BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR APPROVAL OF A GENERAL RATE INCREASE IN ITS RETAIL ELECTRIC UTILITY SERVICE RATES IN WYOMING OF $36.1 MILLION PER YEAR OR 5.3 PERCENT	)	Docket No. 20000-446-ER-14 (Record No. 13816)

APPEARANCES

For the Applicant, Rocky Mountain Power (RMP or the Company):
PAUL J. HICKEY, NANCY VEHR, Hickey & Evans, LLP, Cheyenne, Wyoming,
DANIEL E. SOLANDER, R. JEFF RICHARDS, Corporate Counsel, Salt Lake City, Utah.

For the Office of Consumer Advocate (OCA):
IVAN H. WILLIAMS, CHRISTOPHER LEGER, Counsel, Cheyenne, Wyoming.

For the Intervenor, Wyoming Industrial Energy Consumers (WIEC):
THORVALD A. NELSON, ABBY BRIGGERMAN, Holland & Hart, LLP
Greenwood Village, Colorado.

For the Intervenor, Sierra Club (Sierra):
TRAVIS RITCHIE, Counsel, San Francisco, California.

For the Intervenor, Northern Laramie Range Alliance (NLRA):
CRYSTAL J. McDONOUGH, Counsel, Greeley, Colorado.

HEARD BEFORE

Chairman ALAN B. MINIER
Deputy Chairman WILLIAM F. RUSSELL
Commissioner KARA BRIGHTON

JOHN S. BURBRIDGE, Assistant Secretary,
Presiding pursuant to a *Special Order* of the Commission.

FINDINGS OF FACT, CONCLUSIONS OF LAW, DECISION AND ORDER *NUNC PRO TUNC*

(Issued January 23, 2015)

This matter is before the Wyoming Public Service Commission (Commission) upon the application of RMP for approval of a general retail electric service rate increase and on the interventions of the OCA, WIEC, Sierra and NLRA (collectively, with RMP, the Parties).

The Commission, having reviewed the application and respective attached exhibits, the evidence introduced at the public hearing held on October 13-21, 2014, its files regarding RMP, applicable Wyoming utility law, having heard the arguments of the Parties, and otherwise being fully advised in the premises, FINDS and CONCLUDES:

Introduction

1. RMP is a public utility, as defined in Wyo. Stat. § 37-1-101(a)(vi)(C), providing retail electric public utility service under certificates of public convenience and necessity issued by the Commission. RMP is subject to the Commission's jurisdiction pursuant to Wyo. Stat. § 37-2-112. RMP is a division of PacifiCorp, an Oregon Corporation, which provides electric service to retail customers through its RMP division in Wyoming, Utah, and Idaho, and through its Pacific Power division in Oregon, California and Washington. (Ex. 1, p. 2).

2. On March 3, 2014, RMP submitted an application requesting authority to increase its retail electric utility service rates by approximately $36.1 million per year, or 5.3 percent. RMP included with its application the prefiled direct testimony of 17 witnesses: A. Richard Walje, RMP President and Chief Executive Officer (Ex. 2); Bruce N. Williams, RMP Vice President and Treasurer (Ex. 3); Samuel C. Hadaway, a principal in FINANCO, Inc., Financial Analysis Consultants (Ex. 4); Steven R. McDougal, RMP Director of Revenue Requirement (Ex. 5); Kelcey A. Brown, RMP Manager of Load Forecasting (Ex. 6); Gregory N. Duvall, RMP Director of Net Power Costs (Ex. 7); Cindy A. Crane, Vice President Inter-West Mining Company and Fuel Resources for PacifiCorp Energy (Ex. 8); Rick T. Link, Director of Commercial and Trading for PacifiCorp Energy (Ex. 9); Chad A. Teply, Vice President of Resource Development and Construction for PacifiCorp Energy (Ex. 10); Dana M. Ralston, RMP Vice President of Thermal Generation (Ex. 11); Mark R. Tallman, RMP Vice President of Renewable Resources (Ex. 12); Natalie L. Hocken, RMP Senior Vice President of Transmission and System Operations (Ex. 13); Douglas N. Bennion, RMP Vice President of Engineering Services and Asset Management (Ex. 14); Erich D. Wilson, RMP Director of Human Resources (Ex. 15); Douglas K. Stuver, RMP Senior Vice President and Chief Financial Officer (Ex. 16); Joelle R. Steward, RMP Director of Pricing, Cost of Service and Regulatory Operations (Ex. 17); and F. Robert Stewart, RMP Regulatory Consultant, Customer and Regulatory Liaison in the Customer Service Department. (Ex. 18).

3. On March 5, 2014, the Commission issued a *Suspension Order* suspending the application for the purpose of investigation for the initial six-month period provided in subsection (c) of Wyo. Stat. § 37-3-106. (Ex. 101).

4. On March 5, 2014, WIEC, an unincorporated association comprised of large industrial customers, filed a Petition for Leave to Intervene and Request for Hearing. (Ex. 100).

5. On March 6, 2014, the Commission issued a *Notice of Application* setting a deadline of April 4, 2014, for interested persons to file a statement, intervention petition, protest, or request for a public hearing. A public notice was published in newspapers in RMP's service territory. (Ex. 102).

6. On March 11, 2014, the OCA, a separate, independent division of the Public Service Commission charged with representing the interests of Wyoming citizens and all classes of utility customers pursuant to Wyo. Stat. § 37-2-401, filed its Notice of Intervention. (Ex. 103).

7. On March 25, 2014, the Commission issued a *Special Order Authorizing One Commissioner and/or Presiding Officer to Conduct Public Hearing*. (Ex. 105).

8. On April 3, 2014, Sierra, a national, non-profit environmental and conservation organization, filed a Petition to Intervene. (Ex. 106).

9. On April 4, 2014, NLRA, a citizens' group with members who are residents of Wyoming, filed a Petition for Leave to Intervene. (Ex. 107).

10. On April 17, 2014, the Commission issued orders authorizing the interventions of Sierra, NLRA and WIEC. (Exs. 109, 110 and 111).

11. On April 29, 2014, the Commission issued a *Scheduling Order Nunc Pro Tunc* establishing the procedural schedule and setting a public hearing for October 13, 2014. (Ex. 114).

12. A Protective Order was issued by the Commission on May 1, 2014. (Ex. 115). Accordingly, WIEC, NLRA and Sierra filed their respective Exhibits A to Protective Order.

13. On June 16, 2014, RMP filed the Supplemental Direct Testimony of Gregory N. Duvall. (Ex. 7, GND-1S and GND-2S).

14. Pursuant to the *Scheduling Order Nunc Pro Tunc*: the OCA, WIEC, Sierra and NLRA filed the direct testimony of their witnesses on July 25, 2014; RMP filed its rebuttal testimony on September 5, 2014; the OCA, WIEC and NLRA filed cross answer testimony on September 5, 2014; and, RMP, the OCA, WIEC, and Sierra filed sur-rebuttal testimony on September 19, 2014. (Ex. 114).

15. On September 15, 2014, the Commission issued a *Notice and Order Setting Public Hearing* for October 13, 2014. A public notice was published in newspapers in RMP's service territory. (Ex. 116).

16. The public hearing was held on October 13-21, 2014, pursuant to the Wyoming Administrative Procedure Act, Wyo. Stat. § 16-3-101, *et seq*. (the WAPA). Testifying for RMP were Walje, Williams, Hadaway, McDougal, Wilson, Ralston, Tallman, Bennion, Hocken, Duvall, Stuver, Brian T. Durning, Teply, Brown, Stewart and Steward. Anthony Ornelas, Belinda J. Kolb, Ph.D., Bryce J. Freeman and Denise K. Parrish, testified on behalf of the OCA. Jeremy Fisher, Ph.D., testified on behalf of Sierra. Sally H. Sarvey testified on behalf of NLRA. Michael P. Gorman, Philip Hayet, Bradley G. Mullins, Jeffry Pollock and Kevin C. Higgins, testified on behalf of WIEC.

17. On October 13, 2014, the exhibit conference was held and the following exhibits were received into evidence:

- RMP's Exhibit Nos. 1 through 18. (Tr. Vol. I, p. 7).
- OCA Exhibit Nos. 201 through 207. (Tr. Vol. I, p. 8).
- NLRA Exhibit Nos. 500 and 501. (Tr. Vol. I, p. 10).
- Sierra Club Exhibit Nos. 400 through 404 and 406 through 409. (Tr. Vol. I, p. 11).

• WIEC Exhibit Nos. 300 through 310.3. (Tr. Vol. I, p. 13).
• PSC Exhibit Nos. 100 through 156 and 158 through 166. (Tr. Vol. I, p. 19).

18. Over the course of the hearing, the Commission also received the following exhibits into evidence:

• PSC Confidential Exhibit Nos. 167 and 168. (Tr. Vol. II, pp. 262 and 401).
• PSC Exhibit No. 155, Attachment 14.7. (Tr. Vol. III, p. 526).
• WIEC Exhibit No. 313. (Tr. Vol. V, p. 945).
• WIEC Exhibit No. 328. (Tr. Vol. II, p. 373).
• WIEC Exhibit No. 330. (Tr. Vol. III, p. 596).
• WIEC Exhibit No. 332. (Tr. Vol. VII, p. 1402).
• RMP Exhibit No. 19. (Tr. Vol. IV, p. 748).

19. The Commission took administrative notice of two pleadings filed in Docket Numbers UE-287 and UM-1689 on August 14, 2014 and Order Number 14-331 entered on October 1, 2014, by the Public Utilities Commission of the State of Oregon. (Tr. Vol. VII, pp. 1266 - 1268).

20. At the conclusion of the hearing, the Commission requested post-hearing briefs be filed by November 14, 2014. (Tr. Vol. VII, pp. 1509 and 1513).

21. The Commission held public deliberations on December 10, 2014, pursuant to Wyo. Stat. § 16-4-403. The Commission then directed the preparation of an order consistent with its decision.

Summary of Decision

22. The Commission approved RMP's application for a rate increase, with adjustments, for a revenue requirement of $20,188,227 from $32,365,515, a return on equity of 9.5% from 10.00%, and a rate of return of 7.412% from 7.669%.

Contentions of the Parties and Resulting Issues

23. RMP identifies the issues and decision points before the Commission as follows:

(a) Capital Structure

(i) Should RMP's Proposed Capital Structure set forth below be approved, to wit:

Component	**Percent of Total**	**% Cost**	**Weighted Average**
Long Term Debt	48.551%	5.20%	2.525%
Preferred Stock	0.016%	6.75%	0.001%
Common Equity Stock	51.433%	10.00%	5.143%
	100.000%		7.669%

(b) Return on Equity

(i) Should RMP's proposed Return on Equity of 10.00% be approved?

(c) Revenue Requirement

(i) Should RMP's revised revenue requirement of $32,365,515 be approved?

(ii) Should O&M escalation factors provided by IHS-Global Insights be included in the test year expense? Should a productivity offset be established?

(iii) Should the pre-paid pension asset be included in rate base? Should any adjustment be made to assist ratepayers in transitioning to the inclusion of this asset in rate base?

(iv) Should any legal expenses be removed from this category of expense?

(v) Should RMP labor expense be reduced because of open positions, for which applications are currently being sought are not currently staffed?

(vi) Has RMP reasonably estimated the overhaul expenses for Lake Side 2 and Carbon Plant?

(vii) Should the Company be allowed a one-time recovery of the Carbon Plant labor and non-labor O&M expense required to operate the Carbon Plant until the April 2015 retirement?

(viii) Should RMP be allowed to include in rate base and recover the Allowance for Funds Used During Construction (AFUDC) costs associated with the Blundell Well Installation and Well Integration Project?

(ix) Should the Commission approve the Company's unchallenged investment in Lake Side 2, the Wyoming share of which is $105 million?

(x) Should the Commission approve the Company's unchallenged investment in the Mona-to-Oquirrh and Sigurd-to-Red Butte transmission resources? The respective Wyoming allocated shares of these investments are $59.0 million and $58.1 million, respectively.

(xi) Should the Commission approve the Company's unchallenged investment in the Carbon Plant Replacement Project and the Standpipe Substation Project? The respective Wyoming allocated shares of these investments are $7.4 million and $4.3 million.

(xii) Should the Commission approve the unchallenged non-main grid transmission investments and distribution investments which were included in this case? The Wyoming allocated share of these investments is approximately $32.1 million and $50.1 million, respectively.

(xiii) Should the Commission approve the unchallenged expense of the Merwin fish collector project, the Wyoming allocated share of which is $9.4 million?

(xiv) Should the Commission approve the unchallenged expense of the Hunter Unit I environmental compliance project, the Wyoming allocated share of which is $13.9 million?

(xv) Should the Commission approve RMP's investment in Hayden Unit 1 environmental compliance project?

(d) Net Power Costs

(i) Should the Commission approve RMP's Net Power Costs (NPC) of $1.485 billion company wide and $256.2 million on a Wyoming allocated basis?

(ii) Should the Commission approve RMP's proposal to off-set Energy Imbalance Market (EIM) costs with an equal amount of assumed benefits allowing all additional benefits, above that amount to flow to customers through the ECAM at 70%?

(iii) In the event that EIM benefits are not set in this case at WIEC's suggested level, should any market caps currently in GRID be removed?

(iv) Should two swap gas contracts with J. Aron & Company be removed from NPC on the theory that Goldman Sachs is an "Affiliate" of RMP's parent Company?

(v) Should the Commission approve the wind and load integration charges within NPC?

(vi) Should the Commission set new criteria for inclusion of QFs in NPC in this GRC docket?

(vii) Should the Commission adopt WIEC's proposed heat rate/minimum capacity adjustment?

(viii) Should the Commission remove 3 outages from the averaging of historical outages in setting base NPC, because they were longer than other outages?

(ix) Should the Commission include gas start-up energy in NPC?

(x) Should the Commission remove costs related to non-owned wind integration, even though the case includes revenue from a FERC-approved tariff?

(xi) Should the Commission adjust the short-term non-firm transmission modeled in GRID?

(xii) Should the Commission adjust the modeling assumptions in GRID for either, or both, of the Black Hills Power or UMPA II Contracts?

(xiii) Should the Commission approve the agreed upon adjustment to GRID, which assumes Naughton Unit 3 will continue to operate as coal facility throughout the test period?

(e) Cost of Service/Rate Spread

(i) Should the Commission approve RMP's revised class cost of service study using the classification and allocation methodologies adopted for prior cases?

(ii) Should the Commission approve RMP's proposed rate spread and rate design, which continue to collect between 99 and 101 percent of class target revenues from the cost of service study?

(iii) Should the Commission increase the residential basic service charge from $20.00 to $22.00 in order to better reflect cost of service?

(f) Tariff Changes

(i) Should the Commission approve RMP's proposed changes to Rule 12 of its tariff dealing with line extensions?

(ii) Should the Commission approve the unchallenged "housekeeping" changes proposed by RMP to Rule 7, metering and Rule 10, disconnection of service.

(iii) Should the Commission approve the unchallenged changes to schedule 300, reflecting prices associated with Rules 7, 10, and 12.

24. WEIC identifies the issues and decision points before the Commission as follows:

(a) Has Rocky Mountain Power established that the uncontested issues in its Application are just and reasonable?

(b) Is 9.3% the appropriate return on equity for Rocky Mountain Power, instead of the Company's unreasonable request for 10%?

(c) Is 48.89% debt and 51.11% equity the appropriate capital structure for Rocky Mountain Power?

(d) Should Rocky Mountain Power's capital structure be based on the end of test year period to capture known and measurable changes that will occur before the rate effective period, instead of the five-quarter average that diminishes the effect of those changes?

(e) Is $2,146,335 the appropriate revenue requirement increase for Rocky Mountain Power, instead of the Company's request for a $36,076,026 increase?

(i) With respect to non-net power cost adjustments:

(A) Should the revenue requirement exclude the inflation escalator applied by RMP to its test period non-labor O&M expense, because the inflation escalator is not a known and measurable expense?

(B) Should the revenue requirement be adjusted downward to reflect a reduction to forecasted Lake Side Unit 2 overhaul expenses for the July 2014 to June 2018 period to account for RMP's past tendency to overestimate forecasted overhaul expenses?

(C) Should the revenue requirement for generation overhaul expense be adjusted downward to remove historical overhaul expenses associated with the Carbon Plant?

(D) Should the revenue requirement be adjusted downward to account for certain legal expenses, including those associated with legal disputes (1) regarding RMP's imprudent or unreasonable behavior, (2) regarding shareholder interests only, and (3) involving extraordinary events and therefore unlikely to recur?

(E) Should the revenue requirement be adjusted downward to account for the reduction of full-time equivalent employees at the Carbon Plant and elsewhere in the Company since the 2013 base period?

(F) Should non-labor O&M expenditures projected for the retiring Carbon Plant be removed from base rates and recovered through an alternative mechanism?

(G) Should wage and benefits expenses projected for the retiring Carbon Plant be removed from base rates and recovered through an alternative mechanism?

(H) Should the revenue requirement include an unreasonable return on RMP's prepaid pension asset? And if the Commission allows RMP a return on the prepaid pension asset in its revenue requirement, then:

(I) Should the pretax rate of return on the prepaid pension asset be capped at the long-term return on the pension assets used in calculating RMP's pension expense?

(II) Should the rate of return be limited to changes in the amount of the prepaid pension asset on a going-forward basis?

(III) Should the Commission recognize the full net present value of $9.5 million (using the Company's weighted average cost of capital rather than the consumer price index as the discount rate) of the Company's historic practice to ignore prepaid pension liabilities that would have benefited customers in rates?

(I) Should the revenue requirement be reduced to reflect the WIEC proposed adjustments that were accepted by RMP?

(J) Should the revenue requirement exclude costs associated with Hayden Unit 1's selective catalytic reduction ("SCR") controls? (WIEC did not raise this issue in this proceeding and does not address the issue in its Brief; however it was raised by the Sierra Club and is a decision point for the Commission.)

(ii) With respect to net power cost adjustments:

(A) Should RMP's proposed net power costs be reduced to account for known and measurable benefits from RMP's participation in the Energy Imbalance Market? If yes:

(I) Should the adjustment to account for benefits from the Energy Imbalance Market include $1.3 million for interregional dispatch benefits?

(II) Should the adjustment to account for benefits from the Energy Imbalance Market include $2.0 million for intraregional dispatch benefits?

(III) Should the adjustment to account for benefits from the Energy Imbalance Market include $0.5 million for flexibility reserve benefits?

(IV) Should the adjustment to account for benefits from the Energy Imbalance Market include $0.6 million for within hour dispatch benefits?

(V) If not, should certain unrealistic, unjust, and unreasonable market caps in the GRID model be removed?

(B) Should RMP's proposed net power costs be reduced to account for costs associated with two gas swap contracts entered into with the Company's affiliate, a subsidiary of Goldman Sachs? In the alternative, should RMP's proposed net power costs be reduced to reflect the fact that these two gas swaps were imprudent?

(C) Should RMP's proposed net power costs be reduced to account for the removal of a system balancing inter-hour wind integration charge to avoid double-counting of the cost of inter-hour wind integration in the calculation of net power costs?

(D) Should RMP's proposed net power costs be reduced to account for the removal of a new, inter-hour load integration charge because these costs are already reflected in the hourly system balancing calculated by the GRID model?

(E) Should RMP's proposed net power costs be reduced to account for the removal of Qualifying Facilities that have not started construction of their projects and are unlikely to achieve commercial operation during the test period? Should the Commission establish an objective standard or policy to evaluate whether Qualifying Facilities will be used and useful during the test period and should therefore be included in net power costs?

(F) Should RMP's proposed net power costs be reduced to account for the impact of removing extended forced outages at the Colstrip 4, Lake Side 1, and Gadsby 4 plants as inputs for modeling forced outage rates because these outages were outliers and are unlikely to recur?

(G) Should RMP's proposed net power costs be reduced to account for forced outage rate modeling flaws (use of the deration approach) that result in excessive fuel costs because GRID is restricted from using more efficient heat rates?

(H) Should RMP's proposed net power costs be reduced to account for the benefit of energy produced during start-up, since the Company incorporates a charge for the fuel used during start-up?

(I) Should RMP's proposed net power costs be reduced to account for the GRID model's assumption that Black Hills Power will take power primarily in the highest cost hours possible?

(J) Should RMP's proposed net power costs be reduced to account for the GRID model's assumption that UMPA II sales were made primarily in the high load hours?

(K) Should RMP's proposed net power costs be reduced by changing the modeling of short term non-firm transmission in GRID using transmission rates input on a dollar per megawatt hour basis, instead of input on a fixed cost basis?

(L) Should RMP's proposed net power costs be reduced to avoid retail customers from subsidizing non-owned wind generators due to the intrahour integration costs (fuel and purchase power) that the Company incurs in providing ancillary services to the generators?

(M) Should the Commission order RMP to perform a final GRID run to include all of the Commission-approved adjustments to net power costs, and require RMP to account for any impact caused by combining adjustments and removing adjustments that overlap?

(f) Cost Allocation and Rate Design

(i) Should production/transmission plant-related costs be classified 100% as demand related, with the six coincident peak method used to allocate these costs to Wyoming retail customer classes, based on the principle of allocating costs based on causation?

(ii) Should energy-related costs be allocated to retail customer classes in a manner that recognizes seasonal and time of day cost differentials, based on the principle of allocating costs based on causation?

(iii) Should the Commission reject RMP's use of aggregated loss factors and instead use loss factors further disaggregated by delivery voltage? Should the Commission order RMP to prepare a new loss study for its next rate case for purposes of both inter- and intra-state cost allocation?

(iv) Should the Commission require industrial customers to pay for the residential ratepayers' rate increase proposed by RMP, contrary to the principle of allocating costs based on causation?

(v) Should the Commission reject the proposed $2 increase to residential ratepayers' basic charge? (WIEC did not raise this issue in this proceeding and does not address the issue in its Brief; however it was raised by various parties and is a decision point for the Commission.)

(g) Rule 12

(i) Should RMP have sole discretion to determine the amount of an Extension Allowance?

(ii) Should the Commission require RMP to notify new/expanding customers about the cost of a required line extension within a reasonable period of time after the customer has provided RMP with all of the necessary information?

(iii) Should the Commission reduce the Extension Allowance from 1.0 times annual electric revenues to 0.8 times annual electric revenues?

(iv) Should the Commission accept RMP's proposal to expand the definition of Network Upgrade to include certain transmission facilities?

(v) Should the Commission preclude RMP from interconnecting new customers to facilities if it would cause a decline in service quality to the initial customer of a line extension, or result in a stranded investment?

(vi) Should the Commission permit RMP to limit refunds associated with line extension to five years?

(vii) Should the Commission permit customers to fund a line extension through the customer's choice of either a contribution-in-aid-of-construction or through the payment of a Facilities Charge?

(viii) Should the Commission prohibit Extension Allowances for so-called "speculative loads" and require such loads to pay, up front, both the customer and Company portion of any Network Upgrade?

25. NLRA's issues and decision points are as follows:

(a) Should the Commission deny the Company's request to raise the residential-class base charge from $20 to $22?

(b) Should the Commission ensure that residential ratepayers are not subsidizing industrial consumers' increased energy use?

(c) Should the Commission adjust downward the Company's proposed rate increase, removing wind integration costs and excess payments (above current avoided cost) for non-firm QF energy from the NPC?

(d) Should the Commission adopt a policy wherein the Commission reviews each QF contract on a case-by-case basis for compliance with PURPA and state law so that eash QF PPA may be appropriately included in future NPC's for ratemaking purposes?

26. Sierra Club identifies the issues and decision points before the Commission as follows:

(a) Whether Rocky Mountain Power's construction and installation of Selective Catalytic Reduction ("SCR") controls at the Hayden coal plant unit 1 in Colorado is prudent.

(b) Whether to remove from rate base the capital costs of the Hayden 1 SCR, which is a net rate base adjustment of $395,297 for Wyoming's allocated share of rate base.

(c) Whether to reduce Rocky Mountain Power's requested revenue requirement by $23,358 to remove the Wyoming allocated share of costs associated with the Hayden 1 SCR.

27. OCA identifies the issues and decision points before the Commission as follows:

	ISSUE	OCA RECOMMENDED DECISION
1	Return On Equity	9.35%
2	Capital Structure	Accept Company Filed Case Embedded With Updates And Pro-Forma Adjustments
3	WACC	7.3346%
4	Hunter 1	Accept Company Filed Case
5	Hayden 1	Accept Company Filed Case
6	Total NPC	$249,675,289
7	EIM Adjustment To NPC	$31.995 Million (Total Company) $4.969 Million (Wyoming Allocated)
8	NPC Adjustment Naughton Unit 3	$2.275 Million - RMP Accepted OCA Position In Rebuttal
9	Mona-Oquirrh	Accept Company Filed Case
10	Sigurd- Red Butte	Accept Company Filed Case
11	Carbon Decommissioning Investments	Accept Company Filed Case
12	Standpipe Substation	Accept Company Filed Case
13	Rule 12 – General Service Line Extension Allowance	Adopt .8x Ear To Bring Rate To Cost Of Service
14	Rule 12 - Transmission And Substation Network Upgrade Voltage Thresholds	Adopt 115Kv To Align Rule With BES NERC Definition
15	Facilities Charges	Change To Actual Parameters Of This Rate Case As Ultimately Approved By The Commission
16	NV Energy Impact On Corporate Allocations	RMP Accepted OCA Position In Rebuttal
17	Prepaid Pension Assets	Use 5 Year Average To Bring Item In To Rate Base - $500,000
18	Global Insight Escalators	Eliminate Global Insight Escalators And Replace With Known Cost Increases
19	Blundell AFUDC	Remove Blundell AFUDC In Light Of Construction Delay Rationale - $65,000
20	Cost Of Service	Keep CCOS At 12 CP (75%Demand/25% Energy) – Consistent With MSP
21	Revenue Requirement	$13.2 Million Overall
22	Lakeside 2	Accept Company Filed Case
23	Rate Design	Recalculate 99-101% If Change In CCOS; Additional Notice to Customers Switched Between Classes
24	Residential Customer Charge	Keep At $20

28. For purposes of this findings of fact, conclusions of law and order, we will follow the Company's outline of issues and decision points set forth in paragraph 23 above, as they

adequately present the pertinent components of this case which require consideration relevant to our final decision.

Findings of Fact

CAPITAL STRUCTURE

29. In determining capital structure, RMP uses a five quarter average methodology. RMP's proposed capital structure is the amount of debt and equity the Company uses to finance the business on a consolidated basis in each of its state regulatory proceedings. (Tr. Vol. I, pp. 111-112). The Company requested an overall cost of capital of 7.669 percent, which is a reduction of five basis points (0.05 percent) from its original proposal. (Ex. 3, Williams Rebuttal, p. 3, Table 1). RMP claims its request is reasonable and reduces its revenue requirement by approximately $1.2 million from the capital structure proposed originally. (Ex. 3, Williams Rebuttal, p. 3).

30. The Company calculated the cost of capital based on the actual capital structure by averaging five quarterly projections of total company earnings, dividends, and financing activities beginning with actual June 30, 2014, results projected through June 30, 2015. (Ex. 3, Williams Dir., p. 12). RMP states this method provides the best view of its capital structure over a future period of time. (Tr. Vol. I, p. 91).

31. The Company explained that its proposed structure will allow the Company to maintain its credit rating and finance debt at the lowest possible cost. (Tr. Vol. I, pp. 102-103 and 114-115; Ex. 2, Walje Dir., p. 5; and Ex. 3, Williams Dir., p. 3). RMP stated that due, in part, to maintenance of the Company's strong credit ratings, it has reduced the cost of debt by about 1% since 2010, or a 70 basis point reduction, saving Wyoming customers more than $7 million annually. (Tr. Vol. I, p. 92 and Ex. 3, Williams Dir., pp. 3 and 7).

32. WIEC recommends a common equity component of 51.09 percent which produces an overall weighted average cost of capital of 7.30 percent. (Tr. Vol. VI, p. 1059; Exs. 307, p. 7, and 307.2). WIEC did not propose any changes to the Company's proposed 5.20 percent cost of long term debt or 6.75 percent cost of preferred stock. (Exs. 3, Williams Rebuttal, p. 3, Table 1 and 307.2).

33. The OCA argues that the use of the Company's embedded capital structure, as updated with pro-forma adjustments, is appropriate for use in this proceeding. The OCA believes that it is "reasonable and fair both to the Company and its customers." (Ex. 201, p. 454). As stated in OCA's direct case, this capital structure consists of 48.556% debt, 0.016% preferred stock, and 51.428% common equity. (Ex. 201, p. 45). While this information was initially filed on a confidential basis, RMP stated during the hearing that these numbers are, in fact, not confidential. (Tr. Vol. I, pp. 95-96).

34. In rebuttal, the Company provided an updated capital structure consisting of 48.551% debt, 0.016 % preferred stock, and 51.433% common equity. (Ex. 3, Williams Rebuttal, p. 3).

35. As stated by the OCA:

> The importance of the overall capital structure in setting rates for regulated utilities cannot be overstated. The object of determining the WACC for a regulated utility is to minimize the total cost of capital financing while at the same time preserving the utility's ability to attract and maintain capital. (Ex. 201, p. 43).

36. Based upon the Company's updated embedded capital structure and the OCA's recommended return on equity, the OCA recommended an overall weighted average cost of capital of 7.3345%. (Tr. Vol. IV, p. 886).

RETURN ON EQUITY

37. RMP requests a ROE of 10.0% which it claims is reasonable and appropriate for the following reasons: [i] the technical cost of capital models, which produce lower estimates of ROE, do not reflect the changing and improved economic conditions that currently exist; [2] today's interest rate environment has changed since the Commission approved its existing 9.8% ROE in mid-2012, noting that interest rates are almost 50 basis points higher than they were during 2012; and [iii] its proposal is consistent with the Commission's recent ROE approvals of 9.9% for Cheyenne Light Fuel & Power and Black Hills Power Company. The Company states its requested ROE is consistent with, and virtually identical to, allowed returns for vertically integrated electric utilities from around the country. (Tr. Vol. I, pp. 120-124).

38. WIEC contends the Company's proposed ROE of 10% is unjust and unreasonable and should be reduced to 9.30%. (Tr. Vol. VI, pp. 1069 and 1072; Ex. 307.2).

39. WIEC used five models to estimate the Company's cost of common equity: [i] a constant growth discounted cash flow (DCF) model using consensus analysts' growth rate projections; [ii] a constant growth DCF using sustainable growth rate estimates; [iii] a multi-stage growth DCF model; [iv] a Risk Premium model; and [v] a Capital Asset Pricing Model (CAPM). (Ex. 301, p 12). These models produced results ranging from 9.00% to 9.6%. (*Id*. at 38, Table MPG-4). WIEC's recommended ROE of 9.3% is the midpoint of the model output ranges and represents current market capital costs, increased interest rate risk in the current market due to Federal Reserve policies, and other factors. WIEC contends its recommended ROE supports RMP's ability to maintain its financial integrity, attract capital under reasonable terms, and represents fair compensation to RMP's investors for the total investment risk of its regulated utility activities. (*Id*. at 38).

40. The OCA recommends a cost of equity of 9.35%. (Ex. 201, p. 41). Based upon considerations of market risk dynamics, business risk, comparable companies, constant and non-constant growth discounted cash flow modeling, and capital asset price modeling, the OCA derived an initial range of reasonableness between 6.82% and 10.04%. (*Id*. at 39). Further OCA analysis resulted in a preferred range of reasonableness between 9.04% and 10.04%. (*Id*. at 41).

41. Bryce Freeman described the process the OCA used to derive its 9.35% recommendation as follows:

In the final analysis, I have relied more heavily on the traditional indicators, the constant grown DCF model and the long term CAPM. I am cognizant of the fact that popular opinion seems to support rising interest rates and I have considered that possibility in my analysis. However, I believe it is equally likely, based on the fact that interest rates have declined rather than increased recently, that interest rates will not increase from their present levels. For this reason, I have weighted the historic CAPM estimate and the projected CAPM estimate equally in my final determination. (*Id*.).

42. Mr. Freeman contends the OCA's recommended return will "balance the interests of customers in just and reasonable rates and the interest of the utility in supporting its ability to attract and maintain capital." (*Id*.).

43. The following Table summarized the Parties positions:

	RMP Direct	**RMP Rebuttal**	**OCA**	**WIEC**
DCF - indicated range	9.1% - 9.6%	9.2% - 9.4%	9.19%	
Constant Growth (Analysts' Growth)	9.1% - 9.2%	9.3% - 9.4%		9.10%
Constant Growth (GDP Growth)	9.5% - 9.6%	9.20%		9.10%
Multistage Growth Model	9.4% - 9.5%	9.20%		8.63%
CAPM	10.3% - 11.3%			9.14% - 9.73%
Historical			9.04%	
Projected			10.40%	
Risk Premium				9.2% - 9.95%
Forecast Risk Premium	*10.1%*	*9.65%*		
Current Risk Premium	9.9%	9.59%		
Recommendation	**10.00%**	**10.00%**	**9.35%**	**9.30%**

REVENUE REQUIREMENT

44. RMP proposes an adjusted revenue requirement increase of $32,365,515. (Tr. Vol. I, p. 139; Ex. 5, p. 1; *see also* RMP Post Hearing Brief, p. 28). WIEC proposes adjustments resulting in a total revenue increase of $2,146,335. (Tr. Vol. VII, p. 1375; Ex. 306 (Corrected)). OCA proposes adjustments resulting in a revenue increase of $13,200,000. (Tr. Vol. V, p. 963).

45. The Company uses historical accounting data as the basis to forecast costs for the test period. (Ex. 5, McDougal Dir., p. 6). From this starting point, the Company calculated its requested increase using a 12-month test period ending June 30, 2015, and the 2010 protocol inter-jurisdictional allocation methodology previously approved by the Commission. (Tr. Vol. I, pp. 139-140). The Company's earnings reports, filed with the Commission every six months, demonstrate that the Company is not overearning. This means that the Company has not forecasted costs in such a way as to make excess profit. (*Id*. at 192).

46. WIEC recommended a revenue requirement increase of $2,146,335, plus an additional $1.6 million recovery of non-recurring costs related to the Carbon Plant closure. (Tr. Vol. VII, p. 1375 and Ex. 306 (Corrected)). WIEC does not object to the Company's approach for the removal of the Carbon expense. (*Id*. at 1376). WIEC objects to the Company's request with respect to the inflation escalator, overhaul expenses for the Lake Side and Carbon Plants, legal expenses, number of employees used to determine the wage and benefit expenses, and treatment of the prepaid pension asset. (*Id*. at 1377).

47. The OCA supports a total rate increase of approximately $13.2 million. (Tr. Vol. V, p. 963). The OCA proposed four adjustments. The first adjustment was to incorporate allocations for charges associated with the acquisition of Nevada Energy, Inc. by Berkshire Hathaway Energy. The Company agreed to this adjustment. (Ex. 5, McDougal Rebuttal, p. 6). Other proposed adjustments were to the prepaid pension asset, inflation escalation factors, and AFUDC associated with the Blundell well integration project.

<u>Should O&M escalation factors provided by IHS-Global Insights be included in the test year expense? If so, should a productivity offset be established?</u>

48. The Company included an inflation escalator from IHS/Global Insights to convert historic dollars to test period dollars.[1] WIEC proposed removing the escalator for an adjustment of $795,616. (Ex. 306, p. 8). OCA proposed removal of the escalator and allowance for individual item increases for an overall adjustment of $900,000. (Tr. Vol. 5, p. 971). Sierra Club and NLRA did not take a position on this issue.

49. According to RMP, inflation should not be ignored when trying to forecast costs. (Tr. Vol. I, p. 141; Tr. Vol. VII, p. 1408). Therefore, the Company included an inflation escalator that converts historic June 2013 dollars to the test period June 2015 dollars. However, this does not align with the rate effective period which will produce some lag in the rates. (Tr. Vol. I, pp. 141-142).

50. WIEC's position is that the inflation escalator for non-labor O&M expenses proposed by RMP should be removed from the Company's test period over concerns that it will make inflation "a self-fulfilling prophecy." (Tr. Vol. VII, p. 1378). WIEC also explained the inflation escalators provide RMP with "an unnecessary cost cushion in rates that unduly increases electricity prices to customers." (Ex. 300, pp. 4 and 15).

51. The OCA proposes removing the Global Insights escalators because the inflation factors do not track with available historic data and are not statistically supportable for purposes of estimating future costs. (Tr. Vol. V, p. 970). The OCA mitigated the impact of this removal by adding back increases that have been independently justified. (Tr. Vol. V, p. 971). The net effect is an overall total decrease of approximately $900,000 in the revenue requirement. (*Id*.).

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[1] IHS was formerly known as Global Insights. It is a company that forecasts, among other things, a national utility inflation rate. (Tr. Vol. I, pp. 173-174 and 243-244; Tr. Vol. III, pp. 638-641 and 649-651).

<u>Should the prepaid pension asset be included in rate base? Should any adjustment be made to assist ratepayers in transitioning to the inclusion of this asset in rate base?</u>

52. The prepaid pension asset represents the Company's contributions to its pension and postretirement welfare plans in excess of what is expensed to that time. (Ex. 16, Stuver Dir., p. 2). The Company's revenue requirement reflects a $162 million net on a Company level and $23.7 million on a Wyoming-allocated basis addition to rate base. (Tr. Vol. VII, p. 1491; Ex. 16, Stuver Dir., p. 3).

53. RMP seeks rate base treatment of its prepaid pension asset because it finances the asset with a combination of debt and equity financing. (Tr. Vol. II, p. 441). The Company did not include this rate base item in prior cases. It has therefore not been able to recover its financing costs on this asset. (Tr. Vol. II, p. 429). The Company proposes adding the prepaid pension asset into rate base in order to collect its authorized rate of return on it. (Tr. Vol. II, pp. 430 and 432).

54. RMP's prepaid pension contributions come from cash on hand, short-term debt, or on a long-term basis through the Company's capital structure. (Tr. Vol. I, pp. 107-108). The contributions go into a pension trust dedicated solely to funding retiree pension benefits in the future. (Tr. Vol. II, p. 431). Although the Company incurs a cash cost to fund the contributions, under ERISA it has no ability to use those funds for other purposes. (Tr. Vol. I, pp. 108-109 and 117-118). ERISA sets minimum contribution requirements and the IRS sets maximum tax deductible contribution levels. (Tr. Vol. II, p. 444). However, the trust investment returns and its growth reduce the pension expense (company contribution requirements) and thereby also reduce expenses to customers. (Tr. Vol. II, pp. 443-444).

55. RMP's original request was $2.6 million, but was reduced to $2.564 million in the Company's rebuttal case. (Tr. Vol. III, p. 513 and Tr. Vol. VII, p. 1491). However, the Company stated during the hearing that it is agreeable to an adjustment of $300,000 or the OCA's proposed $570,000 adjustment. (Tr. Vol. III, pp. 513-514, 517-518 and 526-527; Tr. VII, p. 1493 and Ex. 16, DKS-1R). As an alternative to including an adjustment of $300,000 or $570,000 to the Company's proposed revenue requirement in this case, RMP suggested during the hearing it could also be handled as a one-time surcredit. (Tr. Vol. III, pp. 521-522).

56. The Company offered a one-time reduction of approximately $300,000. (Tr. Vol. VII, p. 1493). WIEC recommended disallowance of the asset entirely. (Tr. Vol. VII, p. 1385). At the hearing, WIEC recalculated the adjustment using the RMP methodology and RMP rate of return over that time period to arrive at an adjustment of approximately $9.5 million to the value of the asset. (Ex. 332). Ultimately, the Company stated that OCA's proposed adjustment is an "equitable alternative" to the Company's calculated $300,000 adjustment, and that the Company would be willing to accept it. (Tr. Vol. VII, p. 1493).

<u>Should any legal expenses be removed from this category of expense?</u>

57. Legal expenses are part of RMP's standard operating costs. The Company does not attempt to recover dollar-for-dollar on its legal expenses for specific cases, but instead, attempts to set a normal level of legal expenses on a going forward basis. The Company's legal expenses

in the test period are comparable to the legal expenses incurred by the Company in previous years. (Tr. Vol. I, pp. 142-143; Ex. 5, McDougal Rebuttal, p. 31, Table 6).

58. WIEC challenges the legal expenses for three specific cases: USA Power, Deseret Power and Wood Hollow. WIEC views that, because the interests at stake in the USA Power and Deseret Power cases are solely related to shareholder interests, the legal expenses should be removed from the revenue requirement. WIEC also contends the expenses associated with Wood Hollow should be removed as an abnormal business cost that is unlikely to recur. (Tr. Vol. VII, p. 1382-1383). WIEC's adjustment would reduce the Company's revenue requirement by $712,000. (*Id.*).

<u>Should RMP labor expense be reduced because of open positions?</u>

59. The Company has over 1,380 employees in the state of Wyoming and is actively recruiting 175 additional employees for its Wyoming operations. (Tr. Vol. II, pp. 278-279). These employees are necessary for the Company to provide and maintain adequate facilities and deliver adequate service to its Wyoming customers. (Ex. 15, Wilson Rebuttal, Table, p. 3).

60. RMP calculated its wage and benefit requirements based on the average number of employees during the base period ending June 2013. WIEC proposes that wage and benefits should be calculated based on the actual employee count in April 2014. (Tr. Vol. VII, p. 1384). Under WIEC's approach, the Company's workforce levels should be reduced by 119 employees with a corresponding reduction of $1.7 million in labor expenses. (*Id.* at 1384-1385).

<u>Has RMP reasonably estimated overhaul expenses for Lake Side 2 and the Carbon Plant?</u>

61. Because Lake Side 2 is a new plant and does not have four years of historical overhaul expense, the Company estimated the annual overhaul expense for the plant using four years of projected annual costs for the period July 2014 through June 2018. The Company is seeking recovery of $1.0 million for the four-year average of Lake Side 2. (Ex. 11, Ralston Rebuttal, pp. 1-2).

62. The Company included the Carbon plant in the four-year average because it is still operating and will be in service during most of the test period in this case. (Tr. Vol. I, p. 195). However, the Company scaled back the four-year average by 25 percent to account for the plant's scheduled April 2015 retirement. (*Id.* at 231-232 and 248-249). The Company also incurred a $2.7 million overhaul expense in 2013 that has not been included in any prior rate case. Therefore, RMP contends this expense should be included in order to provide the Company with the revenue it needs to maintain its plants and perform future work. (*Id.* at 142).

63. WIEC proposed removing 100 percent of the Carbon Plant overhaul from the four-year average because the plant will be retired before the end of the test period. (Tr. Vol. VII, pp. 1381-1382). WIEC maintains that the Company overstated its forecasted expense and proposes an adjustment of $43,457 on a Wyoming basis.

<u>Should the Company be allowed a one-time recovery of the Carbon Plant labor and non-labor O&M expense required to operate the Carbon Plant until the April 2015 retirement?</u>

64. WIEC proposed that the costs be recovered only for the first year of the rate effective period through a rider that expires in 12 months or is amortized as part of a regulatory asset. As an alternative, RMP proposed to record the amount in rates resulting from Carbon O&M expense as an offset in Carbon Removal Cost regulatory asset each month beginning in January 2016. (Ex. 306, p. 2). During the hearing, Higgins testified that WIEC does not object to the Company's alternative proposal. (Tr. Vol. VII, pp. 1414-1415).

Should RMP be allowed to include in rate base and recover the Allowance for Funds Used During Construction (AFUDC) costs associated with the Blundell Well Installation and Well Integration Project?

65. RMP explained that, during the time period where OCA claims there was limited activity on the Blundell Well Installation and Well Integration Project (2009-2013), project development and implementation activities continued, including owner's engineering services, technical specification development, procurement of ancillary equipment, installation of tie-in isolation points, and procurement of long-lead primary equipment and components. (Ex. 10, Teply Rebuttal, p. 6).

66. The Company also explained that the Blundell project schedule reflected the realities of coordinating development activities, permitting timelines, existing facility outage schedules, and the procurement and construction schedule while also managing the Company's interface with the Bureau of Land Management. (Tr. Vol. III, pp. 545-546). The Company demonstrated that the implementation schedule associated with the Blundell Project was prudently managed through its planning process and steps taken to mitigate risk. (Ex. 10, Teply Rebuttal, pp. 6-7). The Company also demonstrated that the 2014 well integration tie-in is in the best interests of customers through a PVRR(d) cost comparison analysis. (*Id.* at 7).

67. The OCA argues that ratepayers should not be required to pay costs related to capitalized financing that accrues when a project is not being actively worked on or constructed. (Ex. 202, pp. 22-23). OCA does not address the fact that the Company continued development and implementation activities on the project during the time in question, and that, therefore, the project was being actively worked on. Further, FERC includes permitting, and activities prior to physical construction such as the development of plans or the process of obtaining permits from governmental agencies, in the definition of construction activities that qualify for AFUDC. (Tr. Vol. II, pp. 450-451).

CAPITAL PROJECTS

Should the Commission approve the Company's investment in Lake Side 2?

68. The Company's capital investment in this resource includes $660 million on a Company basis and $105 million on a Wyoming-allocated basis. This resource will provide 645 MW of flexible, cost-effective, gas-fueled generation for RMP's customers. (Ex. 9, Link Dir., p. 14). The Company acquired Lake Side 2 through a competitive bidding process that included oversight from three independent evaluators. (*Id*. at 7-8). No party opposed this investment.

Should the Commission approve the Company's investment in the Mona-to-Oquirrh and Sigurd-to-Red Butte transmission resources?

69. The cost of the Mona-to-Oquirrh project is approximately $369.7 million on a total Company basis and $59.0 million on a Wyoming allocated basis. (Ex. 13, Hocken Dir., p. 5). The Mona-to-Oquirrh transmission project consists of a 100-mile single circuit 500/345 kilovolt (kV) transmission line from the new Clover substation, located near the community of Mona, Utah, to the existing Oquirrh substation, located in West Jordan, Utah. In order to complete construction of this new line, it was also necessary for RMP to upgrade and modify the existing Oquirrh substation. This line was placed into service in May, 2013. (Tr. Vol. II, p. 327; Ex. 13, Hocken Dir., pp. 4-12).

70. The cost of the Sigurd-to-Red Butte transmission project is approximately $363.7 million on a total Company basis and $58.1 million on a Wyoming allocated basis. (Ex. 13, Hocken Dir., pp. 12-19). The Sigurd-to-Red Butte transmission project consists of a single-circuit 345 kV transmission line running from the Sigurd substation located near the town of Richfield, Utah, extending south approximately 170 miles to the Red Butte substation located in Washington County, Utah. This line is currently under construction and is expected to go into service by May 31, 2015. (Tr. Vol. II, p. 327; Ex. 13, Hocken Dir., pp. 12-22).

71. The OCA endorses both transmission projects. (Tr. Vol. IV, pp. 837, 848). No other party opposed these investments.

Should the Commission approve the Company's investment in the Carbon Plant Replacement Project and the Standpipe Substation Project?

72. RMP's investment in the Carbon Plant Replacement Project is approximately $46.5 million on a total Company basis and $7.4 million on a Wyoming-allocated basis. (Ex. 13, Hocken Dir., pp. 22-23). This project is needed because the Company plans to decommission the existing 172 MW Carbon thermal facility located in Carbon County, Utah. This project includes installation of equipment necessary to ensure voltage stability, along with various communications upgrades and protection and control equipment. This project is on schedule to be placed into service in April, 2015. (Tr. Vol. II, p. 327-328; Ex. 13, Hocken Dir., pp. 22-24). The OCA recommended approval of the Carbon decommissioning investments. (Ex. 203, pp. 42-43).

73. The cost of the Standpipe substation project is approximately $26.9 million on a total Company basis and $4.3 million on a Wyoming-allocated basis. (Ex. 13, Hocken Dir., p. 25). The Standpipe 230 kV substation was placed into service in August, 2014. The shunt reactor, which is being relocated from the Platte substation, is forecasted to be placed into service at the Standpipe substation in November, 2014. There is a second phase to this project that includes installation of the synchronous condenser and associated equipment. Because that phase is not expected to go into service until 2016, those costs are not included in this case. (Tr. Vol. II, p. 328; Ex. 13, Hocken Dir., pp. 24-26). The OCA recommended approval of the Standpipe substation. (Ex. 203, pp. 42-43).

Should the Commission approve the non-main grid transmission investments and distribution investments which were included in this case?

74. The Company will place approximately $200.8 million on a total company basis and $32.1 million on a Wyoming-allocated basis of non-main grid transmission investment, and approximately $50.1 million of Wyoming distribution investment, that will be placed into service between June 30, 2013 and June 30, 2015. (Ex. 14, Bennion Dir., p. 2). This includes a number of specific investments that were part of RMP's Stipulated 2010 general rate case. (*Id.* at 3-4).

75. System reinforcement investment in the case includes approximately $7.8 million of system reinforcement at distribution level voltages in Wyoming and approximately $49.1 million of non-main grid system reinforcement investment on the Company's transmission system. In general, upgrading or adding transformers and distribution feeders is initiated when thermal loading is projected to reach 105 percent of thermal rating or when voltage delivery at the customer metering point is projected to fall outside of the American National Standards Institute (ANSI) planning criteria. (*Id.* at 5-6).

76. The Company plans to place in service $8.3 million in Wyoming distribution system compliance work and $78.1 million in Company transmission system compliance work during the test period. These projects include: environmental programs; modifications to facilities to meet National Electric Safety Code requirements; additions to renew distribution and transmission access permits; relocation of facilities for public works or customer requests, overhead to underground conversions and other miscellaneous customer third party requests; and projects and investment programs necessary to comply with the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation standards. (*Id.* at 6-7).

77. During the test period, the Company states it will install new customer connections, including residential (Wyoming distribution connections budgeted at $7.6 million), commercial (Wyoming distribution connections budgeted at $6.1 million), industrial (Wyoming distribution connections budgeted at $1.6 million and Company transmission connections budgeted at $7.0 million), and irrigation, street lighting and miscellaneous other distribution connections (budgeted at $0.6 million). (*Id.* at 7-8). The Company explains the replacement of failed or deteriorating assets is essential to maintaining and/or improving reliable service. The revenue requirement in this case includes $12.5 million in Wyoming distribution plant replacements and $60.5 million for Company transmission replacements. (*Id.* at 8-9). RMP also described the efficiencies it is finding and the steps the Company is taking to improve reliability. (*Id.* at 10). No party opposed RMP's transmission and distribution investments.

Should the Commission approve the expense of the Merwin fish collector project?

78. In order to comply with the Federal Energy Regulatory Commission (FERC) hydroelectric licenses applicable to the Lewis River hydro project, including the Merwin hydroelectric project license issued by FERC, the Company is required to implement the Merwin Fish Collector Project to collect, trap, and haul anadromous fish around three Lewis River dams in Washington State. (Ex. 12, Tallman Dir., pp. 2 and 3). Wyoming customers will benefit from the investment in the Merwin Fish Collector Project because the Company will be able to continue to operate the integrated Lewis River project, which is capable of generating up to 578 MW for the benefit of customers. (*Id.* at 4). No party opposed this investment.

<u>Should the Commission approve the expense of the Hayden Unit I environmental compliance project?</u>

79. PacifiCorp is a minority owner of Hayden Unit 1, with an interest of 24.5 percent. The Participation Agreement governing that ownership interest mandates the installation of capital improvements that are required by applicable law. (Ex. 10, Teply Dir., p. 4).

80. The Company began communicating its intent with respect to planning, assessment, and Hayden Ownership Agreement constraints associated with Hayden environmental compliance in its 2011 IRP Update Confidential Appendix A dated March 30, 2012. (Ex. 10, Confidential Ex. CAT-7R). The Company also documented its justification for participation in the Hayden Unit 1 SCR project in its 2013 IRP Confidential Volume III dated April 30, 2013. (Ex. 10, Confidential Ex. CAT-8R).

81. The Company has also pursued selling its interest in Hayden 1 as an alternative to incurring environmental compliance costs, including an open-ended Request for Expressions of Interest in Hayden Units 1 and 2 with a requested response date of April 18, 2014. The Company did not receive any responses to the Request for Expressions of Interest. (Ex. 10, Teply Rebuttal, p. 13).

82. The Sierra Club claims that the Company's participation in the installation of the SCR on Hayden Unit 1 is in contravention to the Company's own findings with respect to the economic analysis. (Ex. 400, pp. 4 and 5). Sierra Club also maintains that the Company should have either immediately divested itself of its share of Unit 1 rather than participate in the costs, or contested the installation of SCR through arbitration. (*Id.* at 6).

<u>Should the Commission approve RMP's investment in Hunter Unit 1 environmental compliance project?</u>

83. In order to meet RMP's emissions compliance obligations imposed by the Regional Haze rules and the state of Utah's Regional Haze SIP and associated permits, the Company was required to replace the originally installed particulate matter control equipment on Hunter Unit 1 with a best available retrofit technology baghouse. (Ex. 10, Teply Dir., p. 14). The Company also was required to equip Hunter Unit 1 with NO_x combustion controls that replace originally installed equipment. (*Id.* at 15). No party opposed this investment.

ISSUES ON REBUTTAL

84. While RMP contests the foregoing proposed adjustments to the revenue requirement, the Company accepted, or accepted in part, several WIEC-advocated adjustments. Specifically, the Company accepted the following adjustments in full, with the exception of the two noted, which RMP accepts in part. Regarding the two exceptions noted with asterisks in the table below, the Company accepts the adjustment in concept, but proposes a different dollar amount.

	WIEC Adjustment
Affiliate Charge Expense Adjustment	(142,756)
Pension Expense adjustment	(105,197)
Post-Retirement Benefits Other than Pensions (PBOP) Exp. Adjustment	(10,748)
Injuries & Damages Expense Adjustment	(139,123)*
Pension Administrative Expense Adjustment	(22,627)
401(k) Administrative Expense Adjustment	(23,438)
Severance Expense Adjustment	(32,006)
Contingency Reserve Adjustment	(70,375)
Lake Side 1 Rate Base Correction Adjustment	(112,874)
Populus – Terminal Condemnation Rate Base Adjustment	(162,223)
Naughton Unit 3 Extended Coal Operation Adjustment (Non-NPC Portion)	252,559
Energy Imbalance Market (Non-NPC Portion)	698,984*

85. First, it is appropriate to reduce the Wyoming revenue requirement deficiency by $142,756 to account for a reduced level of affiliated charges allocated to PacifiCorp by Berkshire Hathaway Energy Company ("BHEC") and MidAmerican Energy Company ("MEC") in the test period as a result of BHEC's recent acquisition of NV Energy, Inc. (Ex. 300, pp. 4 and 21-22).

86. Second, the test year level of FAS 87 pension expense should be adjusted to reflect the impact of RMP's revised 2014 plan expense. This adjustment reduces RMP's Wyoming revenue requirement deficiency by $105,197. (*Id.* at 4 and 25-27).

87. Third, the Commission should reduce the Wyoming revenue requirement deficiency by $10,748 because the test year level of other post-retirement benefits – FAS 106 ("PBOP") expense should be adjusted to reflect the impact of RMP's revised 2014 plan expense. (*Id.* 5 and 27-28).

88. Fourth, given the high degree of variability in pension administration expense, the test period level of this expense should be based on the historical three-year average, which in turn reduces the Wyoming revenue requirement deficiency by $22,627. (*Id.* at 5 and 35-36).

89. Fifth, it is appropriate to base test period 401(k) administration expense on the historical three-year average level of this expense. Doing so reduces the Wyoming revenue requirement deficiency by $23,438. (*Id.* at 5-6).

90. Sixth, because the Company has no plans to reduce its workforce or eliminate positions during the test period, the Commission should remove severance expense from the test period. This adjustment reduces the Wyoming revenue requirement deficiency by $32,006. (*Id.* at 6).

91. Seventh, the Commission should remove contingency costs for new investments that had been included in the Company's filing, but which since have been revised downward. WIEC further recommended that the Commission consider, as a policy matter, whether forecast test years should include "contingency costs" at any level associated with plant still under construction because almost by definition those costs are not known and measurable. (*Id.* at 5).

However, WIEC acknowledges that this policy issue can be addressed in future rate cases if that is the Commission's preference. This adjustment as accepted by RMP benefits Wyoming ratepayers by further reducing the Wyoming revenue requirement deficiency by $70,375. (*Id.* at 7).

92. Eighth, the Commission should accept the correction to the in-service date of the Lake Side U11 and U12 combustion overhaul projects from March 2015 to May 2015 to avoid double counting which reduces the Wyoming revenue requirement deficiency by $112,874. (*Id.* at 8).

93. Ninth, the Commission should remove the Populus-Terminal 345 kV line condemnation settlement project from test period rate base, since it is not projected to be in service during RMP's test period. This adjustment reduces the Wyoming revenue requirement deficiency by $162,223. (*Id.*).

94. Tenth, the Company accepts a non-NPC adjustment that accompanies the Naughton Unit 3 extended coal operations, presented by WIEC in its recommended base NPC adjustment for this Unit. Upon adoption by the Commission, this adjustment increases the Wyoming revenue requirement deficiency by $252,559. (*Id.*).

95. Next, there are two adjustments which the Company accepts in concept, but RMP proposes an alternative resulting adjustment calculation. Of these two, WIEC accepts RMP's correction for the injuries and damages expense, and for the other, WIEC stands by its calculation.

96. Specifically, WIEC proposed an adjustment for certain injuries and damages expense accrued in the year ended June 2012 that should be excluded from the calculation of the historical three-year average used to determine the test period level of this expense. (*Id.* at 34). This adjustment is consistent with the Company's treatment for this expense accrued in the base period, and reduces the Wyoming revenue requirement deficiency by $147,003. (*Id.* at 35). Although RMP accepts this adjustment, the Company made a correction to its filed case that results in a net positive revenue requirement impact of $139,123. (Ex. 5, McDougal Rebuttal., p. 7).

97. Lastly, WIEC's proposes corresponding non-NPC adjustments which accompany the California Independent System Operator ("CAISO") Energy Imbalance Market ("EIM") NPC adjustment. As initially recommended, this non-NPC adjustment increased the Wyoming revenue deficiency by $653,346. (Ex. 300, p. 8). RMP accepts this adjustment, but offered its alternative calculation of $756,184. (Ex. 306, p. 20). On Sur-Rebuttal, WIEC agreed that the revenue requirement impact of this positive adjustment should be increased by approximately $45,600, resulting in an adjustment to the Wyoming revenue deficiency of $698,984. (*Id.* at 1 and 20).

NET POWER COSTS

<u>Should the Commission approve RMP's requested Net Power Costs (NPC)?</u>

98. The Company proposed net power costs of $1.485 billion, $256.2 million of which would be allocated to Wyoming. The actual NPC for 2013 were $1.61 billion, approximately $130 million above the Company's proposed NPC in this case. (Tr. Vol. II, p. 346). The forecast NPC

for 2014 are projected to be $1.6 billion or approximately $115 million above the company's proposal in this case. (Tr. Vol. II, pp. 346 and 347).

99. The NPC requested on a Wyoming allocated basis of $256.2 million reflect a $5 million reduction from the Company's original request. The requested amount reflects the June 16, 2014 updates, the assumption that the Naughton Unit 3 will continue to use coal throughout the test period, and an adjustment to include benefits in base rates for the new energy imbalance market. (Tr. Vol. II, p. 346).

100. WIEC advocates a reduction in NPC of $8 million dollars on a Wyoming basis relative to the Company's surrebuttal NPC based upon greater assumed EIM benefits and an additional 16 proposed modeling adjustments. (*Id.* at 346).

101. The OCA also advocates for greater assumed EIM benefits which, in its opinion, should reduce the proposed NPC by approximately $5 million dollars on a Wyoming allocated basis relative to the Company's surrebuttal position. OCA did not join in the additional 16 WIEC modeling adjustments. (*Id.* at 346).

Should the Commission approve RMP's proposal to off-set Energy Imbalance Market (EIM) costs with an equal amount of assumed benefits allowing all additional benefits, above that amount to flow to customers through the ECAM at 70%?

102. The EIM is designed to generate cost savings for customers as a result of a more efficient operation of the system. The EIM is premised upon optimal joint re-dispatch of the Company's and the CAISO's system every five minutes. (Tr. Vol. II, p. 347). According to RMP, there are three parts of the EIM that have potential for generating savings for customers: [i] interregional dispatch which enables intra-hour transfers between CAISO and PacifiCorp, [ii] reserve savings; that is, by allowing the Company and the CAISO to operate together, the Company can save on the reserve requirements that it would need in the future, and [iii] intraregional benefit, which would occur within the PacifiCorp system taking advantage of automated five minute dispatch. This optimal dispatch of PacifiCorp's resources has the potential of generating benefits independent of the interconnection with CAISO. (*Id*.).

103. The Company proposed in its rebuttal case to match EIM benefits in NPC to the EIM costs in rates and allow any realized benefits in excess of the predetermined amount to flow through the Energy Cost Adjustment Mechanism (ECAM) wherein retail customers will realize 70 percent of those benefits. The corresponding EIM benefits proposed in base NPC are in an equal amount of $4.9 million on a company basis which results in a reduction of $0.8 million in base NPC on a Wyoming-allocated basis. (*Id.* at 349; Ex. 7, Duvall Rebuttal, p. 7).

104. The Company pointed out it does not have a good forecast of EIM benefits based on known and measurable data comparable to other inputs in the Generation and Regulation Integrated Decision model (GRID**),** used to forecast NPC and base rates. Rather, the Company will be gathering such data during the first year of EIM operation so that future forecasts can be based upon better data. The GRID model does not include the costs of within-hour re-dispatch, and therefore within-hour savings are not applicable to GRID. (Tr. Vol. II, p. 350).

105. The Company also addressed the fact that the report prepared by Energy and Environmental Economics of March 2013, referred to as the E3 Report, is not suitable for setting base NPC. Specifically, the intraregional benefits addressed within the E3 Report were estimated based upon a 2009 study of CAISO's first year of operation of its real-time market in California. These 2009 "California results" were then transposed to PacifiCorp with a simple load ratio and then discounted to show a low to high range of potential benefits given obvious differences between the two systems and prevailing market conditions. Furthermore the 2009 gas prices used to determine intraregional benefits in the E3 Report were much higher than current forward prices for natural gas in the test period. (*Id*. at 349-350). Further discrepancies between the E3 Report assumptions and traditional rate making concepts were pointed out by the Company in that the interregional and flexibility reserve benefits were based on estimates made in March 2013 of what potential benefits might be in 2017. Thus benefits are not based on current assumptions for the test period which ends June 2015. (*Id*.).

106. WIEC recommended in its direct case that $27.6 million of total company EIM benefits be included in base NPC, of which Wyoming's allocation is $4.8 million. In Sur-Rebuttal testimony, WIEC accepted certain recommendations made by RMP, and updated its recommendation to include $25.6 million in EIM benefits. Based on WIEC's calculations with respect to EIM benefits, on a Wyoming-allocated basis the base NPC should be reduced by $1.3 million to account for inter-regional dispatch benefits, $2.0 million to account for intra-regional dispatch benefits, $0.5 million to account for flexibility reserve benefits, and $0.6 million to account for within-hour dispatch benefits. (Ex. 309, p. 6). In total, the base NPC should be reduced by $4.4 million to account for EIM benefits expected to accrue to ratepayers in the test period. (Tr. Vol. VI, p. 1215).

107. The OCA supported a Wyoming allocated base net power cost (NPC) total of $249,675,289 (Tr., Vol. IV, p. 835) incorporating the June 2014 update RMP provided to the NPC. The OCA recommended an Energy Imbalance Market (EIM) benefit adjustment of $4.969 million to NPC on a Wyoming allocated basis. (Tr., Vol. IV, p. 840). The OCA utilized the E3 study (Ex. 303.2) to come up with a benefit calculation that captures a mid-range value for expected EIM benefits. (Tr., Vol. IV, p. 842). The Company used this same study to develop its business case (Tr., Vol. II, p. 383) for going forward on the project, and the OCA argues that it should be relied upon in this area as well. (Tr., Vol. IV, p. 841).

Should two swap gas contracts with J. Aron & Company be removed from NPC on the theory that Goldman Sachs is an "Affiliate" of RMP's parent Company?

108. RMP explained that Goldman Sachs is not an affiliate of Berkshire Hathaway because it never held five percent, or more, of voting stock in Goldman Sachs. (Tr. Vol. II, pp. 453-454). WIEC acknowledged during cross examination that Berkshire Hathaway did not hold five percent, or more, of the voting stock of Goldman Sachs. It simply held non-voting warrants. (Tr. Vol. VI, p. 1233). WIEC further conceded upon examination by Chairman Minier that it would agree it had not discovered any evidence of impropriety or the like [regarding any dealings between Berkshire Hathaway and Goldman Sachs]. (Tr. Vol. VII, p. 1303).

109. WIEC argues for the removal of the two swap contracts with J. Aron Company, a wholly-owned subsidiary of Goldman Sachs, on the theory that Goldman Sachs is an affiliate of

Berkshire Hathaway. In support of its position it made broad references to "heavily integrated" corporations in the 1930s, implying impropriety. *Id.*

Should the Commission approve the wind and load integration charges within NPC?

110. RMP points out that the load integration charge and the wind integration charge have been included in base NPC in prior cases. The inter-hour integration charge included in NPC outside of the GRID model is representative of costs associated with committing resources on a day-ahead basis based on a wind generation forecast. (Ex. 7, Duvall Rebuttal, p. 26). WIEC argues that these charges are already reflected in GRID and therefore should not be allowed. (Ex. 303, pp. 24-25).

Should the Commission set new criteria for inclusion of QFs in NPC in this GRC docket?

111. RMP is required under Federal law to enter into Power Purchase Agreements (PPA) with Qualifying Facilities (QF). The Company stated there is no need to impose new standards regarding which QFs can be included in NPC. (Tr. Vol. II, p. 362).

112. WIEC supports a "more holistic approach" to determine whether a QF resource should be included in NPC. (Tr. Vol. VI, p. 1224). WIEC suggests that in addition to a signed PPA, the Company should also have a signed interconnection agreement and should further inquire or document that construction has been commenced. (*Id*. at 1224).

113. Associated with this issue is the Latigo Wind Park project which is a 60 MW wind facility planned in San Juan County, Utah. (Ex. 303, Mullins Dir., p. 32). It is unlikely, however, that the Latigo Wind Park will achieve commercial operation during the test period used in this proceeding. (Tr. Vol. VII, pp. 1288 and 1293-1294). This results in a $107,609 reduction to base NPC on a Wyoming-allocated basis.

114. To begin, WIEC recommends that when examining whether QFs should be included in base NPC, the Commission should require the QF to: (i) have an executed power purchase agreement, (ii) have an executed interconnection agreement, and (iii) have started construction of the plant. (Ex. 303, Mullins Dir., p. 31). WIEC recommends the Commission adopt this three part test for including QFs in base NPC because, in previous general rate cases, the Company included certain QFs in base NPC that never achieved commercial operation. (Tr. Vol. II, p. 392). For example, the Pioneer Wind Park II project was included in the 2011 general rate case, but it never achieved commercial operation and was ultimately terminated. (Ex. 303, Mullins Dir., pp. 31-32). Though this project never became used and useful, its costs were included in base NPC. There is no reason to include these types of projects in NPC when unconstructed company-owned generation is not included in NPC. (Tr. Vol. II, p. 392).

115. Even if the Commission elects not to establish such a test in this proceeding, WIEC suggests the Commission should still exclude the Latigo Wind Park project in base NPC because the project is highly unlikely to come online during the test period. (Tr. Vol. VII, p. 1285). This is so because the Company stated that it is not aware of any construction activities for the Latigo Wind Park. (Exs. 303, p. 32 and 303.6). Accordingly, and given the timing, there is no real

expectation that the NPC the Company attributes to the Latigo Wind Park in its Application will come to pass within the test period. (Tr. Vol. VII, pp. 1293-1294).

Should the Commission adopt WIEC's proposed heat rate/minimum capacity adjustment?

116. WIEC proposed a modeling adjustment to adjust modeled forced outages. WIEC contends that, because the GRID model de-rates generating units to below their maximum capacity, it does not allow them to achieve maximum efficiency in GRID. (Tr. Vol. VI, p. 1135). WIEC further contends that there should be a shift of the entire heat rate curve for each unit in the model so that the maximum capacity under the modeled heat rate curve is equal to the de-rated maximum capacity in GRID. (*Id*. at 1135).

117. According to RMP, WIEC contends that the heat rate at one point on the heat rate curve is incorrect. That creates errors in the entire remainder of the heat rate curve under its false assumption that the Company's de-rated generation capacity is improperly modeled in these circumstances. (*Id.* at 1137).

118. RMP points out that the majority of WIEC's proposed reduction to net power costs is a result of the errors WIEC creates in the heat rate curve and in minimum generation levels. (Tr. Vol. II, p. 353).

119. To address WIEC's concern about the impact of de-rating each unit's maximum capacity, RMP presented evidence that showed when the de-rating method was replaced with the use of four years of actual forced outage history without de-rating, NPC would increase. (*Id.* at 405-406 and Ex. 168).

120. WIEC suggests that without its proposed adjustment, GRID would overstate the amount of generation that the unit would produce. (Tr. Vol. VI, p. 1122).

Should the Commission remove three outages from the averaging of historical outages in setting base NPC, because they were longer than other outages?

121. Outages occurred at Colstrip 4, Lakeside 1 and Gadsby 4 during the base period of this rate case. WIEC argues that these three outages were exceptionally long, are unlikely to recur in the future, and should, therefore, be excluded. (Tr. Vol. VI, p. 1120; Ex. 308, p. 2). Collectively, these three outages reduce base NPC by $526,447 on a Wyoming-allocated basis. The individual components of this adjustment, on a Wyoming-allocated basis, are as follows: (i) Colstrip 4 extended outage: $163,003 adjustment; (ii) Lake Side 1 extended outage: $340,456 adjustment; and (iii) Gadsby 4 extended outage: $22,988. (Ex. 302, p. 3, Table PH-1).

122. RMP's fleet of thermal generation resources is acknowledged as outperforming the industry's averages for length of outages. (Tr. Vol. II, p. 353). Outages will inevitably vary in length and can never be predicted with certainty. The purpose of averaging the outages over the four years used in the forced outage rate calculation is to set this NPC expense based upon historical experience. The removal of these outages from the calculation will unfairly skew the historical averaging of forced outages. In addition, as the Company has explained, if these costs

are removed from the forced outage rate, the Company has no way to recover the prudently incurred costs associated with the outages. (*Id.*).

Should gas start-up energy be included in NPC?

123. Combined cycle natural gas units take 2-3 hours to ramp up to their minimum generating level. Because a unit as modeled in GRID begins generating its full output immediately without any ramp time, any adjustment including start-up energy would also need to include 2-3 hours of start-up time which would increase NPC. (Tr. Vol. II, p. 355).

124. WIEC contends this adjustment represents a reasonable amount of energy produced during start -up of a gas fired generation resource and thus NPC should be reduced based upon the value of this energy. (Tr. Vol. VI, p. 1124).

125. The Company increases its base NPC using an adjustment after GRID has been run in order to account for the cost of starting up units. WIEC claims this increase is unjust and unreasonable because it adds a cost without also considering the associated benefit that occurs when the units start up – the generation of energy. (Ex. 302, p. 27).

126. The Company argues that start-up costs are not limited to fuel, and that in order to accommodate the start-up of a 500-600 MW gas unit, the Company will incur costs as a result of re-dispatching the system. (Ex. 7, Duvall Rebuttal, p. 41).

Should the Commission remove costs related to non-owned wind integration, even though the case includes revenue from a FERC-approved tariff?

127. RMP collects tariffed rates set by FERC for the non-owned wind integration services it provides wholesale transmission customers. Like rates for RMP's retail customers, FERC rates are based on the embedded cost of service. The transmission customers, subject to these FERC rates, are paying the full costs of the generation facilities used to provide Schedule 3A services. (Tr. Vol. II, pp. 354 and 355).

128. WIEC contends that FERC regulated customer rates are too low because the revenue received by RMP for FERC transmission customers under the open access transmission tariff (OATT) Schedules 3 and 3A only collects fixed costs associated with non-owned wind integration rather than all related costs incurred to integrate the non-owned resources. (Tr. Vol. VI, p. 1128).

129. The Company argues that OATT Schedules 3 and 3A recover the fixed costs associated with integrating wind from wholesale ratepayers. (Ex. 7, Duvall Rebuttal, p. 49). However, during hearing, RMP argued for the first time that OATT Schedule 9 recovers some variable costs associated with integrating wind. (Tr. Vol. II, pp. 409-410).

Should the Commission adjust the short-term non-firm transmission modeled in GRID?

130. Short term wheeling is frequently used to serve load and to facilitate wholesale sale and purchases. (Tr. Vol. II, p. 358). The Company has input an historical average of the Short Term Non-Firm (STNF) transmission expense which is captured in GRID. (*Id.*).

131. WIEC proposes an adjustment to correct alleged modeling flaws, and after accounting for a correction to WIEC's proposed adjustment raised by RMP in its rebuttal case, the Company's base NPC should be reduced by $259,934 on a Wyoming-allocated basis. (Exs. 7, Duvall Rebuttal, p. 47; 308, pp. 13-14). Under WIEC's modeling approach, new cost related inputs are entered into GRID on a dollars per MWh basis, such that STNF transmission cost results are derived dynamically based on transmission flows that actually occur in GRID. (Ex. 302, p. 33).

<u>Should the Commission adjust the modeling assumptions in GRID for either, or both, of the Black Hills Power or UMPA II Contracts?</u>

132. The Company points out that a significant provision in both the BHP and UMPA II contracts is optionality. That is, both of these contracting parties can shape these contracts to meet their needs by purchasing power at high cost hours. GRID properly reflects the optimization that both BHP and UMPA have in their agreements. (Tr. Vol. II, pp. 362 and 363).

133. WIEC argues that GRID overstates NPC associated with these contracts because all power is not purchased at high cost hours. The adjustment for both contracts would reduce NPC on a Wyoming allocated basis by $110,639. (Ex. 308 pp. 10-11).

134. According to WIEC, the Company models the Utah Municipal Power Agency II ("UMPA II") contract in GRID as a "call option sale" contract, the same as it models the Black Hills Power contract. (Ex. 302, p. 29). Just like the Black Hills Power contract, the Company allows GRID to schedule the contract primarily during the high load hours, which are the costliest hours for the Company to meet the requirements of a sales contract. (*Id.* at 29). The fact that most of the sales energy is scheduled in GRID during the high load hours is not consistent with the four-year historic data. (*Id.* at 30).

<u>Should the Commission approve the agreed upon adjustment to GRID, which assumes Naughton Unit 3 will continue to operate as coal facility throughout the test period?</u>

135. The Company and WIEC have agreed to the adjustment to GRID. This agreed upon adjustment reduces NPC on a Wyoming allocated basis by $2.7 million. (Tr. Vol. VI, pp. 1115-1116; Ex. 7, Duvall Rebuttal, p. 39).

COST OF SERVICE/RATE SPREAD

<u>Should the Commission approve RMP's revised class cost of service study using the classification and allocation methodologies adopted for prior cases?</u>

136. The Company's class cost of service (COS) study is based on forecast results of operations for the state of Wyoming for the 12 months ending June 30, 2015. The study employs a three-step process generally referred to as functionalization, classification, and allocation. These

three steps recognize the way a utility provides electrical service and assigns cost responsibility to the customer groups for whom those costs are incurred. (Ex. 17, Steward Dir., p. 4).

137. Functionalization is the process of separating expenses and rate base items according to five utility functions -- production, transmission, distribution, retail and miscellaneous. (*Id.*). Classification identifies the component of utility service being provided as either demand-related, energy-related, or customer-related. Demand-related costs are incurred by the Company to meet the maximum demand imposed on generating units, transmission lines, and distribution facilities. Energy-related costs vary with the output of a kilowatt-hour (kWh) of electricity. Customer-related costs are driven by the number of customers served. (*Id.* at 5).

138. After the costs have been functionalized and classified, they are allocated among the customer classes using allocation factors, which specify each class's share of a particular cost driver such as system peak demand, energy consumed, or number of customers. The appropriate allocation factor is then applied to the respective cost element to determine each class's share of cost. (*Id.* at 6).

139. Production and transmission plant and non-fuel related expenses are classified as 75 percent demand related and 25 percent energy related. The demand-related portion is allocated using 12 monthly peaks coincident with the Company's total system firm peak. The energy related portion is allocated using annual class megawatt-hours (MWh) adjusted for losses to generation level. (*Id.* at 6). WIEC challenges the Company's allocation of production and transmission plant and the energy allocator. No party challenges the remainder of the Company's allocations, including for distribution costs, customer accounting, customer service and sales expenses, administrative and general expenses, general plant, intangible plant, or the treatment of partial requirements customers.

140. WIEC argues that the transmission line loss factors used in the COS study overstate losses to Schedule 48T customers, recommends further disaggregation of the loss factors at different transmission voltage levels, and recommends using a composite factor of 1.035 for Schedule 48T. (Exs. 304, p. 21 and 310, p. 2).

141. WIEC's provides evidence regarding several areas where the methodologies employed by RMP could be improved to better align rates with costs and eliminate or reduce inter-class subsidies. Specifically, WIEC recommends: (i) allocating 100% of the fixed demand-related costs of production based on the contribution of each customer class to peak demands; (Ex. 310, pp. 9-10) (ii) using a six coincident peak ("6CP") rather than twelve coincident peak ("12CP") methodology to allocate fixed demand-related costs of production; (Ex. 304, p. 32) (iii) using an energy allocator that captures the actual seasonal and time-of-day differences in energy costs; (Exs. 304, pp. 32-33; 304.10 and 304.11) and (iv) using a disaggregated loss factor for Schedule 48T. (Ex. 304, p. 20).

142. Finally, WIEC requests that RMP be ordered to prepare a new loss study that includes the development of specific disaggregated transmission loss factors to more accurately reflect the different varying voltage levels on which Schedule 48T customers are served. Further, the updated loss study should address the inconsistencies between the demand and energy loss factors. (Ex. 304, pp. 20-21).

143. The OCA does not raise any concerns relating to class cost of service. The OCA contends the Commission should not restudy the current methodology until after the recommendations regarding changes to interjurisdictional allocations are examined. (Ex. 202, p. 28).

<u>Should the Commission approve RMP's proposed rate spread and rate design?</u>

144. The Company prepared a rate spread that collects between 99 percent and 101 percent of the class target revenue requirement from the COS study. This rate spread methodology has been utilized in prior general rate cases including the Company's 2011 general rate case, Docket No. 20000-405-ER-11. (Ex. 17, Steward Dir., p. 9). According to RMP, the proposed rates cover costs in a way that closely resembles the way individual components of cost are incurred. Rates are proposed based on grouping costs into customer related, demand-related and energy-related categories. (*Id.* at 11).

<u>Should the Commission increase the residential basic service charge from $20.00 to $22.00 in order to better reflect cost of service?</u>

145. The basic residential customer charge has not changed since 2009. (Tr. Vol. IV, pp. 754-755). (Ex. 17, Steward Dir., pp. 11-12).

146. NLRA argues that because residential energy consumption is declining, residential costs remain flat, so the Commission should deny the Company's requested increase in the residential class basic charge and consider a different allocation of costs between residential and industrial customers. (Ex. 500, p. 2). OCA stated that keeping the $20 customer charge would be preferable, but that raising the rate would not be harmful or detrimental. (Ex. 202, p. 33).

TARIFF CHANGES

<u>Should the Commission approve RMP's proposed changes to Rule 12 of its tariff dealing with line extensions?</u>

147. RMP has proposed changes to Rule 12 which addresses line extensions. (Ex. 18, Stewart Dir., p. 3). According to the Company, the proposed changes to the line extension policy are intended to increase consistency in the treatment of similar customers and balance the allowances and other company investment with risk to ratepayers. (Tr. Vol. III, p. 665).

148. The Company has proposed three primary changes to Rule 12. The first addresses when a customer will receive an extension. Language has been added to Rule 12 stating that the Company will not provide an extension allowance to a customer with expected limited revenues unless a special contract is entered into. (*Id.* at 676-677).

149. A second change in Rule 12 removes the option of a customer selecting a Company built and owned substation to serve customer loads that require transmission delivery. (*Id.* at 666).

150. A third area of change in Rule 12 deals with "network upgrades" which are necessary when a capacity request comes in and it would require adding capacity to existing shared facilities. (*Id.*). Currently customers share in the cost of upgrades of facilities below 46 kV. The proposed change would require customers to share in the cost of facilities below 230 kV. Additionally, customers of 1.0 MVA would share in these upgrades rather than the current higher load threshold of 2.5 MVA. (*Id*. at 667). According to RMP, these two changes will bring the thresholds in Wyoming in alignment with the network upgrade thresholds used in the other five states that are served by PacifiCorp. (Ex. 18, Stewart Rebuttal, p. 3).

151. Lastly, the network upgrade modification also requires that if it is later determined a network upgrade was not necessary because the customer overstated its load, the customer would be responsible for the full cost of the upgrade. (*Id*. at 1).

152. WIEC opposes the proposed changes to Rule 12. It contends that the amendments place too much burden and risk on industrial customers in obtaining electricity services. As alternatives to the Company's Rule 12 modifications WIEC proposes: [i] the definition of extension allowance eliminate the Company's discretion, [ii] the Company notify a customer of the cost of required line extensions within a reasonable time of the submission of all necessary information, [iii] the Commission reject the provisions addressing network upgrade, and [iv] the Commission consider modifications to the refund provisions of Rule 12. (Tr. Vol. VII, pp. 1321-1324).

153. OCA recommended that the residential line extension allowance remain unchanged at $1,300. RMP agrees that the residential allowance should remain at $1,300. (Tr. Vol. IV, p. 807).

154. OCA also proposes that the non-residential allowance be lowered from 1.0 times the estimated annual revenues to .80 times the estimated annual revenues. RMP does not propose to lower the current allowance of 1.0 times estimated annual revenues. WIEC opposes OCA recommendation to lower the non-residential allowance to .80 times estimated annual revenues. It contends this will impact economic development. (Tr. Vol. IV, p. 808).

155. OCA contends that the Company should be responsible for the cost of upgrades at such facilities at or above 115 kilovolts rather than the 230 kilovolts proposed by RMP. (*Id.* at 812). However, the OCA generally supports RMP's Rule 12 changes addressing network upgrades with the exception of the voltage threshold of eligible substation and transmission facilities.

<u>Should the Commission approve the unchallenged "housekeeping" changes proposed by RMP to Rule 7, metering, Rule 10, disconnection of service?</u>

156. The Company proposed "housekeeping" changes to Rule 7, metering, Rule 10, disconnection of service, and Schedule 300 to clarify the rules and make them easier for customers to understand. (Ex. 18, FRS 2).

157. The proposed changes to Rule 7 allow a customer who does not wish to have a meter that is capable of being read by automated meter reading have a non-standard meter installed.

The corresponding change to Schedule 300 sets forth the costs for the non-standard meter. (Ex. 18, Stewart Dir., pp. 15-17).

Should the Commission approve the unchallenged changes to schedule 300, reflecting prices associated with Rules 7, 10, and 12?

158. Schedule 300 implements the proposed changes above, including: (i) reducing the disconnection visit charge from $20 to $16; (ii) reducing the reconnection fee from $20 to $18; (iii) increasing the temporary service charge for service drop and meter to $170 for both single-phase and three-phase power; and (iv) adjusting the line extension facilities charges. (*Id.* at 18-23).

159. The OCA supports all filed RMP changes to Rules 7, 10, 12, Tariff – Schedule 300, and the associated Cost Allocation Policy, provided that any changes are reflected in all areas of these documents as required to make them consistent. (Ex. 204, p. 22).

Principles of Law

160. Wyo. Stat. § 37-3-101 requires that:

> All rates shall be just and reasonable, and all unjust and unreasonable rates are prohibited. A rate shall not be considered unjust or unreasonable on the basis that it is innovative in form or in substance, that it takes into consideration competitive marketplace elements or that it provides for incentives to a public utility. * * * The commission may determine that rates for the same service may vary depending on cost, the competitive marketplace, the need for universally available and affordable service, the need for contribution to the joint and common costs of the public utility, volume and other discounts, and other reasonable business practices.

161. Wyo. Stat. § 37-3-106(a) sets the burden of proof in a rate case before the Commission:

> At any hearing as provided in this act involving an increase in rates or charges sought by a public utility, the burden of proof to show that the increased rate or charge is just and reasonable shall be upon the utility.

162. Wyo. Stat. § 37-3-106(b) and (c) allow the Commission to suspend rates for a total of ten months:

> (b) Unless the commission otherwise orders, no public utility shall make any change in any rate which has been duly established except after thirty (30) days notice to the commission, which notice shall plainly state the changes proposed to be made in the rates then in force, and the time when the changed rates will go into effect. . . .
>
> (c) Whenever there is filed with the commission by any public utility any application or tariff proposing a new rate or rates, the commission may, either upon complaint or upon its own initiative, initiate an investigation, hearing, or both, concerning

> the lawfulness of such rate or rates. Pending its decision thereon, the commission may suspend such rate or rates, before they become effective but not for a longer initial period than six (6) months beyond the time when such rate or rates would otherwise go into effect. If the commission shall thereafter find that a longer time will be required, the commission may extend the period of suspension for an additional period or periods not exceeding in the aggregate, three (3) months.

163. Wyo. Stat. § 37-3-112 requires that:

> The service and facilities of every public utility shall be adequate and safe and every service regulation shall be just and reasonable. * * * It shall be unlawful for any public utility to make or permit to exist any unjust discrimination or undue preference with respect to its service, facilities or service regulations.

164. The Commission has broad powers to inquire into the facts surrounding the determination of rates. They include Wyo. Stat. § 37-2-119, which states that:

> In conducting any investigation pursuant to the provisions of this act the commission may investigate, consider and determine such matters as the cost or value, or both, of the property and business of any public utility, used and useful for the convenience of the public, and all matters affecting or influencing such cost or value, the operating statistics for any public utility both as to revenues and expenses and as to the physical features of operation in such detail as the commission may deem advisable; the earnings, investment and expenditures of any such corporation as a whole within this state, and as to rates in plants of any water, electric, or gas corporations, the geographical location thereof shall be considered as well as the population of the municipality in which such plant is located.

165. Wyo. Stat. § 37-2-120 prohibits the Commission from making any order "which requires the change of any rate or service. . . unless or until all parties are afforded an opportunity for a hearing in accordance with the Wyoming Administrative Procedure Act." The Act establishes general procedures for Commission cases, including the giving of reasonable notice. Wyo. Stat. § 16-3-107; in accord are Wyo. Stat. §§ 37-2-201, 37-2-202, and 37-3-106. *See also*, Sections 106 and 115 of the Commission's Rules.

166. Wyo. Stat. § 37-2-121 gives the Commission latitude to determine the actual rates to be charged by a utility and allows public utilities to present innovative regulatory forms, policies, and rate making methods, stating that:

> If upon hearing and investigation, any rate shall be found by the commission to be inadequate or unremunerative, or to be unjust, or unreasonable, or unjustly discriminatory, or unduly preferential or otherwise in any respect in violation of any provision of this act, the commission . . . may fix and order substituted therefor a rate as it shall determine to be just and reasonable and in compliance with the provisions of this act. The rate so ascertained, determined and fixed by the commission shall be charged, enforced, collected and observed by the public utility for the period of time fixed by the commission. The rates may contain provisions for incentives for improvement of the public utility's performance or efficiency, lowering of operating costs, control of expenses or

> improvement and upgrading or modernization of its services or facilities. Any public utility may apply to the commission for its consent to use innovative, incentive or nontraditional rate making methods. In conducting any investigation and holding any hearing in response thereto, the commission may consider and approve proposals which include any rate, service regulation, rate setting concept, economic development rate, service concept, nondiscriminatory revenue sharing or profit-sharing form of regulation and policy, including policies for the encouragement of the development of public utility infrastructure, services, facilities or plant within the state, which can be shown by substantial evidence to support and be consistent with the public interest.

167. Wyo. Stat. § 37-2-122(a) provides further direction:

> In determining what are just and reasonable rates the commission may take into consideration availability or reliability of service, depreciation of plant, technological obsolescence of equipment, expense of operation, physical and other values of the plant, system, business and properties of the public utility whose rates are under consideration.

168. The public interest must come first in Commission decisions; and, as the Wyoming Supreme Court has stated, the desires of the utility are secondary to it. *Mountain Fuel Supply Company* v. *Public Service Comm'n,* 662 P.2d 878 (Wyo. 1983). Construing Wyo. Stat. § 37-3-101, which requires rates to be reasonable, the Court in *Mountain Fuel, supra,* at 883, commented that:

> This court cannot usurp the legislative functions delegated to the PSC in setting appropriate rates, but will defer to the agency discretion so long as the results are fair, reasonable, uniform and not unduly discriminatory.

Later, 662 P.2d at 885, the Court in *Mountain Fuel* observed that:

> We agree that if the end result complies with the 'just and reasonable' standard announced in the statute, the methodology used by the PSC is not a concern of this court, but is a matter encompassed within the prerogatives of the PSC.

In accord are *Great Western Sugar Co.* v. *Wyo. Public Service Comm'n and MDU, 624* P.2d 1184 (Wyo. 1981); and *Union Tel Co.* v. *Public Service Comm'n,* 821 P.2d 550 (Wyo. 1991), wherein the Supreme Court stated, 821 P.2d at 563, that it ". . . has recognized that discretion is vested in the PSC in establishing rate-making methodology so long as the result reached is reasonable." Read *in pari materia*, these statutes articulate the basic mechanism of the public interest standard which the Commission is to follow in its decisions.

Conclusions of Law

169. RMP is duly authorized by the Commission to provide retail electric public utility service in its Wyoming service territory under certificates of public convenience and necessity as issued and amended by the Commission. RMP is an electric public utility as defined in Wyo. Stat. § 37-1-101(a)(vi)(C), subject to the Commission's general and exclusive jurisdiction to regulate it as a public utility in Wyoming pursuant to Wyo. Stat. § 37-2-112.

170. Proper public notice of these proceedings was given in accordance with the APA, Wyo. Stat. § 37-2-203 and the Commission's Rules, specifically Section 106. The public hearings were held and conducted pursuant to Wyo. Stat. §§ 16-3-107, 16-3-108, 37-2-203, and applicable sections of the Commission's Rules. The interventions of the Parties were properly granted, and the entities that intervened became parties to the case for all purposes.

171. RMP's current retail electric utility service rates in Wyoming are inadequate, unrenumerative, and should be increased, but only to the extent provided for in this *Order*. In that regard, the Commission makes its conclusions in the public interest based in the Findings of Fact set forth in paragraphs 29 through 159 above.

Decision

172. Based on our conclusions and findings, we have determined RMP's capital structure should be:

Component	**Percent of Total**	**% Cost**	**Weighted Average**
Long Term Debt	48.551%	5.20%	2.525%
Preferred Stock	0.016%	6.75%	0.001%
Common Equity Stock	51.433%	9.50%	4.886%
	100.000%		7.412%

This capital structure is based on a five quarter average methodology. It is consistent with the Company's application of the five quarter average in prior rate cases and facilitates comparisons over time. The parties have agreed to the percentage costs for Long Term Debt and Preferred Stock.

173. To determine Return on Equity, we find the heavier reliance of OCA and WIEC on technical models to adequately account for risk generally to be more persuasive than the Company's approach of tempering the technical inputs and results with other factors. Specifically, we are not persuaded there is an imminent risk of inflation. We place no reliance on the recently approved settlement returns on equity for Cheyenne Light Fuel & Power and Black Hills Power because these companies present a different risk profile from RMP, and the settlements were considered reasonable as a whole, without regard to a determination of the accuracy of individual elements of the settlements. We similarly place no significant reliance on previously approved RMP settlements, which were also but one element of an overall package, although we have taken into account the magnitude of the movement from the previously approved settlement return on equity. We place no reliance on returns on equity determined by other jurisdictions, which are the result of specific considerations unknown to us, facts not included in our record, and policy judgments which may not be the same as our own. We were not persuaded by Hadaway's general assertion of an inverse relationship between equity risk premiums and interest rate levels, in part for reasons offered by Gorman. We did note, and find significant, the substantial downward reduction in technical modeling results disclosed in RMP's rebuttal case. Taking all of these factors into account, and taking into account all of the results of the technical models of both parties, we find and conclude 9.5% to be a just and reasonable return on equity.

174. The Commission finds and concludes the Company has not carried its burden of persuasion for the adoption of the IHS-Global Insights operations and maintenance escalation factor. Whether or not utility sector cost inflation is real, the Company has not shown that the prospective inflation is fairly captured by the IHS-Global Insights factor. WIEC, in particular, raised significant questions about the factor's accuracy viewed from the standpoint of what we had approved in previous proceedings, and how actual costs proved to be materially lower than the factor had projected. WIEC's factual critique was not adequately rebutted by the Company's argument that the lower actual costs were the result of the Company's own actions to control costs. In reaching this conclusion in this case, we note that OCA and WIEC agreed to some specific adjustments to cost items which could fairly be characterized as operations and maintenance costs. Further, we do not foreclose a future showing by the Company that accuracy of the factor has improved, or some other factor should be used. Finally, by making this finding, we conclude the Company's request for a productivity offset is moot.

175. With regard to the issue of placing RMP's pre-paid pension asset in rate base, we found RMP's position persuasive and conclude the pre-paid pension is an asset that is appropriate to place in rate base. We reach this conclusion subject to the OCA's recommended offset, accepted by Stuver on behalf of the Company as an "equitable alternative" to the Company's proposal, and in the nature of a "transitional item."

176. Where RMP's proposed level of legal expenses is consistent with the experience of previous years, we decline to remove selected litigation expenses from a calculation resting on consistent past practice. We acknowledge that in any specific case, expenses may be difficult to control and adverse results can and will occur from time to time. Further, we note that the adverse result in one case is subject to a pending appeal. Overall, we conclude that the Company's legal expenses, as requested, should be included in this case.

177. We have been asked to reduce the labor expenses requested by RMP due to a substantial number of open positions, and decline to do so. This is generally in the domain of Company management's authority, and we found the testimony on this subject to be credible and reasonable. There has been no evidence of a prolonged or intentional pattern of failure to take initiative to fill the open positions.

178. With regard to RMP's estimated overhaul expenses for the Lake Side 2 and Carbon Plant, we consider the two plants to present separate issues. For Lake Side 2, we find and conclude the forecast of overhaul expenses is reasonable and should be included. For the Carbon Plant, we are not persuaded by the Company's argument that the Carbon Plant expenses will never be recovered, because the four year average used to determine the expense allowance is forward looking. The Company's argument is not made more compelling by its proposal to only ask for a portion of the actual past Carbon overhaul expenses in its four year average, particularly since the Carbon plant is to be shut down in the near future. Therefore, we conclude the overhaul expenses of the Carbon Plant should be excluded from the four year average calculated in this rate case.

179. The Company requested a one-time recovery of the Carbon Plant labor and non-labor operations and maintenance expense required to operate the Carbon Plant until its April 2015 retirement, subject to an agreement between RMP and WIEC to net that expense against the

prospective Carbon Removal Costs. We approve this one-time recovery. However, since this is not a normal calculation, as part of the Company's reporting of Removal Costs, the Commission directs the Company to provide an accounting which clearly shows what the labor and non-labor O & M expenses were, and how they were applied to Carbon Removal Costs.

180. In considering including Allowance for Funds Used During Construction costs associated with the Blundell Well Installation and Well Integration Project in rate base, we conclude the Company's explanation is reasonable and the costs are prudent. As such, these costs should be treated as the Company has proposed.

181. We conclude the following unchallenged RMP capital projects should be included in rate base:

(1) the Company's investment in Lake Side 2 in the amount of $105,000,000;

(2) the Company's investments in the Mona-to-Oquirrh and Sigurd-to-Red Butte transmission resources in the amounts of $59,000,000 and $58,100,000 respectively;

(3) the Company's investments in the Carbon Plant Replacement Project and the Standpipe Substation Project in the amounts of $7,400,000 and $4,300,000 respectively;

(4) the non-main grid transmission investments and distribution investments in the amounts of $32,100,000 and $50,100,000 respectively;

(5) the expense of the Merwin fish collector project in the amount of $9,400,000; and

(6) the expense of the Hunter Unit I environmental compliance project in the amount of $13,900,000.

182. We find the testimony of Teply persuasive and conclude RMP's investment in Hayden Unit 1 environmental compliance project is prudent and appropriate.

183. In deciding the issues in rebuttal, we conclude the ten items agreed to between WIEC and RMP should be accepted as reasonable and prudent. Additionally, we accept WIEC's position on the remaining two items as being reasonable and prudent as well. All twelve items are presented in paragraphs 84 through 97 in the Findings of Fact above and will not be further addressed here.

184. As a part of setting base net power costs (NPC), we have been asked to determine benefits associated with the establishment of an Energy Imbalance Market (EIM) in conjunction with the California Independent System Operator (CAISO). Costs of approximately $800,000 are not in dispute. While we agree with the Company that [i] the E3 Report was not intended to measure specific benefits in this context and [ii] there are substantial uncertainties about how the EIM market will evolve, we also find that (a) E3 is a reasonable starting point, one that was adjusted by Mullins; (b) RMP didn't offer a better starting point, or any alternative other than to set benefits equal to costs; and (c) RMP provided little comfort that it would be able to calculate

benefits as the EIM progresses. Coupled with RMP's interest in having at least a year's worth of data, probably delaying an analysis into 2016, ratepayers have a legitimate concern that the determination of benefits could be subject to considerable delay. Further, whatever assessment is ultimately done may well have to be a stand-alone effort like the E3 study, rather than flowing readily from data generated by the operation of the EIM. We conclude the just and reasonable solution is to shade RMP's number upward toward WIEC's evaluation. We accordingly conclude the benefit amount should be set at $2,600,000, or the approximate midpoint between RMP's proposed benefits, about $800,000 and the $4,400,000 resulting from Mullins' revised version of the E3 approach, which accounts for some of Duvall's criticisms and adjusts for the forecast test period. Our decision in this issue renders moot the question of whether any market caps currently in GRID should be removed, since this WIEC proposal assumed the Commission would not set EIM benefits.

185. We conclude the two swap gas contracts with J. Aron & Company should not be removed from NPC as we are persuaded by the Company's position that Goldman Sachs is not an "Affiliate" of Berkshire Hathaway. We also rest our conclusion on the fact that WIEC offered no evidence of impropriety.

186. On the question of whether wind and load integration charges should be excluded from NPC, we accept the Company's explanation and position.

187. We decline to establish new and additional criteria for inclusion of Qualifying Facilities (QFs) in NPC, in part because such criteria may ultimately be deemed to add burdens above those required by the Federal Energy Regulatory Commission. However, we think it appropriate to exclude specific QFs from NPC when they are not used and useful during the test period. Where, as here, that question has been fairly raised during a proceeding before this Commission, through testimony that the project is not yet under construction and is not expected to achieve commercial operation during RMP's test period, the burden of responding to such specific concerns must rest with the Company. We find that the Company has not so responded with respect to the Latigo Wind Park, which should therefore be excluded from NPC.

188. We conclude WIEC's proposed heat rate/minimum capacity adjustment should not be adopted, and further conclude WIEC has identified a problem that should be addressed by RMP through improved modeling. We direct the Company to include appropriate improvements when filing its next general rate case.

189. Based on the Company's testimony, we accept the Company's position, and conclude the three lengthy outages to which WIEC has objected, Colstrip 4, Lakeside 1 and Gadsby 4, should not be removed from the averaging of historical outages used to set NPC.

190. We find and conclude that RMP's explanation regarding start-up energy costs is reasonable and decline the changes proposed by WIEC. However, we request the Company to provide a more precise accounting of start-up energy costs when filing its next general rate case.

191. With regard to WIEC's request to remove costs related to non-owned wind integration, we conclude that all such costs are not presently recovered under OATT Schedules 3, 3A, and 9, and find the Company should continue to pursue that objective. We direct the Company

to report to this Commission on its progress with changes to the FERC tariff no later than the filing of the next general rate case.

192. We accept RMP's explanation regarding possible adjustments of its short-term non-firm transmission modeled in GRID. Therefore we decline to make any adjustments to RMP's short-term non-firm transmission included in the Company's NPC.

193. We accept RMP's explanation regarding possible adjustments to the Company's modeling assumptions in GRID for the Black Hills Power and UMPA II Contracts. Therefore, we decline to make WIEC's adjustments on this issue.

194. We accept the adjustment to GRID regarding the continued operation of Naughton 3 as a coal-fired unit, as agreed to by the Parties, and accept the testimony that Naughton Unit 3 will continue to operate as coal facility throughout the test period.

195. We conclude RMP's revised class cost of service study using the classification and allocation methodologies adopted for prior cases should be approved. However, with a concern for the pending multi-state protocol process, we direct RMP to prepare a system-wide loss study that includes the development of specific disaggregated transmission loss factors to more accurately reflect the different varying voltage levels on which Schedule 48T customers are served. This updated loss study should address the inconsistencies between the demand and energy loss factors. The Company should prepare a schedule for this study in consultation with Commission staff.

196. We approve RMP's proposed rate spread and rate design, which is based on methods approved in prior rate cases and which continues to collect between 99 and 101 percent of class target revenues derived from the class cost of service study.

197. Based on testimony offered by OCA and NLRA, we conclude RMP's request to increase the residential basic service charge from $20.00 to $22.00 should be denied.

198. We conclude that approval of RMP's proposed changes to Rule 12 of its tariff dealing with line extensions is appropriate with the following adjustments: (1) the Company's $1,300 residential line extension allowance should remain unchanged, and (2) the Company should be responsible for the cost of upgrades at such facilities at or above 115 kilovolts rather than 230 kilovolts. We accept the Company's proposal to maintain the standard of 1.0 times estimated annual revenues. Customers that are currently pursuing projects under the previous standards, as determined by reference to a pending application or documented negotiations as of December 10, 2014, may, at the option of the customer, remain subject to the standards of Rule 12 as it existed prior to the filing of this rate case.

199. We conclude the unchallenged "housekeeping" changes proposed by RMP to Rule 7, metering, and Rule 10, disconnection of service, should be approved.

200. Lastly, we conclude the unchallenged changes to schedule 300, reflecting prices associated with Rules 7, 10, and 12 should be approved.

201. The Commission's conclusions set forth hereinabove are supported by a preponderance of the evidence.

NOW THEREFORE, IT IS ORDERED:

1. Pursuant to the Commission's deliberations held on December 10, 2014, Rocky Mountain Power is hereby authorized to increase its rates to Wyoming customers in an amount consistent with the terms of this *Order*. The increases in rates approved herein, in the amount of $20,188,227 are to be effective with all usage on and after January 1, 2015.

2. Rocky Mountain Power shall provide to the Commission an accounting which clearly shows what the labor and non-labor O&M expenses were, and how they were applied to Carbon Removal Costs.

3. Rocky Mountain Power shall provide a precise accounting of its start-up energy costs when filing its next general rate case.

4. For all non-owned wind integration costs not presently recovered by Rocky Mountain Power under OATT Schedules 3, 3A, and 9, the Company shall continue to pursue the removal of those costs. We direct to Company to report to this Commission on its progress with changes to the FERC tariff no later than the filing of the next general rate case.

5. RMP shall prepare a system-wide loss study that includes the development of specific disaggregated transmission loss factors to more accurately reflect the different varying voltage levels on which Schedule 48T customers are served. This updated loss study shall address the inconsistencies between the demand and energy loss factors. The Company shall prepare a schedule for this study in consultation with Commission staff.

6. The Parties shall promptly hereinafter handle all confidential information in their possession in accordance with and at the time specified in paragraph 8(e) of the *Protective Order* issued May 1, 2014.

7. Any revised tariffs or rate schedules not already approved by the Commission shall be filed with the Commission for approval, consistent with the terms of this *Order*, within two weeks of its issuance.

8. This *Order* is effective immediately.

MADE and ENTERED at Cheyenne, Wyoming, on January 23, 2015.

PUBLIC SERVICE COMMISSION OF WYOMING

ALAN B. MINIER, Chairman

WILLIAM F. RUSSELL, Deputy Chairman

(SEAL)

KARA BRIGHTON, Commissioner

Attest:

JOHN S. BURBRIDGE, Assistant Secretary