BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER TO UPDATE BASE NET POWER COSTS AND IMPLEMENT A RATE STABILITY PLAN	)))))))	**CASE NO. PAC-E-16-12** **DIRECT TESTIMONY OF TED WESTON**

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-16-12

September 2016

Q. Please state your name, business address and present position with Rocky Mountain Power (the "Company"), a division of PacifiCorp.

A. My name is Ted Weston and my business address is 1407 West North Temple, Suite 330, Salt Lake City, Utah, 84116. I am currently employed as the Manager of Regulatory Affairs for Idaho.

QUALIFICATIONS

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Science Degree in Accounting from Utah State University in 1983. I began my employment with the Company in June of 1983 and have held various accounting and regulatory positions since then. In addition to formal education, I have attended educational, professional, and electric industry related seminars during my career with the Company.

Q. What are your responsibilities as Manager of Regulatory Affairs?

A. My primary responsibilities include the coordination and management of Idaho regulatory filings, communications, and oversight of reporting requirements with the Idaho Public Utilities Commission ("Commission").

PURPOSE OF TESTIMONY

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

A. My testimony supports the Company's compliance filing to update net power costs ("NPC") and retail load used for the Load Change Adjustment Rate and other components of the Energy Cost Adjustment Mechanism ("ECAM") effective January 1, 2017, and presents an alternative Rate Stability Plan proposal to mitigate future rate impacts for customers.

BACKGROUND

Q. Please explain why the Company is making this filing.

A. The Company filed an application[1] on May 27, 2015, with the Commission to: (1) increase base rates by $10.2 million effective January 1, 2016; (2) increase the level of NPC in base rates, thereby reducing ECAM deferrals; and (3) modify the ECAM. After negotiating with parties, a Stipulation was reached and later approved by the Commission.[2] The Stipulation requires a NPC update effective January 1, 2017. The update is to be based on the normalized NPC reported in the 2015 annual Result of Operations report, which was provided to the Commission on April 30, 2016. The Stipulation specified that the rate spread and rate design would be on an equal cents per kilowatt hour ("kWh") basis, consistent with the rate increase from that case. The Company committed to make the filing by September 1, 2016, to provide time for review and approval prior to the January 1, 2017, rate effective date.

Net Power Cost Update

Q. Please describe the impact of the NPC update and compare it to the level of NPC currently in rates ("Base NPC").

A. The NPC reported in the 2015 Results of Operations were $1.485 billion on a total Company basis; Idaho's allocation of these costs was $91.6 million or $26.90 per megawatt hour ("MWh"). Base NPC included in rates are $1.529 billion total Company, with Idaho's allocation approximately equal to $94.8 million or $27.21 per MWh. The two main drivers behind the reduction to NPC are reduced load and lower prices. Both total system and Idaho retail load were lower during calendar

[1] Case No. PAC-E-15-09.
[2] Order No. 33440.

year 2015 than they were in the Base NPC. Idaho's 2015 retail load was 3,407,488 MWh compared to the current base of 3,483,480 MWh. This volumetric load change accounted for $2.1 million of the $3.2 million reduction to NPC. Company witness Mr. Michael Wilding's testimony describes the changes to NPC in more detail.

Q. What impact does this update have on Idaho's annual revenue requirement and retail rates?

A. The NPC update reduces Idaho's annual revenue requirement by approximately $1.1 million. When this amount is divided by Idaho's 2015 retail load, the reduction is approximately $0.32 per MWh as shown below.

Rate Stability Proposal	Total	Idaho	MWH	$ / MWH
Base NPC	$ 1,529,427,580	$ 94,801,644	3,483,480	$ 27.215
NPC Collected		$ 92,733,539	3,407,488	$ 27.215
December 2015 Normalized NPC	$ 1,485,447,775	$ 91,646,156	3,407,488	$ 26.896
Impact of NPC Update		$ (1,087,383)	3,407,488	$ (0.319)

Q. What is the rate impact to customers of the update to NPC?

A. A $1.1 million decrease in revenue requirement associated with the reset of the NPC in base rates results in an average annual decrease of approximately 0.4 percent. The impact by rate schedule and calculation of the rate change is shown in Attachment B to Application.

Q. How does the Company propose to handle the customer impact from the NPC update?

A. Absent any agreement or approval on an alternative approach, the adjustment to base rates for the reset of NPC would flow through to all customer rates on an equal cents/kWh basis beginning on January 1, 2017, based on the Commission review and approval of the change being in compliance with Order No. 33440. While implementing a small decrease would be the simplest approach, the Company believes that an alternative exists to address rate stability and mitigate future increases for customers.

RATE STABILITY PLAN

Q. Please explain the Company's alternative proposal.

A. Order No. 33440 authorized the Company to file an NPC update with rates effective January 1, 2017, with the option to file a general rate case by June 1, 2017, for a January 1, 2018, rate effective date. The Company is proposing to work with intervening parties to determine whether support exists to implement a Rate Stability Plan through December 31, 2018, and use potential rate reductions that may otherwise occur during that period to offset growing balances for deferred regulatory assets that will flow into the next rate case as amortization expense. The $1.1 million decrease would be included in this plan to pay down the balance accumulating on the Company's books for depreciation expense that is being deferred as a result of Commission Order 32910.[3]

Q. How would the Rate Stability Plan work?

A. The Company would request an update to Base NPC to $91.6 million, or $26.90 per MWh, but would not adjust retail rates. The NPC update would reduce Idaho's annual revenue requirement by approximately $1.1 million or $0.32 per MWh. However, rather than reducing rates by that amount, the Company recommends keeping rates at the current level and using the incremental revenue collected from

[3] Case No. PAC-E-13-04.

customers to offset the deferred regulatory asset owed from customers for the 2013 depreciation regulatory asset.

Q. Are there other aspects for consideration in the Rate Stability Plan?

A. Yes. In addition to holding base rates constant for the net power cost reset, the Company is evaluating the impact of holding ECAM rates constant at current levels in 2017 if the annual true-up filing would otherwise result in a rate decrease, and use the funds to offset other growing regulatory assets to mitigate the rate impact on future general rate cases. Based on the Company's current estimate for the 2016 ECAM deferral, the June 1, 2017, collection rate could be reduced in the range of $4.5 to $5.5 million. Rather than implementing rate reductions in 2017 followed by a general rate change in the near future, the Rate Stability Plan provides an alternative to hold rates stable and provide more predictability on the timing of the next general rate case when it could be matched up with the ordered implementation of the next depreciation study.

The Company would also agree in this context that it would not file a general rate case prior to June 1, 2018. Customers would benefit from rate stability and predictability in the near-term, and small refunds owed to customers during this same period will be used to offset deferred costs owed to the Company with the intent of minimizing future pressures on rates and continued rate stability.

Q. Would regulatory assets other than deferred depreciation be considered as part of the Rate Stability Plan?

A. Yes. The Commission has authorized deferral of the Carbon plant and Deer Creek mine. While recovery of the investment in the facilities is occurring, the expenses incurred to close and reclaim them are being deferred for future rate recovery.

Q. How would this plan mitigate future rate impact?

A. If the Company simply filed to update Base NPC and decreased rates $1.1 million January 1, 2017, followed by the annual ECAM filing effective June 1 2017, which it anticipates would reduce the ECAM rates, whenever the Company filed its next general rate case, customers will incur a larger increase from the "doubling impact" of the 2013 depreciation expense.

Q. What do you mean by a "doubling impact" of depreciation expense?

A. The 2013 depreciation study increased Idaho's annual depreciation expense approximately $1.7 million; however, that impact has never been included in rates as a result of previous stipulations. The incremental depreciation expense is currently being deferred with a projected balance of $6.9 million by December 31, 2017. If not addressed, the amortization expense from the deferral would also be included in rates at the same time as the incremental depreciation expense. Depending on the amortization period, that expense could be as much or more than the incremental depreciation expense, doubling the impact on rates.

Q. When will the next depreciation study be filed?

A. The next depreciation study needs to be completed and approved with effective dates by January 1, 2019. Depending on the timing of the next general rate case the rate impact of that study may also be part of the rate case. The implementation of a new depreciation study with rates anticipated to be effective January 1, 2019, could potentially triple the incremental impact of depreciation expense in that general rate case.

Q. Please explain the timing and implementation of the Rate Stability Plan.

A. Pursuant to the Stipulation,[4] updated tariffs were filed as Attachment A to the Application to reflect the equal cents per kWh impact for all rate schedules. However, with the option of a Rate Stability Plan, rates would not change January 1, 2017, and instead the Company would calculate the incremental revenues collected by multiplying the actual monthly retail sales by the $0.00032 cents per kWh and offset this incremental revenue collection by a corresponding amount of amortization expense from the depreciation regulatory asset, reducing that balance. The same type of approach could be taken with the 2017 ECAM filing. The Company would calculate the ECAM balance from the 2016 deferral and design rates to collect that amount, but not change rates on Electric Service Schedule No. 94, ECAM Cost Adjustment. Beginning June 1, 2017, the same accounting adjustment would occur; the incremental cents per kWh reduction from the ECAM rate would also be applied to the actual kWh from retail sales to calculate the additional amortization expense applied to the depreciation regulatory asset. The monthly amortization of the depreciation regulatory asset would equal the incremental revenues collected and would continue until May 31, 2018, the end of the rate effective date of the 2017 ECAM filing. Depending on the actual level of

[4] Case No. PAC-E-15-09.

retail sales, the majority of the depreciation regulatory asset could be collected by June 1, 2018.

Q. Why would collection of the depreciation regulatory asset in this manner benefit customers?

A. Customers benefit in several ways: first, future rate increases would be mitigated; second, it assures customers pay only what they owe, no more or less; and third, customers that are benefiting from the use of assets begin to pay for the increased depreciation since a rate case has not been held for several years; and, finally, it eliminates long-term intergenerational inequities. When amortizations are included in base rates, the recovery is dependent on the timing of future rate cases. Recovering the regulatory asset through a balancing account ensures only the exact amount owed is paid which is fair for both customers and the Company.

Q. As part of the Rate Stability Plan, what else will the 2018 ECAM filing consider?

A. Based on current NPC forecasts the Rate Stability Plan could potentially continue to keep rates stable through 2018 by decreasing ECAM rates with a corresponding increase to base rates to shift rate recovery from the ECAM into base rates. For example, the discussions with intervening parties could explore whether recovery of Lake Side II could be shifted from the ECAM to base rates, or could adjust the level of PTC in base rates without any net rate change.

Q. How would the plan handle any over or under collection of the 2013 depreciation regulatory asset?

A. If the ECAM deferral and loads are close to forecasted levels, the remaining depreciation deferral balance would be minimal. The Company recommends transferring any over or under collection of the depreciation deferral into the 2017 ECAM deferred balance.

Q. What would happen under the Rate Stability Plan if actual NPC in 2017 are higher than forecasted, resulting in an increase, rather than a decrease in the ECAM collection rate?

A. If the 2017 ECAM deferral was higher than the current ECAM collection rate of $14.5 million the Company would recommend increasing the ECAM collection rate effective June 1, 2018.

Q. What about the $1.1 million in base rates from the January 1, 2017 Base NPC update?

A. After implementing the NPC update January 1, 2017, base rates will be higher by approximately $1.1 million; initially those additional revenues will be used to recover the deferred depreciation balance. Effective June 1, 2018, the $1.1 million plus an additional increase of approximately $0.6 million will be required to incorporate the $1.7 million incremental annual 2013 depreciation expense into base rates. The $0.6 million would be part of the rate stabilization shift from the ECAM into base rates.

Depreciation Regulatory Asset

Q. What is the 2013 depreciation regulatory asset?

A. In 2013, the Company filed Case No. PAC-E-13-02 to implement new depreciation rates. The Commission approved[5] the 2013 depreciation rates with a January 1, 2014, effective date. The approved rates incrementally increased Idaho's annual depreciation expense by approximately $1.7 million. Order No. 32910[6] authorized the Company to create a regulatory asset to defer, on a monthly basis, any aggregate net increase or decrease in Idaho's allocated depreciation expense beginning January 1, 2014, until the date that the 2013 depreciation rates were included in rates. However, the Company has not filed a general rate case since then so the incremental depreciation expense continues to be deferred. As of July 31, 2016, the balance of the depreciation regulatory asset was $4.3 million and growing by approximately $150 thousand per month. By December 31, 2017, if plant-in-service stays flat, the projected balance of the regulatory asset will be approximately $6.9 million.

Q. When is the Company's next depreciation study due?

A. The Company is required to update depreciation rates at least every five years; therefore, new depreciation rates would need to be approved and effective by January 1, 2019.

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[5] Order No. 32926

[6] Case No. PAC-E-13-04

LAKE SIDE II

Q. Would you explain how recovery of Lake Side II is currently occurring?

A. The Commission authorized[7] recovery of Lake Side II in the ECAM by using a resource adder of $1.99 per MWh for each hour of production, capped at $5.4 million Idaho's annual revenue requirement, with the intent that when the Company filed its next rate case recovery of Lake Side II would be moved into base rates. The Company intends to explore options with parties on the approach and timing of how to move the Lake Side II recovery from the ECAM to base rates and mitigate the impact on rates over time.

PRODUCTION TAX CREDITS

Q. Are PTC currently included in base rates?

A. Yes. Customers receive a credit or reduction to their annual revenue requirement of approximately $7 million due to PTC from Company owned wind facilities. Renewable resources that qualify receive PTC for the first ten years after their in-service date. The Company built most of its wind facilities from 2006 to 2010. Under current tax laws, the level of PTC that the Company receives began declining in 2016 and will be gone by the end of 2020. In Order No. 33440, the Commission approved dollar for dollar tracking of PTC in the ECAM. The Company intends to explore options with parties on the approach and timing of how to reflect the changing level of PTC in base rates and mitigate the impact on the next rate case.

[7] Order No. 32910

Q. If Lake Side II and PTC are tracked in the ECAM with no sharing, how will customers benefit by shifting recovery into base rates?

A. Recovery of the ECAM deferral balance occurs up to seventeen months after it's incurred. Accordingly, when the Company files a rate case, the updated revenue requirement would include the impact for these two items in base rates, which would overlap with recovery of the deferred amounts through the ECAM for up to 17 months before those deferred amounts drop out of the ECAM. However, if recovery of all or a portion of these costs could be transitioned into base rates prior to the next general rate case while holding rates flat on a net basis through a reduction to the ECAM, customers would benefit through rate predictability and less volatility in rates..

CONCLUSION

Q. Please summarize the Company's alternative Rate Stability Plan contained in this Application.

A. The Rate Stability Plan would: (1) update Base NPC effective January 1, 2017, to $91.6 million or $26.90 per MWh; (2) not changing base or ECAM rates prior to June 1, 2018; (3) utilize the incremental revenue collected from base and ECAM rates to amortize the 2013 depreciation deferred balance; and (4) delay filing the next general rate case one year with rates not effective prior to January 1, 2019. The Rate Stability Plan would provide customers two additional years of rate stability while addressing several pending regulatory issues and mitigating future rate impact.

Q. Does this conclude your direct testimony?

A. Yes.