ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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IDAHO PUBLIC UTILITIES COMMISSION

201 South Main, Suite 2300
Salt Lake City, Utah 84111

February 1, 2012

VIA OVERNIGHT DELIVERY

NEW CASE

Jean D. Jewell
Commission Secretary
Idaho Public Utilities Commission
472 W. Washington
Boise, ID 83702

Re: Case No. PAC-E-12-03
In the Matter of the Application of Rocky Mountain Power for Authority to Increase Rates by $2.6 Million to Recover Deferred Net Power Costs Through the Energy Cost Adjustment Mechanism

Dear Ms. Jewell:

Please find enclosed an original and nine copies of Rocky Mountain Power's Application in the above referenced matter, along with Rocky Mountain Power's direct testimony and exhibits. Also enclosed is a CD containing the Application, direct testimony, exhibits and confidential work papers.

All formal correspondence and questions regarding this Application should be addressed to:

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Communications regarding discovery matters, including data requests issued to Rocky Mountain Power, should be addressed to the following:

By E-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah St., Suite 2000
Portland, OR 97232

Informal inquiries may be directed to Ted Weston, Idaho Regulatory Manager at (801) 220-2963.

Very truly yours,

Jeffrey K. Larsen/B

Jeffrey K. Larsen
Vice President, Regulation

Enclosures

Mark C. Moench
Yvonne R. Hogle (pro hac vice application pending)
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NEW CASE

Attorneys for Rocky Mountain Power

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO INCREASE RATES BY $2.6 MILLION TO RECOVER DEFERRED NET POWER COSTS THROUGH THE ENERGY COST ADJUSTMENT MECHANISM	)	**CASE NO. PAC-E-12-03** **APPLICATION OF ROCKY MOUNTAIN POWER**

Rocky Mountain Power, a division of PacifiCorp ("Company" or "Rocky Mountain Power"), in accordance with Idaho Code §61-502, §61-503, and RP 052, hereby respectfully submits this application ("Application") to the Idaho Public Utilities Commission ("Commission") pursuant to its approved energy cost adjustment mechanism ("ECAM"), requesting approval to adjust Schedule 94, Energy Cost Adjustment, and establish the ECAM rate for all customer classes including Monsanto Company ("Monsanto") and Agrium, Inc. ("Agrium") based on the deferral period beginning December 1, 2010 through November 30, 2011 ("Deferral Period"). The Company is requesting approval to add $18.1 million into the ECAM balancing account

for the Deferral Period. This addition would bring the total balance of the account to $24.1 million as of November 30, 2011. The Company is also proposing to adjust Schedule 94 to collect approximately $13.0 million over the period beginning April 1, 2012 through March 31, 2013, representing an increase of $2.6 million over Schedule 94 rates currently in effect as approved in Order No. 32216 of Case No. PAC-E-11-07. Rocky Mountain Power respectfully requests that this increase in Idaho rates become effective on April 1, 2012, pursuant to Schedule 94. In support of its Application, Rocky Mountain Power states as follows:

1. Rocky Mountain Power is a division of PacifiCorp, an Oregon corporation, which provides electric service to retail customers through its Rocky Mountain Power division in the states of Idaho, Wyoming, and Utah. Rocky Mountain Power is a public utility in the state of Idaho and is subject to the Commission's jurisdiction with respect to its prices and terms of electric service to retail customers in Idaho. Rocky Mountain Power is authorized to do and is doing business in the state of Idaho providing retail electric service to approximately 73,000 customers in the state.

2. Communications regarding this filing should be addressed to:

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3. In addition, Rocky Mountain Power requests that all data requests regarding this Application should be sent in Microsoft Word or plain text format to the following:

By email (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 Multnomah, Suite 2000
Portland, Oregon 97232

Informal questions may be directed to Ted Weston, Idaho Regulatory Affairs Manager at (801) 220-2963.

Brief Overview of the ECAM

4. On October 23, 2008, Rocky Mountain Power filed an application with the Commission, Case No. PAC-E-08-08, seeking approval of an ECAM. After meeting with staff and other parties over a period of approximately four months, the Company and the parties entered into a stipulation agreeing to the type of ECAM that would be acceptable to all the parties. On June 29, 2009, the parties filed said ECAM Stipulation with the Commission.

5. On September 29, 2009, by Order No. 30904 issued in Case No. PAC-E-08-08, the Commission approved the implementation of an annual ECAM.

6. By agreement, the costs that are to be included in the ECAM are net power costs ("NPC") that are defined in the Company's general rate cases and modeled by the Company's production dispatch model GRID. Specifically, base and actual NPC include amounts booked to the following FERC accounts:

- Account 447 (sales for resale, excluding on-system wholesale sales and other revenues not modeled in GRID),

- Account 501 (fuel, steam generation, excluding fuel handling, start up fuel/gas, diesel fuel, residual disposal and other costs not modeled in GRID),
- Account 503 (steam from other sources),
- Account 547 (fuel, other generation),
- Account 555 (purchased power, excluding BPA residential exchange credit pass-through if applicable), and
- Account 565 (transmission of electricity by others).

7. The ECAM allows the Company to collect or credit the differences between the actual NPC incurred to serve customers in Idaho and the NPC collected from Idaho customers through rates set in general rate cases.

8. On a monthly basis, the Company compares the actual system net power costs ("Actual NPC") to the net power costs embedded in rates ("Base NPC") from the effective general rate case during the Deferral Period (i.e., for this Deferral Period, the Company used Base NPC established in Case No. PAC-E-08-07 from December 1 – December 27, 2010 and Base NPC established in Case No. PAC-E-10-07 from December 28, 2010 – November 30, 2011), and defers the differences into the ECAM balancing account. This comparison is on a system-wide basis and on a dollar per megawatt-hour basis.

9. In addition to the comparison of Actual NPC to Base NPC, the ECAM includes five additional components: the Load Growth Adjustment Rate ("LGAR") or Load Change Adjustment Rate ("LCAR")[1], a credit for SO_2 allowance sales, an adjustment for the treatment of coal stripping costs, a renewable resource adder for

[1] The LGAR was changed to the "LCAR", pursuant to the Commission's Order No. 32206.

renewable resources that are not yet in rate base and a true-up of Renewable Energy Credit ("REC") revenues, as authorized by the Commission in Order No. 32196. These components are described in more detail below.

10. Finally, the ECAM includes a symmetrical sharing band of 90 percent (customers) / 10 percent (Company) that shares the NPC differential between Actual NPC and Base NPC, LCAR, SO_2 sales, and the coal stripping costs adjustment between the customers and the Company. The sharing band is also described in more detail below.

Proposed Deferred ECAM Rate Increase

11. In support of this Application, Rocky Mountain Power has filed the testimony and exhibits of Company witnesses Gregory N. Duvall and William R. Griffith. Mr. Duvall's testimony and exhibit describes the Actual NPC incurred by the Company to serve retail load for the historical twelve-month period ended November 30, 2011 and explains the main increases between Actual NPC and Base NPC. Mr. Griffith's testimony supports the new ECAM tariff surcharge rates to be effective April 1, 2012 through March 31, 2013 for Monsanto and Agrium.

12. Effective January 1, 2011, Monsanto's and Agrium's loads are included in the calculation of the ECAM balances in this ECAM filing. As of December 31, 2010, Monsanto's and Agrium's tariff contracts expired and, pursuant to a stipulation entered into and approved in Order No. 30904, Case No. PAC-E-08-08, the two customers' loads were to be included as part of the ECAM calculation in this case, along with all other retail customers' loads. In addition, as indicated in the stipulation approved by the Commission in Order No. 32432 in Case No. PAC-E-11-12, the Company will amortize and collect Monsanto's and Agrium's share of the Commission-approved 2011 ECAM balances over three years.

13. In this Application, confidential **Exhibit 1** ("Exhibit 1") to Mr. Duvall's testimony illustrates the detailed calculation of the deferred NPC adjustment. Starting with the base NPC in the amount of approximately $1.02 billion, previously approved by the Commission in its Order 32196, the Company takes the monthly NPC from that amount and divides it by the monthly normalized load used to determine NPC to express the costs on a dollar per megawatt-hour basis [line 1 of **Exhibit 1**][2]. The actual NPC rate on a dollar per megawatt-hour basis is then calculated by taking the monthly actual NPC and dividing it by the actual monthly system load [line 4 of **Exhibit 1**].

14. Next, the deferral amount is calculated on a monthly basis by subtracting the monthly base NPC rate from the actual NPC rate. This results in a monthly NPC rate differential [line 5 of **Exhibit 1**] which is then multiplied by three groups of actual Idaho retail load at input: tariff customers, Monsanto and Agrium [lines 6 through 8, **Exhibit 1**,] to calculate the NPC differential for deferral for each group [lines 10-13, **Exhibit 1**]. For the 12-month period ended November 30, 2011, the NPC differential for deferral was approximately $18.6 million before the 90/10 sharing [line 13 of **Exhibit 1**].

15. As described in Mr. Duvall's testimony, the LCAR is a symmetrical adjustment to offset over or under collection of the Company's production energy related revenue requirement, excluding NPC, due to variances in Idaho load. Pursuant to Commission Order No. 30904, the initial Commission-approved symmetrical LGAR was $17.48 per megawatt-hour. This was updated by Commission approval to $21.89 per megawatt-hour beginning December 28, 2010, and further updated by Commission approval beginning in April 2011, to $5.47 per megawatt-hour. Lines 23 through 26 of

[2] Base NPC Rate and Load from Case No. PAC-E-08-07 in the amount of $987 million were used through 12/27/10. Base NPC Rate and Load from Case No. PAC-E-10-07 in the amount of $1.02 billion were used since 12/28/11.

Exhibit 1 in Mr. Duvall's testimony illustrate the total LCAR adjustment used in this case.

16. Under this Application, credits for SO_2 allowance sales revenues received by the Company from December 1, 2010 to November 30, 2011 are included as an offset to the NPC deferral. Mr. Duvall's testimony describes how the SO_2 sales revenues were offset against deferred NPC in this docket. Line 29 of **Exhibit 1** in Mr. Duvall's testimony contains the SO_2 sales revenues that are credited against the NPC differential for deferral.

17. Line 30 of **Exhibit 1** reflects Idaho's allocated differences between excluding coal stripping costs incurred by the Company and recorded on the Company's books pursuant to the guidance of the accounting pronouncement EITF 04-6, and the amortization of the coal stripping costs when the coal was excavated. The EITF 04-6 deferral adjustment on line 30 of **Exhibit 1** is added to the NPC differential for deferral.

18. Lines 39 through 41 of **Exhibit 1** show the total NPC deferral adjusted for LCAR revenue, SO2 revenue, and EITF 04-6 deferral for tariff customers, Monsanto and Agrium.

19. A sharing band between customers and the Company is included such that customers pay/receive the increase/decrease in Actual NPC when compared to Base NPC, and the Company incurs/retains the remaining 10 percent. The sharing bands also apply to the SO_2, the LCAR and the coal stripping costs. Lines 44 through Line 47 of **Exhibit 1** in Mr. Duvall's testimony summarize by customer groups the customers' (tariff customers', Monsanto's and Agrium's) share of these components

20. As approved in Case No. PAC-E-08-08, the ECAM includes a renewable resource adder which has been used in prior ECAM filings but which ended on the

effective date of rates set in the 2010 rate case (Case No. PAC-E-10-07). Thus, the adder was only applicable to the first 27 days in December 2010 prior to the effective date of the rates set in the 2010 rate case. The renewable resource adder recognizes that the Company has made significant investments in renewable generation projects that were not included in rates effective during 27 days of the Deferral Period, even though these projects provide significant benefits to customers. Specifically, the adjustment recognizes that actual NPC were reduced by power generated from these renewable generation projects. Pursuant to Commission Order No. 30904, the Commission approved a renewable resource adjustment of $55.00 per megawatt-hour multiplied by the prorated actual megawatt-hour output generated in the first 27 days of December 2010 from those renewable resources that were not included in rates during the Deferral Period [line 48, **Exhibit 1**]. Line 50 of **Exhibit 1** reflects this adjustment on a total Company basis. The total Company amount is allocated to Idaho [line 52, **Exhibit 1**] based on the System Generation allocation factor ("SG"), which is further prorated to include only tariff customers' load [line 54, **Exhibit 1**].

21. In addition to the ECAM calculation components discussed above, the deferral balance reflects the difference between actual REC revenues during the Deferral Period and the amount of REC revenues included in base rates. The REC revenue true-up included in the ECAM is symmetrical but no sharing band is applied. In the current filing, the REC revenues are prorated beginning on December 28, 2010, 27 days less than the full twelve-month Deferral Period. Idaho's actual REC revenues for that same time period are located on line 61, **Exhibit 1**.

22. The deferred ECAM balance of $24.1 million as of November 30, 2011 [line 85, **Exhibit 1**] is the sum of the components described above: 90% X (deferred NPC

+ LCAR + SO_2 revenues+ coal stripping costs adjustment) + the renewable resource adder + interest charges + REC revenues. Lines 64 through 70 of **Exhibit 1** in Mr. Duvall's testimony illustrate the detailed calculations for standard tariff customers, with an ending balance of $16.3 million; lines 72 through77 illustrate the detailed calculations for Monsanto, with an ending balance of $7.2 million; and lines 79 through 84 illustrate the detailed calculations for Agrium, with an ending balance of $.5 million. The sum of the three groups' ending balances validates the total ending balance of $24.1 million. The Company will amortize and collect Monsanto's and Agrium's share of the deferral balance, as approved by the Commission in this case, over three years pursuant to the stipulation approved by the Commission in Order No. 32432.

23. The Company is not requesting a change in the ECAM surcharge rate to recover the full $24.1 million deferral at this time. The Company estimates that approximately $3.0 million of the balance will be recovered through Schedule 94 rates from December 1, 2011 to March 31, 2012. Any over or under collection of this amount will be addressed in future ECAM filings. In addition, the Company is not requesting a change to existing Schedule 94 rates for standard tariff customers at this time as it anticipates that an increase in the collection rate this year would be followed by a decrease in the rate next year.

Allocation of Deferred ECAM to Retail Tariffs

24. As previously stated, Mr. Griffith's testimony describes in greater detail the calculation of the proposed Schedule 94 rates for Monsanto and Agrium. **Exhibit 2** of Mr. Griffith's testimony illustrates the allocation of the initial collection rate for each of the two customers and the billing determinants used. **Exhibit 3** is tariff Schedule 94 containing the proposed rates by electric service schedule.

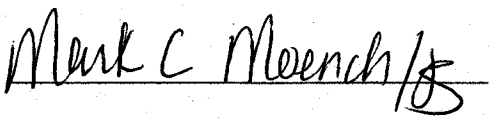
25. Rocky Mountain Power is notifying its customers of this Application by, among other means, issuing a press release sent to local media organizations and messages in customer bills over the course of a billing cycle. In addition, copies of this Application will be made available for review at the Company's local offices in its Idaho service territory.

26. WHEREFORE, Rocky Mountain Power respectfully requests that the Commission issue an order (1) authorizing that this matter be processed by Modified Procedure; (2) approve the ECAM deferred balance; and (3) implement the proposed electric service Schedule 94 as filed in **Exhibit 3.**

DATED this 1st day of February 2012.

Respectfully submitted,

ROCKY MOUNTAIN POWER



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A DIVISION OF PACIFICORP

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No change proposed for residential and commercial customers in Rocky Mountain Power's annual energy cost adjustment request

BOISE, ID Wednesday, Feb. 1, 2012— Rocky Mountain Power's annual energy cost adjustment for 2012 proposes no increase for residential or commercial customers, and a modest increase for two large industrial customers.

The energy cost adjustment mechanism is designed to track the difference between the company's actual costs to provide electricity to customers and the amount collected from customers through current prices. If the commission approves, the adjustment would take effect April 1, 2012.

Because of increases in fuel and other costs to produce and purchase the electricity customers need, the proposed adjustment will allow Rocky Mountain Power to continue to provide safe, reliable electric service to its customers.

The company's proposal requests that the Idaho Public Utilities Commission approve deferral of the 2011 energy related costs of $18.1 million and adjust the energy cost adjustment rider, Schedule 94, by $2.6 million. Those costs will be collected from two large industrial customers who previously were not covered by Schedule 94. The company is proposing no change to standard tariff customer prices.

The proposed increase would have the following impacts:

- Residential, commercial and most industrial customers – no change to current rates
- Industrial customer served on tariff Schedule 400 – $2.4 million increase or 3.3 percent
- Industrial customer served on tariff Schedule 401 – $0.2 million increase or 3.2 percent

The public will have an opportunity to comment on the proposal during the coming months as the commission studies the company's request. The commission must approve the proposed changes before they can take effect. A copy of the company's application is available for public review at the commission offices in Boise and at the company's offices in Rexburg, Preston, Shelley and Montpelier.

Idaho Public Utilities Commission
www.puc.idaho.gov/
472 W. Washington
Boise, ID 83702

Rocky Mountain Power offices

- Rexburg – 25 East Main
- Preston – 509 S. 2nd East
- Shelley – 852 E. 1400 North

###

Keeping you **informed**

Rocky Mountain Power requests recovery of power costs.

On February 1, 2012, Rocky Mountain Power asked the Idaho Public Utilities Commission to approve the 2011 deferral of $18.1 million to the energy balancing account and adjust the energy cost adjustment rider by $2.6 million. The company is proposing no change to tariff customer prices with the exception of tariff contract Schedules 400 and 401.

The energy cost adjustment mechanism is designed to track the difference between the company's actual costs to provide electricity to Idaho customers and the amount collected from customers through current prices. If the commission approves, the rider would take effect April 1, 2012.

Because of increases in fuel and other costs to produce and purchase the electricity Idaho customers need, the proposed adjustment will allow Rocky Mountain Power to continue to provide safe, reliable electric service to its customers.

The proposed increase would have the following impacts:

- **Tariff customers Schedules 1 through 36 –** no change to current rates
- **Addition of tariff contract Schedule 400 –** $2.4 million increase or 3.3 percent
- **Addition of tariff contract Schedule 401 –** $0.2 million increase or 3.2 percent

(continued)

The public will have an opportunity to comment on the proposal during the coming months as the commission studies the company's request. The commission must approve the proposed changes before they can take effect. A copy of the company's application is available for public review at the commission offices in Boise and at the company's offices in Rexburg, Preston, Shelley and Montpelier.

Idaho Public Utilities Commission
www.puc.idaho.gov
472 W Washington
Boise, ID 83702

Rocky Mountain Power offices

- Rexburg – 25 East Main
- Preston – 509 S. 2nd E.
- Shelley – 852 E. 1400 N.
- Montpelier – 24852 US Hwy 89

ROCKY MOUNTAIN POWER

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE	)	
APPLICATION OF ROCKY	)	**CASE NO. PAC-E-12-03**
MOUNTAIN POWER FOR	)	
AUTHORITY TO INCREASE RATES	)	**Direct Testimony of Gregory N. Duvall**
BY $2.6 MILLION TO RECOVER	)	**Redacted**
DEFERRED NET POWER COSTS	)	
THROUGH THE ENERGY COST	)	
ADJUSTMENT MECHANISM	)	

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-12-03

February 2012

1 **Q. Please state your name, business address and present position with**
2 **PacifiCorp, dba Rocky Mountain Power (the "Company").**
3 A. My name is Gregory N. Duvall. My business address is 825 NE Multnomah St.,
4 Suite 600, Portland, Oregon 97232. My title is Director, Net Power Costs.
5 **Qualifications**
6 **Q. Briefly describe your education and business experience.**
7 A. I received a degree in Mathematics from the University of Washington in 1976
8 and a Master of Business Administration degree from University of Portland in
9 1979. I was first employed by Pacific Power in 1976 and have held various
10 positions in resource and transmission planning, regulation, resource acquisitions
11 and trading. From 1997 through 2000 I lived in Australia where I managed the
12 Energy Trading Department for Powercor, a PacifiCorp subsidiary at that time.
13 After returning to Portland, I was involved in direct access issues in Oregon and
14 was responsible for directing the analytical effort for the Multi-State Process
15 ("MSP"). Currently, I direct the work of the net power cost group, the load
16 forecasting group, and the renewable compliance area.
17 **Summary of Testimony**
18 **Q. Will you please summarize your testimony?**
19 A. My testimony provides evidence justifying the need to add $18.1 million ("2011
20 Deferral") into the Energy Cost Adjustment Mechanism ("ECAM") balancing
21 account for the 12-month period from December 1, 2010 through November 30,
22 2011 ("Deferral Period"). This would bring the total balance of the account to
23 $24.1 million as of November 30, 2011. In addition, my testimony presents the

1 background and calculation of the Company's ECAM and describes the actual net
2 power costs ("NPC") incurred by the Company to serve retail load during the
3 Deferral Period.

4 **Q. Are additional witnesses presenting testimony in this case?**

5 A. Yes. Mr. William R. Griffith, Director, Pricing, Cost of Service & Regulatory
6 Operations, is sponsoring testimony supporting new tariff surcharge rates for
7 Monsanto and Agrium for inclusion in Tariff Schedule 94 with an initial
8 collection rate of approximately $2.6 million. The existing surcharge for other
9 customers will remain unchanged.[1] When combined with the existing surcharge
10 rate for other customers, the Company anticipates that Schedule 94 will collect
11 approximately $13.0 million on an annual basis as compared to the current
12 collection rate of $10.4 million.

13 **Q. What are the components of the $18.1 million 2011 Deferral?**

14 A. The components of the 2011 Deferral are the customers' 90 percent share of the
15 difference between the actual and in-rates NPC, the load growth adjustment
16 revenue and load change adjustment revenue ("LGAR/LCAR"), the sulfur dioxide
17 ("SO_2") allowance sales adjustment, the Emerging Issues Task Force ("EITF")
18 04-6 adjustment, and the renewable resource adder adjustment. Also included is
19 100 percent of the true-up of renewable energy credit ("REC") revenues. More
20 specifically, the $18.1 million is made up of the following:

[1] The Company was authorized to set present Schedule 94 rates that were designed to recover approximately $12.8 million in the 2011 ECAM adjustment, Case No. PAC-E-11-07 using the Company's then-most recent general rate case test period, forecasted 12 months ending December 2010. In this current docket, the Company is using the test period, historic 12 months ending December 2010 from its most recent general rate case, Case No. PAC-E-11-12. Using this most recent test period, present Schedule 94 will collect approximately $10.4 million.

1 • $16.6 million is the customers' share of the NPC differential, net of the
2 LGAR/LCAR, SO_2 sales, and EITF 04-6 deferral balance,
3 • $0.3 million is the renewable resource adder, and
4 • $1.2 million is the REC revenue adjustment.
5 **Q. What is included in the remaining $6 million of the ECAM deferral balance**
6 **that brings the total to $24.1 million?**
7 A. The remaining $6 million of the ECAM deferral balance is made up of the
8 following:
9 • $2.4 million as the second year amortization of the 2010 LGAR deferral,
10 • $3.6 million of uncollected balance from the Company's ECAM filing in
11 2011, plus interest, most of which is expected to be recovered before April 1,
12 2012 under the existing Schedule 94 collection rate.
13 **Q. Based on your calculations, what is the potential amount that would be**
14 **required to be collected from customers under Schedule 94 beginning April**
15 **1, 2012?**
16 A. The combined total for potential collection from customers beginning April 1,
17 2012 is estimated to be $21.1 million, of which retail customers other than
18 Monsanto and Agrium are responsible for $13.4 million, Monsanto is responsible
19 for $7.2 million and Agrium is responsible for $0.5 million.
20 **Q. Is the Company proposing to collect this full amount?**
21 A. No.

1 **Q. How much does the Company propose to collect from customers under**
2 **Schedule 94 beginning April 1, 2012?**
3 A. The Company proposes to collect $10.4 million from retail customers other than
4 Monsanto and Agrium beginning April 1, 2012. This will require no change to the
5 ECAM surcharge rate for theses customers. The surcharge rate for Monsanto and
6 Agrium will be set at approximately $2.6 million to reflect the three year
7 amortization outlined in the stipulation agreed to by the parties and approved by
8 the Commission in the 2011 general rate case.
9 **Q. Do you have a summary of your calculations and proposal?**
10 A. Yes. Table 1 summarizes the Company's calculations of the ECAM balance and
11 the proposal in this case.

Table 1

	Tariff Customers	Monsanto	Agrium	Total
NPC Differential for Deferral	10,532,075	7,460,738	576,204	18,569,017
LGAR/LCAR	(237,317)	105,158	(44,888)	(177,047)
SO2	(5,722)	(4,420)	(331)	(10,474)
EITF-06 Adjustment	68,315	21,620	2,145	92,079
	10,357,350	7,583,095	533,130	18,473,575
	90%	90%	90%	90%
Customer Responsibility	9,321,615	6,824,785	479,817	16,626,217
Renewable Resource Adder	282,851	0	0	282,851
REC Deferral	821,390	371,539	31,817	1,224,746
Total Company Recovery for NPC Deferral	**10,425,857**	**7,196,325**	**511,633**	**18,133,815**
Year 2 of LGAR ordered Amortization	**2,378,721**	**0**	**0**	**2,378,721**
Balancing Account Activity				
Prior Deferral	11,181,331	-	-	11,181,331
ECAM Revenue Collection	(7,821,058)	-	-	(7,821,058)
Interest	189,858	-	-	189,858
Estimated Undercollection @ 11/30/11	**3,550,131**	**-**	**-**	**3,550,131**
Balance Subject to Surcharge Collection	**16,354,709**	**7,196,325**	**511,633**	**24,062,667**
Tariff 94 Collection - April 2012 to March 2013	(10,450,734)	(2,409,685)	(171,269)	(13,031,688)
Tariff 94 Collection - Dec 2011 to March 2012	(3,000,000)	-	-	(3,000,000)
Balance After Estimated Collection	**2,903,975**	**4,786,640**	**340,364**	**8,030,979**
Proposed Schedule 94 Changes (Monsanto / Agrium 3 Year Amortization)		2,409,685	171,269	2,580,954

The first section of Table 1 shows the components of the $18.1 million which is summarized on the line labeled "Total Company Recovery for NPC Deferral." The next section of Table 1 shows the components of the total balance of $24.1 million as of November 30, 2011 and is labeled "Balance Subject to Surcharge Collections." The third portion of Table 1 is summarized on the line labeled "Tariff 94 Collection – April 2012 to March 2013" and shows the Company's proposed initial surcharge to Monsanto of $2.4 million, an initial surcharge to Agrium of $171,000, and a surcharge for the remaining tariff customers of $10.4 million, which represents no change to the surcharge for these tariff customers. The final section of Table 1 labeled "Balance After Estimated Collection" shows

1 the estimated remaining balance of the $24.1 million after the 12-month collection
2 period ending March 31, 2013 if the Company's proposed surcharge was
3 approved.

4 **Q. It appears the primary driver of the $18.1 million 2011 Deferral is a result of**
5 **the difference between the in-rates NPC and the actual NPC for the Deferral**
6 **Period. Please explain the causes of this difference.**

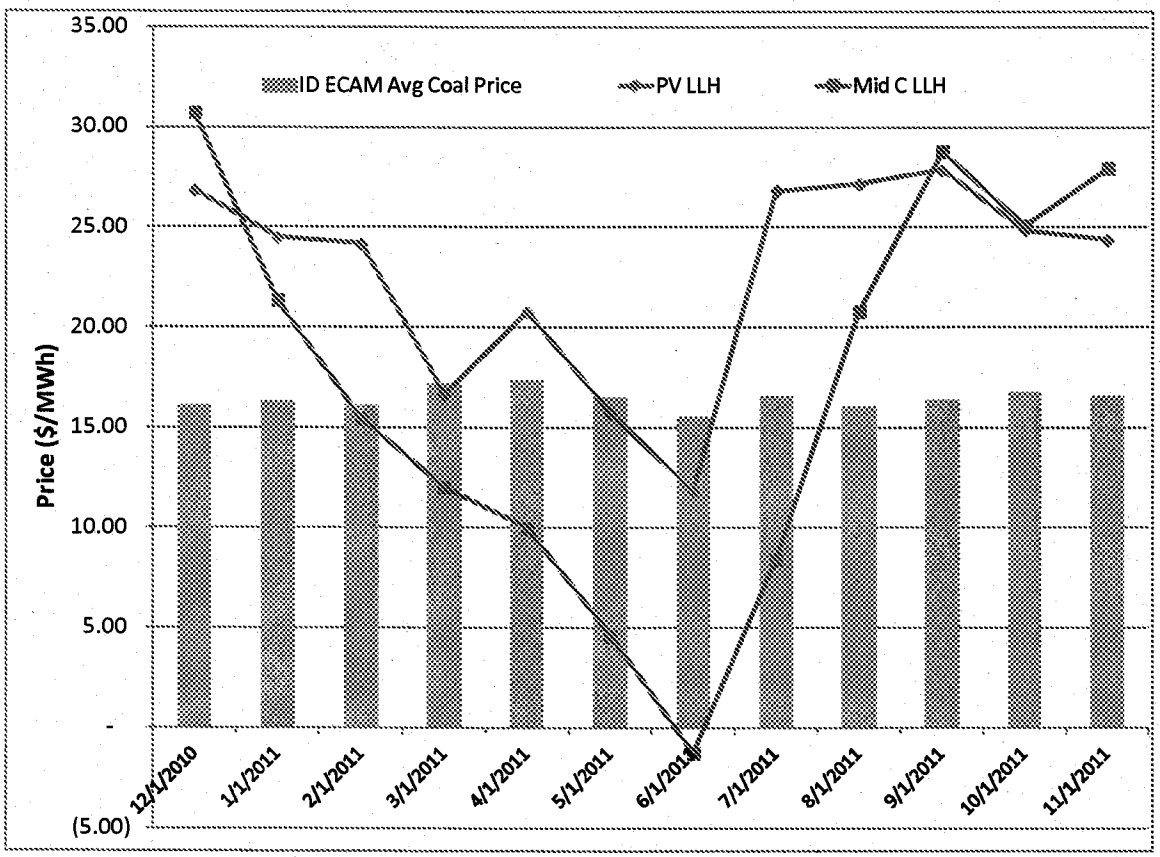
7 A. The in-rates NPC for the Deferral Period were $1.025 billion, were based on 2008
8 and 2010 test periods and excluded wind integration costs of about $34 million.
9 Actual NPC for the Deferral Period were $1.344 billion, or $319 million higher
10 than the in-rates NPC. The difference is primarily driven by a 29 percent drop in
11 wholesale sales prices and a reduction in the volume of wholesale sales of 9.3
12 million megawatt-hours, or nearly 50 percent as compared to what was included
13 in the in-rates amount. This caused a reduction in wholesale sales revenues of
14 $505 million, offset partially by a reduction in purchased power expense of $60
15 million and a reduction in natural gas fuel expense of $118 million for a net
16 increase in NPC from these three components of $327 million. Small changes in
17 coal and wheeling expenses make up the difference.

18 **Q. Why did sales volumes drop by 9.3 million megawatt-hours?**

19 A. The loss of sales volume reflects the impact that low power prices had on the
20 economics of the Company's coal and natural gas units. The Company generated
21 7.9 million fewer megawatt-hours from its thermal fleet than were included in
22 rates. Table 2 shows wholesale power prices for low load hours at the Mid-
23 Columbia and Palo Verde trading hubs as compared to the Company's average

1 coal costs.

Table 2



2 Table 2 shows that for six months in 2011, the average low load hour wholesale
3 power prices at Mid-C were below the average coal price of the Company's coal
4 fleet. Palo Verde low load hour wholesale power prices were below the average
5 coal prices three months of the year. In June, the monthly average low load price
6 was negative. These low price conditions make it uneconomic at times to run coal
7 and gas units.

8 **Q. Did the Company anticipate that the actual NPC for the Deferral Period**
9 **would be $319 million higher than the NPC included in rates during the**
10 **Deferral Period?**

11 A. Yes. In the 2011 general rate case, I testified that NPC for calendar year 2011

1 would be $1.312 billion. This was not a true forecast of 2011 NPC since it used
2 2010 temperature adjusted loads. In Company witness Mr. J. Ted Weston's
3 testimony filed on November 2, 2011 in support of the stipulation in the 2011 rate
4 case, he indicated that the Company expected actual NPC for 2011 to be $1.35
5 billion and that the expected ECAM deferral would be in the range of $15 to $18
6 million. These estimates compare well to the $1.344 billion actual NPC for the
7 Deferral Period.

8 **Q. Why is the 2011 Deferral $18.1 million when the 2010 deferral was only $12.8**
9 **million?**

10 A. The increase in the 2011 Deferral over the 2010 deferred amount is mainly
11 attributable to the inclusion of Monsanto and Agrium for the first time in 2011.
12 Their share of the deferral is $7.7 million, or 43 percent; the remaining $10.4
13 million is the responsibility of all other tariff customers and is actually less than
14 the 2010 deferral for these customers.

15 **Q. Are you sponsoring an exhibit that details the calculations of the ECAM?**

16 A. Yes. Exhibit No. 1 presents the calculation of the ECAM.

17 **ECAM Background**

18 **Q. Please briefly describe the Company's ECAM authorized by the**
19 **Commission.**

20 A. Order No. 30904 dated September 29, 2009, from Case No. PAC-E-08-08,
21 approved the stipulation entered into by the Commission Staff, the Idaho
22 Irrigation Pumpers Association, Monsanto and the Company that set up the
23 structure and content of the ECAM mechanism.

In general, power cost adjustment mechanisms track and defer deviations between actual NPC and the NPC in rates. The deferred costs that accumulate over a one-year period are then passed on to customers as a rate surcharge or credit.

The ECAM Schedule 94 charge, which appears as a separate line item on customer bills, defers the difference between actual NPC incurred by the Company to serve Idaho customers over a specified period ("Actual NPC") and a base NPC level established through a general rate case proceeding ("Base NPC"). When Actual NPC is greater than Base NPC, the difference is charged to customers; conversely, where Base NPC is greater than Actual NPC, the difference is credited to customers through the ECAM.

In addition to the variance between Actual and Base NPC, the ECAM reflects the impact of the LCAR applied to the differences in actual and base period retail load, a credit for SO_2 revenues, an adjustment for the treatment of EITF 4-06 coal stripping costs and a renewable resource adder that reflects generation from new renewable resources that were not included in rates during the deferral period. Pursuant to Order No. 32196, 100 percent of the difference between base REC revenues established in a general rate case and actual REC revenues are also tracked in the ECAM. The annual deferral period for the ECAM is December 1 to November 30. The Company is required to file an application with the Commission by February 1 of each year to seek approval of the deferral amount and to adjust the ECAM rate effective April 1.

1 **ECAM Calculation**

2 **Q. Has the ECAM calculation changed from the calculation used in the prior**
3 **ECAM?**

4 A. Yes. In the current filing, Monsanto's and Agrium's loads are included in the
5 calculation of the ECAM balances. In the 2007 general rate case, Case No. PAC-
6 E-07-05, the Commission approved a stipulation including electric service
7 agreements with specific planned rate increases for Monsanto and Agrium
8 through December 31, 2010. Beginning on January 1, 2011, those tariff contracts
9 expired and the two customers' loads are included in the ECAM calculation in the
10 same way as all other retail customers. However, as indicated in the stipulation
11 Order No. 32432 in the 2011 rate case, the Company will amortize and collect
12 Monsanto's and Agrium's share of the Commission approved 2011 ECAM
13 balances over three years. As a result, the ECAM balances for the two customers
14 will be tracked separately through the amortization periods.

15 **Q. Please describe the ECAM as calculated in Exhibit No. 1.**

16 A. This Application includes deferred amounts from December 1, 2010 to November
17 30, 2011. The deferral was calculated by comparing the Actual NPC to the Base
18 NPC on a monthly basis and deferring the differences into an ECAM balancing
19 account. During the Deferral Period, the Base NPC in rates were from two rate
20 cases: Case No. PAC-E-08-07 ("2008 Rate Case") from December 1 to December
21 27, 2010, and Case No. PAC-E-10-07 ("2010 Rate Case") from December 28,
22 2010 through November 30, 2011. The calculation is made by utilizing the system
23 dollar per megawatt-hour rate applied to the Idaho retail load. Exhibit No. 1

1 details the ECAM calculation and contains supporting information, portions of
2 which are confidential.

3 **Q. How are the Base NPC and Actual NPC dollar per megawatt-hour rates**
4 **calculated?**

5 A. With respect to the Base NPC rate, the Company started with the NPC of $982
6 million and $1,025 million approved by the Commission in Order No. 30783 from
7 the 2008 Rate Case and Order No. 32224 from the 2010 Rate Case, respectively.
8 Prorating the December value included in the $982 million for 27 days in
9 December 2010 and applying corresponding months from the $1,025 million for
10 the rest of the Deferral Period, the Base NPC for the Deferral Period are $1,028
11 million. The Company then divided the monthly NPC dollar amount by the
12 monthly normalized load of the corresponding months to express the costs on a
13 dollar per megawatt-hour basis (Exhibit No. 1, line 1). The Actual NPC rate on a
14 dollar per megawatt-hour basis is calculated by dividing the monthly Actual NPC
15 dollar amount by the actual monthly system load (Exhibit No. 1, line 4).

16 **Q. Please describe how the NPC deferral is determined.**

17 A. The deferral is calculated on a monthly basis by subtracting the Base NPC rate
18 from the Actual NPC rate. The resulting monthly NPC rate differential (Exhibit
19 No. 1, line 5) is then multiplied by three groups of actual Idaho retail load at
20 input: tariff customers, Monsanto, and Agrium (Exhibit No. 1, lines 6 through 8)
21 to calculate the NPC differential for deferral for each customer group (Exhibit No.
22 1, lines 10 through 13). For the 12-month period ended November 2011 the NPC
23 differential for deferral was approximately $18.6 million before the 90 / 10

1 sharing.

2 **Q. What types of costs are included in the NPC differential for deferral?**

3 A. The NPC differential for deferral captures all components of NPC as defined in
4 the Company's general rate case proceedings and modeled by the Company's
5 production dispatch model ("GRID"). Specifically, Base NPC and Actual NPC
6 include amounts booked to the following Federal Energy Regulatory Commission
7 ("FERC") accounts:

8 Account 447 – Sales for resale, excluding on-system wholesale sales and
9 other revenues that are not modeled in GRID

10 Account 501 – Fuel, steam generation; excluding fuel handling, start up
11 fuel[2] (gas and diesel fuel, residual disposal) and other costs
12 that are not modeled in GRID

13 Account 503 – Steam from other sources

14 Account 547 – Fuel, other generation

15 Account 555 – Purchased power, excluding the Bonneville Power
16 Administration ("BPA") residential exchange credit pass-
17 through if applicable

18 Account 565 – Transmission of electricity by others

19 **Q. In addition to the comparison of Actual NPC to Base NPC, what other**
20 **components are included in the ECAM?**

21 A. There are five additional components included in the ECAM calculations: (i)
22 LGAR revenues, which have been changed to LCAR revenues beginning April 1,

[2] Start up fuel is accounted for separately from the primary fuel for steam power generation plants. Start up costs are not accounted for separately for natural gas plants, and therefore all fuel for natural gas plants is included in the determination of both Base NPC and Actual NPC.

2011, as authorized by the Commission in Order No. 32206, (ii) credit for any SO_2 allowance sales variances, (iii) adjustment for deferred costs associated with coal mine stripping activities recorded under the Financial Accounting Standards Board ("FASB") EITF 04-6, (iv) a renewable resource adder for 27 days in December 2010, and (v) true-up of REC revenues as authorized by the Commission in Order No. 32196.

Q. Please describe the LGAR and LCAR revenues.

A. The calculation of both LGAR and LCAR revenues is a symmetrical adjustment for any over or under collection of the Company's production related revenue requirement, excluding NPC, due to variances in Idaho load. In Order No. 32206 of Case No. GNR-E-10-03, the Commission revisited the load growth adjustment in ECAMs.

The Commission order specified five LGAR items; (1) to only include the energy classified portion of embedded production revenue requirement in the calculation, (2) that a symmetrical approach for growing and declining loads continued to be just and reasonable to both the utility and its customers, (3) to change the terminology from Load Growth Adjustment Rate to Load Change Adjustment Rate, (4) compute the LCAR based on the most recent Commission-approved cost of service results, and (5) the newly-calculated LCAR shall be used in ECAM calculations beginning on April 1, 2011.

Q. How are the LGAR and LCAR calculated and what is their impact on the 2011 Deferral?

A. In Commission Order No. 30904, the Commission approved a symmetrical

1 LGAR of $17.48 per megawatt-hour, which was updated to $21.89 per megawatt-
2 hour beginning on December 28, 2010 as authorized by the Commission in the
3 2010 Rate Case. Beginning in April 2011, the Commission approved the LCAR,
4 at $5.47 per megawatt-hour, which replaced the LGAR. Both the LGAR and
5 LCAR revenues are calculated in the same manner by starting with subtracting
6 Idaho's load at input established in rates ("Base Load" shown in Exhibit No. 1,
7 lines 14 through 17), from actual Idaho load at input ("Actual Load" shown in
8 Exhibit No. 1, lines 6 through 9). The difference (Exhibit No. 1, lines 18 through
9 21) is then multiplied by the LGAR of $17.48 per megawatt-hour for 27 days in
10 December 2010 (Order No. 30783), $21.89 per megawatt-hour (Order No. 32196
11 and 32224) through March 31, 2011, and $5.47 per megawatt-hour (Order No.
12 32206) from April 1 through November 30, 2011 (Exhibit No. 1, line 22) to arrive
13 at the LGAR and LCAR credits (Exhibit No. 1, lines 23 through 26) of $177,047
14 for the Deferral Period before the 90 / 10 sharing.

15 **Q. How are SO_2 sales revenues included in the ECAM?**

16 A. Line 27 of Exhibit No. 1 contains the total Company SO_2 sales revenue during the
17 Deferral Period on a total Company basis., Line 29 of Exhibit No. 1 is Idaho's
18 allocated share of the SO_2 sales revenue which is calculated using Idaho's System
19 Energy ("SE") allocation factor authorized by the Commission from the 2008
20 Rate Case and 2010 Rate Case. The SO_2 sales revenue on line 29 of Exhibit No. 1
21 is credited against the NPC differential for deferral. For the Deferral Period, the
22 total SO_2 sales revenue credit is a $10,474 reduction to the NPC deferral balance
23 before the 90 / 10 sharing.

1 **Q. How is the adjustment for the accounting pronouncement EITF 04-6**
2 **included in the ECAM?**
3 A. Line 30 of Exhibit No. 1 reflects Idaho's allocated differences between excluding
4 coal stripping costs incurred by the Company and recorded on the Company's
5 books pursuant to the guidance of the accounting pronouncement EITF 04-6, and
6 the amortization of the coal striping costs when the coal was excavated. The EITF
7 04-6 deferral adjustment on line 30 of Exhibit No. 1 is added to the NPC
8 differential for deferral. For the Deferral Period, the total EITF 04-6 coal stripping
9 deferral adjustment is a $92,079 increase to the NPC deferral balance before the
10 90 / 10 sharing.
11 **Q. What is the total amount of the NPC differential and the adjustments**
12 **described above?**
13 A. Lines 39 through 41 of Exhibit No. 1 show the total NPC deferral adjusted for
14 LGAR/LCAR revenue, SO2 revenue, and EITF 04-6 deferral for tariff customers,
15 Monsanto and Agrium, which is approximately $18.5 million for the Deferral
16 Period before the 90 / 10 sharing.
17 **Q. Is the deferral subject to a sharing ratio between the Company and**
18 **customers in the ECAM?**
19 A. Yes. The ECAM includes a symmetrical sharing ratio where customers pay or
20 receive 90 percent of the ECAM deferral balance and the Company is responsible
21 for the remaining 10 percent. Lines 44 through 47 of Exhibit No. 1 reflect the
22 customers' 90 percent share of the monthly deferral shown on lines 39 through 42
23 of Exhibit No. 1. For the Deferral Period, the customers' share of the deferred

1 balance is approximately $16.6 million. The remaining balance of approximately
2 $1.8 million is not included in the deferral calculation and is not recoverable from
3 customers.

4 **Q. Is the deferred balance adjusted for a renewable resource adder?**

5 A. Yes. However, the adder was only applicable to the first 27 days in December
6 2010 prior to the time the rates from the 2010 Rate Case went in effect. The
7 renewable resource adder was implemented to recognize that the cost of the
8 renewable generation resources that were not yet being recovered in Idaho rates
9 were providing benefits to customers through the near-zero cost energy generation
10 included in the Actual NPC. The adjustment is calculated by multiplying the
11 authorized amount of $55.00 per megawatt-hour by the prorated actual megawatt-
12 hour output generated in the first 27 days of December 2010 from those
13 renewable resources that were not included in rates during the Deferral Period
14 (Exhibit No. 1, line 48). Line 50 of Exhibit No. 1 reflects this adjustment on a
15 total Company basis. The total Company amount is allocated to Idaho (Exhibit
16 No. 1, line 52) based on the System Generation allocation factor ("SG"), which is
17 further prorated to include only the tariff customers load (Exhibit No. 1, line 54).
18 The renewable resource adder adjustment is $282,851 for the 27 days in
19 December 2010.

20 **Q. What is the amount of REC revenue true-up in the current filing?**

21 A. As authorized by the Commission in Docket No. PAC-E-10-07, Order No. 32196,
22 the Company included the difference between actual REC revenues during the
23 Deferral Period and the amount of REC revenues included in base rates. The REC

revenue true-up included in the ECAM is symmetrical but no sharing band is applied. Thus, 100 percent of the difference between base and actual REC revenues is either refunded or surcharged to customers. Case No. PAC-10-07 established an annual level of REC revenue in base rates of $7,031,166. In the current filing, the REC revenues are prorated beginning on December 28, 2010, 27 days less than the full 12-month Deferral Period, so the amount included in base rates during the deferral period was $6.5 million. Idaho's actual REC revenues for that same time period were approximately $5.3 million, a difference of approximately $1.2 million (Exhibit No. 1, line 61).

Q. What is the total ECAM deferred balance as calculated in Exhibit No. 1?

A. The total ECAM deferred balance as of November 30, 2011 is 24.1 million and is shown on line 85 of Exhibit No. 1.

Q. How is this balance divided among customers?

A. The ECAM deferral is divided into three customer groups based on each group's actual load during the deferral period. Of the $24.1 million, $16.3 million is allocated to the tariff customers (Exhibit No. 1, Line 70), $7.2 million to Monsanto (Exhibit No. 1, Line 77) and $0.5 million to Agrium (Exhibit No. 1, Line 84). The Company will amortize and collect Monsanto's and Agrium's share of the Commission approved 2011 ECAM balance over three years pursuant to the stipulation approved by the Commission in Order No. 32432.

1 **Q. In your opinion does the calculation of the deferred NPC adjustment in this**
2 **application comply with the parameters of the Idaho ECAM as approved by**
3 **the Commission?**
4 A. Yes.
5 **Q. Is the Company requesting a rate increase to recover the full $24.1 million**
6 **deferral?**
7 A. No. The Company estimates that approximately $3.0 million of the under
8 collection will be recovered through Schedule 94 rates from December 1, 2011 to
9 March 31, 2012. Any over or under collection of this amount will be addressed in
10 future ECAM filings. Additionally, the Company is not requesting a change to the
11 existing Schedule 94 rates for tariff standard customers at this time as it anticipates
12 that an increase in the collection rate this year would be followed by a decrease in
13 the rate next year. The Company is recommending that the rate be held constant
14 for these customers in order to achieve rate stability potentially over the next two
15 years.
16 **Actual NPC - Base NPC Comparison**
17 **Q. How do the Actual NPC differ from the Base NPC for this Deferral Period?**
18 A. The Base NPC approved by the Commission and included in rates is $1,028
19 million on a total Company basis. Total adjusted Actual NPC during the Deferral
20 Period is $1,344 million, which is $316 million higher than what was included in
21 rates during the Deferral Period. On a dollar per megawatt-hour basis, the Base
22 NPC average is $17.83 per megawatt-hour, and the Actual NPC averages to
23 $22.92 per megawatt-hour, $5.09 per megawatt-hour higher.

1 **Q. Please explain why Actual NPC are adjusted.**

2 A. The Actual NPC recorded on the Company's books are adjusted to remove entries
3 that are not included in the determination of the Company's Base NPC for
4 regulatory purposes, such as adjustments made to remove entries in months
5 outside the current Deferral Period. In addition, Actual NPC are adjusted to reflect
6 prior Commission approved adjustments, such as the revenue imputation of the
7 sales contract with the Sacramento Municipal Utility District.

8 **Q. In your summary, you indicated that several power contracts have expired.**
9 **Please provide some examples of these expiring power contracts?**

10 A. Some examples include:

11 • On June 30, 2011, the exchange contract between the Company and the Alcoa
12 Power Generating Inc. for approximately 100 megawatts of capacity from the
13 Rocky Reach project expired. Under this contract, the Company received
14 energy during peak periods and returns energy during off-peak periods.

15 • On October 31, 2011, the contract between the Company and the Chelan
16 Public Utility District for generation from the Rocky Reach project expired.
17 Power purchased by the Company under this contract was priced at the
18 embedded cost of the project.

19 • On August 31, 2011, the contract between the Company and BPA for 575
20 MW of capacity expired. Under this contract, the Company received energy
21 during peak periods and returns energy during off-peak periods. In addition,
22 power received under this contract was delivered directly to a variety of the
23 Company's load pockets in the western area at the Company's discretion.

- On September 30, 2011, the contract between the Company and the Grant Public Utility District for displacement generation expired, which was priced at BPA's Priority Firm Power rate.
- On January 1, 2011, the amount of sales to the Public Service Company of Colorado reduces per the contract terms, which was a legacy sales contract at relatively high contract prices.

Q. You also mentioned in your summary that coal prices had increased. What are the primary drivers of the coal price increases?

A. Both third party coal purchase expense and captive mine costs have increased. The primary factors are:

- Naughton – approximately $4 million increase. Subsequent to the filing of 2010 Idaho General Rate Case, the Company amended the Naughton coal supply agreement with Chevron Mining Company. The amended coal supply agreement included advancement of the January 2011 price reopener to July 2010, changes to the contract structure and a lump sum prepayment by the Company of [redacted] million. The prepayment which is being amortized to fuel expense over the primary term of the agreement resulted in a $1.4 million increase in actual net power costs. Additionally, the contract incorporates a two-tiered pricing structure. The Base NPC included 395 thousand tons of Tier 2 coal, the lower priced tier; actual net power costs included only 337 thousand tons of Tier 2 coal. The reduction of 58 thousand tons of Tier 2 resulted in an approximately [redacted] million increase. Finally, a change in the contract price structure as well as escalation of the producer price indices

contributed to the remainder of the increase.

- Dave Johnston – approximately $6 million increase. Through 2011, the Dave Johnston plant was supplied by three mines under multi-year agreements: Peabody's Rawhide mine, Western Fuels' Dry Fork mine and Wyodak Resources' Wyodak mine. Approximately [redacted] million of the price increase at Dave Johnston plant is due to annual increases in fixed prices from the base year to 2011 with almost [redacted] million attributable to the Dry Fork mine itself. Increased rail rates during 2011 relative to what was in Base NPC have also contributed approximately [redacted] million of the total price increase at the plant.
- Hunter – approximately $14 million increase. The majority of the Hunter plant requirements are supplied under a long-term coal supply agreement with Arch Coal Sales. Arch supplied approximately 90 percent of the plant deliveries assumed in the Base NPC and approximately 75 percent during the 12 months ending November 30, 2011. Approximately [redacted] million of the $14 million increase is a result of the January 2011 price reopener under the Arch contract. As a result of the reopener, the contract price increased by almost [redacted] per ton between 2010 and 2011. The remainder of the increase at the Hunter plant is due to increased Deer Creek operating costs and a new long-term coal supply agreement with West Ridge that commenced January 2011. The reduction in Sufco deliveries from the levels included in Base NPC was offset by increase in deliveries from the West Ridge mine under the new coal supply agreement.
- Huntington – approximately $7 million increase. The majority of the Huntington plant is supplied by the Deer Creek mine. The increase is

predominantly the result of higher operating costs associated with movement of longwall operations from the Blind Canyon seam to the lower Hiawatha seam in December 2010 and reduced longwall production due to adverse geological conditions associated with elevated levels of ash and sulfur encountered in the Hiawatha seam.

- Bridger – approximately $26 million increase. The price increase at the Bridger Plant is the result of higher Bridger Coal Company production costs, [redacted] million, and increased Black Butte costs, [redacted] million. The inclusion of 378 thousand tons of Black Butte 2009 contract at a Freight-On-Board ("F.O.B") mine price of [redacted] per ton in the Base NPC versus an approximate [redacted] per ton F.O.B mine price in the actual results accounts for approximately [redacted] million of the Black Butte increase. Escalation of producer price indices under the Black Butte contract account for the remaining [redacted] million of the Black Butte increase. Higher operating costs of approximately [redacted] million at the Bridger mine in 2011 are a result of reductions in the Jim Bridger plant burn and poor underground mining conditions.

Q. Does this conclude your direct testimony?

A. Yes.

Case No. PAC-E-12-03
Exhibit No. 1
Witness: Gregory N. Duvall

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Gregory N. Duvall

February 2012

Idaho ECAM Deferral
December 2010 through November 2011

Line No.			Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11
1	Base NPC Rate ($/MWh) - See (1) below		16.93	14.76	14.63	15.38	16.64	17.06	17.31	21.60	22.89	20.75	17.28	17.77
2	Total Company Adjusted Actual NPC ($)		95,757,018	107,401,699	102,209,579	99,507,678	96,035,896	96,927,539	103,624,344	140,645,161	147,796,095	122,984,469	110,065,405	121,246,771
3	Actual Retail Load (MWh)		5,261,325	5,299,026	4,692,843	4,882,154	4,531,018	4,505,487	4,632,662	5,367,046	5,321,022	4,680,341	4,621,700	4,859,771
4	Actual NPC ($/MWh)	= Line 2 / Line 3	18.20	20.27	21.78	20.38	21.20	21.51	22.37	26.21	27.78	26.28	23.81	24.95
5	NPC Differential $/MWh	= Line 4 - Line 1	1.27	5.51	7.15	5.00	4.55	4.46	5.05	4.61	4.88	5.53	6.54	7.18
6	Actual Tariff Customer Load		153,102	159,059	140,655	134,761	123,639	144,490	220,158	356,132	212,590	174,387	126,874	137,645
7	Actual Monsanto Load			130,992	110,188	129,320	125,556	126,288	128,065	131,411	124,511	93,671	133,501	127,752
8	Actual Agrium Load			10,828	9,563	10,608	10,266	9,923	4,865	9,379	9,616	9,634	10,178	9,678
9	Actual Idaho Load (MWh)		153,102	300,879	260,406	274,689	259,461	280,701	353,088	496,921	346,717	277,691	270,554	275,075
10	**Tariff Customer NPC for Deferral**	= Line 5 * Line 6	193,806	876,648	1,005,996	674,051	563,173	644,053	1,112,684	1,641,387	1,038,029	964,428	829,633	988,185
11	**Monsanto NPC for Deferral**	= Line 5 * Line 7		721,962	788,092	646,833	571,904	562,920	647,246	605,663	607,956	518,035	872,971	917,154
12	**Agrium NPC for Deferral**	= Line 5 * Line 8		59,677	68,398	53,060	46,760	44,232	24,588	43,226	46,952	53,278	66,556	69,477
13	**Total NPC Differential for Deferral ($)**		193,806	1,658,288	1,862,486	1,373,945	1,181,838	1,251,204	1,784,519	2,290,276	1,692,937	1,535,742	1,769,161	1,974,816
14	Tariff Customer Base Load		175,051	144,717	119,568	135,644	129,164	181,576	233,767	288,806	245,224	162,268	139,580	137,975
15	Monsanto Base Load			138,565	117,487	124,170	124,111	124,052	119,988	122,207	122,094	120,978	120,235	117,407
16	Agrium Base Load			10,384	9,340	9,340	9,340	9,340	7,692	9,340	9,340	9,340	9,340	9,340
17	Total Base Load		175,051	293,666	246,395	269,155	262,615	314,969	361,447	420,354	376,659	292,587	269,155	264,722
18	Tariff Customer Load Differential	= Line 6 - Line 14	(21,949)	14,342	21,087	(883)	(5,525)	(37,087)	(13,610)	67,326	(32,634)	12,119	(12,707)	(329)
19	Monsanto Base Load Differential	= Line 7 - Line 15		(7,572)	(7,299)	5,150	1,445	2,236	8,077	9,203	2,416	(27,308)	13,267	10,344
20	Agrium Base Load Differential	= Line 8 - Line 16		444	223	1,268	925	583	(2,827)	39	276	293	838	337
21	Difference Base Load to Actual Load		(21,949)	7,213	14,011	5,535	(3,154)	(34,268)	(8,359)	76,567	(29,941)	(14,896)	1,398	10,352
22	Load Change Adjustment Rate (LCAR) ($/MWH) (2)		18.05	21.89	21.89	21.89	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47
23	**Tariff Customer LCA**	= -Line 18 x Line 22	396,120	(313,944)	(461,602)	19,330	30,220	202,865	74,444	(368,272)	178,506	(66,290)	69,505	1,802
24	**Monsanto Base LCA**	= -Line 19 x Line 22		165,762	159,777	(112,728)	(7,905)	(12,230)	(44,181)	(50,341)	(13,218)	149,374	(72,570)	(56,582)
25	**Agrium Base LCA**	= -Line 20 x Line 22		(9,710)	(4,881)	(27,756)	(5,062)	(3,189)	15,463	(211)	(1,508)	(1,605)	(4,584)	(1,845)
26	**Load Change Adjustment Revenues**		396,120	(157,893)	(306,706)	(121,154)	17,252	187,446	45,726	(418,824)	163,780	81,479	(7,649)	(56,626)
27	SO2 Allowances Sales		-	-	($78,000)	($41,737)	($4,505)	$0	($40,509)	$0	$0	$0	$0	$0
28	Idaho SE Factor		6.5570%	6.3575%	6.3575%	6.3575%	6.3575%	6.3575%	6.3575%	6.3575%	6.3575%	6.3575%	6.3575%	6.3575%
29	Idaho Allocated SO2 Allowance Sales	= Line 27 x Line 28	-	-	(4,959)	(2,653)	(286)	-	(2,575)	-	-	-	-	-
30	Idaho Allocated EITF 04-6 Deferral Adjustment		33,727	(11,997)	(20,948)	(11,103)	(50,550)	(33,494)	(33,248)	47,975	31,771	46,838	78,031	30,412
31	Total Adjustments		33,727	(11,997)	(25,906)	(13,756)	(50,836)	(33,494)	(35,824)	47,975	31,771	46,838	78,031	30,412
32	Tariff Customer - ID Load %		54.53%	52.86%	54.01%	49.06%	47.65%	51.47%	62.35%	71.67%	61.32%	62.80%	46.89%	50.04%
33	Monsanto - ID Load %			43.54%	42.31%	47.08%	48.39%	44.99%	36.27%	26.44%	35.91%	33.73%	49.34%	46.44%
34	Agrium - ID Load %			3.60%	3.67%	3.86%	3.96%	3.54%	1.38%	1.89%	2.77%	3.47%	3.76%	3.52%
35	**Tariff Customer Adjustments**	= Line 31 x Line 32	18,392	(6,342)	(13,993)	(6,749)	(24,225)	(17,241)	(22,337)	34,382	19,481	29,413	36,592	15,218
36	**Monsanto Adjustments**	= Line 31 x Line 33		(5,223)	(10,962)	(6,476)	(24,600)	(15,069)	(12,993)	12,687	11,409	15,799	38,504	14,124
37	**Agrium Adjustments**	= Line 31 x Line 34		(432)	(951)	(531)	(2,011)	(1,184)	(494)	905	881	1,625	2,936	1,070
38	**Total Adjustments**		18,392	(11,997)	(25,906)	(13,756)	(50,836)	(33,494)	(35,824)	47,975	31,771	46,838	78,031	30,412
39	Tariff Customer NPC Differential + LCA + SO2 + EITF	= Sum of Lines 10, 23, 35	608,318	556,362	530,401	686,633	569,168	829,677	1,164,792	1,307,498	1,236,015	927,552	935,730	1,005,205
40	Monsanto NPC Differential + LCA + SO2 + EITF	= Sum of Lines 11, 24, 36	-	882,501	936,907	527,629	539,400	535,621	590,072	568,008	606,148	683,209	838,905	874,696
41	Agrium NPC Differential + LCA + SO2 + EITF	= Sum of Lines 12, 25, 37	-	49,535	62,566	24,773	39,686	39,859	39,558	43,921	46,325	53,298	64,908	68,702
42	Total NPC Differential + LCA + SO2 + EITF		608,318	1,488,398	1,529,874	1,239,035	1,148,254	1,405,157	1,794,421	1,919,427	1,888,488	1,664,058	1,839,543	1,948,602
43	Customer / Company Sharing ratio		90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%
44	**Tariff Customer NPC Differential + LCA + SO2 + EITF Deferral**	= Line 39 x Line 43	547,486	500,726	477,361	617,969	512,251	746,709	1,048,313	1,176,748	1,112,414	834,796	842,157	904,684
45	**Monsanto NPC Differential + LCA + SO2 + EITF Deferral**	= Line 40 x Line 43	-	794,251	843,216	474,866	485,460	482,059	531,064	511,207	545,533	614,888	755,015	787,226
46	**Agrium NPC Differential + LCA + SO2 + EITF Deferral**	= Line 41 x Line 43	-	44,581	56,309	22,296	35,718	35,873	35,602	39,529	41,693	47,968	58,417	61,832
47	**Customer / Company Sharing (90/10)**		547,486	1,339,558	1,376,887	1,115,131	1,033,429	1,264,641	1,614,979	1,727,484	1,699,639	1,497,652	1,655,589	1,753,742
48	Renewables Generation (MWhs)		155,931											
49	Renewable Adder Rate per MWh		$55.00											
50	Total Renewable Resources Adder	= Line 48 x Line 49	8,576,210											
51	Idaho SG Factor		6.0479%											
52	Idaho Allocation	= Line 50 x Line 51	518,681											
53	Idaho Tariff Customers Percent		54.53%											
54	Renewable Resources Adder	= Line 52 x Line 53	282,851											

Rocky Mountain Power
Exhibit No. 1 Page 1 of 2
Case No. PAC-E-12-03
Witness: Gregory N. Duvall

Idaho ECAM Deferral
December 2010 through November 2011

Line No.			Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11
55	Idaho Actual Renewable Energy Credit Revenues ($)		(156,409)	(383,764)	(476,676)	(702,633)	(649,126)	(705,294)	(578,135)	(81,049)	(96,023)	(182,551)	(671,459)	(649,714)
56	Idaho Base Renewable Energy Credit Revenues ($)		(75,604)	(585,930)	(585,930)	(585,930)	(585,930)	(585,930)	(585,930)	(585,930)	(585,930)	(585,930)	(585,930)	(585,930)
57	REC Revenue Adjustment ($)	= Line 55 - Line 56	(80,805)	202,166	109,255	(116,702)	(63,195)	(119,363)	7,795	504,882	489,907	403,379	(85,529)	(63,784)
58	Tariff Customer REC Revenue Adjustment	= Line 32 x Line 57	(44,065)	106,874	59,012	(57,254)	(30,114)	(61,442)	4,861	361,837	300,388	253,318	(40,108)	(31,917)
59	Monsanto REC Revenue Adjustment	= Line 33 x Line 57		88,016	46,230	(54,942)	(30,581)	(53,702)	2,827	133,516	175,932	136,068	(42,203)	(29,623)
60	Agrium REC Revenue Adjustment	= Line 34 x Line 57		7,275	4,012	(4,507)	(2,500)	(4,220)	107	9,529	13,587	13,994	(3,218)	(2,244)
61	Total REC Revenue Adjustment ($)		(44,065)	202,166	109,255	(116,702)	(63,195)	(119,363)	7,795	504,882	489,907	403,379	(85,529)	(63,784)
62	Interest Rate		1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
63	**Tariff Customer Balancing Account ($)**													
64	Beginning Balance Excluding Unamortized LGA		11,181,331	11,841,987	12,317,988	12,735,718	13,188,061	13,360,297	13,359,361	13,585,451	13,564,345	13,599,858	13,642,584	13,722,396
65	Unamortized 2010 Load Growth Adjustment		2,378,721	2,378,721	2,378,721	2,378,721	2,378,721	2,378,721	2,378,721	2,378,721	2,378,721	2,378,721	2,378,721	2,378,721
65	Incremental Deferral	= Line 44	547,486	500,726	477,361	617,969	512,251	746,709	1,048,313	1,176,748	1,112,414	834,796	842,157	904,684
66	Renewable Resources Adder	= Line 54	282,851	-	-	-	-	-	-	-	-	-	-	-
67	REC Revenue Adjustment	= Line 58	(44,065)	106,874	59,012	(57,254)	(30,114)	(61,442)	4,861	361,837	300,388	253,318	(40,108)	(31,917)
68	Less: Monthly ECAM Rider Revenues		(137,186)	(143,643)	(131,060)	(121,152)	(322,939)	(699,313)	(840,287)	(1,572,981)	(1,390,584)	(1,058,715)	(735,616)	(667,582)
69	Interest		11,570	12,044	12,416	12,779	13,039	13,110	13,204	13,289	13,295	13,328	13,379	13,503
70	**Tariff Customer Ending Balance ($)**		14,220,707	14,696,708	15,114,439	15,566,781	15,739,018	15,738,082	15,964,172	15,943,066	15,978,578	16,021,305	16,101,117	16,319,805
71	**Monsanto Balancing Account ($)**													
72	Beginning Balance			-	882,635	1,773,187	2,194,764	2,651,661	3,082,407	3,619,090	4,267,097	4,992,419	5,747,848	6,465,746
73	Incremental Deferral	= Line 45		794,251	843,216	474,866	485,460	482,059	531,064	511,207	545,533	614,888	755,015	787,226
74	REC Revenue Adjustment	= Line 59		88,016	46,230	(54,942)	(30,581)	(53,702)	2,827	133,516	175,932	136,068	(42,203)	(29,623)
75	Less: Monthly ECAM Rider Revenues													
76	Interest			368	1,106	1,653	2,019	2,388	2,791	3,285	3,857	4,473	5,087	5,704
77	**Monsanto Ending Balance ($)**			882,635	1,773,187	2,194,764	2,651,661	3,082,407	3,619,090	4,267,097	4,992,419	5,747,848	6,465,746	7,229,054
78	**Agrium Balancing Account ($)**													
79	Beginning Balance			-	51,878	112,268	130,158	163,498	195,300	231,187	280,458	335,995	398,263	453,817
80	Incremental Deferral	= Line 46		44,581	56,309	22,296	35,718	35,873	35,602	39,529	41,693	47,968	58,417	61,832
81	REC Revenue Adjustment	= Line 60		7,275	4,012	(4,507)	(2,500)	(4,220)	107	9,529	13,587	13,994	(3,218)	(2,244)
82	Less: Monthly ECAM Rider Revenues													
83	Interest			22	68	101	122	149	178	213	257	306	355	403
84	**Agrium Ending Balance ($)**			51,878	112,268	130,158	163,498	195,300	231,187	280,458	335,995	398,263	453,817	513,807
85	**Total ECAM Deferral Balance**	= Sum of Lines 70, 77, 84	14,220,707	15,631,221	16,999,894	17,891,704	18,554,177	19,015,789	19,814,449	20,490,621	21,306,992	22,167,415	23,020,680	24,062,666

(1) Base NPC Rate and Load from Case No. PAC-E-08-07 $982 million through 12/27/2010, from Case No. PAC-E-11-07 $1,024.8 million since 12/28/2010
(2) Represents Load Growth Adjustment in months December 10 - March 11, then revised to Load Change Adjustment beginning in April 2011.

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE	)	
APPLICATION OF ROCKY	)	**CASE NO. PAC-E-12-03**
MOUNTAIN POWER FOR	)	
AUTHORITY TO INCREASE RATES	)	**Direct Testimony of William R. Griffith**
BY $2.6 MILLION TO RECOVER	)	
DEFERRED NET POWER COSTS	)	
THROUGH THE ENERGY COST	)	
ADJUSTMENT MECHANISM	)	

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-12-03

February 2012

1 **Q. Please state your name, business address and present position with the**
2 **Company (also referred to as Rocky Mountain Power).**
3 A. My name is William R. Griffith. My business address is 825 NE Multnomah
4 Street, Suite 2000, Portland, Oregon 97232. My present position is Director,
5 Pricing, Cost of Service & Regulatory Operations in the Regulation Department.
6 **Qualifications**
7 **Q. Briefly describe your educational and professional background.**
8 A. I have a B.A. degree with High Honors and distinction in Political Science and
9 Economics from San Diego State University and an M.A. in Political Science
10 from that same institution; I was subsequently employed on the faculty. I attended
11 the University of Oregon and completed all course work towards a Ph.D. in
12 Political Science. I joined the Company in the Rates & Regulation Department in
13 December 1983. In June 1989, I became Manager, Pricing in the Regulation
14 Department. In February 2001, I was promoted to my current position.
15 **Q. Have you appeared as a witness in previous regulatory proceedings?**
16 A. Yes. I have testified for the Company in regulatory proceedings in Idaho, Utah,
17 Oregon, Wyoming, Washington, and California.
18 **Q. What are your responsibilities in this proceeding?**
19 A. I am responsible for the Company's proposed rates in this case.
20 **Background**
21 **Q. What level of revenues is Schedule 94 currently designed to collect?**
22 A. Order No. 32216 authorized the Company to collect $10.4 million on an annual
23 basis from April 1, 2011 to March 31, 2012. Currently Schedule 94 is designed to

1 collect that level of revenues based on Idaho actual loads from Case No. PAC-E-
2 11-07. However, Idaho's actual loads were slightly lower during the collection
3 period and the Company anticipates that it will collect approximately $10.2
4 million over that collection period.

5 **Proposed Rate Change for Schedule 94**

6 **Q. Please describe Rocky Mountain Power's proposed rate change in this case.**

7 A. As stated in the direct testimony of the Company's witness Mr. Gregory N.
8 Duvall, in this annual ECAM filing the Company proposes no change to its
9 current ECAM surcharge collection rates, equal to $10.4 million, from retail
10 customers other than Monsanto and Agrium. For Monsanto and Agrium, the
11 Company proposes to implement new tariff surcharge rates for inclusion in Tariff
12 Schedule 94 with an initial collection rate of approximately $2.6 million.
13 Including Monsanto's and Agrium's tariff schedules in with the current energy
14 cost adjustment tariff Schedule 94 surcharge rates will increase the annual
15 collection level to $13.0 million.

16 **Q. Please explain the proposed rate change for Monsanto and Agrium.**

17 A. As indicated by Mr. Duvall, Monsanto's Schedule 400 service is responsible for
18 $7.2 million and Agrium's Schedule 401 service is responsible for $0.5 million of
19 the current ECAM deferral. The Company proposes to amortize these amounts for
20 Monsanto and Agrium, respectively, over three years to reflect the three year
21 amortization outlined in the Stipulation, agreed to by the parties, and approved by
22 the Commission, Order No. 32432, in the Company's 2011 general rate case. This
23 amortization results in new tariff surcharge rates for Monsanto and Agrium for

1 inclusion in Tariff Schedule 94 equal to an initial collection rate of approximately
2 $2.6 million.

3 **Q. What is the impact from the above ECAM rate change proposals?**

4 A. These rate change proposals result in a 3.3 percent increase for Monsanto and 3.2
5 percent increase for Agrium. As indicated above, the Company proposes no
6 changes for other retail tariff customers.

7 **Proposed Rate Design for Schedule 94**

8 **Q. How were the proposed Schedule 94 rates developed for Monsanto (Schedule**
9 **400) and Agrium (Schedule 401)?**

10 A. The proposed rates for these two customers were developed by dividing their
11 November 30, 2011, ECAM balance by three (to reflect the three year
12 amortization) and then dividing that amount by their kWh consumption at the
13 transmission voltage level. As a result, a proposed Schedule 94 rate of 0.175 cents
14 per kWh is indicated for Monsanto and 0.164 cents per kWh for Agrium.

15 **Q. Please describe Exhibit No. 2.**

16 A. Exhibit No. 2 illustrates the metered loads, the line loss adjusted loads, the
17 allocation of the ECAM price change, and the percentage change by rate schedule
18 based on present revenues from Order No. 32432, PAC-E-11-12, the Company's
19 2011 general rate case.

20 **Q. Please describe Exhibit No. 3.**

21 A. Exhibit No. 3 is the proposed tariff Schedule 94, Energy Cost Adjustment,
22 designed to collect approximately $13.0 million of the ECAM deferred balance.
23 The only revisions to the Schedule 94 surcharge proposed in this case are the

1 proposed rates for Monsanto (Schedule 400) and Agrium (Schedule 401) discussed
2 above. Rates for other customers are unchanged. Consistent with the ECAM
3 mechanism, the Company proposes that these rate changes become effective on
4 April 1, 2012.

5 **Q. Does this conclude your testimony?**

6 A. Yes, it does.

Case No. PAC-E-12-03
Exhibit No. 2
Witness: William R. Griffith

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of William R. Griffith

February 2012

EXHIBIT 2
ESTIMATED IMPACT OF PROPOSED ECAM ADJUSTMENT
FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN IDAHO
HISTORIC 12 MONTHS ENDED DECEMBER 2010

Line No.	Description	Sch.	Average Cust	MWH	Present Rev ($000)	At Meter MWh by Voltage S	P	T	At Generation MWh[1]	ECAM Proposal Rev ($000)	Rate ¢/kWh[2] S	P	T	Present ECAM Rev ($000)[3]	Net Change ($000)	%
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Residential Sales															
1	Residential Service	1	42,207	424,153	$43,920	424,153			467,196	$2,413	0.569	0.550	0.535	$2,413	$0	0.0%
2	Residential Optional TOD	36	14,902	285,516	$24,327	285,516			314,490	$1,625	0.569	0.550	0.535	$1,625	$0	0.0%
3	AGA Revenue				$3											
4	Total Residential		57,109	709,669	$68,250	709,669	0	0	781,686	$4,038				$4,038	$0	0.0%
5	**Commercial & Industrial**															
6	General Service - Large Power	6	1,055	270,876	$19,781	225,143	45,732		296,685	$1,533	0.569	0.550	0.535	$1,533	$0	0.0%
7	General Svc. - Lg. Power (R&F)	6A	235	32,618	$2,627	32,618			35,929	$186	0.569	0.550	0.535	$186	$0	0.0%
8	*Subtotal-Schedule 6*		*1,289*	*303,494*	*$22,407*	*257,762*	*45,732*	*0*	*332,613*	*$1,718*				*$1,718*	*$0*	*0.0%*
9	General Service - High Voltage	9	12	112,052	$6,303			112,052	116,092	$599	0.569	0.550	0.535	$599	$0	0.0%
10	Irrigation	10	4,845	555,304	$44,817	555,304			611,656	$3,160	0.569	0.550	0.535	$3,160	$0	0.0%
11	Comm. & Ind. Space Heating	19	127	6,225	$483	6,225			6,856	$35	0.569	0.550	0.535	$35	$0	0.0%
12	General Service	23	6,681	133,757	$12,029	132,608	1,149		147,288	$761	0.569	0.550	0.535	$761	$0	0.0%
13	General Service (R&F)	23A	1,586	19,973	$1,881	19,973			22,000	$114	0.569	0.550	0.535	$114	$0	0.0%
14	*Subtotal-Schedule 23*		*8,267*	*153,730*	*$13,910*	*152,581*	*1,149*	*0*	*169,288*	*$875*				*$875*	*$0*	*0.0%*
15	General Service Optional TOD	35	3	1,639	$110	1,639			1,806	$9	0.569	0.550	0.535	$9	$0	0.0%
16	Special Contract 1[4]	400	1	1,378,699	$72,237			1,378,699	1,428,401	$2,410			0.175		$2,410	3.3%
17	Special Contract 2[4]	401	1	104,412	$5,326			104,412	108,176	$171			0.164		$171	3.2%
18	AGA Revenue				$749											
19	Total Commercial & Industrial		14,546	2,615,555	$166,343	973,510	46,881	1,595,163	2,774,888	$8,978				$6,397	$2,581	1.5%
20	**Public Street Lighting**															
21	Security Area Lighting	7	200	251	$94	251			276	$1	0.569	0.550	0.535	$1	$0	0.0%
22	Security Area Lighting (R&F)	7A	151	118	$48	118			130	$1	0.569	0.550	0.535	$1	$0	0.0%
23	Street Lighting - Company	11	29	99	$44	99			109	$1	0.569	0.550	0.535	$1	$0	0.0%
24	Street Lighting - Customer	12	313	2,366	$419	2,366			2,606	$13	0.569	0.550	0.535	$13	$0	0.0%
25	AGA Revenue				$0											
26	Total Public Street Lighting		694	2,833	$604	2,833	0	0	3,120	$16				$16	$0	0.0%
27	**Total Sales to Ultimate Customers**		72,348	3,328,057	$235,197	1,686,012	46,881	1,595,163	3,559,694	$13,032				$10,451	$2,581	1.1%

29 [1] Equal to MWh sales by voltage times the corresponding loss factors in this line: 1.10148 1.06475 1.03605

30 [2] Total Proposed ECAM Revenue ($000) and Rate by Voltage (cents/kWh): 0.569 0.550 0.535

31 [3] Equal to MWh sales by voltage times the corresponding present rate in this line: 0.569 0.550 0.535

$10,451	< Tariff Cust	
$2,410	< Sch 400	
$171	< Sch 401	

32 [4] The ECAM Deferral Balances for Monsanto and Agrium are $7,229,054 and $513,807 respectively that will be amortized over three years through these proposed ECAM rates for them.

Case No. PAC-E-12-03
Exhibit No. 3
Witness: William R. Griffith

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of William R. Griffith

February 2012

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

Second Revision of Sheet No. 94.1
I.P.U.C. No. 1 **Cancelling First Revision of Sheet No. 94.1**

ROCKY MOUNTAIN POWER

ELECTRIC SERVICE SCHEDULE NO. 94

STATE OF IDAHO

Energy Cost Adjustment

AVAILABILITY: At any point on the Company's interconnected system.

APPLICATION: This Schedule shall be applicable to all retail tariff Customers taking service under the Company's electric service schedules.

ENERGY COST ADJUSTMENT: The Energy Cost Adjustment is calculated to collect the accumulated difference between total Company Base Net Power Cost and total Company Actual Net Power Cost calculated on a cents per kWh basis.

MONTHLY BILL: In addition to the Monthly Charges contained in the Customer's applicable schedule, all monthly bills shall have applied the following cents per kilowatt-hour rate by delivery voltage.

		Delivery Voltage		
		Secondary	Primary	Transmission
Schedule	1	0.569¢ per kWh		
Schedule	6	0.569¢ per kWh	0.550¢ per kWh	
Schedule	6A	0.569¢ per kWh	0.550¢ per kWh	
Schedule	7	0.569¢ per kWh		
Schedule	7A	0.569¢ per kWh		
Schedule	9			0.535¢ per kWh
Schedule	10	0.569¢ per kWh		
Schedule	11	0.569¢ per kWh		
Schedule	12	0.569¢ per kWh		
Schedule	19	0.569¢ per kWh		
Schedule	23	0.569¢ per kWh	0.550¢ per kWh	
Schedule	23A	0.569¢ per kWh	0.550¢ per kWh	
Schedule	24	0.569¢ per kWh	0.550¢ per kWh	
Schedule	35	0.569¢ per kWh	0.550¢ per kWh	
Schedule	35A	0.569¢ per kWh	0.550¢ per kWh	
Schedule	36	0.569¢ per kWh		
Schedule	400			0.175¢ per kWh
Schedule	401			0.164¢ per kWh

Submitted Under Case No. PAC-E-12-03

ISSUED: February 1, 2012 **EFFECTIVE**: April 1, 2012

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

I.P.U.C. No. 1

~~First~~ Second Revision of Sheet No. 94.1
Cancelling ~~Original~~ First Revision of Sheet No. 94.1

ROCKY MOUNTAIN POWER

ELECTRIC SERVICE SCHEDULE NO. 94

STATE OF IDAHO

Energy Cost Adjustment

AVAILABILITY: At any point on the Company's interconnected system.

APPLICATION: This Schedule shall be applicable to all retail tariff Customers taking service under the Company's electric service schedules.

ENERGY COST ADJUSTMENT: The Energy Cost Adjustment is calculated to collect the accumulated difference between total Company Base Net Power Cost and total Company Actual Net Power Cost calculated on a cents per kWh basis.

MONTHLY BILL: In addition to the Monthly Charges contained in the Customer's applicable schedule, all monthly bills shall have applied the following cents per kilowatt-hour rate by delivery voltage.

Submitted Under Case No. ~~PAC-E-11-07~~ PAC-E-12-03

ISSUED: ~~March 31, 2011~~February 1, 2012

EFFECTIVE: April 1, 2012~~1~~

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

~~First~~ Second Revision of Sheet No. 94.1
I.P.U.C. No. 1 **Cancelling ~~Original~~ First Revision of Sheet No. 94.1**

		Delivery Voltage		
		Secondary	Primary	Transmission
Schedule	1	0.569¢ per kWh		
Schedule	6	0.569¢ per kWh	0.550¢ per kWh	
Schedule	6A	0.569¢ per kWh	0.550¢ per kWh	
Schedule	7	0.569¢ per kWh		
Schedule	7A	0.569¢ per kWh		
Schedule	9			0.535¢ per kWh
Schedule	10	0.569¢ per kWh		
Schedule	11	0.569¢ per kWh		
Schedule	12	0.569¢ per kWh		
Schedule	19	0.569¢ per kWh		
Schedule	23	0.569¢ per kWh	0.550¢ per kWh	
Schedule	23A	0.569¢ per kWh	0.550¢ per kWh	
Schedule	24	0.569¢ per kWh	0.550¢ per kWh	
Schedule	35	0.569¢ per kWh	0.550¢ per kWh	
Schedule	35A	0.569¢ per kWh	0.550¢ per kWh	
Schedule	36	0.569¢ per kWh		
Schedule	400			0.175¢ per kWh
Schedule	401			0.164¢ per kWh

Submitted Under Case No. ~~PAC-E-11-07~~ PAC-E-12-03

ISSUED: ~~March 31, 2011~~February 1, 2012 **EFFECTIVE:** April 1, 2012~~1~~