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IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA ROCKY MOUNTAIN POWER FOR APPROVAL OF CHANGES TO ITS ELECTRIC SERVICE SCHEDULES	)))))))))	CASE NO. PAC-E-11-12

DIRECT TESTIMONY OF RANDY LOBB IN SUPPORT OF THE STIPULATION AND SETTLEMENT

IDAHO PUBLIC UTILITIES COMMISSION

NOVEMBER 2, 2011

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

A. My name is Randy Lobb and my business address is 472 West Washington Street, Boise, Idaho.

Q. By who are you employed?

A. I am employed by the Idaho Public Utilities Commission as Utilities Division Administrator.

Q. What is your educational and professional background?

A. I received a Bachelor of Science Degree in Agricultural Engineering from the University of Idaho in 1980 and worked for the Idaho Department of Water Resources from June of 1980 to November of 1987. I received my Idaho license as a registered professional Civil Engineer in 1985 and began work at the Idaho Public Utilities Commission in December of 1987. I have conducted analysis of utility rate applications, rate design, tariff analysis and customer petitions. I have testified in numerous proceedings before the Commission including cases dealing with rate structure, cost of service, power supply, line extensions, regulatory policy and facility acquisitions. My duties at the Commission currently include case management and oversight of all technical Staff assigned to Commission filings.

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

A. The purpose of my testimony is to describe the comprehensive settlement reach by most of the parties to the case and explain Staff's support.

Q. Please summarize your testimony.

A. Staff supports the Stipulated Settlement proposing a two-year rate plan that recovers a limited level of capital expenditures and an increasing level of power supply costs through a combination of base rate increases and Energy Cost Adjustment Mechanism (ECAM) surcharges. Staff believes that the comprehensive multi-year approach to resolving revenue requirement represents a significantly better deal for customers than could be achieved through either a one year settlement, litigation of the current rate case, or resolution of additional rate filings in 2012.

Staff further supports provisions of the Stipulation that spread the revenue increase to customer classes based in part on cost of service, generally increases rate components on a uniform basis, addresses Populous to Terminal transmission costs and provides resolution of Monsanto interruptible credit valuation over the next two years.

Q. How is your testimony organized?

A. My testimony is subdivided under the following headings:

Stipulation Overview

Q. Would you please describe the terms of the Stipulation?

A. Yes. The Stipulation specifies a two-year rate plan increasing base rates by $17 million (7.8%) in year one and $17 million (7.2%) in year two. The base rate increase proposed to take effect on January 1, 2012 and January 1, 2013 consists of an $11 million increase in Net Power Supply Expenses (NPSE) and a $6 million increase in non-NPSE each year. This compares with the Company's original proposal of increasing base rates by $32.7 million (15%) in one year.

While the Stipulation represents a comprehensive settlement, it does not provide agreement or acceptance of specific revenue requirement adjustments or cost of service methodology. However, it does incorporate all Commission ordered adjustments from Case PAC-E-10-07, Order No. 32196.

The Stipulation specifically identifies base NPSE in 2012 and 2013 for use in the ECAM including annual Renewable Energy Credit (REC) revenue and establishes a load change adjustment rate (LCAR) for the rate period. The Stipulation also specifies how Monsanto and Agrium's share of

ECAM deferral balances will be amortized and collected through 2014.

The Stipulation further specifies spreading the revenue increase to customer classes based, in part, on the Company's proposed Cost of Service (COS) Study. The parties agreed to a 25% move toward COS each year of the rate plan as part of the proposed settlement in this case without accepting the Company's COS methodology for revenue allocation in the future. The parties also agreed that rate component changes within individual customer classes will be prorated based on the original proposal filed by the Company. However, customer charges for Residential Schedules 1 and 36 would remain unchanged.

Other terms in the Stipulation include: 1) escalation in the current Monsanto curtailment product value by [redacted] million each year of the two-year plan; 2) agreement on the used and useful nature of the Populous to Terminal Transmission line (including dismissal of the pending Idaho Supreme Court appeal and excluding that portion of the line's cost deemed plant held for future use (PHFU) from rate base until January 1, 2014); 3) continued deferral of depreciation expense associated with the Populus to Terminal transmission line, pursuant to Order No. 32224; and 4) tracking Idaho's share of the customer load control service credit through the ECAM at the base amount of $1,045,423 pending cost allocation treatment of the dispatchable irrigation load control program.

Finally, the Stipulation specifies a series of collaborative meetings to address: 1) terms, conditions and valuation of Monsanto's curtailment products; 2) cost of service methodologies as applied to Monsanto and the irrigation class and how said methodologies will be utilized in the next general rate case; 3) terms of the irrigation load control program for the 2013 season and beyond; 4) hedging limits consistent with workgroup processes established in Utah and Oregon.

The Stipulation specifies that Rocky Mountain Power will not file another general rate case before May 31, 2013, with new rates not effective prior to January 1, 2014. The Stipulation does not prohibit the Company from revising rates as part of its annual ECAM filing. The Stipulation is attached as Staff Exhibit No. 101.

Q. How does the annual base revenue requirement increase proposed in the Stipulation compare to the increase originally proposed by Rocky Mountain Power?

A. As noted above, the Company proposed to increase annual base electric revenue in 2012 by $32.7 million or 15% overall. The Stipulation increases annual base electric revenue by $17 million in 2012 or approximately 52% of the Company's original request. The Company did not propose a base rate increase in 2013 as part of its filing in this case.

The Settlement Process

Q. Would you please describe the process leading to the Stipulated Settlement?

A. Yes. The Company filed its rate application on May 27, 2011 and the Commission set a June 21, 2011 intervention deadline. Parties ultimately approved for intervention included the Monsanto Company, the Idaho Irrigation Pumpers Association (IIPA), PacifiCorp Idaho Industrial Customers (PIIC), the Community Action Partnership Association of Idaho (CAPAI) and the Idaho Conservation League (ICL).

Once the parties to the case were determined, they met to establish a schedule for production requests/responses, pre-filed direct testimony, pre-filed rebuttal testimony and the dates for the technical hearing. The parties also established August 23, 2011 and September 22, 2011 as Settlement conference dates.

During the period prior to the first Settlement conference, Staff thoroughly reviewed the Company's rate filing and conducted onsite audit of Company expenses and investments. In addition, Staff met informally with the Company and other parties to discuss a variety of issues in preparation for settlement negotiations. Issues discussed included potential expense adjustments, increasing NPSE and associated ECAM rate impacts, cost of service, revenue spread and the valuation of curtailment products.

The first Settlement conference held in August was attended by all the parties in the case and focused primarily on revenue requirement. Return on Equity, power supply expenses, wages and benefits, risk management and wheeling revenues were just a few of the revenue requirement issues presented and discussed. The parties discussed revenue requirement adjustments and stated their positions on issues ranging from jurisdictional and class cost of service cost allocation, to rate design and low income weatherization programs. There was no discussion of a multi-year rate plan and Settlement was not achieved at the first conference.

Q. Did additional informal discussions take place among the parties prior to the second Settlement conference?

A. Yes. As a result of discussions during the initial Settlement conference, it became apparent to the parties that NPSE decisions in this case had multi-year impact through the ECAM. The parties began to analyze the combined base and ECAM rate impact on the various customer classes through the year 2014. Prior to the September Settlement conference, the parties circulated numerous multi-year revenue proposals so all participants could evaluate and agree on how rates would likely change over the period under difference scenarios.

On September 22, a proposed two-year rate plan consisting of a combination of NPSE and non-NPSE base revenue increases was presented. Negotiations ensued on the level of increase each year, the split between NPSE and non-NPSE revenue, how revenue spread to customer classes would occur and how ECAM impacts could be mitigated. No Settlement was reached during the second Settlement conference.

Q. How did the parties ultimately agree on the terms in the Stipulation?

A. Informal discussions among the conference participants continued after the second conference which ultimately led to agreement in principal regarding the two year revenue requirement, revenue spread to customer classes and ECAM rate mitigation. Significant negotiation also occurred over language in the Stipulation regarding treatment of the Populous to Terminal transmission line and the scope of additional discussions that must occur between the Company and interested parties before the next general rate case. As a result of much discussion, negotiation and compromise, all parties to the case except CAPAI signed the Stipulation. ICL officially withdrew as an Intervenor in the case on October 14, 2011.

Staff Evaluation

Q. How did Commission Staff evaluate the Stipulation to determine that it was reasonable?

A. There were several steps taken by Staff in this case to fully evaluate the Stipulation and conclude that it was reasonable. The focus of the evaluation was to assure the best deal for customers. The first step was to identify revenue requirement adjustments based on a thorough review of the Company's filing and an extensive audit of Company financial records. The identified adjustments reducing the requested increase must be supported by evidence on the record and have a reasonable chance of being accepted by the Commission.

The second step was to determine if the identified adjustments removed costs from rate recovery or simply removed costs from base rate recovery. For example, NPSE adjustments might remove costs from base rate recovery only to have them tracked for later recovery through the ECAM mechanism.

Q. What adjustments did Staff identify and how were they categorized?

A. Staff identified a broad range of adjustments starting with adjustments previously approved by the Commission in the Company's last rate case, Case No. PAC-E-10-07. These adjustments included a lower ROE than that proposed by the Company in this case, continued removal of Populus to Terminal transmission costs until the next rate case, removal of salary increases and reduction in coal stockpile costs. Other identified adjustments included

Klamath Falls expenses, coal settlement costs, property taxes, abandoned project costs, a variety of power supply expenses and a number of other miscellaneous costs. Staff's proposed adjustments, if fully accepted by the Commission, would have reduced the Company's revenue increase request by approximately $14.3 million, $5 million of which were power supply costs subject to recovery through the ECAM.

Q. Did other parties to the case propose revenue requirement adjustments?

A. Yes. Other parties suggested adjusting power supply costs, ROE, wheeling revenues, hedging expenses and REC revenues. However, most of these suggestions were already incorporated in Staff adjustments, previously decided by the Commission, or in Staff's view, were without sufficient support. Consequently, Staff evaluated the revenue requirement settlement at this point primarily based on Staff adjustments alone.

Q. Did Staff consider proceeding to hearing rather than settling the case?

A. Yes. Staff considered proceeding to hearing with the identified adjustments. In this case, Staff was not confident that it could successfully defend all of the identified adjustments on the record in the face of rebuttal testimony provided by the Company.

While the Commission makes the final decision on

Company revenue requirement based on the record at hearing, it is the parties to the case that make revenue requirement adjustment recommendations for the Commission to consider. The outcome at hearing in terms of revenue requirement must therefore be evaluated based on both the adjustments to the Company's revenue request that are presented on the record and how the Commission might decide each adjustment.

In Staff's opinion, the best case scenario at hearing would have been an increase in the range of $18.5 million (8.5%) achieved in part by pushing $5 million in NPSE to the ECAM for later recovery.

Q. Why did Staff pursue settlement on a multi-year basis?

A. Staff determined that approximately $17 million of the Company's requested $32.7 million increase in this case was for increased NPSE that is already accumulating in the ECAM deferral balance for recovery starting in April of next year. Failure to recover legitimate NPSE in base rates as part of this case pushes recovery of the expenses to the ECAM in 2013. Clearly, cost recovery decisions in this case have a multi-year impact on customer rates.

Q. What are the reasons for the NPSE increase?

A. The primary reason for the NPSE increase in this case is the declining revenue from surplus electricity sales used to offset system power supply expenses and to a lesser extent, expiration of low-cost power purchase agreements and increasing coal costs. Surplus sales revenue has declined due to reduced market value of electricity caused by declining natural gas prices and increasing surplus wind generation. While surplus sales volume has increased and the cost to fuel natural gas generating plants has decreased, it has not been enough to offset the decline in surplus sales revenue.

NPSE has been characterized as the utility's power bill that is passed on to customers. Historically, it has been very difficult to remove expenses in this category from both base rate and ECAM recovery.

Q. How has NPSE changed over the last few years and what is the forecast for next year?

A. In Case No. PAC-E-10-07, the Company proposed an increase in Idaho NPSE from $66.1 million to $69.2 million. The Commission approved Idaho NPSE of approximately $66.2 million in that case. In this case, the Company requested Idaho NPSE of approximately $82.8 million or approximately $17.7 million more than currently in base rates. In its most recent rate filing in the State of Utah, the Company forecasted NPSE through year end 2012 to be approximately $1.521 billion on a system basis or approximately $98.4 million in Idaho. This amount is approximately $15.6 million more in NPSE than the Company requested in this case. The

Company indicates that NPSE should level off somewhat after 2012. In the meantime, the difference between NPSE recovered in base rates and NPSE actually incurred will be recovered through the ECAM.

Q. How does the multi-year settlement address the NPSE issue?

A. The multi-year settlement spreads recovery of increasing NPSE over three years by combining the proposed $22 million in NPSE base rate increases with the existing $10 million of NPSE currently recovered through the ECAM. By the end of the rate plan in 2013, annual NPSE recovery in Idaho will total approximately $98.2 million with the potential for ECAM rate reduction. This will allow customers to better manage the impact of increasing power supply costs over time.

Q. How did Staff evaluate the non-NPSE increases specified in the Stipulation?

A. Unlike NPSE costs, non-NPSE costs can only be recovered through base rates. Therefore, Staff focused on achieving a lower level of recovery for this category of costs and a better deal for customers through settlement than could be achieved through the hearing process.

The Company requested an increase of approximately $16 million in non-NPSE in this case. Based on Staff's identified adjustments for this category of costs, the best outcome that could be expected at hearing was an increase of approximately $6.7 million. The Stipulation proposes an increase of $6 million or less than 38% of the amount originally requested by the Company. This stipulated amount is equivalent to the Commission accepting every adjustment proposed by the Staff plus an additional $700,000.

Q. How did Staff determine that the rate increase proposed in the second year of the Stipulation was reasonable?

A. Staff evaluated the rate increase proposed for the second year based on the rate request made by the Company last year, the overall rate request made this year and the likelihood that the Company would make a similar rate increase request next year. Last year the Company requested an increase of $27.7 million (13.7%) of which $24.6 million was for non-NPSE. The Commission approved an increase of $14.35 million (7.07%) all of which was non-NPSE. In this case, the Company requested an increase of $32.7 million (15%) of which $16 million was non-NPSE.

Using a 2012 forecasted test year, the Company filed in the State of Utah to increase NPSE (over Company proposed 2011 levels) by approximately $15.6 million on an equivalent Idaho jurisdictional basis. The proposed rate base increase in the Utah filing was approximately $153 million on an Idaho equivalent basis. The non-NPSE increase associated with just the return on the increased rate base is approximately $12 million in Idaho. Absent approval of the Settlement, the Company could and likely would file for a rate increase in 2012 exceeding $30 million, with more than $12 million of the requested increase for non-NPSE. The Stipulation proposes a non-NPSE increase that is less than 50% of that level.

Q. Could you please summarize Staff's support of the Stipulation with regard to the revenue requirement increase over the two-year period?

A. Yes. Because actual power supply expenses are tracked for recovery through the ECAM, customers can pay them now through base rates or pay them later through the ECAM. The $22 million NPSE base rate increase specified in the Stipulation, when combined with expenses currently collected through the ECAM, will reasonably spread recovery of expected power supply costs through 2014.

Staff believes the $12 million non-NPSE increase specified in the Stipulation represents a fraction of the non-NPSE that the Company has requested in this case and would request in a filing next year. Staff maintains that the $6 million non-NPSE increase this year is only 38% of the Company's request and a better deal for customers than could be achieved at hearing. Staff further maintains that the $6 million increase in non-NPSE in 2013 is less than 50% of what the Company would otherwise request in a filing next year.

The Stipulation prohibits the Company from any further base rate increases until January 1, 2014.

Cost of Service

Q. Could you please describe the Stipulation with respect to customer class cost of service (COS) and revenue spread?

A. Yes. While the parties to the Stipulation agreed to a revenue spread in this case based on the Company's proposed class COS study, they did not agree to accept the methodology in future rate cases. The Stipulation specifies that the revenue spread to customer classes in each year of the rate plan will include a 25% move toward the Company's proposed COS in this case.

The resulting revenue spread to the various customer classes in year one of the rate plan range from an increase of 5.88% for Schedule 1 residential customers to 8.91% for Irrigators, Agrium and the Monsanto Company. Year two increases range from 5.43% for residential customers to 8.25% for Irrigators, Agrium and the Monsanto Company. The revenue spread and associated increases for each class, in each year of the rate plan, is shown on Attachment 1 to the Stipulation.

Staff believes that the 50% move toward COS over two years is a reasonable compromise that balances the need for each customer class to pay its fair share while mitigating an even greater rate impact that would otherwise occur with a full COS move. The compromise also allows parties to accept some COS responsibility without accepting a COS methodology.

Rate Design

Q. How are individual rate components proposed to change under the Stipulation?

A. The Parties agreed to accept, for the purposes of this case, the Company's proposals to adjust rate components within each rate schedule with the exception of customer charges in Residential Schedules 1 and 36. Customer charges for these schedules will remain unchanged at $5 and $14 per month, respectively.

Demand charges for Schedules 6, 6A, 9 and 10 will increase each year based in part on cost of service and prorated to reflect the revenue increase assigned to each customer class. Other rate components will increase uniformly reflecting the overall increase in class revenue requirement. Staff believes that the stipulated rate changes are reasonable in allowing customer charges to remain stable, demand charges to generally reflect cost of service and for other charges including energy to reflect the class revenue requirement increase.

Schedule 1 residential customers using the annual monthly average of 837 kWh per month will see a monthly base rate increase of $5.47 and $4.20 in summer and winter, respectively, in the first year. Customers will see an additional increase of $5.36 and $4.10 per month in summer and winter, respectively, in the second year. A monthly billing comparison for Residential Schedule 1 at various monthly consumption levels is shown in Staff Exhibit No. 102.

ECAM Issues

Q. What ECAM issues are addressed in the Stipulation?

A. Besides specifying the ECAM level of system NPSE in base rates for 2012 and 2013 at $1.205 billion and $1.385 billion, respectively, the Stipulation specifies the ECAM level of system Renewable Energy Credits (RECs) included in rates at $78.8 million and establishes the ECAM LCAR at $5.47 per Mwh through 2013. The Stipulation also establishes the level of Idaho allocated Irrigation Load Control program credits at $1.05 million to be tracked through the ECAM pending resolution of system allocation issues.

Q. Could you please explain Staff's support for these ECAM terms specified in the Stipulation?

A. Yes. Staff supports the system NPSE levels specified in the Stipulation for 2012 and 2013 because they are consistent with stipulated NPSE revenue requirement increases for those years. These levels must be specified in order for the ECAM to work properly. The ECAM REC revenue levels are as filed by the Company and within a reasonable range of expected revenue on an annual basis. Actual annual revenue above or below this level will be tracked through the ECAM and trued up each year.

The specified LGAR of $5.47 per Mwh was approved by the Commission as part of Case No. PAC-E-10-7 and is currently used in the ECAM. Staff supports continued use of the previously approved LGAR level through 2013.

The Irrigation Load Control program credit level of $1.05 million specified in the Stipulation is consistent with Irrigation program costs currently allocated to Idaho. Staff agrees that the ability to track irrigation program costs assigned to Idaho through the ECAM during the period of the rate plan is consistent with the Stipulation approved by the Commission in Case No. PAC-E-11-06. The Multi-State Process (MSP) on jurisdictional allocations will determine during the rate plan period if Idaho Irrigation Load control costs will be accepted by other state jurisdictions as a system resource.

Q. Are there any other ECAM issues specified in the Stipulation?

A. Yes. The Stipulation provides for multi-year amortization of ECAM costs assigned to Agrium and the Monsanto Company. Monsanto and Agrium are not currently subject to ECAM rates. However, these customers will be subject to the ECAM starting in 2012. Consequently, they will experience a base rate increase on January 1, 2012 and a significant ECAM rate increase on April 1, 2012 as they become subject to the tracking mechanism. This will occur again in 2013. To mitigate the rate impact of both the base rate increase and the ECAM increase, the Stipulation provides for amortization of ECAM balances subject to recovery from the two customers. 2012 (2011 deferrals) ECAM balances will be amortized through 2014, 2013 (2012 deferrals) ECAM balances will be amortized through 2015 and 2014 (2013 deferrals) ECAM balances will be amortized over two years through 2016.

Staff fully supports amortization of the ECAM deferral balance for these customers to mitigate the much larger rate impact that would otherwise occur. Staff notes that agreement to amortize ECAM expense recovery for these customers has no impact on other Rocky Mountain Power customers in Idaho.

Other Items

Q. Would you please describe the terms in the Stipulation with regard to the Populous to Terminal transmission line.

A. Yes. The parties agreed as part of the Stipulation in this case that the Populous to Terminal transmission line is currently, fully used and useful. However, the parties also agree that the portion of the transmission line deemed plant held for future use in Case No. PAC-E-10-07 shall not be included in rates until on or after January 1, 2014. The parties further agree that the Staff and the Company will file a motion to suspend the Appeal now pending in the Idaho Supreme Court, docketed as Case No. 38930-2011. The parties also agree that the Company will file a stipulation for dismissal of the appeal with each party to bear its own costs upon receipt of a final order from the Commission approving this Stipulation. Consistent with the terms of the Stipulation, the Company and Staff filed the motion to suspend the appeal on October 25, 2011.

The Stipulation also directs the Company to continue deferring depreciation expense associated with the Populus to Terminal transmission line, pursuant to Order No. 32224, until it is included in rates on or after January 1, 2014 and that the accumulated deferral balance will be amortized over three years from the date the costs are included in rates.

Q. Why did Staff agree to these terms?

A. Staff agreed to the terms in the Stipulation as a compromise in order to achieve a comprehensive settlement in this case on revenue requirement. Staff believed that it could agree to the position that the Populous to Terminal transmission line was now fully used and useful as long as that portion of the transmission line deemed plant held for future use by the Commission was not included in rates until on or after January 1, 2014. Staff supported continued deferral of the Populous to Terminal depreciation expense in compliance with Commission Order until after all costs are included in rates. Staff further viewed future amortization of those costs over three years as a reasonable period for recovery.

Q. What other items are addressed in the Stipulation?

A. The Stipulation specifies that the value of Monsanto curtailment products will increase from [redacted] million in 2011 to [redacted] million in 2012 and to [redacted] million in 2013. Staff believes the proposed escalation provides a reasonable resolution of an otherwise contentious issue during the period of the rate plan.

Finally, the Stipulation provides for workshops and collaborative discussions to address cost of service methodologies as applied to Monsanto and the irrigation class and how methodologies could be utilized in the next general rate case. Workshops will also be conducted to discuss terms of the irrigation load control program for the 2013 season and beyond and hedging limits consistent with workgroup processes established in Utah and Oregon.

Staff supports and plans to participate in the discussion on all of these issues. The two-year base rate moratorium provides all parties the opportunity to work together to gain a common understanding of cost of service issues. Agreement to discuss Irrigation credit valuation and hedging practices of the Company will also provide a timely review of resource acquisition choices and strategies.

Q. Does this conclude your testimony in this case?

A. Yes it does.

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IDAHO PUBLIC
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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA ROCKY MOUNTAIN POWER FOR APPROVAL OF CHANGES TO ITS ELECTRIC SERVICE SCHEDULES AND A PRICE INCREASE OF $32.7 MILLION, OR APPROXIMATELY 15.0 PERCENT	)	**CASE NO. PAC-E-11-12** **STIPULATION**

This stipulation ("Stipulation") is entered into by and among Rocky Mountain Power, a division of PacifiCorp ("Rocky Mountain Power" or the "Company"); Staff for the Idaho Public Utilities Commission ("Staff"); Monsanto Company ("Monsanto"); PacifiCorp Idaho Industrial Customers ("PIIC"); and the Idaho Irrigation Pumper Association Inc. ("IIPA") collectively referred to as the "Parties". Community Action Partnership Association of Idaho ("CAPAI") participated in the settlement negotiations however they have chosen not to be a party to the Stipulation.

I. INTRODUCTION

1. The terms and conditions of this Stipulation are set forth herein. The Parties agree that this Stipulation represents a fair, just and reasonable compromise of the issues in this proceeding and that this Stipulation is in the public interest. The Parties recommend that the Idaho Public Utilities Commission ("Commission"), pursuant to its authority under Commission

Rules 271, 272 and 274, approve the Stipulation and all of its terms and conditions. *See* IDAPA 31.01.01.271, 272, and 274.

II. BACKGROUND

2. On May 27, 2011, Rocky Mountain Power filed an Application seeking authority to increase the Company's base rates for electric service by $32.7 million annually, an overall average increase of approximately 15.0%. The increase in rates varies by customer class and actual usage. Rocky Mountain Power sought an increase in rates effective December 27, 2011.

3. With a view toward resolving the issues raised in Rocky Mountain Power's Application in this proceeding, representatives of the Parties met on August 23, 2011 and September 22, 2011, pursuant to IDAPA 31.01.01.271 and 272, to engage in settlement discussions.

Based upon the settlement discussions between the Parties, as a compromise of the positions in this proceeding, and for other consideration as set forth below, the Parties stipulate and agree to the following:

III. TERMS OF THE STIPULATION

Revenue Requirement

4. The Parties agree to support a two-year rate plan with annual rate increases of $17.0 million per year, which results in overall average annual revenue increases of approximately 7.8 percent in 2012 and 7.2 percent in 2013. The first increase to base rates will occur January 1, 2012, and will be comprised of $6.0 million of non-net power cost components (capital, operations and maintenance, and other) and $11.0 million of net power costs. The second increase to base rates will occur January 1, 2013, and will be comprised of $6.0 million of non-net power cost components and $11.0 million of net power costs. The Company will make a compliance filing November 1, 2012 to implement the second year increase of $17.0 million effective January 1, 2013 that will include revised tariffs.

5. Unless explicitly specified within the Stipulation, the Parties agree that determining the annual increases of $17.0 million per year for two years is a "black box"

settlement, with no agreement or acceptance by the Parties of any specific revenue requirement, cost allocation or cost of service methodology. However, the Parties agree that the starting point of the Stipulation was to accept all Commission ordered adjustments from Case PAC-E-10-07, Order No. 32196. All Parties agree that this Stipulation represents a fair, just and reasonable compromise of the issues in this proceeding and that this Stipulation is in the public interest.

Power Costs

6. The Parties agree that based on the revenue requirement split specified in paragraph 4, net power costs in base rates will increase from the current level of $1.025 billion to $1.205 billion in 2012 and from $1.205 billion to $1.385 billion in 2013. These amounts will become the total Company base net power costs for tracking in the Company's energy cost adjustment mechanism ("ECAM").

7. The Parties agree that $78.8 million, on a total Company basis or $6,526,622 allocated to Idaho (RMP Exhibit 2 page 3.5) of renewable energy certificate ("REC") revenue is included in rates in 2012 and 2013. The Idaho allocated amount will become the base for purposes of tracking at 100 percent in the Company's ECAM mechanism.

8. The Parties agree to update the Idaho load in the 2012 ECAM load change adjustment revenue ("LCAR") calculation to the 2010 actual load included in PAC-E-11-12 for the 2012 ECAM deferral calculation and use 2011 actual load reported in the Annual Results of Operations Report for the 2013 ECAM deferral calculation. The LCAR unit value would be frozen over the rate plan period at the current rate of $5.47 per MWh (Case No. PAC-E-10-07).

9. The Parties agree that the Company shall amortize and collect Agrium and Monsanto's share of Commission approved ECAM balances, which includes deferred net power costs, deferred REC's, LCAR adjustments and other ECAM components, including the irrigation load control credit as specified in paragraph 10, over the following periods:

a) The 2012 ECAM balance (2011 deferrals) over a period of three years;

b) The 2013 ECAM balance (2012 deferrals) over a period of three years;

c) The 2014 ECAM balance (2013 deferrals) over a period of two years.

d) Beginning with the 2015 ECAM balance (2014 deferrals), Monsanto and Agrium will pay new ECAM costs based on a 12-month collection period.

Any over-collection or under-collection at the end of the amortization periods identified in paragraphs 9(a) through 9(c) above will be trued up for each contract customer and refunded or collected as part of a subsequent ECAM collection period from these contract customers and not from other retail customers. All other customers will continue to pay ECAM charges on the 12-month collection period as they currently do during the rate plan.

10. The Parties agree that, due to the uncertainty of the jurisdictional treatment of the dispatchable irrigation load control program currently being discussed by the MSP Standing Committee, Idaho's share of the customer load control service credit will be tracked in the ECAM. The Parties further agree that $1,045,423 (RMP Exhibit 2 page 4.4.1) is Idaho's base amount to be tracked in the ECAM for 2012 and 2013.

Rate Spread and Rate Design

11. The Parties agree to a rate spread based upon $17.0 million in annual increases for 2012 and 2013 as set forth in more detail in Attachment 1 to this Stipulation.

12. The Parties agree that the design of rates by rate schedule (rate design) shall be consistent with the Company's proposals filed in its Application and adjusted for the revenue requirement specified in this Stipulation. Details of the rate design are included in Attachment 2 to this Stipulation.

13. The Parties agree that the Company's residential customer service charge for Schedule 1 and 36 will remain at $5.00 per month and $14.00 per month, respectively, during the time period covered by this Stipulation.

Other Items

14. The Parties agree that the value of Monsanto's curtailment products will be increased from [redacted] million in 2011, to [redacted] million in 2012, and [redacted] million in 2013. Monsanto and the Company will execute a new energy service agreement for 2012 and 2013 in order to reflect the terms of the Stipulation. Monsanto and the Company agree to work

collaboratively and in good faith during the rate plan period to address the terms, conditions and valuation of Monsanto's curtailment products in an effort to maximize value to the Company and Monsanto and also to discuss cost of service methodologies as applied to the Monsanto load and how said methodologies will be utilized in the next general rate case. Monsanto and the Company will report to the Staff and Commission as appropriate on the progress made.

15. The Parties agree that this Stipulation does not change or alter the irrigation load control service credit in 2012 or prior agreements governing the irrigation load control program that require the irrigation load control service credit to be renegotiated for the 2013 season and beyond. The Company and IIPA will work collaboratively during calendar year 2012 to renegotiate the irrigation load control program for the 2013 season and beyond. The Company and IIPA will work collaboratively during the rate plan period to discuss cost of service methodologies as applied to the irrigation class and how said methodologies will be utilized in the next general rate case.

16. The Parties agree that the portion of the Populus to Terminal transmission line determined by the Commission in Case No. PAC-E-10-07 to be plant held for future use (PHFU) is now used and useful. The parties further agree that the Commission should make a specific finding that the entire Populus to Terminal transmission line is now used and useful. Although the Parties agree that the Populus to Terminal transmission line is used and useful, they further agree that the portion of the transmission line deemed PHFU in Case No. PAC-E-10-07 shall not be included in rates until on or after January 1, 2014. Following the filing of this Stipulation, Staff and the Company agree to file a Motion to Suspend the Appeal now pending in the Idaho Supreme Court, docketed as Case No. 38930-2011. Upon receipt of a final Order from the Commission approving the Stipulation, the Company agrees that it will within 10 days thereof file a stipulation for Dismissal of the appeal with each party to bear its own costs.

17. The Parties agree that the Company will continue to defer the depreciation expense associated with the Populus to Terminal transmission line, pursuant to Order No. 32224,

until it is included in rates on January 1, 2014 and that the accumulated deferral balance will be amortized over three years from the date the costs are included in rates.

18. The Parties agree that the Company will work with the Parties to establish hedging limits consistent with workgroup processes established in Utah and Oregon for costs beginning January 1, 2013, and forward.

19. The Parties agree that, in recognition of the two-year rate plan covered by this Stipulation, Rocky Mountain Power will not file another general rate case before May 31, 2013, with new rates not effective prior to January 1, 2014. Rocky Mountain Power will continue to file annual Results of Operations Reports with the Commission to enable the Commission to ensure that rates during the two-year rate plan continue to be just and reasonable. This Stipulation does not prohibit the Company from revising rates due to the ECAM, which will still occur April 1 each year.

IV. GENERAL PROVISIONS

20. The Parties agree that this Stipulation represents a compromise of the disputed claims and positions of the Parties on all issues in this proceeding. Other than the above referenced positions and any testimony filed in support of the approval of this Stipulation, and except to the extent necessary for a Party to explain before the Commission its own statements and positions with respect to the Stipulation, all negotiations relating to this Stipulation shall not be admissible as evidence in this or any other proceeding regarding this subject matter.

21. The Parties submit this Stipulation to the Commission and recommend approval of the Stipulation in its entirety pursuant to Commission Rule 274, IDAPA 31.01.01.274. The Parties shall support this Stipulation before the Commission, and no Party shall appeal any portion of this Stipulation or any subsequent Order approving the same. If this Stipulation is challenged by any person not a party to the Stipulation, the Parties to this Stipulation reserve the right to cross-examine witnesses and put on such case as they deem appropriate to respond fully to the issues presented, including the right to raise issues that are incorporated in the settlement embodied in this Stipulation. Notwithstanding this reservation of rights, the Parties to this

Stipulation agree that they will continue to support the Commission's adoption of the terms of this Stipulation.

22. In the event the Commission rejects any part or all of this Stipulation, or imposes any additional material conditions on approval of this Stipulation, each Party reserves the right, upon written notice to the Commission and the other Parties to this proceeding, within 15 days of the date of such action by the Commission, to withdraw from this Stipulation. In such case, no Party shall be bound or prejudiced by the terms of this Stipulation, and each Party shall be entitled to seek reconsideration of the Commission's order, file testimony as it chooses, cross-examine witnesses, or otherwise present its case in a manner consistent with the Commission's Rules and Procedures.

23. The Parties agree that this Stipulation is in the public interest and that all of its terms and conditions are fair, just and reasonable.

24. No Party shall be bound, benefited or prejudiced by any position asserted in the negotiation of this Stipulation, except to the extent expressly stated herein, nor shall this Stipulation be construed as a waiver of the rights of any Party unless such rights are expressly waived herein. This is a "black box" settlement and execution of this Stipulation shall not be deemed to constitute an acknowledgment by any Party of the validity or invalidity of any particular method, theory or principle of regulation or cost recovery. No Party shall be deemed to have agreed that any method, theory or principle of regulation or cost recovery employed in arriving at this Stipulation is appropriate for resolving any issues in any other proceeding in the future. No findings of fact or conclusions of law other than those stated herein shall be deemed to be implicit in this Stipulation.

25. The obligations of the Parties under this Stipulation are subject to the Commission's approval of this Stipulation in accordance with its terms and conditions and, if judicial review is sought, upon such approval being upheld on appeal by a court of competent jurisdiction.

Respectfully submitted this 17th day of October, 2011.

Rocky Mountain Power

By [signature]
Mark C. Moench

Monsanto Company

By [signature]
Randall C. Budge

Idaho Public Utilities Commission Staff

By________________________
D. Neil Price

PacifiCorp Idaho Industrial Customers

By________________________
Ronald L. Williams

Idaho Irrigation Pumper Association Inc.

By [signature]
Eric L. Olsen

Exhibit No. 101
Case No. PAC-E-11-12
R. Lobb, Staff
11/02/11 Page 8 of 18

Respectfully submitted this 17th day of October, 2011.

Rocky Mountain Power

By______________________________
Mark C. Moench

Monsanto Company

By______________________________
Randall C. Budge

Idaho Public Utilities Commission Staff

By______________________________
D. Neil Price

PacifiCorp Idaho Industrial Customers

By______________________________
Ronald L. Williams

Idaho Irrigation Pumper Association Inc.

By______________________________
Eric L. Olsen

Respectfully submitted this 17th day of October, 2011.

Rocky Mountain Power

By ______________________
Mark C. Moench

Monsanto Company

By ______________________
Randall C. Budge

Idaho Public Utilities Commission Staff

By ______________________
D. Neil Price

PacifiCorp Idaho Industrial Customers

By ______________________
Ronald L. Williams

Idaho Irrigation Pumper Association Inc.

By ______________________
Eric L. Olsen

ATTACHMENT 1

Attachment 1 - Settlement Revenue Requirement and Rate Spread
ROCKY MOUNTAIN POWER - STATE OF IDAHO
CASE NO. PAC-E-11-12

Description	Sch. No.	Base Revenue	First Year Increase	First Year Total	First Year Percent	Second Year Increase	Second Year Total	Second Year Percent	Two Year Increase	Two Year Total	Two Year Percent
Residential	01	$41,480,591	$2,439,725	$43,920,316	5.88%	$2,385,257	$46,305,573	5.43%	$4,824,982	$46,305,573	11.63%
Residential - TOD	36	$22,532,610	$1,794,697	$24,327,307	7.96%	$1,796,941	$26,124,248	7.39%	$3,591,638	$26,124,248	15.94%
General Service - Large	06, 35	$21,103,808	$1,413,559	$22,517,367	6.70%	$1,397,532	$23,914,899	6.21%	$2,811,091	$23,914,899	13.32%
General Service - High Voltage	09	$5,889,323	$413,459	$6,302,782	7.02%	$410,273	$6,713,055	6.51%	$823,732	$6,713,055	13.99%
Irrigation	10	$41,151,802	$3,664,898	$44,816,700	8.91%	$3,695,252	$48,511,952	8.25%	$7,360,150	$48,511,952	17.89%
Street & Area Lighting	07,11,12	$597,888	$6,405	$604,293	1.07%	$3,670	$607,963	0.61%	$10,075	$607,963	1.69%
Space Heating	19	$454,158	$29,088	$483,246	6.40%	$28,653	$511,899	5.93%	$57,741	$511,899	12.71%
General Service - Small	23	$13,014,299	$895,307	$13,909,606	6.88%	$887,023	$14,796,629	6.38%	$1,782,330	$14,796,629	13.70%
Contract 1	400	$66,330,739	$5,907,284	$72,238,023	8.91%	$5,956,211	$78,194,234	8.25%	$11,863,495	$78,194,234	17.89%
Contract 2	401	$4,890,954	$435,579	$5,326,533	8.91%	$439,186	$5,765,719	8.25%	$874,765	$5,765,719	17.89%
State of Idaho	Total	$217,446,172	$17,000,000	$234,446,172	7.82%	$17,000,000	$251,446,172	7.25%	$34,000,000	$251,446,172	15.64%
AGA Revenue		*$751,615*		*$751,615*			*$751,615*			*$751,615*	
State of Idaho + AGA	Total	$218,197,787		$235,197,787	7.79%		$252,197,787	7.23%		$252,197,787	15.58%

ATTACHMENT 2

Attachment 2 - Settlement Rates
ROCKY MOUNTAIN POWER - STATE OF IDAHO
CASE NO. PAC-E-11-12

		Settlement	
	Present	Year 1 1/1/2012	Year 2 1/1/2013
SCHEDULE NO. 1 - Residential Service			
Customer Charge	$5.00	$5.00	$5.00
All kWh (May - Oct)			
<= 700 kWh	9.6018 ¢	10.2013 ¢	10.7874 ¢
> 700 kWh	12.9624 ¢	13.7717 ¢	14.5630 ¢
All kWh (Nov - Apr)			
<= 1,000 kWh	7.3496 ¢	7.8085 ¢	8.2571 ¢
> 1,000 kWh	9.9220 ¢	10.5415 ¢	11.1472 ¢
Seasonal Service Charge	$60.00	$60.00	$60.00
SCHEDULE NO. 36 - Residential Service Optional TOD			
Customer Charge	$14.00	$14.00	$14.00
On-Peak kWh (May - Oct)	12.2191 ¢	13.3102 ¢	14.4027 ¢
Off-Peak kWh (May - Oct)	4.1697 ¢	4.5420 ¢	4.9148 ¢
On-Peak kWh (Nov - Apr)	10.4377 ¢	11.3697 ¢	12.3029 ¢
Off-Peak kWh (Nov - Apr)	3.8162 ¢	4.1570 ¢	4.4982 ¢
Seasonal Service Charge	$168.00	$168.00	$168.00
SCHEDULE NO. 6/6A - General Service - Large Power			
Customer Charge (Secondary Voltage)	$33.00	$35.00	$37.00
Customer Charge (Primary Voltage)	$99.00	$105.00	$111.00
All kW (May - Oct)	$12.22	$13.28	$14.36
All kW (Nov - Apr)	$10.05	$10.92	$11.81
All kWh	3.3805 ¢	3.5305 ¢	3.6696 ¢
Seasonal Service Charge (Secondary)	$396.00	$420.00	$444.00
Seasonal Service Charge (Primary)	$1,188.00	$1,260.00	$1,332.00
Voltage Discount	($0.57)	($0.61)	($0.65)
SCHEDULE NO. 7 - Customer Owned Light			
Residential			
Charges Per Lamp			
16,000 Lumens, HPSV	$14.67	$14.82	$14.91
SCHEDULE NO. 7/7A - Security Area Lighting			
Charges Per Lamp			
7000 Lumens, MV	$26.40	$26.67	$26.83
20,000 Lumens, MV	$47.09	$47.58	$47.86
5,600 Lumens, HPSV, Co Owned Pole	$16.77	$16.94	$17.04
5,600 Lumens, HPSV, No Co Owned Pole	$13.34	$13.48	$13.56
9,500 Lumens, HPSV, Co Owned Pole	$19.20	$19.40	$19.51
9,500 Lumens, HPSV, No Co Owned Pole	$15.77	$15.93	$16.02
16,000 Lumens, HPSV, Co Owned Pole	$25.29	$25.55	$25.70
16,000 Lumens, HPSV, No Co Owned Pole	$22.52	$22.75	$22.88
27,500 Lumens, HPSV, Co Owned Pole	$36.37	$36.75	$36.97

		Settlement	
	Present	Year 1 1/1/2012	Year 2 1/1/2013
27,500 Lumens, HPSV, No Co Owned Pole	$32.94	$33.28	$33.48
50,000 Lumens, HPSV, Co Owned Pole	$50.84	$51.37	$51.67
50,000 Lumens, HPSV, No Co Owned Pole	$45.00	$45.47	$45.74
16,000 Lumens, HPS Flood, Co Owned Pole	$25.29	$25.55	$25.70
16,000 Lumens, HPS Flood, No Co Owned Pole	$22.52	$22.75	$22.88
27,500 Lumens, HPS Flood, Co Owned Pole	$36.37	$36.75	$36.97
27,500 Lumens, HPS Flood, No Co Owned Pole	$32.94	$33.28	$33.48
50,000 Lumens, HPS Flood, Co Owned Pole	$50.84	$51.37	$51.67
50,000 Lumens, HPS Flood, No Co Owned Pole	$45.00	$45.47	$45.74
8,000 Lumens, LPSV, Energy Only	$3.60	$3.64	$3.66
13,500 Lumens, LPSV, Energy Only	$5.32	$5.38	$5.41
22,500 Lumens, LPSV, Energy Only	$7.40	$7.48	$7.52
33,000 Lumens, LPSV, Energy Only	$9.01	$9.10	$9.15
SCHEDULE NO. 9 - General Service - High Voltage			
Customer Charge	$324.00	$347.00	$370.00
All kW (May - Oct)	$8.48	$9.35	$10.26
All kW (Nov - Apr)	$6.41	$7.06	$7.74
Minimum kW Summer	$8.48	$9.35	$10.26
Minimum kW Winter	$6.41	$7.06	$7.74
All kWh	3.5006 ¢	3.6970 ¢	3.8835 ¢
SCHEDULE NO. 10 - Irrigation			
Small Customer Charge (Season)	$12.00	$13.00	$14.00
Large Customer Charge (Season)	$35.00	$38.00	$41.00
Post-Season Customer Charge	$19.00	$21.00	$23.00
All kW (June 1 - Sept 15)	$4.69	$5.31	$5.98
First 25,000 kWh (June 1 - Sept 15)	7.3477 ¢	7.9434 ¢	8.5312 ¢
Next 225,000 kWh (June 1 - Sept 15)	5.4349 ¢	5.8755 ¢	6.3103 ¢
All Add'l kWh (June 1 - Sept 15)	4.0116 ¢	4.3368 ¢	4.6577 ¢
All kWh (Sept 16 - May 31)	6.2144 ¢	6.7187 ¢	7.2164 ¢
SCHEDULE NO. 11 - Company-Owned Street Lighting Service			
Charges per Lamp			
5,800 Lumens, High Intensity Discharge	$14.89	$15.05	$15.14
9,500 Lumens, High Intensity Discharge	$18.58	$18.78	$18.89
16,000 Lumens, High Intensity Discharge	$25.33	$25.60	$25.75
27,500 Lumens, High Intensity Discharge	$35.38	$35.75	$35.96
50,000 Lumens, High Intensity Discharge	$51.93	$52.48	$52.79
9,500 Lumens, High Intensity Discharge - Series 1	$30.73	$31.06	$31.25
16,000 Lumens, High Intensity Discharge - Series 1	$33.73	$34.09	$34.29
9,500 Lumens, High Intensity Discharge - Series 2	$25.29	$25.56	$25.71
16,000 Lumens, High Intensity Discharge - Series 2	$28.21	$28.51	$28.68
12,000 Metal Halide	$27.42	$27.71	$27.88

Attachment 2 - Settlement Rates
ROCKY MOUNTAIN POWER - STATE OF IDAHO
CASE NO. PAC-E-11-12

	Present	Settlement Year 1 1/1/2012	Settlement Year 2 1/1/2013
19,500 Metal Halide	$34.03	$34.39	$34.60
32,000 Metal Halide	$41.28	$41.72	$41.97
9,000 Metal Halide - Series 1	$31.00	$31.33	$31.52
12,000 Metal Halide - Series 1	$35.64	$36.02	$36.24
9,000 Metal Halide - Series 2	$30.17	$30.49	$30.67
12,000 Metal Halide - Series 2	$31.85	$32.19	$32.38
SCHEDULE NO. 12E - Customer-Owned Street Lighting Service-Energy Only			
Charges per Lamp			
33,000 Lumens, LPSV	$9.01	$9.11	$9.16
12,000 Metal Halide	$6.94	$7.01	$7.05
19,500 Metal Halide	$9.49	$9.59	$9.65
32,000 Metal Halide	$14.92	$15.08	$15.17
107,800 Metal Halide	$35.72	$36.10	$36.32
9,000 Metal Halide	$3.95	$3.99	$4.01
5,800 Lumens, HPSV	$2.79	$2.82	$2.84
9,500 Lumens, HPSV	$3.91	$3.95	$3.97
16,000 Lumens, HPSV	$5.81	$5.87	$5.91
27,500 Lumens, HPSV	$9.93	$10.04	$10.10
50,000 Lumens, HPSV	$15.27	$15.43	$15.52
Non-Listed Luminaire - Energy Only	10.1259 ¢	10.2330 ¢	10.2944 ¢
SCHEDULE NO. 12F - Customer-Owned Street Lighting Service-Full Maintenance			
Charges per Lamp			
5,800 Lumens, HPSV	$6.45	$6.52	$6.56
9,500 Lumens, HPSV	$8.22	$8.31	$8.36
16,000 Lumens, HPSV	$9.88	$9.98	$10.04
27,500 Lumens, HPSV	$12.94	$13.08	$13.16
50,000 Lumens, HPSV	$17.27	$17.45	$17.55
SCHEDULE NO. 12P - Customer-Owned Street Lighting Service-Partial Maintenance			
Charges per Lamp			
10,000 Lumens, MV	$16.15	$16.32	$16.42
20,000 Lumens, MV	$21.62	$21.85	$21.98
5,800 Lumens, HPSV	$5.78	$5.84	$5.88
9,500 Lumens, HPSV	$7.44	$7.52	$7.57
27,500 Lumens, HPSV	$11.94	$12.07	$12.14
50,000 Lumens, HPSV	$16.09	$16.26	$16.36
SCHEDULE NO. 19 - Commercial and Industrial Space Heating			
Customer Charge Secondary	$21.00	$22.00	$23.00
All kWh (May - Oct)	8.2953 ¢	8.8093 ¢	9.3152 ¢
All kWh (Nov - Apr)	6.1465 ¢	6.5274 ¢	6.9023 ¢

Attachment 2 - Settlement Rates
ROCKY MOUNTAIN POWER - STATE OF IDAHO
CASE NO. PAC-E-11-12

	Present	Settlement Year 1 1/1/2012	Settlement Year 2 1/1/2013
SCHEDULE NO. 23/23A - General Service			
Customer Charge Secondary	$14.00	$15.00	$16.00
Customer Charge Primary	$43.00	$46.00	$49.00
Total Customer Charges			
All kWh (May - Oct)	8.0585 ¢	8.5835 ¢	9.1030 ¢
All kWh (Nov - Apr)	7.0345 ¢	7.4928 ¢	7.9463 ¢
Seasonal Service Charge (Secondary)	$168.00	$180.00	$192.00
Seasonal Service Charge (Primary)	$516.00	$552.00	$588.00
Voltage Discount	(0.3892) ¢	(0.4146) ¢	(0.4397) ¢
SCHEDULE NO. 35 - General Service - Optional TOD			
Customer Charge Secondary	$59.00	$63.00	$67.00
Customer Charge Primary	$145.00	$155.00	$165.00
All On-Peak kW	$14.52	$15.49	$16.45
All kWh	4.3260 ¢	4.6154 ¢	4.9015 ¢
Seasonal Service Charge (Secondary)	$708.00	$756.00	$804.00
Seasonal Service Charge (Primary)	$1,740.00	$1,860.00	$1,980.00
Voltage Discount	($0.74)	($0.79)	($0.84)
SCHEDULE 400			
Firm Energy and Power			
Customer Charges	$1,345.00	$1,465.00	$1,586.00
kWh	2.6180 ¢	2.8515 ¢	3.0870 ¢
kW	$13.50	$14.70	$15.91
Excess kVar	$0.82	$0.89	$0.96
Interruptible Energy and Power			
kWh	2.6180 ¢	2.8515 ¢	3.0870 ¢
kW	$13.50	$14.70	$15.91
SCHEDULE 401			
Customer Charges	$375.00	$408.00	$442.00
HLH kWh (May-October)	3.0820 ¢	3.3565 ¢	3.6332 ¢
HLH kWh (November-April)	2.5630 ¢	2.7913 ¢	3.0214 ¢
LLH kWh (May-October)	2.3110 ¢	2.5168 ¢	2.7243 ¢
LLH kWh (November-April)	2.3110 ¢	2.5168 ¢	2.7243 ¢
All kW (May-October)	$14.93	$16.26	$17.60
All kW (November-April)	$12.04	$13.11	$14.19

CERTIFICATE OF SERVICE

I hereby certify that on this 17th day of October, 2011, I caused to be served, via overnight delivery and E-mail, a true and correct copy of Rocky Mountain Power's Stipulation in PAC-E-11-12 to the following:

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Carrie Meyer
Carrie Meyer
Coordinator, Regulatory Operations

PAC-E-11-12
Monthly Billing Comparison
Idaho Public Utilities Commission
General Rate Case

Residential Service
Schedule 1

First Year Stipulated Increase[1]

Energy kWh	Energy kWh[2]	Summer Present	Summer First Yr.	Summer % Δ	Non-Summer Present	Non-Summer First Yr.	Non-Summer % Δ	Avg. Mth Cost -12 Mths Present	Avg. Mth Cost -12 Mths First Yr.	Avg. Mth Cost -12 Mths % Δ
0		$5.17	$5.17	0.00%	$5.17	$5.17	0.00%	$5.17	$5.17	0.00%
100		$15.69	$16.31	3.95%	$13.36	$13.83	3.55%	$14.52	$15.07	3.79%
200		$26.20	$27.44	4.73%	$21.55	$22.49	4.40%	$23.87	$24.97	4.61%
300		$36.72	$38.58	5.06%	$29.73	$31.16	4.79%	$33.23	$34.87	4.94%
400		$47.24	$49.72	5.25%	$37.92	$39.82	5.01%	$42.58	$44.77	5.14%
500		$57.75	$60.85	5.37%	$46.11	$48.48	5.15%	$51.93	$54.67	5.28%
600		$68.27	$71.99	5.45%	$54.30	$57.14	5.24%	$61.28	$64.57	5.37%
700		$78.79	$83.13	5.51%	$62.48	$65.81	5.32%	$70.64	$74.47	5.42%
716	Summer	$81.02	$85.50	5.52%	$64.22	$67.64	5.33%	$72.62	$76.57	5.44%
800		$92.78	$97.95	5.58%	$73.33	$77.29	5.40%	$83.06	$87.62	5.49%
837	Annual	$97.95	$103.44	5.60%	$77.35	$81.55	5.43%	$87.65	$92.49	5.52%
900		$106.77	$112.78	5.63%	$84.18	$88.78	5.47%	$95.47	$100.78	5.56%
958	Non-Summer	$114.88	$121.38	5.66%	$90.47	$95.45	5.50%	$102.68	$108.41	5.58%
1,000		$120.76	$127.61	5.67%	$95.03	$100.27	5.52%	$107.89	$113.94	5.61%
1,200		$148.74	$157.27	5.73%	$116.72	$123.25	5.59%	$132.73	$140.26	5.67%
1,400		$176.73	$186.92	5.77%	$138.42	$146.22	5.64%	$157.57	$166.57	5.71%
1,600		$204.71	$216.58	5.80%	$160.11	$169.20	5.68%	$182.41	$192.89	5.75%
1,800		$232.69	$246.24	5.82%	$181.81	$192.18	5.70%	$207.25	$219.21	5.77%
2,000		$260.68	$275.89	5.84%	$203.50	$215.15	5.72%	$232.09	$245.52	5.79%
2,500		$330.63	$350.03	5.87%	$257.74	$272.59	5.76%	$294.19	$311.31	5.82%
3,000		$400.59	$424.18	5.89%	$311.98	$330.04	5.79%	$356.29	$377.11	5.84%
5,000		$680.42	$720.74	5.93%	$528.94	$559.80	5.84%	$604.68	$640.27	5.89%

Second Year Stipulated Increase[1]

Energy kWh	Energy kWh[2]	Summer First Yr.	Summer Second Yr.	Summer % Δ	Non-Summer First Yr.	Non-Summer Second Yr.	Non-Summer % Δ	Avg Mth Cost -12 Mths First Yr.	Avg Mth Cost -12 Mths Second Yr.	Avg Mth Cost -12 Mths % Δ
0		$5.17	$5.17	0.00%	$5.17	$5.17	0.00%	$5.17	$5.17	0.00%
100		$16.31	$16.91	3.72%	$13.83	$14.30	3.35%	$15.07	$15.60	3.52%
200		$27.44	$28.66	4.42%	$22.49	$23.42	4.12%	$24.97	$26.04	4.29%
300		$38.58	$40.40	4.71%	$31.16	$32.55	4.47%	$34.87	$36.47	4.59%
400		$49.72	$52.14	4.88%	$39.82	$41.67	4.66%	$44.77	$46.91	4.78%
500		$60.85	$63.88	4.98%	$48.48	$50.80	4.78%	$54.67	$57.34	4.88%
600		$71.99	$75.63	5.05%	$57.14	$59.93	4.87%	$64.57	$67.78	4.97%
700		$83.13	$87.37	5.10%	$65.81	$69.05	4.93%	$74.47	$78.21	5.02%
716	Summer	$85.50	$89.87	5.11%	$67.64	$70.99	4.95%	$76.57	$80.43	5.04%
800		$97.95	$103.01	5.17%	$77.29	$81.17	5.01%	$87.62	$92.09	5.10%
837	Annual	$103.44	$108.80	5.18%	$81.55	$85.65	5.03%	$92.49	$97.23	5.12%
900		$112.78	$118.66	5.21%	$88.78	$93.28	5.07%	$100.78	$105.97	5.15%
958	Non-Summer	$121.38	$127.74	5.23%	$95.45	$100.31	5.09%	$108.41	$114.02	5.17%
1,000		$127.61	$134.31	5.25%	$100.27	$105.40	5.11%	$113.94	$119.85	5.19%
1,200		$157.27	$165.60	5.30%	$123.25	$129.63	5.18%	$140.26	$147.61	5.24%
1,400		$186.92	$196.89	5.33%	$146.22	$153.86	5.22%	$166.57	$175.37	5.28%
1,600		$216.58	$228.19	5.36%	$169.20	$178.08	5.25%	$192.89	$203.14	5.31%
1,800		$246.24	$259.48	5.38%	$192.18	$202.31	5.27%	$219.21	$230.90	5.33%
2,000		$275.89	$290.77	5.39%	$215.15	$226.54	5.29%	$245.52	$258.66	5.35%
2,500		$350.03	$369.00	5.42%	$272.59	$287.12	5.33%	$311.31	$328.06	5.38%
3,000		$424.18	$447.24	5.44%	$330.04	$347.69	5.35%	$377.11	$397.46	5.40%
5,000		$720.74	$760.17	5.47%	$559.80	$589.98	5.39%	$640.27	$675.07	5.44%

[1] Includes current Schedule 34-BPA Credit which equals zero, ECAM and Customer Efficiency Services Rate Adjustment.

[2] Monthly average usage for summer, non-summer and annual.

Exhibit No. 102
Case No. PAC-E-11-12
R. Lobb, Staff
11/02/11

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 2ND DAY OF NOVEMBER 2011, SERVED THE FOREGOING **DIRECT TESTIMONY OF RANDY LOBB IN SUPPORT OF THE STIPULATION AND SETTLEMENT**, IN CASE NO. PAC-E-11-12, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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Jo Nelson
SECRETARY