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IDAHO PUBLIC
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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	**)**	**CASE NO. PAC-E-20-02**
OF ROCKY MOUNTAIN POWER	)	
REQUESTING APPROVAL OF $21.2	**)**	**DIRECT TESTIMONY OF**
MILLON NET POWER COST DEFERRAL	**)**	**DAVID G. WEBB**

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-20-02

April 2020

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Rocky Mountain Power ("Rocky Mountain Power" or the "Company").

A. My name is David G. Webb and my business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Manager, Net Power Costs.

QUALIFICATIONS

Q. Please describe your education and professional experience.

A. I received a Master of Accountancy degree from Southern Utah University in 1999 and a Bachelor of Science degree in Business Management from Brigham Young University in 1994. I am a Certified Public Accountant licensed in the state of Nevada. I have been employed by PacifiCorp since 2005 and have held various positions in the regulation, finance, fuels, and mining departments. I assumed my current role managing the regulatory net power cost group in 2019.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously provided testimony to the public utility commissions in Utah, Wyoming, and Oregon.

PURPOSE OF TESTIMONY

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

A. My testimony presents and supports the Company's calculation of the Energy Cost Adjustment Mechanism ("ECAM") balancing account for the 12-month period of January 1, 2019 through December 31, 2019 ("Deferral Period"). More specifically, I provide the following:

- A summary of the ECAM calculation, including changes made to comply with Commission orders;

- Details supporting the addition of approximately $21.6 million to the deferral balance, including $11.5 million customers' share of excess ECAM-related costs, $4.5 million Lake Side 2 Resource Adder, a $4.7 million reduction in renewable energy production tax credits ("PTCs"), $0.5 million resource tracking mechanism ("RTM") deferral, $32 thousand renewable energy credit ("REC") revenue differential, and $0.5 million interest accrued;
- Discussion of the main differences between adjusted actual net power costs ("Actual NPC") and net power costs in rates ("Base NPC"); and,
- Discussion about the Company's participation in the energy imbalance market ("EIM") with the California Independent System Operator ("CAISO") and the benefits from EIM that are passed through to customers.

Q. What other witnesses present testimony for the ECAM and Tariff Schedule 94 in this case?

A. Mr. Robert M. Meredith, Director, Pricing and Cost of Service, provides testimony on the proposed rates in Electric Service Schedule No. 94, Energy Cost Adjustment ("Schedule 94") and Mr. Steven R. McDougal, Director, Revenue Requirement, provides testimony on wind repowering costs as calculated and deferred through the approved RTM.

SUMMARY OF THE ECAM DEFERRAL CALCULATION

Q. Please briefly describe the Company's ECAM authorized by the Commission.

A. In general, the ECAM tracks deviations between Actual NPC and Base NPC and defers 90 percent of the difference for later recovery.[1] Other items, described in detail later in

[1] *See* Order No. 30904 in Case No. PAC-E-08-08 and Order No. 33440 in Case No. PAC-E-15-09.

my testimony, are also tracked in the ECAM to true-up the amount in base rates to actuals. These items include a resource adder for the Lake Side 2 gas generation plant, PTCs, RTM deferral, and revenues from the sale of RECs.[2] The balance that accumulates over a deferral period is then passed on to customers as a rate surcharge or credit. The Schedule 94 rate, described in Mr. Meredith's testimony appears as a separate line item on customer bills, collects from or credits to customers the balance of deferred costs. Schedule 94 is adjusted as needed in the Company's annual ECAM filings.

The Company is required to file an application with the Commission annually by April 1st to seek approval of the deferral amount and the new Schedule 94 rate, which becomes effective June 1st.

Q. How is the ECAM deferral calculation presented in your testimony?

A. The calculation of the ECAM deferral is contained in Exhibit No. 1, discussed later in my testimony. Table 1 is a summary of the major components.

Q. Are there any changes to the ECAM calculation?

A. Yes. As discussed in Mr. McDougal's testimony, the Company and intervening parties reached a stipulated agreement approved in Order No. 33954, that authorized the Company to use the ECAM to recover the replacement of certain assets, new investment, incremental energy production, and wind repowering project PTCs through the RTM. The RTM and ECAM will capture the costs and benefits of the repowered wind facilities until they are recovered in base rates through a general rate case. Exhibit No. 1 has been modified from previous years to include the RTM deferral.

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[2] *See* Order No. 33440 in Case No. PAC-E-15-09 pages 5–6.

ECAM DEFERRAL CALCULATION

Q. Please describe the calculation of the ECAM deferral included in this filing.

A. Table 1 provides a summary of the total ECAM deferral and a breakdown of the individual components of the ECAM. Additionally, Exhibit No. 1 presents the detailed calculation of the ECAM deferral on a monthly basis.

Table 1
Annual ECAM Calculation

Calendar Year 2019 ECAM Deferral		
NPC Differential	$	13,470,193
EITF 04-6 Adjustment		115,324
LCAR		(829,632)
Total Deferral Before Sharing	$	12,755,886
Sharing Band		90%
Customer Reponsibility	$	11,480,297
Lake Side 2 Resource Adder	$	4,540,985
Production Tax Credits		4,717,273
RTM Adjustment		452,488
REC Deferral		(31,947)
Interest on Deferral		462,786
Annual Deferral (Jan - Dec 2019)	$	21,621,882

Table 1 summarizes the components of the ECAM balance. The first section summarizes the Idaho-allocated share of those items for which Idaho customers and the Company share responsibility, including: NPC differential, EITF 04-6 adjustment, and load change adjustment revenue (“LCAR”) costs. The next section calculates the 90 percent customers’ share of the items above and adds the following items which are refunded or collected in full (i.e., 100 percent): the Lake Side 2 resource adder, PTCs, RTM deferral and REC revenues. The total of these items equal the ECAM deferral.

Q. Please explain how the depreciation regulatory asset has been included in the ECAM calculation.

A. In Case No. PAC-E-18-01, the Commission ordered the Company to include the depreciation regulatory asset created in Case No. PAC-E-13-02 in future Idaho ECAM filings. As seen in Exhibit No. 1, the beginning balance, monthly deferral, and monthly amortization are included as part of the ECAM deferral balance.

Q. Based on your calculations, what is the balance expected to be in the ECAM deferral account as of June 1, 2020?

A. The projected balance in the ECAM deferral account as of June 1, 2020 is approximately $22.3 million. Table 2 summarizes the ECAM balancing account activity starting with the calendar year 2018 ECAM deferral balance of $17.4 million approved in Case No. PAC-E-19-04. Approximately $21.6 million is added to the balance from the annual deferral and interest during the Deferral Period, offset by $11.7 million of ECAM revenue collections. Table 2 then summarizes the depreciation regulatory asset balance activity; the sum of the two is the balance for collection as of December 31, 2019.

Table 2
Balancing Account Activity

ECAM Deferral Balance		
Prior Deferral	$	17,365,652
Annual Deferral (Jan - Dec 2019)		21,159,096
Interest		462,786
ECAM Revenue Collection - Schedule 94		(11,701,152)
Activity Through December 31, 2019	$	27,286,382
Depreciation Regulatory Asset Balance		
Beginning Balance	$	(86,905)
Annual Deferral (Jan - Dec 2019)		1,914,765
ECAM Revenue Collection - Schedule 94		(1,904,737)
Activity Through December 31, 2019	$	(76,878)
December 31, 2019 Balance For Collection	$	27,209,505
Schedule 94 Collection - Jan - May 2020	$	(5,100,346)
Interest		206,406
Expected Balance as of June 1, 2020	**$**	**22,315,564**

Q. Please describe the ECAM calculations in Exhibit No. 1.

A. The ECAM deferral is calculated by comparing Idaho-allocated Actual NPC to the NPC collected in rates on a monthly basis and deferring the differences into an ECAM balancing account. Exhibit No. 1 includes details of the ECAM calculation. I have also provided confidential work papers supporting this exhibit.

Q. How are the Base NPC and Actual NPC calculated?

A. The monthly Base NPC collected in rates, as set forth in Exhibit No. 1 line 6, is calculated by taking the dollar-per-megawatt-hour Base NPC rate multiplied by the actual Idaho retail sales. The Actual Idaho NPC, as set forth in Exhibit No. 1 line 15, is calculated by dividing the monthly total Company Actual NPC in the Deferral Period by the actual monthly system megawatt-hours ("MWh") in the Deferral Period. The total Company Actual NPC dollar-per-megawatt-hour basis is then multiplied by Idaho actual monthly MWh to calculate Actual Idaho NPC.

Q. Please describe how the NPC deferral is calculated.

A. The deferral is calculated on a monthly basis by subtracting the Base NPC collected in rates from the Actual Idaho NPC. For the Deferral Period, the NPC differential was $13.5 million before applying the 90 / 10 percent sharing.

Q. What costs are included in the NPC differential for deferral?

A. The NPC differential for deferral captures all components of NPC as defined in the Company's general rate case proceedings and modeled by the Company's production dispatch model the Generation and Regulation Initiative Decision Tool ("GRID"). Specifically, Base NPC and Actual NPC include amounts booked to the following FERC accounts:

Account 447 – Sales for resale; excluding on-system wholesale sales and other revenues that are not modeled in GRID

Account 501 – Fuel, steam generation; excluding fuel handling, start-up fuel (gas and diesel fuel, residual disposal), and other costs that are not modeled in GRID

Account 503 – Steam from other sources

Account 547 – Fuel, other generation

Account 555 – Purchased power; excluding the Bonneville Power Administration ("BPA") residential exchange credit pass-through if applicable

Account 565 – Transmission of electricity by others

Q. Are adjustments made to the Actual NPC before comparing them to Base NPC?

A. Yes. The Company adjusts Actual NPC to reflect the ratemaking treatment of several items, including:

- out of period accounting entries booked in the Deferral Period that relate to operations before implementation of the ECAM on July 1, 2009;
- buy-through of economic curtailment by interruptible industrial customers;
- revenue from a contract related to the Leaning Juniper wind resource;
- situs assignment of the generation from Oregon solar resources procured to satisfy Oregon Revised Statute ("ORS") 757.370 solar capacity standard;
- situs assignment of Oregon allocated excess amortization related to a prepaid wheeling expense;
- situs assignment of certain Utah solar resources and Schedule 32 contract costs;
- coal inventory adjustments to reflect coal costs in the correct period;
- legal fees related to fines and citations included in the cost of coal; and,
- adjustments related to liquidated damages that occurred outside the Deferral Period (all liquidated damage fees per a coal supply agreement are booked in accordance with generally accepted accounting principles).

Q. Why is the July 1, 2009 cutoff used to determine out of period entries?

A. Since the ECAM took effect, customers' rates have been adjusted to recover essentially all of the Company's actual net power costs, excluding any differences due to the 90 / 10 percent sharing band. Consequently, any accounting entries made during the current Deferral Period that relate to any operating period since the ECAM took effect, should also be reflected in customer rates, whether they increase or decrease Actual NPC. Accounting entries related to operating periods before the inception of the ECAM should not impact the ECAM deferral.

Q. In addition to comparing Actual NPC to Base NPC, what other components are included in the ECAM?

A. Six additional components are included in the ECAM calculations: (i) an adjustment for deferred costs associated with coal mine stripping activities recorded under the Financial Accounting Standards Board ("FASB") EITF 04-6; (ii) the LCAR adjustment; (iii) a resource adder to collect the investment in the Lake Side 2 natural gas generation facility; (iv) a true-up of PTCs; (v) the resource tracking mechanism deferral; and (vi) a true-up of REC revenues as authorized in Order No. 32196.

Q. How is the adjustment for accounting pronouncement EITF 04-6 included in the ECAM?

A. The calculation of coal stripping costs on Line 17 of Exhibit No. 1 reflects Idaho's allocated differences between the coal stripping costs incurred by the Company during excavation and recorded on the Company's books pursuant to the guidance of the accounting pronouncement EITF 04-6, and the amortization of the coal stripping costs as approved by the Commission in Case No. PAC-E-09-08, Order No. 30987. For the Deferral Period, the total EITF 04-6 coal stripping deferral adjustment is a $0.1 million increase to the ECAM deferral balance before the 90 / 10 percent sharing.

Q. Please describe the LCAR adjustment.

A. The calculation of the LCAR adjustment is a symmetrical adjustment for over- or under-collection of the energy-related portion of the Company's embedded revenue requirement for production facilities as specified in Case No. GNR-E-10-03, Order No. 32206. The LCAR accounts for variances in Idaho load that cause the Company to collect more or less of these production-related costs. The LCAR rate of $5.54 per MWh is used for the Deferral Period.

Q. How is the LCAR adjustment calculated and what impact does it have on the Deferral Period?

A. The LCAR adjustment assumes that the actual production-related costs of the LCAR are equal to base, Exhibit No. 1 line 18. The actual production-related costs are then compared to the LCAR revenue collection in rates, calculated by multiplying the LCAR rate by the actual Idaho retail sales, Exhibit No. 1 line 21. The LCAR adjustment is the difference between the actual production-related costs and the LCAR revenue, line 22 of Exhibit No. 1, and is a $0.8 million decrease to the ECAM deferral balance before the 90 / 10 percent sharing.

Q. Please explain the sharing ratio between the Company and customers in the ECAM.

A. The ECAM includes a symmetrical sharing ratio in which customers either pay or receive 90 percent of the ECAM deferral balance, and the Company is responsible for the remaining 10 percent. Line 24 of Exhibit No. 1 represents the customers' 90 percent share of the monthly deferral shown on line 23 of Exhibit No. 1. For the Deferral Period, the customers' share of the deferred balance is $11.5 million. The remaining balance of $1.3 million associated with the Company's 10 percent share is not included in the deferral balance as it is not recoverable from customers.

Q. What is the amount of the Lake Side 2 resource adder in the current filing?

A. Pursuant to the stipulation in Case No. PAC-E-13-04, approved by the Commission in Order No. 32910, the Company included a resource adder to recover the investment in the Lake Side 2 generation plant which is not yet included in base rates. The resource adder amounts to $1.99/MWh of the Lake Side 2 generation capped at 2,729,500 MWh or $5.4 million for the calendar year. The total Lake Side 2 resource adder for the Deferral Period was $4.5 million based on 2,281,902 MWh of generation, line 27 of Exhibit No. 1.

Q. What is the amount of the PTC true-up in the current filing?

A. The PTC Deferral, on line 32 of Exhibit No. 1, is calculated by comparing the actual Idaho-allocated PTC to the PTC customers receive through base rates. The PTC credit in base rates is calculated by multiplying the approved PTC rate of $1.99/MWh by Idaho retail sales. The difference is a $4.7 million increase to the ECAM deferral.

Q. Please explain the RTM deferral.

A. The RTM deferral, on line 33 of Exhibit No. 1, is calculated per Exhibit No. 4 described in Mr. McDougal's testimony. The RTM deferral during calendar year 2019 is $0.5 million.

Q. What is the amount of REC revenue adjustment in the current filing?

A. The REC revenue adjustment, on line 38 of Exhibit No. 1, is calculated by comparing the actual Idaho-allocated REC revenue to the REC revenue credit customers receive through base rates. The REC revenue credit in base rates is calculated by multiplying the approved REC revenue rate of $0.09/MWh by Idaho retail sales. The difference is a $32 thousand decrease to the ECAM deferral.

Q. What is the total ECAM deferred balance calculated in Exhibit No. 1?

A. The total ECAM deferred balance as of December 31, 2019 is $21.2 million, shown on line 39 plus $463 thousand of interest on line 48 of Exhibit No. 1, for a total deferral of $21.6 million.

Q. Does the calculation of the ECAM deferral in this application comply with the parameters of the Idaho ECAM as approved by the Commission?

A. Yes. Therefore, the Company recommends the Commission approve the ECAM application for recovery of the $21.6 million prudently incurred ECAM costs.

DIFFERENCES IN NPC

Q. On a total-Company basis, what was the difference between Actual NPC and Base NPC for the Deferral Period?

A. On a total-Company basis, Actual NPC for the Deferral Period were $1,653 million, exceeding Base NPC for the Deferral Period by $167 million. Table 3 provides a high level summary of the difference between Base NPC and Actual NPC by category on a total-Company basis.

Table 3
Net Power Cost Reconciliation ($ millions)

	TOTAL
Base NPC	$ 1,485
Increase/(Decrease) to NPC:	
Wholesale Sales Revenue	157
Purchased Power Expense	91
Coal Fuel Expense	(83)
Natural Gas Expense	2
Wheeling and Other Expense	0
Total Increase/(Decrease)	$ 167
Adjusted Actual NPC	$ 1,653

Q. Please describe the Base NPC the Company used to calculate the NPC component of the ECAM deferral.

A. The Base NPC were set in Case No. PAC-E-16-12 and became effective January 1, 2017. Base NPC used the 12 month test period of January 2016 through December 2016 and set total-Company Base NPC at $1,485 million.

Q. Please describe the primary differences between Actual NPC and Base NPC.

A. From an accounting perspective, and as shown in Table 3, Actual NPC were higher than Base NPC due to a $157 million reduction in wholesale sales, a $91 million increase in purchased power expense, a $2 million increase in natural gas expense, and a $0.2 million increase in wheeling and other expenses. The items were partially offset by an $83 million reduction in coal fuel expense.

Q. Please explain the changes in wholesale sales revenue.

A. Wholesale sales revenue declined relative to Base NPC due to higher market prices and a reduction in the wholesale sales volume of market transactions (represented in GRID as short-term firm and system balancing sales).

Revenue from market transactions is $141 million lower than Base NPC due to higher market prices and lower volume of market sales transactions. The average price of actual market sales transactions was $9.94/MWh, or 42 percent, higher than the average price in Base NPC. Actual wholesale market volumes were 8,148 GWh, or 62 percent, lower than the Base NPC. In addition, an expired contract accounted for $9 million of the decrease in wholesale sales revenue.

Q. Please explain the changes in purchased power expense.

A. Purchased power expense increased due to a $104 million increase (49 percent) in qualifying facility ("QF") transactions, partially offset by the expiration of a long-term purchase power contract. Actual QF transaction volumes were 1,690 GWh (47 percent) higher than Base NPC. The expiration of the Hermiston purchase power agreement ("PPA") resulted in lower purchased power costs of $31.3 million.

Additionally, expenses from market transactions (represented in GRID as short-term firm and system balancing purchases) increased by $37.0 million compared to Base NPC. Actual market purchases were 2,714 GWh (38 percent) lower than Base NPC, but the average price of actual market purchases transactions was $23.51/MWh (94 percent) higher than Base NPC.

Q. Please explain the changes in wheeling expenses.

A. Actual long-term wheeling expenses decreased by $1.4 million when compared to Base NPC due to expired wheeling contracts. This was offset by an increase of $6.8 million of short-term wheeling expenses.

Q. Please explain the changes in coal fuel expense.

A. Coal fuel expense decreased because coal generation volume decreased 4,587 GWh (12 percent) compared to Base NPC. The average cost of coal generation increased from $19.96/MWh in Base NPC to $20.22/MWh in the Deferral Period, but the lower generation volume results in an overall decrease of $83 million in coal fuel expense.

Q. Please explain the changes in natural gas fuel expense.

A. The total natural gas fuel expense in Actual NPC increased by $2 million compared to Base NPC mainly due to an increase in average cost of natural gas generation from $23.06/MWh in Base NPC to $23.79/MWh in the Deferral Period. This was partially offset by a decrease in gas generation volumes of 291 GWh (2 percent).

Q. Please provide an update of the Enbridge natural gas pipeline rupture and its impact on Company operations and costs.

A. On October 9, 2018, the Enbridge natural gas pipeline that transports natural gas produced in the Western Canadian Sedimentary Basin to consumers in British Columbia ("B.C.") and, through interconnecting pipelines, the Northwestern United States ("U.S."), experienced a massive rupture. The pipeline was brought back into service in late October 2018, however, at a reduced capacity until testing of the many segments of the pipeline were completed. Spot natural gas prices at the Sumas B.C.-U.S. border trading point traded as high as $159 per million British thermal units on days of intense demand due to cold weather and reduced natural gas supply in the first quarter of 2019.

The pipeline rupture and reduced operating capacity impacted electricity prices primarily at the Mid-Columbia power market hub, but also increased electricity prices at other trading points where PacifiCorp transacts. Because of PacifiCorp's geographical and resource diversity, the impact to the Company was not as severe as other utilities and power producers that have a high reliance on Sumas natural gas supplies. PacifiCorp has one natural gas-fired generator—the Chehalis plant—that is sourced from the Sumas natural gas hub. Due to the pipeline rupture, there were times of limited availability of natural gas flowing to the Sumas gas hub and limited ability to withdraw out of storage facilities at Jackson Prairie. With the inability to run Chehalis due to limited gas availability and supplies, plus the impact of uneconomical market conditions, the result contributed to higher prices at Mid-Columbia ultimately increasing net power costs.

IMPACT OF PARTICIPATING IN THE EIM

Q. Are the actual benefits from participating in the EIM with CAISO included in the ECAM deferral?

A. Yes. Participation in the EIM provides benefits to customers in the form of reduced Actual NPC. The EIM benefits are embedded in Actual NPC through lower fuel and purchased power costs. The Company is able to calculate the margin realized on its EIM imports and exports, the inter-regional benefit. The Company's EIM inter-regional benefit for the deferral period was $57.2 million.

Q. How does the Company calculate its actual EIM benefits?

A. Using actual information from the EIM, including five- and 15-minute pricing, the Company identifies the incremental resource that could have facilitated the transfer to an adjacent EIM area or the CAISO in each five-minute interval. The benefit is then calculated as the difference between the revenue received less the expense of generation assumed to supply the transfer. In the event of an import, the benefit is equal to the cost of the import minus the avoided expense of the generation that would have otherwise been dispatched.

Q. Please summarize your testimony.

A. The ECAM deferral of $21.6 million, including interest, for the Deferral Period, was accurately calculated in compliance with previous Commission orders and Exhibit No. 1 was updated to include the RTM deferral. Therefore, I respectfully request that the Commission approve this application as filed with rates effective June 1, 2020.

Q. Does this conclude your direct testimony?

A. Yes.

Case No. PAC-E-20-02
Exhibit No. 1
Witness: David G. Webb

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of David G. Webb

April 2020

Rocky Mountain Power
Exhibit No. 1 Page 1 of 1
Case No. PAC-E-20-02
Witness: David G. Webb

Idaho Energy Cost Adjustment Mechanism Deferral
January 1, 2019 - December 31, 2019

Line No.			CY 2016	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total
1	ID Base NPC Embedded in Rates ($)	PAC-E-16-12	$ 91,646,727													
2	Annual Idaho Base Load @ meter (MWh)	PAC-E-16-12	3,407,488													
3	NPC Rate Embedded in Base Rates ($/MWh)	Line 1 / Line 2	$ 26.90													
4	NPC Rate Embedded in Base Rates ($/MWh)	Line 3		$ 26.90	$ 26.90	$ 26.90	$ 26.90	$ 26.90	$ 26.90	$ 26.90	$ 26.90	$ 26.90	$ 26.90	$ 26.90	$ 26.90	
5	ID Actual Sales @ Meter (MWh)			265,847	228,005	224,041	256,736	299,205	375,159	461,865	363,198	268,554	253,051	192,951	289,227	
6	ID NPC Collected in Rates ($)	Line 4 x Line 5		$ 7,150,126	$ 6,132,342	$ 6,025,730	$ 6,905,083	$ 8,047,329	$ 10,090,146	$ 12,422,175	$ 9,768,464	$ 7,222,945	$ 6,805,983	$ 5,189,547	$ 7,778,962	$ 93,538,833
7	Total Company Adjusted Actual NPC Excl. Integration Adj. ($)	Adjusted Actual NPC		$ 130,489,153	$ 163,670,302	$ 135,840,668	$ 107,270,416	$ 112,405,479	$ 127,565,260	$ 167,438,953	$ 177,313,166	$ 151,964,267	$ 126,337,144	$ 124,053,482	$ 128,176,511	$ 1,652,524,800
8	Intra-Hour Wind Integration Cost ($/MWh)			$ 0.30	$ 0.30	$ 0.30	$ 0.30	$ 0.30	$ 0.30	$ 0.30	$ 0.30	$ 0.30	$ 0.30	$ 0.30	$ 0.30	
9	Third Party Wind Sold to Wholesale (MWh)	Note (1)		108,559	124,823	60,434	110,686	79,669	89,929	83,330	69,561	96,488	120,999	81,451	91,553	
10	Third Party Wind Adjustment ($)	Line 8 x Line 9		$ 32,781	$ 37,692	$ 18,249	$ 33,424	$ 24,058	$ 27,156	$ 25,163	$ 21,005	$ 29,136	$ 36,538	$ 24,595	$ 27,646	$ 337,443
11	Total Company Adjusted Actual NPC ($)	Line 7 - Line 10		$ 130,456,372	$ 163,632,610	$ 135,822,419	$ 107,236,993	$ 112,381,422	$ 127,538,104	$ 167,413,790	$ 177,292,161	$ 151,935,130	$ 126,300,606	$ 124,028,887	$ 128,148,865	$ 1,652,187,357
12	Total Company Load @ Input (MWh)			5,235,844	4,866,183	4,863,598	4,367,099	4,499,373	4,835,312	5,630,023	5,553,937	4,727,937	4,697,397	4,759,085	5,252,004	59,287,792
13	Actual NPC ($/MWh)	Line 11 / Line 12		$ 24.92	$ 33.63	$ 27.93	$ 24.56	$ 24.98	$ 26.38	$ 29.74	$ 31.92	$ 32.14	$ 26.89	$ 26.06	$ 24.40	$ 27.87
14	ID Actual Load @ Input (MWh)			291,330	256,060	247,493	267,400	302,457	399,479	491,112	388,012	313,411	299,376	257,399	317,695	
15	Actual ID NPC	Line 13 x Line 14		$ 7,258,788	$ 8,610,407	$ 6,911,561	$ 6,566,184	$ 7,554,510	$ 10,536,809	$ 14,603,654	$ 12,386,079	$ 10,071,654	$ 8,049,428	$ 6,708,195	$ 7,751,756	$ 107,009,026
16	NPC Differential	Line 15 - Line 6		**$ 108,662**	**$ 2,478,065**	**$ 885,831**	**$ (338,899)**	**$ (492,819)**	**$ 446,663**	**$ 2,181,479**	**$ 2,617,615**	**$ 2,848,709**	**$ 1,243,445**	**$ 1,518,649**	**$ (27,206)**	**$ 13,470,193**
	EITF 04-6 Adjustment															
17	Idaho Allocated EITF 04-6 Deferral Adjustment ($)			**$ 5,511**	**$ 58,064**	**$ 53,072**	**$ (24,470)**	**$ (55,958)**	**$ (1,052)**	**$ (46,700)**	**$ 1,949**	**$ 8,296**	**$ 13,124**	**$ 38,197**	**$ 65,291**	**$ 115,324**
	LCAR															
18	Actual Idaho Jurisdictional ECPC minus NPC (Assume Actual = E	PAC-E-16-12		$ 1,536,179	$ 1,536,179	$ 1,536,179	$ 1,536,179	$ 1,536,179	$ 1,536,179	$ 1,536,179	$ 1,536,179	$ 1,536,179	$ 1,536,179	$ 1,536,179	$ 1,536,179	$ 18,434,143
19	LCAR Rate @ Meter ($/MWh)	PAC-E-16-12		$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54	
20	ID Actual Sales @ Meter (MWh)	Line 5		265,847	228,005	224,041	256,736	299,205	375,159	461,865	363,198	268,554	253,051	192,951	289,227	
21	LCAR Revenue Collected through Base Rates ($)	Line 19 x Line 20		$ 1,472,527	$ 1,262,920	$ 1,240,964	$ 1,422,061	$ 1,657,300	$ 2,078,006	$ 2,558,274	$ 2,011,758	$ 1,487,523	$ 1,401,652	$ 1,068,757	$ 1,602,032	$ 19,263,774
22	LCAR Adjustment	Line 18 - Line 21		**$ 63,652**	**$ 273,259**	**$ 295,215**	**$ 114,117**	**$ (121,122)**	**$ (541,828)**	**$ (1,022,096)**	**$ (475,579)**	**$ 48,655**	**$ 134,526**	**$ 467,422**	**$ (65,853)**	**$ (829,632)**
	ECAM Deferral															
23	Total ECAM Deferral (NPC Deferral, EITF 04-6 Adjustment, LCAR	Sum of Lines: 16, 17, 22		177,824	2,809,388	1,234,119	(249,251)	(669,899)	(96,217)	1,112,683	2,143,985	2,905,661	1,391,095	2,024,267	(27,768)	12,755,886
24	**Total ECAM Deferral after 90% Sharing**	Line 23 x 90%		**$ 160,042**	**$ 2,528,449**	**$ 1,110,707**	**$ (224,326)**	**$ (602,909)**	**$ (86,596)**	**$ 1,001,415**	**$ 1,929,586**	**$ 2,615,095**	**$ 1,251,986**	**$ 1,821,841**	**$ (24,991)**	**$ 11,480,297**
	Lakeside 2 Resource Adder															
25	Lake Side 2 Generation (MWh)	Adjusted Actual NPC		209,439	278,134	292,197	236,474	264,613	274,835	364,415	202,094	32,373	14,292	67,641	45,395	
26	Resource Adder Rate ($/MWh)	PAC-E-13-04		$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	
27	Total Lake Side 2 Resource Adder ($)	Line 25 x Line 26		**$ 416,784**	**$ 553,487**	**$ 581,472**	**$ 470,583**	**$ 526,580**	**$ 546,922**	**$ 725,186**	**$ 402,167**	**$ 64,422**	**$ 28,441**	**$ 134,606**	**$ 90,336**	**$ 4,540,985**
	Production Tax Credits (PTCs)															
28	ID Allocated PTCs in Rates ($/MWh)	PAC-E-16-12		$ (1.99)	$ (1.99)	$ (1.99)	$ (1.99)	$ (1.99)	$ (1.99)	$ (1.99)	$ (1.99)	$ (1.99)	$ (1.99)	$ (1.99)	$ (1.99)	
29	ID Actual Sales @ Meter (MWh)	Line 5		265,847	228,005	224,041	256,736	299,205	375,159	461,865	363,198	268,554	253,051	192,951	289,227	
30	ID PTCs in Rates ($)	Line 28 x Line 29		$ (530,038)	$ (454,590)	$ (446,686)	$ (511,873)	$ (596,547)	$ (747,981)	$ (920,854)	$ (724,135)	$ (535,436)	$ (504,526)	$ (384,700)	$ (576,653)	
31	ID Allocated Actual PTCs ($)			(248,733)	(177,483)	(109,254)	(152,546)	(107,091)	(80,900)	(64,557)	(69,850)	(137,960)	(307,692)	(311,206)	(449,473)	
32	ID PTCs Deferral ($)	Line 31 - Line 30		**$ 281,305**	**$ 277,106**	**$ 337,432**	**$ 359,327**	**$ 489,456**	**$ 667,081**	**$ 856,297**	**$ 654,285**	**$ 397,476**	**$ 196,834**	**$ 73,494**	**$ 127,180**	**$ 4,717,273**
	RTM Adjustment															
33	ID RTM Adjustment ($)											**$ (14,610)**	**$ 147,489**	**$ 143,243**	**$ 176,366**	**$ 452,488**
	Renewable Energy Credits (REC) Revenue															
34	ID REC Revenue in Rates ($/MWh)	PAC-E-16-12		$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	
35	ID Actual Sales @ Meter (MWh)	Line 5		265,847	228,005	224,041	256,736	299,205	375,159	461,865	363,198	268,554	253,051	192,951	289,227	
36	ID REC Revenue in Rates ($)	Line 34 x Line 35		$ (23,858)	$ (20,462)	$ (20,106)	$ (23,040)	$ (26,851)	$ (33,668)	$ (41,449)	$ (32,594)	$ (24,101)	$ (22,709)	$ (17,316)	$ (25,956)	
37	ID Allocated Actual REC Revenue ($)			(11,355)	(65,239)	(31,047)	(21,052)	(15,058)	(19,386)	(54)	(52)	(25,114)	(47,181)	(56,539)	(51,982)	
38	REC Revenue Adjustment ($)	Line 37 - Line 36		**$ 12,503**	**$ (44,778)**	**$ (10,941)**	**$ 1,989**	**$ 11,794**	**$ 14,282**	**$ 41,395**	**$ 32,542**	**$ (1,013)**	**$ (24,472)**	**$ (39,223)**	**$ (26,026)**	**$ (31,947)**
39	**Total Deferral**	Sum of Lines 24, 27, 32,33, 38		**$ 870,634**	**$ 3,314,264**	**$ 2,018,670**	**$ 607,572**	**$ 424,920**	**$ 1,141,689**	**$ 2,624,293**	**$ 3,018,580**	**$ 3,061,370**	**$ 1,600,278**	**$ 2,133,960**	**$ 342,866**	**$ 21,159,096**
40	Interest Rate	Order No. 34204		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
	ECAM Balancing Account ($)															
41	Beginning Balance			$ 17,365,652	$ 17,680,004	$ 20,464,039	$ 22,001,190	$ 22,178,592	$ 22,067,609	$ 22,113,287	$ 23,060,226	$ 24,550,622	$ 26,413,667	$ 27,084,557	$ 27,963,124	
42	ECAM Deferral After Sharing	Line 24		160,042	2,528,449	1,110,707	(224,326)	(602,909)	(86,596)	1,001,415	1,929,586	2,615,095	1,251,986	1,821,841	(24,991)	
43	Lake Side 2 Resource Adder	Line 27		416,784	553,487	581,472	470,583	526,580	546,922	725,186	402,167	64,422	28,441	134,606	90,336	
44	PTCs Deferral	Line 32		281,305	277,106	337,432	359,327	489,456	667,081	856,297	654,285	397,476	196,834	73,494	127,180	
45	RTM Adjustment	Line 33		-	-	-	-	-	-	-	-	(14,610)	147,489	143,243	176,366	
46	REC Revenue Adjustment	Line 38		12,503	(44,778)	(10,941)	1,989	11,794	14,282	41,395	32,542	(1,013)	(24,472)	(39,223)	(26,026)	
47	Less: Monthly ECAM Rider Revenues allocated to ECAM			(585,462)	(561,989)	(516,878)	(466,956)	(572,743)	(1,132,798)	(1,714,966)	(1,567,827)	(1,240,761)	(973,933)	(1,301,227)	(1,065,611)	
48	Interest			29,180	31,760	35,358	36,786	36,841	36,787	37,613	39,643	42,435	44,545	45,835	46,003	
49	**ECAM Deferral Balance ($)**			**$ 17,680,004**	**$ 20,464,039**	**$ 22,001,190**	**$ 22,178,592**	**$ 22,067,609**	**$ 22,113,287**	**$ 23,060,226**	**$ 24,550,622**	**$ 26,413,667**	**$ 27,084,557**	**$ 27,963,124**	**$ 27,286,382**	**$ 27,286,382**

Depreciation Regulatory Asset Balancing Account ($)

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	**)**	**CASE NO. PAC-E-20-02**
OF ROCKY MOUNTAIN POWER	)	
REQUESTING APPROVAL OF $21.2	**)**	**DIRECT TESTIMONY OF**
MILLON NET POWER COST DEFERRAL	**)**	**ROBERT M. MEREDITH**

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-20-02

April 2020

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

A. My name is Robert M. Meredith. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. My present position is Director, Pricing and Cost of Service.

QUALIFICATIONS

Q. Briefly describe your educational and professional background.

A. I graduated from Oregon State University in 2004 with a Bachelor of Science degree in Business Administration and a minor in Economics. In addition to my formal education, I have attended various industry-related seminars. I have worked for the Company for 15 years in various roles of increasing responsibility in the Customer Service, Regulation, and Integrated Resource Planning departments. I have over nine years of experience preparing cost of service and pricing related analyses for all of the six states that PacifiCorp serves. In March 2016, I became Manager, Pricing and Cost of Service. In June 2019, I was promoted to my current position.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously filed testimony on behalf of the Company in regulatory proceedings in Idaho, Utah, Wyoming, Oregon, Washington, and California.

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

A. My testimony presents and supports the Company's proposed rates to recover the 2019 Energy Cost Adjustment Mechanism ("ECAM") deferral balances through Electric Service Schedule No. 94, Energy Cost Adjustment ("Schedule 94").

BACKGROUND

Q. What level of revenues is Schedule 94 currently designed to collect?

A. Schedule 94 is currently designed to collect approximately $10.6 million—$4.2 million for Tariff Contract 400, $0.3 million for Tariff Contract 401, and $6.1 million for the standard tariff customers—based on Idaho loads from Case No. PAC-E-15-09.

PROPOSED RATE CHANGE FOR SCHEDULE 94

Q. Please describe the Company's proposed rate change in this case.

A. The 2020 ECAM application proposes to increase Schedule 94 rates to recover approximately $22.3 million from June 1, 2020 to May 31, 2021. The $22.3 million includes $21.6 million for the 2019 ECAM Deferral, plus approximately $5.7 million remaining from the 2018 ECAM balance, for a total balance of $27.3 million as of December 31, 2019. This is offset by a net credit of $76,878 in the depreciation regulatory asset balance and $4.9 million Schedule 94 forecasted revenue collection from January 1, 2020 through May 31, 2020, as shown in Table 2 of Mr. David G. Webb's testimony. Mr. Webb explains in his testimony the components of the 2019 ECAM deferred balance. The $22.3 million balance summarized in Table 2 is also partially offset by a $3.1 million amortization of the amount representing the savings from federal tax reform resulting from the Tax Cuts and Jobs Act, enacted in December 2017 ("ECAM Tax Reform Credit"), as further discussed in the testimony of Mr. Steven R. McDougal.

Q. Please explain the proposed rate change for Tariff Contracts 400 and 401.

A. The proposed rate for Tariff Contracts 400 and 401 is the same as for standard tariff customers with transmission delivery service voltage.

Q. What is the impact of the proposed ECAM rates?

A. As summarized in my Exhibit No. 2, these rate change proposals result in an increase of 3.8 percent for Tariff Contract 400, and an increase of 3.9 percent for Tariff Contract 401. Standard tariff customers will also see an average increase of 2.6 percent, or $4.9 million.

CALCULATION OF PROPOSED RATES FOR SCHEDULE 94

Q. How were the proposed Schedule 94 rates developed for all customers?

A. The proposed rates for all customers were developed in four steps. First, I developed their kilowatt-hour ("kWh") consumption at the generation level by multiplying their retail loads at the delivery service voltage level with the corresponding line loss factors. Next, an overall average rate at the generation level was developed by dividing their total collection target identified above with their kWh consumption at the generation level. Finally, rates by delivery voltage level were developed by multiplying the above overall average rate at the generation level with the corresponding line loss factors. As a result, the Company proposes Schedule 94 rates of 0.571, 0.549 and 0.532 cents per kWh for secondary, primary and transmission delivery service voltages, respectively, for all customers.

Q. Please describe Exhibit No. 2.

A. Exhibit No. 2 shows the 2014 loads used to develop rates, the line loss adjusted loads, the allocation of the ECAM price change including the ECAM Tax Reform Credit, and the percentage change by rate schedule.

Q. Please describe Exhibit No. 3.

A. Exhibit No. 3 contains clean and legislative copies of the proposed Electric Service

Schedule No. 94, Energy Cost Adjustment. The Company requests that the proposed Schedule 94 rates become effective on June 1, 2020.

Q. Does this conclude your direct testimony?

A. Yes.

Case No. PAC-E-20-02
Exhibit No. 2
Witness: Robert M. Meredith

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Robert M. Meredith

April 2020

EXHIBIT NO. 2
ESTIMATED IMPACT OF PROPOSED ECAM ADJUSTMENT
FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN IDAHO
HISTORIC 12 MONTHS ENDED DECEMBER 2014

Line			Average		Present	At Meter			At	Tax	ECAM Proposal				Present	Net Change	
					Rev	MWh by Voltage			Generation	Rev	Rev	Rate ¢/kWh			ECAM Rev		
No.	Description	Sch.	Cust	MWH	($000)	S	P	T	MWh	($000)	($000)	S	P	T	($000)	($000)	%
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
	Residential Sales																
1	Residential Service	1	46,059	442,589	$49,602	442,589			487,503	($394)	$2,920	0.571	0.549	0.532	$1,399	$1,127	2.2%
2	Residential Optional TOD	36	13,484	235,152	$22,484	235,152			259,016	($209)	$1,551	0.571	0.549	0.532	$743	$599	2.6%
3	AGA Revenue				$3												
4	Total Residential		59,543	677,741	$72,090	677,741	0	0	746,519	($603)	$4,471				$2,142	$1,726	2.3%
5	**Commercial & Industrial**																
6	General Service - Large Power	6	1,036	303,011	$23,667	258,477	44,534		332,125	($270)	$1,989	0.571	0.549	0.532	$951	$768	3.1%
7	General Svc. - Lg. Power (R&F)	6A	214	30,600	$2,616	30,600			33,705	($27)	$202	0.571	0.549	0.532	$97	$78	2.9%
8	*Subtotal-Schedule 6*		*1,250*	*333,611*	*$26,283*	*289,077*	*44,534*	*0*	*365,830*	*($297)*	*$2,191*				*$1,048*	*$846*	*3.1%*
9	General Service - High Voltage	9	17	121,001	$7,626			121,001	125,363	($108)	$751	0.571	0.549	0.532	$353	$290	3.6%
10	Irrigation	10	4,969	602,488	$54,316	602,488			663,629	($536)	$3,975	0.571	0.549	0.532	$1,904	$1,535	2.7%
11	Comm. & Ind. Space Heating	19	103	5,151	$438	5,151			5,674	($5)	$34	0.571	0.549	0.532	$16	$13	2.9%
12	General Service	23	6,634	153,848	$14,913	152,484	1,364		169,411	($137)	$1,015	0.571	0.549	0.532	$486	$392	2.5%
13	General Service (R&F)	23A	2,314	33,450	$3,376	32,839	611		36,822	($30)	$221	0.571	0.549	0.532	$106	$85	2.4%
14	*Subtotal-Schedule 23*		*8,948*	*187,299*	*$18,289*	*185,323*	*1,975*	*0*	*206,233*	*($167)*	*$1,235*				*$592*	*$477*	*2.5%*
15	General Service Optional TOD	35	3	1,893	$123	1,893			2,085	($2)	$12	0.571	0.549	0.532	$6	$5	3.7%
16	Special Contract 1	400	1	1,443,926	$86,967			1,443,926	1,495,980	($1,285)	$8,960			0.532	$4,216	$3,459	3.8%
17	Special Contract 2	401	1	107,486	$6,264			107,486	111,361	($96)	$667			0.532	$314	$257	3.9%
18	AGA Revenue				$478												
19	Total Commercial & Industrial		15,293	2,802,855	$200,786	1,083,932	46,510	1,672,413	2,976,154	($2,495)	$17,825				$8,449	$6,882	3.3%
20	**Public Street Lighting**																
21	Security Area Lighting	7	193	267	$102	267			294	($0)	$2	0.571	0.549	0.532	$1	$1	0.7%
22	Security Area Lighting (R&F)	7A	136	107	$44	107			117	($0)	$1	0.571	0.549	0.532	$0	$0	0.6%
23	Street Lighting - Company	11	37	87	$40	87			95	($0)	$1	0.571	0.549	0.532	$0	$0	0.6%
24	Street Lighting - Customer	12	234	2,424	$436	2,424			2,670	($2)	$16	0.571	0.549	0.532	$8	$6	1.4%
25	AGA Revenue				$0												
26	Total Public Street Lighting		600	2,884	$621	2,884	0	0	3,177	($3)	$19				$9	$7	1.2%
27	**Total Sales to Ultimate Customers**		75,435	3,483,480	$273,497	1,764,558	46,510	1,672,413	3,725,850	($3,100)	$22,316				$10,600	$8,615	3.0%
28	**Total (w/o Sch 400, 401)**		75,433	1,932,068	$180,265	1,764,558	46,510	121,001	2,118,509	($1,720)	$12,689				$6,070	$4,899	2.6%
				Rev. Rqmt	Unallocated		Allocated						**Proposed Rates**			**Current Rates**	
29	Voltage Line Loss Factors applied to rates:					1.10148	1.06475	1.03605				S	P	T	S	P	T
30	Total Company Current Deferral Rate (cents/kWh):				0.599	0.660	0.638	0.621									
31			ECAM deferral	$22,316	Tax Offset	-0.089	-0.089	-0.089	Total Tariff Customer Rate			0.571	0.549	0.532	0.316	0.302	0.292
32			Tax Offset	($3,100)	Net Rate	0.571	0.549	0.532	Total Schedule 400 Rate					0.532			0.292
33			% of Tax Offset	-16%					Total Schedule 401 Rate					0.532			0.292

Case No. PAC-E-20-02
Exhibit No. 3
Witness: Robert M. Meredith

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Robert M. Meredith

April 2020

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

~~Ninth~~ Tenth Revision of Sheet No. 94.1

I.P.U.C. No. 1 **Canceling ~~Eighth~~ Ninth Revision of Sheet No. 94.1**

ROCKY MOUNTAIN POWER

ELECTRIC SERVICE SCHEDULE NO. 94

STATE OF IDAHO

Energy Cost Adjustment

AVAILABILITY: At any point on the Company's interconnected system.

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

ENERGY COST ADJUSTMENT: The Energy Cost Adjustment is calculated to collect the accumulated difference between total Company Base Net Power Cost and total Company Actual Net Power Cost calculated on a cents per kWh basis.

MONTHLY BILL: In addition to the Monthly Charges contained in the Customer's applicable schedule, all monthly bills shall have applied the following cents per kilowatt-hour rate by delivery voltage.

		Delivery Voltage		
		Secondary	Primary	Transmission
Schedule	1	0.571~~316~~¢ per kWh		
Schedule	6	0.571~~316~~¢ per kWh	0.549~~302~~¢ per kWh	
Schedule	6A	0.571~~316~~¢ per kWh	0.549~~302~~¢ per kWh	
Schedule	7	0.571~~316~~¢ per kWh		
Schedule	7A	0.571~~316~~¢ per kWh		
Schedule	9			0.532~~292~~¢ per kWh
Schedule	10	0.571~~316~~¢ per kWh		
Schedule	11	0.571~~316~~¢ per kWh		
Schedule	12	0.571~~316~~¢ per kWh		
Schedule	19	0.571~~316~~¢ per kWh		
Schedule	23	0.571~~316~~¢ per kWh	0.549~~302~~¢ per kWh	
Schedule	23A	0.571~~316~~¢ per kWh	0.549~~302~~¢ per kWh	
Schedule	24	0.571~~316~~¢ per kWh	0.549~~302~~¢ per kWh	
Schedule	35	0.571~~316~~¢ per kWh	0.549~~302~~¢ per kWh	
Schedule	35A	0.571~~316~~¢ per kWh	0.549~~302~~¢ per kWh	
Schedule	36	0.571~~316~~¢ per kWh		
Schedule	400			0.532~~292~~¢ per kWh
Schedule	401			0.532~~292~~¢ per kWh

Tenth Revision of Sheet No. 94.1
I.P.U.C. No. 1 **Canceling Ninth Revision of Sheet No. 94.1**

ROCKY MOUNTAIN POWER

ELECTRIC SERVICE SCHEDULE NO. 94

STATE OF IDAHO

Energy Cost Adjustment

AVAILABILITY: At any point on the Company's interconnected system.

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

ENERGY COST ADJUSTMENT: The Energy Cost Adjustment is calculated to collect the accumulated difference between total Company Base Net Power Cost and total Company Actual Net Power Cost calculated on a cents per kWh basis.

MONTHLY BILL: In addition to the Monthly Charges contained in the Customer's applicable schedule, all monthly bills shall have applied the following cents per kilowatt-hour rate by delivery voltage.

		Delivery Voltage		
		Secondary	Primary	Transmission
Schedule	1	0.571¢ per kWh		
Schedule	6	0.571¢ per kWh	0.549¢ per kWh	
Schedule	6A	0.571¢ per kWh	0.549¢ per kWh	
Schedule	7	0.571¢ per kWh		
Schedule	7A	0.571¢ per kWh		
Schedule	9			0.532¢ per kWh
Schedule	10	0.571¢ per kWh		
Schedule	11	0.571¢ per kWh		
Schedule	12	0.571¢ per kWh		
Schedule	19	0.571¢ per kWh		
Schedule	23	0.571¢ per kWh	0.549¢ per kWh	
Schedule	23A	0.571¢ per kWh	0.549¢ per kWh	
Schedule	24	0.571¢ per kWh	0.549¢ per kWh	
Schedule	35	0.571¢ per kWh	0.549¢ per kWh	
Schedule	35A	0.571¢ per kWh	0.549¢ per kWh	
Schedule	36	0.571¢ per kWh		
Schedule	400			0.532¢ per kWh
Schedule	401			0.532¢ per kWh

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	**)**	**CASE NO. PAC-E-20-02**
OF ROCKY MOUNTAIN POWER	**)**	
REQUESTING APPROVAL OF $21.2	**)**	**DIRECT TESTIMONY OF**
MILLON NET POWER COST DEFERRAL	**)**	**STEVEN R. MCDOUGAL**

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-20-02

April 2020

Q. Please state your name and business address with PacifiCorp dba Rocky Mountain Power ("Company").

A. My name is Steven R. McDougal, and my business address is 1407 W. North Temple, Suite 330, Salt Lake City, Utah 84116.

QUALIFICATIONS

Q. Please describe your education and professional background.

A. I received a Master of Accountancy from Brigham Young University with an emphasis in Management Advisory Services and a Bachelor of Science degree in Accounting from Brigham Young University. In addition to my formal education, I have also attended various educational, professional, and electric industry-related seminars. I have been employed with PacifiCorp and its predecessor, Utah Power and Light Company (the "Company"), since 1983. My experience includes various positions with regulation, finance, resource planning, and internal audit. My current position is the Director of Revenue Requirements.

Q. What are your current responsibilities with the Company?

A. My primary responsibilities include overseeing the calculation and reporting of the Company's regulated earnings and revenue requirement, assuring that the interjurisdictional cost allocation methodology is correctly applied, and explaining those calculations to regulators in the jurisdictions in which the Company operates.

Q. Have you testified in previous proceedings?

A. Yes. I have provided testimony in regulatory proceedings in California, Idaho, Oregon, Utah, Washington, and Wyoming.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I explain and support the Company's request, through this Energy Cost Adjustment Mechanism (ECAM), for recovery of $452 thousand, before carrying charge, associated with the wind repowering costs as calculated and deferred through the approved Resource Tracking Mechanism (RTM). This amount is included the ECAM as shown in Mr. Dave Webb's Testimony, Exhibit No. 1, line 33. I also summarize the 2017 Tax Reform Credit and modifications to the accounting treatment of the excess deferred income tax, ("EDIT"), balances.

RESOURCE TRACKING MECHANISM

Q. Please briefly describe the background and purpose of the resource tracking mechanism, ("RTM").

A. In Case No. PAC-E-17-06, filed on July 3, 2017, the Company applied for approval of the plan to upgrade (or "repower") its existing wind resources and approval of associated ratemaking treatment. On November 21, 2017, the Company and intervening parties reached a stipulated agreement that allows the Company to use the ECAM to recover the replacement of certain assets, new investment, incremental energy production, and wind repowering project PTCs through the RTM. The RTM and ECAM will capture the costs and benefits of the repowered wind facilities until they are recovered in base rates through a general rate case. The Stipulation between the parties was approved by Commission Order No. 33954, dated December 28, 2017.

Q. Which repowering projects are included in the RTM and this ECAM?

A. Nine repowering projects were completed and placed in service during 2019 that produced an Idaho-allocated net incremental benefit of $529,156. These include Leaning Juniper, Glenrock I, Glenrock III, Rolling Hills, Seven Mile Hill I, Seven Mile Hill II, High Plains, McFadden Ridge and Goodnoe Hills wind facilities. Other future repowered wind projects, as they are completed and placed in service, will be included in future RTM deferrals.

Q. Has the Company calculated the wind repowering deferral under the RTM guidelines that were agreed to in the Stipulation and approved by the Commission?

A. Yes. The deferral calculations follow the design and operation of the RTM as submitted in the Direct Testimony of Mr. Jeffrey K. Larsen pages 6-16 and Exhibit 12 that was referenced and approved in the Stipulation and Final Order of Case No. PAC-E-17-06. The RTM, along with the ECAM, will capture and match all the costs and benefits of the repowered wind facilities until such time as they are recovered in base rates.

Q. What are the costs and benefits associated with repowering that the Company has included in the RTM deferral?

A. The Company has included the following items in the RTM on a monthly basis beginning when a repowered wind project is placed into service:

- The pre-tax return on investment;
- Operation and maintenance expense;
- Depreciation expense;
- Property taxes;
- Wind taxes, if assessed;
- NPC benefits; and

- PTC benefits.

Q. Has the Company prepared an exhibit showing the calculated amount of the wind repowering deferral under the approved RTM guidelines?

A. Yes. Exhibit No. 4 shows the calculation of the December 31, 2019 RTM deferral balance which results in a $452 thousand charge to be collected from customers through the ECAM. This exhibit is structured similar to Exhibit 12 of Mr. Larsen's Direct Testimony referenced above.

Q. Line 18 of Exhibit No. 4 shows that the repowered wind projects produced a net revenue requirement benefit of $(529) thousand. Why is the Company seeking recovery of $452 thousand through the ECAM?

A. The RTM was approved to match all of the costs and benefits associated with the repowered wind projects and pass those onto customers. Absent the RTM the ECAM only captures some of the benefits and does not included any of the costs incurred to produce those benefits. The ECAM will return to customers 100 percent of the Production Tax Credits (PTC) of $882 thousand, and 90 percent of Net Power Cost (NPC) benefit of $100 thousand, shown on lines 21 and 24, respectively. Combined, the ECAM would return to customers $982 thousand, absent the RTM. Due to the sharing band in the ECAM 10 percent of the NPC benefits wouldn't be passed onto customers. However the ECAM does not capture any of the costs incurred by the Company to repower the wind facilities. The purposes of the RTM is to capture those costs and match them with the benefits. The $529 thousand, on line 18, represents Idaho's share of the net benefit produced by the repowered wind facilities. The

$452 thousand RTM deferral allows the Company to recover the net costs that are not reflected in the ECAM.

Q. Has the Company included a carrying charge on the RTM deferral balance in Exhibit No. 4?

A. No. Although the RTM deferral balance is subject to a carrying charge, the monthly RTM deferral balance is summed with the other ECAM components and receives a carrying charge as part of the overall carrying charge calculation.

TAX REFORM CREDIT

Q. Was the Federal Tax Act Adjustment credit netted against the ECAM?

A. Yes. The savings from federal tax reform, resulting from the Tax Cuts and Jobs Act, enacted in December 2017, as prescribed in the tax stipulation among the Company and parties filed with the Commission March 5, 2019 in Case No. GNR-U-18-01 ("ECAM Tax Reform Credit") were netted against the ECAM deferral as described in Mr. Robert M. Meredith's testimony.

Q. Please summarize the ECAM Tax Reform Credit approved in Order No. 34331.

A. The Order approved the $1,141,000 deferred balance of current tax savings for the period of January 1, 2018, through May 31, 2019, that had not been returned to customers through Schedule 197. This balance was tracked and amortized over two years ($570,500 per year), beginning June 1, 2019, through the Energy Cost Adjustment Mechanism ("ECAM"). The Tax Reform Act resulted in Idaho-allocated Excess Deferred Income Taxes ("EDIT"), composed of the following amounts, grossed-up for taxes:

- Protected property-related EDIT of $105,924,604[1], with estimated annual amortizations through the average rate assumption method ("ARAM") of $2,564,410 in 2018, $2,352,309 in 2019, and $2,306,632 in 2020; and
- Non-protected property and non-property EDIT of $14,883,505.[2]

The Order also specified that as the EDIT balances amortize in rates, the amounts will include a rate base carrying charge offset to account for the corresponding increase in rate base associated with the amortized EDIT until the next Idaho general rate case.

Q. What was the amount of Tax Reform Credit included in this Application?

A. Table 1 summarizes the Tax Reform Credit Mr. Meredith netted against the ECAM deferral to calculate the net ECAM rates.

Table 1

ECAM Tax Benefits	**2020**
Amortization Of Current Tax Savings	$ (570,500)
2019 Protected EDIT	$ (2,352,309)
2019 Non-Protected EDIT (7yr Amort)	$ (2,126,215)
2013 Depreciation Offset	$ 1,889,100
EDIT Rate Base Offset	$ 137,173
2019 ECAM Net Tax Savings	$ (3,022,751)
Amount Over/(Under) Refunded	$ (70,120)
2020 ECAM Tax Offset	$ (3,092,871)

Q. Did the Company determine a change to the accounting treatment for the EDIT amortization was needed?

A. Yes. During December 2019, the Company determined that it was necessary to use a different method of amortizing protected EDIT balances. While the tax filing was based

[1] The protected property EDIT is $79,881,345, or $105,924,604 grossed up for taxes.
[2] The non-protected property EDIT is $10,009,386, or $13,272,689 grossed up for taxes, and non-protected non-property total EDIT is $1,214,771, or $1,610,816 grossed up for taxes.

on the ARAM the Company determined that it didn’t have the necessary records to support that method and had to switch to the Reverse South Georgia Method, (“RSGM”).

Q. Does the RSGM change the EDIT balances?

A. No, but it does modify the amortization of those balances. The RSGM method uses a shorter amortization period which increases the protected EDIT amortization in the front-end.

Q. Did the Company incorporate the RSGM amortization in the 2020 ECAM?

A. No. The Company used the Tax Reform Credits approved in Order 34331. The Company intends to propose treatment for the unamortized portion of the protected property, non-protected property and non-property EDIT balances in the Idaho general rate case in June 2020.

Q. Does this conclude your direct testimony?

A. Yes.

Case No. PAC-E-20-02
Exhibit No. 4
Witness: Steven R. McDougal

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Steven R. McDougal

April 2020

PacifiCorp
Idaho
Wind Repowering - RTM Deferral Calculation
Revenue Requirement
For the Year Ending December 31, 2019

				(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	$-Dollars			Sept. - Dec. 2019				Sep-19				Oct-19			
Line No.		Reference		Total Company	Factor	Factor %		Total Company	Factor	Factor %	Idaho Allocated	Total Company	Factor	Factor %	Idaho Allocated
	Plant Revenue Requirement														
1	Capital Investment	Footnote 1		312,646,463	SG	6.0136%	18,801,308	-	SG	6.0136%	-	344,566,723	SG	6.0136%	20,720,864
2	Depreciation Reserve	Footnote 1		(1,195,678)	SG	6.0136%	(71,903)	-	SG	6.0136%	-	(474,166)	SG	6.0136%	(28,514)
3	Accumulated DIT Balance	Footnote 1		(11,843,794)	SG	6.0136%	(712,238)	-	SG	6.0136%	-	(12,759,144)	SG	6.0136%	(767,284)
4	Net Rate Base (previous month)	sum of lines 1-3		299,606,990			18,017,166	-			-	331,333,413			19,925,066
5	Pre-Tax Rate of Return	line 36		9.234%			9.234%	9.234%			9.234%	9.234%			9.234%
6	Pre-Tax Return on Rate Base	line 4 * line 5		9,221,805			554,562	-			-	2,549,583			153,322
7	Wholesale Wheeling Revenue	Footnote 4		-	SG	6.0136%	-	-	SG	6.0136%	-	-	SG	6.0136%	-
8	Operation & Maintenance	Footnote 3		(902,185)	SG	6.0136%	(54,254)	(169,466)	SG	6.0136%	(10,191)	75,544	SG	6.0136%	4,543
9	Depreciation	Footnotes 3 & 6		4,430,740	SG	6.0136%	266,447	474,166	SG	6.0136%	28,514	1,053,862	SG	6.0136%	63,375
10	Property Taxes	Footnote 3		-	GPS	5.7978%	-	-	GPS	5.7978%	-	-	GPS	5.7978%	-
11	Wind Tax	Footnote 3		49,722	SG	6.0136%	2,990	2,305	SG	6.0136%	139	12,500	SG	6.0136%	752
12	**Total Plant Revenue Requirement**	sum of lines 6-11		**12,800,081**			**769,746**	**307,005**			**18,462**	**3,691,489**			**221,991**
	Net Power Cost														
13	NPC Incremental Savings	Footnote 3		(1,839,586)	SG	6.0136%	(110,625)	(166,696)	SG	6.0136%	(10,024)	(458,536)	SG	6.0136%	(27,575)
	PTC Benefit														
14	PTC Benefit	Footnote 3		(11,061,724)	SG	6.0136%	(665,208)	(720,211)	SG	6.0136%	(43,311)	(2,944,659)	SG	6.0136%	(177,080)
15	Gross- up for taxes	line 14 * (line 34 - 1)		(3,606,391)			(216,874)	(234,806)			(14,120)	(960,030)			(57,732)
16	PTC Revenue Requirement	sum of lines 14 and 15		(14,668,114)			(882,082)	(955,018)			(57,431)	(3,904,689)			(234,812)
17	Depreciation Expense Adjustment	Footnotes 6 & 7		(5,091,705)	SG	6.0136%	(306,195)	(533,279)	SG	6.0136%	(32,069)	(1,193,051)	SG	6.0136%	(71,745)
18	**Rev. Requirement**	sum of lines 12, 13, 16, 17		(8,799,324)			(529,156)	(1,347,988)			(81,063)	(1,864,788)			(112,141)
	Adjustment for ECAM Pass-through														
19	PTC Revenue Requirement	line 16					(882,082)				(57,431)				(234,812)
20	Percentage included in ECAM (100%)	ID ECAM Sharing %					100%				100%				100%
21	ECAM Pass-through	line 19 * line20					(882,082)				(57,431)				(234,812)
22	NPC Incremental Savings	line 13					(110,625)				(10,024)				(27,575)
23	Percentage included in ECAM (90%)	ID ECAM Sharing %					90%				90%				90%
24	ECAM Pass-through	line 22 * line 23					(99,563)				(9,022)				(24,817)
25	**Rev. Reqt. after ECAM Pass-through**	line 18 - line 21 - line 24					452,488				(14,610)				147,489
25.5	**Authorized Capped Recovery**	line 26 - line 25					-				-				-
26	**Total Deferral - ID Share**	Footnote 5					452,488				(14,610)				147,489
27	**Net Customer (Benefit)**	sum of lines 21, 24, 26					(529,156)				(81,063)				(112,141)
	Deferral Balance - ID Share														
28	Beginning Deferral Balance	line 32 of previous year					-				-				(14,610)
29	Monthly Deferral	Footnote 5					452,488				(14,610)				147,489
30	Deferral Collection	Footnote 3					-				-				-
31	Carrying Charge	Footnote 2					-				-				-
32	**Ending Deferral Balance**	sum of lines 28-31					452,488				(14,610)				132,879
33	Federal/State Combined Tax Rate		24.5866%												
34	Net to Gross Bump up Factor	(1/(1-tax rate))	1.3260												
35	Deferred Balance Carrying Charge	Footnote 2	2.00%												
36	Pretax Return	Case No. PAC-E-15-09	9.234%												
37	Property Tax Rate	Rate as percent of net plant in PAC-E-15-09	0.78%												
38	Idaho SG Factor	Case No. PAC-E-15-09	6.0136%												
39	Idaho GPS Factor	Case No. PAC-E-15-09	5.7978%												

Footnotes:
1) Ending monthly capital balance of the previous month.
2) The RTM deferral balance is included in the ECAM carrying charge calculation and is therefore zero here.
3) Equals the monthly sum of all projects
4) Not Applicable for Repowering
5) The RTM is capped until the next general rate case so that, after taking into account the wind repowering benefits that will flow through the Company's ECAM, it will not operate to surcharge customers.
6) Actual depreciation expense will be adjusted by the impact of the retired assets until the next depreciation study
7) Depreciation Expense for the replaced equipment currently in rates is removed as an incremental revenue requirement savings.

PacifiCorp
Idaho
Wind Repowering - RTM Deferral Calculation
Revenue Requirement
For the Year Ending December 31, 2019

Line No.	$-Dollars	Reference		(m) Nov-19 Total Company	(n) Nov-19 Factor	(o) Nov-19 Factor %	(p) Nov-19 Idaho Allocated	(q) Dec-19 Total Company	(r) Dec-19 Factor	(s) Dec-19 Factor %	(t) Dec-19 Idaho Allocated
	Plant Revenue Requirement										
1	Capital Investment	Footnote 1		419,607,677	SG	6.0136%	25,233,527	486,411,451	SG	6.0136%	29,250,839
2	Depreciation Reserve	Footnote 1		(1,528,028)	SG	6.0136%	(91,889)	(2,780,520)	SG	6.0136%	(167,209)
3	Accumulated DIT Balance	Footnote 1		(15,537,430)	SG	6.0136%	(934,359)	(19,078,602)	SG	6.0136%	(1,147,311)
4	Net Rate Base (previous month)	sum of lines 1-3		402,542,219			24,207,279	464,552,329			27,936,319
5	Pre-Tax Rate of Return	line 36		9.234%			9.234%	9.234%			9.234%
6	Pre-Tax Return on Rate Base	line 4 * line 5		3,097,529			186,273	3,574,692			214,968
7	Wholesale Wheeling Revenue	Footnote 4		-	SG	6.0136%	-	-	SG	6.0136%	-
8	Operation & Maintenance	Footnote 3		(499,453)	SG	6.0136%	(30,035)	(308,811)	SG	6.0136%	(18,571)
9	Depreciation	Footnotes 3 & 6		1,252,493	SG	6.0136%	75,320	1,650,219	SG	6.0136%	99,238
10	Property Taxes	Footnote 3		-	GPS	5.7978%	-	-	GPS	5.7978%	-
11	Wind Tax	Footnote 3		13,995	SG	6.0136%	842	20,922	SG	6.0136%	1,258
12	**Total Plant Revenue Requirement**	sum of lines 6-11		**3,864,564**			**232,399**	**4,937,022**			**296,893**
	Net Power Cost										
13	NPC Incremental Savings	Footnote 3		(518,375)	SG	6.0136%	(31,173)	(695,979)	SG	6.0136%	(41,853)
	PTC Benefit										
14	PTC Benefit	Footnote 3		(3,038,577)	SG	6.0136%	(182,728)	(4,358,277)	SG	6.0136%	(262,089)
15	Gross- up for taxes	line 14 * (line 34 - 1)		(990,650)			(59,574)	(1,420,904)			(85,447)
16	PTC Revenue Requirement	sum of lines 14 and 15		(4,029,226)			(242,302)	(5,779,181)			(347,537)
17	Depreciation Expense Adjustment	Footnotes 6 & 7		(1,430,737)	SG	6.0136%	(86,039)	(1,934,638)	SG	6.0136%	(116,341)
18	**Rev. Requirement**	sum of lines 12, 13, 16, 17		(2,113,774)			(127,114)	(3,472,775)			(208,839)
	Adjustment for ECAM Pass-through										
19	PTC Revenue Requirement	line 16					(242,302)				(347,537)
20	Percentage included in ECAM (100%)	ID ECAM Sharing %					100%				100%
21	ECAM Pass-through	line 19 * line20					(242,302)				(347,537)
22	NPC Incremental Savings	line 13					(31,173)				(41,853)
23	Percentage included in ECAM (90%)	ID ECAM Sharing %					90%				90%
24	ECAM Pass-through	line 22 * line 23					(28,056)				(37,668)
25	**Rev. Reqt. after ECAM Pass-through**	line 18 - line 21 - line 24					143,243				176,366
25.5	**Authorized Capped Recovery**	line 26 - line 25					-				-
26	**Total Deferral - ID Share**	Footnote 5					143,243				176,366
27	**Net Customer (Benefit)**	sum of lines 21, 24, 26					(127,114)				(208,839)
	Deferral Balance - ID Share										
28	Beginning Deferral Balance	line 32 of previous year					132,879				276,122
29	Monthly Deferral	Footnote 5					143,243				176,366
30	Deferral Collection	Footnote 3					-				-
31	Carrying Charge	Footnote 2					-				-
32	**Ending Deferral Balance**	sum of lines 28-31					276,122				452,488
33	Federal/State Combined Tax Rate		24.5866%								
34	Net to Gross Bump up Factor	(1/(1-tax rate))	1.3260								
35	Deferred Balance Carrying Charge	Footnote 2	2.00%								
36	Pretax Return	Case No. PAC-E-15-09	9.234%								
37	Property Tax Rate	Rate as percent of net plant in PAC-E-15-09	0.78%								
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