- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

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	)	DOCKET NO. 13-035-184 REPORT AND ORDER

ISSUED: August 29, 2014

SHORT TITLE

PacifiCorp dba Rocky Mountain Power 2014 General Rate Case

SYNOPSIS

The Commission approves a comprehensive, multi-year, uncontested settlement stipulation addressing revenue requirement, revenue spread to classes of customers, rate design, and deferred accounting treatment of certain costs. The Commission concludes PacifiCorp dba Rocky Mountain Power's proposed net metering facilities charge requires further study and is not implemented at this time (one Commissioner dissents, in part, from this finding). The Commission initiates a process for further analysis of the net metering program costs and benefits.

The revenue requirement changes are implemented in two steps. In Step 1, the Commission increases Rocky Mountain Power's annual revenue requirement by $35.0 million effective September 1, 2014, based on a forecasted test period of 12 months ending June 30, 2015, using a 13-month average rate base. This is a 1.86 percent increase in Rocky Mountain Power's forecast of general business revenue in Utah. In Step 2, the Commission increases Rocky Mountain Power's annual revenue requirement by $19.2 million, conditionally effective September 1, 2015. This is a 1.02 percent increase in Rocky Mountain Power's forecast of general business revenue in Utah.

The Commission authorizes a 7.57 percent rate of return on rate base, based in part on an allowed 9.8 percent rate of return on common equity, which remains unchanged from the current authorized level.

For the Step 1 revenue increase, the Commission allocates approximately 41 percent to residential customers and 59 percent to commercial and industrial customers. For the Step 2 revenue increase, the Commission allocates approximately 39 percent to residential customers and 61 percent to commercial and industrial customers.

For residential customers taking single-phase service, the Commission increases the customer charge from $5 to $6 per month and the minimum bill from $7 to $8 per month. The remainder of the revenue increase assigned to residential customers is derived from an increase in the second tier of non-summer rates; all other residential rates remain unchanged. The impacts of the Step 1 and Step 2 increases and rate design changes to a residential customer using 700 kilowatt hours per month are $1.77 or 2.32 percent, and $0.73 or 0.94 percent per month, respectively.

The Commission approves deferred accounting treatment for: (1) Utah's allocated portion of energy imbalance market ("EIM") related operations and maintenance expenses as well as depreciation expense related to capital investments necessary to implement the EIM; (2) costs related to the impacts of any proposed disposition of PacifiCorp's Deer Creek Mine and related mining assets; and (3) impacts of the possible sale of PacifiCorp's ownership interests in the Craig and Hayden generating plants.

The Commission approves (1) the base levels of net power cost and wheeling revenue for energy balancing account measurement, (2) the base level of renewable energy credit revenue contained in general rates, and (3) certain accounting treatment related to the amortization of future approved balancing account charges or refunds.

The Commission approves the extension of the EBA pilot program approved in Docket No. 09-035-15, from December 31, 2015, to December 31, 2016.

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I. PROCEDURAL HISTORY

On November 5, 2013, PacifiCorp, through its operating division Rocky Mountain Power, (referred to herein as "PacifiCorp" or "Company"), filed its notice of intent to file a general rate case on or about January 3, 2014. In this notice, PacifiCorp, a Utah public utility subject to Commission regulation, also requested the Public Service Commission of Utah ("Commission") approve its proposed forecast test period of twelve months ending June 30, 2015, consistent with the settlement stipulation filed and approved in Docket Nos. 11-035-200, 12-035-79, and 12-035-80.[1] On November 5, 2013, the Commission issued an action request to the Utah Division of Public Utilities ("Division") to review PacifiCorp's notice of intent. On November 20, 2013, the Commission issued a Notice of Proposed Forecast Test Period that provided all potential participants in this docket the opportunity to respond to PacifiCorp's proposed forecast test period. In response to the Commission's November 5 action request, on November 19, 2013, the Division filed comments stating it did not oppose PacifiCorp's proposed forecast test period of the twelve months ending June 2015. No other party filed comments on the proposed test period. On December 10, 2013, the Commission issued an Order Approving Test Period.

On January 3, 2014, PacifiCorp filed an application ("Application") requesting Commission authority to increase its retail rates by $76.3 million, or approximately 4 percent, effective September 1, 2014. The Application was based on the forecast test period ending June 30, 2015, a 13-month average rate base with an historical base period, a return on equity of 10.0

[1] *See 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*, Docket No. 11-035-200 (Report and Order; September 19, 2012).

percent, and allocation of total PacifiCorp costs to Utah using rolled-in inter-jurisdictional allocation results, consistent with the 2010 Protocol method approved in Docket No. 02-035-04.[2] In the Application, PacifiCorp requested approval to increase the residential customer charge from $5 per month to $8 per month and to increase the minimum bill from $7 to $15 per month. PacifiCorp also proposed a fixed monthly net metering facilities charge of $4.25 per month for residential net metering customers in Electric Service Schedule No. 135, Net Metering Service.

On January 3, 2014, the Commission issued an action request to the Division to review the Application pursuant to Utah Code Ann. § 54-7-12(2) to determine if it satisfies the requirements of a complete filing pursuant to Utah Administrative Code R746-700-1 through 23 (“Rules”). On January 6, 2014, the Commission issued a Notice of Scheduling Conference to be held on January 16, 2014. On January 17, 2014, the Division filed a memorandum summarizing the results of its review of the Application. In this filing the Division identified instances where certain responses to the filing requirements were in partial compliance with the Rules, indicated it did not believe the deficiencies were significant, and recommended the Commission acknowledge PacifiCorp’s filing as being complete.

On January 22, 2014, the Commission issued a Scheduling Order setting the procedural schedule for this docket consisting of two phases: Phase I – addressing revenue requirement and Phase II – addressing cost-of-service. Discussion of the parties at the scheduling conference also led to agreement to amend the schedule set for Rocky Mountain Power’s

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[2] *See In the Matter of the Application of PacifiCorp for an Investigation of Inter-Jurisdictional Issues*, Docket No. 02-035-04 (Report and Order; February 3, 2012).

application in Docket No. 13-035-196[3] to revise its Back-Up, Maintenance, and Supplementary Power Service Tariff, Electric Service Schedule 31 ("Schedule 31 Application"). The parties agreed to address the Schedule 31 Application concurrently with Phase II of this docket.

Between January 15 and March 20, 2014, the following 12 parties petitioned for leave to intervene in this case which the Commission granted: Nucor Steel-Utah, a Division of Nucor Corporation ("Nucor"); Holcim, Inc., Kennecott Utah Copper LLC, Kimberly-Clark Corp., Malt-O-Meal, Praxair, Inc., Proctor & Gamble, Inc., Tesoro Refining and Marketing Co., collectively referred to as Utah Industrial Energy Consumers ("UIEC"); Utah Association of Energy Users, Air Liquide, ATK Propulsion Systems, American Pacific Corporation, Anadarko Midstream, Chevron Global Power, ConocoPhillips Gas and Power, Hexcel Corporation, Intermountain Healthcare, IM Flash Technologies, LLC, May Foundry & Machine Company and Simplot Phosphates, collectively known as UAE Intervention Group ("UAE"); US Magnesium LLC ("US MAG"); Sierra Club; International Brotherhood of Electrical Workers, Local 57 ("IBEW Local 57"); The Kroger Co. ("Kroger"); Utah Clean Energy ("UCE"); Federal Executive Agencies ("FEA"); Wal-Mart Stores, Inc. and Sam's West, Inc. ("Wal-Mart"); The Alliance for Solar Choice ("TASC"); and Utah Citizens Advocating Renewable Energy ("UCARE").

The following organizations filed written comments with the Commission: Salt Lake City Corporation, Sustainability Division; Salt Lake County; Millcreek Township Council; Liberty Wells Community Council; White City Township Community Council; Magna

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[3] *See In the Matter of the Application of Rocky Mountain Power for Approval of Revisions to Back-Up, Maintenance, and Supplementary Power Service Tariff, Electric Service Schedule 31,* Docket No. 13-035-196.

Community Council; Sandy Hills Community Council; Fairpark Community Council; Sugarhouse Community Council; Big Cottonwood Canyon Community Council; Wasatch Hollow Community Council; Salt Lake Community Solar Steering Committee; Summit Community Solar Steering Committee; Moab City and Park City along with local businesses; Utah Solar Energy Association; Utah Physicians for a Healthy Environment; Renewable Energy Advisors; and the Edison Electric Institute. In addition, as of July 29, 2014, the Commission had received over 1,800 email and written comments from the public on the case, primarily regarding PacifiCorp's proposed net metering facilities charge. In addition to written and email comments, interested persons provided verbal comments or testimony at the Public Witness hearing held on July 29, 2014.

On April 10, 2014, PacifiCorp filed its updated net power costs ("NPC") along with updated information regarding the U.S. Environmental Protection Agency's ("EPA") regulation of PacifiCorp's Naughton plant, as proposed in its direct testimony and consistent with the Scheduling Order. With this update, PacifiCorp reduced NPC from $1,521.9 million to $1,510.2 million ($11.7 million decrease) on a total Company basis and from $641.1 million to $636.1 million ($4.96 million decrease) on a Utah-allocated basis for the test period ending June 30, 2015.

On April 16, 2014, the Commission issued a public notice addressing Utah Determinations Required by Senate Bill 208 ("S.B. 208"). S.B. 208 was passed by the Utah State Legislature in its 2014 Session and signed on March 25, 2014, by Governor Herbert. It amends Utah Code Ann. §§ 54-15-102, 54-15-104 and 54-15-106 and enacts Utah Code Ann. § 54-15-105.1. S.B. 208 states the Commission shall:

> (1) determine, after appropriate notice and opportunity for public comment, whether costs that the electrical corporation or other customers will incur from a net metering program will exceed the benefits of the net metering program, or whether the benefits of the net metering program will exceed the costs; and (2) determine a just and reasonable charge, credit, or ratemaking structure, including new or existing tariffs, in light of the costs and benefits.

In the April 16th notice, the Commission stated its intent to make the S.B. 208 determinations in this docket. The Commission invited the public to submit written comments on PacifiCorp's proposed $4.25 per month net metering facilities charge, and also encouraged the public to provide verbal comments at the Public Witness Hearing, pursuant to the Commission's January 22, 2014, Scheduling Order. The Commission also directed intervening parties to address the costs and benefits of the net metering program as part of their written testimony on cost-of-service issues.

On April 16 and 17, 2014, the following parties filed direct testimony on cost of capital: the Division, the Office of Consumer Services ("Office"), and FEA. On April 28, 2014, and May 12, 2014, FEA filed errata direct testimony on cost of capital. On May 1, 2014, direct testimony on revenue requirement was filed by the Division, the Office, UAE, UIEC, UCE, FEA, and Sierra Club in both original and, when necessary, redacted form.

On May 15, 2014, PacifiCorp filed rebuttal testimony on cost of capital. On May 22, 2014, the Division, the Office, and FEA filed surrebuttal testimony on cost of capital. Also on May 22, 2014, the following parties filed testimony on cost of service and rate design: the Division, the Office, UAE, UIEC, UCE, FEA, Sierra Club, Kroger, Wal-Mart, TASC, and UCARE.

On May 27, 2014, the Commission issued a notice reminding interested parties in this docket that, consistent with the Commission's January 22 Scheduling Order, the public was invited to provide verbal comments on any topic applicable to this case at the Public Witness Hearing scheduled for Tuesday, July 29, 2014.

On May 29, 2014, the Commission convened a hearing to examine cost-of-capital issues.

On June 4, 2014, PacifiCorp, the Division, the Office, UAE, UCE, and IBEW Local 57 filed rebuttal testimony on revenue requirement and UIEC filed supplemental direct testimony on revenue requirement. On June 16, 2014, the Commission issued its First Order Modifying Scheduling Order, directing PacifiCorp to file a joint position matrix, by July 25, 2014, addressing all disputed issues in Phase I and Phase II in this docket, including disputed issues in Docket No. 13-035-196.

On June 18, 2014, the Division filed a Motion to Amend Schedule and Request for Stipulation Hearing and Request for Expedited Treatment ("June 18 Motion"). The June 18 Motion stated the Division's belief that an executed settlement was imminent and recommended suspension of the remaining Phase I and Phase II dates for testimony and hearings in this docket, with the exception of the net metering facilities charge issue in Phase II. The June 18 Motion also recommended the hearing dates for Phase II issues, as well as the public witness hearing date, remain as scheduled. The motion further requested the Commission set a hearing to examine the executed stipulation on June 30, 2014. The June 18 Motion was supported by PacifiCorp, the Office, UAE, FEA, Kroger, Wal-Mart, Nucor, and the Sierra Club, with no party in opposition, and was granted by the Commission in its June 19, 2014, Second Order Modifying Scheduling Order.

On June 25, 2014, PacifiCorp filed the Settlement Stipulation ("Settlement Stipulation" or "Stipulation") and related attachments for Commission approval, signed by the following parties: PacifiCorp, the Division, the Office, UAE, UIEC, Kroger, FEA, and Wal-Mart. As noted above, the Commission set June 30, 2014, as the date for hearing testimony.

On June 26, 2014, PacifiCorp, the Division, the Office, UCE, TASC, and UCARE submitted rebuttal testimony addressing PacifiCorp's proposed net metering facilities charge. On June 30, 2014, the Commission held a hearing to examine the Stipulation.

On July 17, 2014, the following parties submitted surrebuttal testimony on PacifiCorp's proposed net metering facilities charge: PacifiCorp, the Division, the Office, UCE, Sierra Club, TASC, and UCARE. On July 28 and 29, 2014, the Commission held hearings to examine cost of service issues related to PacifiCorp's proposed net metering facilities charge. On July 29, 2014, the Commission held a public witness hearing.

II. SETTLEMENT STIPULATION

Without modifying its terms in any way, we briefly highlight major features of the Stipulation that contains 52 numbered Paragraphs and Exhibits A, B, C, and D. The Stipulation, excluding confidential Exhibit B, is attached as an appendix to this Report and Order. PacifiCorp, the Division, the Office, UAE, UIEC, Kroger, FEA, and Wal-Mart signed the Stipulation and are collectively referred to in this Report and Order as the "Stipulating Parties."

A. COST OF CAPITAL

1. Costs of Long-term Debt, Preferred Equity, and Common Equity

In Paragraph 23 and Table 1, the Parties agree PacifiCorp's allowed cost of long-term debt, preferred stock, and common stock equity will be 5.20 percent, 6.75 percent, and 9.80 percent, respectively.

2. Capital Structure

In Paragraph 23 and Table 1, the Stipulating Parties agree PacifiCorp's allowed capital structure will be 48.55 percent long-term debt, 0.02 percent preferred stock, and 51.43 percent common stock equity.

3. Rate of Return on Rate Base

In Paragraph 23, Table 1, based on the cost of capital and capital structure noted above, the Stipulating Parties agree PacifiCorp should be allowed to earn a 7.57 percent rate of return on rate base.

B. REVENUE REQUIREMENT

1. Multi-year Revenue Requirement Increases

Paragraph 18 states PacifiCorp should be allowed to implement a multi-year rate plan ("Plan") to change rates. In Paragraphs 20 and 22, the Stipulating Parties agree to the following components in this Plan:

- Step 1 general rate increase of $35.0 million, effective September 1, 2014;
- Step 2 general rate increase of $19.2 million, effective September 1, 2015, if the Sigurd-Red Butte transmission line is in service. If the Sigurd-Red Butte

transmission line is not in service by September 1, 2015, the Step 2 rate increase will be delayed until the Sigurd-Red Butte transmission line is placed into service.

2. Energy Balancing Account

In Paragraphs 24 through 27, the Stipulating Parties agree to the following items pertaining to the EBA:

- Base NPC for the total system is $1,495.8 million annually, and $630.0 million is allocated to Utah, effective September 1, 2014;
- the level of base EBA costs in dollars per megawatt hour in base rates by month for EBA measurement purposes are shown in Tables 2 and 3 of the Stipulation and will remain the same until new monthly base NPC amounts are set in a general rate case or other proceeding filed on or after January 1, 2016;
- the Stipulating Parties request the Commission extend the current EBA pilot, which currently ends December 31, 2015, by one year through December 31, 2016; [4]
- subject to Commission approval as requested in Paragraph 26, the Division's final report on the EBA pilot, due within four months after the conclusion of the third calendar year of the EBA pilot, shall likewise be extended one year to be due within four months after the conclusion of the fourth calendar year of the EBA pilot;

[4] The EBA pilot program was approved in Docket No. 09-035-15, *In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism* (Report and Order; March 2, 2011).

- EBA filings will continue on their established schedules, subject to the requested one-year extension of the EBA pilot;
- effective November 1, 2014, all deferral balances currently being collected in the EBA from Docket Nos. 10-035-124, 12-035-67 and 13-035-32, shall be added together with any Commission-approved balance from the currently pending EBA adjustment proceeding, Docket No. 14-035-31, with the total balance to be collected over one year beginning November 1, 2014, and such prior EBA balances shall continue to be collected from customers without interest during the collection period;
- the Commission-approved balance from the pending EBA adjustment in Docket No. 14-035-31, will accrue interest during the collection period, unless otherwise ordered by the Commission or agreed to by stipulation in Docket No. 14-035-31;
- PacifiCorp agrees to report the calculation of base monthly NPC as set forth in Exhibit A, "Utah Allocated EBA Base (Step 1 Increase)," and Exhibit B, "Utah Allocated EBA Base (Step 2 Increase)," both of which are based on the Commission Approved Utah Allocation Method.

3. Naughton Unit 3

In Paragraph 28, the Stipulating Parties agree to the following items pertaining to the proposed repowering of Naughton Unit 3:

- For purposes of the revenue requirement calculation, PacifiCorp will assume Naughton Unit 3 will continue to operate as a coal-fueled resource through December 31, 2017;

- if PacifiCorp does not obtain an amended permit in 2014 that would allow it to continue to operate Naughton Unit 3 as a coal-fueled resource through December 31, 2017, the Stipulating Parties agree PacifiCorp will be entitled to request, and the Stipulating Parties will not oppose, a deferred accounting order for the revenue requirement impact for potential recovery from customers pursuant to a Commission order in a future rate case;
- the Stipulating Parties may contest the costs to be recovered notwithstanding their agreement not to oppose deferred accounting treatment.

4. Renewable Energy Credit Balancing Account

In Paragraph 29, the Stipulating Parties agree to the following items pertaining to the Renewable Energy Credit ("REC") Balancing Account:

- Base REC revenue in rates for the purpose of determining amounts accruing in the REC balancing account ("RBA") is $2.0 million effective with the Step 1 rate increase on September 1, 2014, and it shall continue at this level until rates are set through a subsequent general rate case filed on or after January 1, 2016;
- the $2.0 million base REC amount is net of the 10 percent incentive per paragraph 39 of the stipulation in Docket No. 11-035-200.

5. Energy Imbalance Market

In Paragraphs 30 and 31, the Stipulating Parties agree to the following items pertaining to the Energy Imbalance Market ("EIM"):

- The Commission may enter a deferred accounting order to permit PacifiCorp to begin to defer Utah's allocated portion of EIM-related operations and maintenance expenses incurred on or after September 1, 2014, as well as depreciation expense related to capital investments necessary to implement EIM recorded on or after September 1, 2014, for potential recovery;

- any deferral of EIM-related labor costs shall be limited to positions exclusively created as a result of PacifiCorp's participation in the EIM in excess of the full time equivalent employee positions reflected in PacifiCorp's direct filing in this rate case of 5,460 and the Stipulating Parties further agree this number is being used solely for purposes of calculating the labor costs that qualify for EIM deferrals.

6. Next General Rate Case

In Paragraph 32, PacifiCorp agrees not to file its next general rate case ("2016 GRC") or a major plant addition case in Utah prior to January 1, 2016, or with a rate effective date prior to September 1, 2016.

C. COST OF SERVICE, REVENUE SPREAD AND RATE DESIGN

1. Cost of Service

The Stipulating Parties represent no agreement has been reached with regard to the net metering facilities charge proposed by PacifiCorp. In light of this, Stipulation Exhibit D shows impacts to residential rates under two scenarios; one containing a net metering facilities charge and one excluding a net metering facilities charge. The Stipulating Parties agree the outcome could be different depending on the Commission's decision regarding the proposed charge. PacifiCorp also agrees to complete and provide a marginal cost study for its next general rate case.

2. Revenue Spread

In Paragraph 33, the Stipulating Parties agree the Step 1 and Step 2 revenue increases set forth in Paragraphs 20 and 22 of the Stipulation should be allocated to customer classes and applied to customer rates as set forth in Exhibits C and D to the Stipulation. Exhibits C and D also provide monthly billing comparisons for Step 1 and 2 rate changes. Exhibit C shows about 46 percent of the Step 1 increase is allocated to residential customers and 54 percent is allocated to commercial and industrial customers. Approximately 36 percent of the Step 2 increase is allocated to residential customers and 64 percent is allocated to commercial and industrial customers. The Stipulating Parties agree special contract rates are not established by the Stipulation, and will be governed by the terms of the applicable contract approved by the Commission.

3. Rate Design

In Paragraph 34, the Stipulating Parties agree the Commission should increase the residential customer charge to $6 per month, and the remainder of the revenue requirement assigned to Schedules 1, 2 and 3 shall be applied to Tier 2 winter rates. The Schedule 1 revenue requirement increase in Step 2 will also be applied to Tier 2 winter rates. In Paragraph 35, the Stipulating Parties agree the Commission should increase the residential minimum bill to $8 per month.

In Paragraph 37, the Stipulating Parties agree to apply a Facilities Charge to Schedule 6 and Schedule 6B. The Stipulating Parties further agree that the Schedules 6 and 6B Step 1 revenue requirement increase be applied to both the Power Charge and the Facilities

Charge and the Schedules 6 and 6B Step 2 revenue requirement increase be applied to the Power Charge, as shown in Stipulation Exhibit C.

D. OTHER ITEMS

1. Cost Recovery of Certain Rate Base Items

In Paragraph 39, the Stipulating Parties agree the stay-out provision in Paragraph 32 will not prevent PacifiCorp from seeking deferred accounting orders, for potential recovery from or return to customers pursuant to a Commission order in a future rate case, of costs related to the impacts of any proposed disposition, through sale, closure or other means, of the Deer Creek mine and related mining assets as well as for the impacts of the possible sale of PacifiCorp's ownership interests in the Craig and Hayden generating plants.

2. Net Power Cost Updates

In Paragraphs 41 and 42, PacifiCorp agrees that, in future general rate cases, all updates to NPC will be filed at least six weeks prior to the intervenor direct testimony due date. PacifiCorp also agrees that if the NPC or other updates include a new forward price curve, it will ensure intervenors have at least six weeks to respond to such updates in intervenor direct testimony.

3. Pension Benefits

In Paragraph 43, PacifiCorp agrees to obtain and provide actuarial updates to its pension expense and prepaid pension projections, and also to its post-retirement benefits other than pension expense and prepaid pension projections, for the entirety of the test period of its next general rate case.

E. PARTIES' COMMENTS

The Stipulating Parties represent the Stipulation is "just and reasonable in result, will result in rates that are just and reasonable and will provide the Company a reasonable opportunity to earn its authorized rate of return."[5] Three of the Stipulating Parties, PacifiCorp, the Division, and the Office testified recommending the Commission approve the Stipulation.

At hearing, PacifiCorp provided an overview of the process leading to the Stipulation. PacifiCorp argues substantial evidence was presented and reviewed prior to engaging in settlement discussions. For example, PacifiCorp filed the direct or rebuttal testimony of 18 witnesses, including 2,400 pages of testimony and exhibits in support of its requested rate increase. Thirteen intervening parties filed the testimony of 35 witnesses. PacifiCorp responded to over 2,400 data requests in addition to filing the 160 items required by rule.

Following settlement discussions, the Stipulating Parties agreed to the terms and conditions in the Stipulation. PacifiCorp notes the Stipulation does not, however, resolve the net metering facilities charge proposed by PacifiCorp in its Application.

PacifiCorp states the Stipulating Parties considered and relied on different factors in coming to agreement on the terms of the Stipulation. Included in these considerations, according to PacifiCorp, was evidence PacifiCorp provided in its rate case filing, including PacifiCorp's support for a multi-year rate plan, and the Stipulating Parties' evaluation of the in-service date of the Sigurd-Red Butte transmission line, along with other factors. PacifiCorp represents a multi-year rate plan will provide a measure of rate certainty for customers and will

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[5] *See* Stipulation p. 1, P. 2.

afford PacifiCorp a reasonable opportunity to earn its authorized rate of return and recover its cost of service.

Following its overview of the Stipulation, PacifiCorp explained the Stipulating Parties worked hard to come to agreement and did so by negotiating in good faith. PacifiCorp believes the Stipulation is in the public interest and recommends the Commission approve it as filed.

The Division testifies the Stipulation’s revenue requirement is reasonable because it is similar to the amount the Division would have advocated in its surrebuttal testimony absent the Stipulation. The Division also believes the Stipulation’s components regarding cost of service and rate design are reasonable, as they result in movement toward full cost of service for some rate schedules. In addition, the Stipulation does not result in radical changes to current cost of service principles and therefore is reasonable in light of ongoing discussions with other states regarding inter-jurisdictional cost allocation and pending outcomes of the current Multi-state Process (“MSP”) proceedings.

In spite of initial concerns, the Division testifies the stipulated 9.8 percent return on equity is well-balanced in light of some of the Stipulation’s other terms and conditions. The Division also notes the rate impacts from the capital additions PacifiCorp plans to add during the test period are mitigated by the multi-year rate schedule.

For all of the foregoing reasons, the Division concludes the Stipulation provides for just and reasonable rates and recommends its approval.

The Office testifies it reviewed all aspects of the general rate case and filed the testimony of seven witnesses covering cost of capital, return on equity, revenue requirement, cost of service, and residential rate design. The Office represents it fully participated in all settlement discussions on behalf of residential, small commercial and irrigation customers.

The Office notes that although its initial position included a reduced revenue requirement, additional evidence became known through testimony and discovery that allows the Office to support the Stipulation's rate increase, which, the Office testifies, is substantially lower than what PacifiCorp originally requested.

The Office also identifies certain other factors leading to its support for the Stipulation. First, the Office believes the $19.2 million Step 2 increase is reasonable because it is tied, both in calculation and implementation, to the Sigurd-Red Butte transmission line, and is supported by the evidence presented in the case. The Office believes it is in the public interest to agree to this increase now rather than pursue a full rate case next year.

The Office testifies the rate spread included in the Stipulation moves all customer classes towards closer alignment with actual cost of service. The Office also supports the increase in residential customer charge from $5 to $6 per month because it is supported by the Office's cost of service evidence. Finally, the Office notes it recommended and supports the increase for the residential class being assigned to the second energy tier for winter rates. In conclusion, the Office believes the Stipulation is in the public interest and will result in just and reasonable rates and therefore recommends the Commission approve the Stipulation.

F. DISCUSSION, FINDINGS, AND CONCLUSIONS (STIPULATION)

The Stipulating Parties state settlement discussions between May and June 2014 were held to which all intervening parties in this docket were invited. The Stipulating Parties also state drafts of the Stipulation were circulated to all intervening parties for review and comment.

The eight Stipulating Parties represent a diversity of interests and all of the major customer groups. These Stipulating Parties agree the Settlement Stipulation is in the public interest, and all of its terms and conditions will produce fair, just and reasonable results. Three of the Stipulating Parties, PacifiCorp, the Division, and the Office testified at hearing, describing the basis for their support for the Stipulation, and recommending the Commission's approval. No intervening party opposes approval of the Stipulation.

The Stipulation presents a settlement of many issues associated with the Application. Our consideration of the Stipulation is guided by provisions in Utah Code Ann. § 54-7-1 *et seq*. encouraging informal resolution of matters brought before the Commission. The Commission may approve a stipulation or settlement after considering the interests of the public and other affected persons if it finds the stipulation or settlement in the public interest.[6] In reviewing a settlement, the Commission also may consider whether it was the result of good faith, arms-length negotiations.[7] When reviewing a settlement involving a rate increase, the Commission may limit factors and issues to be considered in its determination of just and reasonable rates.[8]

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[6] *See also Utah Dept. of Admin. Services v. Public Service Comm'n*, 658 P.2d 601, 613-14 (Utah 1983).
[7] *See Utah Dept. of Admin. Services*, 658 P.2d at 614, n.24.
[8] *See* Utah Code Ann. § 54-7-1(4).

Based on our consideration of the evidence before us, the testimony and recommendations of the Stipulating Parties, and the applicable legal standards, we find approval of the Settlement Stipulation to be in the public interest and conclude it constitutes a reasonable and lawful basis for establishing just and reasonable rates. Accordingly, the Commission approves the Settlement Stipulation.

Our approval of the Settlement Stipulation, as in similar cases, is not intended to alter any existing Commission policy or to establish any Commission precedent.

III. RESIDENTIAL NET METERING FACILITIES CHARGE

PacifiCorp provides net metering service to its customers through Electric Service Schedule No. 135 (“Schedule 135”). This service is provided for residential and non-residential customers who have a renewable generating facility located on, or adjacent to the customer’s premises, that is interconnected with PacifiCorp’s existing distribution facilities, and that is intended to offset part or all of the customer’s own use of electricity. The net metered customer may directly use the electricity it generates, or it may deliver its electricity to PacifiCorp, or it may use electricity supplied by PacifiCorp. Net metering means measuring the difference between the electricity supplied by PacifiCorp and the electricity delivered to PacifiCorp over the applicable billing period. Residential net metered customers receive a monthly bill credit at the applicable residential rate for excess customer generated electricity based on the meter reading for the billing period.

PacifiCorp proposes adding a new monthly facilities charge to Schedule 135 for residential net metered customers. Based on the settled revenue requirement in the Stipulation, PacifiCorp proposes a charge of $4.65 per month.[9] The charge is calculated to recover from net metered customers an amount that will produce the same average monthly revenue per customer for distribution and customer costs that is recovered in energy charges from all residential customers based on the cost of service study. Alternatively, PacifiCorp does not oppose the Office's recommendation to charge $1.55 per kilowatt ("kW") of system capacity to residential net metered customers to achieve the same goal.[10]

The Division, the Office, some public comments, and one public witness support a charge for residential net metered customers. UCE, the Sierra Club, TASC, UCARE, and all but one of the 38 public witnesses who provided statements or testimony at the Commission's July 29, 2014, hearing generally oppose the charge. Additionally, virtually all of the more than 1,800 letters and emails the Commission received during the weeks leading up to the hearings express opposition to any charge.

A. PARTIES' POSITIONS

1. PacifiCorp

PacifiCorp testifies the total number of Utah customers participating in net metering has increased by over 30 percent annually over the past three years. According to PacifiCorp, as of November 30, 2013, there were 2,139 customers in Utah participating in the net metering program. PacifiCorp asserts that with the continued reduction in costs of solar equipment and the existence of the Utah Solar Incentive Program, it expects the trend of

[9] PacifiCorp's Application requested a net metering facilities charge of $4.25 per month. PacifiCorp updated this request to $4.65 in its rebuttal testimony to account for the revenue requirement contained in the Settlement Stipulation.

[10] We note the Office recommends $1.54 per kW rather than $1.55 per kW as referenced by PacifiCorp.

increased net metering activity to continue. PacifiCorp notes that although participation is rapidly increasing, net metering still represents a very small fraction of PacifiCorp's Utah customers.

As discussed more fully below, PacifiCorp believes it is important to create an appropriate price structure for residential net metered customers before the shifting of distribution and customer costs from net metered customers produces a much larger cost burden on non-participating customers, as PacifiCorp asserts has occurred in other states. Additionally, PacifiCorp states it is important that residential customers considering a significant economic investment in rooftop solar generation have the appropriate price signals. The current rate structure, according to PacifiCorp, fails to allocate to net metering customers the true costs of their net metering service because it ignores the shifting of certain costs away from net metered customers and onto the remaining residential customers. PacifiCorp proposes the net metering facilities charge to better reflect the costs of PacifiCorp's net metering service.

PacifiCorp testifies it is proposing a charge only for residential net metered customers at this time because it believes the demand charge components of non-residential rate design "provide a significant portion of distribution and retail fixed cost recovery."[11] PacifiCorp indicates it will not propose a net metering facilities charge for non-residential net metered customers until it completes additional analysis.

PacifiCorp testifies its proposed charge is based on its analysis of the shifting of distribution and customer costs resulting from a residential rate design that recovers a significant

[11] Direct Testimony of Joelle R. Steward, p. 23 line 499.

portion of these fixed costs through energy rates. PacifiCorp presents an exhibit detailing the calculation of the proposed charge that indicates residential net metered customers purchase less energy on average, about 518 kilowatt hours ("kWh") per month, than the residential class average of 698 kWh per month.[12] PacifiCorp notes the net metering facilities charge generates no additional revenue for the utility; rather, it simply recovers the revenue requirement allocated to the residential class differently than the current rate structure.

PacifiCorp further explains that "when net metering customers are credited with the full retail energy rate, their contribution to fixed costs [is] reduced and therefore shifted to other customers."[13] PacifiCorp testifies the net metering program credits every kWh generated by the net metered customer's system that is in excess of the customer's usage (i.e., the kWh flowing onto the grid or delivered to PacifiCorp) against the customer's usage at other times during the billing period, or future billing periods. PacifiCorp asserts, "[a]s a result of the kWh credits, the customer may not pay for all usage they have taken from the Company. Since the full retail rate that the customer is able to offset recovers both variable energy costs along with a significant portion of fixed costs, the net metering customer is not contributing to fixed cost recovery through the usage that the customer's excess generation is credited against. Since these fixed costs are not recovered from net metering customers, they increase the burden on other customers."[14]

With respect to the distribution and customer costs recovered through energy rates, PacifiCorp calculates the cost shift from net metered customers to all customers is $4.65

[12] *See* Exhibit RMP _ (JRS-8), p. 1 of 1.
[13] Direct Testimony of Joelle R. Steward, pp. 22-23, lines 496-498.
[14] Direct Testimony of Joelle R. Steward, p. 23, lines 509-515.

per month per customer, or $116,794 per year, based on forecasted test period billing units for residential customers.[15] PacifiCorp bases this cost shift calculation on its cost of service study adjusted for the Stipulation results.

Specifically, PacifiCorp testifies its calculation of cost shift is based on the average of $24.19 per customer per month of distribution and customer[16] cost allocated to the residential class from its cost of service study. According to PacifiCorp, "[t]his amount is reduced by the proposed customer charge [$6.00] and fixed costs to be recovered through the forecast energy sales to net metering customers in the test period."[17] Subtracting the customer charge amount of $6.00 from $24.19 yields $18.19 in distribution and customer costs recovered through energy charges per month from residential customers. PacifiCorp then divides the remaining amount of distribution and customer costs not recovered by the customer charge ($162,148,233) by the total residential usage in kWh in the test period (6,203,851,850) resulting in an average of $0.026 per kWh of recovery from residential customers in the test period. PacifiCorp applies this average per unit of distribution and customer cost recovery to the test period forecast of net metered customer billed sales, 13,012,995 kWh, to estimate $340,117 of annual recovery of distribution and customer costs from net metered customers through energy rates or $13.54 per month per customer, based on 25,117 test period net metered customer bills. Based on this calculation, the $13.54 per month collected from net metered customers is $4.65 less than the $18.19 per month collected from the average residential customers' energy sales.

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[15] As an alternative to the $4.65 net metering facilities charge, PacifiCorp in surrrebuttal testimony does not oppose a monthly net metering charge of $1.55 per kW.

[16] PacifiCorp also refers to customer cost as "retail cost" in its testimony.

[17] Direct Testimony of Joelle R. Steward, p. 24, lines 540-542.

Thus, the shortfall, $4.65 per customer per month, or $116,764 per year based on 25,117 test period net metered customer bills, is PacifiCorp's measure of the cost shift from other residential customers to net metered customers and is the basis for the charge.

PacifiCorp further testifies net metered residential customers underpay for generation and transmission facilities fixed costs; however, it is not requesting the net metering facilities charge recover those costs at this time. PacifiCorp indicates it will in a future proceeding pursue a structural change to rate design to address the full amount of cost shifting, rather than recover fixed generation and transmission cost in a fixed facilities charge.

PacifiCorp disputes the contention of some parties that reduced consumption by net metered customers is similar to the reduced consumption of energy efficient customers. While energy efficiency predictably reduces load and impacts on the grid, PacifiCorp contends customers installing distributed generation systems have the same or even an increased impact on local distribution facilities. As an example, PacifiCorp asserts it must frequently modify the distribution network to accommodate the flow of electrons from a new net metered customer to the grid.

Similarly, PacifiCorp maintains the reduction in billed kWh for net metered customers differs from other low use customers. PacifiCorp asserts, "low usage full requirements customers are distinct from net metering or partial requirements customers in that their load shape and load factor are more consistent with the residential class, for which rates are designed. Also, with net metering customers the cost shifting is exacerbated by the fact that the full retail energy rate is applied to the excess generation that is sold back to the Company, thus shifting additional costs to other customers because of the fixed cost recovery that is embedded in the full retail energy."[18]

PacifiCorp refers to net metered customers as a distinct sub-class of customers taking partial requirements service. PacifiCorp argues this sub-class is different from low usage full requirements customers who have a more similar load shape and load factor to the residential class for which rates are designed. PacifiCorp explains it is exploring "the development of a new rate schedule class for these customers by deploying a load research study to gather specific time-based data that will allow the development of allocation factors and billing determinants for residential customers with distributed generation… The load research study will allow [PacifiCorp] to measure these customers' usage at the time of the system coincident peaks, which is the driver for allocations of transmission and generation costs."[19] PacifiCorp does not recommend the Commission wait for the outcome of this load study before approving the net metering facilities charge because it believes sufficient evidence exists in this docket to support the net metering facilities charge.

PacifiCorp testifies it examined, through a modeling exercise, the impact of solar rooftop generation on one distribution circuit in 2011 and concludes rooftop generation provides limited ability to offset distribution infrastructure upgrades. According to PacifiCorp, this limitation is because the peak hour of demand on this distribution circuit basically is unaltered by the presence of solar rooftop generation. PacifiCorp represents that even under the best case assumption regarding the penetration of solar rooftop systems, *i.e.*, all viable roof space contains

[18] Rebuttal Testimony of Joelle R. Steward, p. 12, lines 224-230.
[19] *Id*., p. 13, lines 241-249.

solar rooftop systems, only a seven percent reduction in demand on the distribution circuit peak occurred. PacifiCorp claims that at the potential and optimal seven percent reduction, PacifiCorp is unable to defer distribution system upgrades.

To validate its model, PacifiCorp measured the total rooftop solar production, energy delivered to PacifiCorp, and energy received by the customer from PacifiCorp, of several net metered customers for calendar year 2012. The data validated the model output to the extent that customer generation peaked between 1:00 and 2:00 p.m. and "the peak energy received"[20] from PacifiCorp occurred at 4:00 p.m. or later, as the energy from rooftop solar is declining. Therefore, PacifiCorp concludes it must "design the distribution system for this peak time of energy consumption to ensure reliable electric service for these customers."[21]

PacifiCorp presents testimony on distribution system costs it has incurred in its service territories in Oregon, Washington and California resulting from the penetration of net-metered customers in those areas. PacifiCorp further states its concerns regarding voltage fluctuation caused by a high penetration of net metered customers. For example, PacifiCorp notes that fast changes in large load or generation must be handled with additional equipment if voltage is to stay within the range of reasonable tolerances. PacifiCorp states voltage fluctuations trigger increased automated operations in line equipment, reducing the life of the equipment, leading to higher maintenance costs.

In its rebuttal testimony, PacifiCorp compares the costs and benefits of its net metering program. Specifically, PacifiCorp assesses the value of solar generation in avoiding

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[20] Rebuttal Testimony of Douglas L. Marx, p. 4, line 82.
[21] *Id*., p. 5, lines 89-90.

transmission and distribution costs, and capacity and energy costs. Based on its analysis, PacifiCorp asserts the costs it and its non net metered customers will incur from a net metering program exceed its benefits.

On the cost side of the analysis, PacifiCorp explains residential net metered customers are compensated for the power they produce at the retail price, ranging from 8.8 cents per kWh to 14.4 cents per kWh "depending on which pricing block is being displaced at the time the N[et] E[nergy] M[etered] customer production is being applied to avoid paying for energy from the grid."[22]

On the benefit side of the analysis, for the value of solar, PacifiCorp relies on the Commission's determinations in Docket No. 12-035-100[23] regarding avoided cost payments (considering energy, capacity, integration cost, and environmental attributes) to solar projects that are qualifying facilities ("QF") under the Public Utility Regulatory Policies Act of 1978 ("PURPA"). PacifiCorp cites a value of $30 per megawatt hour (3 cents per kWh) for 2015 from Docket No. 14-035-T04[24] as the value of the net metering program. At hearing, PacifiCorp indicated this value would apply to the total generation of the net metered customers in Utah. PacifiCorp implies the difference between the costs and benefits of net metering, as described above, is 5.8 to 11.4 cents per kWh. Accordingly, PacifiCorp concludes the proposed $4.65 monthly charge is not only reasonable but probably is a low value.

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[22] Rebuttal Testimony of Gregory N. Duvall, p. 2, lines 34-36.

[23] *See In the Matter of the Application of Rocky Mountain Power for Approval of Changes to Renewable Avoided Cost Methodology for Qualifying Facilities Projects Larger than Three Megawatts,* Docket No. 12-035-100 (Order on Phase II Issues; August 16, 2013).

[24] *See In the Matter of Rocky Mountain Power's Proposed Revisions to Electric Service Schedule No. 37, Avoided Cost Purchases from Qualifying Facilities,* Docket No. 14-035-T04.

2. The Division

The Division recommends the Commission adopt the proposed net metering facilities charge but in the amount of $4.25 rather than $4.65. The Division maintains its support for the $4.25 charge originally proposed in PacifiCorp's direct testimony is based on the principle of gradualism. Alternatively, the Division does not oppose further study of the costs and benefits of the net metering program in a docket established for that purpose as recommended by other parties. The Division believes additional study will help the Commission determine whether a net metering program is in the public interest, how the program should be structured, and the rate at which the net metering customer should be compensated. Further, the Division recommends any comprehensive costs and benefits analysis include evaluating adjustments to the net metering credits as an alternative to a fixed charge.

The Division supports a $4.25 net metering facilities charge for residential customers because it will facilitate better recovery of existing distribution costs, consistent with cost causation and sound rate design principles. The Division explains costs are allocated to the residential class based on dynamic class allocation factors and posits: "Given those allocated costs, the Commission must adopt an equitable rate design – a rate design that is just and reasonable – that collects the costs from all customers. If, as the Division holds, an identifiable subclass of customers, such as the net metered customers, are allowed to shift a portion of their share of the costs to other customers, the resulting rate design will violate the principle of cost causation and, therefore, will not be just and reasonable."[25]

[25] Cost of Service Surrebuttal Testimony of Artie Powell, Ph.D., pp. 2-3, lines 20-25.

In explaining its support for the charge, the Division notes rate design serves at least two purposes. One purpose is to allow the utility a reasonable opportunity to recover its cost of providing service. A second purpose is to promote efficient use of resources and consumption. Should rate design fail in its first purpose, the utility can experience difficulty in attracting capital. If rate design fails in the second purpose, poor price signals can result and cause inefficient use of scarce resources. The Division states residential rates currently are designed to recover some fixed costs through usage rates to promote conservation. The Division concludes "the increased penetration of net metering customers and future penetration by these customers (and even increased conservation from other customers) will make it more difficult for the Company to recover those fixed costs."[26] Further, the Division contends the increased penetration of net metered customers will result in an unfair shift of costs to other residential customers and may cause a "downward incentive spiral of increasing volumetric rates, and difficulty collecting fixed costs and attracting capital."[27]

The Division disagrees with other parties' claims that the proposed net metering facilities charge is discriminatory and therefore prohibited by law. The Division argues the charge is "not about charging different customers different 'prices' but rather about ensuring that all customers pay the same price."[28] In defense of singling out net metered customers for the charge, the Division notes net metered customers are different from, for example, energy efficient customers. The Division contends energy efficient customers reduce their overall consumption and peak consumption, while net metered customers still rely on the grid for their

[26] Cost of Service Confidential Direct Testimony of Artie Powell, Ph.D., p. 10, lines 202-205.
[27] *Id*., p. 10, lines 208-210.
[28] *Id*., p. 12, lines 241-243.

energy needs at the time of peak energy demand. Thus, since net metered customers "are not similarly situated as non-net metering customers, a net metering charge does not constitute price discrimination."[29]

Regarding the requirements of S.B. 208, the Division states it has made no attempt since the issuance of the Commission's April 16, 2014, Public Notice, to quantify the costs or benefits of the net metering program and recommends the Commission open a docket to explore issues raised by S.B. 208. At hearing, the Division testified it did not think PacifiCorp provided a comprehensive benefits analysis in its direct testimony. The Division asserts: "If additional or uncaptured benefits exist, then those benefits should be reflected in how net metering customers are compensated. A cost benefit analysis of net metering on PacifiCorp's system will inform the Commission whether a net metering program is in the public interest, how such a program should be designed and the appropriate compensation. However, no party to this docket has presented persuasive evidence that net metering customers are undercompensated or, if so, what the appropriate compensation is. Meanwhile, the Company has submitted, particularly in rebuttal testimony, significant evidence of the costs to the distribution system imposed on other customers by net metering customers' diminished contribution to those costs through usage rates."[30]

The Division testifies "[n]o cost benefit study will change the fact that net metering customers are using the distribution system at the time of the distribution peak for their own needs and therefore should pay, consistent with cost causation, an equitable share for that

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[29] Cost of Service Surrebuttal Testimony of Artie Powell, Ph.D., p. 10, lines 183-185.
[30] *Id.*, pp. 10-11, lines 193-203.

service. In the absence of demand charges, the net metering charge in the Division's view is an equitable way of collecting those costs from net metering customers. Given the amount of testimony filed by net metering advocates, the absence of persuasive evidence of undercompensation does not suggest inadequacy of the SB 208 cost-benefit determination. In light of the testimony filed by all parties on this issue, it is in the public interest for the Commission to approve a net metering charge."[31]

3. The Office

The Office recommends a net metering facilities charge be applied to the bills of net metered customers and suggests such a charge be based on the rated kW output of a residential net metered customer system. The Office produces an exhibit[32] in its rebuttal testimony recommending a monthly net metering facilities charge of $1.54 per kW. This charge represents the ratio of total annual net metering facilities charge revenue, based on PacifiCorp's proposed $4.65 flat monthly charge, and total net metered residential capacity of 6,294 kW. The Office recommends the Commission apply this rate to net metered customers on a monthly basis.

Alternatively, the Office agrees with other parties that the Commission should open a separate docket to consider net metering program costs and benefits for all customer classes to make an informed decision on whether a residential net metering facilities charge "at any level is reasonable and in the public interest."[33] Specifically, the Office supports a separate docket so the Commission "can fully understand the differences in valuation models, data inputs

[31] Cost of Service Surrebuttal Testimony of Artie Powell, Ph.D., p. 11, lines 204-213.
[32] *See* Exhibit OCS 5.1R (Gimble), p. 1 of 1.
[33] Rebuttal COS/RD Testimony of Daniel E. Gimble, p. 18, lines 508-509.

and assumptions… ."[34] The Office recommends the Commission ultimately adopt a "valuation method that best fits the legal, policy and factual circumstances unique to Utah and relies on data inputs and assumptions that are generally consistent across resource planning and ratemaking cases."[35]

The Office does not oppose Commission adoption of PacifiCorp's flat monthly $4.65 charge for each net metered customer. However, it argues its proposed capacity-based charge ensures the monthly amount paid by each net metered customer will more equitably reflect the costs associated with the rated capacity of each residential customer's individual system. The Office states its capacity-based rate is consistent with an interim net metering charge recently implemented by the Arizona Public Service Commission.

Consistent with the arguments put forward by both PacifiCorp and the Division, the Office contends that since net metered customers use PacifiCorp's distribution infrastructure, they impose costs on the system and should pay for using that infrastructure. The Office expresses concern that residential net metered customers underpay distribution costs in comparison to other residential customers.

The Office testifies PacifiCorp provides sufficient evidence showing a shifting of distribution related costs from net metered customers to other customers annually and argues without a net metering facilities charge in place, this cost shift will increase as participation in the net metering program expands. According to the Office, since fixed distribution costs are recovered through energy rates in the current rate design, and since the load requirements of net

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[34] Rebuttal COS/RD Testimony of Daniel E. Gimble, p. 18, lines 510-511.
[35] *Id.*, p. 18, lines 513-515.

metered customers are lower and variable, net metered customers are not paying an appropriate share of costs needed to maintain the distribution system.

While the Office notes "SB 208 requires the Commission to consider both the costs and benefits of [net metering] in order to determine the impacts on the utility and other customers,"[36] it argues there is insufficient evidence showing generation from residential net metered customers provides enough value to offset the distribution related fixed costs these customers incur. The Office states no party in this docket has provided evidence that net metered resources offset energy generation or market purchases that are significantly higher than average energy costs.

The Office concludes PacifiCorp's avoided cost representation of the value of solar for PURPA QFs is compelling and "substantially lower than N[et] M[eter] avoided costs (benefits) estimated by UCE and the Sierra Club." [37] The Office testifies the 2015 avoided cost value for solar resources is approximately 3.0 cents per kWh and notes this value is substantially lower than the 11.6 cent avoided cost estimate provided by UCE and the 6.1 cent estimate provided by Sierra Club. According to the Office, evidence from recent avoided cost proceedings shows net metering benefits are not large enough to offset the need for the net metering facilities charge, and the Office suggests there is sufficient evidence in the record for the Commission to implement such a charge.

As interpreted by the Office, in Docket No. 12-035-100, the Commission determined how potential costs associated with environmental risk and fuel price volatility

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[36] Surrebuttal COS/RD Testimony of Daniel E. Gimble, p. 2, lines 42-44.
[37] *Id*., p. 3, lines 58-59.

should be accounted for in PacifiCorp's Integrated Resource Plan ("IRP") modeling and evaluation process. The Office expresses concern that some of the methods, assumptions and data used by the parties opposing the charge to analyze net metering costs and benefits are not consistent with PacifiCorp's 2013 IRP, neither are they consistent with the outcomes of relevant ratemaking proceedings. The Office argues that in acknowledging the 2013 IRP, the Commission essentially accepted PacifiCorp's approach for evaluating assumptions such as carbon price impacts, which, according to the Office, have been challenged by parties in this proceeding. To justify these challenges, the Office contends a party opposing the net metering facilities charge would have to demonstrate that new evidence exists or circumstances differ significantly from the time when the Commission rendered its relevant decisions in prior rate proceedings. Further, the Office argues that because the Commission's order in Docket No. 12-035-100 allows QFs to retain renewable energy credits, the Commission did not accept proposed adjustments to the value of environmental risks or fuel price volatility.

While the Office maintains a residential net metering facilities charge is supported by the evidence, the Office acknowledges the net metering issues raised in this proceeding are complex and require a deliberate review process. At hearing, the Office acknowledged the Commission may require additional analyses prior to authorizing a net metering facilities charge. Consistent with this view, the Office notes additional forthcoming studies and analyses may be needed, such as the load research study PacifiCorp plans to initiate by December 2014, the purpose of which, according to the Office, is to obtain more precise time-based data for purposes of developing specific allocation factors, billing determinants and possibly a three-part rate structure consisting of demand, customer, and energy charges. The Office states this information could be used to develop a separate residential net metering rate schedule for partial requirements service. The Office notes it considered the possibility of developing a distinct tariff for residential net metered customers and recommends the concept of a three-part net metering rate design should be explored further once PacifiCorp has made the results from its load research study available to the Commission and interested parties.

The Office represents it is not opposed to deferring implementation of the proposed charge, if the Commission decides that additional analysis of net metering costs and benefits and impacts on the utility and other customers is required. If the Commission decides to delay implementation of a new facilities charge until net metering costs and benefits can be further studied, the Office recommends the Commission inform current net metering customers and the general public that the proposed net metering facilities charge is undergoing review and that a scheduling conference will be held in the near future in a separate docket established for that purpose. Additionally, the Office recommends the Commission follow the process guidelines the Office outlined in its rebuttal testimony for further investigating the costs and benefits of net metering, and also recommends that any such investigation be completed by mid-2015.

4. Utah Clean Energy (“UCE”)

UCE recommends the Commission not implement a net metering facilities charge without consideration of a full cost and benefit analysis across all customer classes for the following reasons. First, customer-side-of-the-meter investments in energy efficiency, demand response, and distributed generation have the opportunity to bring value to, and reduce risk for, all ratepayers in the changing energy and regulatory landscape. Therefore it is critical to appropriately analyze and value these investments.

Second, UCE claims PacifiCorp's proposal is inconsistent with both the net metering law in effect when the Application was filed and the changes to the net metering law enacted in 2014 by S.B. 208 because both require a cost and benefit analysis. In addition, changes enacted by S.B. 208 require an evaluation of the entire net metering program, while PacifiCorp's proposal is applicable only to residential customers. UCE asserts the cost and benefit analysis must be comprehensive across all customer classes with net metered facilities and notes that PacifiCorp's commercial and industrial customers host about half, if not more, of the net metered photovoltaic distributed generation capacity on PacifiCorp's system.

Third, UCE insists there is insufficient evidence in the record, and there has been insufficient opportunity for stakeholder input, to determine whether net metering costs exceed the benefits, or vice versa, to determine a just and reasonable fee, credit, or ratemaking structure as required by Utah Code 54-15-105. UCE asserts PacifiCorp's Application provided neither unique costs nor an evaluation of benefits associated with net metering. Rather, according to UCE, PacifiCorp's proposed net metering fee is based upon residential net metering customers' lower-than-average consumption as a group. UCE states it was not until rebuttal testimony filed on June 26, 2014, that PacifiCorp presented any testimony or other evidence pertaining to its view of the benefits of net metering. UCE asserts PacifiCorp's inability to timely furnish analysis or information relating to net metering benefits is a major deficiency in this docket and that PacifiCorp's substantial rebuttal filing demonstrates the need for a new docket to address net metering costs and benefits.

Fourth, UCE states there is no evidence in the record demonstrating a net metered customer causes any more cost for PacifiCorp than does the customer without a net metering system who consumes the same amount of electricity.

UCE recommends the testimony in this case should be reviewed in light of a customer's historic right to use as much or as little energy as desired. UCE asserts that nowhere in the list of "customer benefits and obligations" [38] encompassed in PacifiCorp's regulatory compact is there any limitation or other restriction on when and how a customer may consume electricity provided by PacifiCorp. UCE maintains the implications of establishing fees and charges for customers based on one specific behavior (i.e., reducing consumption of PacifiCorp's energy) are "problematic and far reaching."[39]

UCE claims the only case PacifiCorp has made is that a residential customer consuming less than the average of all residential customers contributes less to the recovery of demand-related costs embedded in the residential usage rate. UCE references PacifiCorp's Exhibit RMP _ (JRS-8) which indicates that, on average, a residential net metered customer purchases 518 kWh per month while the average residential customer uses 698 kWh per month. Based on information from the residential bill frequency distribution for 2012 (provided by PacifiCorp in its response to Discovery Request OCS-5.6), UCE points out more residential customers purchase 500 to 600 kWh per month than any other amount of monthly electricity use. UCE asserts this information demonstrates net metered customers are like most other residential

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[38] Direct Testimony of Rick Gilliam, p. 8, lines 131-132.
[39] *Id.*, p. 7, lines 117-118.

customers in their usage levels of PacifiCorp's energy. Consequently, their usage pattern does not justify the imposition of a separate charge, in UCE's view.

UCE concludes PacifiCorp's "presentation of costs associated with net metering customers does not reflect costs that are unique to net metering customers, but rather is an illustration of revenues lost through lower than average consumption, which may be achieved through means other than net metering (including having a small house or investing in energy efficiency)."[40] Based on the bill frequency data mentioned above, UCE concludes: "Treating net metering customers differently than similarly situated customers without a net metered system is improper and discriminatory, as on average both contribute about the same towards the fixed costs of the utility."[41]

UCE observes PacifiCorp's net metering analysis assumes 2,093 customers, or an increase of about 225 residential customers between December 31, 2013, and the middle of the future test year. This is approximately the same number of new customers added to the net metering program in 2010. UCE asserts the test period forecast of net metered customers comprises less than 0.3 percent of all residential bills. Moreover, net metered customers who reduce their purchases, in UCE's view do so in a relatively small way and fall well within the range of normal consumption strata. Based on this evidence, UCE concludes there is no reason for the Commission to act now, before it receives load profile data essential to understanding net metered customers' cost causation.

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[40] Direct Testimony of Sarah Wright, pp. 20-21, lines 393-397.
[41] Direct Testimony of Rick Gilliam, p. 12, lines 204-207.

UCE does not believe PacifiCorp has developed a net metering charge that is consistent with cost causation. UCE asserts PacifiCorp's proposed net metering charge should be rejected because it is based on reduced revenue contribution, not on changes in cost responsibility or deferred or avoided costs. UCE also argues PacifiCorp's study based on one residential circuit does not capture the full range of utility-functionalized costs that must be reviewed in a comprehensive cost and benefit evaluation. UCE emphasizes the need for a comprehensive evaluation of all benefits and costs across all customer classes.

UCE observes that PacifiCorp's rebuttal testimony equates the energy-only value of solar QFs with the benefits of net metering and that PacifiCorp states there is no reason to apply a different standard to rooftop solar. UCE disagrees with PacifiCorp's assertion that many of the issues associated with solar valuation were addressed in Docket No. 12-035-100 and insists that nowhere in that proceeding did the Commission consider evidence or make a determination that QF avoided cost pricing reflects the benefits of distributed solar generation. UCE argues the avoided cost determination required by PURPA does not satisfy the requirements of Utah Code 54-15-105.1.

UCE presents a list of benefits provided by rooftop solar distributed generation including energy during the summer peak daytime hours, line loss savings, generation capacity savings, protection against fuel price volatility, a hedge against economic risks associated with environmental regulations, transmission and distribution capacity savings, energy security benefits, job creation and economic development benefits, and environmental and health benefits, and possibly the potential to dramatically reduce the need for demand response programs. UCE believes all such benefits need to be valued in the Commission's cost and benefit determination.

UCE refers to two solar photovoltaic evaluations, one final and one draft, and includes in its testimony a study conducted for UCE by Clean Power Research ("CPR") entitled "Value of Solar in Utah." [42] These analyses provide information on the costs and benefits of net metering. Specifically, the CPR study evaluates the fuel price guarantee value, avoided environmental cost, avoided transmission and distribution capacity cost, generation capacity value, plant operations and maintenance value, and fuel value.

UCE applies the CPR study to estimate the benefits of the net metering program for Rate Schedules 1, 3, 6, and 8. UCE performs the analysis over a 25-year period and presents the results on a levelized per unit basis. For all rate schedules studied, UCE testifies the levelized value of solar is 11.6 cents per kWh. UCE also estimates the cost of the net metering program to PacifiCorp for these same select rate schedules. UCE generally estimates the cost of the program as certain revenue lost due to sales and load reduction. Again, UCE performs its analysis over a 25-year period and presents the results on a levelized per unit basis. UCE estimates the cost of the net metering program is between 5.8 cents per kWh and 11.9 cents per kWh depending on rate schedule. UCE concludes the benefits net metering customers provide outweigh the costs for schedules 6 and 8 and show a small net cost for the residential schedules, and asserts these results are consistent with studies performed in other states.

[42] Direct Testimony of Sarah Wright, UCE Exhibit 2.1(DT) [COS+RD].

UCE maintains other distributed solar generation benefits exist that also have not been considered in PacifiCorp's proposal to impose a net metering charge. For example, PacifiCorp's 2013 Integrated Resource Plan ("2013 IRP") preferred portfolio includes 300 MW of distributed solar generation over the 20-year planning horizon. In addition, distributed solar generation provides some capacity coincident with many of PacifiCorp's monthly system peaks, thereby resulting in a lower cost responsibility for Utah customers in general.

To address these issues, UCE recommends the Commission initiate a comprehensive evaluation of the costs and benefits of net metering. UCE recommends the process include neutral process facilitation, third-party independent cost-benefit analysis, and technical conferences with experts in solar valuation.

5. The Sierra Club

The Sierra Club recommends the Commission reject the proposed net metering facilities charge because the benefits provided by residential net metering customers far outweigh any revenue the proposed charge would generate. The Sierra Club states PacifiCorp's claim that net metered customers are not paying their fair share is not true; rather, net metered customers are providing a significant benefit to the PacifiCorp system. The Sierra Club suggests the imposition of a net metering facilities charge would increase the payback period for residential solar rooftop generation and likely would reduce investment in solar resources.

The Sierra Club testifies PacifiCorp has failed to provide a cost and benefit study of the net metering program, as required by S.B. 208. The Sierra Club further testifies it is clear S.B. 208 requires that a new fee can only be imposed after a full cost and benefit study is performed, and the results of such a study are found to justify a fee.

The Sierra Club contends the benefits produced by the net metering program (the avoided fuel and other direct costs) for the utility system are greater than the amount PacifiCorp is proposing to collect from the net metered customers with the facilities charge. The Sierra Club asserts that while the revenue from the net metering facilities charge PacifiCorp would collect is $116,784, the direct system benefits attributed to the existence of net metered customers amount to $1,413,367.

The Sierra Club testifies its study of benefits is based on widely recognized approaches to valuing net metered facilities utilizing Utah specific inputs where possible. The Sierra Club notes it used generic data for its analytical effort when necessary due to the lack of data it could obtain from PacifiCorp. The Sierra Club estimated the direct utility benefits by examining each of the following components: avoided cost of energy, generation capacity, transmission and distribution capacity, and ancillary services.

The Sierra Club states that, consistent with Utah practice, it uses the proxy approach for periods of resource deficiency and the differential revenue requirement approach for periods of resource sufficiency to determine displaced avoided costs. It uses an effective load carrying capability approach (based on a one in ten year standard) to value the generation capacity contribution. The Sierra Club cites several studies to show distributed solar generation results in reduced load growth and reduced system congestion, and that these effects result in reduced investments in transmission and distribution facilities over time.

To address ancillary services the Sierra Club uses a tool developed by E3 that identifies the impact on regulation up, regulation down, spinning reserves, and non-spinning reserves. The Sierra Club concludes the average avoided cost (*i.e.,* the program benefit) per net metered customer per bill is $56.27, for a total of $1,413,367 for the test period. It concludes: “Before the Commission approves any additional fees that would affect net metered facilities, it should consider the multiple monetary and reliability benefits that N[et] E[nergy] M[etering] provides, and not only the costs as asserted by RMP.”[43]

The Sierra Club testifies distributed solar generation provides other significant benefits to ratepayers, including reducing the effect of gas price volatility and reducing environmental and social costs. Further, the Sierra Club clarifies it is not proposing PacifiCorp pay net metered customers for all the benefits the net metered customers produce for the system, rather it is demonstrating the produced benefits far outweigh the amount of the costs at issue in this docket.

The Sierra Club testifies that PacifiCorp’s proposed facilities charge is not based on any load data evidence, nor any evidence of the effect of net metered customers on coincident peak. The Sierra Club argues an adequate analysis of the costs and benefits of the net metering program cannot be done without this information. The Sierra Club recommends that “[u]nless and until the Company can provide reliable data proving that there is a net system cost, the Commission should avoid implementing any charges that would discourage N[et] E[nergy] M[eter] growth.”[44]

The Sierra Club also disputes PacifiCorp’s claim that net metered customers and energy efficient customers are entirely different and that it is reasonable to apply the facilities charge to net metered customers exclusively. While the Sierra Club agrees there are some

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[43] Direct Testimony of Dustin Mulvaney, p. 19, lines 14-16.
[44] *Id.*, p. 26, lines 17-19.

differences, for example, net metered customers can export electricity to the grid, it asserts there are similarities between net metered customers and energy efficiency (low usage) customers because both reduce total energy consumption and both reduce peak loads. It concludes: "Overall, the similarities between these N[et] E[nergy] M[etered] customers and those who adopt energy efficiency measures are more striking than the differences, so it seems unjustified at this time to impose a fee on N[et] E[nergy] M[etered] customers on the basis of their reduced energy purchases."[45]

In response to PacifiCorp's testimony regarding the development of a separate class or rate structure for net metered customers due to differences in load shape, the Sierra Club points out the different load shape attributed to net metered customers most likely is less costly to serve because their solar production reduces load during the hours electricity is most expensive to produce or purchase. The Sierra Club asserts the one significant difference between customers who reduce system load through energy efficiency versus those who do so via rooftop solar generation is that the revenue reducing impacts of energy efficiency are greater.

The Sierra Club testifies it is incorrect for PacifiCorp to use the PURPA-derived avoided cost calculations to value net metered customer generation. In the Sierra Club's view, the two types of generation are substantially different. A QF operating under a PURPA contract exports all of its production to PacifiCorp's system and typically delivers its output at the transmission voltage level. It also receives payments (not credits) for all of the electricity it produces, and it is able to lock in pricing or pricing methods through power purchase

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[45] Surrebuttal Testimony of Dustin Mulvaney, p. 25, lines 10-13.

agreements. In contrast, net metered customers often lose some production credits every year due to the fact that unused credits expire each March. Also, their production is primarily for their own use (reducing load); their excess production is delivered at the distribution level (no line losses or transmission system usage); and they do not receive a cash payment for their production.

The Sierra Club also addresses the Office's proposal to prorate the charge based on installed kW. The Sierra Club points out solar system owners generally constrain the size of their systems to approximately match their expected load. Therefore, it is not logical to conclude those with a larger system are avoiding a greater share of costs (relative to an average residential user). It is possible net metered customers with large systems still have higher than average billed kWh as the amount of billed kWh is the difference between total use and total production (less the lost credits during the March billing cycle).

The Sierra Club asserts integrating net metered customer facilities will not negatively impact PacifiCorp's electricity system as PacifiCorp claims. The Sierra Club testifies PacifiCorp has not provided any credible evidence supporting its claims of adverse system impacts attributed to net metered customers such as an increase in capital investments, increased labor costs, unintended operations and maintenance costs, and increased wear and tear on equipment caused by the intermittent nature of customer solar generation. The Sierra Club responds to PacifiCorp's assertion that the presence of net metered customers may cause voltage levels to be out of the acceptable range by noting any large change in load by other residential customers will cause similar challenges for PacifiCorp in maintaining voltage levels. The Sierra

Club testifies this phenomenon is not unique to net metered customers and states it is actually more likely for customers which are not supplying part of their own load.

The Sierra Club challenges PacifiCorp's contention that solar production does not significantly reduce peak loads, requires network upgrades, and does not reduce capacity upgrades. The Sierra Club argues PacifiCorp's evidence consists of the study of only one circuit, and the conclusions are relative to that circuit's peak, not the system peak. Further, the Sierra Club states that while PacifiCorp alludes to other studies in its rebuttal testimony, it does not cite them, or provide them. The Sierra Club testifies it reviewed PacifiCorp's study and found it contained no analysis regarding a residential rooftop solar systems' ability to offset system peak. Hence, in the Sierra Club's view, PacifiCorp's one circuit study provides little insight concerning the central question of the real nature of the costs and benefits of having net metered customers on PacifiCorp's grid.

The Sierra Club points out that while PacifiCorp's most recent IRP shows no new major additions to capacity until 2027, the past IRP analysis does not account for the new costs and possible capacity additions and retirements necessary to comply with Section 111(d) of the Clean Air Act. The Sierra Club believes the value of clean power in such an environment will increase. Finally, the Sierra Club argues solar systems installed today will still be producing power in 2027 and in fact for many years beyond that date.

6. The Alliance for Solar Choice ("TASC")

TASC opposes PacifiCorp's proposed residential net metering facilities charge claiming PacifiCorp has not shown there is a cost shift from net metered to other residential customers and has not provided sufficient evidence on the costs and benefits of the net metering program. TASC testifies such evidence is required by S.B. 208. TASC recommends the Commission open a separate proceeding to "develop a comprehensive cost-benefit framework that could be used in future rate cases."[46] TASC suggests "[a] cost-benefit study that analyzes actual long-term cost to serve and considers rate designs other than a fixed or demand charge with the goal of finding a first-best solution to the related problems of price/cost alignment and meaningful price signaling could satisfy all parties."[47]

TASC recommends the Commission consider any net metering charge or credit in PacifiCorp's next rate case rather than this case because: 1) based on all parties' testimony, the program has at most a de minimis impact on other residential customers and therefore the delay in the determination carries little risk of adverse ratepayer impacts; 2) such a delay will provide the Commission time to develop a robust cost and benefit framework for determining the cost-effectiveness and policy value of net metering going forward; 3) many relevant cost and benefit proceedings are under way throughout the nation in states with low penetration of net metering that may prove valuable for developing the best approach to capturing net metering costs and benefits in Utah, and; 4) a delay will allow PacifiCorp to provide critical information that is currently missing to assess the costs and benefits of the net metering program.

TASC testifies the record is insufficient to justify the proposed charge. TASC asserts PacifiCorp's concern about the reduced contribution of net metered customers to distribution and customer costs "is equally applicable to any customer who reduced their overall demand, and ignores the cost-causation principle of rate-making."[48] TASC acknowledges the

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[46] Surrebuttal Testimony of Nathanael Miksis, p. 4, lines 5-6.
[47] *Id*., p. 19, lines 19-22.
[48] *Id.*, p. 10, lines 7-9.

alignment of rates with cost causation involves compromise solutions for allocating fixed costs to customers based on a combination of usage and contribution to peak demand. TASC argues this process requires analysis of customer class demand patterns stating: “In order to justify a charge to a sub-class, it is necessary to show that their demand pattern has caused a gap between their impact on system infrastructure and their contribution to its costs.”[49] TASC testifies the record does not include such information.

TASC disagrees with PacifiCorp’s analysis of the cost shift from net metered customers to other residential customers because PacifiCorp provides no actual data relative to net meter customer contribution to distribution system peak, coincident system peak or non-coincident peak. Absent this data, TASC testifies “it is not possible to positively show that N[et] E[nergy] M[etered] customers are avoiding their responsibility for distribution system costs through lower energy sales.”[50]

TASC understands PacifiCorp to conclude the cost shift caused by the net metering program is based on the value of the credit provided to net metered customers for exported generation, which TASC notes is the one distinction between net metered customers and other customers in the residential class. TASC argues net metered customers have three types of relationships to the grid: 1) as a retail customer when the sun is down, 2) as an energy efficient customer when the sun offsets load, and 3) as a power exporter when its generation exceeds its load. Thus, TASC argues the net metered customer in some cases is functionally

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[49] Surrebuttal Testimony of Nathanael Miksis, p.10, lines 14-16.
[50] *Id.*, p.15, lines 17-19.

similar to an energy efficient customer and assigning a charge to one group and not the other is discriminatory.

TASC argues PacifiCorp provides no actual data to demonstrate the load shapes and load factors of net metered customers. Thus, TASC claims PacifiCorp is unable to support its contentions regarding the comparison of energy efficient residential customers and net metered customers as distinct from one another, and therefore is unable to justify the disparate charge. TASC also asserts that the graphs PacifiCorp provides using modeled data for net metered rooftop solar customers as an illustration, indicate these customers contribute greater reduction to distribution peak (40 percent) than energy efficient customers (20 percent). Accordingly, TASC asserts the proposed net metering facilities charge would be both disparate and punitive.

Further, based on the evidence of "an approximate 40 percent reduction in contribution to distribution system peak and a minimum of seven percent contribution to circuit peak, respectively,"[51] TASC calculates $17.37 of the $24.19 in distribution and customer cost identified by PacifiCorp is related to distribution cost. Further, TASC calculates 40 percent of $17.39 is $6.95, which exceeds PacifiCorp's proposed $4.65 net metering facilities charge. In other words, TASC maintains PacifiCorp's own data, properly understood, suggests net metered customers already pay for the distribution costs they cause and this amount exceeds the $4.65 shift in distribution costs PacifiCorp alleges.

[51] July 29, 2014, Tr. 393: 21-24.

TASC criticizes PacifiCorp's use of the $0.03 per kWh avoided cost of utility scale solar projects as a reasonable estimate of the system benefits produced by net metering output. TASC believes this estimate ignores cost savings associated with locating generation at a customer's site, *i.e.*, savings related to "transmission and distribution-related fixed costs, lines losses, increased reliability through geographic diversity of [photovoltaic or "PV"] installations reducing the vulnerability of production levels to local weather phenomena..."[52] Further, TASC claims the $0.03 per kWh avoided cost value ignores locationally-differentiated avoided costs due to import constraints and includes a cost for integrating utility-scale solar plant. TASC argues that without accounting for these differences, using the $0.03 per kWh estimate as a measure of benefit is not justified.

TASC disputes PacifiCorp's testimony that net metering results in the need for distribution system upgrades and in increased grid wear and tear. TASC cites a recent study by Sandia National Laboratories entitled "Technical Analysis of Prospective Photovoltaic Systems in Utah" finding "no appreciable negative impact on the distribution grid" and finding that "solar PV tends to reduce overall peak demand on distribution feeders."[53]

TASC agrees with PacifiCorp's testimony that time differentiated rates and other rate designs could "provide better incentives to customers with distributed generation to maximize the benefits to the grid and the customers it serves."[54] TASC suggests the Commission examine "optional rate designs that align customer decision-making with utility planning, and

[52] Surrebuttal Testimony of Nathanael Miksis, p. 12, lines 8-11.
[53] Direct Testimony of Nathanael Miksis, p. 15, lines 11-13.
[54] Rebuttal Testimony of Joelle R. Steward, p. 14, lines 267-269.

reward customers for making investments and behavior changes that can provide value to the grid."[55]

7. Utah Citizens Advocating Renewable Energy ("UCARE")

UCARE contends PacifiCorp's analysis of the systemic and societal impacts of imposing a net metering facilities charge upon residential net metered customers is flawed and incomplete. UCARE believes a diligent inventory and analysis of all potential benefits from net metering, including the deferral, reduction or elimination of future infrastructure costs as well as the benefits from reductions in emissions, solid wastes, or water usage should be evaluated prior to any decision regarding imposition of a net metering facilities charge. If a net metering facilities charge is approved, according to UCARE, it will unfairly disadvantage residential net metered customers and will impede expansion of residential renewable energy generation resulting in environmental impacts harmful to the public.

UCARE argues it is unfair to single out net metered customers for cost shifting impacts because under the current tiered residential rate structure, any customer reducing their energy consumption, regardless of the means, is shifting costs to those residential customers with higher usage rates. UCARE asserts it is likewise unfair to charge net metered customers a fee for reduced system usage when other members of the same residential class who reduce their system usage using different methods are not required to pay the same fee. Further, UCARE asserts that since PacifiCorp charges all customers for fixed facilities costs within its current tiered rate

[55] Surrebuttal Testimony of Nathanael Miksis, p. 19, lines 6-8.

design, net metered customers will be charged double if they pay an additional surcharge to cover the same costs they purportedly have caused.

UCARE contends PacifiCorp's calculation of the $4.65 charge is flawed. UCARE testifies the billing units PacifiCorp uses to calculate its proposed charge are inappropriate, arguing the calculations should be based on the difference between the gross amount of energy a net metered customer consumes and the excess amount of energy that customer puts back into the system. UCARE argues that since residential solar systems typically produce energy during peak usage periods of the day, the proposed charge does not reflect the value of higher cost energy offset during such periods. Further, UCARE claims excess generation credits forfeited by net metered customers at the end of each billing year are not considered in the proposed facilities charge calculation.

Applying PacifiCorp's proposed net metering facilities charge over the life of a three kW solar PV system, according to UCARE, would represent an approximate 10 percent increase in the system's basic investment cost. UCARE is concerned residential customers of modest means will be discouraged from investing in solar PV systems, as it will be difficult to financially justify such an investment given the proposed and potential future net metering monthly charges. The reduced or eliminated return on investment renders the solar net metering option unaffordable, according to UCARE, which also notes sales of residential solar systems have declined in Arizona because of the recent imposition of a surcharge on solar facilities in that state.

PacifiCorp's proposed $4.65 charge implies all residential net metered customers have the same electricity consumption and production patterns, according to UCARE. UCARE argues PacifiCorp's proposed flat charge is inequitable because no two net metered customers have the same consumption profiles and system performance characteristics. UCARE also contends a capacity-based rate is inequitable because it only accounts for a system's maximum rated capacity, not its actual effective capacity or performance which is a function of site-related factors such as shade, panel inclination, panel orientation, and tracking capability.

UCARE asserts PacifiCorp's claims of added wear and tear on distribution infrastructure are unsubstantiated. UCARE disputes PacifiCorp's implication that because of the unpredictability of net metered solar generation, PacifiCorp must modify the distribution network to minimize this wear and tear. On the contrary, UCARE argues PacifiCorp can accurately predict residential solar production and claims PacifiCorp has the capability to adjust for load variation on the distribution system for a variety of factors. Further, UCARE argues that during peak consumption, solar PV production actually reduces feeder and transformer loads by not only reducing the net metered customer's demand, but also by reducing the demand of net metered customers' neighbors.

UCARE argues Commission implementation of a net metering facilities charge at this time would be premature and inequitable, would inhibit residential renewable energy development, and would result in no apparent customer benefit. Further, it would be based on incomplete information, unsupported assertions, and faulty logic. UCARE recommends the Commission reject proposals for any type of facilities or capacity charge applicable to net metered residential customers. Instead, the Commission should initiate a study to properly evaluate the costs and benefits of net metering.

8. Public Witness Comments and Testimony

Thirty-eight witnesses personally testified at the Public Witness Hearing conducted by the Commission on July 29, 2014, from 5 p.m. to 11 p.m. Approximately 90 percent of the witnesses provided sworn testimony, over 90 percent are PacifiCorp customers, and over 50 percent are PacifiCorp net metered customers. Of the witnesses, one individual supports the proposed net metering facilities charge and over 25 individuals voiced their opposition to the charge.

The witness supporting the net metering facilities charge argued every customer should pay for the costs of the system (*i.e*., labor, poles, wires, transformers, and associated system maintenance expenses), otherwise someone else is paying more to ensure the safety and reliability of the electric system. Further, this witness asserted that solar customers cause greater costs to be spread over other users, which ultimately will cause power rates to spike, primarily harming the poor and middle-class residents who spend a larger share of their income on energy.

The witnesses opposing the proposed net metering facilities charge, or recommending further studies to resolve the net metering issue, generally offered some or all of the following points in support of their position:

1) Lack of Analytical Support: PacifiCorp’s studies and analyses are either inadequate, insufficient, or flawed. All relevant system, environmental, health, and economic benefits must be assessed. PacifiCorp has not provided details on specific costs caused by net metered customers in terms of actual data or electrical theory and principles. Studies should be rigorous and based on empirical information and data, not on hypothetical information.

PacifiCorp's external costs have not been evaluated. Studies are required by law and should address all customer classes.

2) Discriminatory and Arbitrary Application: Imposing the proposed charge on only one group of customers using less than the average amount of energy is arbitrary and discriminatory. There are many groups that use less than the average amount of energy (for example, communities where there is no need for air conditioning and customers that have smaller than average homes). Some net metered customers pay for their share of the system as they use more than the average amount of energy used by PacifiCorp's customers. Some net metered customers' solar panels are more efficient than others because they face west or are at a low angle. Customers should not be penalized for providing clean energy. The concept of paying one's way should apply to all customers, and net metered customers already pay more through minimum bill payments.

3) Inconsistency: PacifiCorp's position is inconsistent with its solar incentive and demand side management rebate programs, its current rate structure that encourages efficiency, and its commitment to conservation.

4) Electric Vehicles: some solar panels are installed to offset electric vehicle energy requirements.

5) Price Regulation: Price regulation is an imprecise methodology in which rates are based on averages causing some customers to pay more and some to pay less. Before imposing the net metering facilities charge, PacifiCorp should be required to demonstrate that, on average, net metered customers significantly shift costs to other ratepayers. PacifiCorp has not done so.

6) Other Comments: The proposed fee will be a disincentive for future development potentially affecting the solar market and economic development in Utah. Solar is an important option for rural Utah and for maintaining affordable utility bills. Utah should start moving away from burning fossil fuels, and renewable energy should be encouraged. The proposed fee does not reflect investments made and risks undertaken by net metered customers, the loss of excess generation credits at the end of the annualized billing period, or the value of renewable energy certificates. The population of Utah is growing and the Commission should consider the message we are sending to our youth. An informal survey of neighborhood community councils generally indicates support for renewable energy. PacifiCorp's contribution to air pollution in the Salt Lake Valley should be considered. The capacity of PacifiCorp's proposed solar farm in Utah is approximately equal to the aggregate capacity of the residential net metered customers' systems, for which the individual customers have paid.

B. DISCUSSION, FINDINGS AND CONCLUSIONS (NET METERING FACILITIES CHARGE)

1. The Net Metering Program Statute

PacifiCorp customers have the option to net meter electricity under Schedule 135. PacifiCorp initially proposed Schedule 135 in response to the 2002 enactment of House Bill 7 – Net Metering of Electricity, now codified at Utah Code Ann. § 54-15-101, *et. seq*. ("Net Metering Code"). Since the Commission's original approval of Schedule 135 in 2002,[56] Schedule 135 has evolved to address challenges and opportunities identified as the net metering program matures. For example, in Docket No. 08-035-T04 the Commission approved a series of

[56] *See The proposed schedule offers Net Metering Service to qualifying customers in compliance with Utah Code Ann. § 54-15-101 to 106*, Docket 02-035-T05 (Tariff Approval Letter; June 24, 2002).

revisions to Schedule 135 proposed in part to reflect modifications to the Net Metering Code resulting from the 2008 enactment of Senate Bill 84.[57]

In 2009 the Commission issued an order in Docket No. 08-035-78 ("2009 Order")[58] directing PacifiCorp to revise Schedule 135 consistent with findings in an investigative docket regarding barriers to the implementation of net metering.[59] Most recently, Governor Herbert signed S.B. 208 on March 25, 2014, with an effective date of May 13, 2014. S.B. 208 amends several sections of the Net Metering Code, including Utah Code Ann. §§ 54-15-102, 54-15-104 and 54-15-106, and deletes § 54-15-105 in its entirety replacing it with a new § 54-15-105.1 which states:

The governing authority shall:[60]

> (1) determine, after appropriate notice and opportunity for public comment, whether costs that the electrical corporation or other customers will incur from a net metering program will exceed the benefits of the net metering program, or whether the benefits of the net metering program will exceed the costs; and
>
> (2) determine a just and reasonable charge, credit, or ratemaking structure, including new or existing tariffs, in light of the costs and benefits.

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[57] *See In the Matter of the Approval of Rocky Mountain Power's Tariff P.S.C.U. No. 47, Re: Schedule 135 - Net Metering Service,* Docket No. 08-035-T04 (Order Approving Tariff With Certain Conditions; June 13, 2008); (Tariff Approval Letter; August 13, 2008). The approved revisions include: (1) an increase in the capacity limits for non-residential net metering customers from 25 kW to two MW; (2) allowing net metering facilities to be controlled by either an inverter or switchgear; (3) an increase in the capacity limit for the net metering program from 3,516 kW to 4,615 kW; (4) revision and expansion of the definition of a renewable generating facility; (5) a change to the expiration date of unused credits from the end of the calendar year to March of each year; and (6) revised applicability of Schedule 135 from "any customer that owns or operates a fuel cell or renewable generating facility" to "any customer that owns or leases a customer-operated renewable generating facility."

[58] *See In the Matter of the Consideration of Changes to Rocky Mountain Power's Schedule No. 135 – Net Metering Service*, Docket No. 08-035-78 (Report and Order Directing Tariff Modifications; February 12, 2009).

[59] *See In the Matter of an Investigation of Net Metering,* Docket No. 07-999-08.

[60] The term "governing authority" in the context above is defined to mean the Commission. *See* Utah Code Ann. § 54-15-102(8)(b).

We interpret Utah Code Ann. § 54-15-105.1 as delegating to the Commission the responsibility to gather and evaluate relevant facts, opinions and public comments, and to determine whether the costs of PacifiCorp's net metering program will exceed the benefits of the net metering program, or *vice versa*. Under subsection (2), the Commission is then required to determine a charge (for example, a net metering facilities charge like the one proposed in this proceeding), credit, or ratemaking structure that is just and reasonable in light of the costs and benefits of the net metering program identified through the Commission's evaluation. In other words, we interpret Utah Code Ann. § 54-15-105.1 as directing a determination under subsection (1) before the determination under subsection (2) is made.

To address the requirements of S.B. 208, the Commission issued in this docket a public notice on April 16, 2014, stating our intent to reach the determinations specified in subsections (1) and (2) of Utah Code Ann. § 54-15-105.1 in this proceeding, in light of the residential customer net metering facilities charge proposed previously in this docket by PacifiCorp. The public notice further invited public comment on "whether costs that PacifiCorp or other customers will incur from PacifiCorp's net metering program will exceed the benefits of the net metering program, or whether the benefits of the net metering program will exceed the costs." The public notice pointed parties to the Commission's January 22, 2014, scheduling order, and states parties that had intervened in this proceeding could address this topic as part of their written direct testimony on cost of service issues (scheduled for filing on May 22, 2014). Non-intervening parties also were invited to comment on this topic.

As discussed in more detail below, the testimony and comments (both written and verbal) provided in this proceeding fall short of providing the Commission the substantial evidence necessary to make the determinations required under Utah Code Ann. § 54-15-105.1(1). Thus, we are unable to determine at this time whether it is just and reasonable to impose a charge or credit, or to alter the current ratemaking structure applicable to net metering customers. Later in this order we initiate a process to provide additional information and analyses.

We recognize our expressed intent on April 16, 2014, to conduct the S.B. 208 analysis in this docket may have been overly optimistic. PacifiCorp had months earlier filed and supported, in conventional cost of service ratemaking fashion, this general rate case, including the net metering charge in question. That showing, with respect to the net metering charge, though apparently persuasive to the Division and Office, was not fashioned to address the determinations required by S.B. 208. Indeed, PacifiCorp's direct testimony and exhibits contain no discussion at all of net metering program benefits; yet, any such benefits are an integral part of the analysis required by the statute.[61] Moreover, the schedule for the various filings and hearings in this docket had long since been set and could not be altered materially due to the statutory requirement to act on the Application within 240 days.

It now appears these immutable factors combined to impede the development and presentation of evidence that is essential to making the S.B. 208 determinations. The validity of this conclusion is underscored by the fact that virtually every party has either recommended or at

[61] We observe the now-repealed Utah Code Ann. § 54-15-105 (in effect at the time of PacifiCorp's initial filing) provided, among other things, that PacifiCorp could not charge a net metering customer an additional standby, capacity, interconnection, or other fee or charge, unless the Commission made a determination regarding whether PacifiCorp will incur direct costs from the interconnection or from administering the net metering program that exceed benefits resulting from the program. Because Utah Code Ann. § 54-15-105 was repealed prior to the conclusion of this proceeding and was replaced by Utah Code Ann. § 54-15-105.1, the specific determinations required under Utah Code Ann. § 54-15-105 are now moot and inapplicable to PacifiCorp's proposed net metering facilities charge.

least acknowledged that an appropriate outcome for this issue in this docket would be an order directing further study of the complex questions presented. Even PacifiCorp candidly states the facilities charge it recommends is but an interim step in its own consideration of net metering cost causation and rate design. Indeed, it intends to undertake a statistically valid analysis of net metering customer loads and potentially to recommend a more comprehensive approach to the rate design for residential customers engaging in distributed generation. Accordingly, we conclude the just and reasonable outcome for now is to leave in place the program as presently constituted and to outline a path forward that we trust will bring to light the information necessary to fulfilling our statutory responsibilities. The following discussion illustrates the need for the additional information and greater clarity we require.

2. Inadequate Net Metering Program Cost Evidence

PacifiCorp presents two views regarding net metering program costs. First, PacifiCorp focuses its estimate of net metering program costs on the distribution and customer costs it believes net metering customers shift to the remaining members of the residential customer class. PacifiCorp argues the rationale for the charge is that the residential rate schedules recover a significant portion of fixed costs in energy rates. Accordingly, PacifiCorp begins its calculation by identifying test-period distribution and customer costs allocated to the residential class. PacifiCorp implies the shift of distribution and customer costs from net metered customers to all other residential customers can be identified by comparing test period billed consumption between net metered customers and all residential customers.

As described in more detail above, PacifiCorp concludes the average monthly distribution and customer cost responsibility per residential customer is $24.19. PacifiCorp then calculates the amount remaining after accounting for revenue collected from the customer charge portion of each residential bill and identifies this value as the average amount residential customers contribute to distribution and customer costs per month through energy rates. Next, PacifiCorp calculates the amount a residential net metered customer pays per month toward these fixed costs through its energy rates based again on test period billed consumption.

PacifiCorp compares the difference between these two monthly amounts and concludes the difference is the distribution and customer cost the net metering program shifts to non-participating customers. This amount is $116,794 annually or a cost shift from residential net metered customers to other residential customers of about 1 cent per customer per month. [62]

UCE, the Sierra Club, and TASC argue PacifiCorp's cost analysis is faulty and incomplete because it does not recognize the differences in the costs net metered customers may impose on the distribution system due to their unique demand characteristics as compared to the typical residential customer. For example, a net metered customer may have lower demand than the average residential customer at the time of distribution peak and therefore have a lower share of cost responsibility. Indeed, PacifiCorp presents a chart in its rebuttal testimony comparing an average Utah residential customer load without distributed generation facilities with the load profile of a residential customer with a rooftop solar facility[63] at the time of the summer distribution peak day. The comparison shows a reduced contribution to the distribution peak for this generic rooftop solar facility.

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[62] The $116,794 is simply the proposed net meter facilities charge times the number of test period net meter bills contained in Exhibit RMP_ (JRS-1R).

[63] PacifiCorp states this load profile is based on a generation profile from National Renewable Energy Labs PV Watts calculator for a 3.2 kW facility in Salt Lake City.

Opponents of the charge also contend targeting only net metered customers for this charge is discriminatory. These parties point out many, indeed most, residential customers use less than the average amount of usage for the residential class. Thus, the fact that net metered customers on average use less electricity than the residential class average does not justify imposing a facilities charge on them alone. To demonstrate this point, UCE presents evidence on the size of residential bills, referred to as the frequency of residential billed consumption. UCE's evidence shows the typical residential customer uses 500-600 kWh per month, not the average of 698 kWh per month relied upon by PacifiCorp in calculating the proposed charge which is skewed upward by residential billings with very high usage. The record shows net metered customers average use of 518 kWh per month is in the same range as that of other typical residential customers. These facts undermine PacifiCorp's reasoning that net metered customers shift distribution costs to other residential customers in a fashion that warrants distinct rate treatment.

PacifiCorp argues net metered customers comprise a subgroup of the residential customers that imposes different costs on the system and the Division and the Office agree. This assertion, however, is not supported by any empirical data. Thus, the parties opposing the net metering facilities charge justifiably respond that none of the facilities charge proponents has presented evidence showing that the level of usage or the load characteristics of net metered customers are materially different from the typical residential customer.

As previously noted, the absence of load characteristic data for residential net metered customers is a significant gap in the record before us. At this juncture we believe information identifying and explaining the differences in load characteristics is critical to our understanding of the costs net metered customers uniquely cause, prior to making the determinations called for in Utah Code Ann. § 54-15-105.1. Importantly, PacifiCorp acknowledges the criticality of this information and stated on this record its intention to perform such a study beginning this year. Specifically, PacifiCorp states it is undertaking a load research study to gather time-based data for the development of allocation factors and billing determinants for residential customers with distributed generation in order to explore the development of a new rate schedule for this group of customers. This research, PacifiCorp states, will provide measurement of net metered customer usage at the time of system coincident peaks. PacifiCorp testifies this information is the driver for the allocation of transmission and generation costs.

We also note that in addition to conducting this future study, PacifiCorp indicates other rate structures may provide a better long-term solution to the unique issues presented by net metered customer generation, rather than only a fixed charge as PacifiCorp now proposes. Moreover, PacifiCorp plans to further evaluate such structures for presentation to the Commission. We conclude the determinations and potential rate structure changes the net metering statute directs us to make must necessarily await the data and analyses all parties, including PacifiCorp, agree are important, even foundational, to our understanding of the pertinent issues.

In rebuttal testimony, PacifiCorp offers an alternative view of the cost of the residential net metering program. This view addresses all costs of service, not just the distribution and customer cost components. This calculation is based on the retail credit a net metered customer receives for "the power they produce at their retail price, which ranges from

8.8 cents per kilowatt-hour (“kWh”) to 14.4 cents per kWh depending on which pricing block is being displaced at the time the N[et] E[nergy] M[etered] customer production is being applied to avoid paying for energy from the grid.”[64]

It is unclear from the record whether PacifiCorp believes the cost of the net metering program is the retail rate times total net metered customer generation or times just the excess or exported customer generated electricity that gets credited against consumption, as provided under Utah Code Ann. § 54-15-104.

If PacifiCorp intends this alternative view of net metering program cost to apply the retail rate to total net metered customer generation, it is not readily apparent how the production and consumption of net metered power on the customers’ side of the meter harms or causes costs to other residential customers. Further, such an approach does not appear to be consistent with the statutory definition governing charges or credits for “net electricity.” Indeed, the Net Metering Code excludes the amount of the net metered customers’ production and consumption behind the meter in the definition of electricity eligible for credit. Moreover, PacifiCorp does not provide the test period quantity of kWh for total net metered production. The Office, however, provides with its testimony a data request response from PacifiCorp that includes an estimated quantity (kWh) for total residential net metered generation in 2013 (data request OCS 30.1). Assuming the 20 percent capacity factor and 11,026,668 kWh of production shown on the data response produces a residential net metering program cost of between

[64] Rebuttal Testimony Gregory N. Duvall, p. 2, lines 32-36.

$970,000 and $1.6 million (based on a retail rate range of 8.8 cents per kWh and 14.4 cents per kWh).

If, on the other hand, PacifiCorp intends its alternative view of program cost to apply the retail rate only to excess customer generation, PacifiCorp testifies excess generation "is about 161 kilowatt-hours per [net metering] customer[]."[65] Assuming this quantity, 2,093 residential net metered customers using 161 kWh cause net metering program costs of between $29,654 and $48,524 (depending on the applicable retail rate of 8.8 cents to 14.4 cents per kWh).[66] These amounts are well below the $116,794 PacifiCorp proposes to recover through the net metering facilities charge.

3. Insufficient Net Metering Program Benefit Evidence

PacifiCorp's Application and direct testimony do not address the benefits of its net metering program. PacifiCorp, however, filed rebuttal testimony on this subject on June 26, 2014, about four weeks after S.B. 208 became law. PacifiCorp recommends the Commission adopt a program benefit value equal to the value solar QFs receive under PURPA and references a value of $0.03 per kWh. PacifiCorp testifies this value should apply to the total generation of net metered customers to determine benefits.[67] Based on the 11,026,668 kWh of annual output from the facilities of residential net metered customers noted above, one may calculate $330,800 in annual benefits using this method.

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[65] July 28, 2014, Tr. 122:19-20.

[66] It is unclear from the record whether the 161 kWh is a test period value or an historical value, whether it refers to the total amount of generation exported to the grid *i.e.*, "delivered to the electrical corporation," as defined in Utah Code Ann. § 54-15-102(10)(b), or refers to the "excess" amount of generation that is credited to intra- or inter-month usage that is addressed under Utah Code Ann. §§ 54-15-102(6) and 54-15-104.

[67] July 28, 2014, Tr. 197.

A program benefit value of $330,800 is over double the amount of program cost PacifiCorp seeks to recover through the net metering facilities charge. This comparison, however, may be misleading because avoided cost calculations encompass broader cost categories, notably generation, while PacifiCorp's proposed charge is only based on distribution and customer costs. This observation simply highlights another insufficiency in the record before us. The record does not contain a reliable evaluation of net metering program impacts on all cost categories. Those favoring the charge point to distribution costs shifted. Those opposing the charge point to benefits conferred in the form of generation cost savings. What we lack at this time is a comprehensive view of all the program costs and cost savings that are appropriate to consider in making the S.B. 208 determinations.

4. Conclusions

Based on our review of the record in this proceeding, we conclude the evidence is inconclusive, insufficient, and inadequate to make a determination under Utah Code Ann. § 54-15-105.1(1) whether costs PacifiCorp or its customers will incur from the net metering program will exceed the benefits of the net metering program, or whether the benefits of the net metering program will exceed the costs. Thus, we cannot conclude that the proposed net metering facilities charge is just and reasonable under Utah Code Ann. § 54-15-105.1(2), and we decline to approve the charge at this time.

We recognize PacifiCorp's electric system is undergoing transformation as it integrates customer-owned generation, and that this integration has cost implications. Although there is insufficient evidence to make the determinations required in Utah Code Ann. § 54-15-105.1 in this proceeding, we acknowledge PacifiCorp, the Division and the Office have raised important issues regarding the potential for cost shifting from net metered customers to PacifiCorp's general body of customers. We also recognize other parties have provided at least some evidence of a range of asserted benefits to the system and ratepayers from residential rooftop solar generation. We feel strongly that the questions these positions raise should be thoroughly examined based on the appropriate data and analysis pertaining to the full array of relevant, measurable costs and benefits.

We note there is at least a consensus among the parties in this proceeding that the current number of net metered customers on PacifiCorp's system at this time is relatively small. Numerically, the rate of annual growth in net metered customers is also small, although more dramatic in percentage terms. We also note the distribution and customer intra-class cost shift asserted by PacifiCorp and supported by the Division and the Office is very small, at about 1 cent per customer per month. We conclude under these circumstances the better course is for PacifiCorp and interested parties to gather and analyze the necessary data, including the load profile data that is foundational to this analysis, and present to us their results and recommendations in a future proceeding.

We emphasize that ratemaking is a dynamic process and must respond appropriately as the demands customers place on the utility system change. Prior to approving responsive new rate structures, we must understand these changes. For example, if net metered customers are a subclass (as PacifiCorp asserts), data must confirm this assertion. We cannot determine from the record in this proceeding that this group of customers is distinguishable on a cost of service basis from the general body of residential customers. Simply using less energy than average, but about the same amount as the most typical of PacifiCorp's residential customers, is not sufficient justification for imposing a charge, as there will always be customers who are below and above average in any class. Such is the nature of an average. In this instance, if we are to implement a facilities charge or a new rate design, we must understand the usage characteristics, e.g., the load profile, load factor, and contribution to relevant peak demand, of the net metered subgroup of residential customers. We must have evidence showing the impact this demand profile has on the cost to serve them, in order to understand the system costs caused by these customers. This type of analysis is a necessary part of determining the relationship of costs and benefits of the net metering program as required by the Net Metering Code.

In our future deliberations, it will be necessary and appropriate to re-examine various aspects of the net metering program called into question in this proceeding. For example, some parties questioned the rate paid for QF generation under PURPA versus the rate credited currently to net metered customers for excess customer generation under Utah Code Ann. § 54-15-104. We last addressed this topic in our 2009 Order in which we set the credit for net excess generation for residential and small commercial net metering customers at the retail rate per kilowatt-hour. In deciding to apply a kilowatt-hour credit rather than a credit based on the Schedule 37 avoided cost, the Commission stated:

> We also observe there are protections in place for both the Company and ratepayers which help support the kilowatt-hour credit for netexcess generation. First, the Company has the ability to be made whole for the net metering program as it is operated today. Second, even though the program was implemented in 2002, it is still relatively small and all parties involved are on the learning curve. To the extent the program is small, with proper reporting it is possible to identify

> shortcomings and to refine the program in the early stages of implementation.[68]

We will carry out our future examination of net metering costs and benefits in anticipation of a day when rooftop solar may be far more prevalent than it is now. Accordingly, that examination should include the possibility of the program refinements we alluded to in the 2009 Order.

Similarly, in our order issued October 7, 2009 in Docket No. 09-035-27, we concluded to apply demand side management ("DSM") cost and benefit tests in evaluating small-scale renewable resources such as solar photovoltaic projects "until other economic tests are available."[69] We expect the future examination we direct in this order will include an evaluation of whether the DSM tests or some other economic tests are best suited to measuring the costs and benefits of the net metering program.

5. Process, Next Steps

We will establish a new docket, Docket No. 14-035-114, in which the costs and benefits of PacifiCorp's net metering program will be examined. We will shortly issue a notice of a technical conference in that docket at which PacifiCorp will present its plan for performing a load research study focused on residential net metered customers, and its schedule for the study's completion. This technical conference will be held on November 5, 2014.

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[68] 2009 Order, p. 19.

[69] *In the Matter of the Proposed Revisions to the Utah Demand Side Resource Program Performance Standards*, Docket No. 09-035-27 (Order; October 7, 2009), p. 15.

IV. ORDER

Pursuant to the foregoing discussion, findings and conclusions made herein, we order:

1. The terms and conditions of the Settlement Stipulation filed in these matters on June 25, 2014, are approved.
2. PacifiCorp shall file appropriate tariff revisions increasing Utah jurisdictional revenue by $35 million, effective September 1, 2014, using the rates determined without the net metering facilities charge.
3. The tariff revisions shall reflect the determinations and decisions contained in this Report and Order. The Division shall review the tariff revisions for compliance with the terms of this Report and Order.
4. A revenue increase of $19.2 million in Utah jurisdictional revenue is conditionally approved, effective September 1, 2015, subject to the conditions set forth in the Settlement Stipulation.
5. PacifiCorp shall file appropriate tariff revisions increasing Utah jurisdictional revenue by $19.2 million, 60 days in advance of the desired effective date of the revenue increase, for review and approval. The Division shall review the tariff revisions for compliance with the terms of this Report and Order.
6. PacifiCorp shall file a revised Schedule No. 135 for review to reflect the deletion of the words “or switchgear” in Utah Code Ann. § 54-15-102(3)(a)(v), and the additional language in § 54-15-102(9)(b) and § 54-15-102(13)(b)(ii).

7. PacifiCorp's request for a $4.65 net metering facilities charge for residential customers is not approved.

DATED at Salt Lake City, Utah, this 29th day of August, 2014.

/s/ Ron Allen, Chairman

/s/ David R. Clark, Commissioner

Attest:

/s/ Gary L. Widerburg
Commission Secretary
DW#260065

Notice of Opportunity for Agency Review or Rehearing

Pursuant to §§ 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 §§ 63G-4-401 and 63G-4-403 of the Utah Code and Utah Rules of Appellate Procedure.

CONCURRING AND DISSENTING STATEMENT OF COMMISSIONER THAD LeVAR

I concur with all the decisions in this order except for the decision to decline to impose PacifiCorp's proposed net metering facilities charge, from which I dissent. I decline to reject the joint recommendation of PacifiCorp, the Division, and the Office, and find the proposed charge represents costs PacifiCorp's residential non net metered customers incur from the net metering program that exceed the demonstrated benefits of the net metering program. Accordingly, I find the proposed charge is just and reasonable, and I would approve its implementation.

I do not find any legal flaw in the portion of this order that declines to impose the proposed charge. Utah Code Ann. § 54-15-105.1 provides requirements and discretion that this order appropriately considers. My disagreement is factual, not legal.

Declining to impose the net metering facilities charge constitutes a *de facto* finding that at least until September 2016, net metering benefits exceed net metering costs. Because the proposed charge is revenue neutral to PacifiCorp and only modifies allocation of costs among residential customers, a subsidy will exist during that time period under which costs imposed by residential net metered customers are paid by residential non net metered customers. It is appropriate for Congress or for the Utah Legislature to subsidize installation of residential distributed generation through tax credits or other economic incentives. In my view, it is not appropriate to impose the same kind of subsidization through public utility rates. Tax subsidies can be structured progressively; utility rate subsidies are regressive.

Public utility rates are not permanent or static. The approved stipulation in this proceeding allows another general rate case for PacifiCorp in 2016. Every aspect of rates, including the demonstrable costs and benefits of the net metering program, is subject to reevaluation in a future general rate case. Potential future reevaluation does not change my finding that in this proceeding, the evidence demonstrated concrete and identifiable net metering costs that exceed concrete and identifiable net metering benefits.

I recognize future and continued evaluation and analysis is appropriate, and could include an analysis of appropriate compensation for excess customer generated electricity and whether the net metering program warrants more fundamental changes to rate design and customer classes. However, I do not believe maintaining the existing subsidy for an additional two years is the proper starting point for that analysis. In my view, a move towards cost of service provides a more appropriate launch to further analysis.

COSTS

The net metering program is shifting distribution system and customer service costs caused by residential net metered customers to residential non net metered customers. PacifiCorp, the Division, and the Office all agree that this subsidy is occurring not simply because residential net metered customers purchase less energy, but also because they receive net metering credits at full retail value.[70] In other words, net metered customers not only use less energy, but they also draw electricity from PacifiCorp's distribution system for which they pay

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[70] *See* Direct Testimony of Joelle R. Steward, pages 21-24; Rebuttal Testimony of Joelle R. Steward, page 12; Surrebuttal Testimony of Joelle R. Steward, pages 4-5, 6-7; Cost of Service Confidential Direct Testimony of Artie Powell, Ph.D., pages 11-13; Rebuttal Testimony of Stan Farynairz, pages 6-8; Cost of Service/Rate Design Direct Testimony of Daniel E. Gimble, pages 24-25; Cost of Service/Rate Design Rebuttal Testimony of Daniel E. Gimble, pages 1-2, 9. Additionally, residential net metered customers receive the Renewable Energy Certificates associated with their generation, s*ee In the Matter of the Consideration of Changes to Rocky Mountain Power's Schedule No. 135 – Net Metering Service*, Docket No. 08-035-78 (Report and Order Directing Tariff Modifications, February 12, 2009, at p. 30), a scenario that arguably is inconsistent with compensation for excess customer generated electricity at full retail rates.

with a net metering credit instead of with a rate. For that electricity purchased with a credit, the net metered customer has not paid the customer service and distribution system costs reflected in energy rates. PacifiCorp's methodology of calculating the proposed charge reflects this concept. While some parties challenged them,[71] I find that PacifiCorp's cost calculations, as endorsed by the Division and the Office, are supported by substantial evidence.

BENEFITS

No party argued that residential net metered customers utilize PacifiCorp's customer service functions to a greater or lesser extent than residential non net metered customers.[72] Accordingly, I see no benefits concomitant to the customer service costs of residential net metered customers that are being subsidized by residential non net metered customers.

Residential net metered customers are using the distribution system to a greater extent than residential non net metered customers are using the same system. Residential non net metered customers buy electricity through the distribution system. Residential net metered customers buy and sell electricity through the same distribution system. Additionally, PacifiCorp established that residential net metered customer usage does not materially reduce the peak demand to which the distribution system must be maintained.[73] PacifiCorp's testimony along with the Pilot Solar Energy Study from a circuit in the Salt Lake City area indicated that the

[71] *See* Direct Testimony of Michael D. Rossetti, pages 4-6; Surrebuttal Testimony of Michael D. Rossetti, pages 5-9; Direct Testimony of Nathanael Miksis, pages 19-26; Direct Testimony of Dustin Mulvaney, pages 6-11; Direct Testimony of Rick Gilliam, pages 11-16; Rebuttal Testimony of Rick Gilliam, pages 3-7; Surrebuttal Testimony of Rick Gilliam, pages 3-5.

[72] Additionally, it seems intuitive that net metered customers, whose monthly bills are more complicated than non net metered customers, utilize customer service costs to a greater extent than non net metered customers.

[73] *See* Rebuttal Testimony of Douglas L. Marx, pages 2-7; Exhibit RMP_ (DLM-1R).

residential net metering program is not currently benefitting the distribution system, and that even under a best case adoption of solar distributed generation in the circuit and optimal generation conditions, the highest peak demand is reduced by seven percent, a reduction insufficient to defer distribution system upgrades.[74] While some parties anecdotally criticized PacifiCorp's use of a single circuit for that evaluation and challenged other aspects of the study,[75] no party presented a concrete alternate for a study sample or specific methodology to measure the impact of the net metering program on distribution system peak demand.[76]

Other parties presented alternative analyses of net metering program benefits[77] and argued additional study is necessary. However, none of those analyses directly addressed customer service benefits, and none of them addressed benefits as concomitant to the distribution system costs as PacifiCorp's evidence of benefits related to distribution system peak demand.[78] Additionally, those analyses included some benefits we recently concluded were too speculative or otherwise not measurable or quantifiable.[79] Accordingly, I accept PacifiCorp's Pilot Solar

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[74] *See* Rebuttal Testimony of Douglas L. Marx, pages 2-7; Exhibit RMP_ (DLM-1R). *See also* July 29, 2014, Tr. 402:1 to 406:4.

[75] *See* July 28, 2014, Hearing Transcript, Volume I, p. 73, line 1 through p. 83, line 13; July 29, 2014, Hearing Transcript, Volume II, p. 321, line 11 through page 322, line 11; Surrebuttal Testimony of Dustin Mulvaney, pages 8-10; Surrebuttal Testimony of Rick Gilliam, page 7.

[76] *Id.*

[77] *See Value of Solar in Utah*, UCE Exhibit 2.1 (DT); *NEM Avoided Cost Methodology*, Exhibit SC_DRM-2.

[78] While PacifiCorp also posited that net metering benefits should be inferred from avoided cost determinations in other dockets, *see generally* Duvall Rebuttal, it seems intuitive that the utility scale solar projects for which those avoided costs are calculated demonstrate some system benefits that are not applicable to residential rooftop solar. Additionally, avoided costs relate primarily to capacity and energy, benefits that are not directly applicable to the customer service and distribution system costs presented by PacifiCorp in this docket. PacifiCorp also presented anecdotal evidence about additional expenses distributed generation may impose on the distribution system, *see* Marx Rebuttal at pp. 7-8, but that evidence should be evaluated as a net metering program cost rather than a net metering program benefit. PacifiCorp did not calculate those costs into the proposed charge.

[79] *See In the Matter of the Application of Rocky Mountain Power for Approval of Changes to Renewable Avoided Cost Methodology for Qualifying Facilities Projects Larger than Three Megawatts*, Docket No. 12-035-100 (Order on Phase II Issues; August 16, 2013, at pp. 39-41). *See also generally PacifiCorp's 2013 Integrated Resource Plan*, Docket No. 13-2035-01 (Report and Order; January 2, 2014).

Energy Study and other testimony as substantial evidence the net metering program does not reduce the capacity to which the distribution system must be maintained.

I find PacifiCorp established that the net metering program benefits do not reduce customer service costs and do not reduce the peak demand to which the distribution system must be maintained. Accordingly, I find PacifiCorp met its burden[80] to establish that with respect to concrete and identifiable costs and benefits identified in this docket, the costs residential non net metered customers incur from the net metering program exceed the benefits of the net metering program.

PRICE SIGNALS

As a matter of policy, I believe imposition of the net metering facilities charge sends the correct price signal to potential future net metered customers. Net metering adoption in Utah is increasing, and there is no evidence that might change. Homeowners deserve to have accurate price signals in front of them as they decide whether to invest in a residential distributed generation system.

Public comment in this proceeding included many net metered customers who rightfully believe they installed their residential distributed generation systems for altruistic reasons. I agree with those reasons and support them. The residential net metering program deserves viable and stable future growth. Accurate and stable price signals contribute to that objective much more than does a subsidy with an uncertain future.

[80] Various parties have discussed at length the proper burden of proof to which PacifiCorp should be held. While I find PacifiCorp has met its burden, I also note that some parties improperly attempt to elevate that burden to something more similar to a marshaling requirement than to a burden of proof.

The Office noted that a future cost and benefit analysis could include messaging to better inform the public about the process.[81] In practice, though, messaging only reaches a small percentage of the customer base, especially messaging about imprecise future changes that might or might not occur. Additionally, it is not reasonable to expect sellers of residential distributed generation systems to present anything to potential purchasers other than actual, current price signals.

Current net metered customers understandably do not want their pricing structure to change. Continuing the subsidy of residential net metering costs by residential non net metered customers will increase the number of residential net metered customers who will see themselves as the victims of a bait-and-switch in the event the subsidy ends in the future. I believe those customers deserve accurate price signals on which to base their decisions, and I believe they deserve those accurate price signals now.

PROCESS AND METHODOLOGY

I find it instructive to compare Utah Code Ann. § 54-15-105.1, enacted by the Utah Legislature in 2014, with Minn. Statute § 216B.164, Subd. 10, enacted by the Minnesota Legislature in 2013. Each of these statutes requires the respective Utah and Minnesota commissions to address costs, benefits, or value of distributed generation.[82]

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[81] *See* Cost of Service/Rate Design Surrebuttal Testimony of Daniel E. Gimble, page 14.

[82] Utah Code Ann. § 54-15-105.1 contains three requirements: (1) notice and opportunity for public comment; (2) a determination regarding "whether costs that the electrical corporation or other customers will incur from a net metering program will exceed the benefits of the net metering program, or whether the benefits of the net metering program will exceed the costs"; and (3) determination of "a just and reasonable charge, credit, or ratemaking structure, including new or existing tariffs, in light of the costs and benefits." Minn. Statute § 216B.164, Subd. 10, in contrast, requires that state's Department of Commerce and Public Utilities Commission to establish a distributed solar value methodology. Minnesota's statute dictates that the agency "shall consult stakeholders with experience and expertise in power systems, solar energy, and electric utility ratemaking regarding the proposed methodology, underlying assumptions, and preliminary data" and requires that the methodology "must, at a minimum, account for

It is apparent the Utah Legislature intended and enacted a very different process than the process mandated by the Minnesota Legislature. It is entirely appropriate for two individual laboratories of democracy to establish different approaches and different methodologies. The agencies implementing these statutes must recognize and respect those differences. Comparing these two statutory requirements strengthens my factual finding that the Utah requirements have been satisfied in this docket.

CONCLUSION

I find that PacifiCorp demonstrated the net metering facilities charge represents costs residential non net metered customers incur from the residential net metering program that exceed the demonstrated benefits of the residential net metering program. Additionally, I believe imposition of the proposed charge represents good public policy, sends proper price signals to homeowners considering an investment in a residential distributed generation system, and better ensures viable and stable future growth of the residential net metering program. The residential net metering program is important both now and in the future, but it should not be subsidized by residential non net metered customers. Accordingly, I find the net metering facilities charge is just and reasonable, and I would approve its implementation.

/s/ Thad LeVar, Commissioner

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the value of energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value" and may "incorporate other values . . . including credit for locally manufactured or assembled energy systems, systems installed at high-value locations on the distribution grid, or other factors."

CERTIFICATE OF SERVICE

I CERTIFY that on the 29th day of August, 2014, a true and correct copy of the foregoing Report and Order was served upon the following as indicated below:

By Electronic Mail:

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ATTACHMENT: SETTLEMENT STIPULATION

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

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	**))))))))**	**Docket No. 13-035-184**

SETTLEMENT STIPULATION

This Settlement Stipulation ("Stipulation") is entered into by and among the parties whose signatures appear on the signature pages hereof (collectively referred to herein as the "Parties" and individually as a "Party").

1. The Parties have conducted settlement discussions over the course of several weeks and had numerous meetings on and between May 28, 2014, and June 16, 2014 to which intervening parties in this docket were invited. In addition, drafts of this Stipulation were circulated to intervening parties for review and comment on June 19, 2014 and June 23, 2014 and there have been further discussions among various parties. This Stipulation has been entered into by the Parties after consideration of the views expressed during that process by participating intervening parties. No intervening party has indicated that it intends to oppose this Stipulation.

2. The Parties represent that this Stipulation is just and reasonable in result, will result in rates that are just and reasonable and will provide the Company a reasonable opportunity to earn its authorized rate of return. The Parties recommend that the Public Service Commission of Utah ("Commission") approve the Stipulation and all of its terms

and conditions. The Parties request that the Commission make findings of fact and reach conclusions of law based on the evidence and on this Stipulation and issue an appropriate order thereon.

BACKGROUND

3. On January 3, 2014, Rocky Mountain Power ("Company" or "Rocky Mountain Power") filed an application, together with pre-filed testimony and exhibits from seventeen witnesses, and revised tariff sheets requesting authority to increase its retail electric utility service rates in Utah by approximately $76.3 million per annum or an average overall increase of 4.0 percent including a requested return on equity of 10.0 percent, effective September 1, 2014 ("2014 GRC"). Rocky Mountain Power's request was based upon a forecast test period ending June 30, 2015, using a 13-month average rate base with a historical base period of twelve months ending June 30, 2013.

4. On January 6, 2014, the Commission issued its Notice of Scheduling Conference setting a scheduling conference to be held January 16, 2014.

5. On January 22, 2014, the Commission issued its Scheduling Order setting a procedural schedule. Hearings were scheduled to begin May 29, 2014 on cost of capital, June 30, 2014 on revenue requirement, July 28, 2014 on cost of service, rate spread and rate design. Public witness day is scheduled July 29, 2014.

6. On April 10, 2014, the Company filed its net power costs ("NPC") Update pursuant to the Scheduling Order.

7. On April 17, 2014, intervenors filed cost of capital direct testimony.

8. On May 1, 2014, intervenors filed revenue requirement direct testimony. In their testimony, intervenors proposed numerous adjustments to the Company's requested rate increase.

9. On May 15, 2014, the Company and intervenors filed cost of capital rebuttal testimony.

10. On May 22, 2012, intervenors filed cost of service and rate design direct testimony.

11. On May 28, 2014, parties held settlement discussions.

12. On May 29, 2014, the Commission conducted a hearing concerning the Company's cost of capital.

13. On June 4, 2014, the Company and intervenors filed revenue requirement rebuttal testimony.

14. On June 9, 2014, June 12-13, 2014, and June 16, 2014, parties held further settlement discussions. Parties also held rate design discussions June 16, 2014.

15. The Parties have reached a compromise as specified herein on the rate increase and request approval consistent with the terms and conditions provided in this Stipulation.

16. This Stipulation is intended to resolve most of the issues in this general rate case, in accordance with their respective terms and conditions. This Stipulation does not resolve the net metering facilities charge proposed by the Company in its direct filing.

17. On June 19, 2014, the Commission granted a motion to amend the schedule in this docket to change the filing date for cost of service and rate design rebuttal testimony and other matters based on the Parties ongoing settlement discussions.

SETTLEMENT TERMS

For purposes of this Stipulation, the Parties agree and recommend the Commission approve the following:

18. The Parties agree that the Company should be allowed to implement a multi-year rate plan ("Plan") that will provide a measure of rate certainty to customers while affording the Company a reasonable opportunity to earn its authorized rate of return and recover its costs of service. In reaching this Stipulation, various Parties have considered and relied upon many different factors and considerations, including but not limited to: a) evidence included in the 2014 GRC that provides a justification for the stipulated two-step rate increase, b) the projected in-service date of the Sigurd-Red Butte transmission line, c) timing considerations, and d) various other factors.

19. Other than as set forth in this Stipulation, the Parties have not agreed on any specific adjustments or regulatory principles at issue in this Docket. The components are as follows:

Step 1 Rate Change

20. The Parties agree that Rocky Mountain Power should be permitted to implement a Step 1 general rate increase in the amount of $35.0 million for service effective on and after September 1, 2014.

21. The Parties agree that the Sigurd-Red Butte transmission line investment is prudent and that cost recovery will occur in the Step 2 rate change.

Step 2 Rate Change

22. The Parties agree that Rocky Mountain Power should be permitted to implement a Step 2 general rate increase in the amount of $19.2 million, which includes the costs of the Sigurd-Red Butte transmission line, effective on the later of the in service date of the transmission line or September 1, 2015. If the Sigurd-Red Butte transmission line is not in service by September 1, 2015, the Step 2 rate increase will be delayed until the Sigurd-Red Butte transmission line is placed into service.

Cost of Capital

23. The Parties agree that the Company's allowed Return on Equity ("ROE") shall remain unchanged at the current authorized level of 9.8 percent, and that cost of capital and capital structure for Steps 1 and 2 will be as shown in Table 1 below:

Table 1

Stipulated Cost of Capital			
	Capital Structure	Rate	Weighted Rate
Long-term Debt	48.55%	5.200%	2.53%
Preferred Stock	0.02%	6.753%	0.00%
Common Stock	51.43%	9.800%	5.04%
WACC			7.57%

Net Power Costs

24. The Parties agree that a base NPC amount of $1,495.8 million annually total Company, or $630.0 million annually on a Utah-allocated basis, should be established as the base NPC beginning on the Step 1 rate effective date of September 1, 2014. Table 2 below reflects the stipulated level of base Energy Balancing Account ("EBA") costs (the base NPC less wheeling revenue) in dollars per megawatt hour ("$/MWh") in base rates by month for EBA measurement purposes in Step 1. Exhibit A to this Stipulation provides details showing the stipulated $/MWh calculations and the allocation of EBA costs among rate schedules based on the composite NPC allocator. EBA costs allocated to special contracts, whether or not they are included in the composite NPC allocator in Exhibit A, will be subject to the terms of the contracts. The monthly base NPC amounts for the purpose of EBA filings will be the monthly test

period base NPC amounts stated in Table 2 below until base NPC are re-set in Step 2, as set forth in Paragraph 25 below.

Table 2

	Utah EBA $/MWh
July	$ 26.141
August	26.716
September	24.913
October	25.183
November	24.752
December	24.947
January	24.597
February	25.185
March	25.955
April	24.557
May	25.245
June	25.548
Total	$ 25.337

25. The Parties agree that a base NPC amount of $1,491.1 million annually total Company, or $628.0 million annually on a Utah-allocated basis, should be established as the base NPC beginning September 1, 2015. Table 3 below reflects the stipulated level of base Energy Balancing Account ("EBA") costs (the base NPC less wheeling revenue) in dollars per megawatt hour ("$/MWh") in base rates by month for EBA measurement purposes in Step 2. Exhibit B to this Stipulation provides details showing the stipulated $/MWh calculations and the allocation of EBA costs among rate schedules based on the composite NPC allocator. EBA costs allocated to special contracts, whether or not they are included in the composite NPC allocator in Exhibit B, will be subject to the terms of the contracts.

The monthly base NPC amounts for the purpose of EBA filings will be the monthly test period base NPC amounts stated in Table 3 below until such time as new base NPC amounts are set in a general rate case or other proceeding filed on or after January 1, 2016.

Table 3

	Utah EBA $/MWh
July	$ 26.065
August	26.639
September	24.824
October	25.092
November	24.663
December	24.865
January	24.515
February	25.094
March	25.867
April	24.466
May	25.154
June	25.460
Total	$ 25.251

26. The Parties agree and request that the Commission approve herein an extension of the current EBA pilot, which currently ends December 31, 2015, of one year through December 31, 2016. The Parties further agree that, subject to Commission approval as requested in this Paragraph 26, the final report from the Division of Public Utilities ("Division") on the EBA pilot due "within four months after the conclusion of the third calendar year of the pilot," pursuant to the Commission's Corrected Report and Order in

Docket No. 09-035-15,[83] shall likewise be extended one year to be due within four months after the conclusion of the fourth calendar year of the pilot. The Parties agree that the EBA filings will continue on their established schedules, subject to the one-year extension of the EBA pilot as requested herein if approved by the Commission.

27. The Parties agree that, effective November 1, 2014, all deferral balances currently being collected in the EBA from Docket Nos. 10-035-124, 12-035-67 and 13-035-32, shall be added together with any Commission-approved balance from the currently pending EBA adjustment proceeding, Docket No. 14-035-31, with the total balance to be collected over one year beginning November 1, 2014. The Parties further agree that such prior EBA balances shall continue to be collected from customers without interest during the collection period, but that the Commission-approved balance from the pending EBA adjustment in Docket No. 14-035-31, will accrue interest during the collection period, unless otherwise ordered by the Commission or agreed to by stipulation in Docket No. 14-035-31.

Naughton Unit 3

28. The Parties agree that for purposes of the revenue requirement calculation, the Company will assume Naughton Unit 3 will continue to operate as a coal-fueled resource through December 31, 2017. If the Company does not obtain an amended permit in 2014 that would allow it to continue to operate Naughton Unit 3 as a coal-fueled resource through December 31, 2017, the Parties agree that the Company will be entitled to request, and the Parties will not oppose, a deferred accounting order for the revenue requirement impact for potential recovery from customers pursuant to a Commission order in a future rate case. The

[83] *In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism* Docket No. 09-035-15, Corrected Report and Order, p. 79, March 3, 2011.

Parties may contest the costs to be recovered notwithstanding their agreement not to oppose deferred accounting treatment.

Base Renewable Energy Credits (REC)

29. The Parties agree that the base REC revenues in rates for RBA purposes should be set at $2 million effective with the Step l rate increase on September 1, 2014, and that it shall continue at this level until rates are set through a subsequent general rate case filed on or after January 1, 2016. The $2.0 million base REC amount is net of the 10 percent incentive per paragraph 39 of the stipulation in Docket No. 11-035-200. The Parties agree that its RBA mechanism filing will continue on its normal schedule.

Energy Imbalance Market

30. The Parties agree that the Commission may enter a deferred accounting order to permit the Company to begin to defer a) Utah's allocated portion of energy imbalance market ("EIM")-related operations and maintenance expenses incurred on or after September 1, 2014, and b) depreciation expense related to capital investments necessary to implement EIM recorded on or after September 1, 2014 for potential recovery from customers pursuant to a Commission order in a future rate case. The Parties further agree that the prudence of the deferred EIM costs shall be determined in such future rate case and that the Parties may contest costs to be recovered notwithstanding their agreement not to oppose deferred accounting treatment.

31. The Parties agree that any deferral of EIM-related labor costs shall be limited to positions exclusively created as a result of the Company's participation in the EIM in excess of the full time equivalent employee positions reflected in the Company's direct filing in this rate case of 5,460. The Parties further agree that this number is being used solely for purposes of calculating the labor costs that qualify for EIM deferrals.

Future Rate Cases

32. The Company agrees that it will not file another general rate case, a major plant addition case or, with the exception of the Step 2 increase and other Commission-approved and currently existing rate adjustment mechanisms, will not otherwise seek any rate increase in Utah (a) prior to January 1, 2016 or (b) with a rate effective date prior to September 1, 2016.

Cost of Service, Rate Spread and Rate Design

33. The Steps 1 and 2 rate increases set forth in Paragraphs 20 and 22 above shall be allocated as set forth in Exhibits C and D to this Stipulation. Exhibits C and D also include the monthly billing comparisons for the Steps 1 and 2 rate changes. Special contract rates are not established by this Stipulation, and will be governed by the terms of the applicable contract approved by the Commission.

34. The Parties agree the customer charge should increase to $6.00 per month for single-phase residential customers and to $12.00 per month for 3-phase residential customers until there is a change to the customer charge by Commission order. The remainder of the revenue requirement assigned to Schedules 1, 2 and 3 shall be applied to Tier 2 for the winter rates. The Schedule 1 revenue requirement increase in Step 2 will also be applied to Tier 2 winter rates.

35. The Parties agree that the residential minimum bill shall be $8.00 for single-phase residential customers and $16.00 for three-phase residential customers.

36. The Parties represent that no agreement has been reached with regard to the net metering facilities charge proposed by the Company in its filing. Exhibit D shows the impacts to residential rates rate design under two scenarios; one containing a net metering facilities charge and one excluding a net metering facilities charge. Parties agree that the

outcome could be different than these two positions and that the principles described above will be followed regardless of the outcome.

37. The Parties agree that a Facilities Charge will apply to Schedule 6 and Schedule 6B. The Parties further agree that the Schedules 6 and 6B Step 1 revenue requirement increase will be applied to both the Power Charge and the Facilities Charge and the Schedules 6 and 6B Step 2 revenue requirement increase will be applied to the Power Charge, as shown in Exhibit C. The compliance filing for this proceeding will reflect a change in the current EBA and RBA rates on Schedules 94 and 98, respectively, for Schedules 6 and 6B to recover the previously approved allocated amounts based on the revised Power Charge for the period until the new EBA and RBA rates are set. Exhibit C also reflects the agreed upon rates for Schedule 31 that were reached by parties by stipulation in Docket No. 13-035-196.

Other Items

38. The Parties stipulate to the admission into evidence in the 2014 GRC of all pre-filed testimony that has been filed to date in the cost of capital, revenue requirement and cost of service phases of this case. This stipulation to the admission of the testimony does not represent an agreement by the Parties as to any positions taken in such testimony.

39. The Parties agree that the stay-out provision of Paragraph 32 will not prevent Rocky Mountain Power from seeking deferred accounting orders, for potential recovery from or return to customers pursuant to a Commission order in a future rate case, of costs related to the impacts of any proposed disposition, through sale, closure or other means, of the Deer Creek mine and related mining assets as well as for the impacts of the

possible sale of the Company's ownership interests in the Craig and Hayden generating plants. This Stipulation does not represent an agreement by the Parties as to any position to be taken on any request for such deferred accounting orders.

40. The Company agrees to file a) backup workpapers for blanket capital addition projects greater than $1 million and b) the Company's capital additions data base with the filing of its next general rate case. Parties agree that the Company's agreement to provide this information in its next general rate case is not a commitment to file the information in all subsequent rate cases.

41. The Company agrees that, in future general rate cases, all updates to NPC will be filed at least six weeks prior to the intervenor direct testimony due date. The Company agrees to provide, at the time of filing NPC updates, a GRID Project File, which contains a group of inputs files associated with the GRID runs, and an associated set of NPC Report files. These documents support the NPC updates and will be provided to each individual for which GRID access has been granted in the then-current general rate case along with the associated workpapers necessary to support the updates.

42. The Company agrees that if its NPC or other updates include a new forward price curve, it will ensure intervenors have at least six weeks to respond to such updates in intervenor direct testimony.

43. The Company agrees to obtain and provide actuarial updates, with the Company's workpapers included in its direct filing, to its pension expense and prepaid pension projections and to its Post-Retirement Benefits Other than Pensions expense and prepaid pension projections for the entirety of the test period of its next general rate case.

The Parties agree that this is not a commitment to file the information in all subsequent rate cases.

44. The Company agrees to complete and provide a marginal cost study for its next general rate case. The Parties agree that this is not a commitment to file the information in all subsequent rate cases.

GENERAL TERMS AND CONDITIONS

45. Not all Parties agree that each aspect of 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 that each specific component of this Stipulation is just and reasonable in isolation, all of the Parties agree that this Stipulation as a whole is just and reasonable in result and in the public interest.

46. 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, and 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.

47. The Parties agree that no part of this Stipulation or the formulae and method used in developing the same or a Commission Order approving the same shall in any manner be argued or considered as precedential in any future case except with regard to

issues expressly called-out and forever resolved by this Stipulation. This Stipulation does not resolve and does not provide any inferences regarding, and the Parties are free to take any position with respect to, any issues not specifically called-out and settled herein.

48. The Parties request that the Commission hold a hearing on this Stipulation. Rocky Mountain Power, Division, and the Office of Consumer Services ("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.

49. 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 proceeding in opposition to the Stipulation.

50. Except with regard to the obligations of the Parties under the five 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.

51. 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.

52. 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.

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DATED this 25th day of June 2014.

UTAH OFFICE OF CONSUMER SERVICES /s/ Michele Beck Michele Beck Director Office of Consumer Services 160 East 300 South, 2nd Floor Salt Lake City, UT 84114	ROCKY MOUNTAIN POWER /s/ R. Jeff Richards R. Jeff Richards VP and General Counsel Rocky Mountain Power 201 S. Main St., Suite 2400 Salt Lake City, UT 84111
UTAH DIVISION OF PUBLIC UTILITIES /s/ Chris Parker Chris Parker Director Utah Division of Public Utilities 160 East 300 South, 4th Floor Salt Lake City, UT 84114	UTAH INDUSTRIAL ENERGY CONSUMERS /s/ William J. Evans F. Robert Reeder William J. Evans Vicki M. Baldwin Parsons Behle & Latimer 201 South Main Street, Suite 1800 Salt Lake City, UT 84111 *Attorneys for Utah Industrial Energy Consumers*
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FEDERAL EXECUTIVE AGENCIES	WAL-MART STORES, INC. and SAM'S WEST, INC.
<u>/s/ Thomas A. Jernigan</u> Capt Thomas A. Jernigan Staff Attorney USAF Utility Law Field Support Center 139 Barnes Ave. Tyndall AFB, FL 32403 *Attorney for FEA*	<u>/s/ Meshach Y. Rhoades</u> Meshach Y. Rhoades Leslie S. Godfrey GREENBERG TRAURIG LLP Tabor Center 1200 Seventeenth Street, Suite 2400 Denver, CO 80202 *Attorneys for Wal-Mart Stores, Inc. and Sam's West, Inc.*

Exhibit A

Rocky Mountain Power
Utah General Rate Case - June 2015
Settlement Stipulation
Exhibit A - Utah Allocated EBA Base (Step 1 Increase)

Net Power Cost Calculation
Utah Allocation Based on Commission Approved Method

	Rebuttal Net Power Costs		Wheeling Revenues				
	Total Company	Utah Allocated	Total Company	Utah Allocated	Utah EBA Base	Utah Retail Sales	Utah EBA $/MWh
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Jul-2014	$ 144,073,551	$ 60,701,243	$ (8,045,793)	$ (3,422,346)	$ 57,278,897	2,191,141	$ 26.141
Aug-2014	145,163,754	61,062,006	(8,045,793)	(3,422,346)	57,639,660	2,157,502	26.716
Sep-2014	118,774,949	49,906,721	(8,045,793)	(3,422,346)	46,484,375	1,865,837	24.913
Oct-2014	117,668,710	49,492,155	(8,045,793)	(3,422,346)	46,069,809	1,829,381	25.183
Nov-2014	118,512,261	49,898,556	(8,045,793)	(3,422,346)	46,476,210	1,877,678	24.752
Dec-2014	127,406,631	53,654,820	(8,045,793)	(3,422,346)	50,232,473	2,013,529	24.947
Jan-2015	126,091,151	53,117,941	(8,045,793)	(3,422,346)	49,695,594	2,020,370	24.597
Feb-2015	117,516,974	49,507,269	(8,045,793)	(3,422,346)	46,084,922	1,829,854	25.185
Mar-2015	125,262,265	52,799,108	(8,045,793)	(3,422,346)	49,376,762	1,902,391	25.955
Apr-2015	114,967,768	48,414,025	(8,045,793)	(3,422,346)	44,991,678	1,832,113	24.557
May-2015	117,066,906	49,396,079	(8,045,793)	(3,422,346)	45,973,732	1,821,070	25.245
Jun-2015	123,259,960	52,050,078	(8,045,793)	(3,422,346)	48,627,732	1,903,419	25.548
Total	$ 1,495,764,879	$ 630,000,000	$ (96,549,514)	$ (41,068,157)	$ 588,931,843	23,244,285	$ 25.337
	[note 1]	[note 2]	[see detail below]		[(b) + (d)]	[note 3]	[(e) / (f)]

Footnotes: (1) See Exhibit A page 2 of 3
(2) See Exhibit A page 3 of 3
(3) Total per SRM-3, page 3.1.6; monthly per pricing backup.

Utah Allocated Wheeling Revenues

SRM-3 Page 3.2			
Firm Wheeling	$ (82,952,588)		86%
Utah SG Allocation	42.6283%		
Non-firm Wheeling	$ (13,596,926)		
Utah SE Allocation	41.9717%		

Rocky Mountain Power
Utah General Rate Case - June 2015
Settlement Stipulation
Exhibit A - Utah Allocated EBA Base (Step 1 Increase)

Exhibit A
Page 2 of 4

TOTAL COMPANY NET POWER COSTS

	FERC Acct	Total	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15
Sales for Resale														
Existing Firm PPL	447	$ 19,224,295	$ 2,597,755	$ 3,080,169	$ 2,853,989	$ 1,529,464	$ 1,168,230	$ 1,184,703	$ 1,170,997	$ 1,120,224	$ 1,181,705	$ 1,157,316	$ 1,132,828	$ 1,046,916
Existing Firm UPL	447	29,139,801	2,830,751	2,828,315	2,013,576	3,397,116	2,281,743	2,504,305	2,402,996	2,058,084	2,080,694	1,645,803	2,403,743	2,692,677
Post-Merger Firm	447	343,457,771	32,286,170	40,432,292	38,243,830	32,965,775	32,362,693	29,206,336	27,036,673	26,726,862	27,515,893	24,849,072	18,818,973	13,013,202
Non-Firm	447	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Sales for Resale		**391,821,867**	**37,714,675**	**46,340,776**	**43,111,394**	**37,892,354**	**35,812,666**	**32,895,344**	**30,610,666**	**29,905,170**	**30,778,291**	**27,652,191**	**22,355,544**	**16,752,795**
Purchased Power														
Existing Firm Demand PPL	555	$ 2,521,559	$ 132,420	$ 93,075	$ 75,411	$ 69,480	$ 62,437	$ 110,885	$ 259,947	$ 256,452	$ 304,359	$ 381,856	$ 407,969	$ 367,269
Existing Firm Demand UPL	555	52,652,282	4,911,035	4,819,934	3,903,154	5,092,622	4,205,955	4,463,422	4,461,302	4,011,275	4,183,816	3,206,869	4,456,906	4,935,993
Existing Firm Energy	555	26,048,264	1,928,490	1,770,832	1,674,305	1,590,784	1,662,672	1,865,603	2,367,883	2,309,189	2,570,909	2,626,324	2,909,227	2,772,046
Post-merger Firm	555	532,716,582	55,834,030	49,524,237	36,627,112	37,206,436	43,753,749	43,860,601	44,059,168	41,646,210	48,914,501	37,719,540	45,884,730	47,686,269
Secondary Purchases	555	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Purchased Power		**613,938,687**	**62,805,976**	**56,208,078**	**42,279,982**	**43,959,321**	**49,684,813**	**50,300,511**	**51,148,300**	**48,223,126**	**55,973,584**	**43,934,589**	**53,658,832**	**55,761,577**
Wheeling Expense														
Firm Wheeling (all)	565	$ 139,254,558	$ 12,032,669	$ 12,354,184	$ 10,856,230	$ 11,449,962	$ 11,689,354	$ 11,884,063	$ 11,576,577	$ 11,918,708	$ 11,548,573	$ 10,723,039	$ 11,368,922	$ 11,852,278
Non-firm Wheeling	565	8,165,410	778,232	488,560	635,633	342,500	628,712	764,351	883,168	562,943	987,705	1,057,076	366,719	669,810
Total Wheeling Expense		**147,419,968**	**12,810,901**	**12,842,744**	**11,491,863**	**11,792,462**	**12,318,066**	**12,648,413**	**12,459,745**	**12,481,651**	**12,536,278**	**11,780,115**	**11,735,641**	**12,522,089**
Fuel Expense														
Fuel Consumed - Coal	501	$ 785,358,188	$ 71,102,229	$ 73,414,902	$ 68,471,816	$ 67,791,793	$ 65,441,880	$ 69,689,487	$ 69,184,533	$ 63,383,675	$ 62,757,325	$ 59,364,706	$ 56,590,643	$ 58,165,200
Fuel Consumed - Coal (Cholla)	501	$ 57,861,242	$ 4,796,780	$ 5,456,121	$ 5,211,101	$ 5,080,140	$ 5,197,110	$ 5,171,234	$ 5,189,681	$ 4,787,676	$ 5,278,372	$ 3,311,743	$ 4,276,125	$ 4,105,159
Fuel Consumed - Gas	501	3,151,826	1,020,862	2,059,972	-	-	-	-	35,496	35,496	-	-	-	-
Natural Gas Consumed	547	272,521,946	28,349,602	40,349,517	33,598,595	26,181,707	21,133,638	21,984,943	18,305,882	18,165,511	18,954,765	23,634,117	12,854,497	9,009,170
Simple Cycle Combustion Turbines	547	3,584,981	589,474	860,705	520,898	423,084	217,729	164,751	35,496	35,496	197,549	283,562	109,012	147,223
Steam from Other Sources	503	3,749,908	312,402	312,491	312,089	332,557	331,692	342,635	342,683	309,514	342,683	311,126	197,699	302,336
Total Fuel Expense		**1,126,228,091**	**106,171,350**	**122,453,709**	**108,114,498**	**99,809,282**	**92,322,048**	**97,353,050**	**93,093,771**	**86,717,368**	**87,530,695**	**86,905,255**	**74,027,977**	**71,729,089**
ADJUSTED ACTUAL NET POWER COST		**$ 1,495,764,879**	**$ 144,073,551**	**$ 145,163,754**	**$ 118,774,949**	**$ 117,668,710**	**$ 118,512,261**	**$ 127,406,631**	**$ 126,091,151**	**$ 117,516,974**	**$ 125,262,265**	**$ 114,967,768**	**$ 117,066,906**	**$ 123,259,960**
check		-	-	-	-	-	-	-	-	-	-	-	-	-

Rocky Mountain Power
Utah General Rate Case - June 2015
Settlement Stipulation
Exhibit A - Utah Allocated EBA Base (Step 1 Increase)

Exhibit A
Page 3 of 4

COMMISSION ORDER METHOD - UTAH ALLOCATED NET POWER COSTS

	ALLOCATION	Total	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15
SE Allocator	SE		41.9717%	41.9717%	41.9717%	41.9717%	41.9717%	41.9717%	41.9717%	41.9717%	41.9717%	41.9717%	41.9717%	41.9717%
SG Allocator	SG		42.6283%	42.6283%	42.6283%	42.6283%	42.6283%	42.6283%	42.6283%	42.6283%	42.6283%	42.6283%	42.6283%	42.6283%
Sales for Resale														
Existing Firm PPL	SG	$ 8,194,993	$ 1,107,379	$ 1,313,024	$ 1,216,607	$ 651,985	$ 497,997	$ 505,019	$ 499,176	$ 477,533	$ 503,741	$ 493,344	$ 482,906	$ 446,283
Existing Firm UPL	SG	12,421,807	1,206,702	1,205,663	858,353	1,448,133	972,669	1,067,543	1,024,357	877,327	886,965	701,578	1,024,675	1,147,843
Post-Merger Firm	SG	146,410,268	13,763,051	17,235,606	16,302,701	14,052,755	13,795,671	12,450,170	11,525,279	11,393,212	11,729,562	10,592,741	8,022,212	5,547,309
Non-Firm	SE	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Sales for Resale		**167,027,068**	**16,077,131**	**19,754,293**	**18,377,662**	**16,152,873**	**15,266,337**	**14,022,731**	**13,048,812**	**12,748,071**	**13,120,268**	**11,787,664**	**9,529,792**	**7,141,434**
Purchased Power														
Existing Firm Demand PPL	SG	$ 1,074,898	$ 56,449	$ 39,676	$ 32,146	$ 29,618	$ 26,616	$ 47,268	$ 110,811	$ 109,321	$ 129,743	$ 162,779	$ 173,910	$ 156,561
Existing Firm Demand UPL	SG	22,444,782	2,093,492	2,054,657	1,663,849	2,170,899	1,792,928	1,902,682	1,901,778	1,709,939	1,783,490	1,367,034	1,899,904	2,104,131
Existing Firm Energy	SE	10,932,905	809,420	743,249	702,735	667,680	697,852	783,026	993,841	969,206	1,079,055	1,102,313	1,221,053	1,163,475
Post-merger Firm	SG	227,088,114	23,801,107	21,111,349	15,613,521	15,860,477	18,651,487	18,697,036	18,781,682	17,753,078	20,851,429	16,079,205	19,559,888	20,327,854
Secondary Purchases	SE	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Purchased Power		**261,540,699**	**26,760,468**	**23,948,930**	**18,012,251**	**18,728,674**	**21,168,883**	**21,430,012**	**21,788,112**	**20,541,545**	**23,843,716**	**18,711,332**	**22,854,755**	**23,752,021**
Wheeling Expense														
Firm Wheeling (all)	SG	$ 59,361,875	$ 5,129,325	$ 5,266,381	$ 4,627,828	$ 4,880,926	$ 4,982,975	$ 5,065,976	$ 4,934,900	$ 5,080,744	$ 4,922,962	$ 4,571,051	$ 4,846,380	$ 5,052,427
Non-firm Wheeling	SE	3,427,163	326,637	205,057	266,786	143,753	263,881	320,811	370,681	236,277	414,557	443,673	153,918	281,131
Total Wheeling Expense		**62,789,038**	**5,455,962**	**5,471,438**	**4,894,614**	**5,024,679**	**5,246,856**	**5,386,787**	**5,305,581**	**5,317,022**	**5,337,519**	**5,014,724**	**5,000,298**	**5,333,558**
Fuel Expense														
Fuel Consumed - Coal	SE	$ 329,628,360	$ 29,842,830	$ 30,813,499	$ 28,738,801	$ 28,453,383	$ 27,467,084	$ 29,249,878	$ 29,037,940	$ 26,603,220	$ 26,340,330	$ 24,916,390	$ 23,752,068	$ 24,412,936
Fuel Consumed - Coal (Cholla)	SE	$ 24,285,360	$ 2,013,291	$ 2,290,028	$ 2,187,189	$ 2,132,222	$ 2,181,317	$ 2,170,456	$ 2,178,199	$ 2,009,470	$ 2,215,424	$ 1,389,996	$ 1,794,763	$ 1,723,006
Fuel Consumed - Gas	SE	1,322,876	428,474	864,606	-	-	-	-	14,898	14,898	-	-	-	-
Natural Gas Consumed	SE	114,382,155	11,898,816	16,935,388	14,101,909	10,988,913	8,870,152	9,227,460	7,683,294	7,624,378	7,955,641	9,919,646	5,395,254	3,781,304
Simple Cycle Combustion Turbines	SE	1,504,678	247,413	361,253	218,630	177,576	91,385	69,149	14,898	14,898	82,915	119,016	45,754	61,792
Steam from Other Sources	SE	1,573,901	131,121	131,158	130,989	139,580	139,217	143,810	143,830	129,908	143,830	130,585	82,978	126,896
Total Fuel Expense		**472,697,331**	**44,561,944**	**51,395,931**	**45,377,517**	**41,891,675**	**38,749,154**	**40,860,752**	**39,073,059**	**36,396,773**	**36,738,140**	**36,475,633**	**31,070,817**	**30,105,934**
ADJUSTED ACTUAL NET POWER COST		**$ 630,000,000**	**$ 60,701,243**	**$ 61,062,006**	**$ 49,906,721**	**$ 49,492,155**	**$ 49,898,556**	**$ 53,654,820**	**$ 53,117,941**	**$ 49,507,269**	**$ 52,799,108**	**$ 48,414,025**	**$ 49,396,079**	**$ 52,050,078**

Rocky Mountain Power
Step 1 EBA Base Composite Allocator By Rate Schedule
State of Utah
2010 Protocol (Non Wgt)
12 Months Ended June 2015

FERC ACCT	DESCRIPTION	COS Factor	Utah Jurisdiction Normalized	Residential Sch 1	General Large Dist. Sch 6	General +1 MW Sch 8	Street & Area Lighting Sch. 7,11,12	General Trans Sch 9	Irrigation Sch 10	Traffic Signals Sch 15	Outdoor Lighting Sch 15	General Small Dist. Sch 23	Industrial Cust 1	Industrial Cust 2	
447	Sales for Resale														
	Demand	F10	167,027,068	55,569,690	45,502,424	15,145,334	312,079	31,151,219	1,210,480	38,549	68,827	11,621,267	3,275,937	3,131,261	-
456	Other Electric Revenue														
	Demand	F10	35,361,292	11,764,656	9,633,316	3,206,418	66,070	6,595,023	256,271	8,161	14,571	2,460,338	693,548	662,919	-
	Energy	F30	5,706,864	1,594,963	1,561,619	555,992	21,972	1,246,293	48,819	1,588	4,508	357,587	131,689	181,834	-
501	Fuel Related	F30	332,661,294	92,972,666	91,028,995	32,409,560	1,280,752	72,648,223	2,845,745	92,584	262,806	20,844,241	7,676,329	10,599,392	-
	Cholla	F30	22,575,302	6,309,379	6,177,476	2,199,401	86,915	4,930,107	193,120	6,283	17,835	1,414,547	520,937	719,304	-
503	Steam From Other Sources	F30	1,573,901	439,876	430,680	153,337	6,060	343,716	13,464	438	1,243	98,619	36,319	50,148	-
547	Fuel	F30	111,522,622	31,168,506	30,516,902	10,865,103	429,364	24,354,863	954,018	31,038	88,104	6,987,902	2,573,441	3,553,380	-
	Simple Cycle Combustion Turbine	F30	4,364,212	1,219,716	1,194,217	425,184	16,802	953,078	37,334	1,215	3,448	273,457	100,706	139,054	-
555	Purchased Power														
	Demand	F10	250,607,794	83,376,890	68,271,940	22,724,094	468,245	46,739,360	1,816,207	57,838	103,269	17,436,576	4,915,223	4,698,151	-
	Energy	F30	10,932,905	3,055,544	2,991,666	1,065,139	42,092	2,387,582	93,525	3,043	8,637	685,045	252,282	348,349	-
565	Transm of Electricity by Others	F10	59,361,875	19,749,619	16,171,685	5,382,693	110,914	11,071,228	430,208	13,700	24,461	4,130,230	1,164,277	1,112,859	-
	Energy	F30	3,427,163	957,829	937,804	333,892	13,195	748,441	29,318	954	2,707	214,743	79,084	109,198	-
	TOTAL NET POWER COSTS		588,931,843	170,320,716	161,024,008	56,650,659	2,054,217	125,184,063	4,897,368	158,796	424,604	37,646,169	13,217,424	17,353,820	-
	Class % of NPC		100.00%	28.92%	27.34%	9.62%	0.35%	21.26%	0.83%	0.03%	0.07%	6.39%	2.24%	2.95%	
	Demand Related	75%	80,685,981	26,844,122	21,980,915	7,316,276	150,757	15,048,259	584,748	18,622	33,249	5,613,901	1,582,511	1,512,622	-
			13.70%	15.76%	13.65%	12.91%	7.34%	12.02%	11.94%	11.73%	7.83%	14.91%	11.97%	8.72%	
	Energy Related		508,245,862	143,476,594	139,043,094	49,334,383	1,903,461	110,135,804	4,312,620	140,174	391,355	32,032,268	11,634,913	15,841,197	-
			86.30%	84.24%	86.35%	87.09%	92.66%	87.98%	88.06%	88.27%	92.17%	85.09%	88.03%	91.28%	
	TOTAL NET POWER COSTS		588,931,843	170,320,716	161,024,008	56,650,659	2,054,217	125,184,063	4,897,368	158,796	424,604	37,646,169	13,217,424	17,353,820	-

		Sch 1	Sch 6	Sch 8	Sch. 7,11,12	Sch 9	Sch 10	Sch 15	Sch 15	Sch 23	Cust 1	Cust 2	Total
F10	Coin Peak, Sys	0.33270	0.27243	0.09068	0.00187	0.18650	0.00725	0.00023	0.00041	0.06958	0.01961	0.01875	1.00000
F30	MWH @ Input	0.27948	0.27364	0.09743	0.00385	0.21838	0.00855	0.00028	0.00079	0.06266	0.02308	0.03186	1.00000

Exhibit B

Net Power Cost Calculation
Utah Allocation Based on Commission Approved Method

	Rebuttal Net Power Costs		Wheeling Revenues				
	Total Company	Utah	Total Company	Utah	Utah EBA Base	Utah Retail	Utah EBA
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Jul-2014	$ 143,682,575	$ 60,534,576	$ (8,045,793)	$ (3,422,346)	$ 57,112,230	2,191,141	$ 26.065
Aug-2014	144,772,778	60,895,340	(8,045,793)	(3,422,346)	57,472,993	2,157,502	26.639
Sep-2014	118,383,972	49,740,054	(8,045,793)	(3,422,346)	46,317,708	1,865,837	24.824
Oct-2014	117,277,734	49,325,488	(8,045,793)	(3,422,346)	45,903,142	1,829,381	25.092
Nov-2014	118,121,285	49,731,889	(8,045,793)	(3,422,346)	46,309,543	1,877,678	24.663
Dec-2014	127,015,654	53,488,153	(8,045,793)	(3,422,346)	50,065,807	2,013,529	24.865
Jan-2015	125,700,174	52,951,274	(8,045,793)	(3,422,346)	49,528,928	2,020,370	24.515
Feb-2015	117,125,998	49,340,602	(8,045,793)	(3,422,346)	45,918,256	1,829,854	25.094
Mar-2015	124,871,288	52,632,441	(8,045,793)	(3,422,346)	49,210,095	1,902,391	25.867
Apr-2015	114,576,791	48,247,358	(8,045,793)	(3,422,346)	44,825,011	1,832,113	24.466
May-2015	116,675,930	49,229,412	(8,045,793)	(3,422,346)	45,807,066	1,821,070	25.154
Jun-2015	122,868,983	51,883,412	(8,045,793)	(3,422,346)	48,461,065	1,903,419	25.460
Total	$ 1,491,073,162	$ 628,000,000	$ (96,549,514)	$ (41,068,157)	$ 586,931,843	23,244,285	$ 25.251
	[note 1]	[note 2]	[see detail below]		[(b) + (d)]	[note 3]	[(e) / (f)]

Footnotes: (1) See Exhibit B page 2 of 3
(2) See Exhibit B page 3 of 3
(3) Total per SRM-3, page 3.1.6; monthly per pricing backup.

Utah Allocated Wheeling Revenues

SRM-3 Page 3.2	
Firm Wheeling	$ (82,952,588)
Utah SG Allocation	42.6283%
Non-firm Wheeling	$ (13,596,926)
Utah SE Allocation	41.9717%

Rocky Mountain Power
Utah General Rate Case - June 2015
Settlement Stipulation
Exhibit B - Utah Allocated EBA Base (Step 2 Increase)

TOTAL COMPANY NET POWER COSTS

	FERC Acct	Total	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15
Sales for Resale														
Existing Firm PPL	447	$ 19,224,295	$ 2,597,755	$ 3,080,169	$ 2,853,989	$ 1,529,464	$ 1,168,230	$ 1,184,703	$ 1,170,997	$ 1,120,224	$ 1,181,705	$ 1,157,316	$ 1,132,828	$ 1,046,916
Existing Firm UPL	447	29,139,801	2,830,751	2,828,315	2,013,576	3,397,116	2,281,743	2,504,305	2,402,996	2,058,084	2,080,694	1,645,803	2,403,743	2,692,677
Post-Merger Firm	447	343,457,771	32,286,170	40,432,292	38,243,830	32,965,775	32,362,693	29,206,336	27,036,673	26,726,862	27,515,893	24,849,072	18,818,973	13,013,202
Non-Firm	447	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Sales for Resale		**391,821,867**	**37,714,675**	**46,340,776**	**43,111,394**	**37,892,354**	**35,812,666**	**32,895,344**	**30,610,666**	**29,905,170**	**30,778,291**	**27,652,191**	**22,355,544**	**16,752,795**
Purchased Power														
Existing Firm Demand PPL	555	$ 2,521,559	$ 132,420	$ 93,075	$ 75,411	$ 69,480	$ 62,437	$ 110,885	$ 259,947	$ 256,452	$ 304,359	$ 381,856	$ 407,969	$ 367,269
Existing Firm Demand UPL	555	52,652,282	4,911,035	4,819,934	3,903,154	5,092,622	4,205,955	4,463,422	4,461,302	4,011,275	4,183,816	3,206,869	4,456,906	4,935,993
Existing Firm Energy	555	26,048,264	1,928,490	1,770,832	1,674,305	1,590,784	1,662,672	1,865,603	2,367,883	2,309,189	2,570,909	2,626,324	2,909,227	2,772,046
Post-merger Firm	555	528,024,865	55,443,054	49,133,261	36,236,135	36,815,459	43,362,772	43,469,624	43,668,192	41,255,233	48,523,524	37,328,564	45,493,754	47,295,292
Secondary Purchases	555	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Purchased Power		**609,246,970**	**62,414,999**	**55,817,101**	**41,889,005**	**43,568,344**	**49,293,836**	**49,909,535**	**50,757,324**	**47,832,149**	**55,582,607**	**43,543,613**	**53,267,856**	**55,370,600**
Wheeling Expense														
Firm Wheeling (all)	565	$ 139,254,558	$ 12,032,669	$ 12,354,184	$ 10,856,230	$ 11,449,962	$ 11,689,354	$ 11,884,063	$ 11,576,577	$ 11,918,708	$ 11,548,573	$ 10,723,039	$ 11,368,922	$ 11,852,278
Non-firm Wheeling	565	8,165,410	778,232	488,560	635,633	342,500	628,712	764,351	883,168	562,943	987,705	1,057,076	366,719	669,810
Total Wheeling Expense		**147,419,968**	**12,810,901**	**12,842,744**	**11,491,863**	**11,792,462**	**12,318,066**	**12,648,413**	**12,459,745**	**12,481,651**	**12,536,278**	**11,780,115**	**11,735,641**	**12,522,089**
Fuel Expense														
Fuel Consumed - Coal	501	$ 785,358,188	$ 71,102,229	$ 73,414,902	$ 68,471,816	$ 67,791,793	$ 65,441,880	$ 69,689,487	$ 69,184,533	$ 63,383,675	$ 62,757,325	$ 59,364,706	$ 56,590,643	$ 58,165,200
Fuel Consumed - Coal (Cholla)	501	$ 57,861,242	$ 4,796,780	$ 5,456,121	$ 5,211,101	$ 5,080,140	$ 5,197,110	$ 5,171,234	$ 5,189,681	$ 4,787,676	$ 5,278,372	$ 3,311,743	$ 4,276,125	$ 4,105,159
Fuel Consumed - Gas	501	3,151,826	1,020,862	2,059,972	-	-	-	-	35,496	35,496	-	-	-	-
Natural Gas Consumed	547	272,521,946	28,349,602	40,349,517	33,598,595	26,181,707	21,133,638	21,984,943	18,305,882	18,165,511	18,954,765	23,634,117	12,854,497	9,009,170
Simple Cycle Combustion Turbines	547	3,584,981	589,474	860,705	520,898	423,084	217,729	164,751	35,496	35,496	197,549	283,562	109,012	147,223
Steam from Other Sources	503	3,749,908	312,402	312,491	312,089	332,557	331,692	342,635	342,683	309,514	342,683	311,126	197,699	302,336
Total Fuel Expense		**1,126,228,091**	**106,171,350**	**122,453,709**	**108,114,498**	**99,809,282**	**92,322,048**	**97,353,050**	**93,093,771**	**86,717,368**	**87,530,695**	**86,905,255**	**74,027,977**	**71,729,089**
ADJUSTED ACTUAL NET POWER COST		**$ 1,491,073,162**	**$ 143,682,575**	**$ 144,772,778**	**$ 118,383,972**	**$ 117,277,734**	**$ 118,121,285**	**$ 127,015,654**	**$ 125,700,174**	**$ 117,125,998**	**$ 124,871,288**	**$ 114,576,791**	**$ 116,675,930**	**$ 122,868,983**
check		-	-	-	-	-	-	-	-	-	-	-	-	-

COMMISSION ORDER METHOD - UTAH ALLOCATED NET POWER COSTS

	ALLOCATION	Total	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15
SE Allocator	SE		41.9717%	41.9717%	41.9717%	41.9717%	41.9717%	41.9717%	41.9717%	41.9717%	41.9717%	41.9717%	41.9717%	41.9717%
SG Allocator	SG		42.6283%	42.6283%	42.6283%	42.6283%	42.6283%	42.6283%	42.6283%	42.6283%	42.6283%	42.6283%	42.6283%	42.6283%
Sales for Resale														
Existing Firm PPL	SG	$ 8,194,993	$ 1,107,379	$ 1,313,024	$ 1,216,607	$ 651,985	$ 497,997	$ 505,019	$ 499,176	$ 477,533	$ 503,741	$ 493,344	$ 482,906	$ 446,283
Existing Firm UPL	SG	12,421,807	1,206,702	1,205,663	858,353	1,448,133	972,669	1,067,543	1,024,357	877,327	886,965	701,578	1,024,675	1,147,843
Post-Merger Firm	SG	146,410,268	13,763,051	17,235,606	16,302,701	14,052,755	13,795,671	12,450,170	11,525,279	11,393,212	11,729,562	10,592,741	8,022,212	5,547,309
Non-Firm	SE	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Sales for Resale		**167,027,068**	**16,077,131**	**19,754,293**	**18,377,662**	**16,152,873**	**15,266,337**	**14,022,731**	**13,048,812**	**12,748,071**	**13,120,268**	**11,787,664**	**9,529,792**	**7,141,434**
Purchased Power														
Existing Firm Demand PPL	SG	$ 1,074,898	$ 56,449	$ 39,676	$ 32,146	$ 29,618	$ 26,616	$ 47,268	$ 110,811	$ 109,321	$ 129,743	$ 162,779	$ 173,910	$ 156,561
Existing Firm Demand UPL	SG	22,444,782	2,093,492	2,054,657	1,663,849	2,170,899	1,792,928	1,902,682	1,901,778	1,709,939	1,783,490	1,367,034	1,899,904	2,104,131
Existing Firm Energy	SE	10,932,905	809,420	743,249	702,735	667,680	697,852	783,026	993,841	969,206	1,079,055	1,102,313	1,221,053	1,163,475
Post-merger Firm	SG	225,088,114	23,634,441	20,944,682	15,446,855	15,693,811	18,484,820	18,530,369	18,615,015	17,586,412	20,684,762	15,912,539	19,393,222	20,161,187
Secondary Purchases	SE	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Purchased Power		**259,540,699**	**26,593,802**	**23,782,264**	**17,845,585**	**18,562,007**	**21,002,216**	**21,263,345**	**21,621,445**	**20,374,878**	**23,677,050**	**18,544,665**	**22,688,089**	**23,585,354**
Wheeling Expense														
Firm Wheeling (all)	SG	$ 59,361,875	$ 5,129,325	$ 5,266,381	$ 4,627,828	$ 4,880,926	$ 4,982,975	$ 5,065,976	$ 4,934,900	$ 5,080,744	$ 4,922,962	$ 4,571,051	$ 4,846,380	$ 5,052,427
Non-firm Wheeling	SE	3,427,163	326,637	205,057	266,786	143,753	263,881	320,811	370,681	236,277	414,557	443,673	153,918	281,131
Total Wheeling Expense		**62,789,038**	**5,455,962**	**5,471,438**	**4,894,614**	**5,024,679**	**5,246,856**	**5,386,787**	**5,305,581**	**5,317,022**	**5,337,519**	**5,014,724**	**5,000,298**	**5,333,558**
Fuel Expense														
Fuel Consumed - Coal	SE	$ 329,628,360	$ 29,842,830	$ 30,813,499	$ 28,738,801	$ 28,453,383	$ 27,467,084	$ 29,249,878	$ 29,037,940	$ 26,603,220	$ 26,340,330	$ 24,916,390	$ 23,752,068	$ 24,412,936
Fuel Consumed - Coal (Cholla)	SE	$ 24,285,360	$ 2,013,291	$ 2,290,028	$ 2,187,189	$ 2,132,222	$ 2,181,317	$ 2,170,456	$ 2,178,199	$ 2,009,470	$ 2,215,424	$ 1,389,996	$ 1,794,763	$ 1,723,006
Fuel Consumed - Gas	SE	1,322,876	428,474	864,606	-	-	-	-	14,898	14,898	-	-	-	-
Natural Gas Consumed	SE	114,382,155	11,898,816	16,935,388	14,101,909	10,988,913	8,870,152	9,227,460	7,683,294	7,624,378	7,955,641	9,919,646	5,395,254	3,781,304
Simple Cycle Combustion Turbines	SE	1,504,678	247,413	361,253	218,630	177,576	91,385	69,149	14,898	14,898	82,915	119,016	45,754	61,792
Steam from Other Sources	SE	1,573,901	131,121	131,158	130,989	139,580	139,217	143,810	143,830	129,908	143,830	130,585	82,978	126,896
Total Fuel Expense		**472,697,331**	**44,561,944**	**51,395,931**	**45,377,517**	**41,891,675**	**38,749,154**	**40,860,752**	**39,073,059**	**36,396,773**	**36,738,140**	**36,475,633**	**31,070,817**	**30,105,934**
ADJUSTED ACTUAL NET POWER COST		**$ 628,000,000**	**$ 60,534,576**	**$ 60,895,340**	**$ 49,740,054**	**$ 49,325,488**	**$ 49,731,889**	**$ 53,488,153**	**$ 52,951,274**	**$ 49,340,602**	**$ 52,632,441**	**$ 48,247,358**	**$ 49,229,412**	**$ 51,883,412**

Rocky Mountain Power
Step 2 EBA Base Composite Allocator By Rate Schedule
State of Utah
2010 Protocol (Non Wgt)
12 Months Ended June 2015

FERC ACCT	DESCRIPTION	COS Factor	Utah Jurisdiction Normalized	Residential Sch 1	General Large Dist. Sch 6	General +1 MW Sch 8	Street & Area Lighting Sch. 7,11,12	General Trans Sch 9	Irrigation Sch 10	Traffic Signals Sch 15	Outdoor Lighting Sch 15	General Small Dist. Sch 23	Industrial Cust 1	Industrial Cust 2	
447	Sales for Resale														
	Demand	F10	167,027,068	55,569,690	45,502,424	15,145,334	312,079	31,151,219	1,210,480	38,549	68,827	11,621,267	3,275,937	3,131,261	-
456	Other Electric Revenue														
	Demand	F10	35,361,292	11,764,656	9,633,316	3,206,418	66,070	6,595,023	256,271	8,161	14,571	2,460,338	693,548	662,919	-
	Energy	F30	5,706,864	1,594,963	1,561,619	555,992	21,972	1,246,293	48,819	1,588	4,508	357,587	131,689	181,834	-
501	Fuel Related	F30	332,661,294	92,972,666	91,028,995	32,409,560	1,280,752	72,648,223	2,845,745	92,584	262,806	20,844,241	7,676,329	10,599,392	-
	Cholla	F30	22,575,302	6,309,379	6,177,476	2,199,401	86,915	4,930,107	193,120	6,283	17,835	1,414,547	520,937	719,304	-
503	Steam From Other Sources	F30	1,573,901	439,876	430,680	153,337	6,060	343,716	13,464	438	1,243	98,619	36,319	50,148	-
547	Fuel	F30	111,522,622	31,168,506	30,516,902	10,865,103	429,364	24,354,863	954,018	31,038	88,104	6,987,902	2,573,441	3,553,380	-
	Simple Cycle Combustion Turbine	F30	4,364,212	1,219,716	1,194,217	425,184	16,802	953,078	37,334	1,215	3,448	273,457	100,706	139,054	-
555	Purchased Power														
	Demand	F10	248,607,794	82,711,493	67,727,090	22,542,743	464,508	46,366,352	1,801,713	57,377	102,445	17,297,421	4,875,997	4,660,657	-
	Energy	F30	10,932,905	3,055,544	2,991,666	1,065,139	42,092	2,387,582	93,525	3,043	8,637	685,045	252,282	348,349	-
565	Transm of Electricity by Others	F10	59,361,875	19,749,619	16,171,685	5,382,693	110,914	11,071,228	430,208	13,700	24,461	4,130,230	1,164,277	1,112,859	-
	Energy	F30	3,427,163	957,829	937,804	333,892	13,195	748,441	29,318	954	2,707	214,743	79,084	109,198	-
	TOTAL NET POWER COSTS		586,931,843	169,655,318	160,479,157	56,469,307	2,050,480	124,811,055	4,882,874	158,334	423,780	37,507,015	13,178,198	17,316,325	-
	Class % of NPC		100.00%	28.91%	27.34%	9.62%	0.35%	21.26%	0.83%	0.03%	0.07%	6.39%	2.25%	2.95%	
	Demand Related	75%	79,185,981	26,345,074	21,572,276	7,180,262	147,954	14,768,503	573,877	18,276	32,630	5,509,535	1,553,091	1,484,502	-
			13.49%	15.53%	13.44%	12.72%	7.22%	11.83%	11.75%	11.54%	7.70%	14.69%	11.79%	8.57%	
	Energy Related		507,745,862	143,310,244	138,906,881	49,289,045	1,902,526	110,042,552	4,308,997	140,059	391,149	31,997,480	11,625,106	15,831,824	-
			86.51%	84.47%	86.56%	87.28%	92.78%	88.17%	88.25%	88.46%	92.30%	85.31%	88.21%	91.43%	
	TOTAL NET POWER COSTS		586,931,843	169,655,318	160,479,157	56,469,307	2,050,480	124,811,055	4,882,874	158,334	423,780	37,507,015	13,178,198	17,316,325	-

		Sch 1	Sch 6	Sch 8	Sch. 7,11,12	Sch 9	Sch 10	Sch 15	Sch 15	Sch 23	Cust 1	Cust 2	Total
F10	Coin Peak, Sys	0.33270	0.27243	0.09068	0.00187	0.18650	0.00725	0.00023	0.00041	0.06958	0.01961	0.01875	1.00000
F30	MWH @ Input	0.27948	0.27364	0.09743	0.00385	0.21838	0.00855	0.00028	0.00079	0.06266	0.02308	0.03186	1.00000

Exhibit C

Price Summary
Rocky Mountain Power - State of Utah

	Present Price	Step 1 - 9/1/2014 Price	Step 2 - 9/1/2015 Price
Schedule No. 6 - Composite			
Customer Charge	$54.00	$54.00	$54.00
All kW (May - Sept)	$18.12		
All kW (Oct - Apr)	$14.54		
Voltage Discount	($0.93)	($0.94)	($0.96)
Facilities kW		$4.04	$4.04
All kW (May - Sept)		$14.27	$14.62
All kW (Oct - Apr)		$10.65	$10.91
All kWh			
kWh (May - Sept)	3.8127 ¢	3.8127 ¢	3.8127 ¢
kWh (Oct - Apr)	3.5143 ¢	3.5143 ¢	3.5143 ¢
Seasonal Service	$648.00	$648.00	$648.00
Schedule No. 6B - Demand Time-of-Day Option - Composite			
Customer Charge	$54.00	$54.00	$54.00
All On-peak kW (May - Sept)	$18.12		
All On-peak kW (Oct - Apr)	$14.54		
Voltage Discount	($0.93)	($0.94)	($0.96)
Facilities kW		$4.04	$4.04
All On-peak kW (May - Sept)		$14.27	$14.62
All On-peak kW (Oct - Apr)		$10.65	$10.91
All kWh			
kWh (May-Sept)	3.8127 ¢	3.8127 ¢	3.8127 ¢
kWh (Oct-Apr)	3.5143 ¢	3.5143 ¢	3.5143 ¢
Seasonal Service	$648.00	$648.00	$648.00
Schedule No. 6A - Energy Time-of-Day Option - Composite			
Customer Charge	$54.00	$54.00	$54.00
Facilities kW (May - Sept)	$6.41	$6.45	$6.52
Facilities kW (Oct - Apr)	$5.38	$5.41	$5.47
Voltage Discount	($0.60)	($0.60)	($0.61)
On-Peak kWh (May - Sept)	11.7307 ¢	11.7997 ¢	11.9266 ¢
Off-Peak kWh (May - Sept)	3.5318 ¢	3.5526 ¢	3.5908 ¢
On-Peak kWh (Oct - Apr)	9.8056 ¢	9.8633 ¢	9.9693 ¢
Off-Peak kWh (Oct - Apr)	2.9603 ¢	2.9770 ¢	3.0060 ¢
Schedule No. 7 - Security Area Lighting - Composite			
MERCURY VAPOR LAMPS			
4,000 Lumen Energy Only	$5.68	$5.68	$5.68
7,000 Lumen	$16.38	$16.38	$16.38
7,000 Lumen Energy Only	$8.05	$8.05	$8.05
20,000 Lumen	$26.78	$26.78	$26.78
SODIUM VAPOR LAMPS			
5,600 Lumen New Pole	$14.60	$14.60	$14.60
5,600 Lumen No New Pole	$12.23	$12.23	$12.23
9,500 Lumen New Pole	$15.47	$15.47	$15.47

Price Summary
Rocky Mountain Power - State of Utah

	Present Price	Step 1 - 9/1/2014 Price	Step 2 - 9/1/2015 Price
9,500 Lumen No New Pole	$13.31	$13.31	$13.31
16,000 Lumen New Pole	$19.46	$19.46	$19.46
16,000 Lumen No New Pole	$17.13	$17.13	$17.13
22,000 Lumen	$21.07	$21.07	$21.07
27,500 Lumen New Pole	$23.51	$23.51	$23.51
27,500 Lumen No New Pole	$21.23	$21.23	$21.23
50,000 Lumen New Pole	$28.30	$28.30	$28.30
50,000 Lumen No New Pole	$25.99	$25.99	$25.99
SODIUM VAPOR FLOOD LAMPS			
16,000 Lumen New Pole	$19.46	$19.46	$19.46
16,000 Lumen No New Pole	$17.13	$17.13	$17.13
27,500 Lumen New Pole	$23.51	$23.51	$23.51
27,500 Lumen No New Pole	$21.23	$21.23	$21.23
50,000 Lumen New Pole	$28.30	$28.30	$28.30
50,000 Lumen No New Pole	$25.99	$25.99	$25.99
METAL HALIDE LAMPS			
12,000 Lumen New Pole	$29.40	$29.40	$29.40
12,000 Lumen No New Pole	$21.79	$21.79	$21.79
19,500 Lumen New Pole	$34.34	$34.34	$34.34
19,500 Lumen No New Pole	$27.43	$27.43	$27.43
32,000 Lumen New Pole	$36.69	$36.69	$36.69
32,000 Lumen No New Pole	$29.72	$29.72	$29.72
107,000 Lumen New Pole	$57.58	$57.58	$57.58
107,000 Lumen No New Pole	$49.10	$49.10	$49.10
Schedule No. 8 - Composite			
Customer Charge	$68.00	$69.00	$70.00
Facilities kW	$4.62	$4.71	$4.76
On-Peak kW (May - Sept)	$15.10	$15.40	$15.56
On-Peak kW (Oct - Apr)	$10.87	$11.08	$11.19
Voltage Discount	($1.10)	($1.12)	($1.13)
On-Peak kWh (May - Sept)	4.8999 ¢	4.9961 ¢	5.0474 ¢
On-Peak kWh (Oct - Apr)	3.8356 ¢	3.9109 ¢	3.9511 ¢
Off-Peak kWh	3.3019 ¢	3.3641 ¢	3.4002 ¢
Schedule No. 9 - Composite			
Customer Charge	$247.00	$255.00	$259.00
Facilities kW	$2.12	$2.19	$2.22
On-Peak kW (May - Sept)	$13.32	$13.75	$13.96
On-Peak kW (Oct - Apr)	$9.03	$9.32	$9.47
On-Peak kWh (May-Sept)	4.4379 ¢	4.5818 ¢	4.6531 ¢
On-Peak kWh (Oct-Apr)	3.3371 ¢	3.4453 ¢	3.4989 ¢
Off-Peak kWh	2.7873 ¢	2.8777 ¢	2.9225 ¢
Schedule No. 9A - Energy TOD - Composite			
Customer Charge	$247.00	$255.00	$259.00

Price Summary
Rocky Mountain Power - State of Utah

	Present Price	Step 1 - 9/1/2014 Price	Step 2 - 9/1/2015 Price
Facilities Charge per kW	$2.12	$2.19	$2.22
On-Peak kWh	8.2002 ¢	8.4770 ¢	8.6029 ¢
Off-Peak kWh	3.5251 ¢	3.6440 ¢	3.6981 ¢
Schedule No. 10 - Irrigation			
Annual Cust. Serv. Chg. - Primary	$121.00	$124.00	$125.00
Annual Cust. Serv. Chg. - Secondary	$37.00	$38.00	$38.00
Monthly Cust. Serv. Chg.	$14.00	$14.00	$14.00
All On-Season kW	$7.04	$7.25	$7.33
Voltage Discount	($1.97)	($2.03)	($2.05)
First 30,000 kWh	7.0156 ¢	7.2207 ¢	7.2971 ¢
All add'l kWh	5.1855 ¢	5.3371 ¢	5.3936 ¢
Post Season			
Customer Charge	$14.00	$14.00	$14.00
kWh	4.8055 ¢	4.9460 ¢	4.9983 ¢
Schedule No. 10-TOD			
Annual Cust. Serv. Chg. - Primary	$121.00	$124.00	$125.00
Annual Cust. Serv. Chg. - Secondary	$37.00	$38.00	$38.00
Monthly Cust. Serv. Chg.	$14.00	$14.00	$14.00
All On-Season kW	$7.04	$7.25	$7.33
Voltage Discount kW	($1.97)	($2.03)	($2.05)
On-Peak kWh	13.8603 ¢	14.2655 ¢	14.4164 ¢
Off-Peak kWh	4.0252 ¢	4.1252 ¢	4.1542 ¢
Post Season			
Customer Charge	$14.00	$14.00	$14.00
kWh	4.8055 ¢	4.9460 ¢	4.9983 ¢
Schedule No. 11 - Street Lighting - Company-Owned System			
Sodium Vapor Lamps (HPS)			
5,600 Lumen - Functional	$11.80	$11.80	$11.80
9,500 Lumen - Functional	$12.78	$12.78	$12.78
9,500 Lumen - Functional @ 90%	$11.50	$11.50	$11.50
9,500 Lumen - S1	$46.54	$46.54	$46.54
9,500 Lumen - S2	$38.05	$38.05	$38.05
16,000 Lumen - Functional	$16.94	$16.94	$16.94
16,000 Lumen - Functional @ 90%	$15.25	$15.25	$15.25
16,000 Lumen - S1	$47.83	$47.83	$47.83
16,000 Lumen - S2	$39.34	$39.34	$39.34
27,500 Lumen - Functional	$21.14	$21.14	$21.14
27,500 Lumen - Functional @ 90%	$19.03	$19.03	$19.03
27,500 Lumen - S1	$51.48	$51.48	$51.48
27,500 Lumen - S2	$43.01	$43.01	$43.01
50,000 Lumen - Functional	$26.02	$26.02	$26.02
125,000 Lumen	$51.54	$51.54	$51.54
Metal Halide Lamps (MH)			

Price Summary

Rocky Mountain Power - State of Utah

	Present Price	Step 1 - 9/1/2014 Price	Step 2 - 9/1/2015 Price
9,000 Lumen - S1	$48.74	$48.74	$48.74
9,000 Lumen - S2	$40.27	$40.27	$40.27
12,000 Lumen - Functional	$20.13	$20.13	$20.13
12,000 Lumen - S1	$50.65	$50.65	$50.65
12,000 Lumen - S2	$42.17	$42.17	$42.17
19,500 Lumen - Functional	$22.13	$22.13	$22.13
19,500 Lumen - S1	$53.69	$53.69	$53.69
19,500 Lumen - S2	$45.20	$45.20	$45.20
32,000 Lumen - Functional	$25.78	$25.78	$25.78
32,000 Lumen - S1	$55.33	$55.33	$55.33
32,000 Lumen - S2	$46.86	$46.86	$46.86
Mercury Vapor Lamps (No New Service) (MV)			
4,000 Lumen	$11.09	$11.09	$11.09
7,000 Lumen	$13.83	$13.83	$13.83
10,000 Lumen	$19.40	$19.40	$19.40
10,000 Lumen @ 90%	$17.46	$17.46	$17.46
20,000 Lumen	$24.43	$24.43	$24.43
Incandescent Lamps (No New Service) (INC)			
500 Lumen	$11.99	$11.99	$11.99
600 Lumen	$4.24	$4.24	$4.24
2,500 Lumen	$17.11	$17.11	$17.11
4,000 Lumen	$20.43	$20.43	$20.43
6,000 Lumen	$23.82	$23.82	$23.82
10,000 Lumen	$31.47	$31.47	$31.47
Fluorescent Lamps (No New Service) (FLOUR)			
21,000 Lumen	$27.85	$27.85	$27.85
Special Service (No New Service)			
50,000 Lumen - Flood	$39.04	$39.04	$39.04
Schedule No. 12 - Street Lighting - Customer-Owned System			
1. Energy Only, No Maintenance			
High Pressures Sodium Vapor Lamps			
5,600 Lumen	$1.83	$1.83	$1.83
9,500 Lumen	$2.50	$2.50	$2.50
16,000 Lumen	$3.66	$3.66	$3.66
27,500 Lumen	$6.52	$6.52	$6.52
50,000 Lumen	$10.02	$10.02	$10.02
Metal Halide Lamps			
9,000 Lumen	$2.55	$2.55	$2.55
12,000 Lumen	$4.46	$4.46	$4.46
19,500 Lumen	$6.17	$6.17	$6.17
32,000 Lumen	$9.77	$9.77	$9.77
Non-listed Luminaries kWh	6.5279 ¢	6.5279 ¢	6.5279 ¢
2a - Partial Maintenance (No New Service)			
Incandescent Lamps			
2,500 Lumen or Less	$8.96	$8.96	$8.96

Price Summary
Rocky Mountain Power - State of Utah

	Present Price	Step 1 - 9/1/2014 Price	Step 2 - 9/1/2015 Price
4,000 Lumen	$12.19	$12.19	$12.19
Mercury Vapor Lamps			
4,000 Lumen	$4.64	$4.64	$4.64
7,000 Lumen	$7.00	$7.00	$7.00
20,000 Lumen	$13.33	$13.33	$13.33
54,000 Lumen	$28.38	$28.38	$28.38
High Pressure Sodium Vapor Lamps			
5,600 Lumen	$4.08	$4.08	$4.08
9,500 Lumen	$5.37	$5.37	$5.37
9,500 Lumen - Decorative	$6.96	$6.96	$6.96
16,000 Lumen	$6.52	$6.52	$6.52
16,000 Lumen - Decorative	$8.27	$8.27	$8.27
22,000 Lumen	$8.26	$8.26	$8.26
27,500 Lumen	$9.59	$9.59	$9.59
27,500 Lumen - Decorative	$11.93	$11.93	$11.93
50,000 Lumen	$14.00	$14.00	$14.00
50,000 Lumen - Decorative	$15.56	$15.56	$15.56
Metal Halide Lamps			
9,000 Lumen - Decorative	$9.19	$9.19	$9.19
12,000 Lumen	$13.57	$13.57	$13.57
12,000 Lumen - Decorative	$11.09	$11.09	$11.09
19,500 Lumen	$13.71	$13.71	$13.71
19,500 Lumen - Decorative	$14.13	$14.13	$14.13
32,000 Lumen	$14.58	$14.58	$14.58
32,000 Lumen - Decorative	$15.79	$15.79	$15.79
Fluorescent Lamps			
1,000 Lumen	$3.75	$3.75	$3.75
21,800 Lumen	$13.92	$13.92	$13.92
2b - Full Maintenance (No New Service)			
Incandescent Lamps			
6,000 Lumen	$17.73	$17.73	$17.73
10,000 Lumen	$23.40	$23.40	$23.40
Mercury Vapor Lamps			
7,000 Lumen	$8.03	$8.03	$8.03
20,000 Lumen	$15.30	$15.30	$15.30
54,000 Lumen	$32.48	$32.48	$32.48
Sodium Vapor Lamps			
5,600 Lumen	$4.68	$4.68	$4.68
9,500 Lumen	$6.16	$6.16	$6.16
16,000 Lumen	$7.47	$7.47	$7.47
22,000 Lumen	$9.44	$9.44	$9.44
27,500 Lumen	$10.99	$10.99	$10.99
50,000 Lumen	$16.02	$16.02	$16.02
Metal Halide Lamps			
12,000 Lumen	$15.58	$15.58	$15.58
19,500 Lumen	$15.73	$15.73	$15.73

Price Summary
Rocky Mountain Power - State of Utah

	Present Price	Step 1 - 9/1/2014 Price	Step 2 - 9/1/2015 Price
32,000 Lumen	$16.72	$16.72	$16.72
107,000 Lumen	$33.05	$33.05	$33.05
Schedule 15.1 - Metered Outdoor Nighttime Lighting - Composite			
Annual Facility Charge	$11.00	$11.00	$11.00
Annual Customer Charge	$72.50	$72.50	$72.50
Annual Minimum Charge	$127.50	$127.50	$127.50
Monthly Customer Charge	$6.20	$6.20	$6.20
All kWh	5.3437 ¢	5.3437 ¢	5.3437 ¢
Schedule 15.2 - Traffic Signal Systems - Composite			
Customer Charge	$5.50	$5.50	$5.50
All kWh	8.4049 ¢	8.4049 ¢	8.4049 ¢
Schedule No. 21 - Electric Furnace Operations - Limited Service - Industrial			
Primary Voltage			
Customer Charge	$121.00	$125.00	$127.00
Charge per kW (Facilities)	$4.10	$4.24	$4.30
First 100,000 kWh	6.5264 ¢	6.7459 ¢	6.8447 ¢
All add'l kWh	5.4799 ¢	5.6642 ¢	5.7472 ¢
44KV or Higher			
Customer Charge	$121.00	$125.00	$127.00
Charge per kW (Facilities)	$4.10	$4.24	$4.30
First 100,000 kWh	5.1346 ¢	5.3073 ¢	5.3851 ¢
All add'l kWh	4.4977 ¢	4.6361 ¢	4.7169 ¢
Schedule No. 23 - Composite			
Customer Charge	$10.00	$10.00	$10.00
kW over 15 (May - Sept)	$8.55	$8.65	$8.65
kW over 15 (Oct - Apr)	$8.60	$8.70	$8.70
Voltage Discount	($0.48)	($0.48)	($0.48)
First 1,500 kWh (May - Sept)	11.6096 ¢	11.7300 ¢	11.7336 ¢
All Add'l kWh (May - Sept)	6.5088 ¢	6.5763 ¢	6.5783 ¢
First 1,500 kWh (Oct - Apr)	10.6859 ¢	10.7967 ¢	10.8000 ¢
All Add'l kWh (Oct - Apr)	5.9947 ¢	6.0524 ¢	6.0567 ¢
Seasonal Service	$120.00	$120.00	$120.00
Schedule No.31 - Composite			
Secondary Voltage			
Customer Charge per month	$127.00	$131.00	$133.00
Facilities Charge, per kW month	$4.66	$5.52	$5.60
Back-up Power Charge			
Regular, per On-Peak kW day	$0.6419		
May - Sept		$0.87	$0.88
Oct - Apr		$0.61	$0.62
Maintenance, per On-Peak kW day	$0.3210		

Price Summary
Rocky Mountain Power - State of Utah

	Present Price	Step 1 - 9/1/2014 Price	Step 2 - 9/1/2015 Price
May - Sept		$0.435	$0.440
Oct - Apr		$0.305	$0.310
Excess Power, per kW month	$60.48		
May - Sept		$40.22	$40.81
Oct - Apr		$31.58	$32.04
Primary Voltage			
Customer Charge per month	$577.00	$596.00	$605.00
Facilities Charge, per kW month	$3.66	$4.40	$4.46
Back-up Power Charge			
Regular, per On-Peak kW day	$0.6248		
May - Sept		$0.85	$0.86
Oct - Apr		$0.59	$0.60
Maintenance, per On-Peak kW day	$0.3124		
May - Sept		$0.425	$0.430
Oct - Apr		$0.295	$0.300
Excess Power, per kW month	$43.59		
May - Sept		$37.98	$38.54
Oct - Apr		$29.34	$29.77
Transmission Voltage			
Customer Charge per month	$646.00	$668.00	$678.00
Facilities Charge, per kW month	$2.08	$2.59	$2.63
Back-up Power Charge			
Regular, per On-Peak kW day	$0.4906		
May - Sept		$0.75	$0.76
Oct - Apr		$0.50	$0.51
Maintenance, per On-Peak kW day	$0.2453		
May - Sept		$0.375	$0.380
Oct - Apr		$0.250	$0.255
Excess Power, per kW month	$41.97		
May - Sept		$31.88	$32.35
Oct - Apr		$23.02	$23.36
Lighting Contract - Post Top Lighting - Composite			
Energy Only Res	$2.18	$2.18	$2.18
Energy Only Non-Res	$2.1858	$2.1858	$2.1858

Rocky Mountain Power
Estimated Effect of Proposed Changes
on Revenues from Electric Sales to Ultimate Consumers in Utah
Base Period 12 Months Ending June 2013
Forecast Test Period 12 Months Ending June 2015

Line No.	Description	Sch No.	Present Revenues ($000)	Step 1 Increase 9/1/2014 ($000)	Step 1 Increase 9/1/2014 (%)	Step 2 Increase 9/1/2015 ($000)	Step 2 Increase 9/1/2015 (%)
	Residential						
1	Residential	1,3	$661,257	$16,282	2.46%	$6,968	1.03%
2	Residential-Optional TOD	2	$338	$8	2.46%	$4	1.03%
3	AGA/Revenue Credit	--	$33	$0	0.00%	$0	0.00%
4	**Total Residential**		$661,628	$16,291	2.46%	$6,971	1.03%
	Commercial & Industrial & OSPA						
5	General Service-Distribution	6	$486,921	$2,738	0.56%	$5,036	1.03%
6	General Service-Distribution-Energy TOD	6A	$33,690	$189	0.56%	$348	1.03%
7	General Service-Distribution-Demand TOD	6B	$341	$2	0.56%	$4	1.03%
8	*Subtotal Schedule 6*		$520,951	$2,930	0.56%	$5,388	1.03%
9	General Service-Distribution > 1,000 kW	8	$162,435	$3,188	1.96%	$1,703	1.03%
10	General Service-High Voltage	9	$271,735	$9,137	3.36%	$4,116	1.47%
11	General Service-High Voltage-Energy TOD	9A	$3,139	$106	3.36%	$48	1.47%
12	*Subtotal Schedule 9*		$274,874	$9,242	3.36%	$4,164	1.47%
13	Irrigation	10	$12,709	$364	2.86%	$134	1.03%
14	Irrigation-Time of Day	10TOD	$1,239	$35	2.86%	$13	1.03%
15	*Subtotal Irrigation*		$13,949	$399	2.86%	$148	1.03%
16	Electric Furnace	21	$454	$15	3.36%	$7	1.47%
17	General Service-Distribution-Small	23	$137,739	$1,326	0.96%	$39	0.03%
18	Back-up, Maintenance, & Supplementary	31	$4,219	$142	3.36%	$66	1.47%
19	Contract 1	--	$27,177	$505	1.86%	$277	1.00%
20	Contract 2	--	$35,063	$0	0.00%	$0	0.00%
21	Contract 3	--	$28,645	$963	3.36%	$437	1.47%
22	AGA/Revenue Credit	--	$2,928	$0	0.00%	$0	0.00%
23	**Total Commercial & Industrial & OSPA**		$1,208,434	$18,709	1.55%	$12,229	1.00%
24	**(excluding Contracts 2, AGA)**		$1,170,443	$18,709	1.60%	$12,229	1.03%
	Public Street Lighting						
25	Security Area Lighting	7	$2,999	$0	0.00%	$0	0.00%
26	Street Lighting - Company Owned	11	$4,979	$0	0.00%	$0	0.00%
27	Street Lighting - Customer Owned	12	$4,145	$0	0.00%	$0	0.00%
28	Traffic Signal Systems	15	$682	$0	0.00%	$0	0.00%
29	Metered Outdoor Lighting	15	$1,235	$0	0.00%	$0	0.00%
30	*Subtotal Public Street Lighting*		$14,040	$0	0.00%	$0	0.00%
31	Security Area Lighting-Contracts (PTL)	--	$1	$0	0.00%	$0	0.00%
32	AGA/Revenue Credit	--	$5	$0	0.00%	$0	0.00%
33	**Total Public Street Lighting**		$14,045	$0	0.00%	$0	0.00%
34	**Total Sales to Ultimate Customers**		$1,884,107	$35,000	1.86%	$19,200	1.00%
35	**(excluding Contract 2, AGA)**		$1,846,079	$35,000	1.90%	$19,200	1.02%

Rocky Mountain Power - State of Utah
Blocking Based on Adjusted Actuals and Forecasted Loads
Base Period 12 Months Ending June 2013
Forecast Test Period 12 Months Ending June 2015

		Forecasted Units	Present Price	Forecasted Revenue Dollars	Step 1 - 9/1/2014 Price	Step 1 - 9/1/2014 Revenue Dollars
Schedule No. 6 - Composite						
Customer Charge		156,864	$54.00	$8,470,675	$54.00	$8,470,675
All kW (May - Sept)		7,568,683	$18.12	$137,144,536		
All kW (Oct - Apr)		9,009,450	$14.54	$130,997,403		
Voltage Discount		679,134	($0.93)	($631,595)	($0.94)	($638,386)
Facilities kW		16,578,133			$4.04	$66,975,657
All kW (May - Sept)		7,568,683			$14.27	$108,005,106
All kW (Oct - Apr)		9,009,450			$10.65	$95,950,643
All kWh		5,783,806,261				
kWh (May - Sept)		2,573,577,152	3.8127 ¢	$98,122,776	3.8127 ¢	$98,122,776
kWh (Oct - Apr)		3,210,229,109	3.5143 ¢	$112,817,082	3.5143 ¢	$112,817,082
Seasonal Service		0	$648.00	$0	$648.00	$0
Unbilled		0		$0		$0
Total		5,783,806,261		$486,920,877		$489,703,553
Schedule No. 6B - Demand Time-of-Day Option - Composite						
Customer Charge		438	$54.00	$23,652	$54.00	$23,652
All On-peak kW (May - Sept)		6,224	$18.12	$112,779		
All On-peak kW (Oct - Apr)		4,264	$14.54	$61,999		
Voltage Discount		0	($0.93)	$0	($0.94)	$0
Facilities kW		10,488			$4.04	$42,372
All On-peak kW (May - Sept)		6,224			$14.27	$88,816
All On-peak kW (Oct - Apr)		4,264			$10.65	$45,412
All kWh		3,907,497				
kWh (May-Sept)		1,628,124	3.8127 ¢	$62,075	3.8127 ¢	$62,075
kWh (Oct-Apr)		2,279,373	3.5143 ¢	$80,104	3.5143 ¢	$80,104
Seasonal Service		0	$648.00	$0	$648.00	$0
Unbilled		0		$0		$0
Total		3,907,497		$340,609		$342,431
Schedule No. 6A - Energy Time-of-Day Option - Composite						
Customer Charge		27,307	$54.00	$1,474,578	$54.00	$1,474,578
Facilities kW (May - Sept)		918,610	$6.41	$5,888,290	$6.45	$5,925,035
Facilities kW (Oct - Apr)		1,059,783	$5.38	$5,701,633	$5.41	$5,733,426
Voltage Discount		39,296	($0.60)	($23,578)	($0.60)	($23,578)
On-Peak kWh (May - Sept)		62,251,233	11.7307 ¢	$7,302,505	11.7997 ¢	$7,345,459
Off-Peak kWh (May - Sept)		59,556,790	3.5318 ¢	$2,103,427	3.5526 ¢	$2,115,815
On-Peak kWh (Oct - Apr)		90,625,426	9.8056 ¢	$8,886,367	9.8633 ¢	$8,938,658
Off-Peak kWh (Oct - Apr)		79,597,650	2.9603 ¢	$2,356,329	2.9770 ¢	$2,369,622
Unbilled		0		$0		$0
Total		292,031,100		$33,689,551		$33,879,015
Schedule No. 7 - Security Area Lighting - Composite						
MERCURY VAPOR LAMPS						
4,000 Lumen Energy Only	29	24	$5.68	$136	$5.68	$136.00
7,000 Lumen	1	45,001	$16.38	$737,116	$16.38	$737,116
7,000 Lumen Energy Only	28	0	$8.05	$0	$8.05	$0
20,000 Lumen	2	10,830	$26.78	$290,027	$26.78	$290,027
SODIUM VAPOR LAMPS						
5,600 Lumen New Pole	3	3,563	$14.60	$52,020	$14.60	$52,020
5,600 Lumen No New Pole	4	1,746	$12.23	$21,354	$12.23	$21,354

Rocky Mountain Power - State of Utah
Blocking Based on Adjusted Actuals and Forecasted Loads
Base Period 12 Months Ending June 2013
Forecast Test Period 12 Months Ending June 2015

		Forecasted Units	Present Price	Forecasted Revenue Dollars	Step 1 - 9/1/2014 Price	Step 1 - 9/1/2014 Revenue Dollars
9,500 Lumen New Pole	5	23,403	$15.47	$362,044	$15.47	$362,044
9,500 Lumen No New Pole	6	23,123	$13.31	$307,767	$13.31	$307,767
16,000 Lumen New Pole	7	2,646	$19.46	$51,491	$19.46	$51,491
16,000 Lumen No New Pole	8	2,564	$17.13	$43,921	$17.13	$43,921
22,000 Lumen	9	114	$21.07	$2,402	$21.07	$2,402
27,500 Lumen New Pole	10	3,134	$23.51	$73,680	$23.51	$73,680
27,500 Lumen No New Pole	11	4,178	$21.23	$88,699	$21.23	$88,699
50,000 Lumen New Pole	12	1,248	$28.30	$35,318	$28.30	$35,318
50,000 Lumen No New Pole	13	2,456	$25.99	$63,831	$25.99	$63,831
SODIUM VAPOR FLOOD LAMPS						
16,000 Lumen New Pole	14	4,670	$19.46	$90,878	$19.46	$90,878
16,000 Lumen No New Pole	15	4,976	$17.13	$85,239	$17.13	$85,239
27,500 Lumen New Pole	16	1,102	$23.51	$25,908	$23.51	$25,908
27,500 Lumen No New Pole	17	1,570	$21.23	$33,331	$21.23	$33,331
50,000 Lumen New Pole	18	9,734	$28.30	$275,472	$28.30	$275,472
50,000 Lumen No New Pole	19	11,772	$25.99	$305,954	$25.99	$305,954
METAL HALIDE LAMPS						
12,000 Lumen New Pole	20	0	$29.40	$0	$29.40	$0
12,000 Lumen No New Pole	21	265	$21.79	$5,774	$21.79	$5,774
19,500 Lumen New Pole	22	110	$34.34	$3,777	$34.34	$3,777
19,500 Lumen No New Pole	23	97	$27.43	$2,661	$27.43	$2,661
32,000 Lumen New Pole	24	469	$36.69	$17,208	$36.69	$17,208
32,000 Lumen No New Pole	25	630	$29.72	$18,724	$29.72	$18,724
107,000 Lumen New Pole	26	24	$57.58	$1,382	$57.58	$1,382
107,000 Lumen No New Pole	27	60	$49.10	$2,946	$49.10	$2,946
Subtotal		159,509		$2,999,060		$2,999,060
kWh Included		12,440,931				
Unbilled		0		$0		$0
Customers		8,046				
Total (kWh)		12,440,931		$2,999,060		$2,999,060
Schedule No. 8 - Composite						
Customer Charge		3,282	$68.00	$223,176	$69.00	$226,458
Facilities kW		5,010,201	$4.62	$23,147,129	$4.71	$23,598,047
On-Peak kW (May - Sept)		2,097,818	$15.10	$31,677,052	$15.40	$32,306,397
On-Peak kW (Oct - Apr)		2,761,958	$10.87	$30,022,483	$11.08	$30,602,495
Voltage Discount		2,132,830	($1.10)	($2,346,113)	($1.12)	($2,388,770)
On-Peak kWh (May - Sept)		260,094,535	4.8999 ¢	$12,744,372	4.9961 ¢	$12,994,583
On-Peak kWh (Oct - Apr)		625,992,212	3.8356 ¢	$24,010,557	3.9109 ¢	$24,481,929
Off-Peak kWh		1,300,960,579	3.3019 ¢	$42,956,417	3.3641 ¢	$43,765,615
Unbilled		0		$0		$0
Total		2,187,047,326		$162,435,073		$165,586,754
Schedule No. 9 - Composite						
Customer Charge		1,791	$247.00	$442,377	$255.00	$456,705
Facilities kW		9,053,509	$2.12	$19,193,439	$2.19	$19,827,185
On-Peak kW (May - Sept)		3,715,246	$13.32	$49,487,077	$13.75	$51,084,633
On-Peak kW (Oct - Apr)		5,150,021	$9.03	$46,504,690	$9.32	$47,998,196
On-Peak kWh (May-Sept)		507,349,132	4.4379 ¢	$22,515,647	4.5818 ¢	$23,245,723
On-Peak kWh (Oct-Apr)		1,382,941,034	3.3371 ¢	$46,150,125	3.4453 ¢	$47,646,467
Off-Peak kWh		3,137,145,375	2.7873 ¢	$87,441,653	2.8777 ¢	$90,277,632
Unbilled		0		$0		$0
Total		5,027,435,541		$271,735,008		$280,536,541

Rocky Mountain Power - State of Utah
Blocking Based on Adjusted Actuals and Forecasted Loads
Base Period 12 Months Ending June 2013
Forecast Test Period 12 Months Ending June 2015

	Forecasted Units	Present Price	Forecasted Revenue Dollars	Step 1 - 9/1/2014 Price	Step 1 - 9/1/2014 Revenue Dollars
Customer Charge	108	$247.00	$26,676	$255.00	$27,540
Facilities Charge per kW	235,118	$2.12	$498,450	$2.19	$514,908
On-Peak kWh	23,805,248	8.2002 ¢	$1,952,078	8.4770 ¢	$2,017,971
Off-Peak kWh	18,785,533	3.5251 ¢	$662,209	3.6440 ¢	$684,545
Unbilled	0		$0		$0
Total	42,590,781		$3,139,413		$3,244,964
Schedule No. 10 - Irrigation					
Annual Cust. Serv. Chg. - Primary	6	$121.00	$726	$124.00	$744
Annual Cust. Serv. Chg. - Secondary	2,778	$37.00	$102,798	$38.00	$105,577
Monthly Cust. Serv. Chg.	12,565	$14.00	$175,910	$14.00	$175,910
All On-Season kW	323,633	$7.04	$2,278,376	$7.25	$2,346,339
Voltage Discount	10,067	($1.97)	($19,832)	($2.03)	($20,436)
First 30,000 kWh	71,130,178	7.0156 ¢	$4,990,209	7.2207 ¢	$5,136,097
All add'l kWh	51,830,436	5.1855 ¢	$2,687,667	5.3371 ¢	$2,766,242
Total On Season	122,960,614		$10,215,854		$10,510,473
Post Season					
Customer Charge	5,886	$14.00	$82,404	$14.00	$82,404
kWh	50,172,778	4.8055 ¢	$2,411,053	4.9460 ¢	$2,481,546
Total Post Season	50,172,778		$2,493,457		$2,563,950
Unbilled	0		$0		$0
TOTAL RATE 10	173,133,392		$12,709,311		$13,074,423
Schedule No. 10-TOD					
Annual Cust. Serv. Chg. - Primary	5	$121.00	$605	$124.00	$620
Annual Cust. Serv. Chg. - Secondary	256	$37.00	$9,472	$38.00	$9,728
Monthly Cust. Serv. Chg.	1,143	$14.00	$16,002	$14.00	$16,002
All On-Season kW	37,541	$7.04	$264,289	$7.25	$272,172
Voltage Discount kW	1,037	($1.97)	($2,043)	($2.03)	($2,105)
On-Peak kWh	2,262,299	13.8603 ¢	$313,561	14.2655 ¢	$322,728
Off-Peak kWh	8,574,215	4.0252 ¢	$345,129	4.1252 ¢	$353,704
Total On Season	10,836,514		$947,015		$972,849
Post Season					
Customer Charge	570	$14.00	$7,980	$14.00	$7,980
kWh	5,920,094	4.8055 ¢	$284,490	4.9460 ¢	$292,808
Total Post Season	5,920,094		$292,470		$300,788
Unbilled	0		$0		$0
TOTAL RATE 10-TOD	16,756,608		$1,239,485		$1,273,637
Schedule No. 11 - Street Lighting - Company-Owned System					
Sodium Vapor Lamps (HPS)					
5,600 Lumen - Functional	34,757	$11.80	$410,133	$11.80	$410,133
9,500 Lumen - Functional	218,738	$12.78	$2,795,472	$12.78	$2,795,472
9,500 Lumen - Functional @ 90%	132	$11.50	$1,518	$11.50	$1,518
9,500 Lumen - S1	409	$46.54	$19,035	$46.54	$19,035
9,500 Lumen - S2	60	$38.05	$2,283	$38.05	$2,283
16,000 Lumen - Functional	21,158	$16.94	$358,417	$16.94	$358,417
16,000 Lumen - Functional @ 90%	96	$15.25	$1,464	$15.25	$1,464
16,000 Lumen - S1	2,421	$47.83	$115,796	$47.83	$115,796
16,000 Lumen - S2	886	$39.34	$34,855	$39.34	$34,855
27,500 Lumen - Functional	26,178	$21.14	$553,403	$21.14	$553,403
27,500 Lumen - Functional @ 90%	12	$19.03	$228	$19.03	$228
27,500 Lumen - S1	1,253	$51.48	$64,504	$51.48	$64,504

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	Forecasted Units	Present Price	Forecasted Revenue Dollars	Step 1 - 9/1/2014 Price	Step 1 - 9/1/2014 Revenue Dollars
27,500 Lumen - S2	0	$43.01	$0	$43.01	$0
50,000 Lumen - Functional	11,406	$26.02	$296,784	$26.02	$296,784
125,000 Lumen	0	$51.54	$0	$51.54	$0
Metal Halide Lamps (MH)					
9,000 Lumen - S1	36	$48.74	$1,755	$48.74	$1,755
9,000 Lumen - S2	602	$40.27	$24,243	$40.27	$24,243
12,000 Lumen - Functional	127	$20.13	$2,557	$20.13	$2,557
12,000 Lumen - S1	0	$50.65	$0	$50.65	$0
12,000 Lumen - S2	1,598	$42.17	$67,388	$42.17	$67,388
19,500 Lumen - Functional	386	$22.13	$8,542	$22.13	$8,542
19,500 Lumen - S1	41	$53.69	$2,201	$53.69	$2,201
19,500 Lumen - S2	365	$45.20	$16,498	$45.20	$16,498
32,000 Lumen - Functional	61	$25.78	$1,573	$25.78	$1,573
32,000 Lumen - S1	0	$55.33	$0	$55.33	$0
32,000 Lumen - S2	0	$46.86	$0	$46.86	$0
Mercury Vapor Lamps (No New Service) (MV)					
4,000 Lumen	3,279	$11.09	$36,364	$11.09	$36,364
7,000 Lumen	9,152	$13.83	$126,572	$13.83	$126,572
10,000 Lumen	186	$19.40	$3,608	$19.40	$3,608
10,000 Lumen @ 90%	0	$17.46	$0	$17.46	$0
20,000 Lumen	996	$24.43	$24,332	$24.43	$24,332
Incandescent Lamps (No New Service) (INC)					
500 Lumen	0	$11.99	$0	$11.99	$0
600 Lumen	145	$4.24	$615	$4.24	$615
2,500 Lumen	32	$17.11	$548	$17.11	$548
4,000 Lumen	162	$20.43	$3,310	$20.43	$3,310
6,000 Lumen	161	$23.82	$3,835	$23.82	$3,835
10,000 Lumen	24	$31.47	$755	$31.47	$755
Fluorescent Lamps (No New Service) (FLOUR)					
21,000 Lumen	12	$27.85	$334	$27.85	$334
Special Service (No New Service)					
50,000 Lumen - Flood	12	$39.04	$468	$39.04	$468
Subtotal	334,883		$4,979,390		$4,979,390
kWh Included	16,496,197				
Customers	809				
Unbilled	0		$0		$0
Total	16,496,197		$4,979,390		$4,979,390

Schedule No. 12 - Street Lighting - Customer-Owned System

1. Energy Only, No Maintenance

	Forecasted Units	Present Price	Forecasted Revenue Dollars	Step 1 - 9/1/2014 Price	Step 1 - 9/1/2014 Revenue Dollars
High Pressures Sodium Vapor Lamps					
5,600 Lumen	103,438	$1.83	$189,292	$1.83	$189,292
9,500 Lumen	159,006	$2.50	$397,515	$2.50	$397,515
16,000 Lumen	134,332	$3.66	$491,655	$3.66	$491,655
27,500 Lumen	48,293	$6.52	$314,870	$6.52	$314,870
50,000 Lumen	65,553	$10.02	$656,841	$10.02	$656,841
Metal Halide Lamps					
9,000 Lumen	6,583	$2.55	$16,787	$2.55	$16,787
12,000 Lumen	18,818	$4.46	$83,928	$4.46	$83,928
19,500 Lumen	28,281	$6.17	$174,494	$6.17	$174,494
32,000 Lumen	27,914	$9.77	$272,720	$9.77	$272,720
Non-listed Luminaries kWh	10,059,553	6.5279 ¢	$656,678	6.5279 ¢	$656,678
Subtotal kWh	49,653,570		$3,254,780		$3,254,780

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	Forecasted Units	Present Price	Forecasted Revenue Dollars	Step 1 - 9/1/2014 Price	Step 1 - 9/1/2014 Revenue Dollars
Unbilled					
Total	49,653,570		$3,254,780		$3,254,780
Customer	519				
2a - Partial Maintenance (No New Service)					
Incandescent Lamps					
2,500 Lumen or Less	76	$8.96	$681	$8.96	$681
4,000 Lumen	91	$12.19	$1,109	$12.19	$1,109
Mercury Vapor Lamps					
4,000 Lumen	47	$4.64	$218	$4.64	$218
7,000 Lumen	546	$7.00	$3,822	$7.00	$3,822
20,000 Lumen	140	$13.33	$1,866	$13.33	$1,866
54,000 Lumen	0	$28.38	$0	$28.38	$0
High Pressure Sodium Vapor Lamps					
5,600 Lumen	34,609	$4.08	$141,205	$4.08	$141,205
9,500 Lumen	15,632	$5.37	$83,944	$5.37	$83,944
9,500 Lumen - Decorative	8,817	$6.96	$61,366	$6.96	$61,366
16,000 Lumen	2,548	$6.52	$16,613	$6.52	$16,613
16,000 Lumen - Decorative	799	$8.27	$6,608	$8.27	$6,608
22,000 Lumen	0	$8.26	$0	$8.26	$0
27,500 Lumen	5,601	$9.59	$53,714	$9.59	$53,714
27,500 Lumen - Decorative	143	$11.93	$1,706	$11.93	$1,706
50,000 Lumen	10,133	$14.00	$141,862	$14.00	$141,862
50,000 Lumen - Decorative	157	$15.56	$2,443	$15.56	$2,443
Metal Halide Lamps					
9,000 Lumen - Decorative	702	$9.19	$6,451	$9.19	$6,451
12,000 Lumen	1,617	$13.57	$21,943	$13.57	$21,943
12,000 Lumen - Decorative	225	$11.09	$2,495	$11.09	$2,495
19,500 Lumen	518	$13.71	$7,102	$13.71	$7,102
19,500 Lumen - Decorative	6,034	$14.13	$85,260	$14.13	$85,260
32,000 Lumen	544	$14.58	$7,932	$14.58	$7,932
32,000 Lumen - Decorative	669	$15.79	$10,564	$15.79	$10,564
Fluorescent Lamps					
1,000 Lumen	0	$3.75	$0	$3.75	$0
21,800 Lumen	83	$13.92	$1,155	$13.92	$1,155
Subtotal kWh	5,219,065		$660,059		$660,059
Unbilled					
Total	5,219,065		$660,059		$660,059
Customer	221				
2b - Full Maintenance (No New Service)					
Incandescent Lamps					
6,000 Lumen	36	$17.73	$638	$17.73	$638
10,000 Lumen	12	$23.40	$281	$23.40	$281
Mercury Vapor Lamps					
7,000 Lumen	42	$8.03	$337	$8.03	$337
20,000 Lumen	0	$15.30	$0	$15.30	$0
54,000 Lumen	96	$32.48	$3,118	$32.48	$3,118
Sodium Vapor Lamps					
5,600 Lumen	4,275	$4.68	$20,007	$4.68	$20,007
9,500 Lumen	14,686	$6.16	$90,466	$6.16	$90,466
16,000 Lumen	1,259	$7.47	$9,405	$7.47	$9,405
22,000 Lumen	0	$9.44	$0	$9.44	$0
27,500 Lumen	2,408	$10.99	$26,464	$10.99	$26,464
50,000 Lumen	1,967	$16.02	$31,511	$16.02	$31,511

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	Forecasted Units	Present Price	Forecasted Revenue Dollars	Step 1 - 9/1/2014 Price	Step 1 - 9/1/2014 Revenue Dollars
Metal Halide Lamps					
12,000 Lumen	1,188	$15.58	$18,509	$15.58	$18,509
19,500 Lumen	724	$15.73	$11,389	$15.73	$11,389
32,000 Lumen	881	$16.72	$14,730	$16.72	$14,730
107,000 Lumen	96	$33.05	$3,173	$33.05	$3,173
Subtotal kWh	1,644,140		$230,028		$230,028
Unbilled					
Total	1,644,140		$230,028		$230,028
Customer	99				
kWh Street Lighting	56,516,774		$4,144,867		$4,144,867
Customers	839				
Unbilled			$0		$0
Total	56,516,774		$4,144,867		$4,144,867
Schedule 15.1 - Metered Outdoor Nighttime Lighting - Composite					
Annual Facility Charge	20,286	$11.00	$223,146	$11.00	$223,146
Annual Customer Charge	497	$72.50	$36,033	$72.50	$36,033
Annual Minimum Charge	0.0	$127.50	$0	$127.50	$0
Monthly Customer Charge	6,182	$6.20	$38,328	$6.20	$38,328
All kWh	17,536,445	5.3437 ¢	$937,095	5.3437 ¢	$937,095
Unbilled	0		$0		$0
Total	17,536,445		$1,234,602		$1,234,602
Schedule 15.2 - Traffic Signal Systems - Composite					
Customer Charge	29,596	$5.50	$162,778	$5.50	$162,778
All kWh	6,177,947	8.4049 ¢	$519,250	8.4049 ¢	$519,250
Unbilled	0		$0		$0
Total	6,177,947		$682,028		$682,028
Schedule No. 21 - Electric Furnace Operations - Limited Service - Industrial					
Primary Voltage					
Customer Charge	36	$121.00	$4,356	$125.00	$4,500
Charge per kW (Facilities)	10,893	$4.10	$44,661	$4.24	$46,186
First 100,000 kWh	423,833	6.5264 ¢	$27,661	6.7459 ¢	$28,591
All add'l kWh	0	5.4799 ¢	$0	5.6642 ¢	$0
Unbilled	0				$0
Subtotal	423,833		$76,678		$79,277
44KV or Higher					
Customer Charge	24	$121.00	$2,904	$125.00	$3,000
Charge per kW (Facilities)	47,371	$4.10	$194,221	$4.24	$200,853
First 100,000 kWh	2,660,898	5.1346 ¢	$136,626	5.3073 ¢	$141,222
All add'l kWh	963,969	4.4977 ¢	$43,356	4.6361 ¢	$44,691
Unbilled	0		$0		$0
Subtotal	3,624,867		$377,107		$389,766
Total	4,048,700		$453,785		$469,043
Schedule No. 23 - Composite					
Customer Charge	992,018	$10.00	$9,920,180	$10.00	$9,920,180
kW over 15 (May - Sept)	387,746	$8.55	$3,315,228	$8.65	$3,354,003
kW over 15 (Oct - Apr)	347,761	$8.60	$2,990,745	$8.70	$3,025,521
Voltage Discount	7,029	($0.48)	($3,374)	($0.48)	($3,374)
First 1,500 kWh (May - Sept)	295,977,608	11.6096 ¢	$34,361,816	11.7300 ¢	$34,718,173

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	Forecasted Units	Present Price	Forecasted Revenue Dollars	Step 1 - 9/1/2014 Price	Step 1 - 9/1/2014 Revenue Dollars
All Add'l kWh (May - Sept)	309,000,008	6.5088 ¢	$20,112,193	6.5763 ¢	$20,320,768
First 1,500 kWh (Oct - Apr)	424,820,226	10.6859 ¢	$45,395,865	10.7967 ¢	$45,866,565
All Add'l kWh (Oct - Apr)	361,090,369	5.9947 ¢	$21,646,284	6.0524 ¢	$21,854,633
Seasonal Service	0	$120.00	$0	$120.00	$0
Unbilled	0		$0		$0
Total	1,390,888,211		$137,738,937		$139,056,469
Schedule No.31 - Composite					
Secondary Voltage					
Customer Charge per month	0	$127.00	$0	$131.00	$0
Facilities Charge, per kW month	0	$4.66	$0	$5.52	$0
Back-up Power Charge					
Regular, per On-Peak kW day	0	$0.6419	$0		
May - Sept	0			$0.87	$0
Oct - Apr	0			$0.61	$0
Maintenance, per On-Peak kW day	0	$0.3210	$0		
May - Sept	0			$0.435	$0
Oct - Apr	0			$0.305	$0
Excess Power, per kW month	0	$60.48	$0		
May - Sept	0			$40.22	$0
Oct - Apr	0			$31.58	$0
Primary Voltage					
Customer Charge per month	24	$577.00	$13,848	$596.00	$14,304
Facilities Charge, per kW month	38,791	$3.66	$141,975	$4.40	$170,680
Back-up Power Charge					
Regular, per On-Peak kW day	195,683	$0.6248	$122,263		
May - Sept	79,030			$0.85	$67,176
Oct - Apr	116,653			$0.59	$68,825
Maintenance, per On-Peak kW day	24,254	$0.3124	$7,577		
May - Sept	24,254			$0.425	$10,308
Oct - Apr	0			$0.295	$0
Excess Power, per kW month	30	$43.59	$1,308		
May - Sept	0			$37.98	$0
Oct - Apr	30			$29.34	$880
Transmission Voltage					
Customer Charge per month	24	$646.00	$15,504	$668.00	$16,032
Facilities Charge, per kW month	153,429	$2.08	$319,132	$2.59	$397,381
Back-up Power Charge					
Regular, per On-Peak kW day	391,585	$0.4906	$192,112		
May - Sept	239,920			$0.75	$179,940
Oct - Apr	151,665			$0.50	$75,833
Maintenance, per On-Peak kW day	0	$0.2453	$0		
May - Sept	0			$0.375	$0
Oct - Apr	0			$0.250	$0
Excess Power, per kW month	0	$41.97	$0		
May - Sept	0			$31.88	$0
Oct - Apr	0			$23.02	$0
Subtotal			$813,719		$1,001,359
Supplemental billed at Schedule 6/8/9 rate					
Schedule 8					
Facilities kW	16,065	$4.62	$74,220	$4.71	$75,666
On-Peak kW (May - Sept)	0	$15.10	$0	$15.40	$0
On-Peak kW (Oct - Apr)	16,065	$10.87	$174,627	$11.08	$178,000

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	Forecasted Units	Present Price	Forecasted Revenue Dollars	Step 1 - 9/1/2014 Price	Step 1 - 9/1/2014 Revenue Dollars
Voltage Discount	16,065	($1.10)	($17,672)	($1.12)	($17,993)
On-Peak kWh (May - Sept)	1,044,794	4.8999 ¢	$51,194	4.9961 ¢	$52,199
On-Peak kWh (Oct - Apr)	3,934,668	3.8356 ¢	$150,918	3.9109 ¢	$153,881
Off-Peak kWh	5,030,285	3.3019 ¢	$166,095	3.3641 ¢	$169,224
Schedule 9					
Facilities kW	103,313	$2.12	$219,024	$2.19	$226,255
On-Peak kW (May - Sept)	49,491	$13.32	$659,220	$13.75	$680,501
On-Peak kW (Oct - Apr)	50,080	$9.03	$452,222	$9.32	$466,746
On-Peak kWh (May-Sept)	7,647,176	4.4379 ¢	$339,374	4.5818 ¢	$350,378
On-Peak kWh (Oct-Apr)	10,898,121	3.3371 ¢	$363,681	3.4453 ¢	$375,473
Off-Peak kWh	27,727,401	2.7873 ¢	$772,846	2.8777 ¢	$797,911
Subtotal			$3,405,749		$3,508,241
Unbilled	0		$0		$0
Total (Aggregated)	56,282,445		$4,219,468		$4,509,600
Contract 1					
Customer Charge	12		$2,618		$2,667
kW High Load Hours	949,050		$11,046,723		$11,251,932
kWh High Load Hours	237,232,647		$8,372,879		$8,528,417
kWh Low Load Hours	298,488,523		$7,754,732		$7,898,787
Total	535,721,170		$27,176,952		$27,681,803
Contract 2					
Customer Charge	12				
Interruptible kWh	795,798,676		$35,062,890		$35,062,890
Total	795,798,676		$35,062,890		$35,062,890
Contract 3-Current Contract					
Customer Charge	4	$646.00	$2,584	$668.00	$2,672
Facilities Charge per kW - Back-Up	140,833	$2.08	$292,932	$2.59	$364,757
kW Back-Up					
Regular, per On-Peak kW day	728,698	$0.4906	$357,499		
May - Sept	650,698			$0.75	$488,023
Oct - Apr	78,001			$0.50	$39,000
Maintenance, per On-Peak kW day	0	$0.2453	$0		
May - Sept	0			$0.375	$0
Oct - Apr	0			$0.250	$0
Excess Power, per kW month	0	$41.97	$0		
May - Sept	0			$31.88	$0
Oct - Apr	0			$23.02	$0
kW Supplemental					
On-Peak kW (May - Sept)	4,961	$13.32	$66,086	$13.75	$68,219
On-Peak kW (Oct - Apr)	328,029	$9.03	$2,962,106	$9.32	$3,057,234
kWh Supplemental					
On-Peak kWh (May-Sept)	4,559,372	4.4379 ¢	$202,340	4.5818 ¢	$208,901
On-Peak kWh (Oct-Apr)	87,526,656	3.3371 ¢	$2,920,852	3.4453 ¢	$3,015,556
Off-Peak kWh	131,594,536	2.7873 ¢	$3,667,935	2.8777 ¢	$3,786,896
Total	223,680,564		$10,472,334		$11,031,258
Contract 3-New Contract					
Customer Charge	8	$646.00	$5,168	$668.00	$5,344
Facilities Charge per kW - Back-Up	281,665	$2.08	$585,864	$2.15	$605,580
kW Back-Up					

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	Forecasted Units	Present Price	Forecasted Revenue Dollars	Step 1 - 9/1/2014 Price	Step 1 - 9/1/2014 Revenue Dollars
Regular, per On-Peak kW day	2,706,792	$0.4906	$1,327,952	$0.5071	
May - Sept	2,602,790			$0.5071	$1,319,875
Oct - Apr	104,001			$0.5071	$52,739
Maintenance, per On-Peak kW day	0	$0.2453	$0	$0.2536	
May - Sept	0			$0.2536	$0
Oct - Apr	0			$0.2536	$0
Excess Power, per kW month	0	$41.97	$0	$43.38	
May - Sept	0			$43.38	$0
Oct - Apr	0			$43.38	$0
kW Supplemental					
On-Peak kW (May - Sept)	19,846	$13.32	$264,343	$13.75	$272,877
On-Peak kW (Oct - Apr)	437,373	$9.03	$3,949,474	$9.32	$4,076,312
kWh Supplemental					
On-Peak kWh (May-Sept)	18,237,489	4.4379 ¢	$809,362	4.5818 ¢	$835,605
On-Peak kWh (Oct-Apr)	116,702,207	3.3371 ¢	$3,894,469	3.4453 ¢	$4,020,741
Off-Peak kWh	263,189,073	2.7873 ¢	$7,335,869	2.8777 ¢	$7,573,792
Total	398,128,769		$18,172,501		$18,762,865
Lighting Contract - Post Top Lighting - Composite					
Energy Only Res	60	$2.18	$131	$2.18	$131
Energy Only Non-Res	207	$2.1858	$452	$2.1858	$452
Subtotal	267		$583		$583
KWH Included	7,737				
Customers	5				
Unbilled	0				$0
Total	7,737		$583		$583
Annual Guarantee Adjustment					
Residential			$33,040		$33,040
Commercial			$2,726,578		$2,726,578
Industrial			($5,447)		($5,447)
Irrigation			$206,563		$206,563
Public Street & Highway Lighting			$4,662		$4,662
Other Sales Public Authorities			$0		$0
Total AGA			$2,965,396		$2,965,396
TOTAL - ALL CLASSES	23,244,284,922		$1,884,107,458		$1,919,107,319

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			Step 1 - 9/1/2014		Step 2 - 9/1/2015	
		Forecasted Units	Present Price	Revenue Dollars	Proposed Price	Revenue Dollars
Schedule No. 6 - Composite						
Customer Charge		156,864	$54.00	$8,470,675	$54.00	$8,470,675
All kW (May - Sept)		7,568,683				
All kW (Oct - Apr)		9,009,450				
Voltage Discount		679,134	($0.94)	($638,386)	($0.96)	($651,969)
Facilities kW		16,578,133	$4.04	$66,975,657	$4.04	$66,975,657
All kW (May - Sept)		7,568,683	$14.27	$108,005,106	$14.62	$110,654,145
All kW (Oct - Apr)		9,009,450	$10.65	$95,950,643	$10.91	$98,293,100
All kWh		5,783,806,261				
kWh (May - Sept)		2,573,577,152	3.8127 ¢	$98,122,776	3.8127 ¢	$98,122,776
kWh (Oct - Apr)		3,210,229,109	3.5143 ¢	$112,817,082	3.5143 ¢	$112,817,082
Seasonal Service		0	$648.00	$0	$648.00	$0
Unbilled		0		$0		$0
Total		5,783,806,261		$489,703,553		$494,681,466
Schedule No. 6B - Demand Time-of-Day Option - Composite						
Customer Charge		438	$54.00	$23,652	$54.00	$23,652
All On-peak kW (May - Sept)		6,224				
All On-peak kW (Oct - Apr)		4,264				
Voltage Discount		0	($0.94)	$0	($0.96)	$0
Facilities kW		10,488	$4.04	$42,372	$4.04	$42,372
All On-peak kW (May - Sept)		6,224	$14.27	$88,816	$14.62	$90,995
All On-peak kW (Oct - Apr)		4,264	$10.65	$45,412	$10.91	$46,520
All kWh		3,907,497				
kWh (May-Sept)		1,628,124	3.8127 ¢	$62,075	3.8127 ¢	$62,075
kWh (Oct-Apr)		2,279,373	3.5143 ¢	$80,104	3.5143 ¢	$80,104
Seasonal Service		0	$648.00	$0	$648.00	$0
Unbilled		0		$0		$0
Total		3,907,497		$342,431		$345,718
Schedule No. 6A - Energy Time-of-Day Option - Composite						
Customer Charge		27,307	$54.00	$1,474,578	$54.00	$1,474,578
Facilities kW (May - Sept)		918,610	$6.45	$5,925,035	$6.52	$5,989,337
Facilities kW (Oct - Apr)		1,059,783	$5.41	$5,733,426	$5.47	$5,797,013
Voltage Discount		39,296	($0.60)	($23,578)	($0.61)	($23,971)
On-Peak kWh (May - Sept)		62,251,233	11.7997 ¢	$7,345,459	11.9266 ¢	$7,424,456
Off-Peak kWh (May - Sept)		59,556,790	3.5526 ¢	$2,115,815	3.5908 ¢	$2,138,565
On-Peak kWh (Oct - Apr)		90,625,426	9.8633 ¢	$8,938,658	9.9693 ¢	$9,034,721
Off-Peak kWh (Oct - Apr)		79,597,650	2.9770 ¢	$2,369,622	3.0060 ¢	$2,392,705
Unbilled		0		$0		$0
Total		292,031,100		$33,879,015		$34,227,404
Schedule No. 7 - Security Area Lighting - Composite						
MERCURY VAPOR LAMPS						
4,000 Lumen Energy Only	29	24	$5.68	$136	$5.68	$136.00
7,000 Lumen	1	45,001	$16.38	$737,116	$16.38	$737,116
7,000 Lumen Energy Only	28	0	$8.05	$0	$8.05	$0
20,000 Lumen	2	10,830	$26.78	$290,027	$26.78	$290,027
SODIUM VAPOR LAMPS						
5,600 Lumen New Pole	3	3,563	$14.60	$52,020	$14.60	$52,020
5,600 Lumen No New Pole	4	1,746	$12.23	$21,354	$12.23	$21,354
9,500 Lumen New Pole	5	23,403	$15.47	$362,044	$15.47	$362,044
9,500 Lumen No New Pole	6	23,123	$13.31	$307,767	$13.31	$307,767

Rocky Mountain Power - State of Utah
Blocking Based on Adjusted Actuals and Forecasted Loads
Base Period 12 Months Ending June 2013
Forecast Test Period 12 Months Ending June 2015

			Step 1 - 9/1/2014		Step 2 - 9/1/2015	
		Forecasted Units	Present Price	Revenue Dollars	Proposed Price	Revenue Dollars
16,000 Lumen New Pole	7	2,646	$19.46	$51,491	$19.46	$51,491
16,000 Lumen No New Pole	8	2,564	$17.13	$43,921	$17.13	$43,921
22,000 Lumen	9	114	$21.07	$2,402	$21.07	$2,402
27,500 Lumen New Pole	10	3,134	$23.51	$73,680	$23.51	$73,680
27,500 Lumen No New Pole	11	4,178	$21.23	$88,699	$21.23	$88,699
50,000 Lumen New Pole	12	1,248	$28.30	$35,318	$28.30	$35,318
50,000 Lumen No New Pole	13	2,456	$25.99	$63,831	$25.99	$63,831
SODIUM VAPOR FLOOD LAMPS						
16,000 Lumen New Pole	14	4,670	$19.46	$90,878	$19.46	$90,878
16,000 Lumen No New Pole	15	4,976	$17.13	$85,239	$17.13	$85,239
27,500 Lumen New Pole	16	1,102	$23.51	$25,908	$23.51	$25,908
27,500 Lumen No New Pole	17	1,570	$21.23	$33,331	$21.23	$33,331
50,000 Lumen New Pole	18	9,734	$28.30	$275,472	$28.30	$275,472
50,000 Lumen No New Pole	19	11,772	$25.99	$305,954	$25.99	$305,954
METAL HALIDE LAMPS						
12,000 Lumen New Pole	20	0	$29.40	$0	$29.40	$0
12,000 Lumen No New Pole	21	265	$21.79	$5,774	$21.79	$5,774
19,500 Lumen New Pole	22	110	$34.34	$3,777	$34.34	$3,777
19,500 Lumen No New Pole	23	97	$27.43	$2,661	$27.43	$2,661
32,000 Lumen New Pole	24	469	$36.69	$17,208	$36.69	$17,208
32,000 Lumen No New Pole	25	630	$29.72	$18,724	$29.72	$18,724
107,000 Lumen New Pole	26	24	$57.58	$1,382	$57.58	$1,382
107,000 Lumen No New Pole	27	60	$49.10	$2,946	$49.10	$2,946
Subtotal		159,509		$2,999,060		$2,999,060
kWh Included		12,440,931				
Unbilled		0		$0		$0
Customers		8,046				
Total (kWh)		12,440,931		$2,999,060		$2,999,060
Schedule No. 8 - Composite						
Customer Charge		3,282	$69.00	$226,458	$70.00	$229,740
Facilities kW		5,010,201	$4.71	$23,598,047	$4.76	$23,848,557
On-Peak kW (May - Sept)		2,097,818	$15.40	$32,306,397	$15.56	$32,642,048
On-Peak kW (Oct - Apr)		2,761,958	$11.08	$30,602,495	$11.19	$30,906,310
Voltage Discount		2,132,830	($1.12)	($2,388,770)	($1.13)	($2,410,098)
On-Peak kWh (May - Sept)		260,094,535	4.9961 ¢	$12,994,583	5.0474 ¢	$13,128,012
On-Peak kWh (Oct - Apr)		625,992,212	3.9109 ¢	$24,481,929	3.9511 ¢	$24,733,578
Off-Peak kWh		1,300,960,579	3.3641 ¢	$43,765,615	3.4002 ¢	$44,235,262
Unbilled		0		$0		$0
Total		2,187,047,326		$165,586,754		$167,313,409
Schedule No. 9 - Composite						
Customer Charge		1,791	$255.00	$456,705	$259.00	$463,869
Facilities kW		9,053,509	$2.19	$19,827,185	$2.22	$20,098,790
On-Peak kW (May - Sept)		3,715,246	$13.75	$51,084,633	$13.96	$51,864,834
On-Peak kW (Oct - Apr)		5,150,021	$9.32	$47,998,196	$9.47	$48,770,699
On-Peak kWh (May-Sept)		507,349,132	4.5818 ¢	$23,245,723	4.6531 ¢	$23,607,462
On-Peak kWh (Oct-Apr)		1,382,941,034	3.4453 ¢	$47,646,467	3.4989 ¢	$48,387,724
Off-Peak kWh		3,137,145,375	2.8777 ¢	$90,277,632	2.9225 ¢	$91,683,074
Unbilled		0		$0		$0
Total		5,027,435,541		$280,536,541		$284,876,452

Schedule No. 9A - Energy TOD - Composite

Rocky Mountain Power - State of Utah
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Base Period 12 Months Ending June 2013
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	Forecasted Units	Step 1 - 9/1/2014 Present Price	Step 1 - 9/1/2014 Revenue Dollars	Step 2 - 9/1/2015 Proposed Price	Step 2 - 9/1/2015 Revenue Dollars
Customer Charge	108	$255.00	$27,540	$259.00	$27,972
Facilities Charge per kW	235,118	$2.19	$514,908	$2.22	$521,962
On-Peak kWh	23,805,248	8.4770 ¢	$2,017,971	8.6029 ¢	$2,047,942
Off-Peak kWh	18,785,533	3.6440 ¢	$684,545	3.6981 ¢	$694,708
Unbilled	0		$0		$0
Total	42,590,781		$3,244,964		$3,292,584
Schedule No. 10 - Irrigation					
Annual Cust. Serv. Chg. - Primary	6	$124.00	$744	$125.00	$750
Annual Cust. Serv. Chg. - Secondary	2,778	$38.00	$105,577	$38.00	$105,577
Monthly Cust. Serv. Chg.	12,565	$14.00	$175,910	$14.00	$175,910
All On-Season kW	323,633	$7.25	$2,346,339	$7.33	$2,372,230
Voltage Discount	10,067	($2.03)	($20,436)	($2.05)	($20,637)
First 30,000 kWh	71,130,178	7.2207 ¢	$5,136,097	7.2971 ¢	$5,190,440
All add'l kWh	51,830,436	5.3371 ¢	$2,766,242	5.3936 ¢	$2,795,526
Total On Season	122,960,614		$10,510,473		$10,619,796
Post Season					
Customer Charge	5,886	$14.00	$82,404	$14.00	$82,404
kWh	50,172,778	4.9460 ¢	$2,481,546	4.9983 ¢	$2,507,786
Total Post Season	50,172,778		$2,563,950		$2,590,190
Unbilled	0		$0		$0
TOTAL RATE 10	173,133,392		$13,074,423		$13,209,986
Schedule No. 10-TOD					
Annual Cust. Serv. Chg. - Primary	5	$124.00	$620	$125.00	$625
Annual Cust. Serv. Chg. - Secondary	256	$38.00	$9,728	$38.00	$9,728
Monthly Cust. Serv. Chg.	1,143	$14.00	$16,002	$14.00	$16,002
All On-Season kW	37,541	$7.25	$272,172	$7.33	$275,176
Voltage Discount kW	1,037	($2.03)	($2,105)	($2.05)	($2,126)
On-Peak kWh	2,262,299	14.2655 ¢	$322,728	14.4164 ¢	$326,142
Off-Peak kWh	8,574,215	4.1252 ¢	$353,704	4.1542 ¢	$356,190
Total On Season	10,836,514		$972,849		$981,737
Post Season					
Customer Charge	570	$14.00	$7,980	$14.00	$7,980
kWh	5,920,094	4.9460 ¢	$292,808	4.9983 ¢	$295,904
Total Post Season	5,920,094		$300,788		$303,884
Unbilled	0		$0		$0
TOTAL RATE 10-TOD	16,756,608		$1,273,637		$1,285,621
Schedule No. 11 - Street Lighting - Company-Owned System					
Sodium Vapor Lamps (HPS)					
5,600 Lumen - Functional	34,757	$11.80	$410,133	$11.80	$410,133
9,500 Lumen - Functional	218,738	$12.78	$2,795,472	$12.78	$2,795,472
9,500 Lumen - Functional @ 90%	132	$11.50	$1,518	$11.50	$1,518
9,500 Lumen - S1	409	$46.54	$19,035	$46.54	$19,035
9,500 Lumen - S2	60	$38.05	$2,283	$38.05	$2,283
16,000 Lumen - Functional	21,158	$16.94	$358,417	$16.94	$358,417
16,000 Lumen - Functional @ 90%	96	$15.25	$1,464	$15.25	$1,464
16,000 Lumen - S1	2,421	$47.83	$115,796	$47.83	$115,796
16,000 Lumen - S2	886	$39.34	$34,855	$39.34	$34,855
27,500 Lumen - Functional	26,178	$21.14	$553,403	$21.14	$553,403
27,500 Lumen - Functional @ 90%	12	$19.03	$228	$19.03	$228
27,500 Lumen - S1	1,253	$51.48	$64,504	$51.48	$64,504

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		Step 1 - 9/1/2014		Step 2 - 9/1/2015	
	Forecasted Units	Present Price	Revenue Dollars	Proposed Price	Revenue Dollars
27,500 Lumen - S2	0	$43.01	$0	$43.01	$0
50,000 Lumen - Functional	11,406	$26.02	$296,784	$26.02	$296,784
125,000 Lumen	0	$51.54	$0	$51.54	$0
Metal Halide Lamps (MH)					
9,000 Lumen - S1	36	$48.74	$1,755	$48.74	$1,755
9,000 Lumen - S2	602	$40.27	$24,243	$40.27	$24,243
12,000 Lumen - Functional	127	$20.13	$2,557	$20.13	$2,557
12,000 Lumen - S1	0	$50.65	$0	$50.65	$0
12,000 Lumen - S2	1,598	$42.17	$67,388	$42.17	$67,388
19,500 Lumen - Functional	386	$22.13	$8,542	$22.13	$8,542
19,500 Lumen - S1	41	$53.69	$2,201	$53.69	$2,201
19,500 Lumen - S2	365	$45.20	$16,498	$45.20	$16,498
32,000 Lumen - Functional	61	$25.78	$1,573	$25.78	$1,573
32,000 Lumen - S1	0	$55.33	$0	$55.33	$0
32,000 Lumen - S2	0	$46.86	$0	$46.86	$0
Mercury Vapor Lamps (No New Service) (MV)					
4,000 Lumen	3,279	$11.09	$36,364	$11.09	$36,364
7,000 Lumen	9,152	$13.83	$126,572	$13.83	$126,572
10,000 Lumen	186	$19.40	$3,608	$19.40	$3,608
10,000 Lumen @ 90%	0	$17.46	$0	$17.46	$0
20,000 Lumen	996	$24.43	$24,332	$24.43	$24,332
Incandescent Lamps (No New Service) (INC)					
500 Lumen	0	$11.99	$0	$11.99	$0
600 Lumen	145	$4.24	$615	$4.24	$615
2,500 Lumen	32	$17.11	$548	$17.11	$548
4,000 Lumen	162	$20.43	$3,310	$20.43	$3,310
6,000 Lumen	161	$23.82	$3,835	$23.82	$3,835
10,000 Lumen	24	$31.47	$755	$31.47	$755
Fluorescent Lamps (No New Service) (FLOUR)					
21,000 Lumen	12	$27.85	$334	$27.85	$334
Special Service (No New Service)					
50,000 Lumen - Flood	12	$39.04	$468	$39.04	$468
Subtotal	334,883		$4,979,390		$4,979,390
kWh Included	16,496,197				
Customers	809				
Unbilled	0		$0		$0
Total	16,496,197		$4,979,390		$4,979,390
Schedule No. 12 - Street Lighting - Customer-Owned System					
1. Energy Only, No Maintenance					
High Pressures Sodium Vapor Lamps					
5,600 Lumen	103,438	$1.83	$189,292	$1.83	$189,292
9,500 Lumen	159,006	$2.50	$397,515	$2.50	$397,515
16,000 Lumen	134,332	$3.66	$491,655	$3.66	$491,655
27,500 Lumen	48,293	$6.52	$314,870	$6.52	$314,870
50,000 Lumen	65,553	$10.02	$656,841	$10.02	$656,841
Metal Halide Lamps					
9,000 Lumen	6,583	$2.55	$16,787	$2.55	$16,787
12,000 Lumen	18,818	$4.46	$83,928	$4.46	$83,928
19,500 Lumen	28,281	$6.17	$174,494	$6.17	$174,494
32,000 Lumen	27,914	$9.77	$272,720	$9.77	$272,720
Non-listed Luminaries kWh	10,059,553	6.5279 ¢	$656,678	6.5279 ¢	$656,678
Subtotal kWh	49,653,570		$3,254,780		$3,254,780

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Forecast Test Period 12 Months Ending June 2015

		Step 1 - 9/1/2014		Step 2 - 9/1/2015	
	Forecasted Units	Present Price	Revenue Dollars	Proposed Price	Revenue Dollars
Unbilled					
Total	49,653,570		$3,254,780		$3,254,780
Customer	519				
2a - Partial Maintenance (No New Service)					
Incandescent Lamps					
2,500 Lumen or Less	76	$8.96	$681	$8.96	$681
4,000 Lumen	91	$12.19	$1,109	$12.19	$1,109
Mercury Vapor Lamps					
4,000 Lumen	47	$4.64	$218	$4.64	$218
7,000 Lumen	546	$7.00	$3,822	$7.00	$3,822
20,000 Lumen	140	$13.33	$1,866	$13.33	$1,866
54,000 Lumen	0	$28.38	$0	$28.38	$0
High Pressure Sodium Vapor Lamps					
5,600 Lumen	34,609	$4.08	$141,205	$4.08	$141,205
9,500 Lumen	15,632	$5.37	$83,944	$5.37	$83,944
9,500 Lumen - Decorative	8,817	$6.96	$61,366	$6.96	$61,366
16,000 Lumen	2,548	$6.52	$16,613	$6.52	$16,613
16,000 Lumen - Decorative	799	$8.27	$6,608	$8.27	$6,608
22,000 Lumen	0	$8.26	$0	$8.26	$0
27,500 Lumen	5,601	$9.59	$53,714	$9.59	$53,714
27,500 Lumen - Decorative	143	$11.93	$1,706	$11.93	$1,706
50,000 Lumen	10,133	$14.00	$141,862	$14.00	$141,862
50,000 Lumen - Decorative	157	$15.56	$2,443	$15.56	$2,443
Metal Halide Lamps					
9,000 Lumen - Decorative	702	$9.19	$6,451	$9.19	$6,451
12,000 Lumen	1,617	$13.57	$21,943	$13.57	$21,943
12,000 Lumen - Decorative	225	$11.09	$2,495	$11.09	$2,495
19,500 Lumen	518	$13.71	$7,102	$13.71	$7,102
19,500 Lumen - Decorative	6,034	$14.13	$85,260	$14.13	$85,260
32,000 Lumen	544	$14.58	$7,932	$14.58	$7,932
32,000 Lumen - Decorative	669	$15.79	$10,564	$15.79	$10,564
Fluorescent Lamps					
1,000 Lumen	0	$3.75	$0	$3.75	$0
21,800 Lumen	83	$13.92	$1,155	$13.92	$1,155
Subtotal kWh	5,219,065		$660,059		$660,059
Unbilled					
Total	5,219,065		$660,059		$660,059
Customer	221				
2b - Full Maintenance (No New Service)					
Incandescent Lamps					
6,000 Lumen	36	$17.73	$638	$17.73	$638
10,000 Lumen	12	$23.40	$281	$23.40	$281
Mercury Vapor Lamps					
7,000 Lumen	42	$8.03	$337	$8.03	$337
20,000 Lumen	0	$15.30	$0	$15.30	$0
54,000 Lumen	96	$32.48	$3,118	$32.48	$3,118
Sodium Vapor Lamps					
5,600 Lumen	4,275	$4.68	$20,007	$4.68	$20,007
9,500 Lumen	14,686	$6.16	$90,466	$6.16	$90,466
16,000 Lumen	1,259	$7.47	$9,405	$7.47	$9,405
22,000 Lumen	0	$9.44	$0	$9.44	$0
27,500 Lumen	2,408	$10.99	$26,464	$10.99	$26,464
50,000 Lumen	1,967	$16.02	$31,511	$16.02	$31,511

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Forecast Test Period 12 Months Ending June 2015

		Step 1 - 9/1/2014		Step 2 - 9/1/2015	
	Forecasted Units	Present Price	Revenue Dollars	Proposed Price	Revenue Dollars
Metal Halide Lamps					
12,000 Lumen	1,188	$15.58	$18,509	$15.58	$18,509
19,500 Lumen	724	$15.73	$11,389	$15.73	$11,389
32,000 Lumen	881	$16.72	$14,730	$16.72	$14,730
107,000 Lumen	96	$33.05	$3,173	$33.05	$3,173
Subtotal kWh	1,644,140		$230,028		$230,028
Unbilled					
Total	1,644,140		$230,028		$230,028
Customer	99				
kWh Street Lighting	56,516,774		$4,144,867		$4,144,867
Customers	839				
Unbilled			$0		$0
Total	56,516,774		$4,144,867		$4,144,867
Schedule 15.1 - Metered Outdoor Nighttime Lighting - Composite					
Annual Facility Charge	20,286	$11.00	$223,146	$11.00	$223,146
Annual Customer Charge	497	$72.50	$36,033	$72.50	$36,033
Annual Minimum Charge	0.0	$127.50	$0	$127.50	$0
Monthly Customer Charge	6,182	$6.20	$38,328	$6.20	$38,328
All kWh	17,536,445	5.3437 ¢	$937,095	5.3437 ¢	$937,095
Unbilled	0		$0		$0
Total	17,536,445		$1,234,602		$1,234,602
Schedule 15.2 - Traffic Signal Systems - Composite					
Customer Charge	29,596	$5.50	$162,778	$5.50	$162,778
All kWh	6,177,947	8.4049 ¢	$519,250	8.4049 ¢	$519,250
Unbilled	0		$0		$0
Total	6,177,947		$682,028		$682,028
Schedule No. 21 - Electric Furnace Operations - Limited Service - Industrial					
Primary Voltage					
Customer Charge	36	$125.00	$4,500	$127.00	$4,572
Charge per kW (Facilities)	10,893	$4.24	$46,186	$4.30	$46,840
First 100,000 kWh	423,833	6.7459 ¢	$28,591	6.8447 ¢	$29,010
All add'l kWh	0	5.6642 ¢	$0	5.7472 ¢	$0
Unbilled	0				$0
Subtotal	423,833		$79,277		$80,422
44KV or Higher					
Customer Charge	24	$125.00	$3,000	$127.00	$3,048
Charge per kW (Facilities)	47,371	$4.24	$200,853	$4.30	$203,695
First 100,000 kWh	2,660,898	5.3073 ¢	$141,222	5.3851 ¢	$143,292
All add'l kWh	963,969	4.6361 ¢	$44,691	4.7169 ¢	$45,469
Unbilled	0		$0		$0
Subtotal	3,624,867		$389,766		$395,504
Total	4,048,700		$469,043		$475,926
Schedule No. 23 - Composite					
Customer Charge	992,018	$10.00	$9,920,180	$10.00	$9,920,180
kW over 15 (May - Sept)	387,746	$8.65	$3,354,003	$8.65	$3,354,003
kW over 15 (Oct - Apr)	347,761	$8.70	$3,025,521	$8.70	$3,025,521
Voltage Discount	7,029	($0.48)	($3,374)	($0.48)	($3,374)
First 1,500 kWh (May - Sept)	295,977,608	11.7300 ¢	$34,718,173	11.7336 ¢	$34,728,829

Rocky Mountain Power - State of Utah
Blocking Based on Adjusted Actuals and Forecasted Loads
Base Period 12 Months Ending June 2013
Forecast Test Period 12 Months Ending June 2015

	Forecasted Units	Step 1 - 9/1/2014 Present Price	Step 1 - 9/1/2014 Revenue Dollars	Step 2 - 9/1/2015 Proposed Price	Step 2 - 9/1/2015 Revenue Dollars
All Add'l kWh (May - Sept)	309,000,008	6.5763 ¢	$20,320,768	6.5783 ¢	$20,326,948
First 1,500 kWh (Oct - Apr)	424,820,226	10.7967 ¢	$45,866,565	10.8000 ¢	$45,880,584
All Add'l kWh (Oct - Apr)	361,090,369	6.0524 ¢	$21,854,633	6.0567 ¢	$21,870,160
Seasonal Service	0	$120.00	$0	$120.00	$0
Unbilled	0		$0		$0
Total	1,390,888,211		$139,056,469		$139,102,851
Schedule No.31 - Composite					
Secondary Voltage					
Customer Charge per month	0	$131.00	$0	$133.00	$0
Facilities Charge, per kW month	0	$5.52	$0	$5.60	$0
Back-up Power Charge					
Regular, per On-Peak kW day	0				
May - Sept	0	$0.87	$0	$0.88	$0
Oct - Apr	0	$0.61	$0	$0.62	$0
Maintenance, per On-Peak kW day	0				
May - Sept	0	$0.435	$0	$0.440	$0
Oct - Apr	0	$0.305	$0	$0.310	$0
Excess Power, per kW month	0				
May - Sept	0	$40.22	$0	$40.81	$0
Oct - Apr	0	$31.58	$0	$32.04	$0
Primary Voltage					
Customer Charge per month	24	$596.00	$14,304	$605.00	$14,520
Facilities Charge, per kW month	38,791	$4.40	$170,680	$4.46	$173,008
Back-up Power Charge					
Regular, per On-Peak kW day	195,683				
May - Sept	79,030	$0.85	$67,176	$0.86	$67,966
Oct - Apr	116,653	$0.59	$68,825	$0.60	$69,992
Maintenance, per On-Peak kW day	24,254				
May - Sept	24,254	$0.425	$10,308	$0.430	$10,429
Oct - Apr	0	$0.295	$0	$0.300	$0
Excess Power, per kW month	30				
May - Sept	0	$37.98	$0	$38.54	$0
Oct - Apr	30	$29.34	$880	$29.77	$893
Transmission Voltage					
Customer Charge per month	24	$668.00	$16,032	$678.00	$16,272
Facilities Charge, per kW month	153,429	$2.59	$397,381	$2.63	$403,518
Back-up Power Charge					
Regular, per On-Peak kW day	391,585				
May - Sept	239,920	$0.75	$179,940	$0.76	$182,339
Oct - Apr	151,665	$0.50	$75,833	$0.51	$77,349
Maintenance, per On-Peak kW day	0				
May - Sept	0	$0.375	$0	$0.380	$0
Oct - Apr	0	$0.250	$0	$0.255	$0
Excess Power, per kW month	0				
May - Sept	0	$31.88	$0	$32.35	$0
Oct - Apr	0	$23.02	$0	$23.36	$0
Subtotal			$1,001,359		$1,016,286
Supplemental billed at Schedule 6/8/9 rate					
Schedule 8					
Facilities kW	16,065	$4.71	$75,666	$4.76	$76,469
On-Peak kW (May - Sept)	0	$15.40	$0	$15.56	$0
On-Peak kW (Oct - Apr)	16,065	$11.08	$178,000	$11.19	$179,767

Rocky Mountain Power - State of Utah
Blocking Based on Adjusted Actuals and Forecasted Loads
Base Period 12 Months Ending June 2013
Forecast Test Period 12 Months Ending June 2015

		Step 1 - 9/1/2014		Step 2 - 9/1/2015	
	Forecasted Units	Present Price	Revenue Dollars	Proposed Price	Revenue Dollars
Voltage Discount	16,065	($1.12)	($17,993)	($1.13)	($18,153)
On-Peak kWh (May - Sept)	1,044,794	4.9961 ¢	$52,199	5.0474 ¢	$52,735
On-Peak kWh (Oct - Apr)	3,934,668	3.9109 ¢	$153,881	3.9511 ¢	$155,463
Off-Peak kWh	5,030,285	3.3641 ¢	$169,224	3.4002 ¢	$171,040
Schedule 9					
Facilities kW	103,313	$2.19	$226,255	$2.22	$229,355
On-Peak kW (May - Sept)	49,491	$13.75	$680,501	$13.96	$690,894
On-Peak kW (Oct - Apr)	50,080	$9.32	$466,746	$9.47	$474,258
On-Peak kWh (May-Sept)	7,647,176	4.5818 ¢	$350,378	4.6531 ¢	$355,831
On-Peak kWh (Oct-Apr)	10,898,121	3.4453 ¢	$375,473	3.4989 ¢	$381,314
Off-Peak kWh	27,727,401	2.8777 ¢	$797,911	2.9225 ¢	$810,333
Subtotal			$3,508,241		$3,559,306
Unbilled	0		$0		$0
Total (Aggregated)	56,282,445		$4,509,600		$4,575,592
Contract 1					
Customer Charge	12		$2,667		$2,694
kW High Load Hours	949,050		$11,251,932		$11,364,504
kWh High Load Hours	237,232,647		$8,528,417		$8,613,741
kWh Low Load Hours	298,488,523		$7,898,787		$7,977,812
Total	535,721,170		$27,681,803		$27,958,751
Contract 2					
Customer Charge	12				
Interruptible kWh	795,798,676		$35,062,890		$35,062,890
Total	795,798,676		$35,062,890		$35,062,890
Contract 3-Current Contract					
Customer Charge	4	$668.00	$2,672	$678.00	$2,712
Facilities Charge per kW - Back-Up	140,833	$2.59	$364,757	$2.18	$307,015
kW Back-Up					
Regular, per On-Peak kW day	728,698				
May - Sept	650,698	$0.75	$488,023	$0.51	$334,784
Oct - Apr	78,001	$0.50	$39,000	$0.51	$40,131
Maintenance, per On-Peak kW day	0				
May - Sept	0	$0.375	$0	$0.257	$0
Oct - Apr	0	$0.250	$0	$0.257	$0
Excess Power, per kW month	0				
May - Sept	0	$31.88	$0	$44.02	$0
Oct - Apr	0	$23.02	$0	$44.02	$0
kW Supplemental					
On-Peak kW (May - Sept)	4,961	$13.75	$68,219	$13.96	$69,261
On-Peak kW (Oct - Apr)	328,029	$9.32	$3,057,234	$9.47	$3,106,439
kWh Supplemental					
On-Peak kWh (May-Sept)	4,559,372	4.5818 ¢	$208,901	4.6531 ¢	$212,152
On-Peak kWh (Oct-Apr)	87,526,656	3.4453 ¢	$3,015,556	3.4989 ¢	$3,062,470
Off-Peak kWh	131,594,536	2.8777 ¢	$3,786,896	2.9225 ¢	$3,845,850
Total	223,680,564		$11,031,258		$10,980,814
Contract 3-New Contract					
Customer Charge	8	$668.00	$5,344	$678.00	$5,424
Facilities Charge per kW - Back-Up	281,665	$2.15	$605,580	$2.18	$614,030
kW Back-Up					

Rocky Mountain Power - State of Utah
Blocking Based on Adjusted Actuals and Forecasted Loads
Base Period 12 Months Ending June 2013
Forecast Test Period 12 Months Ending June 2015

		Step 1 - 9/1/2014		Step 2 - 9/1/2015	
	Forecasted Units	Present Price	Revenue Dollars	Proposed Price	Revenue Dollars
Regular, per On-Peak kW day	2,706,792	$0.5071		$0.5145	
May - Sept	2,602,790	$0.5071	$1,319,875	$0.5145	$1,339,136
Oct - Apr	104,001	$0.5071	$52,739	$0.5145	$53,509
Maintenance, per On-Peak kW day	0	$0.2536		$0.2573	
May - Sept	0	$0.2536	$0	$0.2573	$0
Oct - Apr	0	$0.2536	$0	$0.2573	$0
Excess Power, per kW month	0	$43.38		$44.02	
May - Sept	0	$43.38	$0	$44.02	$0
Oct - Apr	0	$43.38	$0	$44.02	$0
kW Supplemental					
On-Peak kW (May - Sept)	19,846	$13.75	$272,877	$13.96	$277,045
On-Peak kW (Oct - Apr)	437,373	$9.32	$4,076,312	$9.47	$4,141,918
kWh Supplemental					
On-Peak kWh (May-Sept)	18,237,489	4.5818 ¢	$835,605	4.6531 ¢	$848,609
On-Peak kWh (Oct-Apr)	116,702,207	3.4453 ¢	$4,020,741	3.4989 ¢	$4,083,294
Off-Peak kWh	263,189,073	2.8777 ¢	$7,573,792	2.9225 ¢	$7,691,701
Total	398,128,769		$18,762,865		$19,054,666
Lighting Contract - Post Top Lighting - Composite					
Energy Only Res	60	$2.18	$131	$2.18	$131
Energy Only Non-Res	207	$2.1858	$452	$2.1858	$452
Subtotal	267		$583		$583
KWH Included	7,737				
Customers	5				
Unbilled	0				$0
Total	7,737		$583		$583
Annual Guarantee Adjustment					
Residential			$33,040		$33,040
Commercial			$2,726,578		$2,726,578
Industrial			($5,447)		($5,447)
Irrigation			$206,563		$206,563
Public Street & Highway Lighting			$4,662		$4,662
Other Sales Public Authorities			$0		$0
Total AGA			$2,965,396		$2,965,396
TOTAL - ALL CLASSES	23,244,284,922		$1,919,107,319		$1,938,307,130

Rocky Mountain Power
Monthly Billing Comparison
Schedule 6 - State of Utah
General Service - Distribution Voltage
Step 1 - Effective 9/1/2014

		Summer				Winter			
kW		Monthly Billing[1]		Change		Monthly Billing[1]		Change	
Load Size	kWh	Present	Proposed	$	%	Present	Proposed	$	%
50	5,000	$1,218	$1,228	$10	0.8%	$1,014	$1,022	$8	0.8%
50	10,000	$1,420	$1,430	$10	0.7%	$1,200	$1,208	$8	0.7%
50	20,000	$1,823	$1,833	$10	0.5%	$1,572	$1,580	$8	0.5%
100	20,000	$2,776	$2,796	$20	0.7%	$2,337	$2,353	$16	0.7%
100	40,000	$3,584	$3,604	$20	0.6%	$3,082	$3,098	$16	0.5%
100	60,000	$4,392	$4,412	$20	0.5%	$3,827	$3,843	$16	0.4%
200	40,000	$5,489	$5,529	$40	0.7%	$4,611	$4,642	$32	0.7%
200	80,000	$7,105	$7,145	$40	0.6%	$6,101	$6,132	$32	0.5%
200	120,000	$8,720	$8,760	$40	0.5%	$7,591	$7,622	$32	0.4%
500	100,000	$13,629	$13,729	$100	0.7%	$11,433	$11,512	$79	0.7%
500	200,000	$17,668	$17,767	$100	0.6%	$15,158	$15,236	$79	0.5%
500	300,000	$21,706	$21,806	$100	0.5%	$18,882	$18,961	$79	0.4%
1,000	200,000	$27,195	$27,395	$200	0.7%	$22,803	$22,960	$158	0.7%
1,000	400,000	$35,272	$35,472	$200	0.6%	$30,252	$30,410	$158	0.5%
1,000	600,000	$43,349	$43,549	$200	0.5%	$37,702	$37,860	$158	0.4%

[1] Including HELP, DSM, EBA, REC and SOLAR adjustments.

Rocky Mountain Power
Monthly Billing Comparison
Schedule 8 - State of Utah
General Service - Distribution Voltage > 1 MW
Step 1 - Effective 9/1/2014

kW		On-Peak	Summer				Winter			
			Monthly Billing[1]		Change		Monthly Billing[1]		Change	
Load Size[2]	kWh	kWh %	Present	Proposed	$	%	Present	Proposed	$	%
1,000	365,000	60%	$36,238	$36,947	$709	2.0%	$29,305	$29,870	$565	1.9%
1,000	365,000	50%	$35,622	$36,317	$696	2.0%	$29,099	$29,659	$560	1.9%
1,000	365,000	40%	$35,005	$35,688	$683	2.0%	$28,893	$29,448	$555	1.9%
1,000	511,000	60%	$42,850	$43,686	$836	2.0%	$34,931	$35,605	$674	1.9%
1,000	511,000	50%	$41,987	$42,805	$818	1.9%	$34,643	$35,310	$666	1.9%
1,000	511,000	40%	$41,124	$41,924	$800	1.9%	$34,355	$35,014	$659	1.9%
1,000	657,000	60%	$49,462	$50,426	$964	1.9%	$40,558	$41,340	$782	1.9%
1,000	657,000	50%	$48,352	$49,293	$940	1.9%	$40,188	$40,960	$772	1.9%
1,000	657,000	40%	$47,243	$48,159	$917	1.9%	$39,817	$40,580	$763	1.9%
2,000	730,000	60%	$72,358	$73,775	$1,417	2.0%	$58,491	$59,621	$1,130	1.9%
2,000	730,000	50%	$71,125	$72,516	$1,391	2.0%	$58,080	$59,199	$1,120	1.9%
2,000	730,000	40%	$69,892	$71,257	$1,364	2.0%	$57,668	$58,777	$1,110	1.9%
2,000	1,022,000	60%	$85,582	$87,253	$1,672	2.0%	$69,745	$71,091	$1,346	1.9%
2,000	1,022,000	50%	$83,856	$85,491	$1,635	1.9%	$69,168	$70,500	$1,332	1.9%
2,000	1,022,000	40%	$82,130	$83,728	$1,598	1.9%	$68,592	$69,910	$1,318	1.9%
2,000	1,314,000	60%	$98,806	$100,732	$1,927	1.9%	$80,998	$82,560	$1,562	1.9%
2,000	1,314,000	50%	$96,587	$98,466	$1,879	1.9%	$80,257	$81,801	$1,544	1.9%
2,000	1,314,000	40%	$94,368	$96,200	$1,832	1.9%	$79,516	$81,042	$1,526	1.9%
4,000	1,460,000	60%	$144,598	$147,430	$2,833	2.0%	$116,864	$119,123	$2,259	1.9%
4,000	1,460,000	50%	$142,132	$144,912	$2,780	2.0%	$116,041	$118,279	$2,238	1.9%
4,000	1,460,000	40%	$139,666	$142,394	$2,728	2.0%	$115,218	$117,436	$2,218	1.9%
4,000	2,044,000	60%	$171,046	$174,388	$3,342	2.0%	$139,372	$142,063	$2,691	1.9%
4,000	2,044,000	50%	$167,594	$170,863	$3,269	2.0%	$138,219	$140,881	$2,663	1.9%
4,000	2,044,000	40%	$164,142	$167,338	$3,195	1.9%	$137,066	$139,700	$2,634	1.9%
4,000	2,628,000	60%	$197,494	$201,346	$3,852	2.0%	$161,879	$165,002	$3,123	1.9%
4,000	2,628,000	50%	$193,056	$196,813	$3,758	1.9%	$160,396	$163,483	$3,087	1.9%
4,000	2,628,000	40%	$188,618	$192,281	$3,663	1.9%	$158,914	$161,965	$3,051	1.9%
6,000	2,190,000	60%	$216,837	$221,086	$4,248	2.0%	$175,238	$178,625	$3,387	1.9%
6,000	2,190,000	50%	$213,139	$217,309	$4,170	2.0%	$174,003	$177,360	$3,357	1.9%
6,000	2,190,000	40%	$209,441	$213,532	$4,091	2.0%	$172,767	$176,094	$3,327	1.9%
6,000	3,066,000	60%	$256,509	$261,522	$5,013	2.0%	$208,998	$213,034	$4,036	1.9%
6,000	3,066,000	50%	$251,332	$256,235	$4,903	2.0%	$207,269	$211,263	$3,994	1.9%
6,000	3,066,000	40%	$246,154	$250,947	$4,793	1.9%	$205,540	$209,491	$3,951	1.9%
6,000	3,942,000	60%	$296,182	$301,959	$5,778	2.0%	$242,759	$247,443	$4,685	1.9%
6,000	3,942,000	50%	$289,525	$295,161	$5,636	1.9%	$240,536	$245,166	$4,630	1.9%
6,000	3,942,000	40%	$282,868	$288,362	$5,494	1.9%	$238,312	$242,888	$4,575	1.9%
10,000	3,650,000	60%	$361,317	$368,397	$7,080	2.0%	$291,984	$297,629	$5,645	1.9%
10,000	3,650,000	50%	$355,153	$362,102	$6,949	2.0%	$289,926	$295,520	$5,594	1.9%
10,000	3,650,000	40%	$348,989	$355,807	$6,817	2.0%	$287,867	$293,411	$5,544	1.9%
10,000	5,110,000	60%	$427,437	$435,791	$8,354	2.0%	$348,252	$354,978	$6,726	1.9%
10,000	5,110,000	50%	$418,808	$426,978	$8,171	2.0%	$345,370	$352,025	$6,655	1.9%
10,000	5,110,000	40%	$410,178	$418,165	$7,987	1.9%	$342,488	$349,072	$6,584	1.9%
10,000	6,570,000	60%	$493,557	$503,186	$9,629	2.0%	$404,519	$412,326	$7,807	1.9%
10,000	6,570,000	50%	$482,462	$491,855	$9,393	1.9%	$400,814	$408,530	$7,716	1.9%
10,000	6,570,000	40%	$471,367	$480,524	$9,156	1.9%	$397,109	$404,734	$7,625	1.9%

[1] Including HELP, DSM, EBA, REC and SOLAR adjustments.
[2] Assumes customer monthly peak occurs during On-Peak hours.

Rocky Mountain Power
Monthly Billing Comparison
Schedule 9 - State of Utah
General Service - Transmission Voltage
Step 1 - Effective 9/1/2014

			Summer				Winter			
kW		On-Peak	Monthly Billing[1]		Change		Monthly Billing[1]		Change	
Load Size[2]	kWh	kWh %	Present	Proposed	$	%	Present	Proposed	$	%
500	182,500	60%	$15,775	$16,284	$508	3.2%	$12,228	$12,621	$393	3.2%
500	182,500	50%	$15,456	$15,954	$498	3.2%	$12,122	$12,511	$390	3.2%
500	182,500	40%	$15,137	$15,625	$488	3.2%	$12,015	$12,402	$386	3.2%
500	255,500	60%	$18,708	$19,311	$603	3.2%	$14,651	$15,122	$471	3.2%
500	255,500	50%	$18,262	$18,850	$589	3.2%	$14,502	$14,968	$466	3.2%
500	255,500	40%	$17,815	$18,389	$574	3.2%	$14,353	$14,815	$461	3.2%
500	328,500	60%	$21,641	$22,339	$698	3.2%	$17,073	$17,623	$549	3.2%
500	328,500	50%	$21,067	$21,747	$679	3.2%	$16,882	$17,425	$543	3.2%
500	328,500	40%	$20,493	$21,154	$661	3.2%	$16,691	$17,228	$537	3.2%
1,000	365,000	60%	$31,253	$32,262	$1,009	3.2%	$24,159	$24,937	$778	3.2%
1,000	365,000	50%	$30,615	$31,604	$988	3.2%	$23,946	$24,717	$771	3.2%
1,000	365,000	40%	$29,977	$30,945	$968	3.2%	$23,734	$24,498	$764	3.2%
1,000	511,000	60%	$37,120	$38,318	$1,198	3.2%	$29,004	$29,938	$934	3.2%
1,000	511,000	50%	$36,227	$37,396	$1,169	3.2%	$28,707	$29,631	$925	3.2%
1,000	511,000	40%	$35,334	$36,474	$1,140	3.2%	$28,409	$29,324	$915	3.2%
1,000	657,000	60%	$42,986	$44,373	$1,388	3.2%	$33,850	$34,940	$1,090	3.2%
1,000	657,000	50%	$41,838	$43,188	$1,350	3.2%	$33,467	$34,545	$1,078	3.2%
1,000	657,000	40%	$40,690	$42,003	$1,313	3.2%	$33,085	$34,150	$1,066	3.2%
2,000	730,000	60%	$62,209	$64,219	$2,010	3.2%	$48,021	$49,569	$1,548	3.2%
2,000	730,000	50%	$60,934	$62,902	$1,968	3.2%	$47,596	$49,130	$1,534	3.2%
2,000	730,000	40%	$59,658	$61,585	$1,927	3.2%	$47,171	$48,691	$1,520	3.2%
2,000	1,022,000	60%	$73,942	$76,331	$2,388	3.2%	$57,712	$59,572	$1,860	3.2%
2,000	1,022,000	50%	$72,156	$74,487	$2,331	3.2%	$57,117	$58,958	$1,841	3.2%
2,000	1,022,000	40%	$70,370	$72,643	$2,273	3.2%	$56,522	$58,344	$1,822	3.2%
2,000	1,314,000	60%	$85,675	$88,442	$2,767	3.2%	$67,402	$69,575	$2,173	3.2%
2,000	1,314,000	50%	$83,378	$86,071	$2,693	3.2%	$66,638	$68,786	$2,148	3.2%
2,000	1,314,000	40%	$81,082	$83,701	$2,618	3.2%	$65,873	$67,996	$2,123	3.2%
4,000	1,460,000	60%	$124,122	$128,133	$4,012	3.2%	$95,745	$98,832	$3,088	3.2%
4,000	1,460,000	50%	$121,570	$125,499	$3,929	3.2%	$94,895	$97,955	$3,060	3.2%
4,000	1,460,000	40%	$119,019	$122,865	$3,846	3.2%	$94,045	$97,077	$3,033	3.2%
4,000	2,044,000	60%	$147,587	$152,356	$4,769	3.2%	$115,126	$118,839	$3,713	3.2%
4,000	2,044,000	50%	$144,015	$148,668	$4,653	3.2%	$113,936	$117,610	$3,674	3.2%
4,000	2,044,000	40%	$140,443	$144,981	$4,537	3.2%	$112,747	$116,382	$3,635	3.2%
4,000	2,628,000	60%	$171,052	$176,579	$5,526	3.2%	$134,508	$138,845	$4,338	3.2%
4,000	2,628,000	50%	$166,460	$171,837	$5,378	3.2%	$132,978	$137,266	$4,288	3.2%
4,000	2,628,000	40%	$161,867	$167,096	$5,229	3.2%	$131,448	$135,687	$4,238	3.2%
6,000	2,190,000	60%	$186,034	$192,047	$6,013	3.2%	$143,468	$148,096	$4,627	3.2%
6,000	2,190,000	50%	$182,207	$188,096	$5,889	3.2%	$142,194	$146,780	$4,586	3.2%
6,000	2,190,000	40%	$178,380	$184,145	$5,765	3.2%	$140,919	$145,464	$4,545	3.2%
6,000	3,066,000	60%	$221,232	$228,381	$7,149	3.2%	$172,541	$178,106	$5,565	3.2%
6,000	3,066,000	50%	$215,874	$222,850	$6,976	3.2%	$170,756	$176,263	$5,507	3.2%
6,000	3,066,000	40%	$210,516	$217,318	$6,802	3.2%	$168,971	$174,421	$5,449	3.2%
6,000	3,942,000	60%	$256,430	$264,716	$8,286	3.2%	$201,613	$208,116	$6,502	3.2%
6,000	3,942,000	50%	$249,541	$257,604	$8,062	3.2%	$199,319	$205,747	$6,428	3.2%
6,000	3,942,000	40%	$242,653	$250,492	$7,839	3.2%	$197,024	$203,378	$6,354	3.2%

[1] Including HELP, DSM, EBA, REC and SOLAR adjustments.
[2] Assumes customer monthly peak occurs during On-Peak hours.

Rocky Mountain Power
Monthly Billing Comparison
Schedule 10 - State of Utah
Irrigation and Soil Drainage Pumping Power Service - Distribution Voltage
Step 1 - Effective 9/1/2014

kW		Irrigation Season				Post-Irrigation Season			
		Monthly Billing[1]		Change		Monthly Billing[1]		Change	
Load Size	kWh	Present	Proposed	$	%	Present	Proposed	$	%
10	3,000	$312	$321	$9	2.8%	$168	$172	$4	2.6%
10	5,000	$460	$473	$13	2.8%	$270	$277	$7	2.7%
10	7,000	$609	$626	$17	2.8%	$372	$382	$10	2.8%
20	6,000	$609	$626	$17	2.9%	$321	$330	$9	2.8%
20	10,000	$906	$932	$26	2.9%	$524	$539	$15	2.8%
20	14,000	$1,202	$1,237	$35	2.9%	$728	$749	$21	2.8%
50	15,000	$1,499	$1,542	$43	2.9%	$779	$801	$22	2.9%
50	25,000	$2,241	$2,306	$65	2.9%	$1,288	$1,325	$37	2.9%
50	35,000	$2,886	$2,970	$84	2.9%	$1,797	$1,849	$52	2.9%
100	30,000	$2,983	$3,070	$87	2.9%	$1,542	$1,587	$44	2.9%
100	50,000	$4,081	$4,200	$119	2.9%	$2,560	$2,634	$74	2.9%
100	70,000	$5,179	$5,330	$151	2.9%	$3,578	$3,682	$104	2.9%
200	60,000	$5,372	$5,529	$157	2.9%	$3,069	$3,158	$89	2.9%
200	100,000	$7,568	$7,789	$221	2.9%	$5,105	$5,254	$148	2.9%
200	140,000	$9,764	$10,049	$285	2.9%	$7,142	$7,349	$207	2.9%
300	90,000	$7,761	$7,988	$227	2.9%	$4,596	$4,730	$133	2.9%
300	150,000	$11,055	$11,378	$323	2.9%	$7,651	$7,873	$222	2.9%
300	210,000	$14,349	$14,768	$419	2.9%	$10,705	$11,016	$311	2.9%

[1] Including HELP, DSM, EBA, REC and SOLAR adjustments.. Not including annual customer service charge.

Rocky Mountain Power
Monthly Billing Comparison
Schedule 23 - State of Utah
General Service - Distribution Voltage
Step 1 - Effective 9/1/2014

		Summer				Winter			
kW		Monthly Billing[1]		Change		Monthly Billing[1]		Change	
Load Size	kWh	Present	Proposed	$	%	Present	Proposed	$	%
0 to 15	200	$34.98	$35.23	$0.25	0.7%	$33.03	$33.26	$0.23	0.7%
	500	$71.77	$72.40	$0.63	0.9%	$66.90	$67.49	$0.59	0.9%
	1,000	$133.08	$134.35	$1.27	1.0%	$123.35	$124.52	$1.17	0.9%
	2,000	$228.85	$231.11	$2.26	1.0%	$211.55	$213.61	$2.06	1.0%
20	5,000	$480.60	$485.52	$4.92	1.0%	$447.32	$451.72	$4.40	1.0%
	7,500	$652.87	$659.56	$6.69	1.0%	$606.04	$611.97	$5.93	1.0%
	10,000	$825.13	$833.60	$8.47	1.0%	$764.77	$772.21	$7.44	1.0%
25	7,500	$697.90	$705.12	$7.22	1.0%	$651.34	$657.79	$6.45	1.0%
	10,000	$870.16	$879.16	$9.00	1.0%	$810.06	$818.03	$7.97	1.0%
	12,500	$1,042.42	$1,053.20	$10.78	1.0%	$968.79	$978.28	$9.49	1.0%
30	10,000	$915.19	$924.72	$9.53	1.0%	$855.36	$863.85	$8.49	1.0%
	12,500	$1,087.45	$1,098.76	$11.31	1.0%	$1,014.08	$1,024.10	$10.02	1.0%
	15,000	$1,259.72	$1,272.80	$13.08	1.0%	$1,172.81	$1,184.34	$11.53	1.0%

[1] Including HELP, DSM, EBA, REC and SOLAR adjustments.

Rocky Mountain Power
Monthly Billing Comparison
Schedule 6 - State of Utah
General Service - Distribution Voltage
Step 2 - Effective 9/1/2015

kW		Summer				Winter			
		Monthly Billing[1]		Change		Monthly Billing[1]		Change	
Load Size	kWh	Present	Proposed	$	%	Present	Proposed	$	%
50	5,000	$1,228	$1,246	$18	1.5%	$1,022	$1,035	$14	1.3%
50	10,000	$1,430	$1,448	$18	1.3%	$1,208	$1,221	$14	1.1%
50	20,000	$1,833	$1,852	$18	1.0%	$1,580	$1,594	$14	0.9%
100	20,000	$2,796	$2,833	$37	1.3%	$2,353	$2,380	$27	1.2%
100	40,000	$3,604	$3,641	$37	1.0%	$3,098	$3,125	$27	0.9%
100	60,000	$4,412	$4,448	$37	0.8%	$3,843	$3,870	$27	0.7%
200	40,000	$5,529	$5,603	$74	1.3%	$4,642	$4,697	$55	1.2%
200	80,000	$7,145	$7,218	$74	1.0%	$6,132	$6,187	$55	0.9%
200	120,000	$8,760	$8,834	$74	0.8%	$7,622	$7,677	$55	0.7%
500	100,000	$13,729	$13,913	$184	1.3%	$11,512	$11,648	$137	1.2%
500	200,000	$17,767	$17,951	$184	1.0%	$15,236	$15,373	$137	0.9%
500	300,000	$21,806	$21,990	$184	0.8%	$18,961	$19,098	$137	0.7%
1,000	200,000	$27,395	$27,763	$368	1.3%	$22,960	$23,234	$273	1.2%
1,000	400,000	$35,472	$35,840	$368	1.0%	$30,410	$30,683	$273	0.9%
1,000	600,000	$43,549	$43,917	$368	0.8%	$37,860	$38,133	$273	0.7%

[1] Including HELP, DSM, EBA, REC and SOLAR adjustments.

Rocky Mountain Power
Monthly Billing Comparison
Schedule 8 - State of Utah
General Service - Distribution Voltage > 1 MW
Step 2 - Effective 9/1/2015

			Summer				Winter			
kW		On-Peak	Monthly Billing[1]		Change		Monthly Billing[1]		Change	
Load Size[2]	kWh	kWh %	Present	Proposed	$	%	Present	Proposed	$	%
1,000	365,000	60%	$36,947	$37,333	$386	1.0%	$29,870	$30,177	$307	1.0%
1,000	365,000	50%	$36,317	$36,697	$380	1.0%	$29,659	$29,965	$306	1.0%
1,000	365,000	40%	$35,688	$36,062	$374	1.0%	$29,448	$29,752	$304	1.0%
1,000	511,000	60%	$43,686	$44,142	$456	1.0%	$35,605	$35,972	$367	1.0%
1,000	511,000	50%	$42,805	$43,252	$447	1.0%	$35,310	$35,674	$365	1.0%
1,000	511,000	40%	$41,924	$42,363	$439	1.0%	$35,014	$35,377	$362	1.0%
1,000	657,000	60%	$50,426	$50,951	$525	1.0%	$41,340	$41,766	$426	1.0%
1,000	657,000	50%	$49,293	$49,807	$515	1.0%	$40,960	$41,383	$423	1.0%
1,000	657,000	40%	$48,159	$48,664	$504	1.0%	$40,580	$41,001	$421	1.0%
2,000	730,000	60%	$73,775	$74,545	$771	1.0%	$59,621	$60,235	$614	1.0%
2,000	730,000	50%	$72,516	$73,274	$759	1.0%	$59,199	$59,810	$610	1.0%
2,000	730,000	40%	$71,257	$72,004	$747	1.0%	$58,777	$59,385	$607	1.0%
2,000	1,022,000	60%	$87,253	$88,164	$910	1.0%	$71,091	$71,823	$733	1.0%
2,000	1,022,000	50%	$85,491	$86,385	$894	1.0%	$70,500	$71,228	$728	1.0%
2,000	1,022,000	40%	$83,728	$84,606	$877	1.0%	$69,910	$70,633	$724	1.0%
2,000	1,314,000	60%	$100,732	$101,782	$1,050	1.0%	$82,560	$83,412	$851	1.0%
2,000	1,314,000	50%	$98,466	$99,495	$1,029	1.0%	$81,801	$82,647	$846	1.0%
2,000	1,314,000	40%	$96,200	$97,207	$1,007	1.0%	$81,042	$81,882	$840	1.0%
4,000	1,460,000	60%	$147,430	$148,970	$1,540	1.0%	$119,123	$120,349	$1,226	1.0%
4,000	1,460,000	50%	$144,912	$146,429	$1,517	1.0%	$118,279	$119,499	$1,220	1.0%
4,000	1,460,000	40%	$142,394	$143,887	$1,493	1.0%	$117,436	$118,649	$1,213	1.0%
4,000	2,044,000	60%	$174,388	$176,207	$1,819	1.0%	$142,063	$143,527	$1,464	1.0%
4,000	2,044,000	50%	$170,863	$172,649	$1,786	1.0%	$140,881	$142,337	$1,455	1.0%
4,000	2,044,000	40%	$167,338	$169,091	$1,754	1.0%	$139,700	$141,147	$1,446	1.0%
4,000	2,628,000	60%	$201,346	$203,444	$2,098	1.0%	$165,002	$166,704	$1,702	1.0%
4,000	2,628,000	50%	$196,813	$198,869	$2,056	1.0%	$163,483	$165,174	$1,691	1.0%
4,000	2,628,000	40%	$192,281	$194,295	$2,014	1.0%	$161,965	$163,644	$1,679	1.0%
6,000	2,190,000	60%	$221,086	$223,395	$2,310	1.0%	$178,625	$180,464	$1,839	1.0%
6,000	2,190,000	50%	$217,309	$219,583	$2,275	1.0%	$177,360	$179,189	$1,829	1.0%
6,000	2,190,000	40%	$213,532	$215,771	$2,239	1.0%	$176,094	$177,914	$1,820	1.0%
6,000	3,066,000	60%	$261,522	$264,251	$2,728	1.0%	$213,034	$215,230	$2,196	1.0%
6,000	3,066,000	50%	$256,235	$258,914	$2,679	1.0%	$211,263	$213,445	$2,182	1.0%
6,000	3,066,000	40%	$250,947	$253,577	$2,630	1.0%	$209,491	$211,660	$2,169	1.0%
6,000	3,942,000	60%	$301,959	$305,106	$3,147	1.0%	$247,443	$249,996	$2,552	1.0%
6,000	3,942,000	50%	$295,161	$298,244	$3,084	1.0%	$245,166	$247,701	$2,535	1.0%
6,000	3,942,000	40%	$288,362	$291,382	$3,020	1.0%	$242,888	$245,406	$2,518	1.0%
10,000	3,650,000	60%	$368,397	$372,245	$3,849	1.0%	$297,629	$300,693	$3,064	1.0%
10,000	3,650,000	50%	$362,102	$365,892	$3,790	1.0%	$295,520	$298,568	$3,048	1.0%
10,000	3,650,000	40%	$355,807	$359,538	$3,732	1.0%	$293,411	$296,443	$3,032	1.0%
10,000	5,110,000	60%	$435,791	$440,338	$4,547	1.0%	$354,978	$358,636	$3,659	1.0%
10,000	5,110,000	50%	$426,978	$431,443	$4,464	1.0%	$352,025	$355,661	$3,636	1.0%
10,000	5,110,000	40%	$418,165	$422,548	$4,382	1.0%	$349,072	$352,686	$3,614	1.0%
10,000	6,570,000	60%	$503,186	$508,430	$5,244	1.0%	$412,326	$416,580	$4,253	1.0%
10,000	6,570,000	50%	$491,855	$496,994	$5,139	1.0%	$408,530	$412,755	$4,225	1.0%
10,000	6,570,000	40%	$480,524	$485,557	$5,033	1.0%	$404,734	$408,930	$4,197	1.0%

[1] Including HELP, DSM, EBA, REC and SOLAR adjustments.
[2] Assumes customer monthly peak occurs during On-Peak hours.

Rocky Mountain Power
Monthly Billing Comparison
Schedule 9 - State of Utah
General Service - Transmission Voltage
Step 2 - Effective 9/1/2015

			Summer				Winter			
kW		On-Peak	Monthly Billing[1]		Change		Monthly Billing[1]		Change	
Load Size[2]	kWh	kWh %	Present	Proposed	$	%	Present	Proposed	$	%
500	182,500	60%	$16,284	$16,531	$248	1.5%	$12,621	$12,817	$196	1.6%
500	182,500	50%	$15,954	$16,197	$243	1.5%	$12,511	$12,705	$194	1.6%
500	182,500	40%	$15,625	$15,863	$238	1.5%	$12,402	$12,594	$192	1.6%
500	255,500	60%	$19,311	$19,606	$295	1.5%	$15,122	$15,356	$234	1.5%
500	255,500	50%	$18,850	$19,138	$288	1.5%	$14,968	$15,200	$232	1.5%
500	255,500	40%	$18,389	$18,670	$281	1.5%	$14,815	$15,044	$230	1.5%
500	328,500	60%	$22,339	$22,681	$342	1.5%	$17,623	$17,896	$273	1.5%
500	328,500	50%	$21,747	$22,079	$333	1.5%	$17,425	$17,695	$270	1.5%
500	328,500	40%	$21,154	$21,477	$323	1.5%	$17,228	$17,495	$267	1.5%
1,000	365,000	60%	$32,262	$32,754	$492	1.5%	$24,937	$25,324	$387	1.6%
1,000	365,000	50%	$31,604	$32,085	$482	1.5%	$24,717	$25,101	$384	1.6%
1,000	365,000	40%	$30,945	$31,416	$471	1.5%	$24,498	$24,879	$381	1.6%
1,000	511,000	60%	$38,318	$38,903	$586	1.5%	$29,938	$30,403	$465	1.6%
1,000	511,000	50%	$37,396	$37,967	$571	1.5%	$29,631	$30,091	$460	1.6%
1,000	511,000	40%	$36,474	$37,031	$557	1.5%	$29,324	$29,779	$455	1.6%
1,000	657,000	60%	$44,373	$45,053	$680	1.5%	$34,940	$35,482	$542	1.6%
1,000	657,000	50%	$43,188	$43,849	$661	1.5%	$34,545	$35,081	$536	1.6%
1,000	657,000	40%	$42,003	$42,645	$643	1.5%	$34,150	$34,680	$530	1.6%
2,000	730,000	60%	$64,219	$65,199	$980	1.5%	$49,569	$50,339	$771	1.6%
2,000	730,000	50%	$62,902	$63,861	$959	1.5%	$49,130	$49,894	$764	1.6%
2,000	730,000	40%	$61,585	$62,524	$939	1.5%	$48,691	$49,448	$757	1.6%
2,000	1,022,000	60%	$76,331	$77,498	$1,167	1.5%	$59,572	$60,497	$925	1.6%
2,000	1,022,000	50%	$74,487	$75,625	$1,139	1.5%	$58,958	$59,874	$916	1.6%
2,000	1,022,000	40%	$72,643	$73,753	$1,110	1.5%	$58,344	$59,250	$906	1.6%
2,000	1,314,000	60%	$88,442	$89,797	$1,355	1.5%	$69,575	$70,655	$1,080	1.6%
2,000	1,314,000	50%	$86,071	$87,389	$1,318	1.5%	$68,786	$69,854	$1,068	1.6%
2,000	1,314,000	40%	$83,701	$84,982	$1,281	1.5%	$67,996	$69,052	$1,056	1.6%
4,000	1,460,000	60%	$128,133	$130,089	$1,955	1.5%	$98,832	$100,369	$1,537	1.6%
4,000	1,460,000	50%	$125,499	$127,414	$1,914	1.5%	$97,955	$99,478	$1,524	1.6%
4,000	1,460,000	40%	$122,865	$124,739	$1,874	1.5%	$97,077	$98,587	$1,510	1.6%
4,000	2,044,000	60%	$152,356	$154,687	$2,331	1.5%	$118,839	$120,686	$1,847	1.6%
4,000	2,044,000	50%	$148,668	$150,942	$2,273	1.5%	$117,610	$119,438	$1,828	1.6%
4,000	2,044,000	40%	$144,981	$147,197	$2,216	1.5%	$116,382	$118,191	$1,809	1.6%
4,000	2,628,000	60%	$176,579	$179,285	$2,706	1.5%	$138,845	$141,002	$2,156	1.6%
4,000	2,628,000	50%	$171,837	$174,470	$2,632	1.5%	$137,266	$139,398	$2,132	1.6%
4,000	2,628,000	40%	$167,096	$169,655	$2,559	1.5%	$135,687	$137,794	$2,108	1.6%
6,000	2,190,000	60%	$192,047	$194,978	$2,931	1.5%	$148,096	$150,399	$2,304	1.6%
6,000	2,190,000	50%	$188,096	$190,966	$2,870	1.5%	$146,780	$149,063	$2,283	1.6%
6,000	2,190,000	40%	$184,145	$186,953	$2,808	1.5%	$145,464	$147,727	$2,263	1.6%
6,000	3,066,000	60%	$228,381	$231,876	$3,494	1.5%	$178,106	$180,874	$2,768	1.6%
6,000	3,066,000	50%	$222,850	$226,258	$3,408	1.5%	$176,263	$179,003	$2,740	1.6%
6,000	3,066,000	40%	$217,318	$220,640	$3,322	1.5%	$174,421	$177,132	$2,711	1.6%
6,000	3,942,000	60%	$264,716	$268,773	$4,057	1.5%	$208,116	$211,348	$3,233	1.6%
6,000	3,942,000	50%	$257,604	$261,550	$3,947	1.5%	$205,747	$208,943	$3,196	1.6%
6,000	3,942,000	40%	$250,492	$254,327	$3,836	1.5%	$203,378	$206,537	$3,159	1.6%

[1] Including HELP, DSM, EBA, REC and SOLAR adjustments.
[2] Assumes customer monthly peak occurs during On-Peak hours.

Rocky Mountain Power
Monthly Billing Comparison
Schedule 10 - State of Utah
Irrigation and Soil Drainage Pumping Power Service - Distribution Voltage
Step 2 - Effective 9/1/2015

		Irrigation Season				Post-Irrigation Season			
kW		Monthly Billing[1]		Change		Monthly Billing[1]		Change	
Load Size	kWh	Present	Proposed	$	%	Present	Proposed	$	%
10	3,000	$321	$324	$3	1.0%	$172	$174	$2	1.0%
10	5,000	$473	$478	$5	1.0%	$277	$280	$3	1.0%
10	7,000	$626	$633	$6	1.0%	$382	$386	$4	1.0%
20	6,000	$626	$633	$7	1.0%	$330	$333	$3	1.0%
20	10,000	$932	$941	$10	1.0%	$539	$545	$6	1.0%
20	14,000	$1,237	$1,250	$13	1.0%	$749	$756	$8	1.0%
50	15,000	$1,542	$1,559	$16	1.1%	$801	$809	$8	1.0%
50	25,000	$2,306	$2,330	$24	1.1%	$1,325	$1,339	$14	1.0%
50	35,000	$2,970	$3,002	$31	1.1%	$1,849	$1,868	$19	1.0%
100	30,000	$3,070	$3,102	$33	1.1%	$1,587	$1,603	$17	1.0%
100	50,000	$4,200	$4,244	$44	1.1%	$2,634	$2,662	$28	1.0%
100	70,000	$5,330	$5,386	$56	1.1%	$3,682	$3,721	$39	1.0%
200	60,000	$5,529	$5,588	$59	1.1%	$3,158	$3,191	$33	1.0%
200	100,000	$7,789	$7,872	$83	1.1%	$5,254	$5,309	$55	1.0%
200	140,000	$10,049	$10,155	$107	1.1%	$7,349	$7,426	$77	1.0%
300	90,000	$7,988	$8,073	$85	1.1%	$4,730	$4,779	$50	1.0%
300	150,000	$11,378	$11,499	$121	1.1%	$7,873	$7,955	$83	1.0%
300	210,000	$14,768	$14,925	$157	1.1%	$11,016	$11,131	$116	1.1%

[1] Including HELP, DSM, EBA, REC and SOLAR adjustments.. Not including annual customer service charge.

Rocky Mountain Power
Monthly Billing Comparison
Schedule 23 - State of Utah
General Service - Distribution Voltage
Step 2 - Effective 9/1/2015

		Summer				Winter			
kW		Monthly Billing[1]		Change		Monthly Billing[1]		Change	
Load Size	kWh	Present	Proposed	$	%	Present	Proposed	$	%
0 to 15	200	$35.23	$35.24	$0.01	0.0%	$33.26	$33.27	$0.01	0.0%
	500	$72.40	$72.42	$0.02	0.0%	$67.49	$67.50	$0.01	0.0%
	1,000	$134.35	$134.39	$0.04	0.0%	$124.52	$124.56	$0.04	0.0%
	2,000	$231.11	$231.18	$0.07	0.0%	$213.61	$213.68	$0.07	0.0%
20	5,000	$485.52	$485.65	$0.13	0.0%	$451.72	$451.93	$0.21	0.0%
	7,500	$659.56	$659.74	$0.18	0.0%	$611.97	$612.29	$0.32	0.1%
	10,000	$833.60	$833.84	$0.24	0.0%	$772.21	$772.65	$0.44	0.1%
25	7,500	$705.12	$705.30	$0.18	0.0%	$657.79	$658.11	$0.32	0.0%
	10,000	$879.16	$879.39	$0.23	0.0%	$818.03	$818.47	$0.44	0.1%
	12,500	$1,053.20	$1,053.49	$0.29	0.0%	$978.28	$978.83	$0.55	0.1%
30	10,000	$924.72	$924.95	$0.23	0.0%	$863.85	$864.29	$0.44	0.1%
	12,500	$1,098.76	$1,099.05	$0.29	0.0%	$1,024.10	$1,024.65	$0.55	0.1%
	15,000	$1,272.80	$1,273.14	$0.34	0.0%	$1,184.34	$1,185.01	$0.67	0.1%

[1] Including HELP, DSM, EBA, REC and SOLAR adjustments.

Exhibit D

Price Summary
Rocky Mountain Power - State of Utah

		A - Net Metering Facilities Charge		B - No Net Metering Facilities Charge	
	Present	Step 1 - 9/1/2014	Step 2 - 9/1/2015	Step 1 - 9/1/2014	Step 2 - 9/1/2015
	Price	Price	Price	Price	Price
Schedule No. 1- Residential Service					
Customer Charge - 1 Phase	$5.00	$6.00	$6.00	$6.00	$6.00
Customer Charge - 3 Phase	$10.00	$12.00	$12.00	$12.00	$12.00
Net Metering Facilities Charge		$4.65	$4.65	$0.00	$0.00
First 400 kWh (May-Sept)	8.8498 ¢	8.8498 ¢	8.8498 ¢	8.8498 ¢	8.8498 ¢
Next 600 kWh (May-Sept)	11.5429 ¢	11.5429 ¢	11.5429 ¢	11.5429 ¢	11.5429 ¢
All add'l kWh (May-Sept)	14.4508 ¢	14.4508 ¢	14.4508 ¢	14.4508 ¢	14.4508 ¢
All kWh (Oct-Apr)					
First 400 kWh (Oct-Apr)	8.8498 ¢	8.8498 ¢	8.8498 ¢	8.8498 ¢	8.8498 ¢
All add'l kWh (Oct-Apr)	9.8913 ¢	10.3045 ¢	10.7006 ¢	10.3111 ¢	10.7072 ¢
Minimum 1 Phase	$7.00	$8.00	$8.00	$8.00	$8.00
Minimum 3 Phase	$14.00	$16.00	$16.00	$16.00	$16.00
Minimum Seasonal	$84.00	$96.00	$96.00	$96.00	$96.00
Schedule No. 3- Residential Service - Low Income Lifeline Program					
Customer Charge - 1 Phase	$5.00	$6.00	$6.00	$6.00	$6.00
Customer Charge - 3 Phase	$10.00	$12.00	$12.00	$12.00	$12.00
Net Metering Facilities Charge		$4.65	$4.65	$0.00	$0.00
First 400 kWh (May-Sept)	8.8498 ¢	8.8498 ¢	8.8498 ¢	8.8498 ¢	8.8498 ¢
Next 600 kWh (May-Sept)	11.5429 ¢	11.5429 ¢	11.5429 ¢	11.5429 ¢	11.5429 ¢
All add'l kWh (May-Sept)	14.4508 ¢	14.4508 ¢	14.4508 ¢	14.4508 ¢	14.4508 ¢
All kWh (Oct-Apr)					
First 400 kWh (Oct-Apr)	8.8498 ¢	8.8498 ¢	8.8498 ¢	8.8498 ¢	8.8498 ¢
All add'l kWh (Oct-Apr)	9.8913 ¢	10.3045 ¢	10.7006 ¢	10.3111 ¢	10.7072 ¢
Minimum 1 Phase	$7.00	$8.00	$8.00	$8.00	$8.00
Minimum 3 Phase	$14.00	$16.00	$16.00	$16.00	$16.00
Minimum Seasonal	$84.00	$96.00	$96.00	$96.00	$96.00
Low Income Lifeline Credit	$11.00	$12.60	$12.60	$12.60	$12.60
Life Support Assistance Credit	$10.00	$10.00	$10.00	$10.00	$10.00
Schedule No. 2 - Residential Service - Optional Time-of-Day					
Customer Charge - 1 Phase	$5.00	$6.00	$6.00	$6.00	$6.00
Customer Charge - 3 Phase	$10.00	$12.00	$12.00	$12.00	$12.00
Net Metering Facilities Charge		$4.65	$4.65	$0.00	$0.00
On-Peak kWh (May - Sept)	4.3560 ¢	4.3560 ¢	4.3560 ¢	4.3560 ¢	4.3560 ¢
Off-Peak kWh (May - Sept)	(1.6334) ¢	(1.6334) ¢	(1.6334) ¢	(1.6334) ¢	(1.6334) ¢
First 400 kWh (May-Sept)	8.8498 ¢	8.8498 ¢	8.8498 ¢	8.8498 ¢	8.8498 ¢
Next 600 kWh (May-Sept)	11.5429 ¢	11.5429 ¢	11.5429 ¢	11.5429 ¢	11.5429 ¢
All add'l kWh (May-Sept)	14.4508 ¢	14.4508 ¢	14.4508 ¢	14.4508 ¢	14.4508 ¢
All kWh (Oct-Apr)					
First 400 kWh (Oct-Apr)	8.8498 ¢	8.8498 ¢	8.8498 ¢	8.8498 ¢	8.8498 ¢
All add'l kWh (Oct-Apr)	9.8913 ¢	10.3045 ¢	10.7006 ¢	10.3111 ¢	10.7072 ¢
Minimum 1 Phase	$7.00	$8.00	$8.00	$8.00	$8.00
Minimum 3 Phase	$14.00	$16.00	$16.00	$16.00	$16.00
Minimum Seasonal	$84.00	$96.00	$96.00	$96.00	$96.00

Rocky Mountain Power - State of Utah
Blocking Based on Adjusted Actuals and Forecasted Loads
Base Period 12 Months Ending June 2013
Forecast Test Period 12 Months Ending June 2015

				A - Net Metering Facilities Charge				B - No Net Metering Facilities Charge			
				Step 1 - 9/1/2014		Step 2 - 9/1/2015		Step 1 - 9/1/2014		Step 2 - 9/1/2015	
	Forecasted Units	Present Price	Forecasted Revenue Dollars	Price	Revenue Dollars	Price	Revenue Dollars	Price	Revenue Dollars	Price	Revenue Dollars
Schedule No. 1- Residential Service											
Total Customer	8,511,800										
Customer Charge - 1 Phase	8,398,777	$5.00	$41,993,885	$6.00	$50,392,662	$6.00	$50,392,662	$6.00	$50,392,662	$6.00	$50,392,662
Customer Charge - 3 Phase	14,094	$10.00	$140,940	$12.00	$169,128	$12.00	$169,128	$12.00	$169,128	$12.00	$169,128
Net Metering Facilities Charge	23,932			$4.65	$111,284	$4.65	$111,284	$0.00	$0	$0.00	$0
First 400 kWh (May-Sept)	1,274,636,742	8.8498 ¢	$112,802,802	8.8498 ¢	$112,802,802	8.8498 ¢	$112,802,802	8.8498 ¢	$112,802,802	8.8498 ¢	$112,802,802
Next 600 kWh (May-Sept)	1,040,456,011	11.5429 ¢	$120,098,797	11.5429 ¢	$120,098,797	11.5429 ¢	$120,098,797	11.5429 ¢	$120,098,797	11.5429 ¢	$120,098,797
All add'l kWh (May-Sept)	358,873,906	14.4508 ¢	$51,860,150	14.4508 ¢	$51,860,150	14.4508 ¢	$51,860,150	14.4508 ¢	$51,860,150	14.4508 ¢	$51,860,150
All kWh (Oct-Apr)											
First 400 kWh (Oct-Apr)	1,613,094,234	8.8498 ¢	$142,755,614	8.8498 ¢	$142,755,614	8.8498 ¢	$142,755,614	8.8498 ¢	$142,755,614	8.8498 ¢	$142,755,614
All add'l kWh (Oct-Apr)	1,704,644,903	9.8913 ¢	$168,611,541	10.3045 ¢	$175,655,134	10.7006 ¢	$182,407,232	10.3111 ¢	$175,767,641	10.7072 ¢	$182,519,739
Minimum 1 Phase	98,763	$7.00	$691,341	$8.00	$790,104	$8.00	$790,104	$8.00	$790,104	$8.00	$790,104
Minimum 3 Phase	166	$14.00	$2,324	$16.00	$2,656	$16.00	$2,656	$16.00	$2,656	$16.00	$2,656
Minimum Seasonal	0	$84.00	$0	$96.00	$0	$96.00	$0	$96.00	$0	$96.00	$0
kWh in Minimum	501,472										
kWh in Minimum - Summer	223,485										
kWh in Minimum - Winter	277,987										
Unbilled	0		$0		$0		$0		$0		$0
Total	5,992,207,269		$638,957,394		$654,638,331		$661,390,429		$654,639,554		$661,391,652
Schedule No. 3- Residential Service - Low Income Lifeline Program											
Total Customer	370,465										
Customer Charge - 1 Phase	369,457	$5.00	$1,847,285	$6.00	$2,216,742	$6.00	$2,216,742	$6.00	$2,216,742	$6.00	$2,216,742
Customer Charge - 3 Phase	257	$10.00	$2,570	$12.00	$3,084	$12.00	$3,084	$12.00	$3,084	$12.00	$3,084
Net Metering Facilities Charge	0			$4.65	$0	$4.65	$0	$0.00	$0	$0.00	$0
First 400 kWh (May-Sept)	47,435,117	8.8498 ¢	$4,197,913	8.8498 ¢	$4,197,913	8.8498 ¢	$4,197,913	8.8498 ¢	$4,197,913	8.8498 ¢	$4,197,913
Next 600 kWh (May-Sept)	31,907,309	11.5429 ¢	$3,683,029	11.5429 ¢	$3,683,029	11.5429 ¢	$3,683,029	11.5429 ¢	$3,683,029	11.5429 ¢	$3,683,029
All add'l kWh (May-Sept)	10,205,740	14.4508 ¢	$1,474,811	14.4508 ¢	$1,474,811	14.4508 ¢	$1,474,811	14.4508 ¢	$1,474,811	14.4508 ¢	$1,474,811
All kWh (Oct-Apr)					$0		$0		$0		$0
First 400 kWh (Oct-Apr)	64,598,419	8.8498 ¢	$5,716,831	8.8498 ¢	$5,716,831	8.8498 ¢	$5,716,831	8.8498 ¢	$5,716,831	8.8498 ¢	$5,716,831
All add'l kWh (Oct-Apr)	54,308,077	9.8913 ¢	$5,371,775	10.3045 ¢	$5,596,176	10.7006 ¢	$5,811,290	10.3111 ¢	$5,599,760	10.7072 ¢	$5,814,874
Minimum 1 Phase	751	$7.00	$5,257	$8.00	$6,008	$8.00	$6,008	$8.00	$6,008	$8.00	$6,008
Minimum 3 Phase	0	$14.00	$0	$16.00	$0	$16.00	$0	$16.00	$0	$16.00	$0
Minimum Seasonal	0	$84.00	$0	$96.00	$0	$96.00	$0	$96.00	$0	$96.00	$0
kWh in Minimum	4,249										
kWh in Minimum - Summer	2,043										
kWh in Minimum - Winter	2,206										
Unbilled	0		$0		$0		$0		$0		$0
Total	208,458,911		$22,299,471		$22,894,594		$23,109,708		$22,898,178		$23,113,292
Schedule No. 2 - Residential Service - Optional Time-of-Day											
Total Customer	5,364										
Customer Charge - 1 Phase	5,243	$5.00	$26,215	$6.00	$31,458	$6.00	$31,458	$6.00	$31,458	$6.00	$31,458
Customer Charge - 3 Phase	0	$10.00	$0	$12.00	$0	$12.00	$0	$12.00	$0	$12.00	$0
Net Metering Facilities Charge	1,185			$4.65	$5,510	$4.65	$5,510	$0.00	$0	$0.00	$0
On-Peak kWh (May - Sept)	280,149	4.3560 ¢	$12,203	4.3560 ¢	$12,203	4.3560 ¢	$12,203	4.3560 ¢	$12,203	4.3560 ¢	$12,203
Off-Peak kWh (May - Sept)	954,590	(1.6334) ¢	($15,592)	(1.6334) ¢	($15,592)	(1.6334) ¢	($15,592)	(1.6334) ¢	($15,592)	(1.6334) ¢	($15,592)
First 400 kWh (May-Sept)	675,062	8.8498 ¢	$59,742	8.8498 ¢	$59,742	8.8498 ¢	$59,742	8.8498 ¢	$59,742	8.8498 ¢	$59,742
Next 600 kWh (May-Sept)	474,415	11.5429 ¢	$54,761	11.5429 ¢	$54,761	11.5429 ¢	$54,761	11.5429 ¢	$54,761	11.5429 ¢	$54,761
All add'l kWh (May-Sept)	185,128	14.4508 ¢	$26,752	14.4508 ¢	$26,752	14.4508 ¢	$26,752	14.4508 ¢	$26,752	14.4508 ¢	$26,752
All kWh (Oct-Apr)											
First 400 kWh (Oct-Apr)	912,816	8.8498 ¢	$80,782	8.8498 ¢	$80,782	8.8498 ¢	$80,782	8.8498 ¢	$80,782	8.8498 ¢	$80,782
All add'l kWh (Oct-Apr)	937,823	9.8913 ¢	$92,763	10.3045 ¢	$96,638	10.7006 ¢	$100,353	10.3111 ¢	$96,700	10.7072 ¢	$100,415
Minimum 1 Phase	121	$7.00	$847	$8.00	$968	$8.00	$968	$8.00	$968	$8.00	$968
Minimum 3 Phase	0	$14.00	$0	$16.00	$0	$16.00	$0	$16.00	$0	$16.00	$0
Minimum Seasonal	0	$84.00	$0	$96.00	$0	$96.00	$0	$96.00	$0	$96.00	$0
kWh in Minimum	428										
kWh in Minimum - Summer	118										
kWh in Minimum - Winter	310										
Unbilled	0		$0		$0		$0		$0		$0
Total	3,185,671		$338,473		$353,222		$356,937		$347,774		$351,489

Rocky Mountain Power
Monthly Billing Comparison
Schedule 1 - State of Utah
Residential Service
Step 1 - Effective 9/1/2014

A - Net Metering Facilities Charg

	Summer				Winter			
	Monthly Billing[1]		Change		Monthly Billing[1]		Change	
kWh	Present	Proposed	$	%	Present	Proposed	$	%
100	$14.64	$15.64	$1.00	6.8%	$14.64	$15.64	$1.00	6.8%
200	$24.02	$25.02	$1.00	4.2%	$24.02	$25.02	$1.00	4.2%
300	$33.39	$34.39	$1.00	3.0%	$33.39	$34.39	$1.00	3.0%
400	$42.77	$43.77	$1.00	2.3%	$42.77	$43.77	$1.00	2.3%
500	$54.99	$55.99	$1.00	1.8%	$53.25	$54.68	$1.43	2.7%
600	$67.21	$68.21	$1.00	1.5%	$63.72	$65.60	$1.88	3.0%
700	$79.43	$80.43	$1.00	1.3%	$74.20	$76.51	$2.31	3.1%
663 w					$70.36	$72.51	$2.15	3.1%
698 a	$79.20	$80.20	$1.00	1.3%	$74.00	$76.30	$2.30	3.1%
747 s	$85.15	$86.15	$1.00	1.2%				
800	$91.65	$92.65	$1.00	1.1%	$84.68	$87.42	$2.74	3.2%
900	$103.87	$104.87	$1.00	1.0%	$95.16	$98.34	$3.18	3.3%
1,000	$116.09	$117.09	$1.00	0.9%	$105.63	$109.25	$3.62	3.4%
1,100	$131.38	$132.38	$1.00	0.8%	$116.11	$120.16	$4.05	3.5%
1,200	$146.67	$147.67	$1.00	0.7%	$126.59	$131.07	$4.48	3.5%
1,300	$161.96	$162.96	$1.00	0.6%	$137.06	$141.99	$4.93	3.6%
1,400	$177.25	$178.25	$1.00	0.6%	$147.54	$152.90	$5.36	3.6%
1,500	$192.54	$193.54	$1.00	0.5%	$158.02	$163.81	$5.79	3.7%
2,000	$268.98	$269.98	$1.00	0.4%	$210.40	$218.38	$7.98	3.8%
3,000	$421.87	$422.87	$1.00	0.2%	$315.17	$327.51	$12.34	3.9%
4,000	$574.76	$575.76	$1.00	0.2%	$419.94	$436.64	$16.70	4.0%
5,000	$727.65	$728.65	$1.00	0.1%	$524.71	$545.77	$21.06	4.0%

B - No Net Metering Facilities Charge

100	$14.64	$15.64	$1.00	6.8%	$14.64	$15.64	$1.00	6.8%
200	$24.02	$25.02	$1.00	4.2%	$24.02	$25.02	$1.00	4.2%
300	$33.39	$34.39	$1.00	3.0%	$33.39	$34.39	$1.00	3.0%
400	$42.77	$43.77	$1.00	2.3%	$42.77	$43.77	$1.00	2.3%
500	$54.99	$55.99	$1.00	1.8%	$53.25	$54.69	$1.44	2.7%
600	$67.21	$68.21	$1.00	1.5%	$63.72	$65.61	$1.89	3.0%
700	$79.43	$80.43	$1.00	1.3%	$74.20	$76.53	$2.33	3.1%
663 w					$70.36	$72.53	$2.17	3.1%
698 a	$79.20	$80.20	$1.00	1.3%	$74.00	$76.32	$2.32	3.1%
747 s	$85.15	$86.15	$1.00	1.2%				
800	$91.65	$92.65	$1.00	1.1%	$84.68	$87.45	$2.77	3.3%
900	$103.87	$104.87	$1.00	1.0%	$95.16	$98.37	$3.21	3.4%
1,000	$116.09	$117.09	$1.00	0.9%	$105.63	$109.29	$3.66	3.5%
1,100	$131.38	$132.38	$1.00	0.8%	$116.11	$120.21	$4.10	3.5%
1,200	$146.67	$147.67	$1.00	0.7%	$126.59	$131.13	$4.54	3.6%
1,300	$161.96	$162.96	$1.00	0.6%	$137.06	$142.05	$4.99	3.6%
1,400	$177.25	$178.25	$1.00	0.6%	$147.54	$152.97	$5.43	3.7%
1,500	$192.54	$193.54	$1.00	0.5%	$158.02	$163.89	$5.87	3.7%
2,000	$268.98	$269.98	$1.00	0.4%	$210.40	$218.49	$8.09	3.8%
3,000	$421.87	$422.87	$1.00	0.2%	$315.17	$327.69	$12.52	4.0%
4,000	$574.76	$575.76	$1.00	0.2%	$419.94	$436.89	$16.95	4.0%
5,000	$727.65	$728.65	$1.00	0.1%	$524.71	$546.09	$21.38	4.1%

[1] Including HELP, DSM, EBA, REC and SOLAR adjustments.
w: Winter average usage; a: Annual average usage; s: Summer average usage.

Monthly Billing Comparison
Schedule 1 - State of Utah
Residential Service
Step 2 - Effective 9/1/2015

A - Net Metering Facilities Charg

	Summer				Winter			
	Monthly Billing[1]		Change		Monthly Billing[1]		Change	
kWh	Present	Proposed	$	%	Present	Proposed	$	%
100	$15.64	$15.64	$0.00	0.0%	$15.64	$15.64	$0.00	0.0%
200	$25.02	$25.02	$0.00	0.0%	$25.02	$25.02	$0.00	0.0%
300	$34.39	$34.39	$0.00	0.0%	$34.39	$34.39	$0.00	0.0%
400	$43.77	$43.77	$0.00	0.0%	$43.77	$43.77	$0.00	0.0%
500	$55.99	$55.99	$0.00	0.0%	$54.68	$55.10	$0.42	0.8%
600	$68.21	$68.21	$0.00	0.0%	$65.60	$66.43	$0.83	1.3%
700	$80.43	$80.43	$0.00	0.0%	$76.51	$77.76	$1.25	1.6%
663 w					$72.51	$73.61	$1.10	1.5%
698 a	$80.20	$80.20	$0.00	0.0%	$76.30	$77.55	$1.25	1.6%
747 s	$86.15	$86.15	$0.00	0.0%				
800	$92.65	$92.65	$0.00	0.0%	$87.42	$89.10	$1.68	1.9%
900	$104.87	$104.87	$0.00	0.0%	$98.34	$100.43	$2.09	2.1%
1,000	$117.09	$117.09	$0.00	0.0%	$109.25	$111.76	$2.51	2.3%
1,100	$132.38	$132.38	$0.00	0.0%	$120.16	$123.09	$2.93	2.4%
1,200	$147.67	$147.67	$0.00	0.0%	$131.07	$134.42	$3.35	2.6%
1,300	$162.96	$162.96	$0.00	0.0%	$141.99	$145.75	$3.76	2.6%
1,400	$178.25	$178.25	$0.00	0.0%	$152.90	$157.08	$4.18	2.7%
1,500	$193.54	$193.54	$0.00	0.0%	$163.81	$168.41	$4.60	2.8%
2,000	$269.98	$269.98	$0.00	0.0%	$218.38	$225.07	$6.69	3.1%
3,000	$422.87	$422.87	$0.00	0.0%	$327.51	$338.38	$10.87	3.3%
4,000	$575.76	$575.76	$0.00	0.0%	$436.64	$451.69	$15.05	3.4%
5,000	$728.65	$728.65	$0.00	0.0%	$545.77	$565.00	$19.23	3.5%

B - No Net Metering Facilities Charge

100	$15.64	$15.64	$0.00	0.0%	$15.64	$15.64	$0.00	0.0%
200	$25.02	$25.02	$0.00	0.0%	$25.02	$25.02	$0.00	0.0%
300	$34.39	$34.39	$0.00	0.0%	$34.39	$34.39	$0.00	0.0%
400	$43.77	$43.77	$0.00	0.0%	$43.77	$43.77	$0.00	0.0%
500	$55.99	$55.99	$0.00	0.0%	$54.69	$55.11	$0.42	0.8%
600	$68.21	$68.21	$0.00	0.0%	$65.61	$66.45	$0.84	1.3%
700	$80.43	$80.43	$0.00	0.0%	$76.53	$77.78	$1.25	1.6%
663 w					$72.53	$73.63	$1.10	1.5%
698 a	$80.20	$80.20	$0.00	0.0%	$76.32	$77.57	$1.25	1.6%
747 s	$86.15	$86.15	$0.00	0.0%				
800	$92.65	$92.65	$0.00	0.0%	$87.45	$89.12	$1.67	1.9%
900	$104.87	$104.87	$0.00	0.0%	$98.37	$100.46	$2.09	2.1%
1,000	$117.09	$117.09	$0.00	0.0%	$109.29	$111.80	$2.51	2.3%
1,100	$132.38	$132.38	$0.00	0.0%	$120.21	$123.14	$2.93	2.4%
1,200	$147.67	$147.67	$0.00	0.0%	$131.13	$134.47	$3.34	2.5%
1,300	$162.96	$162.96	$0.00	0.0%	$142.05	$145.81	$3.76	2.6%
1,400	$178.25	$178.25	$0.00	0.0%	$152.97	$157.15	$4.18	2.7%
1,500	$193.54	$193.54	$0.00	0.0%	$163.89	$168.49	$4.60	2.8%
2,000	$269.98	$269.98	$0.00	0.0%	$218.49	$225.18	$6.69	3.1%
3,000	$422.87	$422.87	$0.00	0.0%	$327.69	$338.56	$10.87	3.3%
4,000	$575.76	$575.76	$0.00	0.0%	$436.89	$451.94	$15.05	3.4%
5,000	$728.65	$728.65	$0.00	0.0%	$546.09	$565.32	$19.23	3.5%

[1] Including HELP, DSM, EBA, REC and SOLAR adjustments.
w: Winter average usage; a: Annual average usage; s: Summer average usage.