- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Application of Rocky Mountain Power for Alternative Cost Recovery for Major Plant Additions of the Ben Lomond to Terminal Transmission Line and the Dave Johnston Generation Unit 3 Emissions Control Measure	DOCKET NO. 10-035-13
In the Matter of the Application of the Utah Association of Energy Users for a Deferred Accounting Order Directing Rocky Mountain Power to Defer Incremental REC Revenue for Later Ratemaking Treatment	DOCKET NO. 10-035-14
In the Matter of the Rocky Mountain Power Application for Alternative Cost Recovery for Major Plant Additions - Populus to Ben Lomond Transmission Line and the Dunlap I Wind Project	DOCKET NO. 10-035-89 ORDER APPROVING SETTLEMENT STIPULATION

ISSUED: December 21, 2010

SHORT TITLE

Rocky Mountain Power December 2010 Major Plant Additions Case

SYNOPSIS

The Commission approves a Settlement Stipulation providing for an annual increase in revenue requirement of $33.29 million associated with the Populus to Ben Lomond transmission line and Dunlap I wind project major plant additions (“MPA II”).

Per the terms of the Settlement Stipulation, the Commission also approves ratemaking treatment, effective January 1, 2011, for: 1) the $33.29 million associated with MPA II; 2) the $30.8 million increase in revenue requirement approved in Docket No. 10-035-13 (“MPA I”); 3) the $15.7 million in the MPA I deferred balance account; and, 4) a $3 million monthly rate credit to account for additional renewable energy certificate revenues not currently reflected in rates.

Through Schedule 40, costs will be recovered from customers for the MPA I and MPA II increases in revenue requirement. Through Schedule 97, costs will be recovered from customers for the MPA I deferred balance. Through Schedule 98, customers will receive the rate credit associated with the stipulated additional renewable energy certificate revenues.

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APPEARANCES:

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Patricia Schmid, Esq. Assistant Attorney General	"	Division of Public Utilities
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F. Robert Reeder, Esq. Attorney at Law Parson Behle & Latimer	"	Utah Industrial Energy Consumers
Sophie Hayes Attorney	"	Utah Clean Energy

I. PROCEDURAL HISTORY

On August 3, 2010, pursuant to Utah Code § 54-7-13.4, PacifiCorp, doing business in Utah as Rocky Mountain Power ("Company"), submitted an application requesting approval from the Public Service Commission of Utah ("Commission") for alternative cost recovery of the major plant addition ("MPA") investments the Company is making in the Populus to Ben Lomond transmission line and the Dunlap I wind project ("Application"). In the Application, the Company requests an increase in its retail electric utility service rates in Utah in the amount of $39.0 million. As this case is the Company's second request for cost recovery through the MPA alternative cost recovery mechanism, and to distinguish it from the first case filed earlier this year, we refer to this case as MPA II. This Application was also submitted pursuant to the Test Period Stipulation filed on May 14, 2009, in Docket No. 09-035-23.[1]

In its Application, the Company also requested approval to collect: (a) the $30.8 million revenue requirement related to the Ben Lomond to Terminal transmission line and the Dave Johnston 3 emissions control measure projects approved by the Commission pursuant to its June 15, 2010, Report and Order in Docket No. 10-035-13 [2] ("MPA I"), and (b) the $15.7 million deferral balance for the period of July 1, 2010, through December 31, 2010, attributable to MPA I. The Company requests the rate increase be made effective on January 1, 2011, subject to Utah Code § 54-7-13.4(6)(a).

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[1] Docket No. 09-035-23, " In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations. "

[2] Docket No. 10-035-13, " In the Matter of the Application of Rocky Mountain Power for Alternative Cost Recovery for Major Plant Additions of the Ben Lomond to Terminal Transmission Line and the Dave Johnston Generation Unit 3 Emissions Control Measure."

On August 12, 2010, pursuant to Utah Administrative Code R746-700-30, the Division of Public Utilities ("Division") recommended the Commission accept the Company's Application as a complete filing. On August 26, 2010, the Commission held a duly noticed scheduling conference and, pursuant to the discussion and agreement of the parties, issued a scheduling order on September 15, 2010.

Between August and November 2010, petitions to intervene were filed by: Holcim, Inc., Kennecott Utah Copper, LLC, Kimberly-Clark Corp., Malt-O-Meal, Praxair, Inc., Proctor & Gamble, Inc., Tesoro Refining and Marketing Co., and Western Zirconium, collectively referred to as Utah Industrial Energy Consumers ("UIEC"); Utah Association of Energy Users, ATK Space Systems, American Pacific Corporation, Anadarko Midstream, Chevron U.S.A., Inc., ConocoPhillips Gas and Power, Hexcel Corporation, IHC Health Services, Inc., IM Flash Technologies, LLC, May Foundry & Machine Company, and Simplot Phosphates, collectively referred to as UAE Intervention Group ("UAE"); Nucor Steel-Plymouth; and Utah Clean Energy. All of these petitions were granted by the Commission.

On August 25, 2010, pursuant to Utah Administrative Code R746-100-3.H, UIEC submitted a motion to defer recovery of the MPA costs ("UIEC Motion"). UIEC requested the Commission issue an order deferring collection of the MPA I amounts until the next general rate case and deferring collection of the MPA II amounts until either the next general rate case, or until after certain work groups completed their investigations and a new cost-of-service study was filed and vetted.

On September 9, 2010, the Office of Consumer Services ("Office"), UAE, the Company and the Division filed responses to the UIEC Motion. On September 28, 2010, a hearing was held on the UIEC Motion. On October 13, 2010, the Commission issued a decision ("October Decision") denying the UIEC Motion. On October 21, 2010, the Division requested, and the Commission issued, a clarification of the October Decision. On October 25, 2010, UIEC requested further clarification of the October Decision. On November 16, 2010, the Commission issued further clarification of the October Decision, affirming its denial of the UIEC Motion.

On October 26, 2010, direct testimony was filed in this docket by witnesses for the Division, Office, UIEC and UAE. On November 8, 2010, the Company filed a motion to strike portions of the pre-filed direct testimony of Kevin C. Higgins appearing on behalf of UAE.

On November 18, 2010, the Division and the Office made motions for, and the Commission granted, an extension of time to file rebuttal and sur-rebuttal testimony and to file responses to the Company's motion to strike the pre-filed testimony of Mr. Kevin Higgins.

Following settlement discussions, certain parties agreed the Company's Application should be granted on the terms and conditions set forth in a settlement stipulation. On November 29, 2010, a settlement stipulation ("Stipulation") was signed by the Company, Division, Office, UAE, and UIEC (collectively the "Parties") and filed with the Commission. On December 6, 2010, the Commission heard testimony from the Parties regarding the Stipulation and allowed for public comment. At hearing, the Company provided an addendum ("Settlement Agreement Addendum") and a revised exhibit 2 ("Revised Exhibit 2") to the Stipulation. No public comment was offered in support of, or in opposition to, the amended Stipulation. At the conclusion of the hearing, the Commission issued a bench ruling approving the Stipulation as amended by the Settlement Agreement Addendum and Revised Exhibit 2. This order memorializes that ruling.

II. SETTLEMENT STIPULATION

A. Overview

The complete Stipulation, including its Exhibit 1, Settlement Agreement Addendum, and Revised Exhibit 2, are attached in the Appendix to this order. Without modifying the terms and conditions in any way, the following is a brief summary of some components of the Stipulation:

a. The Commission should enter an order pursuant to Utah Code § 54-7-13.4(4)(a)(ii), approving cost recovery of the MPA II Projects and the MPA I Projects, as specified in the Stipulation.

b. The Commission's Order should determine, pursuant to Utah Code § 54-7-13.4(4)(b)(i), Utah's share of the projected net revenue requirement impact of the MPA II Projects is $33.29 million annually, including prudently-incurred capital costs and other reasonably projected costs, savings, and benefits, as derived in the Stipulation. The Parties agree the Stipulation, and a Commission Order entered in accordance with the Stipulation, do not preclude any party from advocating in a future proceeding the share of costs paid by Utah ratepayers for the MPA II projects should be different.

c. Without any presumptions regarding, or intent to influence, pending or future dockets before the Commission, the Parties agree Utah's share of renewable energy credit ("REC") revenues included in rates in the Company's general rate case, Docket No. 09-035-23, is $9.90 million. This amount does not include Utah's share of the Dunlap I REC revenues of $0.76 million which will be separately included in rates from this MPA II docket through implementation of Schedule 40.

d. The Parties agree a $3.0 million monthly customer sur-credit as reflected in Schedule 98, should be established January 1, 2011, representing incremental REC revenues not currently reflected in Utah rates. However, the actual amount of sur-credit realized by customers will be booked against the deferred REC balancing account approved in Docket No. 10-035-14,[3] ("Deferred REC Balancing Account").

e. UAE withdraws its request for the Commission to determine in this docket the appropriate ratemaking treatment of any balance in the Deferred REC Balancing Account. The Parties further agree the Stipulation renders moot the Company's motion in this docket to strike portions of the testimony of UAE witness Kevin Higgins.

f. The Parties agree the final disposition and ratemaking treatment of any balance in the Deferred REC Balancing Account should be resolved in another appropriate docket. However, there is no agreement on which docket is most appropriate for that purpose.

g. If, prior to the effective date of the next general rate case, the Commission determines all, or any portion, of the Deferred REC Balancing Account should not be credited to customers, the Deferred REC Balancing Account shall be

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[3] Docket No. 10-035-14, "In the Matter of the Application of the Utah Association of Energy Users for a Deferred Accounting Order Directing Rocky Mountain Power to Defer Incremental REC Revenue for Later Ratemaking Treatment," July 14, 2010, Report and Order on Deferred Accounting Stipulation.

adjusted to reflect the Commission's decision, subject to certain conditions identified in the Stipulation.

h. The Parties agree the $30.80 million stipulated net revenue requirement from MPA I plus the $33.29 million stipulated net revenue requirement from MPA II will be spread among customer classes as shown in Exhibit 1, attached to the Stipulation, and collected through Schedule 40, as reflected in Revised Exhibit 2.[4] For example, the residential class will receive a 4.06 percent increase to energy rates, Schedule 6 will receive a 4.81 percent increase to energy and demand rates, and Schedule 9 will receive a 5.99 percent increase in energy and demand rates.

i. Schedule 40 will begin January 1, 2011, and terminate upon the effective date of new rates set in the Company's next general rate case. Upon termination of Schedule 40, actual Schedule 40 revenues will be compared to the approved amounts, i.e., $30.8 million in MPA I plus $33.29 million in MPA II, and any over collection will be refunded to customers or any under collection will be collected from customers through a sur-credit or sur-charge in a subsequent month or months.

j. The Parties agree the $3.0 million monthly REC sur-credit will be spread among customer classes as shown in Exhibit 1, and credited to customers through a new Schedule 98, as reflected in Revised Exhibit 2. For example, the residential class

[4] The Parties agree Exhibit 2 (attached to the Stipulation) referenced in paragraphs 13, 14 and 15 of the Stipulation shall be replaced with Revised Exhibit 2 and incorporated into the settlement agreement. The new prices shown in Revised Exhibit 2 are based on equal percent of demand and energy charges within each rate schedule rather than a separate price for each demand and energy billing component. This change simplifies the rate design and billing of Schedules 40, 97 and 98 while achieving the same monthly bills to customers.

will receive a 2.28 percent reduction to energy rates, Schedule 6 will receive a 2.70 percent reduction to energy and demand rates, and Schedule 9 will receive a 3.36 percent reduction to energy and demand rates.

k. The Parties agree the deferred revenue from MPA I in the amount of $15.72 million will be collected from customers beginning January 1, 2011, over a period of approximately eight months. Parties further agree the deferred revenue from MPA I will be spread among customer classes as shown in Exhibit 1 and collected through Schedule 97, as reflected in Revised Exhibit 2, to achieve collection of the $15.72 million. For example, the residential class will receive a 1.49 percent increase to energy rates, Schedule 6 will receive a 1.76 percent increase to energy and demand rates, and Schedule 9 will receive a 2.23 percent increase to energy and demand rates. Schedule 97 will terminate when the deferred revenue from MPA I, plus carrying charges, has been collected from customers.

l. The Parties agree a total Company base net power cost amount of $994.21 million should be established as the basis for the "in-rates" level of net power costs beginning January 1, 2011, for purposes of any energy cost adjustment mechanism.

m. The Parties agree the Stipulation does not resolve any disputed issues currently before the Commission in any other docket, including Docket Nos. 09-035-15 [5] and 10-035-14.

[5] Docket No. 09-035-15, "In the Matter of the Application of Rocky Mountain Power for Approval of Its Proposed Energy Cost Adjustment Mechanism."

B. Positions of the Parties

The Parties to the Stipulation include the Company, Division, Office, UAE, and UIEC.

The Company testifies not all parties involved in this case have signed the Stipulation; however, no party has opposed it. The Company moves the Stipulation's Exhibit 2 be replaced with a Revised Exhibit 2 which will simplify customer bills while providing the same net effect of recovering costs associated with the MPA I and MPA II cases. The Company testifies no party opposes the inclusion of Revised Exhibit 2.

The Company offers the following testimony in support of the approval of the Stipulation: a) the Bonus Depreciation adjustment shown in paragraph 7 applies only to the MPA II projects; b) paragraphs 8 through 12 were carefully drafted by the Parties so as not to presume any outcome, or to influence the Commission in any way, in any open docket currently before the Commission; c) paragraph 12 will only apply if the Commission determines in a future docket all or any portion of the Deferred REC Balancing Account should not be credited to customers, including any dead-band or sharing mechanism; d) the "true-up" provision in Schedule 40 (Stipulation, paragraph 13) applies to this case only. The Company is in agreement with the "true-up" in this case due to the short period of time between when rates will go into effect in the MPA cases and the next general rate case. The Company believes the Stipulation is in the public interest and recommends the Commission approve it.

The Division's support of the Stipulation is based on several key factors including: a) customers will be receiving a REC revenue credit in the amount of $3 million monthly beginning January 1, 2011; b) the Dunlap I REC revenue credits will be adjusted based on a "true-up" mechanism to ensure correct credit for customers; and c) customers receive the benefits from the bonus depreciation adjustment for the MPA II projects. The Division testifies it has reviewed REC revenues, the MPA I deferred amount of $15.7 million, rate design and rate spread and agrees with the values in the Stipulation and supports the inclusion of Revised Exhibit 2. The Division testifies its consultants reviewed the net power costs shown in paragraph 16 of the Stipulation and found them to be consistent with prior Commission orders and reasonable as base net power costs going forward beginning January 1, 2011. The Division supports the Stipulation as a reasonable compromise and believes it allows for the timely recovery of costs associated with MPA I and MPA II, while also recognizing offsetting REC revenues not currently reflected in rates. The Division believes the Stipulation is in the public interest and recommends the Commission adopt the Stipulation.

The Office believes the Stipulation before the Commission will result in just and reasonable rates for the residential, small commercial and irrigation customers it represents. Several key provisions in the Stipulation were critical in gaining the support of the Office including: a) implementation of the "true-up" mechanism will ensure the Company will not over collect for these new resources; b) the process of adjusting REC revenues associated with Dunlap I will ensure customers are receiving the appropriate credit; and c) the Office supports the rate design and spread proposed by the Company in Revised Exhibit 2. Given the rate protection included in the agreement, the Office recommends the Commission adopt the Stipulation.

UAE fully supports the Stipulation and believes it is a fair agreement. In direct testimony in the MPA II case, UAE identified five key issues and believes the settlement agreement adequately addresses these issues either directly, or by preserving the option for the issues to be addressed at a future time. The two key issues directly addressed by the Stipulation, and important for UAE's support, are: a) the recognition of $3 million per month of REC revenues credited to customers; and b) the use of appropriate billing determinants in setting the monthly revenue requirement as a target and providing a "true-up" mechanism to ensure the correct collection of the revenue requirement.

UIEC signed and supports the Stipulation, including Revised Exhibit 2 as proposed by the Company. UIEC identifies the language contained in paragraphs 17, 19 and 26 as being most critical for UIEC's support.

C. Discussion, Findings and Conclusions

In 2009, the Utah Legislature passed into law, and the Governor signed, Senate Bill 75 which enacted Utah Code § 54-7-13.4, effective March 25, 2009. This section identifies the procedure for alternative cost recovery of MPAs for a gas or an electrical corporation. This is the second such case we have heard since the law was enacted. We issued our Report and Order on MPA I cost recovery on June 15, 2010, but did not rule on the ratemaking treatment of the MPA I costs. Based upon the uncontested representations of the Company, we find the Application is subject to the alternative cost recovery procedure for major plant additions described in Utah Code § 54-7-13.4.

Utah Code § 54-7-13.4 (1)(c) defines a “major plant addition” as “any single capital investment project of a gas or electrical corporation that, in total, exceeds 1 % of the corporation’s rate base, based on the corporation’s most recent general rate case determination ...” allocated to Utah customers. This subsection allows a corporation to file for cost recovery of an MPA if the Commission has entered a final order in a general rate case within 18 months of the projected in-service date of the MPA. In the Company’s last general rate case, Docket No. 09-035-23, the Commission approved a revenue requirement on February 18, 2010.

Utah Code § 54-7-13.4 (1)(c) also requires the Commission to enter its order on cost recovery within 90 days of the Company’s complete filing with respect to significant energy resources (Utah Code § 54-17-301 et.seq.) or 150 days for all other MPAs. It also restricts the corporation from filing for cost recovery more than 150 days before the projected in-service date of the MPA. Utah Code § 54-7-13.4 (6)(a) requires the deferral or collection of the state’s share of the net revenue requirement impacts of an MPA under this section to commence upon the later of the day on which a Commission order is issued approving the deferral or collection amount or the in-service date of the MPA.

Based on the testimony and evidence presented in this case, we find the requirements of the aforementioned statutes will be satisfied upon our approval of the Stipulation except the Company has not formally conveyed to the Commission the in-service dates of the MPA II projects. As noted by the Company in its Application, its request for ratemaking changes associated with MPA II cost recovery is subject to Utah Code § 54-7-13.4 (6)(a).

Consequently, our order approving the Stipulation will be subject to the Company filing in this docket, prior to January 1, 2011, a letter certifying the MPA II projects are in service.

Utah Code § 54-7-1 encourages informal resolution of matters before the Commission by agreement of the parties so long as the settlement, as supported by the evidence, is just and reasonable in result. Five parties to this proceeding, representing diverse interests, signed the Stipulation, and no party to this docket, or public witness, opposes the Stipulation. Prior to reaching the Stipulation, each of the non-Company Parties evaluated the Application and prepared and filed testimony advocating various positions on the issues raised in the Application. While the Parties are not able to agree on each specific component of the adjustments that resulted in this Stipulation, all of the Parties agree the rate changes proposed in this Stipulation are just and reasonable in result and in the public interest. The Parties agree the individual adjustments the Stipulation makes to the Company's Application may not be warranted, or supportable, in isolation, but the adjustments are necessary and appropriate to achieve the agreements embodied in the Stipulation.

Based upon the evidence contained in the record, which includes all of the written testimony and exhibits the Parties initially prepared as well as oral testimony supporting the Stipulation, we find the Stipulation is just and reasonable in result and is in the public interest. We therefore approve the Stipulation which is incorporated herein by reference. Our approval of the Stipulation is not binding precedent for future cases, and is subject to the conditions and limitations contained in the Stipulation.

III. ORDER

Wherefore, pursuant to our discussion, findings and conclusions made herein, we order:

1. The terms and conditions as set forth in the Stipulation as filed and amended at hearing, are approved.
2. The Company shall file, and the Division shall review for compliance, tariff sheets for Schedules 40, 97 and 98 to implement Revised Exhibit 2 of the Stipulation, with an effective date of January 1, 2011, provided the Company certifies by letter delivered to the Commission before that date that the Populus to Ben Lomond transmission line and Dunlap I wind project major plant additions are in service and providing the respective in-service dates.
3. The Company shall terminate Schedule 97 as soon as the deferred revenue from the MPA I docket, including carrying charges, has been collected from customers. The Company shall notify the Commission promptly when this event occurs.
4. The Stipulation renders moot the Company's motion to strike portions of testimony of UAE witness Kevin Higgins. The Parties are excused from filing responses to the motion and the Commission will take no action regarding the motion.
5. This Stipulation does not resolve any disputed issue currently before the Commission in any other docket and approval of the Stipulation does not bind the Commission with respect to any issue in any other docket pending or subsequently opened.

Pursuant to Sections 63G-4-301 and 54-7-15 of the Utah Code, an aggrieved party may request agency review or rehearing of this Order by filing a written request with the Commission within 30 days after the issuance of this Order. Responses to a request for agency review or rehearing must be filed within 15 days of the filing of the request for review or rehearing. If the Commission does not grant a request for review or rehearing within 20 days after the filing of the request, it is deemed denied. Judicial review of the Commission's final agency action may be obtained by filing a petition for review with the Utah Supreme Court within 30 days after final agency action. Any petition for review must comply with the requirements of Sections 63G-4-401 and 63G-4-403 of the Utah Code and Utah Rules of Appellate Procedure.

DATED at Salt Lake City, Utah, this 21st day of December, 2010.

/s/ Ted Boyer, Chairman

/s/ Ric Campbell, Commissioner

/s/ Ron Allen, Commissioner

Attest:

/s/ Julie Orchard
Commission Secretary
G#70198 Docket No. 10-035-13
G#70199 Docket No. 10-035-14
G#70200 Docket No. 10-035-89

APPENDIX: Settlement Stipulation, et. al.

Settlement Stipulation

Exhibit 1

Settlement Agreement Addendum

Revised Exhibit 2

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Alternative Cost Recovery for Major Plant Additions of the Populus to Ben Lomond Transmission Line and the Dunlap I Wind Project	Docket No. 10-035-89 **SETTLEMENT STIPULATION**

Rocky Mountain Power ("Rocky Mountain Power" or the "Company"), the Division of Public Utilities ("Division"), the Office of Consumer Services ("Office"), the parties known as the UAE Intervention Group ("UAE"), and the parties known as the Utah Industrial Energy Consumers ("UIEC") (collectively, "Parties"), pursuant to Utah Code Ann. § 54-7-1 and Utah Admin. Code R746-100-10.F.5, hereby request that the Public Service Commission of Utah ("Commission") enter an order approving this Settlement Stipulation ("Stipulation"). The Parties are authorized to represent that no party to this docket opposes this Stipulation.

BACKGROUND

1. On August 3, 2010, pursuant to Utah Code Ann. § 54-7-13.4, Rocky Mountain Power filed with the Commission an application ("MPA II Application") in Docket 10-035-89 ("MPA II Docket") for alternative cost recovery for major plant additions related to the Populus to Ben Lomond transmission line and the Dunlap I wind project ("MPA II Projects").

2. In the MPA II Application, Rocky Mountain Power requested authorization to recover costs through customer rates beginning on or about January 1, 2011, in the amount of approximately $38.99 million for the MPA II Projects.

3. In the MPA II Application, Rocky Mountain Power also requested authorization to

recover costs through customer rates beginning on or about January 1, 2011, in the amount of approximately $30.80 million for the Ben Lomond to Terminal transmission line and the Dave Johnston Generation Unit 3 environmental improvement measures ("MPA I Projects"), consistent with the Commission's Report and Order in Docket No. 10-035-13, dated June 15, 2010 ("MPA I Order").

4. In addition, in the MPA II Application, Rocky Mountain Power requested authorization to stop deferring the MPA I Deferred Balance on or about December 31, 2010, at which time, said balance will be approximately $15.72 million, and to begin collection of the MPA I Deferred Balance and on-going carrying charges beginning January 1, 2011.

5. The Parties other than the Company filed direct testimony of 10 witnesses October 26, 2010 proposing adjustments to and raising issues regarding the relief sought in the MPA II Application.

6. The Parties have engaged in settlement discussions as a consequence of which, the Parties have agreed to the terms and conditions set forth in this Stipulation.

STIPULATION

Specific Terms and Conditions

Revenue Requirement

7. The Parties agree, for purposes of settlement and for this case only, that:

a. The Commission should enter an order pursuant to Utah Code Ann. § 54-7-13.4(4)(a)(ii), approving cost recovery of the MPA II Projects and the MPA I Projects, as specified herein;

b. The Commission's Order should determine, pursuant to Utah Code Ann. §

54-7-13.4(4)(b)(i), that Utah's share of the projected net revenue requirement impact of the MPA II Projects, including prudently-incurred capital costs and other reasonably projected costs, savings, and benefits, is $33.29 million annually;

c. Utah's share of the projected net revenue requirement impact of the MPA II Projects was derived by the Parties as follows:

Utah MPA II Settlement Proposal ($)	
Adjustments to Filing	Company Offer
Proposed Rate Increase in Filing	**$38.99**
Bonus Depreciation on MPA II Projects	($5.57)
Dunlap I	
Remove contingency not used in project cost	($0.09)
Interconnection Update	($0.02)
REC Revenues - will be trued up to actual	$0.00
Populus Line	
Firm Wheeling	($0.03)
Revenue Requirement Adjustments	**($5.70)**
Proposed Rate Increase	**$33.29**

d. On September 27, 2010, the Small Business Jobs Act of 2010 was signed into law, extending 50 percent bonus depreciation for tax purposes related to qualifying assets. Bonus depreciation can now be recognized for qualifying assets placed into service during calendar year 2010. Income taxes for the MPA II Projects in this case are fully normalized, but revenue requirement is impacted because the bonus depreciation will create a larger accumulated deferred income tax balance (a rate base reduction) in the initial years of these projects' lives than was included in the Company's original filing.

Incorporation of this impact into the case reduces the requested price increase by approximately $5.57 million ($4.05 million for Populus to Ben Lomond and $1.52 million for Dunlap I). This Stipulation addresses only the bonus depreciation for the MPA II Projects.

Renewable Energy Credit ("REC") Revenue

8. The Parties agree that Utah's share of REC revenue at January 1, 2011 that is included in rates from the 2009 General Rate Case, Docket No. 09-035-23 ("2009 GRC") is $9.90 million, which does not include the Dunlap I REC revenues of $0.76 million (Utah's share) that will be separately included in rates from this MPA II Docket through Schedule 40. The Parties further agree that Utah's share of REC revenues in excess of $10.66 million ($9.90m + $0.76m) will continue to be deferred on and after January 1, 2011 in the Deferred REC Balancing Account established by Commission Order ("Deferred REC Balancing Account") in Docket 10-035-14 ("REC Order").

9. The Parties agree that a $3.0 million monthly customer sur-credit ("Sur-credit") as reflected in Schedule 98, should be established January 1, 2011, representing incremental REC revenues not currently reflected in Utah rates based on 2011 Company projections. Schedule 98 is designed to achieve the Sur-credit on an average monthly basis; however the actual amount of Sur-credit realized by customers will be booked against the Deferred REC Balancing Account and may vary from the $3.0 million per month based on customer usage. Schedule 98 is subject to continuance, discontinuance or adjustment as directed in a future Commission order determining the appropriate ratemaking treatment of the Deferred REC Balancing Account. Schedule 98 will otherwise terminate upon the effective date of new rates set in the next Rocky Mountain Power general rate case, subject to the conditions contained in this Stipulation.

10. In light of this Stipulation, UAE hereby withdraws its request that the Commission determine in this docket the appropriate ratemaking treatment of any balance in the Deferred REC Balancing Account. The Parties further stipulate and agree that this Stipulation renders moot the Company's motion in this docket to strike portions of the testimony of UAE witness Kevin Higgins ("Motion") and therefore, the Parties request that (a) they be excused from filing responses thereto, and (b) the Commission take no action upon the Motion. The Parties agree, however, that no Party is conceding any position or argument with respect to said Motion.

11. The Parties agree that the final disposition and ratemaking treatment of any balance in the Deferred REC Balancing Account should be resolved in another appropriate docket. However, no agreement has been reached on which docket is most appropriate for that purpose. The Parties continue to support prompt resolution of this issue and one or more of the Parties may petition the Commission requesting resolution of this issue at any time.

12. If, prior to the effective date of the next general rate case, the Commission determines in a future order that all or any portion of the Deferred REC Balancing Account should not be credited to customers, including any portion subjected to a dead-band or sharing mechanism, the Deferred REC Balancing Account shall be adjusted to reflect the Commission's decision subject to the following conditions:

a. The Parties agree that projected Dunlap I REC revenues of $0.76 million in the MPA II Docket revenue requirement will be trued-up to actual REC revenues properly attributable to Dunlap I and the difference will remain in the Deferred REC Balancing Account for future true-up and return to or collection from customers. A carrying charge will continue to be applied to the Deferred REC Balancing Account as set forth in the REC Order

.

b. The Parties agree that Dunlap I incremental REC revenues not reflected in Schedule 40 will not be subject to any dead-bands or sharing mechanisms during the period January 1, 2011 until rates are reset in the Company's next general rate case.

c. One or more of the Parties may petition the Commission requesting a review of the methodology used to calculate actual Dunlap I REC sales and final determination of the amount of incremental Dunlap I REC revenues that should remain in the Deferred REC Balancing Account.

d. One or more of the Parties may petition the Commission requesting appropriate modifications to Schedule 98 to implement the Commission order, which may include collection of a balance in the Deferred REC Balancing Account owed to the ratepayers or to the Company.

Rate Spread and Rate Design

13. The Parties agree that the $30.80 million stipulated net revenue requirement from MPA I Docket plus the $33.29 million stipulated net revenue requirement from MPA II Docket will be spread among customer classes as shown in Exhibit 1 and collected through Schedule 40, as reflected in the prices shown in Exhibit 2. Schedule 40 will begin January 1, 2011 and will terminate upon the effective date of new rates set in the next Rocky Mountain Power general rate case that incorporate the revenue requirement related to MPA I Docket and MPA II Docket. Upon the termination of Schedule 40, actual Schedule 40 revenues billed to customers will be compared to $5.34 million (($30.80 million + $33.29 million)/12) per month times the number of months, including fractions thereof, Schedule 40 has been in effect. Any over collection will be refunded to customers or any under collection will be collected from customers through a

sur-credit or sur-charge in a subsequent month or months.

14. The Parties agree that the $3.0 million monthly REC Sur-credit will be spread among customer classes as shown in Exhibit 1, attached hereto, and credited to customers through a new Schedule 98, as reflected in the prices shown in Exhibit 2.

15. The Parties agree that the deferred revenue from the MPA I Docket in the amount of $15.72 million will be collected from customers beginning January 1, 2011, over a period of approximately eight months. Parties further agree that the deferred revenue from MPA I Docket will be spread among customer classes as shown in Exhibit 1 and collected through Schedule 97, as reflected in prices shown in Exhibit 2 to achieve the collection of the $15.72 million. Schedule 97 will terminate when the deferred revenue from MPA I Docket plus carrying charges has been collected from customers.

Base Net Power Costs

16. The Parties agree that a total Company base net power cost amount of $994.21m should be established upon Commission approval of the Stipulation as the basis for the in-rates level of net power costs beginning January 1, 2011, for purposes of any energy cost adjustment mechanism ("ECAM") adjustment measurements. The following schedule reflects the level of base net power costs in rates by month for any ECAM measurement:

	Dollars	MWh	$/MWh
January	73,040,669	5,227,809	13.97
February	72,129,571	4,701,939	15.34
March	71,083,020	4,747,272	14.97
April	77,064,993	4,508,612	17.09
May	78,917,495	4,573,831	17.25
June	83,002,560	4,849,122	17.12
July	109,937,437	5,316,123	20.68
August	115,097,206	5,265,574	21.86
September	94,511,149	4,661,261	20.28
October	73,157,862	4,510,209	16.22
November	71,054,730	4,650,023	15.28
December	75,210,210	5,224,676	14.40
	994,206,903	58,236,451	17.07

Other Terms

17. The Parties stipulate that, unless expressly resolved or required by this Stipulation, no party shall be deemed to have waived, compromised or limited any arguments, positions, rights, remedies, or obligations available to it arising out of, or relating to, matters previously determined by, now pending before, or that may be filed with the Commission or any Utah administrative or judicial actions, including the right to conduct discovery, offer evidence and present positions and arguments. This Stipulation does not resolve any disputed issues currently before the Commission in any other docket, including Docket 09-035-15 (ECAM Docket) and Docket 10-035-14 ("REC Docket").

18. The Parties agree that cost recovery for the MPA II Projects in the amount of $33.29 million reflects Utah's share of the projected net revenue requirement impact of the MPA II Projects, including prudently-incurred capital costs and other reasonably projected costs, savings, and benefits.

19. The Parties agree that this Stipulation and a Commission Order entered in accordance

with this Stipulation do not preclude any party from advocating in a future proceeding that the share of costs that should be paid by Utah ratepayers for the MPA II Projects should be different. Furthermore, the Parties agree that all discovery in this MPA II Docket relating to the Populus to Ben Lomond transmission line may be used and relied upon by them in any such future proceedings without the need for further data requests, provided that confidential information will otherwise remain subject to Utah Admin. Code R746-100-16.

General Terms and Conditions

20. Not all Parties agree that each aspect of the adjustments to the Company's MPA II Application necessary to arrive at this Stipulation is warranted or supportable in isolation. Utah Code Ann. § 54-7-1 authorizes the Commission to approve a settlement so long as the settlement is just and reasonable in result. While the Parties are not able to agree on each specific component of the adjustments that resulted in this Stipulation, all of the Parties agree that the rate change proposed by this Stipulation is just and reasonable in result and in the public interest.

21. All negotiations related to this Stipulation are confidential, and no Party shall be bound by any position asserted in negotiations. Except as expressly provided in this Stipulation for purposes of this docket only, in accordance with Utah Admin. Code R746-100-10.F.5, neither the execution of this Stipulation nor the order adopting it shall be deemed to constitute an admission or acknowledgment by any Party of the validity or invalidity of any principle or practice of regulatory accounting or ratemaking; nor shall they be construed to constitute the basis of an estoppel or waiver by any Party; nor shall they be introduced or used as evidence for any other purpose in a future proceeding by any Party except in a proceeding to enforce this Stipulation.

22. The Parties request that the Commission hold a hearing on this Stipulation. Rocky

Mountain Power, the Division, and the Office each will, and other Parties may, make one or more witnesses available to explain and offer further support for this Stipulation. The Parties shall support the Commission's approval of this Stipulation. As applied to the Division and the Office, the explanation and support shall be consistent with their statutory authority and responsibility.

23. The Parties agree that if any person challenges the approval of this Stipulation or requests rehearing or reconsideration of any order of the Commission approving this Stipulation, each Party will use its best efforts to support the terms and conditions of this Stipulation. As applied to the Division and the Office, the phrase "use its best efforts" means that they shall do so in a manner consistent with their statutory authority and responsibility. In the event any person seeks judicial review of a Commission order approving this Stipulation, no Party shall take a position in that judicial review opposed to the Stipulation.

24. Except with regard to the obligations of the Parties under the three immediately preceding paragraphs of this Stipulation, this Stipulation shall not be final and binding on the Parties until it has been approved without material change or condition by the Commission. This Stipulation is an integrated whole, and any Party may withdraw from it if it is not approved without material change or condition by the Commission or if the Commission's approval is rejected or materially conditioned by a reviewing court. If the Commission rejects any part of this Stipulation or imposes any material change or condition on approval of this Stipulation or if the Commission's approval of this Stipulation is rejected or materially conditioned by a reviewing court, the Parties agree to meet and discuss the applicable Commission or court order within five business days of its issuance and to attempt in good faith to determine if they are willing to modify the Stipulation consistent with the order. No Party shall withdraw from the Stipulation prior to complying with the foregoing sentence. If any Party withdraws from the

Stipulation, any Party retains the right to seek additional procedures before the Commission, including presentation of testimony and cross-examination of witnesses, with respect to issues resolved by the Stipulation, and no party shall be bound or prejudiced by the terms and conditions of the Stipulation.

25. This Stipulation may be executed by individual Parties through two or more separate, conformed copies, the aggregate of which will be considered as an integrated instrument.

26. The Parties agree and request that all pre-filed testimony in this MPA II Docket be entered into the record in support of the Stipulation.

RELIEF REQUESTED

27. Based on the foregoing, the Parties request that the Commission schedule a hearing on this Stipulation and, thereafter, enter an order approving the terms and conditions set forth in this Stipulation.

RESPECTFULLY SUBMITTED: November /s/29, 2010.

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Rocky Mountain Power
State of Utah
Settlement Rate Spread for MPA I&II, Deferrals and REC

		Settlement Rate Spread						
	Annual	Sch 40		Sch 97		Sch 98		
Schedule	Present Rev	MPA I & II		Deferrals		REC		Total
No.	($000)	($000)	%	($000)	%	($000)	%	%
1	$583,461	$22,382	3.84%	$5,477	1.41%	($12,571)	-2.15%	3.09%
6	$416,852	$19,702	4.73%	$4,814	1.73%	($11,066)	-2.65%	3.80%
8	$119,912	$5,790	4.83%	$1,426	1.78%	($3,252)	-2.71%	3.90%
7,11,12	$13,383	$135	1.01%	$31	0.35%	($76)	-0.57%	0.79%
9	$165,309	$9,463	5.72%	$2,357	2.14%	($5,315)	-3.22%	4.65%
10	$11,349	$527	4.64%	$134	1.77%	($296)	-2.61%	3.80%
15 Traffic	$487	$14	2.95%	$4	1.09%	($8)	-1.66%	2.38%
15 Metered	$933	$18	1.93%	$3	0.56%	($10)	-1.08%	1.41%
21	$298	$13	4.43%	$3	1.63%	($7)	-2.49%	3.57%
23	$104,484	$4,371	4.18%	$1,062	1.52%	($2,455)	-2.35%	3.36%
25	$870	$40	4.57%	$10	1.68%	($22)	-2.57%	3.68%
31	$854	$38	4.43%	$9	1.63%	($21)	-2.49%	3.57%
Customer A	$9,545	$546	5.72%	$136	2.14%	($307)	-3.22%	4.65%
Customer B	$25,733	$0	0.00%	$0	0.00%	$0	0.00%	0.00%
Customer C	$25,894	$0	0.00%	$0	0.00%	$0	0.00%	0.00%
Customer D	$23,828	$1,056	4.43%	$259	1.63%	($593)	-2.49%	3.57%
Total Utah	$1,503,191	$64,096	4.26%	$15,724	1.57%	($36,000)	-2.39%	3.44%

Note:

1. The percentage for Schedule 97 is the average increase for 8 months.

Docket 10-035-89
Settlement Agreement
Addendum

The Parties agree that Exhibit 2 referenced in paragraphs 13, 14 and 15 of the Settlement Agreement shall be replaced with Revised Exhibit 2 attached to this addendum and incorporated into the Settlement Agreement.[6]

[6] The new prices shown in Revised Exhibit 2 are based on equal percent of demand and energy charges within each rate schedule rather than a separate price for each demand and energy billing component. This change simplifies the rate design and billing of Schedules 40, 97 and 98 while achieving the same monthly bills to customers.

Rocky Mountain Power - State of Utah

Blocking Based on Adjusted Actual and Forecasted Loads
Historical Test Period 12 Months Ending December, 2008
Forecast Test Period 12 Months Ending June 2010

	Forecast Units	Present Price	Revenue Dollars	Price	Proposed Sch 40 Dollars	Price	Proposed Sch 97 Dollars (8 Months)	Price	Proposed Sch 98 Dollars
Schedule No. 1- Residential Service									
Customer Charge	8,115,601	$3.75	$30,433,505						
First 400 kWh (May-Sept)	1,225,982,405	7.5292 ¢	$92,306,667	4.06%	$3,747,651	1.49%	$916,913	-2.28%	($2,104,592)
Next 600 kWh (May-Sept)	1,038,768,927	9.2749 ¢	$96,344,779	4.06%	$3,911,598	1.49%	$957,025	-2.28%	($2,196,661)
All add'l kWh (May-Sept)	640,561,243	11.5361 ¢	$73,895,786	4.06%	$3,000,169	1.49%	$734,031	-2.28%	($1,684,824)
All kWh (Oct-Apr)	3,493,176,837	7.8009 ¢	$272,499,232	4.06%	$11,063,469	1.49%	$2,706,826	-2.28%	($6,212,982)
Minimum 1 Phase	118,231	$3.78	$446,913						
Minimum 3 Phase	536	$11.34	$6,078						
Minimum Seasonal	0	$47.36	$0						
kWh in Minimum	623,648								
kWh in Minimum 1 Phase - Summer	277,180	0.0000							
kWh in Minimum 1 Phase - Winter	315,212	0.0000							
kWh in Minimum 3 Phase - Summer	14,186								
kWh in Minimum 3 Phase - Winter	17,070								
Unbilled	0								
Total	6,399,113,060		$565,932,960		$21,722,886		$5,314,795		($12,199,059)
Schedule No. 3- Residential Service									
Customer Charge	286,598	$3.75	$1,074,744						
First 400 kWh (May-Sept)	45,997,068	7.5292 ¢	$3,463,211	4.06%	$140,606	1.49%	$34,401	-2.28%	($78,961)
Next 600 kWh (May-Sept)	28,555,821	9.2749 ¢	$2,648,524	4.06%	$107,530	1.49%	$26,309	-2.28%	($60,386)
All add'l kWh (May-Sept)	8,161,321	11.5361 ¢	$941,498	4.06%	$38,225	1.49%	$9,352	-2.28%	($21,466)
All kWh (Oct-Apr)	117,397,729	7.8009 ¢	$9,158,079	4.06%	$371,818	1.49%	$90,970	-2.28%	($208,804)
Minimum 1 Phase	1,167	$3.78	$4,411						
Minimum 3 Phase	10	$11.34	$113						
Minimum Seasonal	0	$47.36	$0						
kWh in Minimum	7,140								
kWh in Minimum 1 Phase - Summer	2,396	0.0000							
kWh in Minimum 1 Phase - Winter	3,783	0.0000							
kWh in Minimum 3 Phase - Summer	420								
kWh in Minimum 3 Phase - Winter	542								
Unbilled	0								
Total	200,119,079		$17,290,580		$658,179		$161,032		($369,618)
Schedule No. 2 - Residential Service Optional Time-of-Day									
Customer Charge	3,588	$3.75	$13,457						
On-Peak kWh (May - Sept)	248,162	4.3762 ¢	$10,860						
Off-Peak kWh (May - Sept)	864,799	(1.4014) ¢	($12,119)						
First 400 kWh (May-Sept)	542,279	7.5292 ¢	$40,829	4.06%	$1,658	1.49%	$406	-2.28%	($931)
Next 600 kWh (May-Sept)	390,844	9.2749 ¢	$36,250	4.06%	$1,472	1.49%	$360	-2.28%	($827)
All add'l kWh (May-Sept)	179,832	11.5361 ¢	$20,746	4.06%	$842	1.49%	$206	-2.28%	($473)
All kWh (Oct-Apr)	1,626,697	7.8009 ¢	$126,897	4.06%	$5,152	1.49%	$1,261	-2.28%	($2,893)
Minimum 1 Phase	76	$3.78	$287						
Minimum 3 Phase	10	$11.34	$113						
Minimum Seasonal	0	$47.36	$0						
kWh in Minimum	424								
kWh in Minimum 1 Phase - Summer	127	0.0000							
kWh in Minimum 1 Phase - Winter	100	0.0000							
kWh in Minimum 3 Phase - Summer	195								
kWh in Minimum 3 Phase - Winter	2								
Unbilled	0								
Total	2,740,076		$237,320		$9,124		$2,232		($5,124)
Schedule No. 25 - Mobile Home and House Trailer Park Service									
Customer Charge	132	$20.00	$2,640						
All kW	28,933	$5.60	$162,025	4.53%	$7,340	1.67%	$1,804	-2.54%	($4,115)
Voltage Discount All kW	19,876	($0.50)	($9,938)						
All kWh	12,008,765	5.9533 ¢	$714,918	4.53%	$32,386	1.67%	$7,959	-2.54%	($18,159)
Minimum Per Home	0	$5.00	$0						
Unbilled	0								
Total	12,008,765		$869,645		$39,726		$9,763		($22,274)
Schedule No. 6 - Composite									
Customer Charge	160,064	$45.00	$7,202,880						
All kW (May - Sept)	7,256,011	$15.16	$110,001,127	4.81%	$5,291,054	1.76%	$1,290,680	-2.70%	($2,970,030)
All kW (Oct - Apr)	8,682,583	$12.17	$105,667,035	4.81%	$5,082,584	1.76%	$1,239,827	-2.70%	($2,853,010)
Voltage Discount	420,688	($0.78)	($328,137)						
All kWh	5,561,682,145								
kWh (May - Sept)	2,517,184,734	3.1907 ¢	$80,315,813	4.81%	$3,863,191	1.76%	$942,372	-2.70%	($2,168,527)
kWh (Oct - Apr)	3,044,497,411	2.9416 ¢	$89,556,936	4.81%	$4,307,689	1.76%	$1,050,801	-2.70%	($2,418,037)
Seasonal Service	0	$540.00	$0						
Unbilled	0		$0						
Total	5,561,682,145		$392,415,654		$18,544,518		$4,523,680		($10,409,605)
Schedule No. 6A - Energy Time-of-Day Option - Composite									
Customer Charge	25,141	$45.00	$1,131,345						
Facilities kW (May - Sept)	783,880	$5.37	$4,209,436						
Facilities kW (Oct - Apr)	**897,905**	**$4.50**	**$4,040,573**						

Rocky Mountain Power - State of Utah

Blocking Based on Adjusted Actual and Forecasted Loads
Historical Test Period 12 Months Ending December, 2008
Forecast Test Period 12 Months Ending June 2010

	Forecast Units	Present Price	Revenue Dollars	Price	Proposed Sch 40 Dollars	Price	Proposed Sch 97 Dollars (8 Months)	Price	Proposed Sch 98 Dollars
Voltage Discount	43,628	($0.50)	($21,814)						
On-Peak kWh (May - Sept)	51,554,143	9.8184 ¢	$5,061,792	7.76%	$392,795	2.85%	$96,174	-4.36%	($220,694)
Off-Peak kWh (May - Sept)	57,444,983	2.9560 ¢	$1,698,074	7.76%	$131,771	2.85%	$32,263	-4.36%	($74,036)
On-Peak kWh (Oct - Apr)	73,889,396	8.2071 ¢	$6,064,177	7.76%	$470,580	2.85%	$115,219	-4.36%	($264,398)
Off-Peak kWh (Oct - Apr)	70,300,195	2.4782 ¢	$1,742,179	7.76%	$135,193	2.85%	$33,101	-4.36%	($75,959)
Unbilled	0								
Total	253,188,717		$23,925,762		$1,130,339		$276,758		($635,087)
Schedule No. 6B - Demand Time-of-Day Option - Commercial									
Customer Charge	216	$45.00	$9,720						
All On-peak kW (May - Sept)	4,109	$15.16	$62,292	4.81%	$2,996	1.76%	$731	-2.70%	($1,682)
All On-peak kW (Oct - Apr)	5,438	$12.17	$66,180	4.81%	$3,183	1.76%	$777	-2.70%	($1,787)
Voltage Discount	0	($0.78)	$0						
All kWh	2,973,993								
kWh (May-Sept)	1,208,093	3.1907 ¢	$38,547	4.81%	$1,854	1.76%	$452	-2.70%	($1,041)
kWh (Oct-Apr)	1,765,900	2.9416 ¢	$51,946	4.81%	$2,499	1.76%	$609	-2.70%	($1,403)
Seasonal Service	0	$540.00	$0						
Unbilled	0		$0						
Total	2,973,993		$228,685		$10,532		$2,569		($5,912)
Schedule No. 6B - Demand Time-of-Day Option - Industrial									
Customer Charge	132	$45.00	$5,940						
All On-peak kW (May - Sept)	5,416	$15.16	$82,107	4.81%	$3,949	1.76%	$963	-2.70%	($2,217)
All On-peak kW (Oct - Apr)	7,238	$12.17	$88,086	4.81%	$4,237	1.76%	$1,034	-2.70%	($2,378)
Voltage Discount	0	($0.78)	$0						
All kWh	3,464,946								
kWh (May-Sept)	1,695,323	3.1907 ¢	$54,093	4.81%	$2,602	1.76%	$635	-2.70%	($1,461)
kWh (Oct-Apr)	1,769,623	2.9416 ¢	$52,055	4.81%	$2,504	1.76%	$611	-2.70%	($1,405)
Seasonal Service	0	$540.00	$0						
Unbilled	0								
Total	3,464,946		$282,281		$13,292		$3,242		($7,461)
Schedule No. 7 - Security Area Lighting									
MERCURY VAPOR LAMPS									
4,000 Lumen Energy Only	35	$5.63	$197	1.01%	$2	0.35%	$0	-0.57%	($1)
7,000 Lumen	48,195	$16.23	$782,205	1.01%	$7,900	0.35%	$1,825	-0.57%	($4,459)
7,000 Lumen Energy Only	266	$7.98	$2,123	1.01%	$21	0.35%	$5	-0.57%	($12)
20,000 Lumen	12,645	$26.53	$335,472	1.01%	$3,388	0.35%	$783	-0.57%	($1,912)
SODIUM VAPOR LAMPS									
5,600 Lumen New Pole	3,518	$14.46	$50,870	1.01%	$514	0.35%	$119	-0.57%	($290)
5,600 Lumen No New Pole	1,852	$12.12	$22,446	1.01%	$227	0.35%	$52	-0.57%	($128)
9,500 Lumen New Pole	24,004	$15.33	$367,981	1.01%	$3,717	0.35%	$859	-0.57%	($2,097)
9,500 Lumen No New Pole	23,681	$13.19	$312,352	1.01%	$3,155	0.35%	$729	-0.57%	($1,780)
16,000 Lumen New Pole	2,694	$19.28	$51,940	1.01%	$525	0.35%	$121	-0.57%	($296)
16,000 Lumen No New Pole	2,584	$16.97	$43,850	1.01%	$443	0.35%	$102	-0.57%	($250)
22,000 Lumen	123	$20.87	$2,567	1.01%	$26	0.35%	$6	-0.57%	($15)
27,500 Lumen New Pole	3,416	$23.29	$79,559	1.01%	$804	0.35%	$186	-0.57%	($453)
27,500 Lumen No New Pole	3,283	$21.03	$69,041	1.01%	$697	0.35%	$161	-0.57%	($394)
50,000 Lumen New Pole	1,186	$28.04	$33,255	1.01%	$336	0.35%	$78	-0.57%	($190)
50,000 Lumen No New Pole	1,895	$25.75	$48,796	1.01%	$493	0.35%	$114	-0.57%	($278)
SODIUM VAPOR FLOOD LAMPS									
16,000 Lumen New Pole	4,939	$19.28	$95,224	1.01%	$962	0.35%	$222	-0.57%	($543)
16,000 Lumen No New Pole	5,318	$16.97	$90,246	1.01%	$911	0.35%	$211	-0.57%	($514)
27,500 Lumen New Pole	1,162	$23.29	$27,063	1.01%	$273	0.35%	$63	-0.57%	($154)
27,500 Lumen No New Pole	1,804	$21.03	$37,938	1.01%	$383	0.35%	$89	-0.57%	($216)
50,000 Lumen New Pole	10,639	$28.04	$298,318	1.01%	$3,013	0.35%	$696	-0.57%	($1,700)
50,000 Lumen No New Pole	12,200	$25.75	$314,150	1.01%	$3,173	0.35%	$733	-0.57%	($1,791)
METAL HALIDE LAMPS									
12,000 Lumen New Pole	0	$29.13	$0	1.01%	$0	0.35%	$0	-0.57%	$0
12,000 Lumen No New Pole	243	$21.59	$5,246	1.01%	$53	0.35%	$12	-0.57%	($30)
19,500 Lumen New Pole	105	$34.02	$3,572	1.01%	$36	0.35%	$8	-0.57%	($20)
19,500 Lumen No New Pole	93	$27.18	$2,528	1.01%	$26	0.35%	$6	-0.57%	($14)
32,000 Lumen New Pole	417	$36.35	$15,158	1.01%	$153	0.35%	$35	-0.57%	($86)
32,000 Lumen No New Pole	730	$29.44	$21,491	1.01%	$217	0.35%	$50	-0.57%	($122)
107,000 Lumen New Pole	23	$57.05	$1,312	1.01%	$13	0.35%	$3	-0.57%	($7)
107,000 Lumen No New Pole	104	$48.64	$5,059	1.01%	$51	0.35%	$12	-0.57%	($29)
Subtotal	167,154		$3,119,959						
kWh Included	13,124,895								
Unbilled	0								
Customers	8,479								
Total (kWh)	13,124,895		$3,119,959		$31,512		$7,280		($17,784)
Schedule No. 8 - Composite									
Customer Charge	3,283	$55.00	$180,565						
Facilities kW	4,527,748	$3.77	$17,069,610						
On-Peak kW (May - Sept)	1,922,144	$12.33	$23,700,036	5.56%	$1,317,722	2.05%	$323,900	-3.12%	($739,441)
On-Peak kW (Oct - Apr)	2,508,971	$8.88	$22,279,662	5.56%	$1,238,749	2.05%	$304,489	-3.12%	($695,125)
Voltage Discount	1,716,399	($0.90)	($1,544,759)						
On-Peak kWh (May - Sept)	240,701,778	4.0021 ¢	$9,633,126	5.56%	$535,602	2.05%	$131,653	-3.12%	($300,554)

Rocky Mountain Power - State of Utah

Blocking Based on Adjusted Actual and Forecasted Loads
Historical Test Period 12 Months Ending December, 2008
Forecast Test Period 12 Months Ending June 2010

	Forecast Units	Present Price	Revenue Dollars	Price	Proposed Sch 40 Dollars	Price	Proposed Sch 97 Dollars (8 Months)	Price	Proposed Sch 98 Dollars
On-Peak kWh (Oct - Apr)	559,914,390	3.1328 ¢	$17,540,998	5.56%	$975,279	2.05%	$239,727	-3.12%	($547,279)
Off-Peak kWh	1,150,645,564	2.6987 ¢	$31,052,472	5.56%	$1,726,517	2.05%	$424,384	-3.12%	($968,837)
Unbilled	0								
Total	1,951,261,732		$119,911,710		$5,793,870		$1,424,153		($3,251,236)
Schedule No. 9 - Composite									
Customer Charge	1,793	$200.00	$358,600						
Facilities kW	6,760,603	$1.71	$11,560,631						
On-Peak kW (May - Sept)	2,825,640	$10.76	$30,403,886	5.99%	$1,821,193	2.23%	$452,004	-3.36%	($1,021,571)
On-Peak kW (Oct - Apr)	3,843,734	$7.30	$28,059,258	5.99%	$1,680,750	2.23%	$417,148	-3.36%	($942,791)
On-Peak kWh (May-Sept)	384,941,621	3.5858 ¢	$13,803,237	5.99%	$826,814	2.23%	$205,208	-3.36%	($463,789)
On-Peak kWh (Oct-Apr)	1,013,941,762	2.6963 ¢	$27,338,912	5.99%	$1,637,601	2.23%	$406,438	-3.36%	($918,587)
Off-Peak kWh	2,278,864,469	2.2518 ¢	$51,315,470	5.99%	$3,073,797	2.23%	$762,890	-3.36%	($1,724,200)
Unbilled	0								
Total	3,677,747,852		$162,839,994		$9,040,154		$2,243,689		($5,070,938)
Schedule No. 9A - Energy TOD - Commercial									
Customer Charge	108	$200.00	$21,600						
Customer Charge (LM)	0	$0.00	$0						
Facilities Charge per kW	213,982	$1.71	$365,909						
On-Peak kWh	23,409,585	6.6247 ¢	$1,550,815	6.79%	$105,300	2.54%	$26,260	-3.81%	($59,086)
Off-Peak kWh	18,624,791	2.8479 ¢	$530,415	6.79%	$36,015	2.54%	$8,982	-3.81%	($20,209)
Unbilled	0								
Total	42,034,376		$2,468,739		$141,316		$35,242		($79,295)
Schedule No. 10 - Irrigation									
Annual Cust. Serv. Chg. - Primary	0	$98.00	$0						
Annual Cust. Serv. Chg. - Secondary	2,534	$30.00	$76,020						
Monthly Cust. Serv. Chg.	11,182	$12.00	$134,184						
All On-Season kW	311,366	$5.75	$1,790,355	4.76%	$85,221	1.81%	$21,604	-2.68%	($47,982)
Voltage Discount	31	($1.61)	($50)						
First 30,000 kWh	74,963,422	5.7252 ¢	$4,291,806	4.76%	$204,290	1.81%	$51,788	-2.68%	($115,020)
All add'l kWh	47,994,360	4.2318 ¢	$2,031,025	4.76%	$96,677	1.81%	$24,508	-2.68%	($54,431)
Total On Season	122,957,782		$8,323,340		$386,188		$97,899		($217,433)
Post Season									
Customers	4,707	$12.00	$56,484						
kWh	47,167,286	3.9216 ¢	$1,849,712	4.76%	$88,046	1.81%	$22,320	-2.68%	($49,572)
Total Post Season	47,167,286		$1,906,196		$88,046		$22,320		($49,572)
Unbilled	0								
TOTAL RATE 10	170,125,068		$10,229,536		$474,234		$120,219		($267,006)
Schedule No. 10-TOD									
Annual Cust. Serv. Chg. - Primary	2	$98.00	$196						
Annual Cust. Serv. Chg. - Secondary	233	$30.00	$7,003						
Monthly Cust. Serv. Chg.	1,060	$12.00	$12,720						
All On-Season kW	37,587	$5.75	$216,125	4.76%	$10,288	1.81%	$2,608	-2.68%	($5,792)
Voltage Discount kW	6,054	($1.61)	($9,747)						
On-Peak kWh	2,969,621	11.3110 ¢	$335,894	4.76%	$15,989	1.81%	$4,053	-2.68%	($9,002)
Off-Peak kWh	10,030,915	3.2631 ¢	$327,319	4.76%	$15,580	1.81%	$3,950	-2.68%	($8,772)
Total On Season	13,000,536		$889,510		$41,856		$10,611		($23,566)
Post Season									
Customers	527	$12.00	$6,324						
kWh	5,694,396	3.9216 ¢	$223,311	4.76%	$10,630	1.81%	$2,695	-2.68%	($5,985)
Total Post Season	5,694,396		$229,635		$10,630		$2,695		($5,985)
Unbilled	0								
TOTAL RATE 10-TOD	18,694,932		$1,119,145		$52,486		$13,305		($29,551)
Schedule No. 11 - Street Lighting - Company-Owned System									
Sodium Vapor Lamps									
5,600 Lumen - Functional	82,340	$11.69	$962,555	1.01%	$9,722	0.35%	$2,246	-0.57%	($5,487)
9,500 Lumen - Functional	242,551	$12.66	$3,070,696	1.01%	$31,014	0.35%	$7,165	-0.57%	($17,503)
9,500 Lumen - Functional @ 90%	448	$11.39	$5,103	1.01%	$52	0.35%	$12	-0.57%	($29)
9,500 Lumen - S1	143	$46.09	$6,591	1.01%	$67	0.35%	$15	-0.57%	($38)
9,500 Lumen - S2	76	$37.68	$2,864	1.01%	$29	0.35%	$7	-0.57%	($16)
16,000 Lumen - Functional	28,604	$16.78	$479,975	1.01%	$4,848	0.35%	$1,120	-0.57%	($2,736)
16,000 Lumen - Functional @ 90%	157	$15.10	$2,371	1.01%	$24	0.35%	$6	-0.57%	($14)
16,000 Lumen - S1	54	$47.37	$2,558	1.01%	$26	0.35%	$6	-0.57%	($15)
16,000 Lumen - S2	675	$38.96	$26,298	1.01%	$266	0.35%	$61	-0.57%	($150)
27,500 Lumen - Functional	35,529	$20.94	$743,977	1.01%	$7,514	0.35%	$1,736	-0.57%	($4,241)
27,500 Lumen - Functional @ 90%	191	$18.85	$3,600	1.01%	$36	0.35%	$8	-0.57%	($21)
27,500 Lumen - S1	1,127	$50.99	$57,466	1.01%	$580	0.35%	$134	-0.57%	($328)
27,500 Lumen - S2	0	$42.60	$0	1.01%	$0	0.35%	$0	-0.57%	$0
50,000 Lumen - Functional	13,131	$25.77	$338,386	1.01%	$3,418	0.35%	$790	-0.57%	($1,929)
125,000 Lumen	0	$51.04	$0	1.01%	$0	0.35%	$0	-0.57%	$0
Metal Halide Lamps									
9,000 Lumen - S1	0	$48.27	$0	1.01%	$0	0.35%	$0	-0.57%	$0
9,000 Lumen - S2	525	$39.88	$20,937	1.01%	$211	0.35%	$49	-0.57%	($119)
12,000 Lumen - Functional	0	$19.94	$0	1.01%	$0	0.35%	$0	-0.57%	$0

Rocky Mountain Power - State of Utah

Blocking Based on Adjusted Actual and Forecasted Loads
Historical Test Period 12 Months Ending December, 2008
Forecast Test Period 12 Months Ending June 2010

	Forecast Units	Present Price	Revenue Dollars	Price	Proposed Sch 40 Dollars	Price	Proposed Sch 97 Dollars (8 Months)	Price	Proposed Sch 98 Dollars
12,000 Lumen - S1	0	$50.16	$0	1.01%	$0	0.35%	$0	-0.57%	$0
12,000 Lumen - S2	1,683	$41.76	$70,282	1.01%	$710	0.35%	$164	-0.57%	($401)
19,500 Lumen - Functional	0	$21.92	$0	1.01%	$0	0.35%	$0	-0.57%	$0
19,500 Lumen - S1	478	$53.17	$25,415	1.01%	$257	0.35%	$59	-0.57%	($145)
19,500 Lumen - S2	54	$44.77	$2,418	1.01%	$24	0.35%	$6	-0.57%	($14)
32,000 Lumen - Functional	0	$25.53	$0	1.01%	$0	0.35%	$0	-0.57%	$0
32,000 Lumen - S1	0	$54.80	$0	1.01%	$0	0.35%	$0	-0.57%	$0
32,000 Lumen - S2	0	$46.41	$0	1.01%	$0	0.35%	$0	-0.57%	$0
Mercury Vapor Lamps (No New Service)									
4,000 Lumen	9,898	$10.98	$108,680	1.01%	$1,098	0.35%	$254	-0.57%	($619)
7,000 Lumen	13,971	$13.70	$191,403	1.01%	$1,933	0.35%	$447	-0.57%	($1,091)
10,000 Lumen	227	$19.21	$4,361	1.01%	$44	0.35%	$10	-0.57%	($25)
10,000 Lumen @ 90%	50	$17.29	$865	1.01%	$9	0.35%	$2	-0.57%	($5)
20,000 Lumen	2,309	$24.20	$55,878	1.01%	$564	0.35%	$130	-0.57%	($319)
Incandescent Lamps (No New Service)									
500 Lumen	0	$11.87	$0	1.01%	$0	0.35%	$0	-0.57%	$0
600 Lumen	130	$4.20	$546	1.01%	$6	0.35%	$1	-0.57%	($3)
2,500 Lumen	279	$16.95	$4,729	1.01%	$48	0.35%	$11	-0.57%	($27)
4,000 Lumen	352	$20.23	$7,121	1.01%	$72	0.35%	$17	-0.57%	($41)
6,000 Lumen	1,136	$23.59	$26,798	1.01%	$271	0.35%	$63	-0.57%	($153)
10,000 Lumen	22	$31.17	$686	1.01%	$7	0.35%	$2	-0.57%	($4)
Fluorescent Lamps (No New Service)									
21,000 Lumen	11	$27.58	$303	1.01%	$3	0.35%	$1	-0.57%	($2)
Special Service (No New Service)									
50,000 Lumen - Flood	1,417	$38.66	$54,781	1.01%	$553	0.35%	$128	-0.57%	($312)
Subtotal	437,568		$6,277,643						
kWh Included	21,323,143								
Customers	1,027								
Unbilled	0								
Total	21,323,143		$6,277,643		$63,404		$14,648		-$35,783
Schedule No. 12 - Street Lighting - Customer-Owned System									
1. Energy Only, No Maintenance									
High Pressures Sodium Vapor Lamps									
5,600 Lumen	39,245	$1.81	$71,033	1.01%	$717	0.35%	$166	-0.57%	($405)
9,500 Lumen	86,693	$2.47	$214,132	1.01%	$2,163	0.35%	$500	-0.57%	($1,221)
16,000 Lumen	111,321	$3.62	$402,982	1.01%	$4,070	0.35%	$940	-0.57%	($2,297)
27,500 Lumen	50,134	$6.45	$323,364	1.01%	$3,266	0.35%	$755	-0.57%	($1,843)
50,000 Lumen	70,398	$9.92	$698,348	1.01%	$7,053	0.35%	$1,629	-0.57%	($3,981)
Metal Halide Lamps									
9,000 Lumen	4,865	$2.52	$12,260	1.01%	$124	0.35%	$29	-0.57%	($70)
12,000 Lumen	7,236	$4.41	$31,911	1.01%	$322	0.35%	$74	-0.57%	($182)
19,500 Lumen	24,773	$6.11	$151,363	1.01%	$1,529	0.35%	$353	-0.57%	($863)
32,000 Lumen	23,050	$9.67	$222,894	1.01%	$2,251	0.35%	$520	-0.57%	($1,270)
Non-listed Luminaries kWh	6,480,160	6.4597 ¢	$418,599	1.01%	$4,228	0.35%	$977	-0.57%	($2,386)
Subtotal kWh	39,094,955		$2,546,886						
2a - Partial Maintenance (No New Service)									
Incandescent Lamps									
2,500 Lumen or Less	81	$8.87	$718	1.01%	$7	0.35%	$2	-0.57%	($4)
2,500 Lumen or Less @ 85%	19	$7.54	$143	1.01%	$1	0.35%	$0	-0.57%	($1)
4,000 Lumen	38	$12.06	$458	1.01%	$5	0.35%	$1	-0.57%	($3)
Mercury Vapor Lamps									
4,000 Lumen	839	$4.59	$3,851	1.01%	$39	0.35%	$9	-0.57%	($22)
7,000 Lumen	763	$6.93	$5,288	1.01%	$53	0.35%	$12	-0.57%	($30)
10,000 Lumen	85	$8.99	$764	1.01%	$8	0.35%	$2	-0.57%	($4)
20,000 Lumen	200	$13.19	$2,638	1.01%	$27	0.35%	$6	-0.57%	($15)
54,000 Lumen	25	$28.08	$702	1.01%	$7	0.35%	$2	-0.57%	($4)
High Pressure Sodium Vapor Lamps									
5,600 Lumen	46,417	$4.04	$187,525	1.01%	$1,894	0.35%	$438	-0.57%	($1,069)
9,500 Lumen	18,630	$5.31	$98,925	1.01%	$999	0.35%	$231	-0.57%	($564)
9,500 Lumen @ 85%	148	$4.51	$667	1.01%	$7	0.35%	$2	-0.57%	($4)
9,500 Lumen - Decorative	10,874	$6.89	$74,922	1.01%	$757	0.35%	$175	-0.57%	($427)
16,000 Lumen	7,847	$6.45	$50,613	1.01%	$511	0.35%	$118	-0.57%	($288)
16,000 Lumen @ 85%	10	$5.48	$55	1.01%	$1	0.35%	$0	-0.57%	($0)
16,000 Lumen - Decorative	1,719	$8.18	$14,061	1.01%	$142	0.35%	$33	-0.57%	($80)
22,000 Lumen	53	$8.17	$433	1.01%	$4	0.35%	$1	-0.57%	($2)
27,500 Lumen	7,413	$9.49	$70,349	1.01%	$711	0.35%	$164	-0.57%	($401)
27,500 Lumen @ 85%	0	$8.07	$0	1.01%	$0	0.35%	$0	-0.57%	$0
27,500 Lumen - Decorative	185	$11.81	$2,185	1.01%	$22	0.35%	$5	-0.57%	($12)
50,000 Lumen	11,806	$13.85	$163,513	1.01%	$1,651	0.35%	$382	-0.57%	($932)
50,000 Lumen @ 85%	0	$11.77	$0	1.01%	$0	0.35%	$0	-0.57%	$0
50,000 Lumen - Decorative	267	$15.40	$4,112	1.01%	$42	0.35%	$10	-0.57%	($23)
125,000 Lumen	0	$26.10	$0	1.01%	$0	0.35%	$0	-0.57%	$0
Metal Halide Lamps									
9,000 Lumen - Decorative	564	$9.09	$5,127	1.01%	$52	0.35%	$12	-0.57%	($29)
12,000 Lumen	680	$13.43	$9,132	1.01%	$92	0.35%	$21	-0.57%	($52)
12,000 Lumen @ 85%	68	$11.42	$777	1.01%	$8	0.35%	$2	-0.57%	($4)
12,000 Lumen - Decorative	5,922	$10.97	$64,964	1.01%	$656	0.35%	$152	-0.57%	($370)
19,500 Lumen	2,516	$13.57	$34,142	1.01%	$345	0.35%	$80	-0.57%	($195)

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Forecast Test Period 12 Months Ending June 2010

	Forecast Units	Present Price	Revenue Dollars	Price	Proposed Sch 40 Dollars	Price	Proposed Sch 97 Dollars (8 Months)	Price	Proposed Sch 98 Dollars
19,500 Lumen - Decorative	4,994	$13.98	$69,816	1.01%	$705	0.35%	$163	-0.57%	($398)
32,000 Lumen	1,686	$14.43	$24,329	1.01%	$246	0.35%	$57	-0.57%	($139)
32,000 Lumen - Decorative	390	$15.62	$6,092	1.01%	$62	0.35%	$14	-0.57%	($35)
Fluorescent Lamps									
1,000 Lumen	198	$3.71	$735	1.01%	$7	0.35%	$2	-0.57%	($4)
21,800 Lumen	88	$13.77	$1,212	1.01%	$12	0.35%	$3	-0.57%	($7)
Subtotal kWh	7,180,283		$898,248						
2b - Full Maintenance (No New Service)									
Incandescent Lamps									
6,000 Lumen	86	$17.54	$1,508	1.01%	$15	0.35%	$4	-0.57%	($9)
10,000 Lumen	13	$23.16	$301	1.01%	$3	0.35%	$1	-0.57%	($2)
Mercury Vapor Lamps									
7,000 Lumen	88	$7.95	$700	1.01%	$7	0.35%	$2	-0.57%	($4)
20,000 Lumen	47	$15.14	$712	1.01%	$7	0.35%	$2	-0.57%	($4)
54,000 Lumen	100	$32.14	$3,214	1.01%	$32	0.35%	$7	-0.57%	($18)
Sodium Vapor Lamps									
5,600 Lumen	23,027	$4.63	$106,615	1.01%	$1,077	0.35%	$249	-0.57%	($608)
9,500 Lumen	28,346	$6.10	$172,911	1.01%	$1,746	0.35%	$403	-0.57%	($986)
9,500 Lumen @ 90%	83	$5.49	$456	1.01%	$5	0.35%	$1	-0.57%	($3)
16,000 Lumen	5,713	$7.39	$42,219	1.01%	$426	0.35%	$99	-0.57%	($241)
16,000 Lumen @ 90%	312	$6.65	$2,075	1.01%	$21	0.35%	$5	-0.57%	($12)
22,000 Lumen	77	$9.34	$719	1.01%	$7	0.35%	$2	-0.57%	($4)
27,500 Lumen	4,254	$10.88	$46,284	1.01%	$467	0.35%	$108	-0.57%	($264)
50,000 Lumen	3,774	$15.85	$59,818	1.01%	$604	0.35%	$140	-0.57%	($341)
50,000 Lumen @ 90%	52	$14.27	$742	1.01%	$7	0.35%	$2	-0.57%	($4)
Metal Halide Lamps									
12,000 Lumen	2,062	$15.42	$31,796	1.01%	$321	0.35%	$74	-0.57%	($181)
19,500 Lumen	347	$15.57	$5,403	1.01%	$55	0.35%	$13	-0.57%	($31)
32,000 Lumen	1,411	$16.55	$23,352	1.01%	$236	0.35%	$54	-0.57%	($133)
107,000 Lumen	100	$32.70	$3,270	1.01%	$33	0.35%	$8	-0.57%	($19)
Subtotal kWh	3,557,171		$502,095						
kWh Street Lighting	49,832,409		$3,947,229						
Customers	760								
Unbilled									
Total	49,832,409		$3,947,229		$39,867		$9,210		-$22,499
Schedule 15.1 - Metered Outdoor Nighttime Lighting									
Annual Facility Charge	19,032	$10.76	$204,784						
Annual Customer Charge	388	$71.40	$27,703						
Annual Minimum Charge	0	$125.20	$0						
Monthly Customer Charge	4,564	$6.11	$27,886						
All kWh	12,757,359	5.2746 ¢	$672,900	2.68%	$18,034	0.78%	$3,499	-1.50%	($10,094)
Unbilled	0								
Total	12,757,359		$933,273		$18,034		$3,499		($10,094)
Schedule 15.2 - Traffic Signal Systems									
Customer Charge	26,612	$4.50	$119,754						
All kWh	5,255,307	6.9957 ¢	$367,646	3.91%	$14,375	1.45%	$3,554	-2.20%	($8,088)
Unbilled	0								
Total	5,255,307		$487,400		$14,375		$3,554		($8,088)
Schedule No. 21 - Electric Furnace Operations - Limited Service - Industrial									
Primary Voltage									
Customer Charge	36	$97.00	$3,492						
Charge per kW	12,415	$3.29	$40,845	4.52%	$1,846	1.66%	$452	-2.54%	($1,037)
First 100,000 kWh	470,641	5.2440 ¢	$24,680	4.52%	$1,116	1.66%	$273	-2.54%	($627)
All add'l kWh	0	4.4032 ¢	$0	4.52%	$0	1.66%	$0	-2.54%	$0
Unbilled	0								
Subtotal	470,641		$69,017		$2,962		$725		($1,664)
44KV or Higher									
Customer Charge	24	$97.00	$2,328						
Charge per kW	33,448	$3.29	$110,044	4.52%	$4,974	1.66%	$1,218	-2.54%	($2,795)
First 100,000 kWh	2,365,056	4.1257 ¢	$97,575	4.52%	$4,410	1.66%	$1,080	-2.54%	($2,478)
All add'l kWh	533,046	3.6547 ¢	$19,481	4.52%	$881	1.66%	$216	-2.54%	($495)
Unbilled	0								
Subtotal	2,898,102		$229,428		$10,265		$2,513		($5,768)
Total	3,368,743		$298,445		$13,227		$3,238		($7,433)
Schedule No. 23 - Distribution Voltage - Small Customer - Composite									
Customer Charge	904,591	$8.00	$7,236,728						
kW over 15 (May - Sept)	350,607	$7.25	$2,541,901	4.49%	$114,131	1.64%	$27,791	-2.52%	($64,056)
kW over 15 (Oct - Apr)	332,283	$7.30	$2,425,666	4.49%	$108,912	1.64%	$26,521	-2.52%	($61,127)
Voltage Discount	5,569	($0.41)	($2,283)						
First 1,500 kWh (May - Sept)	266,278,933	9.8214 ¢	$26,152,319	4.49%	$1,174,239	1.64%	$285,932	-2.52%	($659,038)
All Add'l kWh (May - Sept)	285,728,059	5.5063 ¢	$15,733,044	4.49%	$706,414	1.64%	$172,015	-2.52%	($396,473)
First 1,500 kWh (Oct - Apr)	371,991,564	9.0400 ¢	$33,628,037	4.49%	$1,509,899	1.64%	$367,667	-2.52%	($847,427)
All Add'l kWh (Oct - Apr)	330,822,961	5.0688 ¢	$16,768,754	4.49%	$752,917	1.64%	$183,338	-2.52%	($422,573)
Seasonal Service	0	$96.00	$0						

Rocky Mountain Power - State of Utah

Blocking Based on Adjusted Actual and Forecasted Loads
Historical Test Period 12 Months Ending December, 2008
Forecast Test Period 12 Months Ending June 2010

	Forecast Units	Present Price	Revenue Dollars	Price	Proposed Sch 40 Dollars	Price	Proposed Sch 97 Dollars (8 Months)	Price	Proposed Sch 98 Dollars
Unbilled	0								
Total	1,254,821,517		$104,484,166		$4,366,512		$1,063,264		($2,450,693)
Schedule No.31 - Back-Up, Maintenance, and Supplementary Power - Commercial									
Secondary Voltage									
Customer Charge per month	0	$104.00	$0						
Facilities Charge, per kW month	0	$3.81	$0						
Back-up Power Charge									
Regular, per On-Peak kW day	0	$0.5244	$0						
Maintenance, per On-Peak kW day	0	$0.2622	$0						
Excess Power, per kW month	0	$49.40	$0						
Primary Voltage									
Customer Charge per month	24	$471.00	$11,304						
Facilities Charge, per kW month	36,878	$2.99	$110,265						
Back-up Power Charge									
Regular, per On-Peak kW day	237,020	$0.5102	$120,928						
Maintenance, per On-Peak kW day	38,775	$0.2551	$9,892						
Excess Power, per kW month	141	$35.60	$5,020						
Transmission Voltage									
Customer Charge per month	0	$527.00	$0						
Facilities Charge, per kW month	0	$1.70	$0						
Back-up Power Charge									
Regular, per On-Peak kW day	0	$0.4008	$0						
Maintenance, per On-Peak kW day	0	$0.2004	$0						
Excess Power, per kW month	0	$34.28	$0						
Unbilled	0								
Total	0		$257,409		$0		$0		$0
Supplemental billed at Schedule 6/8/9 rate									
Schedule 6									
All kW (May - Sept)	0	$15.16	$0						
All kW (Oct - Apr)	0	$12.17	$0						
Voltage Discount	0	($0.78)	$0						
All kWh	0								
kWh (May-Sept)	0	3.1907 ¢	$0						
kWh (Oct-Apr)	0	2.9416 ¢	$0						
Schedule 8									
Facilities kW	5,401	$3.77	$20,362						
On-Peak kW (May - Sept)	957	$12.33	$11,800	5.56%	$656	2.05%	$161	-3.12%	($368)
On-Peak kW (Oct - Apr)	19,937	$8.88	$177,041	5.56%	$9,843	2.05%	$2,420	-3.12%	($5,524)
Voltage Discount	20,894	($0.90)	($18,805)						
On-Peak kWh (May - Sept)	1,267,360	4.0021 ¢	$50,721	5.56%	$2,820	2.05%	$693	-3.12%	($1,582)
On-Peak kWh (Oct - Apr)	5,078,886	3.1328 ¢	$159,111	5.56%	$8,847	2.05%	$2,175	-3.12%	($4,964)
Off-Peak kWh	7,276,065	2.6987 ¢	$196,359	5.56%	$10,918	2.05%	$2,684	-3.12%	($6,126)
Schedule 9									
Facilities kW	0	$1.71	$0						
On-Peak kW (May - Sept)	0	$10.76	$0						
On-Peak kW (Oct - Apr)	0	$7.30	$0						
On-Peak kWh (May-Sept)	0	3.5858 ¢	$0						
On-Peak kWh (Oct-Apr)	0	2.6963 ¢	$0						
Off-Peak kWh	0	2.2518 ¢	$0						
Total (Aggregated)	13,622,311		$853,998		$33,084		$8,132		($18,565)
SPCL0001									
Customer Charge	12		$2,124						
kW High Load Hours	1,142,724		$10,892,880						
kW Low Load Hours	1,198,977		$0						
kWh High Load Hours	267,114,323		$7,780,278						
kWh Low Load Hours	342,038,300		$7,218,483						
Total High Load Hours			$18,673,158						
Total Low Load Hours			$7,218,483						
Total	609,152,623		$25,893,765						
SPCL0002									
Customer Charge	12								
Non-firm kW	0		$0						
Non-firm kWh	915,454,903		$25,732,720						
Pass Through kWh	35,372,388		$3,437,499						
Total	950,827,291		$29,170,219						
SPCL0003									
Customer Charge	12		$3,303						
Facilities Charge per kW	1,073,572		$1,689,918						
kW Back-Up	4,772,674		$1,884,479						
kW Supplemental	835,200		$5,796,863						
On-Peak kW (May - Sept)	0			5.99%	$0	2.23%	$0	-3.36%	$0
On-Peak kW (Oct - Apr)	835,200			5.99%	$365,208	2.23%	$90,641	-3.36%	($204,858)
kW Maintenance	0		$0						
kWh Supplemental	641,456,680		$14,453,331						

Rocky Mountain Power - State of Utah

Blocking Based on Adjusted Actual and Forecasted Loads
Historical Test Period 12 Months Ending December, 2008
Forecast Test Period 12 Months Ending June 2010

	Forecast Units	Present Price	Revenue Dollars	Price	Proposed Sch 40 Dollars	Price	Proposed Sch 97 Dollars (8 Months)	Price	Proposed Sch 98 Dollars
On-Peak kWh (May-Sept)	23,603,223			5.99%	$50,697	2.23%	$12,583	-3.36%	($28,438)
On-Peak kWh (Oct-Apr)	239,320,200			5.99%	$386,522	2.23%	$95,931	-3.36%	($216,814)
Off-Peak kWh	378,533,257			5.99%	$510,576	2.23%	$126,721	-3.36%	($286,400)
Total	641,456,680		$23,827,894		$1,313,004		$325,876		($736,510)
SPCL0005									
Customer Charge	12		$2,083						
kW Facility	375,553		$602,768						
kW Firm	371,615		$2,993,977						
On-Peak kW (May - Sept)	153,334			5.99%	$98,827	2.23%	$24,528	-3.36%	($55,436)
On-Peak kW (Oct - Apr)	218,281			5.99%	$95,448	2.23%	$23,689	-3.36%	($53,540)
kWh Firm	253,208,400		$5,945,912						
On-Peak kWh (May-Sept)	23,818,054			5.99%	$51,159	2.23%	$12,697	-3.36%	($28,697)
On-Peak kWh (Oct-Apr)	68,063,457			5.99%	$109,928	2.23%	$27,283	-3.36%	($61,663)
Off-Peak kWh	161,326,889			5.99%	$217,602	2.23%	$54,007	-3.36%	($122,061)
Total Firm	253,208,400		$9,544,739		$572,964		$142,205	-3.36%	($321,396)
Rate No. 60 - Street Lighting, 08HAXT0060									
Bills	12								
40 Watt Incandescent Lamps	12	$7.75	$93						
All kWh	141	0.0000 ¢	$0						
Unbilled	0		$0						
Total	141		$93						
Rate No. 77 - Security Lighting, 08THIK0077									
Customer	1	$0.00	$0						
20,000 Mercury Vapor	972	$17.7751	$17,277						
50,000 Lumen	0	$0.00	$0						
All kWh	127,030	0.0000 ¢	$0						
Unbilled	0		$0						
Total	127,030		$17,277						
Lighting Contract - Post Top Lighting - 08PTLD000N/08PTLD000R									
Energy Only Res	7,500	$2.18	$16,350						
Energy Only Non-Res	1,956	$2.1858	$4,275						
7,000 Lumen	46	$4.80	$221						
Subtotal	9,502		$20,846						
KWH Included	277,409								
Customers	78								
Unbilled	0								
Total	277,409		$20,846						
Annual Guarantee Adjustment									
Residential			$28,536						
Commercial			$3,284,110						
Industrial			($6,143)						
Irrigation			$167,216						
Public Street & Highway Lighting			$4,789						
Other Sales Public Authorities			$0						
Interdepartmental			$0						
Total AGA			$3,478,507						
TOTAL - ALL CLASSES	22,088,937,612		$1,506,669,965		$64,096,637		$15,711,587		($35,981,009)