.00	14,041,049.00	17,513,694.00	18,769,296.00	16,447,224.00	12,284,817.00	11,546,178.00	13,367,949.00	14,696,534.00	13,695,653.00	12,388,199.00	163,327,463.00
29	Fuel Expense-Gas	$	429,483.00	423,141.00	507,539.00	633,064.00	678,450.00	594,515.00	444,057.00	417,357.00	483,209.00	531,233.00	495,054.00	447,794.00	6,084,896.00
30	Non-Firm Purchases	$	4,012,962.00	3,953,710.00	5,583,131.00	6,963,955.00	7,463,219.00	6,539,896.00	4,884,802.00	4,591,097.00	5,315,486.00	5,843,770.00	5,445,791.00	4,925,909.00	65,523,728.00
31	Third Party Transmission	$	734,112.00	723,272.00	691,679.00	862,746.00	924,599.00	810,211.00	605,165.00	568,779.00	658,522.00	723,969.00	674,665.00	610,258.00	8,587,977.00
32	Surplus Sales	$	(8,173,502.00)	(8,052,819.00)	(7,755,827.00)	(9,674,005.00)	(10,367,560.00)	(9,084,921.00)	(6,785,741.00)	(6,377,740.00)	(7,384,028.00)	(8,117,896.00)	(7,565,042.00)	(6,842,846.00)	(96,181,927.00)
33	Net 95% Items	$	6,365,307.00	6,271,320.00	13,220,661.00	16,490,407.00	17,672,647.00	15,486,250.00	11,567,042.00	10,871,560.00	12,586,890.00	13,837,847.00	12,895,446.00	11,664,383.00	148,929,760.00
34															
35	Change From Base	$	3,583,448.07	1,072,447.14	3,552,758.47	17,359,478.54	17,869,731.94	(378,496.94)	1,267,088.97	7,001,527.52	8,067,786.99	(5,984,152.87)	(6,610,404.08)	(9,624,123.46)	37,177,090.29
36	Emission Allowance Sales Credit	$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
37	Renewable Energy Credit Sales		(1,037,448.84)	10,739.48	(476,753.73)	505.67	(555,009.78)	(366,860.66)	(449,562.20)	(474,280.32)	(435,464.51)	(614,203.85)	(500,118.59)	(750,661.92)	(5,649,119.25)
38	Subtotal	$	2,545,999.23	1,083,186.62	3,076,004.74	17,359,984.21	17,314,722.16	(745,357.60)	817,526.77	6,527,247.20	7,632,322.48	(6,598,356.72)	(7,110,522.67)	(10,374,785.38)	31,527,971.04
39															
40	Sharing Percentage		95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
41	Idaho Allocation		94.8%	94.8%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
42															
43	**Non-QF Deferral**	$	2,292,926.91	975,517.87	2,776,094.28	15,667,385.75	15,626,536.75	(672,685.23)	737,817.91	5,890,840.60	6,888,171.04	(5,955,016.94)	(6,417,246.71)	(9,363,243.81)	28,447,098.42
44															
45	Actual QF (Includes Net Metering & Raft River 100	$	3,138,812.56	4,806,159.19	7,042,313.92	7,749,956.61	7,523,823.99	6,098,940.40	4,756,343.16	4,167,830.65	4,411,185.38	5,122,517.68	5,186,221.80	4,788,368.90	64,792,474.24
46	Base QF	$	4,436,330.00	4,370,826.00	5,261,808.00	6,563,163.00	7,033,693.00	6,163,509.00	4,603,670.00	4,326,868.00	5,009,567.00	5,507,447.00	5,132,373.00	4,642,411.00	63,051,665.00
47	Change From Base	$	(1,297,517.44)	435,333.19	1,780,505.92	1,186,793.61	490,130.99	(64,568.60)	152,673.16	(159,037.35)	(598,381.62)	(384,929.32)	53,848.80	145,957.90	1,740,809.24
48															
49	Sharing Percentage		100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	
50	Idaho Allocation		94.8%	94.8%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
51															
52	**QF Deferral**	$	(1,230,046.53)	412,695.86	1,691,480.62	1,127,453.93	465,624.44	(61,340.17)	145,039.50	(151,085.48)	(568,462.54)	(365,682.85)	51,156.36	138,660.01	1,655,493.15
53															
54															
55	**Total Deferral**	$	(3,749,889.30)	(3,569,820.84)	2,890,006.80	14,946,782.56	14,125,933.60	(2,531,381.27)	(567,988.45)	4,394,023.93	4,811,635.60	(7,996,194.08)	(7,932,879.94)	(10,669,816.47)	4,150,412.14
56															
57															
58	Principal Balances														
59															
60	Beginning Balance	$	0.00	(3,749,889.30)	(7,319,710.14)	(4,429,703.34)	10,517,079.22	24,643,012.82	22,111,631.55	21,543,643.10	25,937,667.03	30,749,302.63	22,753,108.55	14,820,228.61	
61															
62	Amount Deferred	$	(3,749,889.30)	(3,569,820.84)	2,890,006.80	14,946,782.56	14,125,933.60	(2,531,381.27)	(567,988.45)	4,394,023.93	4,811,635.60	(7,996,194.08)	(7,932,879.94)	(10,669,816.47)	4,150,412.14
63															
64	Ending Balance	$	(3,749,889.30)	(7,319,710.14)	(4,429,703.34)	10,517,079.22	24,643,012.82	22,111,631.55	21,543,643.10	25,937,667.03	30,749,302.63	22,753,108.55	14,820,228.61	4,150,412.14	
65															
66	Interest Balances														
67															
68	Accrual thru Prior Month	$	0.00	0.00	6,619.68	13,240.05	20,021.72	22,769.64	23,701.35	21,984.40	21,531.86	22,771.16	26,661.50	27,652.98	
69															
70	Monthly Interest Rate **		1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	
71															
72	Monthly Interest Inc/(Exp)	$	0.00	6,619.68	6,620.37	6,781.67	2,744.25	931.71	(1,717.02)	(452.54)	1,239.30	3,888.33	991.48	3,048.93	30,696.16
73	Prior Month's Interest Adjustments	$	0.00	0.00	0.00	0.00	3.67	0.00	0.07	0.00	0.00	2.01	0.00	0.00	5.75
74	Total Current Month Interest	$	0.00	6,619.68	6,620.37	6,781.67	2,747.92	931.71	(1,716.95)	(452.54)	1,239.30	3,890.34	991.48	3,048.93	30,701.91
75															
76	Interest Accrued to date	$	0.00	6,619.68	13,240.05	20,021.72	22,769.64	23,701.35	21,984.40	21,531.86	22,771.16	26,661.50	27,652.98	30,701.91	
77															
78	**Balance in All Accounts**	$	(3,749,889.30)	(7,313,090.46)	(4,416,463.29)	10,537,100.94	24,665,782.46	22,135,332.90	21,565,627.50	25,959,198.89	30,772,073.79	22,779,770.05	14,847,881.59	4,181,114.05	4,181,114.05

Exhibit No. 1
Case No. IPC-E-11-06
M. Larkin, IPC
Page 1 of 3

Power Cost Adjustment
April 2010 thru March 2011

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
79															
80	True-Up of True-Up	$	11,284,406.94	14,815,717.29	6,302,047.71	(604,423.09)	(2,956,235.15)	(5,384,424.46)	(7,513,537.74)	(9,283,635.37)	(10,857,895.77)	(12,721,876.37)	(14,674,533.78)	(16,444,669.29)	11,284,406.94
81	Adjustments:														
82	2009-10 PCA trnsfr per IPUC Ord No. 31093	$	11,963,776.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11,963,776.69
83	Emission Allowance Order No. 30790	$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
84	Interest Adj Per IPUC Order No. 31093	$	0.00	(215,027.26)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(215,027.26)
85	True-Up of True-Up Balance	$	23,248,183.63	14,600,690.03	6,302,047.71	(604,423.09)	(2,956,235.15)	(5,384,424.46)	(7,513,537.74)	(9,283,635.37)	(10,857,895.77)	(12,721,876.37)	(14,674,533.78)	(16,444,669.29)	23,033,156.37
86															
87	Monthly Interest Rate		1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	
88															
89	Monthly Interest	$	19,373.49	12,167.24	5,251.71	(503.69)	(2,463.53)	(4,487.02)	(6,261.28)	(7,736.36)	(9,048.25)	(10,601.56)	(12,228.78)	(13,703.89)	(30,241.92)
90															
91	Monthly Collection	$	8,451,839.83	8,310,809.56	6,911,722.51	2,351,308.37	2,425,725.78	2,124,626.26	1,763,836.35	1,566,524.04	1,854,932.35	1,942,055.85	1,757,906.73	1,694,293.20	41,155,580.83
92															
93	Monthly Collection Applied To Interest	$	19,373.49	12,167.24	5,251.71	(503.69)	(2,463.53)	(4,487.02)	(6,261.28)	(7,736.36)	(9,048.25)	(10,601.56)	(12,228.78)	(13,703.89)	
94															
95	Monthly Collection Applied To Balance	$	8,432,466.34	8,298,642.32	6,906,470.80	2,351,812.06	2,428,189.31	2,129,113.28	1,770,097.63	1,574,260.40	1,863,980.60	1,952,657.41	1,770,135.51	1,707,997.09	41,185,822.75
96															
97	Ending True-Up of the True-Up Balance	$	14,815,717.29	6,302,047.71	(604,423.09)	(2,956,235.15)	(5,384,424.46)	(7,513,537.74)	(9,283,635.37)	(10,857,895.77)	(12,721,876.37)	(14,674,533.78)	(16,444,669.29)	(18,152,666.38)	(18,152,666.38)
98															
99	* Negative amounts indicate benefit to the ratepayers.														
100	** Interest rate changed per IPUC Order No. 30965 (Jan 2010)														

IPUC Staff Analysis Using Aurora Modeled
Base Net Power Supply Costs

Power Cost Adjustment April 2010 thru March 2011		April	May	June	July	August	September	October	November	December	January	February	March	Totals
PCA Revenue														
Normalized Idaho Jurisdictional Sales		968,949	998,195	1,123,624	1,316,280	1,400,447	1,280,168	1,033,366	958,498	1,074,126	1,193,372	1,115,947	1,029,368	13,492,340
PCA Component Rate	$	4.967	4.967	1.404	1.404	1.404	1.404	1.404	1.404	1.404	1.404	1.404	1.404	
Revenue	$	4,812,769.68	4,958,034.57	1,577,568.10	1,848,057.12	1,966,227.59	1,797,355.87	1,450,845.86	1,345,731.19	1,508,072.90	1,675,494.29	1,566,789.59	1,445,232.67	25,952,179.43
Load Change Adjustment														
Actual Firm Load - Adjusted	Mwh	1,038,330	1,127,939	1,260,708	1,676,222	1,518,959	1,232,322	1,053,647	1,134,671	1,264,561	1,295,294	1,105,065	1,117,888	14,825,606
Normalized Firm Load	Mwh	1,077,297	1,254,940	1,412,842	1,685,870	1,594,331	1,225,589	1,100,776	1,130,765	1,380,118	1,356,320	1,177,732	1,160,140	15,556,720
Load Change	Mwh	(38,967)	(127,001)	(152,134)	(9,648)	(75,372)	6,733	(47,129)	3,906	(115,557)	(61,026)	(72,667)	(42,252)	(731,114)
Expense Adjustment (@ $26.63)	$	1,037,691.21	3,382,036.63	4,051,328.42	256,926.24	2,007,156.36	(179,299.79)	1,255,045.27	(104,016.78)	3,077,282.91	1,625,122.38	1,935,122.21	1,125,170.76	19,469,565.82
Actual Non-QF PCA														
Expense Adjustment	$	1,037,691.21	3,382,036.63	4,051,328.42	256,926.24	2,007,156.36	(179,299.79)	1,255,045.27	(104,016.78)	3,077,282.91	1,625,122.38	1,935,122.21	1,125,170.76	19,469,565.82
Water Lease Purchases	$	0.00	0.00	0.00	0.00	914,320.00	457,160.00	0.00	0.00	0.00	215,600.00	(46,200.00)	514,305.00	2,055,185.00
Fuel Expense-Coal	$	9,388,937.51	9,136,221.71	7,240,469.21	14,273,343.92	14,070,545.49	15,073,997.60	12,759,450.01	13,666,801.92	15,252,102.81	12,440,920.75	8,622,590.28	6,942,649.02	138,868,030.23
Fuel Expense-Gas	$	570,931.13	456,001.76	633,253.82	2,365,212.17	4,670,666.35	730,456.56	340,715.88	972,483.64	441,023.55	665,501.08	546,640.00	528,630.31	12,921,516.25
Non-Firm Purchases	$	3,057,226.56	2,261,340.91	8,319,121.12	18,739,777.48	15,878,714.12	3,809,004.44	1,801,892.16	6,229,166.97	7,855,057.23	4,865,362.41	2,104,562.47	2,163,843.76	77,085,069.63
Third Party Transmission	$	371,978.28	322,544.48	1,029,307.20	1,122,875.44	978,682.44	325,744.11	347,500.02	206,219.73	243,883.78	286,977.48	251,820.66	324,477.28	5,812,010.90
Surplus Sales	$	(4,452,277.35)	(8,213,149.29)	(4,500,060.30)	(2,908,249.71)	(2,977,705.82)	(5,109,309.86)	(3,670,472.37)	(3,097,567.96)	(6,214,673.29)	(12,245,789.97)	(7,129,493.70)	(9,558,816.59)	(70,077,566.21)
Hoku 1st Block Energy	$	(25,732.27)	(1,229.06)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(26,961.33)
Total Non-QF	$	9,948,755.07	7,343,767.14	16,773,419.47	33,849,885.54	35,542,378.94	15,107,753.06	12,834,130.97	17,873,087.52	20,654,676.99	7,853,694.13	6,285,041.92	2,040,259.54	186,106,850.29
BASE														
Water for Power (Leases)	$	4,734.00	4,664.00	153,090.00	190,953.00	204,643.00	179,325.00	133,942.00	125,889.00	145,752.00	160,237.00	149,325.00	135,069.00	1,587,623.00
Fuel Expense-Coal	$	7,770,564.00	9,055,548.00	12,393,708.00	15,747,018.00	15,883,486.00	15,010,748.00	15,775,050.00	15,582,187.00	16,035,736.00	14,658,737.00	13,338,355.00	14,190,740.00	165,441,877.00
Fuel Expense-Gas	$	412,108.00	316,922.00	304,992.00	1,369,935.00	1,546,814.00	314,293.00	340,729.00	321,462.00	330,153.00	314,266.00	286,321.00	314,261.00	6,172,256.00
Non-Firm Purchases	$	1,622,208.00	2,041,687.00	6,520,825.00	19,530,516.00	16,967,618.00	4,356,873.00	1,942,820.00	3,386,539.00	5,383,755.00	2,558,010.00	1,466,135.00	1,154,042.00	66,931,028.00
Third Party Transmission	$	734,112.00	723,272.00	691,679.00	862,746.00	924,599.00	810,211.00	605,165.00	568,779.00	658,522.00	723,969.00	674,665.00	610,258.00	8,587,977.00
Surplus Sales	$	(16,822,354.00)	(10,712,129.00)	(6,617,532.00)	(1,138,499.00)	(703,684.00)	(4,551,802.00)	(9,373,288.00)	(6,051,829.00)	(7,398,034.00)	(7,653,667.00)	(13,050,062.00)	(15,406,815.00)	(99,479,695.00)
Net 95% Items (1)	$	(6,278,628.00)	1,429,964.00	13,446,762.00	36,562,669.00	34,823,476.00	16,119,648.00	9,424,418.00	13,933,027.00	15,155,884.00	10,761,552.00	2,864,739.00	997,555.00	149,241,066.00
Change From Base	$	16,227,383.07	5,913,803.14	3,326,657.47	(2,712,783.46)	718,902.94	(1,011,894.94)	3,409,712.97	3,940,060.52	5,498,792.99	(2,907,857.87)	3,420,302.92	1,042,704.54	36,865,784.29
Emission Sales Allowance Credit	$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Renewable Energy Credit Sales	$	(1,037,448.84)	10,739.48	(476,753.73)	505.67	(555,009.78)	(366,860.66)	(449,562.20)	(474,280.32)	(435,464.51)	(614,203.85)	(500,118.59)	(750,661.92)	(5,649,119.25)
Subtotal	$	15,189,934.23	5,924,542.62	2,849,903.74	(2,712,277.79)	163,893.16	(1,378,755.60)	2,960,150.77	3,465,780.20	5,063,328.48	(3,522,061.72)	2,920,184.33	292,042.62	31,216,665.04
Sharing Percentage		95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%
Idaho Allocation		94.8%	94.8%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	94.8%/95%
Non QF Deferral	$	13,680,054.77	5,335,643.08	2,572,038.13	(2,447,830.71)	147,913.58	(1,244,326.93)	2,671,536.07	3,127,866.63	4,569,653.95	(3,178,660.70)	2,635,466.36	263,568.46	28,132,922.69
Actual QF (Includes Net Metering)	$	3,138,812.56	4,806,159.19	7,042,313.92	7,749,956.61	7,523,823.99	6,098,940.40	4,756,343.16	4,167,830.65	4,411,185.38	5,122,517.68	5,186,221.80	4,788,368.90	64,792,474.24
Base QF (1)	$	4,113,148.00	5,203,607.00	7,885,376.00	8,327,866.00	7,899,332.00	6,242,936.00	4,444,040.00	3,906,703.00	4,287,766.00	3,672,053.00	3,712,258.00	3,298,933.00	62,994,018.00
Change From Base	$	(974,335.44)	(397,447.81)	(843,062.08)	(577,909.39)	(375,508.01)	(143,995.60)	312,303.16	261,127.65	123,419.38	1,450,464.68	1,473,963.80	1,489,435.90	1,798,456.24
Sharing Percentage		100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Idaho Allocation		94.8%	94.8%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	94.8%/95%
QF Deferral	$	(923,670.00)	(376,780.52)	(800,908.98)	(549,013.92)	(356,732.61)	(136,795.82)	296,688.00	248,071.27	117,248.41	1,377,941.45	1,400,265.61	1,414,964.11	1,711,276.99
Total Deferral	$	7,943,615.09	827.99	193,561.05	(4,844,901.75)	(2,175,046.62)	(3,178,478.62)	1,517,378.21	2,030,206.71	3,178,829.46	(3,476,213.55)	2,468,942.38	233,299.90	3,892,020.26
(1) Includes original base as provided by the Aurora Model														
Principal Balances														
Beginning Balance	$	-	7,943,615.09	7,944,443.08	8,138,004.13	3,293,102.38	1,118,055.76	(2,060,422.86)	(543,044.65)	1,487,162.06	4,665,991.53	1,189,777.98	3,658,720.36	
Amount Deferred	$	7,943,615.09	827.99	193,561.05	(4,844,901.75)	(2,175,046.62)	(3,178,478.62)	1,517,378.21	2,030,206.71	3,178,829.46	(3,476,213.55)	2,468,942.38	233,299.90	3,892,020.26
Ending Balance	$	7,943,615.09	7,944,443.08	8,138,004.13	3,293,102.38	1,118,055.76	(2,060,422.86)	(543,044.65)	1,487,162.06	4,665,991.53	1,189,777.98	3,658,720.36	3,892,020.26	
Interest Balances														
Accrual thru Prior Month	$	0.00	0.00	6,619.68	13,240.05	20,021.72	22,769.64	23,701.35	21,984.40	21,531.86	22,771.16	26,661.50	27,652.98	
Monthly Interest Rate **		1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	
Monthly Interest Inc/(Exp)	$	0.00	6,619.68	6,620.37	6,781.67	2,744.25	931.71	(1,717.02)	(452.54)	1,239.30	3,888.33	991.48	3,048.93	30,696.16
Prior Month's Interest Adjustments	$	0.00	0.00	0.00	0.00	3.67	0.00	0.07	0.00	0.00	2.01	0.00	0.00	5.75
Total Current Month Interest	$	0.00	6,619.68	6,620.37	6,781.67	2,747.92	931.71	(1,716.95)	(452.54)	1,239.30	3,890.34	991.48	3,048.93	30,701.91
Interest Accrued to date	$	0.00	6,619.68	13,240.05	20,021.72	22,769.64	23,701.35	21,984.40	21,531.86	22,771.16	26,661.50	27,652.98	30,701.91	
Balance in All Accounts	$	7,943,615.09	7,951,062.76	8,151,244.18	3,313,124.10	1,140,825.40	(2,036,721.51)	(521,060.25)	1,508,693.92	4,688,762.69	1,216,439.48	3,686,373.34	3,922,722.17	3,922,722.17

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-11-06

IDAHO POWER COMPANY

LARKIN, DI
TESTIMONY

EXHIBIT NO. 2

Idaho Power Company
Calculation of PCA Rate by Class
State of Idaho
Case No. IPC-E-11-06

Line No		Rate Schedule No	(1) Test Year Rider Applicable Revenue (1)	(2) Authorized DSM Rider Deferral Balance Recovery	(3) Test Year Billed kWh (1)	(4) DSM Recovery Rate Cents per kWh	(5) Uniform PCA Rate Cents per kWh	(6) Total PCA Rate Cents per kWh
1	Residential Service	1,3,4,5	$373,098,248	$4,586,919	4,997,560,536	0.0918	(0.0629)	0.0289
2	Small General Service	7	$14,215,377	$174,766	149,738,642	0.1168	(0.0629)	0.0539
3	Large General Service - Secondary	9S	$168,992,758	$2,077,619	3,105,385,167	0.0669	(0.0629)	0.0040
4	Large General Service - Primary	9P	$18,193,900	$223,678	401,521,169	0.0558	(0.0629)	(0.0071)
5	Large General Service - Transmission	9T	$113,461	$1,395	2,488,740	0.0561	(0.0629)	(0.0068)
6	Dusk to Dawn Lighting	15	$1,112,399	$13,676	6,562,095	0.2084	(0.0629)	0.1455
7	Large Power Service - Secondary	19S	$322,729	$3,968	7,166,303	0.0554	(0.0629)	(0.0075)
8	Large Power Service - Primary	19P	$80,418,370	$988,674	2,008,182,401	0.0492	(0.0629)	(0.0137)
9	Large Power Service - Transmission	19T	$1,639,317	$20,154	43,858,733	0.0461	(0.0629)	(0.0168)
10	Agricultural Irrigation Service	24	$101,574,213	$1,248,767	1,679,705,737	0.0743	(0.0629)	0.0114
11	Unmetered General Service	40	$1,046,755	$12,869	16,000,941	0.0804	(0.0629)	0.0175
12	Street Lighting	41	$2,742,058	$33,711	23,018,849	0.1466	(0.0629)	0.0837
13	Traffic Control Lighting	42	$157,859	$1,941	3,477,113	0.0557	(0.0629)	(0.0072)
14	Total Uniform Tariffs		$763,627,444	$9,388,136	12,444,666,426			
15	Special Contracts:							
16	Micron	26	$16,000,606	$196,714	466,741,299	0.0421	(0.0629)	(0.0208)
17	J R Simplot	29	$5,802,147	$71,332	180,758,797	0.0395	(0.0629)	(0.0234)
18	DOE	30	$7,988,553	$98,212	251,548,881	0.0391	(0.0629)	(0.0238)
19	Hoku	32	$19,977,510	$245,606	134,695,800	0.1824	(0.0629)	0.1195
20	Total Special Contracts		$49,768,816	$611,864	1,033,744,777			
21	Total Idaho Jurisdiction		$813,396,260	$10,000,000	13,478,411,203			

(1) June 1, 2011 through May 31, 2012 forecasted test year

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-11-06

IDAHO POWER COMPANY

LARKIN, DI
TESTIMONY

EXHIBIT NO. 3

Idaho Power Company
Calculation of Revenue Impact
State of Idaho
PCA w/ DSM Recovery Funding
Filed April 15, 2011

Summary of Revenue Impact

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers (1)	Normalized Energy (kWh) (1)	Current Billed Revenue	Mills Per kWh	Total Adjustments to Billed Revenue	Proposed Total Billed Revenue	Mills Per kWh	Percent Change Billed to Billed Revenue
	Uniform Tariff Rates:									
1	Residential Service	1	398,890	4,990,482,967	$394,209,984	78.99	($14,098,114)	$380,111,870	76.17	(3.58)%
2	Master Metered Mobile Home Park	3	22	5,160,634	$388,537	75.29	($14,579)	$373,958	72.46	(3.75)%
3	Residential Service Energy Watch	4	42	741,745	$57,719	77.82	($2,096)	$55,623	74.99	(3.63)%
4	Residential Service Time-of-Day	5	74	1,175,190	$91,440	77.81	($3,320)	$88,120	74.98	(3.63)%
5	Small General Service	7	28,258	149,738,642	$14,911,514	99.58	($385,577)	$14,525,937	97.01	(2.59)%
6	Large General Service	9	31,067	3,509,395,076	$198,228,379	56.49	($10,832,718)	$187,395,661	53.40	(5.46)%
7	Dusk to Dawn Lighting	15	0	6,562,095	$1,132,831	172.63	($10,886)	$1,121,945	170.97	(0.96)%
8	Large Power Service	19	115	2,059,207,437	$88,792,784	43.12	($6,695,398)	$82,097,386	39.87	(7.54)%
9	Agricultural Irrigation Service	24	16,710	1,679,705,737	$106,804,816	63.59	($5,039,118)	$101,765,698	60.59	(4.72)%
10	Unmetered General Service	40	1,984	16,000,941	$1,096,581	68.53	($47,027)	$1,049,554	65.59	(4.29)%
11	Street Lighting	41	314	23,018,849	$2,813,736	122.24	($52,414)	$2,761,322	119.96	(1.86)%
12	Traffic Control Lighting	42	358	3,477,113	$168,689	48.51	($11,078)	$157,611	45.33	(6.57)%
13	Total Uniform Tariffs		477,834	12,444,666,426	$808,697,010	64.98	($37,192,325)	$771,504,685	61.99	(4.60)%
15	Special Contracts:									
16	Micron	26	1	466,741,299	$17,454,039	37.40	($1,550,514)	$15,903,525	34.07	(8.88)%
17	J R Simplot	29	1	180,758,797	$6,365,029	35.21	($605,181)	$5,759,848	31.86	(9.51)%
18	DOE	30	1	251,548,881	$8,771,875	34.87	($843,192)	$7,928,683	31.52	(9.61)%
19	Hoku (Retail Only)	32	1	134,695,800	$5,703,826	42.35	($258,482)	$5,445,344	40.43	(4.53)%
20	Total Special Contracts		4	1,033,744,777	$38,294,769	37.04	($3,257,369)	$35,037,400	33.89	(8.51)%
22	Total Idaho Retail Sales		477,838	13,478,411,203	$846,991,779	62.84	($40,449,694)	$806,542,085	59.84	(4.78)%

(1) June 1, 2011 - May 31, 2012 Forecasted PCA Test Year