ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W North Temple, Suite 310
Salt Lake City, Utah 84114

March 16, 2018

VIA ELECTRONIC FILING

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Gary Widerburg
Commission Secretary

RE: **Docket No. 17-035-69 - Investigation of Revenue Requirement Impacts of the New Federal Tax Legislation Titled: "An act to provide for reconciliation pursuant to titles II and V of the concurrent resolution of the budget for fiscal year 2018"**

Rocky Mountain Power hereby submits for filing its application for approval of proposed Tariff Schedule 197 to authorize the Company to begin delivering benefits from the federal tax legislation enacted on December 22, 2107, titled An Act to Provide for Reconciliation Pursuant to Titles II and V of the Concurrent Resolution of the Budget for Fiscal Year 2018 ("Tax Reform Act") to customers on May 1, 2018.

The enclosed proposed tariff sheets are associated with Tariff P.S.C.U No. 50 of PacifiCorp, d.b.a. Rocky Mountain Power, applicable to electric service in the State of Utah. Pursuant to the requirement of Rule R746-405-2D, PacifiCorp states that the proposed tariff sheets do not constitute a violation of state law or Commission rule.

Rocky Mountain Power respectfully requests that all formal correspondence and requests for additional information regarding this filing be addressed to the following:

By E-mail (preferred): datarequest@pacificorp.com
utahdockets@pacificorp.com
Jana.saba@pacificorp.com
yvonne.hogle@pacificorp.com

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

Informal inquiries may be directed to Jana Saba at (801) 220-2823.

Sincerely,

Joelle Steward
Vice President, Regulation

Yvonne R. Hogle (7550)
Jacob A. McDermott (in-house)
Rocky Mountain Power
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Attorneys for Rocky Mountain Power

Before the Public Service Commission of Utah

Investigation of Revenue Requirements Impacts of the New Federal Tax Legislation Titled: "An act to provide for reconciliation pursuant to titles II and V of the concurrent resolution of the budget for fiscal year 2018"	)))))))	Docket No. 17-035-69 Application of Rocky Mountain Power

Pursuant to Utah Admin. Code R746-405 and the Scheduling Order, Notice of Hearing and Notice of Scheduling Conference issued by the Public Service Commission of Utah ("Commission") March 7, 2018, Rocky Mountain Power, a division of PacifiCorp ("Company"), respectfully submits this application ("Application") to the Commission for approval of proposed Tariff Schedule 197, attached as Exhibit A ("Tariff Schedule 197"), to authorize the Company to begin delivering benefits from the federal tax legislation enacted on December 22, 2107, titled An Act to Provide for Reconciliation Pursuant to Titles II and V of the Concurrent Resolution of the Budget for Fiscal Year 2018 ("Tax Reform Act") to customers on May 1, 2018. In support of the Application the Company states as follows:

1. Rocky Mountain Power is a division of PacifiCorp, an Oregon Corporation, which provides electric service to retail customers through its Rocky Mountain Power division

in the states of Utah, Wyoming, and Idaho, and through its Pacific Power division in the states of Oregon, California, and Washington.

2. Rocky Mountain Power is a regulated public utility in the state of Utah and is subject to the Commission's jurisdiction with respect to its prices and terms of electric service to retail customers in Utah. The Company provides retail electric service to over 830,000 customers and has approximately 2,400 employees in Utah. The Company's principal place of business in Utah is 1407 West North Temple, Suite 310, Salt Lake City, Utah 84116.

3. Communications regarding this filing should be addressed to:

Jana L. Saba
Utah Regulatory Affairs Manager
Rocky Mountain Power
1407 West north Temple, Suite 330
Salt Lake City, Utah, 84116
Email: jana.saba@pacificorp.com

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Assistant General Counsel
Rocky Mountain Power
1407 West North Temple, Suite 320
Salt Lake City, Utah 84116
Email: Yvonne.hogle@pacificorp.com

In addition, the Company requests that all data requests regarding this Application be sent in Microsoft Word or plain text format to the following:

By email (preferred):	datarequest@pacificorp.com jana.saba@pacificorp.com
By regular mail:	Data Requests Response Center PacifiCorp 825 NE Multnomah, Suite 2000 Portland, Oregon 97232

Informal questions may be directed to Jana Saba at (801) 220-2823.

4. Tariff Schedule 197, included as Exhibit A and described in more detail below, is designed to implement the Company's proposed ratemaking treatment to begin passing savings back to customers for a portion of the revenue requirements impacts of the Tax Reform Act. The Company proposes an effective date of May 1, 2018 for Schedule 197.

5. As stated in the Company's February 7, 2018 comments in this docket ("Comments"), the initial and partial impacts of the Tax Reform Act are estimated to result in a $76,222,011 reduction to the Utah revenue requirement. The Company's estimate does not yet include the Tax Reform Act's impacts on normalization of excess deferred income tax, and the impositions of limitations on the deductibility of certain expenditures. These items will be addressed in the Company's supplemental tariff filing in this docket, due June 15, 2018.

6. Consistent with the Comments, Tariff Schedule 197 delivers rate reductions of approximately $20 million (or 1.0 percent) to the Utah retail customers, about one quarter of the initial estimate of the impacts.

7. Also consistent with the Comments, the Company will continue to defer the balance of the Tax Reform Act regulatory liability that remains after accounting for the reduction to rates proposed in this Application and will propose to offset future costs once they are known for rate stabilization purposes. Any offsets to the deferral balance would be subject to Commission approval and would occur no later than the effective date of approved rates from the Company's next rate case. Any remaining amount in the deferral balance would be refunded to customers at that time. Nevertheless, in this Application, the Company is not seeking a Commission determination on when and how best to use this remaining balance. Instead, the Company requests that the Commission set a process for addressing these

questions and the ability to seek recovery of offsets to the deferral following its June 21, 2018 scheduling conference.

8. The Company incorporates the procedural background of this docket as referenced in its February 7, 2018 comments ("Comments"). In its Comments, the Company provided an overview of the Tax Reform Act, the estimated revenue requirements impacts of the Act, and its proposed accounting treatment of the impacts. The Company's proposal included providing rate relief of approximately $20 million to customers on May 1, 2018, and deferring the remaining balance, once finally calculated by the Company, to be used for rate stabilization purposes.

9. On February 23, 2018, the Division of Public Utilities ("Division"), the Office of Consumer Services ("Office"), the Utah Association of Energy Users ("UAE"), and the Utah Industrial Energy Users ("UIEC") responded to the Comments. All parties supported an accounting order to allow the Company to create a deferred liability of the income tax benefits arising from the Tax Reform Act. The Division and UIEC each recommended that the entire estimated revenue requirement reduction be credited to customers. UAE recommended that the Company be required to initially reduce rates by 80 percent of the Company's partial estimate of Tax Reform Act's impacts to account for uncertainty in the Company's initial estimate. The Office stated its intent to make more specific recommendations in the course of this docket.

10. The Commission, by its February 28, 2018 order, granted UAE's motion to establish a regulatory liability for the fully determined impacts of the Tax Reform Act on the Company's revenue requirements ("UAE Motion"), and provided notice of a March 6, 2018 scheduling conference in this docket.

11. On March 7, 2018 the Commission issued a scheduling order to establish a procedural schedule in this docket.

12. The Company's proposed tariff is consistent with the accounting treatment recommended in its Comments. The rate reduction of approximately $20 million will begin to deliver a reasonable portion of the estimated benefits of the Tax Reform Act to customers on May 1, 2018 while the Company finalizes its calculations of the full revenue requirements impacts.

13. The Company recognizes the importance of delivering to its customers the benefits of the Tax Reform Act, which is why the Company proposes a May 1, 2018 effective date under proposed Tariff Schedule 197. At the same time, the Company must balance this against the level of uncertainty, given the revenue requirement impacts are currently only estimates. Further, the Company is interested in providing customers long-term rate stability, while mitigating potential near-term adverse impacts resulting from the Tax Reform Act on the Company's credit metrics. The Company's proposals achieve these objectives.

14. Proposed Tariff Schedule 197 provides a reasonable level of near-term benefits to customers given the uncertainty of the Company's initial estimates. As discussed in the Comments, the Company's estimated revenue requirement reduction of $76,222,011 ("Company's Initial Estimate") is based on its June 2017 Utah Results of Operations Report ("June 2017 ROO"), and excludes the impacts of normalization of excess deferred income taxes, and imposition of limitations on deductibility of certain expenditures. The Company proposes to base its final numbers on the December 2017 Results of Operations Report ("December 2017 ROO") to incorporate the most recent data available to make the final

calculations. The December 2017 ROO will be filed by April 30, 2018, and the Company will submit its final Tax Reform Act impact filing by June 15, 2018.

15. The Company's Initial Estimate includes a degree of uncertainty that supports deferring a reasonable balance until final amounts are calculated and evaluated for use against known future rate increases. On the other hand, waiting for the final numbers would delay providing benefits to customers.

16. In its February 23 comments, UAE recognizes the reasonableness of providing near-term relief to customers at a level that is less than the full amount of the Company's Initial Estimate, given the degree of uncertainty in that amount.[1] While UAE and the Company do not agree on the appropriate level of near-term benefits to provide customers, UAE comments support providing near-term rate relief at a level lower than the full amount of the Company's Initial Estimate.

17. The Company is interested in working with the other parties in this docket to develop a strategy that would ensure the benefits will be available to offset future costs that will provide upward pressure on the Company's rates. The June 21, 2018 scheduling conference following the Company's supplemental filing is an ideal time to consider this collaboration. The Division and UIEC submitted comments arguing against this approach, each supporting a sooner flow through of the full tax benefits to customers. The Company understands their desire to more quickly capture the benefits of the Tax Reform Act, but their

[1] *See* Utah PSC Docket No. 17-035-69, UAE Comments, February 23, 2018, at 4, stating that: "While some uncertainty about the final revenue requirement savings calculated using the December 2017 ROO may make it reasonable for the initial reduction to be set at a level that is less than the full amount of the partial estimate, the public interest objective here should be to reduce customer rates as *much* as reasonably possible as *soon* as reasonably possible to reflect the reduction in tax expense." (emphasis in original).

approaches would eliminate other valuable regulatory options that can provide greater stability to customers over time.

18. Deferring a portion of the tax reform benefits in favor of potential rate stabilization benefits provides a valuable tool to address upward cost pressures. For example, the Company plans to file its new depreciation study in September 2018, for rates effective no later than January 1, 2020. The study will include prudent investments the Company made to maintain its low cost thermal fleet such as the environmental equipment upgrades placed into service since its last deprecation study. In addition, the preferred portfolio of the Company's 2017 Integrated Resource Plan sets forth the potential early closure of the Cholla Unit 4, Craig Unit 1, and Jim Bridger 1 and 2 coal plants. These examples could create significant upward pressure on rates that could be partially recovered through the Sustainable Transportation and Energy Plan ("STEP") funds, or through some other regulatory proceeding such as a general rate case in the event STEP funds are insufficient.

19. The Commission approval of closure of the Deer Creek mine in 2014 is another example of a cost driver that could be offset by the tax deferral to reduce upward rate pressure. The recovery of the existing plant net book value was approved for recovery through the Energy Balancing Account ("EBA") and the closure costs were approved and are being deferred for future recovery in Docket No. 14-035-147. The Company proposes removing recovery of the unamortized existing plant from the 2018 EBA and offsetting it by the deferred tax benefits. The Company reflected this treatment as an alternative rate proposal in its EBA filing in Docket No. 18-035-01.

20. Several of the Company's existing wind facilities have reached or are very close to reaching the 10 year expiration of their production tax credits ("PTC"). In the last general

rate case the impact of these PTCs reduced the Utah revenue requirement. Most of the PTCs expire before 2020, and only those associated with the Dunlap facility extend through September 2020. The expiration of the PTC benefits will be a cost driver in the next general rate case, the impact of which could be mitigated by the use of the tax deferral at that time.

21. In addition to the items mentioned above, the tax deferral could be used to offset existing deferrals, such as implementation costs and operations and maintenance expenses related to the energy imbalance market deferred in Docket No. 13-035-184 and the 2017 Protocol deferral in Docket No. 15-035-86.

22. Gradualism and rate stability are longstanding ratemaking principles recognized by this Commission in setting rates for Utah utilities.[2] The Company's proposal to defer the remaining balance of the regulatory liability is intended to support these same principals. The Division, UAE, and UIEC each propose that the Company reduce rates by the full balance of the benefits once the calculation of the impact is finalized. Doing so would provide interim reductions, only to leave customers facing upward pressures on rates a short time thereafter. Significant changes in customer rates downward then upward in a matter of a few years does not meet the principle of gradualism, and is the opposite of rate stability.

23. Beyond providing rate stability benefits to customers and supporting gradualism, the Company's proposal to use the remaining balance in the regulatory liability to

[2] *See* Utah PSC Docket No. 97-035-01, In the Matter of the Investigation Into the Reasonableness of Rates and Charges of PacifiCorp, dba Utah Power & Light Company, Report and Order, March 4, 1999 ("We have consistently embraced the principle of gradualism"; and "Gradualism serves the rate stability objective"); *see also* Utah PSC Docket No. 99-035-10, In the Matter of: the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulations, Report and Order, March 24, 2000 at pp. 87 & 92 ("Finally, we do rely on the ratemaking principle of gradualism…"; and, respectively, "It also satisfies the Division's objectives of stability and gradualism. These are objectives commonly employed in this jurisdiction."); *and see more recently*, Utah PSC Docket No. 09-035-15, In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism, Order, February 16, 2017 ("This would be inconsistent with the concepts of stability and gradualism in ratemaking.")

offset future costs increases will help mitigate some of the adverse impacts the Tax Reform Act will have on the Company in the near-term. At face value it is easy to assume that the primary impacts on the Company of the Tax Reform Act and its reduction of corporate rates from 35 percent down to 21 percent are entirely positive, but a closer analysis shows there are negatives in the case of regulated public utilities. A January 2018 report from The Brattle Group ("Brattle Tax Report") discusses several of these adverse effects.[3]

24. The Brattle Tax Report demonstrates that coverage ratios for utilities will tighten as earnings before interest and taxes ("EBIT") and earnings before interest, taxes, depreciation and amortization ("EBITDA") decrease, EBIT and EBITDA interest coverage is lowered and EBITDA to debt is also lowered. These reduced coverage ratios potentially result in ratings downgrades which may increase utilities' borrowing costs. The report goes on to show that utilities' realized earnings volatility is increased by a lower tax rate because the "cushion" provided by the impact of taxes on utility rates becomes smaller. This will make earnings more sensitive to reductions to EBITDA as the offsetting tax benefit goes from a 35 percent rate to a 21 percent rate. The Brattle Tax Report also states that cash flows may be deferred due to a lower tax rate on depreciation timing differences.

25. The same impacts noted in the Brattle Tax Report led Moody's Investor Service ("Moody's") to lower the outlook for 24 regulated utilities on January 19, 2018 based primarily on the Tax Reform Act's impacts on cash flows. On January 24, 2018, just after issuing its revised negative outlooks, Moody's, issued a Sector Comment for regulated utilities in the US entitled "Tax reform is credit negative for sector, but impacts vary by company." The comment cited many of the same adverse impacts raised in the Brattle Tax Report, noting that while tax

[3] *See* The Brattle Group, "Six Implications of the New Tax Law for Regulated Utilities", January 2018 (available at http://files.brattle.com/files/13011_six_implications_of_the_new_tax_law_for_regulated_utilities.pdf).

reform is neutral for utility earnings it is negative for cash flow and further noting that cash flow to debt ratio could decline by 150-250 basis points.

26. While the Company has not had its outlook revised to negative, the adverse impacts discussed by Moody's and The Brattle Group will likely impact the Company if all benefits are refunded to customers immediately. Deferring part of the reduction to rates to offset future rate increases will ease some of these negative impacts, and allow more time for the Company, the Commission and the other parties to analyze the impacts and reach a solution that keeps the Company financially healthy. Deferring the remaining balance of the Tax Reform Act regulatory liability and allowing it to offset the future known cost increases discussed above gives the Company time to better consider potential adverse impacts from the Tax Reform Act and to adjust its capital structure as appropriate to account for them.

27. Utility regulators in other jurisdictions have approved deferrals of regulatory liability for reasons similar to those advanced by the Company here. For example, in a 2012 proceeding before the New York Public Service Commission involving the application of a previously authorized deferral of bonus depreciation deduction benefits related to the federal Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2014, the New York Commission recognized that it "often uses credits to offset future rate increases or deferred costs incurred during a rate plan.[4] In another example, the Maine Public Utilities Commission allowed one of Maine's regulated electric utilities, Central Maine Power Company, to defer flow-through of several tax related savings that would have otherwise, under the Maine commission's longstanding policy, been immediately reflected as a reduction

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[4] In the Matter of the Disposition of Certain Deferred Credits Owed to Elec. Customers by Consol. Edison Co. of New York, Inc. Proceeding on Motion of the Comm'n As to the Rates, Charges, Rules & Regulations of Consol. Edison Co. of New York, Inc. for Elec. Serv.., 09-E-0428, 2012 WL 1073402 (NYPSC Mar 22, 2012).

the company's rates.[5] The Maine commission based its approval of the deferral on avoiding negative impacts to Central Maine Power's cash flow in the near term, and on the fact that the costs of a large capital expenditure was expected to be included in rate base in roughly two years. The Maine commission reasoned that postponing the tax adjustment until that time would provide an offset to "soften the blow" of that large capital expense and potentially help mitigate other future costs.

28. The Company's proposed Tariff Schedule 197 provides important near-term rate benefits to customers by delivering $20 million of the Company's Initial Estimate of reductions to its revenue requirement on May 1, 2018. The Company's proposal to defer the remaining balance and work with the Commission and other parties to determine when and how to best use it to offset future rate increases supports the principles of gradualism and rate stability by providing a tool to mitigate future upward rate pressures.

Proposed Tariff Schedule 197

Exhibit A is the proposed Tariff Schedule 197 to implement the $20 million rate reduction effective May 1, 2018. **Exhibit B** shows the proposed allocation to customer classes and the calculation of the proposed rates.

The Company proposes to allocate the $20 million rate reduction to all retail tariff customers taking service under the Company's electric service schedules using the rate base allocation to each customer class from the Company's most recent annual cost of service study. This is reasonable because the Company earns a return on its rate base and is ultimately taxed upon that return. In reply comments, the Division and UAE indicated support for this

[5] "Re Cent. Maine Power Co.", 57 PUR4th 488 (Me PUC Dec 15, 1983).

approach.[6] The Division also recommended excluding special contract customers from this refund. The Company agrees with this recommendation. As the Division noted, special contract rates are negotiated independent from the revenue requirement used to set other retail rates.[7] Any consideration of the impact of the Tax Reform Act in the Company's negotiations with special contract customers would need to be made in light of each special contract customer's contract provisions and unique circumstances. Page 1 of attached Exhibit B shows the Company's proposed rate spread for Tariff Schedule 197.

1. The Company proposes prices for Tariff Schedule 197 that were developed as percentage adjustments applied to customers' monthly Power Charges and Energy Charges (as defined in the Company's general service tariffs). This rate design is consistent with the Company's Energy Balancing Account ("EBA") and Renewable Energy Credits Balancing Account filings that are made each year. To determine these rates, the percentage for each rate schedule is calculated by dividing the allocated refund amounts by the corresponding present revenues for each rate schedule. Proposed Schedule 197 would appear on customer bills as a separate line item. To avoid impacting the programs that they fund, the Company proposes that Schedule 193 (Demand Side Management Cost Adjustment) and Schedule 196 (Sustainable Transportation and Energy Plan Cost Adjustment Pilot Program) would not apply to the proposed Schedule 197 sur-credit. Page 2 of attached Exhibit B, contains the billing

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[6] *See* Utah PSC Docket No. 17-035-69, Division Comments, February 23, 2018, at 3 stating that: "The Division agrees with the Company allocating tax savings to rate classes based on the rate base allocation from the most recent annual cost of service study, with the exception of Special Contracts." and Utah PSC Docket No. 17-035-69, UAE Comments, February 23, 2018, at 5 stating that: "UAE asks the Commission to enter orders requiring RMP to...allocate the deferral benefit among classes based on the rate base allocation from the most recent annual cost of service study."

[7] *See* Utah PSC Docket No. 17-035-69, Division Comments, February 23, 2018, at 3 stating that: "Special Contracts are negotiated independently and any benefits from the Tax Act will be realized when contracts are renegotiated."

determinants and calculations for the proposed rates for Tariff Schedule 197. Page 3 of Exhibit B to the Application, shows the net impact by rate schedule of the Company's proposed refund.

2. This Application includes workpapers in support of the amount of rate reduction proposed by the Company and consistent with its proposed Tariff Schedule 197.

WHEREFORE, by this Application, the Company respectfully requests approval of:

a) Proposed Tariff Schedule 197, effective May 1, 2018.

b) The continued deferral of the balance remaining after accounting for the Company's proposed rate reduction of $20 million, effective May 1, 2018, of the regulatory liability established by the Commission's February 28, 2018 order for the purpose of offsetting future costs, with carrying charges equal to the most recently approved customer deposit rate.

c) The accounting treatment to recover approximately $17 million for the unamortized balance of the Deer Creek mine asset approved in Docket No. 14-035-147, as an offset to the regulatory liability in the proceeding.

DATED this 16th day of March, 2018.

Respectfully submitted,

ROCKY MOUNTAIN POWER

Yvonne R. Hogle

Yvonne Hogle
Attorney for Rocky Mountain Power

Exhibit A

ELECTRIC SERVICE SCHEDULES
STATE OF UTAH

Schedule Numbers not listed are not currently used.
*These Schedules are not available to new customers or premises.

ELECTRIC SERVICE SCHEDULES
STATE OF UTAH

Schedule No.		Sheet No.
80	Summary of Effective Rate Adjustments	80
91	Surcharge To Fund Low Income Residential Lifeline Program	91
92	Low Income Residential Lifeline Program Surcharge Refund Credit	92
94	Energy Balancing Account (EBA) Pilot Program	94.1- 94.10
98	REC Revenue Adjustment	98
105	Irrigation Load Control Program	105.1 - 105.2
107	Solar Incentive Program	107.1 - 107.6
111	Residential Energy Efficiency	111.1 - 111.7
114	Air Conditioner Direct Load Control Program (Cool Keeper Program)	114.1 - 114.5
118	Low Income Weatherization	118.1 - 118.6
120	Plug-In Electric Vehicle Incentive Pilot Program	120.1 - 120.3
121	Plug-In Electric Vehicle Load Research Study Program – Temporary	121.1 - 121.2
135	Net Metering Service	135.1 - 135.6
136	Transition Program for Customer Generators	136.1 - 136.6
140	Non-Residential Energy Efficiency	140.1 - 140.25
193	Demand Side Management (DSM) Cost Adjustment	193.1 - 193.2
196	Sustainable Transportation and Energy Plan (STEP) Cost Adjustment Pilot Program	196.1 - 196.2
197	Federal Tax Act Adjustment	197
300	Regulation Charges	300.1 - 300.4

Schedule Numbers not listed are not currently used.
*These Schedules are not available to new customers or premises.

ROCKY MOUNTAIN POWER

ELECTRIC SERVICE SCHEDULE NO. 197

STATE OF UTAH

Federal Tax Act Adjustment

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

MONTHLY BILL: In addition to the Monthly Charges contained in the Customer's applicable schedule, all monthly bills shall have the following percentage adjustments applied to the Monthly Power Charges and Energy Charges of the Customer's applicable schedule.

Schedule 1	-1.33%
Schedule 2	-1.33%
Schedule 2E	-1.33%
Schedule 3	-1.33%
Schedule 6	-1.22%
Schedule 6A	-1.69%
Schedule 6B	-1.22%
Schedule 7*	-0.67%
Schedule 8	-1.08%
Schedule 9	-1.04%
Schedule 9A	-1.15%
Schedule 10	-1.43%
Schedule 11*	-0.67%
Schedule 12*	-0.67%
Schedule 15 (Traffic and Other Signal Systems)	-1.28%
Schedule 15 (Metered Outdoor Nighttime Lighting)	-0.95%
Schedule 21	-2.26%
Schedule 23	-1.12%
Schedule 31	**
Schedule 32	**

* The Adjustment for Schedules 7, 11 and 12 shall be applied to the Charge per Lamp

** The rate for Schedule 31 and Schedule 32 shall be the same as the applicable general service schedule.

Exhibit B

Rate Spread
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)	Rate Base[1] F101	Proposed TAA ($000)	Proposed TAA %
	(1)	(2)	(3)	(4)	(5)	(6)
	Residential					
1	Residential	1,3	$684,505		($8,372.07)	-1.2%
2	Residential-Optional TOD	2	$351		($4)	-1.2%
3	AGA/Revenue Credit	--	$33			
4	**Total Residential**		$684,889	40.6%	($8,376)	-1.2%
	Commercial & Industrial & OSPA					
5	General Service-Distribution	6	$494,681		($5,133)	-1.0%
6	General Service-Distribution-Energy TOD	6A	$34,227		($355)	-1.0%
7	General Service-Distribution-Demand TOD	6B	$346		($4)	-1.0%
8	*Subtotal Schedule 6*		$529,255	26.6%	($5,492)	-1.0%
9	General Service-Distribution > 1,000 kW	8	$167,313	7.6%	($1,567)	-0.9%
10	General Service-High Voltage	9	$284,876		($2,741)	-1.0%
11	General Service-High Voltage-Energy TOD	9A	$3,293		($32)	-1.0%
12	*Subtotal Schedule 9*		$288,169	13.4%	($2,773)	-1.0%
13	Irrigation	10	$13,210		($184)	-1.4%
14	Irrigation-Time of Day	10TOD	$1,286		($18)	-1.4%
15	*Subtotal Irrigation*		$14,496	1.0%	($202)	-1.4%
16	Electric Furnace	21	$476		($5)	-1.0%
17	General Service-Distribution-Small	23	$139,103	7.0%	($1,450)	-1.0%
18	Back-up, Maintenance, & Supplementary	31	$4,576		($47)	-1.0%
19	Contract 1	--	$27,959	1.6%	$0	0.0%
20	Contract 2	--	$35,063	1.8%	$0	0.0%
21	Contract 3	--	$30,035		$0	0.0%
22	AGA/Revenue Credit	--	$2,928			
23	**Total Commercial & Industrial & OSPA**		$1,239,372		($11,534)	-0.9%
	Public Street Lighting					
24	Security Area Lighting	7	$2,999		($20)	-0.7%
25	Street Lighting - Company Owned	11	$4,979		($33)	-0.7%
26	Street Lighting - Customer Owned	12	$4,145		($28)	-0.7%
27	Metered Outdoor Lighting	15	$1,235	0.04%	($9)	-0.7%
28	Traffic Signal Systems	15	$682	0.03%	($7)	-1.0%
29	*Subtotal Public Street Lighting*		$14,040	0.4%	($97)	-0.7%
30	Security Area Lighting-Contracts (PTL)	--	$1			
31	AGA/Revenue Credit	--	$5			
32	**Total Public Street Lighting**		$14,045		($97)	-0.7%
33	**Total Sales to Ultimate Customers**		$1,938,306	100.0%	($20,007)	-1.0%
				Tax Act Rev	($20,000)	
				%	-1.0%	
				Adj	103.5%	-7.5

[1] Rate Base Cost allocator from 2010 cost of service study.

Rate Design
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 2 - 9/1/2015			Proposed TAA	
	Forecasted Units	Present Price		Revenue Dollars	Price	Revenue Dollars
Schedule No. 1- Residential Service						
Total Customer	8,511,800					
Customer Charge - 1 Phase	8,398,777	$6.00		$50,392,662		
Customer Charge - 3 Phase	14,094	$12.00		$169,128		
Net Metering Facilities Charge	23,932					
First 400 kWh (May-Sept)	1,274,636,742	8.8498	¢	$112,802,802	-1.33%	($1,496,844)
Next 600 kWh (May-Sept)	1,040,456,011	11.5429	¢	$120,098,797	-1.33%	($1,593,658)
All add'l kWh (May-Sept)	358,873,906	14.4508	¢	$51,860,150	-1.33%	($688,161)
All kWh (Oct-Apr)						
First 400 kWh (Oct-Apr)	1,613,094,234	8.8498	¢	*$142,755,614*	-1.33%	*($1,894,304)*
All add'l kWh (Oct-Apr)	1,704,644,903	10.7072	¢	*$182,519,739*	-1.33%	*($2,421,957)*
Minimum 1 Phase	98,763	$8.00		$790,104		
Minimum 3 Phase	166	$16.00		$2,656		
Minimum Seasonal	0	$96.00		$0		
kWh in Minimum	501,472					
kWh in Minimum - Summer	223,485					
kWh in Minimum - Winter	277,987					
Unbilled	0			$0		
Total	5,992,207,269			$661,391,652		($8,094,924)
Schedule No. 3- Residential Service - Low Income Lifeline Program						
Total Customer	370,465					
Customer Charge - 1 Phase	369,457	$6.00		$2,216,742		
Customer Charge - 3 Phase	257	$12.00		$3,084		
Net Metering Facilities Charge	0					
First 400 kWh (May-Sept)	47,435,117	8.8498	¢	$4,197,913	-1.33%	($55,704)
Next 600 kWh (May-Sept)	31,907,309	11.5429	¢	$3,683,029	-1.33%	($48,872)
All add'l kWh (May-Sept)	10,205,740	14.4508	¢	$1,474,811	-1.33%	($19,570)
All kWh (Oct-Apr)						
First 400 kWh (Oct-Apr)	64,598,419	8.8498	¢	*$5,716,831*	-1.33%	*($75,860)*
All add'l kWh (Oct-Apr)	54,308,077	10.7072	¢	*$5,814,874*	-1.33%	*($77,161)*
Minimum 1 Phase	751	$8.00		$6,008		
Minimum 3 Phase	0	$16.00		$0		
Minimum Seasonal	0	$96.00		$0		
kWh in Minimum	4,249					
kWh in Minimum - Summer	2,043					
kWh in Minimum - Winter	2,206					
Unbilled	0			$0		
Total	208,458,911			$23,113,292		($277,167)
Schedule No. 2 - Residential Service - Optional Time-of-Day						
Total Customer	5,364					
Customer Charge - 1 Phase	5,243	$6.00		$31,458		
Customer Charge - 3 Phase	0	$12.00		$0		
Net Metering Facilities Charge	1,185					
On-Peak kWh (May - Sept)	280,149	4.3560	¢	$12,203		
Off-Peak kWh (May - Sept)	954,590	(1.6334)	¢	($15,592)		

First 400 kWh (May-Sept)	675,062	8.8498 ¢	$59,742	-1.33%	($793)
Next 600 kWh (May-Sept)	474,415	11.5429 ¢	$54,761	-1.33%	($727)
All add'l kWh (May-Sept)	185,128	14.4508 ¢	$26,752	-1.33%	($355)
All kWh (Oct-Apr)					
First 400 kWh (Oct-Apr)	912,816	8.8498 ¢	*$80,782*	-1.33%	*($1,072)*
All add'l kWh (Oct-Apr)	937,823	10.7072 ¢	*$100,415*	-1.33%	*($1,332)*
Minimum 1 Phase	121	$8.00	$968		
Minimum 3 Phase	0	$16.00	$0		
Minimum Seasonal	0	$96.00	$0		
kWh in Minimum	428				
kWh in Minimum - Summer	118				
kWh in Minimum - Winter	310				
Unbilled	0		$0		
Total	3,185,671		$351,489		($4,279)

Schedule No. 6 - Composite

Customer Charge	156,864	$54.00	$8,470,675		
All kW (May - Sept)	7,568,683				
All kW (Oct - Apr)	9,009,450				
Voltage Discount	679,134	($0.96)	($651,969)		
Facilities kW	*16,578,133*	*$4.04*	$66,975,657		
All kW (May - Sept)	*7,568,683*	*$14.62*	$110,654,145	-1.22%	($1,352,724)
All kW (Oct - Apr)	*9,009,450*	*$10.91*	$98,293,100	-1.22%	($1,201,613)
All kWh	5,783,806,261				
kWh (May - Sept)	2,573,577,152	3.8127 ¢	$98,122,776	-1.22%	($1,199,530)
kWh (Oct - Apr)	3,210,229,109	3.5143 ¢	$112,817,082	-1.22%	($1,379,165)
Seasonal Service	0	$648.00	$0		
Unbilled	0		$0		
Total	5,783,806,261		$494,681,466		($5,133,032)

Schedule No. 6B - Demand Time-of-Day Option - Composite

Customer Charge	438	$54.00	$23,652		
All On-peak kW (May - Sept)	6,224				
All On-peak kW (Oct - Apr)	4,264				
Voltage Discount	0	($0.96)	$0		
Facilities kW	*10,488*	*$4.04*	$42,372		
All On-peak kW (May - Sept)	*6,224*	*$14.62*	$90,995	-1.22%	($1,112)
All On-peak kW (Oct - Apr)	*4,264*	*$10.91*	$46,520	-1.22%	($569)
All kWh	3,907,497				
kWh (May-Sept)	1,628,124	3.8127 ¢	$62,075	-1.22%	($759)
kWh (Oct-Apr)	2,279,373	3.5143 ¢	$80,104	-1.22%	($979)
Seasonal Service	0	$648.00	$0		
Unbilled	0		$0		
Total	3,907,497		$345,718		($3,419)

Schedule No. 6A - Energy Time-of-Day Option - Composite

Customer Charge	27,307	$54.00	$1,474,578		
Facilities kW (May - Sept)	918,610	$6.52	$5,989,337		
Facilities kW (Oct - Apr)	1,059,783	$5.47	$5,797,013		
Voltage Discount	39,296	($0.61)	($23,971)		
On-Peak kWh (May - Sept)	62,251,233	11.9266 ¢	$7,424,456	-1.69%	($125,618)
Off-Peak kWh (May - Sept)	59,556,790	3.5908 ¢	$2,138,565	-1.69%	($36,183)
On-Peak kWh (Oct - Apr)	90,625,426	9.9693 ¢	$9,034,721	-1.69%	($152,863)
Off-Peak kWh (Oct - Apr)	79,597,650	3.0060 ¢	$2,392,705	-1.69%	($40,483)
Unbilled	0		$0		
Total	292,031,100		$34,227,404		($355,147)

Schedule No. 7 - Security Area Lighting - Composite

MERCURY VAPOR LAMPS

4,000 Lumen Energy Only	29	24	$5.68	$136	-0.67%	($1)
7,000 Lumen	1	45,001	$16.38	$737,116	-0.67%	($4,944)
7,000 Lumen Energy Only	28	0	$8.05	$0	-0.67%	$0
20,000 Lumen	2	10,830	$26.78	$290,027	-0.67%	($1,945)
SODIUM VAPOR LAMPS						
5,600 Lumen New Pole	3	3,563	$14.60	$52,020	-0.67%	($349)
5,600 Lumen No New Pole	4	1,746	$12.23	$21,354	-0.67%	($143)
9,500 Lumen New Pole	5	23,403	$15.47	$362,044	-0.67%	($2,428)
9,500 Lumen No New Pole	6	23,123	$13.31	$307,767	-0.67%	($2,064)
16,000 Lumen New Pole	7	2,646	$19.46	$51,491	-0.67%	($345)
16,000 Lumen No New Pole	8	2,564	$17.13	$43,921	-0.67%	($295)
22,000 Lumen	9	114	$21.07	$2,402	-0.67%	($16)
27,500 Lumen New Pole	10	3,134	$23.51	$73,680	-0.67%	($494)
27,500 Lumen No New Pole	11	4,178	$21.23	$88,699	-0.67%	($595)
50,000 Lumen New Pole	12	1,248	$28.30	$35,318	-0.67%	($237)
50,000 Lumen No New Pole	13	2,456	$25.99	$63,831	-0.67%	($428)
SODIUM VAPOR FLOOD LAMPS						
16,000 Lumen New Pole	14	4,670	$19.46	$90,878	-0.67%	($610)
16,000 Lumen No New Pole	15	4,976	$17.13	$85,239	-0.67%	($572)
27,500 Lumen New Pole	16	1,102	$23.51	$25,908	-0.67%	($174)
27,500 Lumen No New Pole	17	1,570	$21.23	$33,331	-0.67%	($224)
50,000 Lumen New Pole	18	9,734	$28.30	$275,472	-0.67%	($1,848)
50,000 Lumen No New Pole	19	11,772	$25.99	$305,954	-0.67%	($2,052)
METAL HALIDE LAMPS						
12,000 Lumen New Pole	20	0	$29.40	$0	-0.67%	$0
12,000 Lumen No New Pole	21	265	$21.79	$5,774	-0.67%	($39)
19,500 Lumen New Pole	22	110	$34.34	$3,777	-0.67%	($25)
19,500 Lumen No New Pole	23	97	$27.43	$2,661	-0.67%	($18)
32,000 Lumen New Pole	24	469	$36.69	$17,208	-0.67%	($115)
32,000 Lumen No New Pole	25	630	$29.72	$18,724	-0.67%	($126)
107,000 Lumen New Pole	26	24	$57.58	$1,382	-0.67%	($9)
107,000 Lumen No New Pole	27	60	$49.10	$2,946	-0.67%	($20)
Subtotal		159,509		$2,999,060		($20,116)
kWh Included		12,440,931				
Unbilled		0		$0		
Customers		8,046				
Total (kWh)		12,440,931		$2,999,060		($20,116)

Schedule No. 8 - Composite

Customer Charge	3,282	$70.00	$229,740		
Facilities kW	5,010,201	$4.76	$23,848,557		
On-Peak kW (May - Sept)	2,097,818	$15.56	$32,642,048	-1.08%	($351,570)
On-Peak kW (Oct - Apr)	2,761,958	$11.19	$30,906,310	-1.08%	($332,875)
Voltage Discount	2,132,830	($1.13)	($2,410,098)		
On-Peak kWh (May - Sept)	260,094,535	5.0474 ¢	$13,128,012	-1.08%	($141,395)
On-Peak kWh (Oct - Apr)	625,992,212	3.9511 ¢	$24,733,578	-1.08%	($266,392)
Off-Peak kWh	1,300,960,579	3.4002 ¢	$44,235,262	-1.08%	($476,434)
Unbilled	0		$0		
Total	2,187,047,326		$167,313,409		($1,568,666)

Schedule No. 9 - Composite

Customer Charge	1,791	$259.00	$463,869		
Facilities kW	9,053,509	$2.22	$20,098,790		
On-Peak kW (May - Sept)	3,715,246	$13.96	$51,864,834	-1.04%	($539,966)
On-Peak kW (Oct - Apr)	5,150,021	$9.47	$48,770,699	-1.04%	($507,753)
On-Peak kWh (May-Sept)	507,349,132	4.6531 ¢	$23,607,462	-1.04%	($245,778)
On-Peak kWh (Oct-Apr)	1,382,941,034	3.4989 ¢	$48,387,724	-1.04%	($503,766)
Off-Peak kWh	3,137,145,375	2.9225 ¢	$91,683,074	-1.04%	($954,514)
Unbilled	0		$0		

Total	5,027,435,541		$284,876,452		($2,751,776)
Schedule No. 9A - Energy TOD - Composite					
Customer Charge	108	$259.00	$27,972		
Facilities Charge per kW	235,118	$2.22	$521,962		
On-Peak kWh	23,805,248	8.6029 ¢	$2,047,942	-1.16%	($23,655)
Off-Peak kWh	18,785,533	3.6981 ¢	$694,708	-1.16%	($8,024)
Unbilled	0		$0		
Total	42,590,781		$3,292,584		($31,679)
Schedule No. 10 - Irrigation					
Annual Cust. Serv. Chg. - Primary	6	$125.00	$750		
Annual Cust. Serv. Chg. - Secondary	2,778	$38.00	$105,577		
Monthly Cust. Serv. Chg.	12,565	$14.00	$175,910		
All On-Season kW	323,633	$7.33	$2,372,230	-1.43%	($33,866)
Voltage Discount	10,067	($2.05)	($20,637)		
First 30,000 kWh	71,130,178	7.2971 ¢	$5,190,440	-1.43%	($74,099)
All add'l kWh	51,830,436	5.3936 ¢	$2,795,526	-1.43%	($39,909)
Total On Season	122,960,614		$10,619,796		($147,875)
Post Season					
Customer Charge	5,886	$14.00	$82,404		
kWh	50,172,778	4.9983 ¢	$2,507,786	-1.43%	($35,802)
Total Post Season	50,172,778		$2,590,190		($35,802)
Unbilled	0		$0		
TOTAL RATE 10	173,133,392		$13,209,986		($183,677)
Schedule No. 10-TOD					
Annual Cust. Serv. Chg. - Primary	5	$125.00	$625		
Annual Cust. Serv. Chg. - Secondary	256	$38.00	$9,728		
Monthly Cust. Serv. Chg.	1,143	$14.00	$16,002		
All On-Season kW	37,541	$7.33	$275,176	-1.43%	($3,928)
Voltage Discount kW	1,037	($2.05)	($2,126)		
On-Peak kWh	2,262,299	14.4164 ¢	$326,142	-1.43%	($4,656)
Off-Peak kWh	8,574,215	4.1542 ¢	$356,190	-1.43%	($5,085)
Total On Season	10,836,514		$981,737		($13,670)
Post Season					
Customer Charge	570	$14.00	$7,980		
kWh	5,920,094	4.9983 ¢	$295,904	-1.43%	($4,224)
Total Post Season	5,920,094		$303,884		($4,224)
Unbilled	0		$0		
TOTAL RATE 10-TOD	16,756,608		$1,285,621		($17,894)
Schedule No. 11 - Street Lighting - Company-Owned System					
Sodium Vapor Lamps (HPS)					
5,600 Lumen - Functional	34,757	$11.80	$410,133	-0.67%	($2,751)
9,500 Lumen - Functional	218,738	$12.78	$2,795,472	-0.67%	($18,750)
9,500 Lumen - Functional @ 90%	132	$11.50	$1,518	-0.67%	($10)
9,500 Lumen - S1	409	$46.54	$19,035	-0.67%	($128)
9,500 Lumen - S2	60	$38.05	$2,283	-0.67%	($15)
16,000 Lumen - Functional	21,158	$16.94	$358,417	-0.67%	($2,404)
16,000 Lumen - Functional @ 90%	96	$15.25	$1,464	-0.67%	($10)
16,000 Lumen - S1	2,421	$47.83	$115,796	-0.67%	($777)
16,000 Lumen - S2	886	$39.34	$34,855	-0.67%	($234)
27,500 Lumen - Functional	26,178	$21.14	$553,403	-0.67%	($3,712)
27,500 Lumen - Functional @ 90%	12	$19.03	$228	-0.67%	($2)
27,500 Lumen - S1	1,253	$51.48	$64,504	-0.67%	($433)
27,500 Lumen - S2	0	$43.01	$0	-0.67%	$0
50,000 Lumen - Functional	11,406	$26.02	$296,784	-0.67%	($1,991)
125,000 Lumen	0	$51.54	$0	-0.67%	$0

Metal Halide Lamps (MH)					
9,000 Lumen - S1	36	$48.74	$1,755	-0.67%	($12)
9,000 Lumen - S2	602	$40.27	$24,243	-0.67%	($163)
12,000 Lumen - Functional	127	$20.13	$2,557	-0.67%	($17)
12,000 Lumen - S1	0	$50.65	$0	-0.67%	$0
12,000 Lumen - S2	1,598	$42.17	$67,388	-0.67%	($452)
19,500 Lumen - Functional	386	$22.13	$8,542	-0.67%	($57)
19,500 Lumen - S1	41	$53.69	$2,201	-0.67%	($15)
19,500 Lumen - S2	365	$45.20	$16,498	-0.67%	($111)
32,000 Lumen - Functional	61	$25.78	$1,573	-0.67%	($11)
32,000 Lumen - S1	0	$55.33	$0	-0.67%	$0
32,000 Lumen - S2	0	$46.86	$0	-0.67%	$0
Mercury Vapor Lamps (No New Service) (MV)					
4,000 Lumen	3,279	$11.09	$36,364	-0.67%	($244)
7,000 Lumen	9,152	$13.83	$126,572	-0.67%	($849)
10,000 Lumen	186	$19.40	$3,608	-0.67%	($24)
10,000 Lumen @ 90%	0	$17.46	$0	-0.67%	$0
20,000 Lumen	996	$24.43	$24,332	-0.67%	($163)
Incandescent Lamps (No New Service) (INC)					
500 Lumen	0	$11.99	$0	-0.67%	$0
600 Lumen	145	$4.24	$615	-0.67%	($4)
2,500 Lumen	32	$17.11	$548	-0.67%	($4)
4,000 Lumen	162	$20.43	$3,310	-0.67%	($22)
6,000 Lumen	161	$23.82	$3,835	-0.67%	($26)
10,000 Lumen	24	$31.47	$755	-0.67%	($5)
Fluorescent Lamps (No New Service) (FLOUR)					
21,000 Lumen	12	$27.85	$334	-0.67%	($2)
Special Service (No New Service)					
50,000 Lumen - Flood	12	$39.04	$468	-0.67%	($3)
Subtotal	334,883		$4,979,390		($33,399)
kWh Included	16,496,197				
Customers	809				
Unbilled	0		$0		
Total	16,496,197		$4,979,390		($33,399)

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

<u>1. Energy Only, No Maintenance</u>

High Pressures Sodium Vapor Lamps					
5,600 Lumen	103,438	$1.83	$189,292	-0.67%	($1,270)
9,500 Lumen	159,006	$2.50	$397,515	-0.67%	($2,666)
16,000 Lumen	134,332	$3.66	$491,655	-0.67%	($3,298)
27,500 Lumen	48,293	$6.52	$314,870	-0.67%	($2,112)
50,000 Lumen	65,553	$10.02	$656,841	-0.67%	($4,406)
Metal Halide Lamps					
9,000 Lumen	6,583	$2.55	$16,787	-0.67%	($113)
12,000 Lumen	18,818	$4.46	$83,928	-0.67%	($563)
19,500 Lumen	28,281	$6.17	$174,494	-0.67%	($1,170)
32,000 Lumen	27,914	$9.77	$272,720	-0.67%	($1,829)
Non-listed Luminaries kWh	10,059,553	6.5279 ¢	$656,678	-0.67%	($4,405)
Subtotal kWh	49,653,570		$3,254,780		($21,831)
Unbilled					
Total	49,653,570		$3,254,780		($21,831)
Customer	519				

2a - Partial Maintenance (No New Service)

Incandescent Lamps					
2,500 Lumen or Less	76	$8.96	$681	-0.67%	($5)
4,000 Lumen	91	$12.19	$1,109	-0.67%	($7)
Mercury Vapor Lamps					
4,000 Lumen	47	$4.64	$218	-0.67%	($1)

7,000 Lumen	546	$7.00	$3,822	-0.67%	($26)
20,000 Lumen	140	$13.33	$1,866	-0.67%	($13)
54,000 Lumen	0	$28.38	$0	-0.67%	$0
High Pressure Sodium Vapor Lamps					
5,600 Lumen	34,609	$4.08	$141,205	-0.67%	($947)
9,500 Lumen	15,632	$5.37	$83,944	-0.67%	($563)
9,500 Lumen - Decorative	8,817	$6.96	$61,366	-0.67%	($412)
16,000 Lumen	2,548	$6.52	$16,613	-0.67%	($111)
16,000 Lumen - Decorative	799	$8.27	$6,608	-0.67%	($44)
22,000 Lumen	0	$8.26	$0	-0.67%	$0
27,500 Lumen	5,601	$9.59	$53,714	-0.67%	($360)
27,500 Lumen - Decorative	143	$11.93	$1,706	-0.67%	($11)
50,000 Lumen	10,133	$14.00	$141,862	-0.67%	($952)
50,000 Lumen - Decorative	157	$15.56	$2,443	-0.67%	($16)
Metal Halide Lamps					
9,000 Lumen - Decorative	702	$9.19	$6,451	-0.67%	($43)
12,000 Lumen	1,617	$13.57	$21,943	-0.67%	($147)
12,000 Lumen - Decorative	225	$11.09	$2,495	-0.67%	($17)
19,500 Lumen	518	$13.71	$7,102	-0.67%	($48)
19,500 Lumen - Decorative	6,034	$14.13	$85,260	-0.67%	($572)
32,000 Lumen	544	$14.58	$7,932	-0.67%	($53)
32,000 Lumen - Decorative	669	$15.79	$10,564	-0.67%	($71)
Fluorescent Lamps					
1,000 Lumen	0	$3.75	$0	-0.67%	$0
21,800 Lumen	83	$13.92	$1,155	-0.67%	($8)
Subtotal kWh	5,219,065		$660,059		($4,427)
Unbilled					
Total	5,219,065		$660,059		($4,427)
Customer	221				
2b - Full Maintenance (No New Service)					
Incandescent Lamps					
6,000 Lumen	36	$17.73	$638	-0.67%	($4)
10,000 Lumen	12	$23.40	$281	-0.67%	($2)
Mercury Vapor Lamps					
7,000 Lumen	42	$8.03	$337	-0.67%	($2)
20,000 Lumen	0	$15.30	$0	-0.67%	$0
54,000 Lumen	96	$32.48	$3,118	-0.67%	($21)
Sodium Vapor Lamps					
5,600 Lumen	4,275	$4.68	$20,007	-0.67%	($134)
9,500 Lumen	14,686	$6.16	$90,466	-0.67%	($607)
16,000 Lumen	1,259	$7.47	$9,405	-0.67%	($63)
22,000 Lumen	0	$9.44	$0	-0.67%	$0
27,500 Lumen	2,408	$10.99	$26,464	-0.67%	($178)
50,000 Lumen	1,967	$16.02	$31,511	-0.67%	($211)
Metal Halide Lamps					
12,000 Lumen	1,188	$15.58	$18,509	-0.67%	($124)
19,500 Lumen	724	$15.73	$11,389	-0.67%	($76)
32,000 Lumen	881	$16.72	$14,730	-0.67%	($99)
107,000 Lumen	96	$33.05	$3,173	-0.67%	($21)
Subtotal kWh	1,644,140		$230,028		($1,543)
Unbilled					
Total	1,644,140		$230,028		($1,543)
Customer	99				
kWh Street Lighting	56,516,774		$4,144,867		($27,801)
Customers	839				
Unbilled			$0		
Total	56,516,774		$4,144,867		($27,801)

Schedule 15.1 - Metered Outdoor Nighttime Lighting - Composite

Annual Facility Charge	20,286	$11.00	$223,146		
Annual Customer Charge	497	$72.50	$36,033		
Annual Minimum Charge	0.0	$127.50	$0		
Monthly Customer Charge	6,182	$6.20	$38,328		
All kWh	17,536,445	5.3437 ¢	$937,095	-0.95%	($8,908)
Unbilled	0		$0		
Total	17,536,445		$1,234,602		($8,908)

Schedule 15.2 - Traffic Signal Systems - Composite

Customer Charge	29,596	$5.50	$162,778		
All kWh	6,177,947	8.4049 ¢	$519,250	-1.28%	($6,629)
Unbilled	0		$0		
Total	6,177,947		$682,028		($6,629)

Schedule No. 21 - Electric Furnace Operations - Limited Service - Industrial

Primary Voltage					
Customer Charge	36	$127.00	$4,572		
Charge per kW (Facilities)	10,893	$4.30	$46,840		
First 100,000 kWh	423,833	6.8447 ¢	$29,010	-2.26%	($654)
All add'l kWh	0	5.7472 ¢	$0	-2.26%	$0
Unbilled	0		$0		
Subtotal	423,833		$80,422		($654)
44KV or Higher					
Customer Charge	24	$127.00	$3,048		
Charge per kW (Facilities)	47,371	$4.30	$203,695		
First 100,000 kWh	2,660,898	5.3851 ¢	$143,292	-2.26%	($3,231)
All add'l kWh	963,969	4.7169 ¢	$45,469	-2.26%	($1,025)
Unbilled	0		$0		
Subtotal	3,624,867		$395,504		($4,257)
Total	4,048,700		$475,926		($4,911)

Schedule No. 23 - Composite

Customer Charge	992,018	$10.00	$9,920,180		
kW over 15 (May - Sept)	387,746	$8.65	$3,354,003	-1.12%	($37,640)
kW over 15 (Oct - Apr)	347,761	$8.70	$3,025,521	-1.12%	($33,954)
Voltage Discount	7,029	($0.48)	($3,374)		
First 1,500 kWh (May - Sept)	295,977,608	11.7336 ¢	$34,728,829	-1.12%	($389,745)
All Add'l kWh (May - Sept)	309,000,008	6.5783 ¢	$20,326,948	-1.12%	($228,119)
First 1,500 kWh (Oct - Apr)	424,820,226	10.8000 ¢	$45,880,584	-1.12%	($514,895)
All Add'l kWh (Oct - Apr)	361,090,369	6.0567 ¢	$21,870,160	-1.12%	($245,438)
Seasonal Service	0	$120.00	$0		
Unbilled	0		$0		
Total	1,390,888,211		$139,102,851		($1,449,792)

Schedule No.31 - Composite

Secondary Voltage			
Customer Charge per month	0	$133.00	$0
Facilities Charge, per kW month	0	$5.60	$0
Back-up Power Charge			
Regular, per On-Peak kW day	0		
May - Sept	0	$0.88	$0
Oct - Apr	0	$0.62	$0
Maintenance, per On-Peak kW day	0		
May - Sept	0	$0.440	$0
Oct - Apr	0	$0.310	$0
Excess Power, per kW month	0		
May - Sept	0	$40.81	$0
Oct - Apr	0	$32.04	$0

Primary Voltage					
Customer Charge per month	24	$605.00	$14,520		
Facilities Charge, per kW month	38,791	$4.46	$173,008		
Back-up Power Charge					
Regular, per On-Peak kW day	195,683				
May - Sept	79,030	$0.86	$67,966		
Oct - Apr	116,653	$0.60	$69,992		
Maintenance, per On-Peak kW day	24,254				
May - Sept	24,254	$0.430	$10,429		
Oct - Apr	0	$0.300	$0		
Excess Power, per kW month	30				
May - Sept	0	$38.54	$0		
Oct - Apr	30	$29.77	$893		
Transmission Voltage					
Customer Charge per month	24	$678.00	$16,272		
Facilities Charge, per kW month	153,429	$2.63	$403,518		
Back-up Power Charge					
Regular, per On-Peak kW day	391,585				
May - Sept	239,920	$0.76	$182,339		
Oct - Apr	151,665	$0.51	$77,349		
Maintenance, per On-Peak kW day	0				
May - Sept	0	$0.380	$0		
Oct - Apr	0	$0.255	$0		
Excess Power, per kW month	0				
May - Sept	0	$32.35	$0		
Oct - Apr	0	$23.36	$0		
Subtotal			$1,016,286		$0
Supplemental billed at Schedule 6/8/9 rate					
Schedule 8					
Facilities kW	16,065	$4.76	$76,469		
On-Peak kW (May - Sept)	0	$15.56	$0	-1.08%	$0
On-Peak kW (Oct - Apr)	16,065	$11.19	$179,767	-1.08%	($1,936)
Voltage Discount	16,065	($1.13)	($18,153)		
On-Peak kWh (May - Sept)	1,044,794	5.0474 ¢	$52,735	-1.08%	($568)
On-Peak kWh (Oct - Apr)	3,934,668	3.9511 ¢	$155,463	-1.08%	($1,674)
Off-Peak kWh	5,030,285	3.4002 ¢	$171,040	-1.08%	($1,842)
Schedule 9					
Facilities kW	103,313	$2.22	$229,355		
On-Peak kW (May - Sept)	49,491	$13.96	$690,894	-1.04%	($7,193)
On-Peak kW (Oct - Apr)	50,080	$9.47	$474,258	-1.04%	($4,938)
On-Peak kWh (May-Sept)	7,647,176	4.6531 ¢	$355,831	-1.04%	($3,705)
On-Peak kWh (Oct-Apr)	10,898,121	3.4989 ¢	$381,314	-1.04%	($3,970)
Off-Peak kWh	27,727,401	2.9225 ¢	$810,333	-1.04%	($8,436)
Subtotal			$3,559,306		($34,262)
Unbilled	0		$0		
Total (Aggregated)	56,282,445		$4,575,592		($34,262)
Contract 1					
Fixed Customer Charge	12		$2,455		
Customer Charge			$1,757,447.77		
kW High Load Hours	949,050		$9,607,156	0.00%	$0
kWh High Load Hours	237,232,647		$8,613,813	0.00%	$0
kWh Low Load Hours	298,488,523		$7,977,879	0.00%	$0
Total	535,721,170		$27,958,751		$0
Contract 2					
Customer Charge	12				
Interruptible kWh	795,798,676		$35,062,890	0.00%	$0
Total	795,798,676		$35,062,890		$0

Contract 3				
Customer Charge	12		$8,136	
Facilities Charge per kW - Back-Up	422,498		$921,045	
kW Back-Up				
Regular, per On-Peak kW day	3,435,490			
May - Sept	3,253,488		$1,673,920	
Oct - Apr	182,002		$93,640	
Maintenance, per On-Peak kW day	0			
May - Sept			$0	
Oct - Apr			$0	
Excess Power, per kW month	0			
May - Sept			$0	
Oct - Apr			$0	
kW Supplemental				
On-Peak kW (May - Sept)	24,807		$346,306	$0
On-Peak kW (Oct - Apr)	765,402		$7,248,357	$0
kWh Supplemental				
On-Peak kWh (May-Sept)	22,796,861	¢	$1,060,761	$0
On-Peak kWh (Oct-Apr)	204,228,863	¢	$7,145,764	$0
Off-Peak kWh	394,783,609	¢	$11,537,551	$0
Total	621,809,333		$30,035,480	$0
Lighting Contract - Post Top Lighting - Composite				
Energy Only Res	60	$2.18	$131	
Energy Only Non-Res	207	$2.1858	$452	
Subtotal	267		$583	
KWH Included	7,737			
Customers	5			
Unbilled	0			
Total	7,737		$583	$0
Annual Guarantee Adjustment				
Residential			$33,040	
Commercial			$2,726,578	
Industrial			($5,447)	
Irrigation			$206,563	
Public Street & Highway Lighting			$4,662	
Other Sales Public Authorities			$0	
Total AGA			$2,965,396	$0
TOTAL - ALL CLASSES	23,244,284,922		$1,938,306,489	($20,007,477)

Table A
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.	No. of Customers Forecast	MWh Forecast	Present Revenue ($000) Base	Present Revenue ($000) TAA	Present Revenue ($000) Net	Proposed Revenue ($000) Base	Proposed Revenue ($000) TAA	Proposed Revenue ($000) Net	Change Base ($000)	Change Base (%)	Change Net ($000)	Change Net (%)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Residential													
1	Residential	1,3	740,189	6,200,666	$684,505	$0	$684,505	$684,505	-$8,372	$676,133	$0	0.0%	($8,372)	-1.2%
2	Residential-Optional TOD	2	447	3,186	$351	$0	$351	$351	-$4	$347	$0	0.0%	($4)	-1.2%
3	AGA/Revenue Credit	--			$33		$33	$33		$33	$0	0.0%	$0	0.0%
4	**Total Residential**		740,636	6,203,852	$684,889	$0	$684,889	$684,889	-$8,376	$676,513	$0	0.0%	($8,376)	-1.2%
	Commercial & Industrial & OSPA													
5	General Service-Distribution	6	13,072	5,783,806	$494,681	$0	$494,681	$494,681	-$5,133	$489,548	$0	0.0%	($5,133)	-1.0%
6	General Service-Distribution-Energy TOD	6A	2,276	292,031	$34,227	$0	$34,227	$34,227	-$355	$33,872	$0	0.0%	($355)	-1.0%
7	General Service-Distribution-Demand TOD	6B	37	3,907	$346	$0	$346	$346	-$3	$342	$0	0.0%	($3)	-1.0%
8	*Subtotal Schedule 6*		15,385	6,079,745	$529,255	$0	$529,255	$529,255	-$5,492	$523,763	$0	0.0%	($5,492)	-1.0%
9	General Service-Distribution > 1,000 kW	8	274	2,187,047	$167,313	$0	$167,313	$167,313	-$1,569	$165,745	$0	0.0%	($1,569)	-0.9%
10	General Service-High Voltage	9	149	5,027,436	$284,876	$0	$284,876	$284,876	-$2,752	$282,125	$0	0.0%	($2,752)	-1.0%
11	General Service-High Voltage-Energy TOD	9A	9	42,591	$3,293	$0	$3,293	$3,293	-$32	$3,261	$0	0.0%	($32)	-1.0%
12	*Subtotal Schedule 9*		158	5,070,026	$288,169	$0	$288,169	$288,169	-$2,783	$285,386	$0	0.0%	($2,783)	-1.0%
13	Irrigation	10	2,784	173,133	$13,210	$0	$13,210	$13,210	-$184	$13,026	$0	0.0%	($184)	-1.4%
14	Irrigation-Time of Day	10TOD	261	16,757	$1,286	$0	$1,286	$1,286	-$18	$1,268	$0	0.0%	($18)	-1.4%
15	*Subtotal Irrigation*		3,045	189,890	$14,496	$0	$14,496	$14,496	-$202	$14,294	$0	0.0%	($202)	-1.4%
16	Electric Furnace	21	5	4,049	$476	$0	$476	$476	-$5	$471	$0	0.0%	($5)	-1.0%
17	General Service-Distribution-Small	23	82,668	1,390,888	$139,103	$0	$139,103	$139,103	-$1,450	$137,653	$0	0.0%	($1,450)	-1.0%
18	Back-up, Maintenance, & Supplementary	31	4	56,282	$4,576	$0	$4,576	$4,576	-$34	$4,541	$0	0.0%	($34)	-0.7%
19	Contract 1	--	1	535,721	$27,959	$0	$27,959	$27,959	$0	$27,959	$0	0.0%	$0	0.0%
20	Contract 2	--	1	795,799	$35,063	$0	$35,063	$35,063	$0	$35,063	$0	0.0%	$0	0.0%
21	Contract 3	--	1	621,809	$30,035	$0	$30,035	$30,035	$0	$30,035	$0	0.0%	$0	0.0%
22	AGA/Revenue Credit	--			$2,928		$2,928	$2,928		$2,928	$0	0.0%	$0	0.0%
23	**Total Commercial & Industrial & OSPA**		101,542	16,931,257	$1,239,372	$0	$1,239,372	$1,239,372	-$11,534	$1,227,838	$0	0.0%	($11,534)	-0.9%
	Public Street Lighting													
24	Security Area Lighting	7	8,046	12,441	$2,999	$0	$2,999	$2,999	-$20	$2,979	$0	0.0%	($20)	-0.7%
25	Street Lighting - Company Owned	11	809	16,496	$4,979	$0	$4,979	$4,979	-$33	$4,946	$0	0.0%	($33)	-0.7%
26	Street Lighting - Customer Owned	12	839	56,517	$4,145	$0	$4,145	$4,145	-$28	$4,117	$0	0.0%	($28)	-0.7%
27	Metered Outdoor Lighting	15	2,466	6,178	$1,235	$0	$1,235	$1,235	-$9	$1,226	$0	0.0%	($9)	-0.7%
28	Traffic Signal Systems	15	515	17,536	$682	$0	$682	$682	-$7	$675	$0	0.0%	($7)	-1.0%
29	*Subtotal Public Street Lighting*		12,675	109,168	$14,040	$0	$14,040	$14,040	-$97	$13,943	$0	0.0%	($97)	-0.7%
30	Security Area Lighting-Contracts (PTL)	--	5	8	$1	$0	$1	$1	$0	$1	$0	0.0%	$0	0.0%
31	AGA/Revenue Credit	--			$5		$5	$5		$5		0.0%	$0	0.0%
32	**Total Public Street Lighting**		12,680	109,176	$14,045	$0	$14,045	$14,045	-$97	$13,948	$0	0.0%	($97)	-0.7%
33	**Total Sales to Ultimate Customers**		854,859	23,244,285	$1,938,306	$0	$1,938,306	$1,938,306	-$20,007	$1,918,299	$0	0.0%	($20,007)	-1.0%

CERTIFICATE OF SERVICE

Docket No. 17-035-69

I hereby certify that on March 16, 2018, a true and correct copy of the foregoing was served by electronic mail to the following:

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Coordinator, Regulatory Operations