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Transmittal Letter

To: Public Service Commission

From: Division of Public Utilities

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Date: May 20, 2016

Docket: Docket No. 09-035-15: In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism.

Pursuant to the Public Service Commission of Utah's Corrected Report and Order in Docket No. 09-035-15, dated March 3, 2011. The Division of Public Utilities was ordered to file a "final evaluation of the pilot program, per Item 4, within four months after the conclusion of the third year of the pilot. This pilot program evaluation will include the Division's recommendation as to whether or not the program should be continued as is, modified, or discontinued."[1] This was extended one year in the Stipulated settlement in Docket No. 13-035-184.

The attached report is the Division's "Final Evaluation Report of PacifiCorp's EBA Pilot Program."

cc Service List

[1] Corrected Report and Order, page 79.

FINAL EVALUATION REPORT OF PACIFICORP'S EBA PILOT PROGRAM

By

The Division of Public Utilities
Utah Department of Commerce

May 20, 2016

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INTRODUCTION

This report is made in response to the Public Service Commission of Utah's (Commission) Corrected Report and Order in Docket No. 09-035-15, dated March 3, 2011 (Corrected Order), wherein the Division of Public Utilities (Division) was ordered to file a "final evaluation of the pilot program, per Item 4, within four months after the conclusion of the third year of the pilot. As described below the due date of the evaluation report was extended one year. This pilot program evaluation will include the Division's recommendation as to whether or not the program should be continued as is, modified, or discontinued."[2] This was extended one year in the Stipulated settlement in Docket No. 13-035-184.[3]

Throughout the narrative below this final evaluation report will be referred to as "the Report." The Division previously filed on May 22, 2014 its "Preliminary Evaluation of PacifiCorp's EBA Pilot Program," which will be referred to as the "Preliminary Report." The program referred to is PacifiCorp's ("the Company," "Rocky Mountain Power," or "RMP") energy balancing account (EBA) that was established through Docket No. 09-035-15. "Item 4" is the following direction from the Commission:

> 4) The pilot program shall evaluate, at a minimum:
>
> a) The sharing mechanism;
> b) which net power cost components are controllable and which are uncontrollable and whether the sharing element should be eliminated from the uncontrollable costs in the EBA;
> c) the effects of the EBA on the Company's resource portfolio;
> d) whether the EBA includes the appropriate net power cost components;
> e) the effects of the EBA on the Company's hedging decisions and level of market reliance on net power cost;
> f) parties' incremental costs to audit the balancing account;

[2] Corrected Report and Order, page 79.
[3] On April 14, 2016 the Division requested an extension of the due date to May 21, 2016. The Commission granted the extension on April 18, 2016.

g) unintended consequences resulting from the EBA; and,
h) monthly vs. annual accrual differences.

Subsequent to this Corrected Order, the Division filed an evaluation plan with the Commission. In its order dated June 15, 2012, the Commission accepted the Division's evaluation plan with the following comments:

> For the EBA Pilot Program Evaluation Plan, the Division proposes evaluating the following issues: auditing, monitoring, and assessing the EBA; EBA agreement or disagreement by the Division and interveners; net power cost variability; electric rate variability; effect on Company return on equity; Company plant and power usage and performance; and other issues. The Division will evaluate whether the Company and customers are better or worse off and lists various issues or criteria it will evaluate...
>
> We accept the Division's evaluation plan as an addendum to item 3 of our EBA Order subject to the following guidance. We direct the Division to: 1) expand its evaluation of changes to integrated resource planning to include the issues identified by the Office; 2) work with the Office to develop baseline performance metrics for evaluation of plant performance under the EBA; and 3) include evaluation of a dynamic composite NPC allocator as discussed in our May Order. Finally, we take note of the Division's intent to examine Security Exchange Commission ("SEC") reports to evaluate the effect of Utah's EBA on the Company's earnings. We look forward to understanding how the Division will determine the Company's earned return in Utah from total company SEC financial reports. We understand the Company's earned return in Utah can be determined only through the Company's semi-annual results of operations reports. We remind the Division Utah ratepayers are not responsible for the earnings results PacifiCorp experiences in other jurisdictions. The pilot program evaluation plan items are summarized at a high level and included in the Attachment.[4]

However, in the Stipulation settling the general rate case in Docket No. 13-035-184 dated June 25, 2014, and which was approved by the Commission, Rocky Mountain Power and the other parties agreed to a one year extension of the EBA pilot program which included a one year

[4] Report and Order on EBA Filing Requirements and Pilot Program Evaluation Plan, Docket No. 09-035-15, June 15, 2012, pages 4 and 11.

extension on the due date of the Division's final evaluation report.[5] The Division understands that this stipulation made the due date of this evaluation report April 30, 2016.

During the just concluded 2016 legislative session, through legislation designated as SB 115, Rocky Mountain Power successfully sought changes to the EBA. Specifically this legislation altered the Commission-ordered pilot program process and, beginning June 1, 2016, nullified the 70-30 sharing bands, giving the Company 100 percent recovery. Other pilot program terms do not appear to have been altered by the legislation. The 70-30 sharing bands had been supported, or at a minimum not opposed, by all of the parties in this docket (Docket No. 09-035-15) with the exception of Rocky Mountain Power itself. The legislation regarding the sharing band is time-limited and is to be in effect through December 2019. The Commission is required to report to the legislature each year regarding the program.[6]

In the current tariff Docket No. 16-035-T05, at least one party argued that SB 115 had no effect on the EBA's status as a pilot program and that it is still scheduled to end this year; alternatively the legislation may merely have extended the pilot program through the end of 2019. The Company in its initial filing in that docket implicitly assumed that the pilot program was terminated by the legislation. Presumably the Commission will make a decision on this issue in Docket No. 16-035-T05.

In spite of the changes mandated by SB 115, the Division believes that it is still obligated to file this final evaluation report on the EBA pilot program. In preparing this report the Division has consulted with the Office of Consumer Services (Office), solicited comments from intervenors in the Docket, and submitted data requests to the Company.

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[5] Stipulation in Docket No. 13-035-184, paragraph 26, pages 7-8.
[6] For details on this legislation see http://le.utah.gov/~2016/bills/static/SB0115.html

SUMMARY AND RECOMMENDATIONS

The Division approached the EBA pilot program as a learning experience for it, the Company, and other interested parties. In this regard the Division and its consultant have tried to work with the Company on developing solutions to many problems that it initially faced in order to improve the process going forward. Each year of the EBA there have been a number of issues that the Division has worked through with the Company. After the first two EBA seasons passed, in 2014 the Division initially believed at the start of the third EBA season that most of the significant issues had been resolved. However, as the annual EBA process in Docket No. 14-035-31 unfolded there arose a number of problems that were very troubling to the Division. These issues were tentatively resolved via a stipulation executed just two days before the hearing on October 8, 2014. The Division hopes that this was the nadir of its relationship with the Company regarding the EBA audit process. The following 2015 EBA audit season ran much more smoothly with the Company following through on its promises to make information and personnel readily available to the Division's staff and consultants. With the 2016 EBA audit season now underway, the Division hopes and expects the process will continue to run relatively well. In sum with regard to process the Division believes that there has been substantial progress toward developing a well-running program.

The Division sought comments for inclusion in this report from the intervening parties and its consultant, Daymark Energy Advisors (Daymark), formerly La Capra Associates, in this docket regarding the list of Item 4 issues. Only two intervening parties provided comments to the Division. The Division solicited information and comments from the Company via a formal data request. The Company's responses are set forth below in their entirety. The Division comments on each of the Item 4 issues as well as the topics set forth by the Commission in its June 15, 2012 order in this docket.

An issue for the Division is its capability to perform an audit on the EBA. With significant help from Daymark, the Division has been able to review selected net power cost-related items. The Division and its consultants review a sample of purchases and sales with third party counterparties for gas and energy physical transactions and financial derivatives. The Division and its consultants have reviewed certain unplanned outages at the Company's generation plants. The Division also reviewed certain out-of-state special contracts, sampled coal costs, and reviewed certain renewable generation projects mandated by other states for compliance with interstate allocation agreements. The Company's failure to maintain some records related to its transactions has made prudency reviews of those transactions more difficult. The Division believes that the Company has been working to improve its record keeping. The Division has come to realize the depth of *post-hoc* review of transactions required by the EBA is one with which the Company personnel in its Portland trading offices is unaccustomed. The Division is encouraged that the Company has been responsive to Division concerns regarding record-keeping issues. The details of the Division's audits can be found in its audit reports for individual years.

The Division's audits are limited in various ways. First, by Commission order it is time limited: the Company files on March 15 and the Division's audit report is due on July 15, four months later.[7] The Commission decided that it would specify the time period for the audit and avoid setting interim rates.[8] Partly due to the time limitation and partly inherent in the complexity of PacifiCorp's operations and the resource limitations of the Division, the Division's audits are not attestations of the material correctness of the Company's EBA filings, but rather representations that Division staff and consultants looked at a few items and did not make an imprudence determination on any of those items not specifically questioned. This issue is discussed further below.

The EBA has had a major impact on the Division's staffing resources and has required it to expend significant funds for consultants. A portion of this expense is necessary because of the compressed time during which the Division must review the EBA filing. The Division continues to believe this compressed time is not necessary and that an interim rate process would provide for relatively contemporaneous payments to either the Company or customers while allowing for

[7] PSC "Order on EBA Interim Rate Process," Docket Nos. 12-035-67, 09-035-15, 11-035-T10, August 30, 2012, page 12.
[8] Ibid.

a more thorough review. The Division also notes that at least one intervenor reported expenditure of sizable resources in tracking the annual EBA process.[9] Probably at least some other parties, especially the Office, have devoted resources to tracking and reviewing the EBA. These are resources that would otherwise be used elsewhere.

The Company claims that it has incurred no incremental labor costs.[10]

The Division is unable to attribute changes in the Company's operations of its generation plant or in its plans as set forth in its IRP to the functioning of the EBA. The lack of attribution is perhaps partly due to the relatively short time period since the implementation of the EBA, but more significantly is due to other events overwhelming and confounding any detectable statistical effect the EBA may have. For example, it is clear to the Division that external forces such as new federal Environmental Protection Agency rules and proposed rules on thermal plant emissions are significant drivers in the Company's IRP process. Other significant drivers in the IRP relate to the statutes and rules coming out of the various states in PacifiCorp's service territory. With respect to generation plant operations, the Division cannot attribute any variations specifically to the EBA not only due to the relatively few data points, but also due to exogenous and internal factors that overwhelm the likely small effect of the EBA, such as fuel price changes, the Company's EIM agreement with the California system operator, plant additions during the period, and simply the inherent variability from year to year in system operations. Because these and many other factors affect the Company's decision-making in addition to the EBA, the effect of the EBA is lost in the "noise" of the other factors. This does not mean there is no effect or that the effect is necessarily negligible.

Responding to a Division data request, the Company makes some recommendations for changes to the EBA. These recommendations and issues include:

- Eliminate duplicative filing requirements.
- Issues resolved in the general rate cases should not be re-litigated in the EBA.

[9] This was reported to the Division for its Preliminary Report in 2014.
[10] See, for example, the Company's response to the Division's Question 9 below.

- A process for expanding the EBA to include other related costs on an as-needed basis should exist.
- Remove the EBA SAP accounts from the tariff.
- Consider unbundling EBA costs from base rates
- Make changes to the EBA calculation.

These suggestions were also made by the Company in its comments for the Division's preliminary evaluation report that was filed with the Commission on May 22, 2014. One suggestion "remove sharing bands" was made obsolete with the successful passage of SB 115. The Company, or any party, may petition the Commission to make changes to the EBA at any time.

Recommendations

SB 115 altered in significant ways the Commission's EBA pilot program since the Commission is now required to make reports on the EBA to the legislature in 2017 and 2018 and this legislation explicitly eliminated the sharing bands for at least through the end of 2019. The sharing bands were a significant issue to the parties, including the Company, as part of the EBA pilot. In its Order issued in Docket No. 16-065-T05 dated May 16, 2016, the Commission seems to accept that the SB 115 legislation effectively extended the EBA pilot program through 2019.

The Division makes the following recommendations:

- As the EBA pilot program nears its end in 2019, a full evidentiary docket should be established by the Commission to consider changes to, or elimination of, the EBA.
- The mismatch issue should be resolved. The Division outlines a couple of possible remedies below. With a third possibility to simply not worry about it.
- The time period for the Division's audits should be extended to one year and interim rates should be established until the Division can complete its audit.
- Wheeling revenues are an inappropriate part of the EBA and should be eliminated.
- The carrying charge in the EBA should be reset to follow the process the Commission ordered in Docket No. 15-035-69, at a minimum. However, since the 100 percent sharing band may give the Company an incentive to under-forecast net power costs for general

rate cases when it can earn an out-sized carrying charge from the EBA, the Division believes it would be appropriate to reduce the carrying charge to a short-term rate, or eliminate it altogether.

- The Commission should set a schedule for a process in the appropriate dockets, or in a new docket, in order for the Commission to consider these recommendations and allow interested parties to weigh in on the Division's proposals, or recommend their own changes to the EBA.

Conclusions

Based on its experience with the EBA, the Division makes the following conclusions

- The EBA was implemented to benefit the Company, which it obviously has done. The Company is now earning its authorized rate of return.
- Concurrently ratepayers are worse off both in higher rates, but also in terms of risk that the Company was able to shift to them.
- The Division perceives no significant benefits to ratepayers as a result of the EBA.
- Despite taxing the Division's resources, the Division can perform an audit of the NPC accounts with continued help of consultants. While ratepayers and other outside parties may take some comfort that the Division is performing an audit, they need to understand that the Division's audit does not result in an attestation of the material correctness of the Company's net power costs. The magnitude of the task and the lack of contemporaneous information for many expenses ensure the Division's review of the EBA will not include specific prudence reviews of most of the NPC items,

DATA REQUEST RESPONSES FROM PACIFICORP

The Division requested comments from the Company via a formal data request. Some of the comments are duplicative of the answers given to a similar data request for the Division's Preliminary Report. The following are Division's questions followed by the Company's responses.

Question 1:

What changes, if any, does Rocky Mountain Power believe would improve the annual EBA true-up process? Please be specific and detailed along with the reasons why any recommendations would improve the EBA process.

Response:

The annual Energy Balancing Account (EBA) true-up process has improved each year since its initiation, including facilitating information exchange between the Division of Public Utilities (DPU) and Rocky Mountain Power (RMP). The process in its current form is generally satisfactory to RMP.

A few things could be improved, including:

1. Eliminate duplicative filing requirements. Currently the Company provides both the original EBA filing requirements and the additional EBA filing requirements with the annual EBA filing. Elimination of duplicative filing requirements would improve utilization of Company resources and response to issues raised by the parties.

2. Issues resolved in the general rate cases (GRC) should not be re-litigated in the EBA. While parties should have the opportunity to generally review all of the Company's actual EBA costs for the previous year, issues that were resolved in the GRC that established base net power costs (NPC), such as prudence of specific contracts, should not be re-litigated in the annual EBA true-up process. Pursuant to Schedule 94, the EBA provides for a review of the difference between base NPC and actual NPC, as those costs are defined under the Schedule 94. Avoiding re-litigation of resolved issues will improve utilization of Company resources and responses raised by parties.

Question 2:

Does Rocky Mountain Power believe that the current components included in the EBA are appropriate? If not, what changes would the Company recommend?

Response:

A process for expanding the Energy Balancing Account (EBA) to include other related costs on an as-needed basis should exist. At a minimum, the following components should be added to the current EBA true-up:

1. Generation costs that vary with megawatt-hour (MWh) production, but not currently included in net power costs (NPC) such as costs of chemicals and reagents, which increase significantly with the addition of new environmental controls at the Company coal plants, and start-up fuel at certain thermal generating units.

2. Renewable energy production tax credits (PTC) are benefits that are directly correlated with generation output and are clearly and closely related to the generation process.

3. Variable costs associated with the Company's participation in the Energy Imbalance Market (EIM). While it is anticipated that essentially all of the benefits of EIM will flow through NPC, not all of the variable costs of EIM will be recorded in accounts that are included in the EBA. Including the variable costs of EIM in the EBA will provide consistent treatment of both the costs and benefits of EIM.

Question 3:

Has the EBA pilot program had an effect on the PacifiCorp's resource portfolio both its current portfolio and its IRP preferred portfolio? Please explain.

Response:

No. PacifiCorp's Integrated Resource Plan (IRP) preferred portfolio identifies a portfolio of resources to meet the projected peak load requirements plus a planning reserve margin (PRM). The projected peak load requirements in the IRP studies reflect historical actual load, regardless if an energy balancing account (EBA) mechanism is in place.

Question 4:

Please describe how the EBA pilot program affected PacifiCorp's hedging program.

Response:

The Energy Balancing Account (EBA) pilot program has had no impact on PacifiCorp's natural gas and power hedging program. PacifiCorp's hedging program is designed consistent with the guidelines that resulted from collaborative hedging workshops with stakeholders.

Question 5:

Has the EBA pilot program affected the level of PacifiCorp's reliance on Front Office Transactions? Please explain.

Response:

No. The Company must plan to provide a least-cost, least-risk portfolio of resources, and it must operate its resources in a prudent manner. Those standards apply regardless of the existence of an energy balancing account (EBA) in Utah, and consequently the EBA has no impact on the Company's day-to-day operations.

Question 6:

Is Rocky Mountain Power aware of any unintended consequences resulting from the EBA? If so, please identify and explain the unintended consequences that you believe are occurring.

Response:

No.

Question 7:

Does the Company believe that after approximately two years[11] into the EBA pilot program, there is a good level of understanding of the PacifiCorp EBA filings and the EBA process among intervenors? Please explain.

Response:

While Rocky Mountain Power (RMP) cannot speak for intervenors, it appears there is a generally good level of understanding of the Energy Balancing Account (EBA) filings and the established process. Disputed issues have generally focused on the prudence of EBA costs rather than the EBA modeling or calculation.

Question 8:

Does the Company believe that the level of dispute and controversy during the annual EBA true-up is "too low," "too high," or "just right"? If your answer is other than "just right," what do you think could be done differently? Please explain.

Response:

Just right.

[11] The Division in its data request had "four years" and the Company responded with "two years." The response appears to be copied and pasted from the Company's comments for the Division's Preliminary Report.

Question 9:

Please describe and document the incremental [ ] cost burden the Company incurs in its administration of the EBA process.

Response:

The Company has not incurred any incremental labor costs in administering the Energy Balancing Account (EBA).

Question 10:

What specific efforts has PacifiCorp made to control and reduce net power cost variability over the past three years? Please explain.

Response:

PacifiCorp's net power cost (NPC) variability from plan occurs primarily due to changes in the volume of energy to be balanced and changes in market prices.

PacifiCorp cannot control the weather driven variability affecting the volume of retail load, wind generation and hydro generation. However, PacifiCorp works to reduce the risk of volume variability through the use of forecasts for load, wind and hydro resources, and by managing, to the extent it can, the thermal resource availability and dispatch. PacifiCorp produces and / or subscribes to forecasts for its load, wind and solar generation and hydro generation at a granularity of five-minutes, 15-minutes, hourly and daily.

Additional efforts PacifiCorp has made in the last three years to reduce NPC and increase reliability include its decision to participate in the California Independent System Operator's (CAISO) Energy Imbalance Market (EIM) starting in November 2014. The EIM has the benefit of increasing reliability and lowering NPC by integrating renewable resources over a broader region and offsetting changes in output through regional diversification. EIM also provides for more efficient dispatch in the real-time market by automating dispatch every five-minutes and 15-minutes within and across the PacifiCorp, Nevada Energy and CAISO Balancing Authority Areas (BAA). Lastly, EIM reduces the flexibility reserves needed by aggregating the load, wind and solar variability across the combined BAAs.

Market prices, among other things, are a function of load, wind, thermal unit availability and hydro generation. To manage market price risk, PacifiCorp maximizes the number of counterparties with which it can transact, pursuant to the terms of PacifiCorp's Energy Risk Management Policy, to maintain a deep market. In addition, PacifiCorp uses its forecasts of load, wind and hydro to minimize the amount of balancing required in the real time market. PacifiCorp continues to use forward hedges of natural gas and electric power to reduce NPC volatility due to forward market prices. These hedges are consistent with PacifiCorp's hedging policy and guidelines that resulted from the Utah hedging collaborative. The hedging policy reflects Utah stakeholders' risk tolerance and their desire to leave a level of exposure to the market so customers can benefit from potential favorable market movements, while also incurring the risk that market movements could be unfavorable.

Question 11:

Please identify and explain any other issues with the EBA that you want to bring to the Division's attention.

Response:

While the Energy Balancing Account (EBA) process is generally satisfactory, is working well mechanically and should continue, there are some areas in addition to those listed in the Company's response to DPU Data Request 20.1, where it could be improved. The Company makes the following recommendations:

1. **Remove the EBA SAP Accounts from the tariff.** Identification of SAP Accounts could still be provided annually with the EBA filing as part of the filling requirements, but including all of the accounting detail in the tariff makes the tariff too detailed for the typical customer.

2. **Consider unbundling EBA costs from base rates.** While EBA costs are differentiated by month, prices in the retail schedules do not change by month. This makes measuring actual recovered EBA costs problematic.

3. **The EBA calculation.** The EBA deferral should be the difference between the EBA costs collected in base rates and the Utah allocated Actual EBA costs. If EBA costs are not unbundled from base rates the EBA costs collected in base rates would be determined by first dividing the Base EBA costs set in a general rate case (GRC) by the billing determinants from the GRC to arrive at a EBA costs base rate. That base rate would be then be multiplied by the actual Utah sales for the month to determine the EBA costs collected in base rates. The EBA deferral would be equal to the difference between the monthly EBA costs collected in base rates and the monthly Utah allocated Actual EBA costs.

$$EBA\ Deferral_{Utah,Month} = \left[Actual\ EBAC_{Utah,Month} - \left(EBAC\ Base\ Rate \times Actual\ Sales_{Utah,Month}\right)\right]$$

INTERVENOR COMMENTS

For its Preliminary Report the Division solicited comments from intervenors and received two responses. The responses from these two intervenors were given lengthy summaries in that report and are not repeated here. For the current report the Division also solicited comments from intervenors; there were also two responses. One response was from the Utah Association of Energy Users (UAE). UAE's comments dealt primarily with the sharing bands component of the EBA and the question of controllable versus uncontrollable costs. UAE argues for the reinstitution of the 70/30 sharing bands and does not support making a distinction for costs claimed to be controllable versus uncontrollable. With permission, the entire UAE comments are attached as Attachment 1.

The other intervenor asked that its response to the Division's survey be kept confidential, but with the understanding that the Division could make some general statements about those comments. This intervenor set forth a lengthy list of topics that it wanted the Division to include in this Report or items to be investigated by the Division, perhaps for use in a general rate case. Concerns were expressed for the loss of the 70/30 sharing band, the move by the Company to become more connected with the California Independent System Operator (CAISO), and the relationships between joining CAISO, Oregon legislation and Utah's SB 115. Perceived structural problems with the EBA were listed and the Division was asked to consider, investigate, and recommend changes. Finally, based on these various apparent flaws, this intervenor encouraged the Division to recommend that the EBA was not in the public interest and should be eliminated or significantly restructured.

In the current tariff Docket No. 16-035-T05 parties made comments that are relevant to the EBA process generally. For example, the intervenor group known as UIEC made the following comments to the Commission:[12]

[12] Comments of Utah Industrial Energy Consumers, Docket No. 16-035-T05, May 2, 2016, paragraphs 4, 5, and 8. http://www.psc.state.ut.us/utilities/electric/elecindx/2016/16035T05indx.html last accessed May 5, 2016.

The EBA statute provides that the Commission may allow an energy balancing account to go into effect only if it finds, among other things, that it is in the public interest. Utah Code Ann. § 54-7-13.5(2)(b)(i). The purpose of the Pilot Program was to implement the EBA on a temporary basis and then to investigate whether (under the procedures put in place in Docket No. 09-035-15), an EBA could operate in a way that would be in the public interest. *See* Report and Order, Docket No. 09-035-15 (March 2, 2011).[13] That investigation is still under way.

Now that SB 115 has amended the EBA to remove the 70/30 sharing bands (which have been in place since the Commission's order in Docket 09-035-15),[14] it is even more important that the Commission complete its evaluation of the Pilot Program to determine whether the EBA is in the public interest. The 70/30 sharing mechanism was put in place because it was thought that to give the Company 100 percent recovery on excess power costs would act as a disincentive to minimizing power costs. To avoid authorizing an EBA that would be contrary to the public interest, the Commission required a 70/30 sharing of the risk.[15] Without the sharing mechanism, the Commission may find it much more difficult to conclude that the EBA is "in the public interest." For that reason, a thorough

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[13] In its Order approving the Pilot Program, the Commission explained:

> <u>To serve the public interest and to ensure just and reasonable rates, most importantly this new mechanism must fairly allocate risk between customers and shareholders, maintain incentives to operate efficiently, both in the long-run and short-run, and satisfy the requirements of the Energy Balancing Account statute</u>. Achieving these objectives is a complex endeavor due to many factors, including another recent statute which allows the Company to request rate changes outside of a general rate proceeding for major plant additions. Both the major plant addition and Energy Balancing Account statutes complicate the traditional ratemaking process of matching all costs and revenues over a given time period to determine just and reasonable rates. <u>We therefore approve a balancing account on a pilot basis and apply the principle of gradualism as we design and implement this additional ratemaking mechanism</u>.

Report and Order, Docket No. 09-035-15 at 67 (March 2, 2011) (emphasis added).

[14] SB 115 states:

> (d) Beginning June 1, 2016, for an electrical corporation with an energy balancing account established before January 1, 2016, the commission shall allow an electrical corporation to recover 100% of the electrical corporation's prudently incurred costs as determined and approved by the commission under this section.

SB 115 at lines 558-61, codified at Utah Code Ann. § 54-7-13.5(2)(d).

[15] In its order approving the EBA Pilot Program, the Commission explained the reason for the sharing mechanism:

> We recognize ... *relying solely on prudence reviews will shift too much of the risk for suboptimal planning and operation currently borne by the Company, who is in the best position to manage this risk, to customers, who are not.* Therefore, the balancing account we adopt requires both Company customers and shareholders to remain at risk for a portion of the actual net power cost which deviates from approved forecasts. This decision recognizes the value of Company management having meaningful financial incentives to minimize net power cost in the short-run and long-run, regardless of the extent of net power cost volatility. *We find a sharing mechanism is the best method, at this point, to ensure customer and shareholder interests are aligned and the public interest is maintained.*

Report and Order, Docket No. 09-035-15, at 70 (emphasis added).

evaluation of the Pilot Program is essential to determine whether the EBA should continue on a more permanent basis…

As the Commission is aware from previous comments and pleadings of interested parties, there are some who believe that the EBA in its current form is not in the public interest, primarily because it unreasonably shifts the risk of power cost recovery to the ratepayers. Were it not for the 70/30 sharing mechanism, the EBA would make the Company's shareholders immune from the consequences of Company decisions that might increase costs,[16] as well as the resource policy decisions of other PacifiCorp jurisdictions.[17] Among other infirmities, the EBA also apparently allows recovery of fixed costs through the EBA (contrary to the EBA statute), may allow double recovery of capacity costs, undercuts the effect of seasonal energy prices on customer bills, and obscures pricing information that customers require to effectively reduce peak demand and energy consumption.

DIVISION'S COMMENTS AND ANALYSIS OF EVALUATION PLAN ITEMS

The Division filed its initial plan for topics to be covered in the EBA evaluation with the Commission on March 1, 2012. The Commission generally accepted, with some amendments, the Division's plan as set forth in its June 15, 2012 report and order. The plan included 21 topics that were listed as Items a through u on the attachment to the June 15, 2012 Report and Order. The Division uses this list to organize its comments below.

a. The Sharing Mechanism

The EBA pilot program provides for a 70-30 sharing percentage of the differences between the baseline and actual NPC. That is, if NPC is higher than the baseline the Company recovers only 70 percent of the difference. If NPC is less than the baseline, it refunds to customers only 70 percent of that difference. As indicated above, the Company has maintained that the sharing

[16] How will PacifiCorp's participation in CAISO, the EIM, and ISO affect the costs that flow through Utah's EBA, and why should ratepayers be solely at risk for the consequences?

[17] Recent legislation in Oregon relating to that state's resource choices may affect the allocation of costs to Utah, potentially increasing power costs that will flow through the EBA to Utah ratepayers. Without modifications to the EBA (or its elimination), Utah ratepayers will be paying for Oregon resource policy choices.

mechanism should be eliminated (effectively making it a 100-0 sharing percentage), and successfully proposed legislation mandating the elimination of the sharing bands until December 31, 2019.

In developing the EBA, the Division supported the 70-30 sharing mechanism to mitigate, among other things, the potential for moral hazard should the Company perceive that it is essentially guaranteed recovery of costs even if the Company makes mistakes in incurring those costs. Whether intentional or not, a utility virtually guaranteed recovery of its expenses is probably less likely to forecast and operate with maximum accuracy and efficiency than one that will bear a part of the difference in projected and actual costs. The Division's experience to date in auditing the EBA supports the view that after-the-fact prudence reviews are, at best, imperfect mechanisms to protect ratepayer interests. (See discussion below).

Most intervenors also supported the 70-30 sharing bands at the time of the inception of the EBA. And as indicated elsewhere, both UAE and the intervention group UIEC continue to support the 70-30 sharing bands.

While not recovering as much as it might wish, the Company is without question better off with the EBA and the sharing bands than it was without the EBA. For five EBA filings in a row—all of them—the Company has shown a net power cost under-recovery versus the baseline established by the most recent general rate case. In requesting an EBA in 2009 (it was originally referred to as an energy cost adjustment mechanism, or ECAM), the Company asserted that it had been under collecting net power costs for eight years in a row.[18] Despite much lower natural gas prices and a significant growth in renewable resources, the Company continues to have net power cost recovery short-falls that are significantly remedied by the EBA. In general, even with the sharing bands the Company has benefited from increased cost recovery, lower risk through nearly guaranteed recovery of a substantial portion of the initial cost shortfalls through the EBA process. Income probably has become less volatile as NPC cost recovery has become more predictable.

[18] See Phase I Rebuttal Testimony of Gregory N. Duvall, page 12, lines 257-262.

Ratepayers have benefited from the 70-30 sharing bands because they have only had to pay 70 percent of the cost recovery shortfalls under the terms of the EBA. There has never been a refund to ratepayers made under the EBA as it has existed. On the downside, ratepayers have had additional risk transferred to them from the Company with the establishment of the EBA, SB 115 shifts more risk.

As argued below in the section reviewing the Division's audit experience, the sharing bands gave some significant comfort to the Division that the Company's incentives were properly aligned with ratepayer interests even when the Division's prudence review of a limited number of net power cost items could not result in an attestation of the material correctness of all net power costs. In the Division's view, the removal of the sharing bands is a significant shift in risk to ratepayers not only in the raw dollar amounts involved but in the manifest lessening of the incentives aligning the Company with ratepayer interests.

b. Controllable versus uncontrollable elements in the EBA.

The Company points out that it cannot control the weather and does not control the prices in the wholesale markets; these factors will always be a source of variability in the actual versus forecast net power costs. The addition of renewable resources in the recent past, and the likely addition of renewable resources in the future through QF power purchase agreements, will potentially add to the volatility of the Company's net power costs. On the other side, the Company is attempting to better manage net power costs by participating in the EIM in California, by improving load and weather forecasting, and through its hedging program. The Division is pleased that the Company has these various efforts underway. Since the Company in advocating the EBA to the Commission in 2009 suggested that there would be times when the baseline NPC would exceed actual NPC,[19] the Division expects the Company to continuously

[19] In its Application dated March 16, 2009 in this Docket, the Company stated "Thus, we are proposing an ECAM mechanism (sic) that is applied symmetrically to safeguard customers when the NPC that the Company actually incurs are lower." See Company Application, page 3, paragraph 5. Further, filed concurrently with the Application, Direct Testimony by Company witness Gregory N. Duvall stated "An ECAM rate will be calculated annually to collect from or credit to customers the accumulated balance over the subsequent year."(See page 2, lines 33-35). Two years later, in Direct Testimony of Gregory N. Duvall on Rehearing filed on July 14, 2011, Mr. Duvall

look for other prudent ways to reduce NPC both in absolute terms and in the variability of actual costs over baseline.

As to the issue of uncontrollable elements in the EBA, the Division notes that every business faces elements in its environment that it can imperfectly control or insure against, which are a significant portion of its business risk. This is why investors in business expect a rate of return that greatly exceeds that of, say, government insured passbook savings rates. Eliminating the risks that the Company has historically dealt with by shifting those risks to consumers, who are even less able to control or insure against those risks than the Company, should be made only with a concurrent reduction in the risk premium included in the Company's allowed rate of return.[20]

Furthermore, as explained by UAE and Daymark in their comments to the Division, all costs are at least somewhat controllable by the Company, especially over time. UAE concludes its comments to the Division with this statement:

> It would be a mistake to attempt to differentiate application of the sharing mechanism by designating certain costs as "controllable" and others as "uncontrollable." While there may be varying degrees of "control" that the utility exercises over various net power cost components, what it (sic) being incented is the Company's *management* of its system, including its *response* to external factors outside its control, such as market prices. This is best addressed with a simple but pervasive incentive mechanism, such as the sharing bands. For example, while RMP may not control market prices, the Company's hedging activities and its exposure to market pricing (whether intra-hour, hourly, daily, weekly, annually, etc.) are a direct result of its management decisions, which in turn impacts net power cost. Moreover, shareholders should also share in risk of NPC cost deviations, irrespective of whether the deviations are caused by controllable or "uncontrollable" NPC components.[21]

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observed "As history has shown, the likelihood of NPC being lower than forecast is much lower than the likelihood of NPC being higher than forecast." (See page 12, lines 247-249).

[20] It remains ironic that the Company once argued for the elimination of an earlier version of the EBA by stating that it was better able to manage risks associated with NPC than customers. See Prefiled Direct Testimony of Verl R. Topham, in Docket No. 90-035-06 p. 13 lines 17 – 26. Mr. Topham was at that time President of Utah Power & Light and Executive Vice President of PacifiCorp Electric Operations Group.

[21] UAE Comments, see page 59 below.

While the issue of controllable versus so-called uncontrollable costs may be mooted by the elimination of sharing bands by SB 115, the Division opposes the categorization of NPC costs into such categories.

c. The effects of the EBA on the Company's resource portfolio.

The Division has not been able to discern any effect of the EBA on the Company's resource portfolio, and as indicated above, the Company denies that there is any effect. In addition to the Company's response above, based upon the Division's participation in the IRP process, it is clear to the Division that external forces are significant drivers in the Company's IRP process such as new federal Environmental Protection Agency's rules and proposed rules on plant emissions. Other significant drivers in the IRP relate to the statutes and rules coming out of the various states in PacifiCorp's service territory. In the future, recently passed legislation in Oregon will likely make system-wide least-cost, least-risk resource planning by the Company increasingly problematic. Topics related to this issue are discussed under Items p and q below.

d. Appropriate Components of the EBA.

The Division generally believes that the current EBA tariff contains the appropriate EBA components.[22] During EBA filings the Division reviews SAP account additions proposed by the Company. The Division's understanding of these additional SAP accounts is that they are merely a subset of the broader GRID-type costs that are included in a general rate case filing. That is, in past general rate cases the Company has based its net power costs on the inputs and outputs of its GRID model.

There are certain situations in which a certain type of cost or revenue has GRID-type characteristics and non-GRID-type characteristics. An example of this kind of situation is the GP Camas adjustment which was included in Docket No. 12-035-67. Division witness Matthew Croft stated the following in his direct testimony in that docket.

[22] The Division will ask the Commission to reconsider the inclusion of wholesale wheeling revenues as part of the EBA since the Division believes that the nature of these revenues is distinct from net power costs.

> In the EBA filing the Company has made an adjustment to FERC Account 555 to include purchased power expenses in the Accounting EBAC for GP Camas or James River Paper Company. This adjustment to Accounting EBAC dollars is needed since the GP Camas expenses are included in base NPC amounts. PacifiCorp receives rental revenues from GP Camas based upon the Company's lease of the generating plant at the mill site to GP Camas. The revenues associated with GP Camas or James River are not included in Base NPC but they are included in general rate case filings.[23] Since these revenues are not included in Base NPC it would not be appropriate to include them in Actual NPC.
>
> Furthermore, the treatment of these rents in NPC is consistent with the Division's view on wheeling revenues.[24] Wheeling revenues are rents the Company receives on its transmission system. The Division believes the Company has accounted for the expenses and revenues for the GP Camas contract correctly and does not believe that the definition of NPC should be expanded to include rents on facilities. Even if the definition of NPC were to be expanded, it would have to take place in a general rate case since that's where Base NPC are set.

In summary, costs from the James River Paper Company contract are included in the EBA while revenues are excluded. To the Division's knowledge, the Company has never advocated that the revenues from James River should be included in the EBA. Interestingly however, the Company does appear to be advocating the inclusion of non-GRID-type EIM costs in the EBA since the anticipated benefits will be included in GRID-type NPC. Why the Company would treat the EIM different from the James River contract is unclear. In order to be consistent with the treatment of the James River contract, one would expect the Company to include GRID-type costs or revenues from the EIM in the EBA but exclude non-GRID-type costs or revenues.

The Company has argued that listing all of the applicable accounts is too complex and difficult for the public to understand. A further problem for the Company is that it makes it more difficult

[23] RMP General Rate Case Docket No. 11-035-200, McDougal Exhibit SRM-3, page 5.2

[24] RMP ECAM Docket No. 09-035-15, Peterson Exhibit 3.0SR (Confidential), October 13, 2010, page21, lines 454 - 463

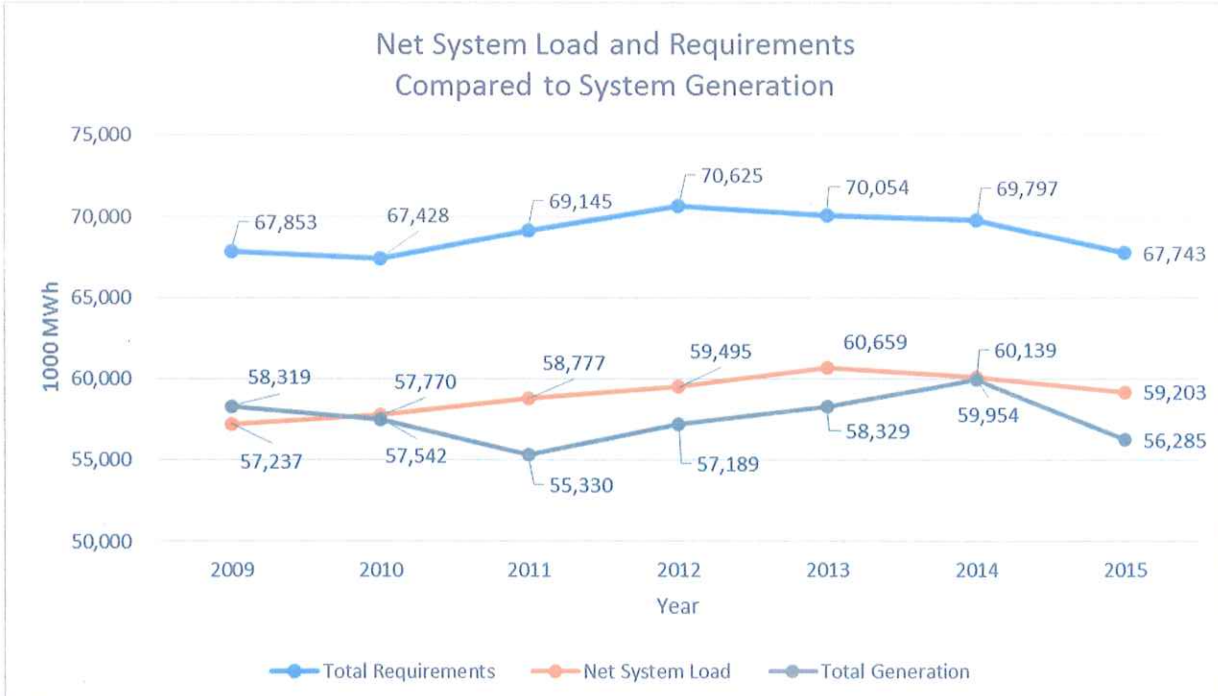
to add to the accounts included in the EBA. The Division is unaware of any customer complaint regarding the EBA tariff. The accounts listed in the tariff are not just for the ratepayers but inform regulators, and the Company, regarding what exactly is included in the EBA. The Division believes that no change to the account presentation in the tariff is required, necessary, or desirable.

e. The effects of the EBA on the Company's hedging practices and front office transactions.

Issues relating to the Company's hedging program were discussed and have been a concern for parties in Energy Balancing Account or EBA (09-035-15), previous general rate cases (09-035-23 & 10-035-124) and in the Natural Gas Price Risk Management docket (09-035-21). In each of these dockets parties provided testimony and expressed concern with the amount and the methods used to hedge the forecast natural gas requirement. As part of the stipulation agreement under Docket No. 10-035-124, parties agreed to convene a collaborative process to discuss appropriate changes to the Company's hedging practices. The collaborative process resulted in revised guidelines for hedging natural gas, which were outlined in a report to the Commission dated March 30, 2012. The stipulated changes to the hedging strategy and the EBA implementation cover the same time period. The Division does believe that the hedging stipulation has had a marked impact on the Company's hedging policies as the Company seeks to follow the stipulation guidelines. As indicated above, the Company asserts that the EBA has no impact on the Company's hedging activities. Based upon its experience with the Company's hedging program both in the EBA dockets and with the semi-annual hedging reports, the Division has no evidence that the EBA is influencing the Company's hedging activities in any material way.

In recent years, the Company has relied more on purchased power and front office transactions compared to self-generation. While the Company is using more purchased power, the reasons may be a function of market prices and state and federal environmental regulation and not the result of the EBA. Below Figure 1 shows the total Company generation compared to the net system load. For the past several years the Company has relied on purchased power and demand-side management programs to meet the balance of the system load requirement.

Figure 1



Source: PacifiCorp's annual NPC report included with its EBA filings, Filing Requirement 17

Between 2009 and 2015 there has been effectively no increase in the the total requirement, and only a 2.48 percent increase in the net system load. Total generation actually declined noticeably in 2015. The largest decline was at natural gas plants, but all categories of generation resources showed declines in output. Recently growth in the requirement has been satisfied with purchased power. The Division is unable to determine if the decision to increase the reliance on market purchases has been influenced by the EBA. Further, because the Company's decisions appear to be market and environmental regulation driven, rather than based on any particular regulatory program, the Division does not believe, at this time, that there are implications for capacity or demand charges.

f. Parties' incremental costs to audit the EBA.

In response to the Division's survey for the Preliminary Report, the one respondent indicated that there was an annual cost of 200 to 300 hours in what are likely consultant and attorneys' fees. These are resources that the respondent could redirect elsewhere if there were no EBA. The Division has no information regarding any other party. As discussed later, the Division has expended much more than 200-300 hours and many dollars in performing its EBA-related functions.

g. Unintended Consequences of the EBA.

As indicated above, neither the Company nor respondents to the Division's survey for its Preliminary Report is aware of any particular unintended consequences.

However, there is a consequence of the EBA as it is currently implemented that arguably is unintended, but it was known going into the EBA pilot program: this is the situation where the EBA period extends beyond, usually by about six months, the test year of the most recent rate case. Thus there is no specific EBA baseline for those months. For example, the test year in a rate case may cover the period from July 1 of year "A" through June 30 of year "B." There is no general rate case with a test year covering July 1 through December 31 of year "B." The EBA filing is for calendar year "B." The practice has been to use as a baseline for July 1 through December 31 of year "B" the amounts for July 1 through December 31 of year "A." The Division has referred to this situation as the "mismatch issue." During periods of generally rising costs, which is expected to be the normal situation, there will likely always be an under-collection of NPC during the EBA period due to this inflation. One solution would be for the Company to forecast NPC for multiple years in a rate case, but then the forecast would have to be put into effect in multiple years to reduce the effect on the annual EBA adjustment. This seems to be undesirable from the perspective that customers would have to endure more rate changes.

Another similar option might be for the Company to file an updated NPC forecast concurrent with its annual March 15 EBA filing that would be for the calendar year that the filing was made. After regulatory review and approval, that updated forecast would become the baseline for the next year's EBA comparison. The updated forecast could go into effect with any changes in EBA collections thus minimizing the frequency of rate changes to customers. The downsides of this proposal is that forecast would necessarily be stale by ten or more months and it would make the annual EBA review more complicated with the necessity to review the updated NPC forecast as well. There may also be a question of the legality of this method, which is roughly equivalent to a partial rate case each year. Other possibilities might exist to resolve this issue. Or, the current practice could be allowed to continue.

An additional change brought about by the EBA is its theoretical effect on general rate case proceedings. As a result of the EBA, for a given revenue requirement in a general rate case proceeding, customers' incentives are to set an NPC figure artificially high and the Company to set the figure artificially low. At any given revenue requirement, an artificially low NPC figure allows the Company greater recovery (or less liability) in EBA proceedings while at the same time collecting a carrying charge that currently is above its borrowing costs. The reverse is true for customers: they can "lend" money to the Company through the EBA at a favorable interest rate. This inverts parties' historical positions on adjustments to NPC items. The Division believes the 70/30 sharing band mitigated these possibly perverse incentives.

h. Monthly vs. Annual accrual differences.

This particular item originated from the Commission's March 3, 2011 Corrected Report and Order in Docket No. 09-035-15. The Division notes that the two main differences between calculating the EBA accrual on a monthly or annual basis revolve around interest expense and allocating total Company EBAC to Utah.

Using a monthly accrual enables the carrying charge on EBA balances to be calculated more precisely. If the EBA accrual was calculated on an annual basis, the carrying charge would be calculated on a single amount that is either positive or negative. Such a calculation assumes the accrual was positive or negative for the entire year while in reality the accrual balance may have been positive for some months of the year but negative for others.

Calculating the EBA accrual on a monthly basis does create slightly more complexity in allocating costs to Utah. Prior to 2015 the Commission required that four allocation methods be calculated and filed with the EBA for its review: the scalar, the "A2 Method," the "Commission Order Method", and the "A3 Method." As a result of the Stipulation in Docket No. 13-035-184, beginning with 2015 only the Commission Method is used given that there was no evidence that the other methods were superior. For informational purposes, a summary of these four methods is shown on Table 1 below with a comparison of the Utah NPC from Docket No. 14-035-31. This table is replicated from the Division's Preliminary Report. As can be seen the overall annual differences were 0.3 percent (0.003) between the methods for that year.

Table 1

Actual NPC Allocation Summary

Method	14-035-31 UT NPC	Description
A2 Method and Commission Method	$ 697,552,380	Applies the **annual** SG and SE factors to total company monthly NPC.
Scalar Method	$ 697,552,380	A scalar is applied to monthly total company $/MWH which is then applied to Utah's load. The scalar is derived by dividing the total UT monthly SE allocated costs by the total UT allocated NPC calculated in the A2 method.
A3 Method	$ 699,655,078	Applies **monthly** SG and SE factors to total company monthly NPC.

i. Quantitative and qualitative assessments of the effect of EBA monitoring on Division staff and resources.

Since the inception of the EBA, the EBA filings have required the greatest collective time and resource commitment of Division staff compared to any other project, with the exception of general rate cases. The complexity of the EBA has also required the Division to retain the services of its consultant Daymark to assist in the audits. In Phase 2 in this docket that created the current EBA, Company expert witness Dr. Karl McDermott opined that the Division would need two full-time equivalent employees to work on the Company's EBA, implying that that wasn't a big deal.[25] The Division suggested that that was a big deal for the Utah Division.[26] As it currently exists, the Division in fact does not and cannot expend the resources that Dr. McDermott suggested would be necessary to adequately monitor and audit the Company's EBA, even with the help of its consultants. The Division is expending approximately one-half the effort that the Company's own expert suggested would be necessary.

The Division once believed that with time, the number of hours required to monitor and review the Company's EBA may decrease, perhaps even eliminating the need for a consultant. At this point the Division is less certain that this will happen any time soon. At a minimum, the Division believes that it will need to employ the services of a consultant for the foreseeable future. To bring the entire EBA process "in-house" would likely require the Division to add staff and to bolster its staff with expertise in engineering and possibly other fields that it currently does not possess. Whether or not the Division could do this at some point in the future is an open question.

j. The level of comprehension by the Division and intervenors.

The Division has no indication that the EBA process is not generally understood, at least at a high level, by interested intervenors.

k. The level of dispute among parties during the true-up process.

As discussed earlier, the Division had considerable difficulties with the Company during the years through 2014. Hopefully that high level of dispute is passed. Other parties have typically not been involved in the annual EBA process. Going forward, the Division expects that the annual EBA true-up process will not be subject to abnormal levels of dispute.

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[25] Oral Testimony of Karl A. McDermott, Docket No. 09-035-15, Hearing Transcript, November 1, 2010, Vol. 1, page 281, lines 15-18.
[26] Oral Testimony of Charles E. Peterson, Docket No. 09-035-15, Hearing Transcript, November 1, 2010, Vol. 2, page 353, lines 10-13.

l. Company progress in smoothing variability of net power cost in addition to the EBA.

As discussed above, the Company reports making positive efforts to improve weather forecasting and has entered into the EIM with the California ISO, among other initiatives. The Division expects the Company to continue to seek other ways to reduce NPC variability and improve forecasts.

Also, see under Item t, below.

m. Changes in Company hedging and front office transactions.

See under Item e, above.

n. Swings in the Company's electricity rates.

The Division has performed an analysis of the historical and going-forward swings in the Company's rates to determine if the EBA resulted in reduction in the rate variability. The table below is a review of Schedule 1 (residential) customers, which would roughly reflect the experience of customers on other rate schedules.

For the purpose of this report, the Division used historical data from the Commission's web site pertaining to rate changes over time for a typical residential customer.[27] The Before-EBA period runs from October 10, 1992 through January 1, 2011, or a little over 18 years. During this time there were 28 rate changes. During this period 14 of the 18 years had rate changes for various reasons. Table 2 sets forth descriptive statistics of these 14 years for which there were rate changes. After January 1, 2011, the next rate change was September 8, 2011. This latter date is taken as the start of the Post-EBA period. The data for the post-EBA period runs through November 1, 2015. There was another rate increase on January 1, 2016, but this was excluded from the descriptive statistics of Table 2. The post-EBA period covers about 5 years. During the post-EBA period there were 24 rate changes. Between March 10, 1992 and January 1, 2011 a

27 http://www.psc.utah.gov/utilities/electric/Rate%20Changes/Rate%20Changes%20Electric%20March%202016.pdf Last accessed May 9, 2016.

typical residential bill[28] increased from $586.44 per month to $768.88 per month, which represents an average annual increase of 1.50 percent. From January 1, 2011 through January 1, 2016 the typical bill increased from $768.88 to $952.94 per month, which represents an average annual increase of 4.39 percent.

Table 2

	Residential Bill Percent Change	
	Before EBA	***Post EBA***
Count	14	5
Mean	1.91%	4.32%
Median	2.08%	3.92%
Sample variance	.00273	.00077
Sample standard deviation	2.73%	2.77%
Minimum	-11.33%	0.87%
Maximum	9.33%	8.38%

While, arguably, the pre- and post- EBA periods had different characteristics that required different rate responses from PacifiCorp, what stands out in these data is that to date the EBA has not decreased the number and amount of rate increases faced by ratepayers and has not decreased the volatility of rate changes as measured by the standard deviation.

o. Return on Equity

One measure of the overall financial health of the Company is the return on common stockholders' equity, a profitability measure which, at its simplest level, is calculated by dividing the annual net income attributed to the common stock by the book value of the common stock. It is interesting to note that there appears to be little correlation between higher authorized returns with higher realized returns.

Consistent earnings and earnings growth are measures that are important to both debt holders and stockholders. PacifiCorp has had a history in recent years of not earning its authorized rate of

[28] A typical residential bill is based upon an assumed 750 kWh monthly usage.

return, as accounted for either on a regulatory basis, or on an SEC basis. Table 3 sets forth the Company's returns on equity since 2006; the first year the Company was owned by Mid American Energy Holdings Company (renamed Berkshire Hathaway Energy in 2014).

Table 3

PacifiCorp
Realized and Authorized Returns on Equity Calculations
2006-2015

		Rocky Mountain Power, December Report of Operations				
Year	SEC Form 10K 1/	System, unadjusted	Utah, unadjusted	Utah, adjusted	Utah AuthorizedReturn on Equity 2/	Effective Date of Return on Equity
2006	9.76%	8.17%	6.13%	7.84%	10.50%	03/01/05
2007	9.79%	8.62%	8.56%	7.47%	10.25%	12/11/06
2008	8.37%	8.70%	7.77%	7.71%	10.25%	08/13/08
2009	8.62%	8.78%	8.45%	8.45%	10.61%	05/08/09
2010	8.08%	8.44%	9.22%	6.70%	10.60%	02/18/10
2011	7.61%	8.24%	7.80%	7.61%	10.00%	09/21/11
2012	7.19%	8.49%	7.89%	8.71%	9.80%	10/12/12
2013	8.84%	9.84%	9.57%	9.17%	9.80%	10/12/12
2014	8.98%	9.72%	10.14%	9.60%	9.80%	09/01/14
2015	9.11%	na	10.15%	9.83%	9.80%	09/01/14
Mean	8.64%	8.78%	8.57%	8.31%	10.14%	

1/ DPU estimates based on the current net income attributable to the common stockholder divided by the average of the common equity balance as of December 31 of the current year and December 31 of the preceding year.

2/ When the ROE changed during the year, the new ROE is shown.
See Docket Nos. 04-035-42
06-035-21
07-035-93
08-035-38
09-035-23
10-035-124
11-035-200
13-035-184

Sources: Rocky Mountain Power, December Report of Operations
To the Public Service Commission, various years.
PacifiCorp SEC Form 10K, various years.

As can be seen on Table 3, the Company reached a low in the 2011-2012 time frame when the EBA was first being implemented in Utah. Actual payments to the Company from Utah ratepayers did not begin until late 2012. Some form of an EBA is available to PacifiCorp in other states. Contributing to the relatively low profitability in 2011-2012 is the timing of rate cases in Utah and other states as well as residual effects from the 2008-2009 recession. In 2013 the reported unadjusted system returns on a regulatory basis approximate the Company's authorized return on equity not only in Utah, but also in the other jurisdictions the Company operates in. However, adjusted, or normalized return on equity was still somewhat below the authorized rate. The data show a clear trend in return on equity since the low in 2010. Adjusted Utah rates of return have increased every year through the end of 2015. By 2015, the Company was earning its allowed rate of return in Utah on an adjusted basis. While there may be other factors in play, the improvement in returns on equity corresponds with the implementation of the EBA in Utah and without question the additional revenue the Company enjoyed as a result of the EBA contributed significantly to this result. The fact that the Company is earning its allowed rate of return in the latest financial report to the Commission has implications going forward with the elimination of the sharing band in the EBA starting in June 2016. To be specific, if the Company can earn its allowed rate of return with the 70-30 sharing band, then it will over-earn without the sharing bands with everything else held constant.

In its Corrected Order, the Commission questioned the value of reviewing system-wide return on equity saying in part that Utah ratepayers are not responsible for what goes on in other states. Because PacifiCorp still operates as an integrated system, the Division believes that this is only partly true. In the case of return on equity and cost of capital generally, the SEC results form the basis for the Company's debt ratings and consequently cost of debt. The Division believes that investors primarily are interested in the SEC results of the Company and not the regulatory results of operations. Less directly, but still consequentially, the cost of equity determined in rate cases is also derived from SEC-based results. For example, the Company is compared to the guideline or proxy companies based upon their SEC filings: the relative risk and hence the expected return is based upon the integrated system. Thus, for better or worse, the results in other states impact Utah ratepayers.[29]

p. Changes to the Company's pre-EBA IRP preferred portfolio and implementation of the Company's IRP action plan.

One of the assumptions in the establishment of the EBA was that the EBA would not affect the Company's efforts to establish a least-cost/least risk generation portfolio. The IRP is developed with public involvement from state utility commission staff, state agencies, customer and industry advocacy groups, and other stakeholders throughout a two-year process. The preferred portfolio selection is determined using system modeling tools that consider cost, risk, supply reliability, uncertainty, and government energy resource policies. The pre-EBA IRP that the Division considered as the baseline was the Company's 2011 IRP, filed on March 31, 2011, with an update filed on March 30, 2012.[30] The post-EBA IRPs were filed on April 30, 2013, with an update filed on March 31, 2014, and March 31, 2015 with an update filed on March 31, 2016. [31]

The Division considered the 2011 IRP preferred portfolio as well as the 2013 IRP and 2015 IRP preferred portfolios. As noted above, the Company's hedging practices and front office transactions have changed in the Company's IRP after the EBA went into effect. However, those changes as well as the preferred portfolio outcomes cannot be directly attributed to the EBA. One survey respondent noted in the Preliminary Report, the possibility that the Company's exposure to risk could be minimized, and therefore there is a potential that the EBA could cause changes to the IRP. However, at this time the Division cannot attribute changes in the Company's IRP to the EBA.

[29] Another area where other states' actions affect Utah ratepayers is transmission and generation resource planning. Utah ratepayers are impacted through PacifiCorp's efforts to reflect the demands and wishes of other jurisdictions in its generation and transmission portfolios.
[30] Docket No. 11-2035-01.
[31] Docket Nos. 13-2035-01 and 15-035-04.

q. Generation Performance Baselines

As set forth in the Introduction, the Commission ordered the Division to "work with the Office to develop baseline performance metrics for evaluation of plant performance under the EBA…." As a result of discussions with the Office, the Division requested certain information on plant performance from the Company. This is also Item q in the attachment list of the June 15, 2012 Report and Order.

The data are collected into tables and charts set forth in Appendix 1. One reason why the Commission and intervenors would be interested in these performance data is the concern that the Company may become lax in maintaining and operating its plants at the highest levels of efficiency given the near-automatic recovery of net power costs through an EBA. Alternatively, as pointed out originally by the Office's representative, the Company might actually have the incentive to maintain and operate its plants at the highest levels of efficiency in order not to jeopardize its EBA. In any case, a detailed discussion of these data follows. The overall conclusion is that to date there is no evidence of the EBA affecting plant performance.

The Division received monthly heat rate data by thermal plant from the Company. These data are summarized on Exhibit A1.1. Besides the Gadsby plants, there are only a handful of instances where the differences between the pre- and post-EBA periods appear noteworthy: the Hayden and Craig plants, Johnston 1, Lake Side 1, and Hunter 2. The differences between the two periods appear to be more or less random fluctuations. Therefore, the heat rate data do not at this time suggest that there is a real difference between the pre- and post-EBA periods.

Exhibit A1.2 summarizes the thermal plant availability and achieved capacity factors. The availability factors actually improved slightly overall between the pre- and post-EBA periods. However, the achieved capacity was lower in the post-EBA period versus the pre-EBA period. This difference appears to be real; that is, the differences are not random fluctuations. It appears that the Company operated its thermal plants differently in the two periods. The actual dispatch of the thermal plants can be affected by a number of factors that are probably more important than the existence, or non-existence, of the EBA such as weather variation, variation and location of demand, availability of renewable generation, and relative prices of fuel and wholesale electricity. Furthermore, during the EBA period in May 2014, the Company began to operate the approximately 650 MW Lake Side 2 facility. The availability of this plant would have an effect on the dispatch of other thermal plants in the Company's fleet. At this time the Division cannot attribute the reduced achieved capacity factors to the EBA.

Exhibits A1.3 and A1.4 provide data on forced outages at thermal plants. In the post-EBA period a number of relatively extreme outage events occurred in 2013, although the total number of outages and the number of operator errors were not exceptional. It appears at this point that 2013 may be a random fluctuation and cannot be attributed to the EBA. Of note is that the Company's reporting of operator errors changed since the Preliminary report, resulting in fewer operator errors reported (now apparently based upon NERC code 9900).

Exhibits A1.5 and A1.6 present data on wind generation mechanical availability and forced outages, respectively. The Company only began collecting wind forced outage data in 2012, so that there is no pre-EBA data to compare it to. The data on Exhibit A1.5 suggest that there is no real difference between the pre- and post-EBA periods. Therefore, the data available do not indicate a systematic deterioration in reliability of the wind generation assets.

Finally, hydro resource data is summarized on Exhibit A1.7. There appears to be a drop in hydro availability after 2011 when the EBA was in effect. Also, there was an increase in the number of forced outage events in 2014; however, the total number of outage hours was lower in the post-EBA period. There is no basis to attribute an EBA effect to these data.

While some statistical differences exist between the pre- and post-EBA periods in the Company's generating plant; there is little evidence at this time to suggest that the differences highlighted above are systematic and related to the EBA. For a variety of reasons, one cannot expect two, relatively short periods to be identical.[32] The value of this exercise is that over time

[32] Differences in weather, changes in load, differences in relative fuel and wholesale prices and forced outages and the addition of the Lake Side II plant all could contribute to one period being different to another.

trends might emerge that then could be investigated for their root causes. At this point the Division makes no attribution to the EBA for the variability in the data cited above.

r. The implicit capacity price.

See under Item e above.

s. Revenue growth by measuring absolute differences between the base and actual net power cost to assess profitability.

See under Item t below. Also see "Preliminary Review of Effects of 100 Percent Recovery on Return on Equity" section, below.

t. The accuracy of GRID in monthly versus annual forecasting.

In order to assess the accuracy of GRID, the absolute differences between base and actual NPC, and the smoothing of NPC variability, the Division compiled data from the previous three general rate cases (Docket Nos. 10-035-124 and 11-035-200, 13-035-184) and all five EBA filings (Docket Nos. 12-035-67, 13-035-32, 14-035-31, 15-035-03, 16-035-01). A summary of those results is shown in the two figures below. The GRID model forecasts are indirectly assessed by using the actual stipulated forecast amounts. Generally the Company's GRID forecast was used as a basis for settlement, but the parties would negotiate a slightly lower total dollar amount. The GRID results were then adjusted downward to reflect the settlement.

Figure 2 shows net power costs, which includes offsetting wheeling revenue. Figure 3 sets forth Utah load amounts. The actual data were taken from the Company's filings in each EBA docket. As identified in the charts' legends, the forecasts were taken from the settlements in the general rate cases. What are identified as the "synthetic" forecasts, are the amounts used by the Company to fill in during periods that the Division has referred to as the mismatch periods, giving rise to the mismatch issue. The mismatch issue reflects those months in which there was no specific forecast in rates from a general rate case to use as a baseline. In those cases the Company practice has been to use the previous in-rates month as the baseline. For example, July 2012 had no baseline number in rates, the Company used the July 2011 forecast that was in rates as the baseline. Prior to the elimination of the sharing bands, the Division considered the mismatch issue to be the most significant issue in the current EBA structure.

Figure 2

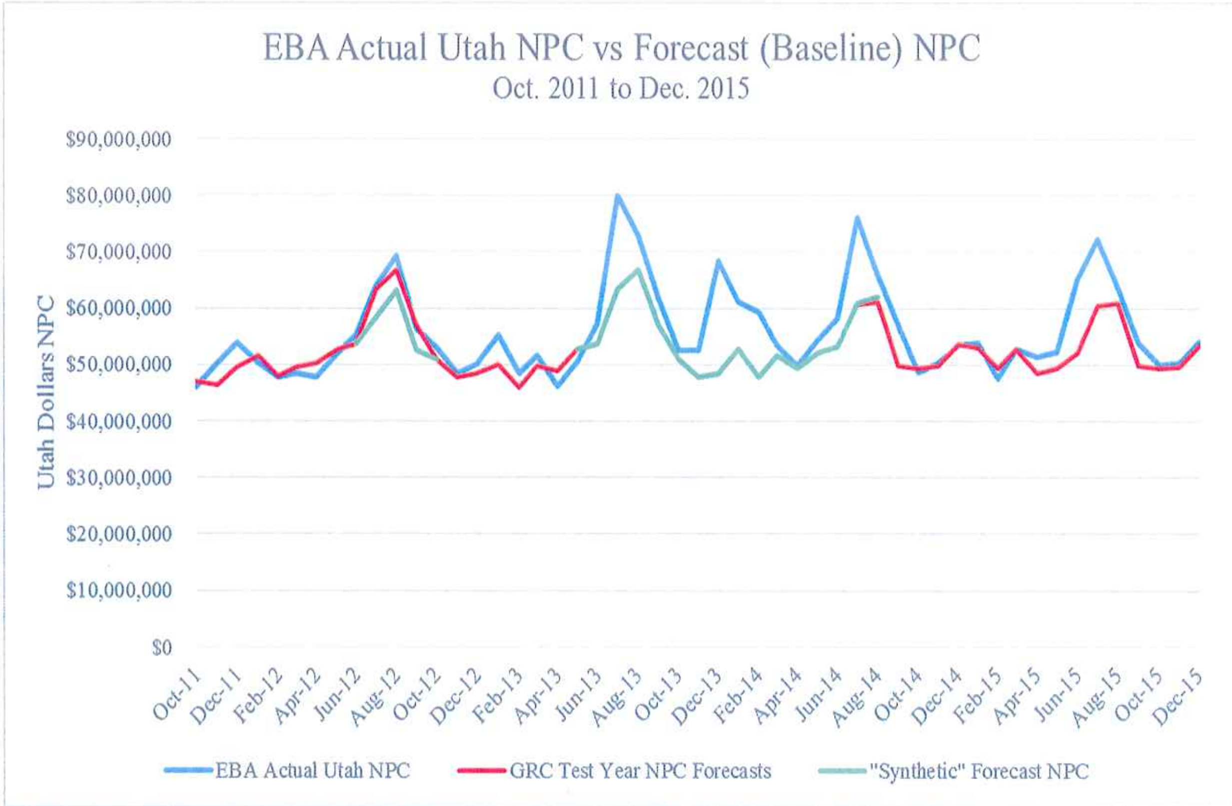
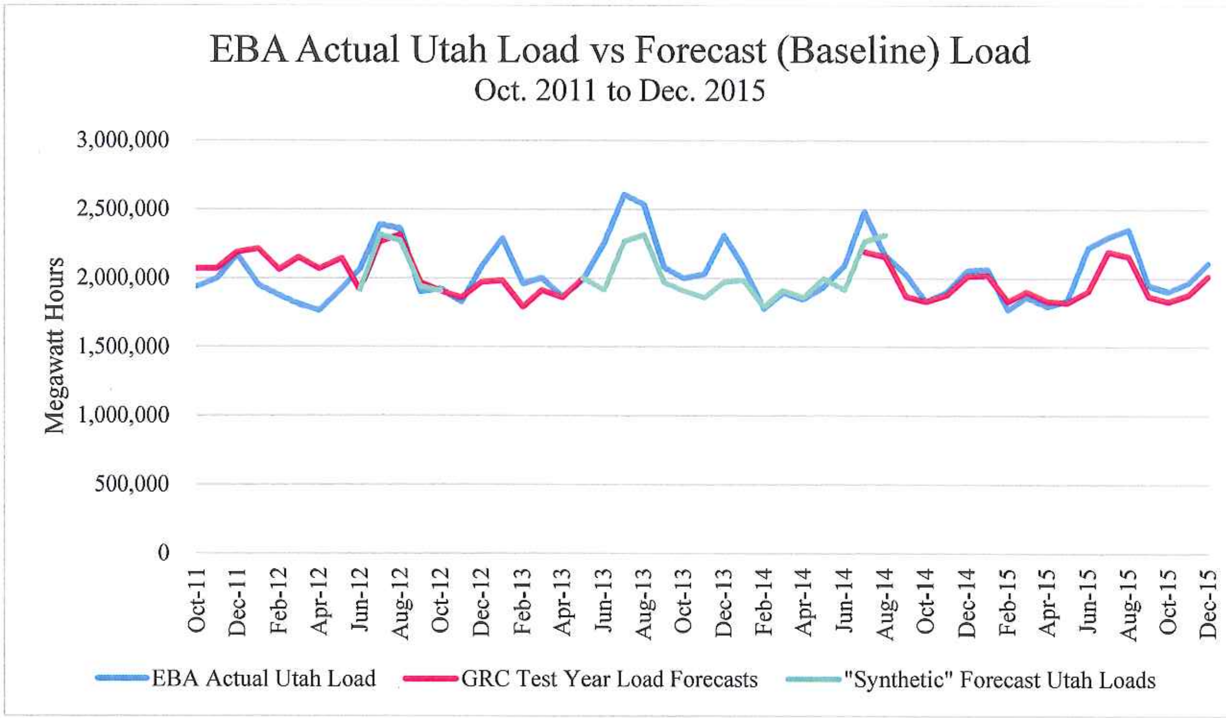


Figure 3



As can be seen from the figures above, from the relatively limited data the general rate case NPC forecasts have tracked reasonably well except for the summer spikes in 2014 and 2015. The "synthetic" forecasts during the mismatch periods did not track the actual data as well, which is not unexpected. Based on the data that are available for these three forecasts, it is not clear whether the Company's monthly forecast improved between rate cases. Curiously, the GRC load forecasts were noticeably higher than actuals from October 2011 through May 2012, but was generally below the actuals thereafter. Table 4 provides descriptive statistics of the monthly data examined here. In terms of means and medians, the GRC forecast did better than the synthetic forecasts, as expected; however the relative standard deviations as measured by the coefficient of variation (CV)[33] were also noticeably higher. The higher CVs are due to the fact that sometimes the monthly GRC forecasts would be higher than the actuals, whereas the synthetic forecasts were more consistently below the actuals.

[33] The coefficient of variation is calculated by dividing the standard deviation by the mean.

Table 4

Comparison of Differences Between Utah Actuals and Forecasts
October 2011 to December 2015

	Actual NPC less GRC Forecast NPC	Actual NPC less "Synthetic" Forecasts	Actual Load less GRC Forecast Load	Actual Load less "Synthetic" Forecasts
Mean	$2,100,402	$6,715,519	20,565	109,974
Median	$851,684	$4,809,556	19,120	95,496
Standard Dev.	$4,099,021	$5,477,500	153,225	145,244
CV	1.952	0.816	7.451	1.321

The Division also considered the annual totals for NPC forecast and load forecasts. Figure 4 sets forth a comparison of the annual actual NPC with the forecast NPC from the various EBA dockets. Note that Docket No. 12-035-67 includes only three months of data at the end of 2011. The forecast NPC includes both the forecasts from general rate cases and the Company's synthetic forecasts. Similarly, Figure 5 presents a comparison of the annual load figures. As Figure 4 shows, net power cost forecasts were consistently below the actual data. Table 5 gives the differences between the actual versus forecast numbers. The error for the load forecasts runs about 2 percent, which the Division believes is in the range of good forecasts. However, the forecast error for NPC was three times higher at over 6 percent.

Figure 4

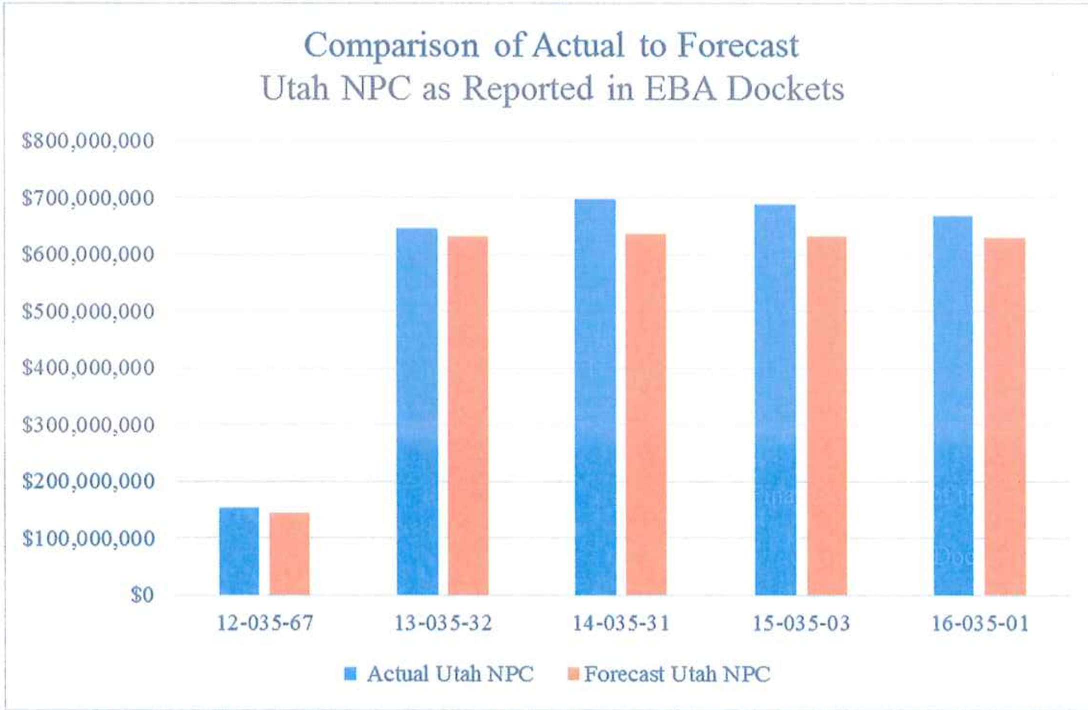


Figure 5

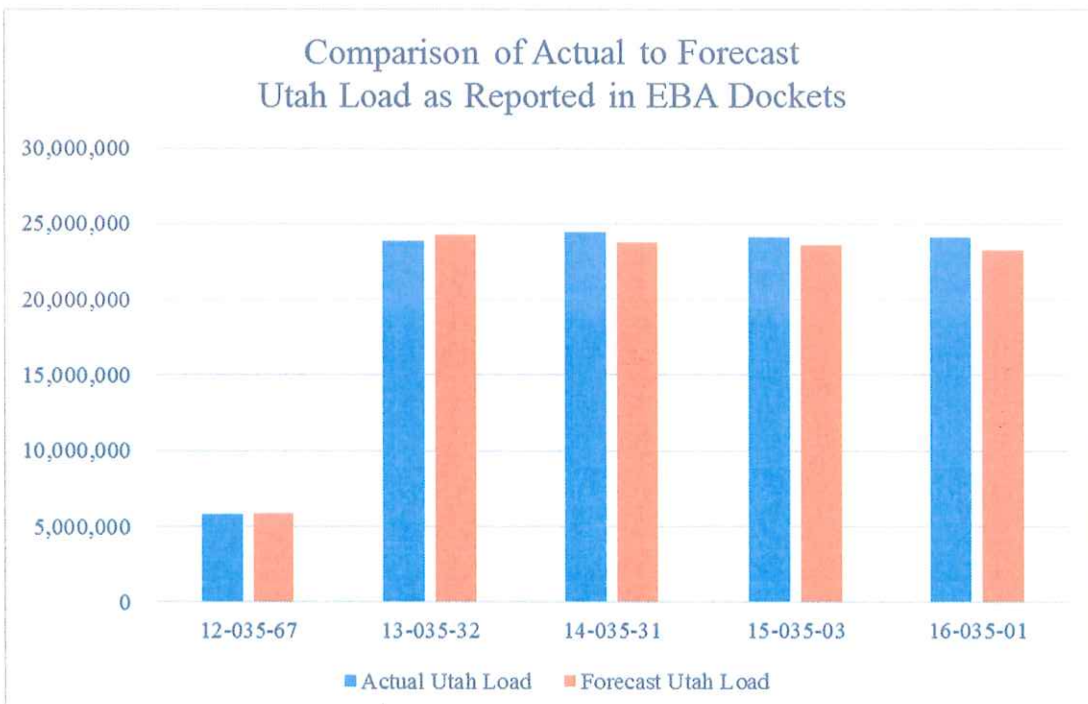


Table 5

Comparison of Differences Between Utah Actuals and Forecasts
EBA Dockets for 2011 to 2015

Docket No.	Actual NPC less GRC Forecast NPC	Percent Difference Compared to Actual	Actual Load less GRC Forecast Load	Percent Difference Compared to Actual
12-035-67 (2011)	$10,876,705	7.07%	(113,610)	-1.96%
13-035-32 (2012)	$14,627,486	2.26%	(412,102)	-1.73%
14-035-31 (2013)	$61,550,659	8.82%	721,885	2.95%
15-035-03 (2014)	$54,694,550	7.95%	471,841	1.96%
16-035-01 (2015)	$38,638,739	5.78%	883,257	3.66%
Mean, 2012-2015	$42,377,859	6.21%	416,220	1.71%

The Division makes no specific recommendation to solve the mismatch problem discussed above. Possible solutions are discussed under Item g, above.

u. The quantitative differences and relative advantages of using a static or dynamic composite allocator for allocating EBA accruals to rate schedules.

The issue of what method to use to spread EBA deferrals among the various rate schedules and special contracts was litigated and decided by the Commission in Docket No. 11-035-T10. The Office proposed a method referred to as the "NPC Allocator," which the Commission adopted as its EBA allocation method and ordered that the method be applied to EBA deferrals beginning October 1, 2011.

In theory and practice the NPC Allocator differs from a simple energy allocator and represents a more accurate method for spreading EBA deferrals to the rate schedules and special contracts. First, the NPC Allocator reflects the way base NPC accounts are allocated to rate schedules and special contracts in the Company's class cost-of-service model in general rate cases (GRC). Second, the NPC Allocator includes NPC elements that are spread on the basis of both demand and energy. Third, the NPC Allocator tracks changes in the energy-demand weighting, which varies in each GRC as the composition of NPC elements (fuel expense, purchase power expense, wheeling expense, wholesale revenue, etc.) changes.

The Division continues to support the NPC Allocator as long as it was used in the most recent prior rate case. If the NPC Allocator was so used, then it is the more precise and dynamic method for spreading EBA deferrals.[34] As the class-specific allocation of NPC changes from one GRC to the next, those differences will be reflected in the NPC Allocator used for spreading EBA deferrals.

COMMENTS ON THE DIVISION'S AUDIT EXPERIENCE TO DATE

The Division's experience with the EBA audit has been mixed. The EBA audit consumes substantial Division staffing resources and funds for outside consultants. As highlighted below there have been problems with both the lack of documentation and access to existing documents, particularly of front office transactions. There have been several issues regarding access to information that were initially difficult and exasperating for both the Division and the Company. These seem to have mostly been worked out. The Division approached the EBA audit process as a learning experience for it, the Company, and other parties. Progress has been made and further progress can be made. That said, the Division has determined that the audit, now and in the future, will require substantial Division staffing resources and funds for outside consultants. The following paragraphs explaining the Divisions review of outages, coal fuel, back and front office transactions, and rate case frequency explain how the Division came to this determination.

The Division has assessed the internal controls over the accounting cycles associated with the EBA. Based on the Division's experience to date in this area, the Company has in place

[34] The Division understands that the Office of Consumer Services also continues to support the NPC Allocator as the preferred method for spreading EBA deferrals.

adequate internal controls.[35] The DPU can move with some assurance, based on its review of the numbers provided by the Company that they are accurate and the accounting is done properly.

The Division has reviewed outages, both forced and unforced. Using accounting review methods, outages were highlighted that required additional investigation. These outages were reviewed by the Division's consultant, Daymark. Adjustments to the EBA due to outages have been recommended by Daymark. At this point the DPU staff is not confident that it will be able to bring outage prudency reviews in-house in the future. While a review of forced and unforced outages results in the Company doing assessments and reviews by in-house and outside experts on the cause of the unforced outage, a determination of imprudence would likely require the review of someone with specific engineering expertise, which the Division does not currently possess. Given state procurement rules, the Division may or may not be able to obtain outside technical assistance on a timely basis.

With respect to the Division's coal fuel review, the Division can report that the Company in the last review provided good supporting documentation for the basic coal transactions and demonstrated clearly how the transactions rolled to total numbers in the EBA. In other words, the accounting appeared proper and well documented. However, the Division lacks the expertise in coal procurement practices, or on the day to day proper management of coal inventories and other such non-accounting matters as to coal activity, to assess the prudency of the inventories and management activities. The Division must rely on outside consultants to assist it in the prudency determinations of these transactions and the related operations.

During any given year there are thousands of transactions affecting the EBA. The addition of the EIM transactions (which was not part of the EBA initially) has increased the transaction count. Thus increasing the audit work in this area and injecting a new learning curve to understand the impacts and the functioning of the EIM in the EBA late in the EBA pilot program period. The Company's seeming propensity to suggest additional deferrals to be collected through the EBA,

[35] Docket No. 13-035-32, Utah Division of Public Utilities Audit Report of Rocky Mountain Power's Energy Balancing Account (Highly Confidential), pages 9-11.

such as the items listed in its response to Question 2 above and costs related to the Deer Creek Mine closure, suggests more factors will be added to the Division's evaluation tasks in the future. In fact, if the pilot program period had not been extended a year, EIM addition to the EBA would have been, except for a couple of months at the end of the initial pilot program period, outside of the pilot program.

The Division is concerned that it may be virtually impossible to meaningfully assess the prudency of daily trading transactions because of a lack of contemporaneous written and verifiable source documentation supporting and justifying the trades made. In the first two EBA audits, the Division identified several supporting documentation issues related to front office transactions. If the Company continues to improve its written documentation, as it has in fact done since the start of the EBA, the Division will be able to more adequately assess the prudence of these transactions. But at this time, it cannot state that improved documentation will alleviate its prudency concerns stated above. Even with supporting documentation, the Division's resources limit it to reviewing small samples and relying on the expertise of its consultant to make a prudency determination. Expanding its scope of review in this area would require additional resources not presently available to the Division.

One of the major arguments put forth by the Company for having an EBA-type mechanism was that it would reduce the number of rate case filings by the Company since it would reduce financial shortfalls from a major component of the Company's cost structure. So far, the Division has not perceived a reduction in the frequency of rate cases due to the EBA. Indeed, as shown under Item n above, customers have experienced a higher rate of rate changes and larger annual rate changes since the implementation than in the years the Company did not have an EBA. Since the EBA has not reduced the frequency of rate case filings, to date the work load on the Division often has been to do both the EBA review and the rate case work in tandem; thus the Division's workload has generally increased. The Division has relied heavily on the resources and expertise of its consultant in order to perform the expected work.

There have been some positive developments in the conduct of the EBA process as both the Division and the Company provide feedback to each other. The documentation provided by the Company and the cooperation of certain sections of the Company in Portland have improved with each additional EBA cycle; the Division has improved its understanding of the Company's systems and data sets, making some parts of the annual review more routine for the Division. The Division hopes this will help to decrease the staff time required for review. This assumes the scope of review and reporting does not change from its current methods of review as explained above (e.g. small sample of transactions with a heavy reliance on consultants).

The time allowed to accomplish the tasks in the past has been too short; however, even as the procedures are repeated and refined, the time frame required still will be an issue, but might not be as important an issue as it is presently. The Division believes its review has tasks requiring both fixed and variable amounts of time. Refining procedures helps to lower the variable time but there are basic EBA parts that require a fixed amount of time, and as mentioned above, the addition of the EIM means that the amount of data to review is rapidly growing. The amount of time and other resources would increase if expanding the scope of the Division's review to larger samples, more documentation review, and more effort to understand why trades were done and if they were prudent. The Company's increased filing of available information throughout the year (now done on a quarterly basis by mutual agreement of the Company and the Division) may provide for decreased review time of some aspects of the EBA during the primary audit period; however, the burden on the Division will remain substantial during the four months following the March 15 EBA filing date.

While the Division was generally supportive of the Company having an EBA in Docket No. 09-035-15, the Division also expressed concern about the Division's ability, based on its staff size and expertise, to be able to do a proper prudency review on the EBA. As discussed above, working with the consultants has given the Division some assurance related to prudency checks on outages and to a lesser degree, other areas of net power costs. The Division continues to have concerns about determining transaction prudency. The Division has relied on the 70/30 sharing split to give it some confidence that the Company will generally act with prudence because of the potential for loss to the Company outside of the threat of a formal prudence disallowance by regulators. That Company incentive is now gone.

In sum, given that the EBA taxes Division staffing and consultant funding resources along with the lack of Division expertise as explained above, the Division's review of the EBA is limited and imprudent costs could elude review. For example, the Division has never attempted to apply the results of its spot-check of a relatively few transactions to the universe of the Company's several tens of thousands of transactions during a given year. While the term "audit" has been used with the Division's annual review of the EBA, it is not an audit in the sense that the Division is making an attestation that the EBA amounts filed by the Company are "materially" correct (except for some few proposed adjustments). Instead the Division's audit means that other than the adjustments to the Company's filing that it brings before the Commission in a given EBA docket, it did not find any other problems with the filing as a result of its fairly limited review.

PRELIMINARY REVIEW OF EFFECTS OF 100 PERCENT RECOVERY ON RETURN ON EQUITY

In its original filing in this Docket, the Company requested an ECAM that would give it 100 percent recovery of its net power costs. The Division performed analyses that attempted to estimate the effects on the Company's realized rate of return had that ECAM been in effect in previous years. That analysis suggested that the Company might have over-earned its return on equity by one full percentage point or more over the Company's then authorized return on equity of 10.25 percent.[36] While the Company disagreed with the Division's analysis, it never offered alternative estimates.

[36] See Direct Testimony of Charles E. Peterson, Docket No. 09-035-15 (Phase 1), pages 11-12, lines 237-262, and Surrebuttal Testimony of Charles E. Peterson, Docket No. 09-035-15 (Phase 1), pages 7-9, lines 149-184.

Given the passage of SB 115, the Division was interested in the effects 100 percent collection of the EBA balance might have on the Company's Results of Operations. Using the Company's filed results of operations for the calendar years 2011 through 2015, the Division added the estimated additional revenues the Company would have received if there had been no sharing bands during that time period. The Division reduced the net income by the additional income taxes the Company would have paid had it received additional revenue. The assumed incremental tax rate was 38 percent for all years. There were no other adjustments made, since it is assumed that there would have been no other effects on the Company's financial statements other than higher revenues and income taxes. Since by stipulation the 2011 amounts were spread over two years, it was assumed that the incremental revenues stemming from 2011 would also be divided between 2011 and 2012.

DPU Exhibit 1 sets forth the Division's estimates. One item of note is that even without 100 percent recovery, the Company was able to earn its authorized return in 2015. The adjustments for the Company totals were only for the Utah amount. It would be of interest to see what the Company's results would be if it had had a 100 percent pass-through of its NPC in all states: no doubt the Company's earnings and returns would have been even higher.

This type of static analysis likely understates the benefits of the additional revenues since, for example, there is no consideration of the dynamic interplay between the Company's income statement and its balance sheet. One effect on the balance sheet is to increase cash balances. Unless ordered to immediately pay the additional cash to the parent holding company as a dividend, the Company could use the cash to pay down debt (alternatively avoid taking on debt) which would reduce its interest expense going forward, which in turn would increase income, and so on.

From a theoretical point of view, just like the expectation that capital will tend to be invested in projects that give the highest risk-adjusted returns, it can be assumed that there is an incentive for costs to gravitate into those accounts in which there is enhanced potential for cost recovery. Through a myriad of subtle decisions, any one of which may appear innocent enough, costs will shift to where they are most likely to be recovered. This was a possibility that the Division and others were concerned about in the original ECAM process that was highlighted in the Division's testimony cited above.

The fact that the Company is now able to earn its authorized return even without 100 percent recovery suggests that its Utah regulators need to pay increased attention to the Company's costs and earnings going forward.

Table 6

Comparison of PacifiCorp Returns on Rate Base With Estimated Adjustments for 100 Percent EBA Collections in Utah
2011 to 2015

	2011 NORMALIZED RESULTS		2012 NORMALIZED RESULTS		2013 NORMALIZED RESULTS		2014 NORMALIZED RESULTS		2015 NORMALIZED RESULTS	
	TOTAL	UTAH	TOTAL	UTAH	TOTAL	UTAH	TOTAL	UTAH	TOTAL	UTAH
Reported Operating Revenues	4,508,850,619	1,888,608,504	4,804,447,885	2,037,536,036	5,023,662,470	2,107,668,468	5,190,825,722	2,202,770,029	5,116,399,256	2,172,604,816
Incremental EBA Revenues to Total 100%	1,671,429	1,671,429	8,100,000	8,100,000	10,842,857	10,842,857	6,642,857	6,642,857	4,842,857	4,842,857
Adjusted Total Revenues	4,510,522,048	1,890,279,933	4,812,547,885	2,045,636,036	5,034,505,327	2,118,511,325	5,197,468,579	2,209,412,886	5,121,242,113	2,177,447,673
Total Operating Expenses	3,681,808,436	1,530,559,326	3,860,595,132	1,633,286,583	4,024,025,360	1,683,035,458	4,161,168,029	1,753,654,640	4,044,635,458	1,706,420,360
Reported Operating Revenue for Return	827,042,183	358,049,178	943,852,753	404,249,453	999,637,110	424,633,010	1,029,657,693	449,115,389	1,071,763,798	466,184,455
Incremental Income Tax on Incremental Revenue (Assumed Tax Rate of 38%)	(635,143)	(635,143)	(3,078,000)	(3,078,000)	(4,120,286)	(4,120,286)	(2,524,286)	(2,524,286)	(1,840,286)	(1,840,286)
Adjusted Operating Revenue for Return	828,078,469	359,085,464	948,874,753	409,271,453	1,006,359,682	431,355,581	1,033,776,264	453,233,960	1,074,766,370	469,187,027
Adjusted Operating Revenue for Equity	486,463,776	212,688,007	618,221,729	264,294,433	670,979,173	285,078,884	690,355,512	302,857,987	725,272,455	314,465,047
Rate Base	12,435,918,937	5,329,357,719	12,911,090,363	5,660,953,517	13,266,634,061	5,786,261,730	13,714,886,294	6,005,430,247	13,951,852,873	6,176,526,131
Reported Return on Rate Base	6.65%	6.72%	7.31%	7.14%	7.53%	7.34%	7.51%	7.48%	7.68%	7.55%
Reported Return on Equity	7.48%	7.61%	9.03%	8.71%	9.55%	9.17%	9.66%	9.60%	10.12%	9.83%
Adjusted Return on Rate Base	**6.66%**	**6.74%**	**7.35%**	**7.23%**	**7.59%**	**7.45%**	**7.54%**	**7.55%**	**7.70%**	**7.60%**
Adjusted Return on Equity	**7.49%**	**7.65%**	**9.10%**	**8.88%**	**9.64%**	**9.40%**	**9.72%**	**9.73%**	**10.16%**	**9.95%**
Authorized Return on Equity as of Year End		10.00%		9.80%		9.80%		9.80%		9.80%

CONCLUSIONS AND RECOMMENDATIONS

As highlighted above, there is generally not enough information to attribute differences in the Company's operations to the EBA, and perhaps there never will be due to the effects of various other factors. As expected, performing the EBA audit is a challenge to the Division's resources. It is unsurprising that there are differing, sometimes opposing views, concerning the EBA among the Company, the Division and the intervening parties. With respect to the audit process itself, the Division believes that many issues with the Division's audit program have been worked out and that much of the EBA program is running as expected. However, the Division cautions that the Division's audit of the EBA, even with the assistance of its able consultants, should not convey a sense that the Division is in any way attesting to the material accuracy of the entirety of the Company's EBA filings. The Division is only able to review and check certain items and can only make statements about the results of those checks on those items and not on the Company's records or process as a whole.

The Division makes the following recommendations:

- As the EBA pilot program nears its end in 2019, the Division recommends that a full evidentiary docket be established by the Commission to consider changes to, or elimination of, the EBA.
- The Division believes that the mismatch issue described above should be resolved. The Division outlined a couple of possible remedies. With a third possibility to simply not worry about it.
- The Division requests that the time period for its audits be extended to one year and that interim rates could be established until the Division can complete its audit.
- The Division has always argued against the inclusion of wheeling revenues as part of the EBA, and recommends eliminating it from the EBA.
- The Division requests that, at a minimum, the carrying charge in the EBA be reset to follow the process the Commission ordered in Docket No. 15-035-69. However, since the 100 percent sharing band may give the Company an incentive to under-forecast net power costs for general rate cases when it can earn an out-sized carrying charge from the

EBA, the Division believes it would be appropriate to reduce the carrying charge to a short-term rate, or eliminate it altogether.

- The Commission should set a schedule for a process in the appropriate dockets, or in a new docket, in order for the Commission to consider these recommendations and allow interested parties to weigh in on the Division's proposals, or recommend their own changes to the EBA.

Based on its experience with the EBA, the Division concludes:

- The EBA was implemented to benefit the Company, which it obviously has done. The Company is now earning its authorized rate of return.
- Concurrently ratepayers are worse off both in higher rates, but also in terms of risk that the Company was able to shift to them.
- The Division perceives no significant benefits to ratepayers as a result of the EBA.
- Despite taxing the Division's resources, the Division can perform an audit of the NPC accounts with continued help of consultants. While ratepayers and other outside parties may take some comfort that the Division is performing an audit, they need to understand that the Division's audit does not result in an attestation of the material correctness of the Company's net power costs.

APPENDIX 1
PLACEHOLDER

Attachment 1
UAE Comments to the DPU

To: Utah Division of Public Utilities

From: UAE

Date: April 15, 2016

Re: UAE Comments on EBA Sharing Mechanism (including "controllable" / "uncontrollable" components); In Response to EBA Evaluation Report Survey

UAE appreciates this opportunity to provide comments to the Utah Division of Public Utilities in response to the Division's EBA Evaluation Report Survey Circulated on March 11, 2016. UAE strongly believes that, if the EBA is to be retained (a position as to which it is not now providing comments), it is essential that the 70/30 sharing mechanism be restored at the earliest opportunity because it provides a critical incentive for the Company to manage its costs. This mechanism also strikes a reasonable balance between customers and shareholders with respect to the sharing of risks associated with deviations in actual net power costs ("NPC") relative to what is established in rates. Sending the right incentive for the Company to manage its costs and requiring the Company and ratepayers to share risk are distinct attributes of the sharing mechanism.

The 70/30 sharing mechanism is a clear and straightforward means to give RMP a material stake in each of its actions and decisions related to power costs, thereby aligning the interests of the Company with those of its customers. When a firm stands to gain or lose from its cost management decisions, as RMP does with a sharing mechanism included in the EBA, the pursuit of its economic self-interest gives it a powerful incentive to perform well in managing its costs. To deny that profit incentives are critical in encouraging strong performance in business actions is tantamount to dismissing the importance of the driving forces behind our capitalist economy.

While RMP may argue that market prices are outside its control, this argument sidesteps the key points with respect to maintaining the incentive from the sharing mechanism. The importance of maintaining regulatory incentives for the Company to perform efficiently does not depend on how much influence RMP has over market prices. The Company may not control market prices, but this does not mean it is a mere passive bystander when it comes to managing its power costs. Every hour of every day, RMP needs to be managing the dispatch of its system to achieve minimum costs, subject to the reliability constraints under which it operates. This requires a sophisticated approach to managing utility-owned resources, as well as conducting a large volume of transactions – purchases and sales – throughout the year. It is in the overall management of its resources, as distinct from control over market prices, that incentives matter.

The Company must continually balance its market position. It does this first with monthly products, then with daily products, both of which are purchased in 25 MW blocks, and finally with hourly products. This layering of products is important because the Company does not want to be more exposed than necessary to the hourly market and it obviously requires active management by Company personnel.

For example, in 2014, the Company made more than 14.2 million MWh of long-term, intermediate term, and short-term firm sales, which is an average of 1,621 MW each hour of the year. These sales were conducted with over 140 counterparties.[37] The Company also transacted for more than 8.0 million MWh of long-term, intermediate-term, and short-term firm purchases, and approximately 4 million MWh of exchanges, consummated with more than 120

[37] According to PacifiCorp's 2014 FERC Form 1 data, as compiled by SNL Financial. Excludes Requirements Service (RQ), Out-of-Period adjustments (AD), Service from designated generating units (LU), and Other service (OS).

counterparties.[38] The depth and breadth of this around-the-clock dispatch and balancing requirement is clearly extensive. It is critical that RMP have the proper incentives for these transactions, as well as in the management of its fuel procurement, to produce the greatest possible net benefit to customers. This incentive is most efficiently implemented by a regime in which RMP significantly shares in the benefits and risks of its decisions. To ensure sound utility cost-management performance, it is far preferable to harness the natural economic self-interest of the Company than to rely on after-the-fact prudence audits to review the reasonableness of past actions.

Incentives also play an important role with respect to the Company's own operations. For example, it is important for RMP to schedule plant maintenance in a manner that takes into account the impact on NPC. By scheduling outages when replacement power is likely to be less or least expensive, the Company is able to control its net power costs. Under a sharing mechanism, the Company has an economic incentive to take proper account of NPC when scheduling outages. Without a sharing mechanism, the Company's natural economic incentive to properly consider the impact on NPC in its operations is removed. For example, RMP would be economically indifferent between scheduling a maintenance outage during a period when the price for replacement power is relatively high versus scheduling it at a time when the price is relatively low. This is not a healthy economic arrangement, as shareholder interests and ratepayer interests would not be aligned as they are now. Further, under the sharing mechanism, if the Company experiences forced outages that are more frequent or of greater duration than is reasonably projected in rates, the Company shares in the economic consequences of these events.

[38] According to PacifiCorp's 2014 FERC Form 1 data, as compiled by SNL Financial. Excludes Requirements Service (RQ), Out-of-Period adjustments (AD), Service from designated generating units (LU and IU), and Other service (OS).

Likewise, if forced outages are less frequent than had been reasonably projected, the Company shares in the benefit of such superior performance. None of this occurs with a 100% pass-through to customers.

It would be a mistake to attempt to differentiate application of the sharing mechanism by designating certain costs as "controllable" and others as "uncontrollable." While there may be varying degrees of "control" that the utility exercises over various net power cost components, what it being incented is the Company's *management* of its system, including its *response* to external factors outside its control, such as market prices. This is best addressed with a simple but pervasive incentive mechanism, such as the sharing bands. For example, while RMP may not control market prices, the Company's hedging activities and its exposure to market pricing (whether intra-hour, hourly, daily, weekly, annually, etc.) are a direct result of its management decisions, which in turn impacts net power cost. Moreover, shareholders should also share in risk of NPC cost deviations, irrespective of whether the deviations are caused by controllable or "uncontrollable" NPC components.

Attachment 2
Daymark Comments to the DPU

To: **Utah Division of Public Utilities**

From: **Richard Hahn and Dan Koehler, Daymark Energy Advisors**

Date: **March 30, 2016**

Subject: **Thoughts on EBA Pilot Evaluation**

Daymark Energy Advisors, Inc. (formerly La Capra Associates) has been assisting the Division with its audit of Rocky Mountain Power Company's ("RMP") EBA deferral filing since the program's inception in 2012. We offer the following high-level thoughts on the EBA process.

The sharing mechanism

Currently the EBA is structured with a 70/30 sharing mechanism. If actual EBA costs are above base rates, the Company can only collect 70% of the difference. If actual EBA costs come in below base rates, the Company must only return 70% of the difference to ratepayers. The purpose of a sharing mechanism is to provide the Company with an economic incentive to minimize EBA costs, and to reduce volatility of customer rates outside of general rate case proceedings. The tradeoff of a sharing mechanism is that it may incentivize the Company to over-forecast EBA costs in general rate cases.

The sharing mechanism must be viewed in the context of other factors in general rate cases. We note that actual EBA costs have been above base rate EBA costs in each of the Company's first 5 EBA filings, indicating that over-forecasting of EBA costs in general rate cases has not been occurring systematically to date. The 70/30 sharing mechanism has effectively protected ratepayers from excessive rate volatility, while at the same time reducing some of the market risk faced by the Company between rate cases. Without the EBA, the Company is 100% exposed to the market risk associated with its forecasts between general rate cases. The EBA with a sharing mechanism reduces risk to the Company when compared to no EBA, but the Company is still exposed to market risk for its portion of the sharing mechanism. The EBA with no sharing mechanism absolves the Company of all of the market risk associated with its forecasts. Since having the EBA in place with or without a sharing mechanism, reduces the Company's risk, such risk reduction could be reflected in the allowed return on equity for the Company. In the process to establish the acceptable range of the Company's ROE, there does not appear to be a quantitative manner through which to reflect this risk reduction. The risk reduction associated with the EBA, with or without a sharing mechanism, could be considered as a qualitative measure in deciding where within the range of reasonable a specific ROE should be established.

We are aware that the Governor is currently considering signing a bill that would remove the sharing mechanism from the EBA. If the sharing mechanism were completely removed, the Company would theoretically have less incentive to make good decisions and would be exposed to less market risk. If this occurs, the DPU could consider: 1) reflecting this risk reduction in the determination of the specific allowed return on equity in general rate cases as discussed above; 2) increase the scrutiny or prudence reviews of actual EBA costs and hedging practices to compensate for the removal of the Company's financial incentive to minimize EBA costs.

Which net power cost components are controllable and which are uncontrollable and whether the sharing element should be eliminated from the uncontrollable costs in the EBA.

The vast majority of net power cost components in the EBA are controllable to some extent, or at least subject to variation based on decisions made by the Company. For instance, gas market prices are uncontrollable, but the Company's hedging program, physical trading, and electric dispatch decisions all affect how much and at what price the Company purchases natural gas.

Some costs may be uncontrollable because they are fixed contractually at the time of the prior rate case (for instance, a life-of-unit QF contract for demand and energy). Even though these costs may be forecast accurately in the rate case, an over- or under-collection could occur due to the mismatch between the rate case test year and the EBA deferral period. Determining what costs are truly "uncontrollable" versus "controllable" would be subjective, administratively burdensome, and there should be no reason that a sharing mechanism would systematically favor either ratepayers or the Company. We do not recommend eliminating the sharing mechanism from "uncontrollable" costs.

The effects of the EBA on the Company's resource portfolio.

In the long term, the EBA should have little to no effect on the Company's resource portfolio. Long-term resource decisions (i.e., those with durations of ten years or more) are typically made using life cycle analyses that assume cost recovery, so the existence of the EBA should not affect such decisions. In the shorter term (i.e. between general rate cases) the existence of the EBA may have some small impacts. The EBA may incentivize the Company to prioritize regulatory approval over cost minimization. In other words, if the Company believes that Option A is most likely to reduce net power costs, but Option B is more likely to pass regulatory scrutiny, the EBA would cause the Company to prefer Option B. This can be a positive, as it discourages reckless risk-taking. But it also might preclude the Company from exploring all options that may be in the interests of ratepayers. To the extent the sharing mechanism is reduced or eliminated, this effect will increase. As noted above, greater scrutiny of such transactions may be appropriate if the sharing mechanism is eliminated.

Whether the EBA includes the appropriate net power cost components.

Our understanding is that the vast majority of costs included in Net Power Costs are variable expenses tied to fluctuating market prices and/or fluctuating consumption due to changing dispatch. These are appropriate costs to include in NPC. Fixed charges such as demand charges for power or natural gas, fixed transportation costs for fuel, etc. should not generally not be included in NPC. For new transactions consummated between rate cases, it may be appropriate to include the fixed, non-variable revenues and costs associated with these deals until the next general rate case.

The effects of the EBA on the Company's hedging decisions and level of market reliance on net power cost.

Our observation has been that the EBA has had a very positive effect on the Company's hedging practices. First, it has resulted in a reduction in the overall amount and the effective transaction period of hedging. This is appropriate, particularly for the Company which is already hedged "naturally" to a certain extent due to its extensive sales activity and its diverse generation fuel supply. The Company's hedging practices have also become substantially more transparent as a result of the Division's review and the stakeholder input through the Hedging Collaborative. This is a tremendous improvement over the situation before the EBA, when we understand that stakeholders had little visibility into the Company's hedging practices.

Parties' incremental costs to audit the balancing account.

We believe that the EBA audit process, particularly in recent years as the Company and the Division have worked collaboratively to improve the efficiency and efficacy of the review process, has been well worth its cost.

Unintended consequences resulting from the EBA.

These are discussed above, particularly in (a) and (c).

Monthly vs. annual accrual differences.

We have not analyzed this issue.