SPENCER J. COX
Governor

DEIDRE M. HENDERSON
Lieutenant Governor

Division of Public Utilities
UTAH DEPARTMENT OF COMMERCE

MARGARET W. BUSSE
Executive Director

CHRIS PARKER
Division Director

Redacted

Action Request Response

To: Public Service Commission of Utah

From: Utah Division of Public Utilities

Chris Parker, Director
Brenda Salter, Assistant Director
Doug Wheelwright, Utility Technical Consultant Supervisor
Trevor Jones, Utility Technical Consultant
Thomas Allred, Utility Analyst

Date: April 15, 2026

Re: **Docket No. 26-035-06,** PacifiCorp's Semi-Annual Hedging Report

Recommendation (No Action)

The Division of Public Utilities ("Division") has reviewed the Semi-Annual Hedging Report submitted by PacifiCorp and its attachments, including the data request responses filed by Rocky Mountain Power ("RMP" or "Company"). The report's format and content, which include historical data and forecasts, are consistent with previous filings. The Division recommends no action from the Utah Public Service Commission ("Commission") at this time but would like to see more analysis from the Company going forward.

Issue

On February 13, 2026, RMP filed PacifiCorp's Semi-Annual Hedging Report with the Commission. On February 17, 2026, the Commission issued an Action Request, directing the Division to review the filing for compliance and to make recommendations by March 16, 2026. Subsequently, on March 6, 2026, the Division requested extra time, which the Commission granted on March 11, 2026. This established a new deadline of April 15, 2026. This memorandum is the Division's response to the Commission's Action Request.

Redacted

Background

The origins of the Company's current hedging reporting requirements are traced back to General Rate Case Docket No. 10-035-124. During those proceedings, it became evident that parties required greater clarity regarding the various products, timing, volumes, and fundamental nature of PacifiCorp's hedging transactions.[1] As part of the resulting settlement stipulation, RMP agreed to a collaborative process intended to refine existing hedging practices, better align the program with customer risk tolerances, and enhance transparency for stakeholders.[2]

A key term of that stipulation requires the Company to submit a Semi-Annual Hedging Report to the Commission, covering the six-month periods ending in June and December of each year.[3] These reports are designed to provide comprehensive insights into hedging activity over the preceding six months while offering an outlook on market conditions and planned activities for the upcoming six months.[4] Specifically, the reports detail market fundamentals, basis risk, liquidity, energy positions, and the specific products and instruments used to secure physical supply. The current report under review encompasses the six-month period ending December 31, 2025.

The Company held tech conferences in October 2025 and February 2026 outlining significant changes it plans on making to the power hedging program. In response to those changes, the Company's hedging report filing in August 2026 is expected to include significant changes. In the August 2026 filing, the Division requests the Company to include information on the new methodology and include a comparative analysis of why it was selected over alternative hedging strategies.

Discussion

The PacifiCorp hedging program involves [redacted] used for power generation. The specific strategy for when and how much to hedge is guided by the Company's Energy Risk Management Policy. It is also

[1] Rocky Mountain Power is DBA PacifiCorp where the hedging transactions originate.
[2] Collaborative Process to Discuss Appropriate Changes to PacifiCorp's Hedging Practices, March 30, 2012, page 2.
[3] Settlement Stipulation, Docket No. 10-035-124, page 14.
[4] Semi-Annual Hedging Report, page 1.

Redacted

influenced [redacted] and the [redacted]

The Company contracts [redacted] to write high-level reports that describe market prices in the non-CAISO WECC region as well as market fundamentals.[5]

ELECTRIC HEDGING

The primary objective of the electric hedging program has been to secure enough power to prevent [redacted]. The existing power hedging program manages energy deficits by mandating minimum purchasing volumes to mitigate the shortest system hour; the hour with the greatest forecasted energy deficit – when the gap between customer load and available resources is largest. These mandatory minimums escalate as the delivery date grows closer, requiring the Company to purchase at least [redacted] of the shortfall for the prompt quarter, with the requirement gradually stepping down to [redacted].[7] To account for extreme weather events or generation unit underperformance, the Company executes purchases [redacted]. These purchases consist of large blocks of Heavy Load Hours (HLH) for extended periods of time, typically at fixed prices. The Company has explained that these larger blocks of HLH power are the most available products to cover their shortest system hour; other standard forward market products that would cover the few needle peak hours simply are not available or do not exist.

The Company recently announced major revisions to its power hedging program, among which the adoption of resource adequacy standards will replace the existing minimum purchasing requirements to manage capacity positions. Under this new resource adequacy framework, the Company will use the WRAP capacity-requirement methodology to secure power to meet its expected peak loads, with an added safety buffer.[8] The Company will use a P50 load forecast to determine the system coincident peak. A Planning Reserve Margin (PRM) will then be added to the peak demand forecast to determine a total capacity requirement. The PRM is a WRAP-

[5] *Ibid*, Attachments B and C.
[6] A short power position is when the load requirement is greater than the resources, which would require day-ahead or real-time purchases. Long is when the resources are greater than the requirement and would require sells.
[7] PacifiCorp's Energy Risk Management Policy, May 12, 2025, Appendix E, page 35.
[8] Response to DPU Data Request 2.5

Redacted

recommended percentage-increase applied to the peak capacity obligation to ensure that there will be sufficient capacity available on the system to manage extreme weather events and unit outages. The Company will then assign its resources' qualifying capacity contribution values, determined through WRAP, to determine a total capacity contribution. The deficit between the total capacity requirement and the capacity contribution will indicate the total volume of required purchases.[9]

In addition to the resource adequacy requirement changes, the Company announced that it will rely on a Balancing & Hedging Strategy Matrix to influence its hedging decisions. While the resource adequacy calculation will dictate the total volume of required purchases, the matrix will help inform the trader of the composition of those purchases – between fixed-priced and index-priced contracts.

The matrix evaluates two different metrics. First, it calculates the Supply Risk Position to determine if the system has a Capacity Deficit, which would indicate a need for purchased power. Second, it reviews the outputs of a PCI economic dispatch model to consider if market prices favor purchases or sales, by comparing wholesale market prices against the Company's own marginal costs. A "Purchase Indicated" from the PCI model would suggest that wholesale fixed-prices were lower than the marginal cost to run the Company's own generation, whereas a "Sales Indicated" or "No Activity Indicated" would suggest that there wouldn't be any economic benefit to transact at the current fixed-price forward prices.

Combining these metrics will create different hedging strategies. If a capacity deficit exists and the PCI model indicates "Purchases", the Company will consider purchasing a mixture of both fixed-price and index-priced purchases to simultaneously secure physical supply while also offsetting marginal generation costs. If the model indicates "Sales" or "No Activity" with a capacity deficit, the Company will only fulfill the deficit using index-price purchases. A capacity surplus plus a "Purchase" suggestion from the PCI model would indicate the opportunity to lower marginal energy costs. A capacity surplus and a "Sales" suggestion will signal the opportunity to secure revenue by selling excess power at fixed prices. A capacity surplus

[9] The Company has withdrawn from WRAP but continues to use WRAP methodologies. It is actively working with other EDAM participants to create a new resource adequacy program in place of WRAP, see: https://www.utilitydive.com/news/western-utilities-weigh-a-new-resource-adequacy-program-under-rowe/815043/

Redacted

coupled with “No Activity Indicated” will indicate that forward fixed prices aren’t high enough to warrant selling excess power.

The Company has historically relied on [redacted] purchases to fulfill its short positions. However, the Company has indicated an incoming shift to more [redacted] transactions, as confirmed by the hedging transaction history beginning in 2023:

Confidential Chart 1

Fixed-price physical power contracts lock in both prices and volume, months or years in advance, providing a defense against market volatility. However, this strategy carries inherit risk of overpayment if market prices decline before the delivery date or if volumes are secured for periods where actual load is lower than anticipated. Furthermore, these contracts typically incorporate an embedded risk premium in order to guarantee forward supply, which significantly reduces their liquidity and make them difficult to divest if needed.

Conversely, index-based contracts secure physical supply without locking in a fixed price. The transaction price for an individual index contract is typically determined by the average of the Day Ahead prices for each day of the delivery month. Index-price transactions are subject to market volatility, which can be good or bad. They provide superior liquidity if needed.

Redacted

Confidential Chart 2

Because fixed-priced contracts tend to have a built-in risk premium, index-price contracts can often outperform them. Confidential Chart 2 shows that Rocky Mountain Power's index-price physical power contracts consistently yielded a significantly lower average price per MW compared to its traditional fixed-priced hedges from 2023 through 2025. The potential benefits of index-priced contracts are straightforward.

The scheduled implementation of the Extended Day Ahead Market (EDAM) on May 1, 2026, will significantly alter the western wholesale power landscape and will influence how the Company executes its electric hedging program. As entities within EDAM transition to participate within the organized market, traditional bilateral trading hubs are anticipated to decrease, possibly restricting the availability of index-priced contracts on the forward market. Additionally, given that index-price deals are settled at the Day Ahead price, a significant change to traditional Day Ahead market participation could impact index pricing. The Division requests that the Company monitor the impact of EDAM on its hedging program and provide an update regarding this impact in the August 2026 hedging report.

The most significant change to the Risk Management Program will be the separate reporting, management, and cost allocation of power between Washington and the other five states within the total system. Under this new framework, Washington and the other five states will be

Redacted

considered two distinct portfolios with unique requirements, each with their own capacity positions, limits, transactions and cost allocations.

While both portfolios will rely on WRAP resource adequacy methodology, this split will allow the Company to manage Washington's CETA-specific capacity requirements and assume those associated costs. Hedges and transactions will no longer be allocated on a total system basis. Instead, transactions for Washington will be situs assigned to Washington while transactions for the other five states will be allocated exclusively to them. The Division supports the Company's decision to manage Washington's unique energy demands separately from the five remaining states within the system. Assuming the Company's sale of its Washington service territory is approved and closes in 2027, the Company should report planned hedging changes in response to the divestiture.[10]

NATURAL GAS HEDGING

PacifiCorp's primary objective in hedging natural gas is to ensure fuel availability for its thermal generation fleet. The program utilizes the [redacted] model to forecast natural gas requirements, with hedging guidelines designed to adjust to shifting market conditions. The Company executes its hedging program through three primary transaction types:

- **Fixed-Price Physical Transactions:** A contract for the guaranteed delivery of a specific volume of natural gas at a predetermined price. This locks in both the cost and the molecule delivery in a single agreement.
- **Index-Price Physical Transactions:** A contract for the physical delivery of natural gas where the price is not fixed but fluctuates based on a published market index (e.g., Henry hub). These are typically recorded as "Index plus basis" transactions, where the "basis" accounts for regional price differentials and transportation costs to a specific delivery location.
- **Financial Swaps:** A cash-settled "paper" contract where no physical gas is exchanged. The parties exchange the difference between a fixed price and the floating market index.

The vast majority of PacifiCorp's natural gas transactions – [redacted] – utilize financial swaps paired with index-price physical purchases. This "decoupled" approach is intended to

[10] Docket No. 26-035-20 Washington Service Area Sale

Redacted

provide greater liquidity and operational flexibility compared to fixed-price physical deals. It is much easier to sell an index transaction. Under this structure, the index-price physical transaction secures the actual fuel supply, while the financial swap serves as a price-stabilization overlay to avoid volatility. For example, if the market index price settles at $2.00/MMBtu and the Company purchased a financial swap at $3.50/MMBtu, the Company pays $2.00/MMBtu to the physical supplier for the index transaction and $1.50/MMBtu to the financial counterparty for the swap. While this achieves the goal of price certainty, it does so at a cost that may diverge significantly from prevailing market rates.

This very conservative approach has resulted in a substantial net cost. For the last 6 months, the realized loss for natural gas swaps is [redacted] with an unrealized loss of [redacted]. The unrealized loss can still change based on market prices. If prices go up, the unrealized loss will decrease and could even go positive with a high enough price spike but if prices go down, then the unrealized loss increases. This means that if the market prices settled or stopped changing at the time this report was created, the hedging premium, the difference between the swap price and the index market price, would be roughly [redacted] in total, meaning the Company would have paid [redacted] more than just using an index-price physical without the financial swap.

The realized losses and gains for index transactions are very different than the swaps. Ever since the change in the power hedging program in 2021, the index losses have been very cyclical. The Division believes this cyclical nature might be because of how the Company executes its power hedges. To cover the short-duration needle peak loads in Q3, the Company [redacted]. This strategy often results in an oversupply during hours outside the needle hours,[11] which forces curtailment of the Company's natural gas units, which in turn causes the gas to be sold at a loss. Also, when index products are sold, the swaps are not necessarily also sold.

Confidential Chart 3 shows the realized losses/gains for natural gas hedges over the past 10 years:

[11] PacifiCorp's Semi-Annual Hedging Report. February 13, 2026. Page 59. "The Company is trying to ensure adequate supply to cover the uncertainty around the peak hour, due to changes in load, VERs and generation. The Company will maintain a net overall long energy position."

Redacted

Confidential Chart 3

While the Division recognizes that natural gas prices are inherently volatile and that financial swaps can be effective under specific market conditions, the Company's heavy reliance on a mostly swap-only strategy has yielded a net negative result for ratepayers. Over the past decade the gas hedging program has incurred a cumulative loss of approximately [redacted], without a single six-month reporting period resulting in a positive net position, even with the significant price spikes in natural gas markets in the winter of 2022. While the Division understands that the Company does not hedge with the intent to "beat the market," it is reasonable to expect a strategy that better balances risk mitigation with the minimization of Net Power Costs. Current financial hedging practices have exposed ratepayers to substantial costs while providing the singular, limited benefit of price stabilization. Furthermore, because the Energy Balancing Account (EBA) functions as a 100% pass-through mechanism in Utah, the

Redacted

financial risks and costs associated with hedging are borne exclusively by ratepayers, with little incentive to reduce NPC. Consequently, the Company's financial performance remains insulated from the outcomes of its hedging decisions, even when those decisions result in significant net costs to the system.

In light of this performance, the Division recommends that the Company evaluate the following alternatives:

1. **Optimization of Hedge Ratios:** Rather than defaulting to a 1:1 pairing of index-price physical transactions with financial swaps, the Company should evaluate eliminating some of the financial swaps. While this introduces greater exposure to market volatility when holding only an index, it may yield significant cost savings by avoiding locked-in swap prices.
2. **Implementation of Zero-Cost (Costless) Collars:**[12] The Company should explore using collars – purchasing a call option (cap) while simultaneously selling a put option (floor) to net the premium to zero. This creates a defined price range that protects ratepayers from extreme price spikes (the cap) while allowing them to benefit from downward market trends until the floor is reached.
3. **Independent Strategic Review**: The Division is less inclined towards this option, but it should be taken into consideration that the Company engages a third-party consultant to conduct an independent review and assist in developing a more diversified and cost-effective hedging framework. This could be done in coordination with the Commission and the Division.

The Division believes these are options the Company should consider going forward with natural gas hedging. Consequently, the Division requests that the Company provide a comprehensive economic analysis of its hedging strategy in the August 2026 hedging report. This analysis should utilize probabilistic Monte Carlo simulations, or some type of sensitivity analysis, to present various risk scenarios amid different price ranges.[13] The Division would like to see these simulations of alternative approaches and how they compare to the current swap-

[12] https://www.pcienergysolutions.com/2022/05/19/use-of-a-costless-collar-for-natural-gas-price-risk-management/
[13] The Company should consider doing something like what this gas distribution company, CenterPoint Energy, is doing on pages 45-50: https://www.centerpointenergy.com/en-us/Documents/2021-Gas-Procurement-Plan.pdf

Redacted

heavy strategy. For example, if the Rockies hub forecast continues to remain at a structural discount due to high regional supply, then the Company could maintain a lower hedge ratio to take advantage of cheaper spot prices. The Siemens PTI data supplied by the Company reports abundant local supply in the Rockies hubs and if the physical market is oversupplied and discounted, the benefit of a swap is a very expensive insurance policy for a risk that is very unlikely. This is where probabilistic modeling can be used to justify hedge ratios and what type of hedges are executed.

During the previous six months, natural gas prices [redacted] by [redacted] in the East region and decreased by [redacted] in the West.[14] The following chart compares the actual price PacifiCorp paid for natural gas over the last 12 months to the first-of-the-month market prices at the Opal (East) and Sumas (West) hubs.

Confidential Chart 4

As Chart 4 illustrates, the Company's realized prices remained substantially above market indices for the duration of the year. This is not too surprising, but the amount of the difference is concerning. A granular review of the underlying data reveals that this difference is primarily attributable to the Company's swap positions, with the most significant impact occurring at the Chehalis plant.

[14] Semi-Annual Hedging Report, page 1.

Redacted

For the forecasted [redacted] hedging period, minimum and maximum natural gas hedged position limits have been established for the East and West and are included in Appendix E of PacifiCorp's Energy Risk Management Policy. Hedging limits are designed to [redacted]. Transactions extending [redacted] are not prohibited but must comply with Transaction Approval Limits.[15] The established ranges for hedging natural gas in the East and West are as follows:

Confidential Chart 5

[redacted]

In December 2025, the Company's natural gas hedges in the West exceeded the upper limit of the Year 1 range before dropping sharply in the opposite direction at the end of the month. This volatility is illustrated in the following chart:[16]

Confidential Chart 6

[redacted]

[15] PacifiCorp Energy Risk Management Policy, May 12, 2025, Appendix E, page 34.
[16] Semi-Annual Hedging Report, page 35

Redacted

In its Semi-Annual Hedging Report, the Company provided the following explanation for these excursions:

> "The extended departure from the hedge bandwidth defined in policy was driven by changes in natural gas requirements resulting from both gas prices themselves and updates to the Chehalis variable operating and maintenance (VOM) adder to reflect increases in environmental compliance costs. If a natural gas percent volume hedge increases above the maximum natural gas percent volume hedge limit due to a change in the unhedged position, then the excursion is allowed indefinitely. This relieves the need for forced risk-increasing transactions to reduce the natural gas percent volume hedge. The sharp decrease in the hedge percentage observed near the end of 2025 was driven by an update to reflect Washington's acceptance of a full allocation of Chehalis, which effectively lowered compliance costs to $0, *sharply decreasing the plant's dispatch cost* and resulting in a *sharp increase to west side gas requirements*. As of December 31, 2025, the Year 1 west natural gas hedge percentage was 42.8 percent, but was returned to within limits on January 8, 2026, after hedges were executed." [17]

While the Division finds the initial upward excursion driven by market price fluctuations to be acceptable,[18] the subsequent sharp decrease caused by Washington compliance costs is deeply concerning. The data clearly shows that the VOM adder for Chehalis compliance costs artificially inflated dispatch costs and skewed natural gas requirements. Specifically, the adder surged from $2 to roughly $22 in mid-March 2025, peaked at over $32 in December 2025, and then plummeted back down to $2 on January 1, 2026.[19]

Adding $30 to a plant's dispatch price is substantial. It is very difficult to know how often the Chehalis plant did not run because of the large adder. If the Chehalis plant did not run because the dispatch price was too high, there is an incremental system cost between when the Chehalis plant would have been dispatched without the CCA adder and if it was dispatched with the CCA adder. More simply, when Chehalis fails to run because of an artificially inflated dispatch price,

[17] *Ibid*, pages 35-36, italics added.
[18] The second point made in Confidential Response to DPU Data Request 1.3.
[19] Confidential Response within DPU DR 1.2

Redacted

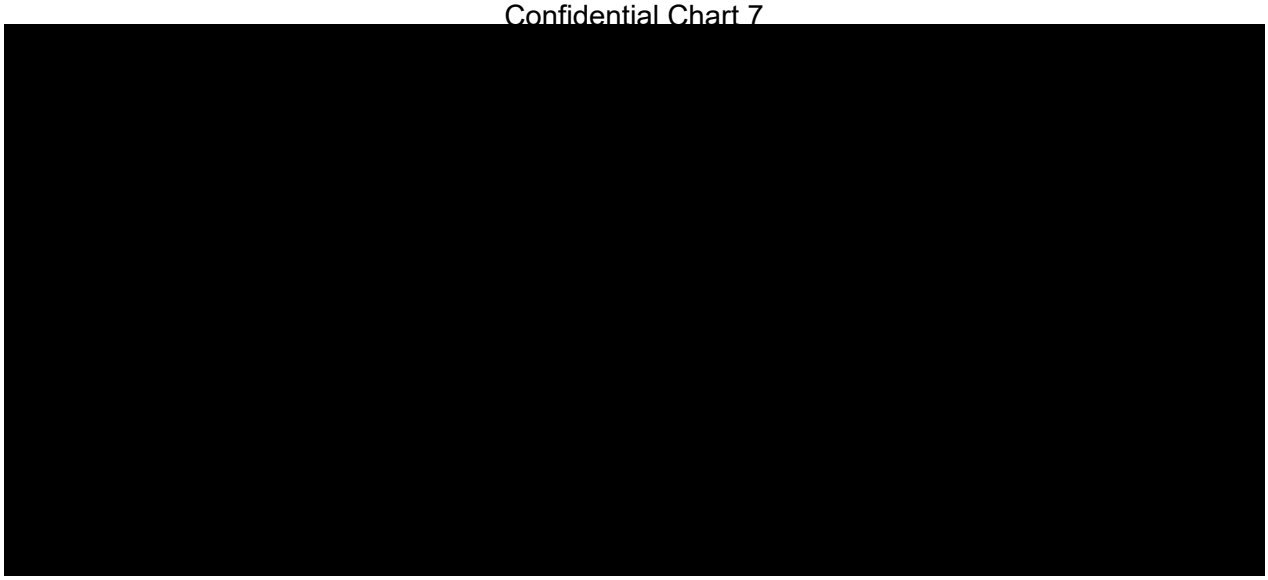
the system is forced to rely on more expensive alternatives. Consequently, ratepayers lose out on the benefit of lower-cost energy.

The Division acknowledges the Company's use of this adder, as the state of Washington is imposing Climate Commitment Act (CCA) costs on PacifiCorp. However, utility commissions in every state outside of Washington have consistently rejected these CCA costs as imprudent.[20] Because the Chehalis plant is treated as a system resource, its operational dispatch should benefit the entire system. Instead, its economic value was stifled by Washington-specific laws and the Company's operational reaction to them.

Applying a dispatch adder based on costs deemed imprudent outside of Washington effectively forces the broader system to absorb inefficiencies. Ultimately, the CCA dispatch adder merely protects shareholders and Company cash at the expense of the public interest and Utah ratepayers. The Division will further analyze the financial impacts of this practice within the EBA. Given the proposed sale of the Chehalis plant, this issue could resolve itself in time.

To provide a comparison of how PacifiCorp's forward prices for natural gas have changed since the last report, Confidential Chart 7 shows the forward prices on the East and West side of the PacifiCorp service territory as reflected in the last two reporting periods. Forward prices have dropped since the last report.

Confidential Chart 7



[20] Docket No. 24-035-04, Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.

Redacted

As economic conditions and market prices change, the forecasted gas requirement will also change. Confidential Chart 8 shows how the forecasted gas requirement for the next [redacted] has changed in the current report compared to the forecast requirement in the previous hedging report. This is only a snapshot based on the date of the report while the gas requirement is updated on a daily basis. The current forecast has a large increase over the next 6 months compared to the prior report. The Company states this is due [redacted].[21]

Confidential Chart 8

[redacted]

To evaluate the Company's gas hedging program, it is important to conduct a variance analysis comparing the forecasted gas requirement against actual consumption. The volume of hedges purchased is derived from the forecast. Consequently, forecast inaccuracies lead to inaccurate hedge positions. For example, a forecast that substantially overestimates actual usage could lead to excessive hedging transactions, which likely become an unnecessary financial burden on ratepayers. Confidential Chart 9 provides a retrospective comparison for the prior year,

[21] Confidential Response to DPU Data Request 1.5.

Redacted

showing the variance between forecasted volume and the actual amount of natural gas consumed.

Confidential Chart 9

As demand and market conditions change, it is reasonable to expect that the actual usage will vary from the anticipated requirement within a reasonable range.

Overall, the natural gas hedging program is working as outlined in the Energy Risk Management Policy. Although the Company currently operates within the parameters of the established Energy Risk Management Policy, the Division believes improvements could be made to lessen the costs while still providing the same assurances the Company seeks. With the pending Washington service area sale on the horizon, and the direct assignment of the Chehalis plant, major structural changes are likely to occur which could significantly alter the natural gas requirements and forecasts. [22] Going forward, the Division would like to see more rigorous, data-driven analysis regarding which hedges the Company chooses to pursue.

[22] Docket No. 26-035-20 Washington Service Area Sale

Redacted

Conclusion

The Division has reviewed the Semi-Annual Hedging Report, the attachments, and responses to the data requests. The information presented in the current report is similar in format and content to previous reports and includes both historical information and a forecast of future hedging activities. However, the Division would like to see more analysis from the Company on why it hedges the way it does for both power and gas. The Division is concerned with the high costs of implementing the current hedging program. The Division is also concerned that Company activities have resulted in imprudently incurred costs through a VOM adder for CCA costs for Chehalis. The Division will continue to investigate and make recommendations as it determines appropriate in other dockets.

cc: Jana Saba, Rocky Mountain Power
Max Backlund, Rocky Mountain Power
Michele Beck, Office of Consumer Services