CHRIS BURDIN
DEPUTY ATTORNEY GENERAL
IDAHO PUBLIC UTILITIES COMMISSION
PO BOX 83720
BOISE, IDAHO 83720-0074
(208) 334-0314
IDAHO BAR NO. 9810

Street Address for Express Mail:
11331 W CHINDEN BLVD, BLDG 8, SUITE 201-A
BOISE, ID 83714

Attorney for the Commission Staff

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AUTHORIZING CONSTRUCTION OF THE BOARDMAN-TO-HEMINGWAY 500-KV TRANSMISSION LINE PROJECT	)	**CASE NO. PAC-E-23-01** **COMMENTS OF THE COMMISSION STAFF**

STAFF OF the Idaho Public Utilities Commission, by and through its Attorney of record, Chris Burdin, Deputy Attorney General, submits the following comments.

BACKGROUND

On January 27, 2023, Rocky Mountain Power, a division of PacifiCorp ("Company" or "PAC") filed an application ("Application") requesting an order granting a Certificate of Public Convenience and Necessity ("CPCN") for Energy Gateway Segment H, the Boardman-to-Hemingway 500-kilovolt ("kV") transmission line ("B2H" or "Project"). The Company will co-own B2H with Idaho Power Company ("IPC"), which recently filed its own CPCN application for the Project in Case No. IPC-E-23-01.

On February 8, 2023, the Commission issued a Notice of Application and Notice of Intervention Deadline. Order No. 35678. Subsequently, the Idaho Irrigation Pumpers Association, Inc. and Bayer Corporation petitioned to intervene. On February 24, 2023, the

Commission granted intervention to both parties. Order No. 35686. On March 8, 2023, the Commission Secretary issued a Notice of Parties.

The Company represents that B2H is an approximately 300-mile-long, 500-kV electric transmission line that will extend from a switching station constructed near Boardman, Oregon to the existing Hemingway Substation located in Owyhee County, Idaho. The Company stated that approximately two hundred and seventy-four (274) miles of the transmission line will be in five Oregon counties: Malheur, Baker, Union, Umatilla, and Morrow Counties, and a 24-mile segment of the Project will be in Owyhee County in Idaho. The Company represents that B2H will also include ten communication stations along the route that are constructed within the right-of way of the transmission line, and B2H will also include the installation of the B2H Midline Series Capacitor Project and development of a remedial action scheme.

The Company represents that B2H enables lower-cost and more reliable transmission service to serve customer load and increases transmission connectivity between PacifiCorp East ("PACE") and PacifiCorp West ("PACW") balancing authority areas ("BAA") and will enable the Company to cost-effectively and reliably serve growing customer load. The Company stated that these benefits primarily result from cost savings in serving load in central Oregon and near the proposed Longhorn substation. Application at 9.

The Company represents that B2H is the most cost-effective means of serving the Company's load, and that without B2H, the Company would be required to acquire higher-cost generation resources and third-party transmission service, which together would increase customer costs by approximately $1.713 billion through 2042. *Id.*

The Company represents that the cost savings are based on an anticipated 2026 in-service date for B2H. The Company states that to ensure that the Project can be energized in time for a 2026 in-service date, construction must begin in the summer of 2023. The Company requested that the Commission issue an order on its Application no later than June 30, 2023. *Id.* at 9-10.

STAFF ANALYSIS

Staff reviewed the Company's Application and its responses to discovery requests. Based on the information, Staff believes that the Company needs to increase the capacity of its transmission system to enable it to meet loads across its east and west balancing areas and the proposed B2H project is the least-cost least-risk solution. Therefore, Staff recommends the following:

1. The Commission should grant a CPCN for the Company to construct the B2H transmission line but make recovery contingent on approval of all agreements requiring Commission approval and the Commission's determination of prudence of actual costs;
2. When the Company files for recovery, it should include evidence of its pursuit of alternative funding sources for the project;
3. The Commission establish a soft cap for the recoverable value of the project. The soft cap should be compared to the all-in total B2H costs including non-B2H expenses that may be incurred if B2H fails to stay on schedule and needs to mitigate any capacity shortfalls; and
4. The Company should provide a detailed breakdown of the soft cap cost components in a subsequent compliance filing with input from Commission Staff on which components to include.

Project Description

The Application describes the B2H project and several other infrastructure project agreements that are necessary to ensure the full benefits of B2H are realized for each party. Below is an inclusive list of the various infrastructure projects categorized by agreement type.

<u>The Boardman to Hemingway Transmission Line Project ("B2H")</u>

The primary project seeks to acquire rights of way ("ROW"), and construct approximately 300 miles of 500-kV transmission lines between Boardman, Oregon and Hemingway, Idaho. It will also:

- Construct or improve access roads for the transmission line;
- Construct communication regeneration sites along the transmission line;
- Rebuild or remove certain other transmission line segments;
    - Remove 12 miles of 69-kV transmission line;
    - Rebuild 1.1 miles of 138-kV transmission line;
    - Rebuild 0.9 miles of 230-kV transmission line;

- Construct the Longhorn substation;
- Upgrade the Hemingway substation; and
- Construct the Midline Series Capacitor substation.

The B2H project will be constructed through a partnership between the Company and IPC, in which the Company will fund and own 55.55 percent, and IPC will fund and own 45.45 percent. IPC will be responsible for managing the construction.

<u>Central Oregon Agreements</u>

The Company and BPA have negotiated a set of agreements ("Central Oregon Agreements") that will more effectively support transmission in central Oregon. The major elements are:

- PAC-BPA agreement to revise or establish 15 point-to-point ("PTP") transmission service tables that will, upon B2H energization, provide PAC with 340MW of transmission rights from the north, and 340MW of transmission from Summerlake, to the central Oregon load;
- PAC-BPA agreement for PAC to upgrade the existing Meridian Series Capacitor at the Meridian substation (or an equivalent series capacitor in the Dixonville-Meridian-Klamath Falls-Captain Jack lines); and
- PAC-BPA agreement to provide BPA 1000 MW of bi-directional capacity in the Summerlake – Malin Line.

<u>Asset Exchanges</u>

The Company and IPC have agreed to a collection of future asset exchanges and construction projects ("Asset Exchanges"), designed to be implemented if B2H is energized. The proposed Asset Exchanges are:

- IPC will transfer to the Company transmission assets between Midpoint and Borah for 300 MW west-to-east capacity;
- IPC will transfer to the Company transmission assets between Borah and Hemingway for 600 MW east-to-west capacity;
- The Company will transfer to IPC transmission assets between Populus and Four Corners for 200 MW of bi-directional capacity;

- The Company will transfer to IPC transmission assets in the Goshen area;
- IPC will construct the Midpoint 500/345-kV transformer project; and
- IPC will construct the Kinport-Midpoint 345-kV series capacitor project.

Miscellaneous Agreements

Miscellaneous other agreements between the three entities will go into effect at various times:

- BPA will transfer to the Company two 100 MW PTP Transmission Service Agreements ("TSA(s)") it has with IPC;
- IPC will buy out BPA's 24 percent ownership share of B2H, increasing IPC's ownership and funding responsibility to 45 percent. IPC will also reimburse BPA for its share of the permitting expenses incurred over the last decade.
- In return for IPC's buyout, BPA will commit to purchasing long term TSAs from IPC to deliver power to BPA's customers in southeastern Idaho; and
- IPC and BPA will establish a 500 MW PTP TSA from the Mid-Columbia ("Mid-C") market hub to the proposed Longhorn substation.

CPCN

Summary of Staff's CPCN Recommendations

The Company must increase the capacity of its transmission system to enable it to meet its increasing loads across its east and west balancing areas, and B2H is the least-cost solution to resolve it. Therefore, Staff recommends that the Commission grant a CPCN for the Company to construct the B2H transmission line. Staff also recommends that the Commission clarify that the CPCN does not include the other agreements described in the Application, and those other agreements should be submitted for separate approval if and when appropriate. Finally, Staff recommends that when the Company does file for recovery of actual cost, it should include evidence of its pursuit of government funding sources for the project.

<u>Company's CPCN Request</u>

Review of Idaho Codes § 61-526 and § 61-528

For authority to construct or extend a transmission line, Idaho Code § 61-526 requires the Company to obtain "from the Commission a certificate that the present or future public convenience and necessity require." Additionally, the Company must show "the financial ability and good faith…and necessity of additional service in the community." *Idaho Code* § 61-528. Staff believes the Company has repeatedly demonstrated its financial ability to obtain capital for a project of this scale. Staff also accepts the Company's assertion that the financial investment for the B2H project will not impair its ability to provide safe and reliable electricity service at reasonable rates. The Company has provided safe and reliable service to its approximately 88,000 Idaho customers, along with its customers in five other states.

Assessment of System Need

The Company anticipates up to 340 MW of incremental load growth in central Oregon, and additional load growth in the Longhorn area, both being within its western BAA. The Company has surplus generation capacity in its eastern BAA but insufficient transmission capacity to reliably deliver the power to western loads. Staff was unable to independently confirm the specific load growth in the Company's 2021 IRP because the IRP considers the larger PACW BAA and doesn't provide granularity for specific regional loads. Response Production Request No. 8. However, the 2021 IRP shows an overall PACW resource capacity deficit in 2026, with shortfalls of 1,105 MW in the summer and 1,301 MW in the winter. 2021 IRP Volume 1 at 154 and 156, Case No. PAC-E-21-19.

Additionally, the Company explained the nature of the incremental growth in its testimony and in its responses to Staff production requests. The Company also provided a confidential joint planning study ("Study"), in which it addressed the incremental central Oregon load. Both the testimony and the 2021 IRP affirm that the existing transmission infrastructure is inadequate to serve the additional load in PACW. Based on these documents, Staff believes that the Company's assertion of need is reasonable.

Scope of CPCN

The Application describes several agreements, but not all of them are part of the Company's request for a CPCN. The Company clarified the specific actions for which it seeks the CPCN. *See* Response to Staff's Production Request No. 1. The actions specific to the Company's CPCN request in this filing are identified in the *Project Description* section above, under the *Boardman to Hemingway Transmission Line Project* heading. The Company is not seeking a CPCN for the Central Oregon Agreements, the Asset Exchanges, or the other miscellaneous agreements.

Staff recommends that the Commission state that CPCN approval does not implicitly approve the other agreements, such as the Asset Exchanges, and the Company should file applications for Commission approval when appropriate.

<u>B2H as a Solution</u>

B2H Meets the System Needs

The Company expects to obtain from B2H 300 MW of west-to-east transmission capacity and 818 MW of east-to-west transmission capacity, which will help the Company serve its customer load across both BAAs.

Staff's analysis identified that the effectiveness of B2H will depend on the successful construction of the B2H transmission line, and on other agreements that are external to the transmission line. For the Company, the Asset Exchanges and the Central Oregon Agreements are also essential to meet the system need.

The Asset Exchanges are necessary to provide additional transmission capacity to the Company from its PACE BAA to the Hemingway terminus of B2H. The Central Oregon Agreements are necessary to provide additional transmission capacity from the Boardman terminus of B2H to the central Oregon load.

Staff discusses the risks associated with these issues in the *Project Risks* and *Other Risks* sections below.

Assuming the project and the related actions are completed, Staff concludes that B2H will resolve the system need. However, given that additional agreements will require separate Commission approval, Staff recommends granting approval of the CPCN but make recovery contingent on the Commission's approval of those additional agreements.

B2H is Cost Reasonable

Staff reviewed the cost of B2H against the next least-cost alternative to assess the decisional prudence of the project. From this review, Staff believes that selecting the B2H project was a prudent decision. For operational prudence, Staff will review the actual project costs once the Company files a subsequent case seeking recovery.[1]

The Company provided extensive modeling and cost analysis using its PLEXOS model through its 2021 IRP process. *See* Case No. PAC-E-21-19. The PLEXOS model is used to optimize resources and transmission lines that the Company will use to serve its customers. The PLEXOS model, under several alternative futures, showed the portfolio with B2H transmission line as the least-cost and least-risk preferred portfolio. "In the 2021 IRP, B2H was projected to result in $453 million in risk-adjusted net benefits.... Similarly, the 2021 IRP Update projected risk-adjusted net benefits of $439 million...." Link Direct at 3. After the 2021 IRP Update, several key changes occurred, and the Company now projects risk-adjusted net benefits of $1.713 billion. The bulk of the benefit is derived by avoiding the cost of constructing a new solar and eight-hour storage[2] facility to serve the central Oregon load.

The Company also believes, and Staff agrees, that B2H will provide "lower-cost and more reliable transmission service" to its customers. Application at 2. Company Witness Link described that with B2H in-service, the Company would reduce its third-party wheeling expenses and those cost savings would be attributed to the Company's retail customers. Link Direct at 25. Staff reviewed the Company's cost estimate and verified that the Company provided sufficient justification for the B2H transmission line as the least-cost least-risk option.

Separately, Staff is concerned that the Company has not pursued alternative funding, such as grants that could potentially reduce the impact to ratepayers. Staff recommends that when the Company seeks recovery of costs for the B2H project, that it provides evidence of conducting investigations, analyses, and/or applications for grants or alternative funding from federal, state, or local agencies.

[1] Decisional prudence is a determination that the "decision" to move forward with an investment is based on need and in this case is the least cost alternative. Operational Prudence is a determination that the Company implemented the investment in a least-cost manner.

[2] The 2021 IRP and 2021 IRP Update both identified 4-hour battery storage duration; however, the Company upgraded it to 8-hour battery storage duration in this filing. Link Direct at 26.

Project Risks

Staff recommends that the Commission establish a soft cap as reflected in response to Production Request No. 3(b) and as shown in Confidential Staff Attachment A for the recoverable cost of constructing the project. The total cost of the project plus any additional cost necessary to meet load if the project fails to stay on schedule should be part of the all-in total B2H costs that will be compared to the established soft cap. The soft cap should be the threshold that will require the Company to provide robust justification for construction costs over the cap to receive recovery.

Because of the complexity and amount of uncertainty associated with the B2H transmission project, the Company faces significant risks throughout the entire project life cycle that may ultimately impact customers. Staff categorized the risks into three types: project capability risk, project schedule risk, and project cost risk. In the following sections, Staff discusses the three types of risk, recommends mitigations for each type, explains each risk issue, and provides the latest status for each. Table No. 1 summarizes the three types of project risk and the key issues contributing to them.

Table No. 1: Project Risks

Capability Risks	Schedule Risks	Cost Risks
Longhorn Substation: B2H will be unusable without this interconnection.	*Longhorn Substation:* The permitting process is in progress and the construction timeline is unknown.	*Longhorn Substation:* The cost of an alternative is unknown.
ROW Acquisitions: B2H cannot be built without the ROW(s).	*ROW Acquisitions:* ROW delays might delay construction, especially if legal action becomes necessary.	*ROW Acquisitions:* ROW negotiations have the potential to increase costs.
Boardman-Ione ("B-I") Alternate Transmission Path: B2H cannot be completed without relocating this line.	*B-I Alternate Transmission Path:* An alternate line is in the early stages of permitting, followed by construction of the line, then demolition of the old line.	*B-I Alternate Transmission Path:* The alternate path and cost are not certain, and environmental mitigation may be required.
	Supply Chain: Substantial delays exist for key project materials.	*Inflation:* High inflation persists, especially for key project materials.
	Outstanding Permits: Various project permits are outstanding, and delays are typical.	

Project Capability Risk

Project capability risk is the risk that an essential part of the project cannot be completed, thereby preventing completion of the overall project. For example, the B2H line terminates in Boardman, but a third party (BPA) must construct the Longhorn substation to interconnect it to the existing transmission grid. Without proper interconnection, B2H will not be usable.

Staff identified three capability risk issues for B2H:

1. The Longhorn substation;
2. Acquisition of the ROWs to construct B2H; and
3. Establishment of an alternate transmission path for BPA's B-I line.

The *Project Risk Issue* section explains each of these in more detail.

Although any of these issues (or other unforeseen ones) could prevent the successful completion of B2H, Staff assumes that the Company will find a workaround to complete the project and make it useful. Staff concludes that these capability risks may translate into increased project costs and/or schedule growth. Therefore, Staff makes no recommendation for capability risk, but will provide recommendations to mitigate schedule and cost risk, which Staff discusses in the following sections.

Project Schedule Risk

Staff identified five risk issues that have potential to delay the overall project schedule:

1. The Longhorn substation;
2. ROW acquisitions for B2H;
3. The B-I alternate transmission path;
4. Supply chain delays; and
5. Outstanding permits.

The *Project Risk Issue* section explains each of these in more detail.

Schedule delays manifest as cost risk to ratepayers. The current planned in-service date for B2H is June 1, 2026. If B2H is not online at that time, the Company may need to incur additional expenses outside of B2H to provide additional capacity for the central Oregon load growth. Staff recommends that if circumstances delay the project beyond the planned in-service date, the Commission should require the Company to track and report any expenses incurred outside of B2H to cover central Oregon capacity deficits until B2H is online. These expenses should be part of the all-in total B2H costs compared to the soft cap limit recommended in the *Project Cost Risk* section.

Project Cost Risk

Staff identified four cost risk issues that have potential to drive the project cost beyond the current estimate:

1. The Longhorn substation;
2. ROW acquisitions;
3. The B-I alternate transmission path; and
4. Inflation.

The *Project Risk Issue* section explains each of these in more detail.

Project cost overruns represent a direct risk to ratepayers, who will be asked to recover the full cost. The Company has retained experienced engineering firms to refine the project estimate and has shown due diligence in responsibly estimating the project cost. The Company has also established cost control policies, in cooperation with IPC, to provide reasonable oversight of the project costs.

However, to further protect customers, Staff recommends that the Commission place a soft cap on the project in accordance with the Application estimate. If the final project cost exceeds the soft cap, the Company should provide convincing evidence of its efforts to remain within the cap, the reasons it had to exceed the cap, and justify any overages at the time recovery is requested.

Quantifying the cost of a complex project like B2H requires careful attention to many details. Items that must be specified include the date of the estimate, major construction features, contingency markups, shared and unshared costs between partners, financing costs, and taxes. Staff requested that the Company provide a detailed breakdown of these costs in Production Request No. 3, but the Company only provided the bottom line total, sub-divided into direct and overhead costs. Staff recommends that the Commission use the Company's bottom line total estimate as the soft cap for any future recovery. Staff also recommends that the Commission require the Company to provide a detailed breakdown of the cost components in a subsequent compliance filing. This detailed breakdown will provide benchmarks to assist Staff and the

Company in any future cost recovery filing. The Company should consult with Staff to determine an appropriate level of cost component breakdown.

Project Risk Issues

Staff performed an analysis of the types of risks described above for specific risk issues associated with the construction of the B2H project. The results of Staff's analysis are described below for each specific risk issue.

Longhorn Substation

The northern terminus of B2H must have the Longhorn substation constructed to connect to the existing transmission network. Without this substation, the transmission path would be incomplete, and the project would not be useful. In short, the Longhorn substation is a critical component of B2H. BPA owns the land for the Longhorn Substation and intends to construct, own, and operate the substation. The substation will have other terminals, one of which is in progress to provide interconnection services for Umatilla Electric Cooperative ("UEC").[3] Based on Staff's analysis described below, Staff believes that the capability, schedule, and cost risks associated with the Longhorn substation are all low.

Staff believes the Company has no realistic alternative to the Longhorn substation. Staff asked the Company to describe its contingency plan if BPA is unable to complete its responsibilities. The Company stated, "At this time, there are no contingencies that would provide for connecting the line into BPA's 500 kV transmission system." Response to Production Request No. 7.

Despite the lack of a contingency plan, Staff believes the risk of BPA not building the substation is low because the substation is critically important to BPA, the Company, IPC, and UEC. Furthermore, BPA owns the land, has completed the environmental review process, and has therefore resolved two major problem areas. Funding for the substation has been built into the overall B2H cost, including a 20 percent contingency.

ROW Acquisitions

The Company has already obtained ROWs across federal and state property, which eliminates much of the risk associated with the project. However, the Company must still

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[3] The Umatilla Electric Cooperative serves a portion of the Columbia Basin and Blue Mountain county in Northeastern Oregon.

acquire many private easements, so significant risks remain relating to costs and scheduling. The Company has estimated the fair market value of the remaining ROWs, added a contingency, and built that into the project budget. Each landowner must be persuaded to grant an easement for a fair price. For each landowner that cannot be persuaded, the Company will have to balance between offering more money (cost risk) or pursuing a legal remedy (schedule risk). Staff believes that both cost and schedule risks are significant for this issue. However, Staff believes that this case pairs well with the statutory framework of the Company's condemnation rights. Staff believes that this can serve as a backstop to reduce these risks. *See Idaho Code* § 7-711A.

Boardman to Ione Alternate Transmission Path

Currently, the 69-kV B-I transmission line crosses U.S Navy property in Umatilla County, Oregon. The B2H transmission line must be constructed across a portion of the B-I path. BPA has agreed to remove the interfering segment, but before the B-I segment can be removed, BPA must construct an alternative transmission path to serve its Columbia Basin load. This creates significant cost and schedule risk for the Company.

The Company and IPC executed an agreement with BPA on March 18, 2020, to pay BPA for its costs associated with removing the B-I line and building the new path. BPA must construct and energize the alternate transmission path by Spring of 2025, to allow time to remove the old line and finish B2H by Spring of 2026.

Currently, BPA is performing environmental studies of the proposed alternate path so potential environmental issues or mitigation to resolve them are not yet known. The Company has included an approximate cost estimate for this work in its overall B2H budget, but the final project scope is yet to be determined.

Supply Chain

Staff believes the current supply chain problems add significant schedule risk to the project. Staff has received reports from utility companies that the purchase lead time for transformers has grown from a few months to 24 to 36 months. Likewise, the purchase lead time for electric meters has grown from 8 weeks to 52 weeks. Similar situations exist for other components. Although national efforts are being directed to alleviate some of these issues, the risk of schedule delay due to supply chain problems is significant.

Inflation

Staff believes that persistent inflation adds significant cost risk to the project. The Company mitigated inflation risk by hiring experienced transmission engineers to update the cost estimates reflecting the most current prices as of January 2023, and then adding 20 percent contingency to account for the uncertainty of inflation. However, Staff has received recent reports from utility companies with evidence that certain electrical components such as transformers, switch gear, and electric cabling have increased in price by as much as 80 percent over the last year. Even with the 20 percent contingency, the Company's final project cost may be underestimated.

The Company has additional cost risk because it does not have direct control of construction oversight, having delegated the construction management to IPC. However, The Construction Funding Agreement defines the Company's and IPC's roles and responsibilities in construction of the B2H project. Application, Exhibit No. 1 at 24-29. This agreement, in conjunction with the Construction Funding Committee, should provide sufficient oversight capability to manage the project cost.

Outstanding Permits

The primary risk from an outstanding permit is schedule delay. The Company has spent years obtaining the most difficult project permits, but several routine permits and permits out of the Company's control are still outstanding.

The environmental review is not complete for the new B-I substation, and the engineering studies are incomplete for the Longhorn substation. These requirements are the responsibility of BPA and are outside of the Company's control. In addition, environmental reviews are frequently used by opponents to block federal actions. These reasons lead Staff to believe that schedule risk for all outstanding permits is at a moderate level.

Other Risks

In addition to the risks associated with the construction of the project, Staff identified and analyzed several other risks that are *external* to the construction of the project but may result in unrealized benefits after the project is put into operation. However, Staff believes its analysis of these costs and benefits from the project supports the CPCN when comparing it to the costs and benefits of the next best alternative.

Asset Exchanges

The Company's primary purpose for B2H is to obtain a robust transmission corridor to better connect the PACW and PACE BAAs. B2H will provide most of the benefits to the Company's system, but without the Asset Exchanges between the Company and IPC listed in the *Project Description* section, the full extent of the project benefits to the Company will be limited, posing a risk if the exchanges do not occur.

These Asset Exchanges require Commission approval under Idaho Code §61-328. The Company and IPC have mitigated this risk by signing an agreement to execute these exchanges; however, these agreements are contingent on obtaining Commission approval. Under the statute, the remaining risk of obtaining Commission approval is if the value of the assets being exchanged is not comparable. This issue will need to be resolved when the two companies file for authorization from the Commission. Given the current signed agreement between the Company and IPC, Staff believes the risk in completing the Asset Exchanges is low. However, Staff recommends that recovery for the cost of the project be contingent on both the Company and IPC obtaining Commission approval of these exchanges.

Central Oregon Agreements

The major components of Central Oregon Agreements are described in the *Project Description* section. This set of agreements is necessary for the Company to deliver power via B2H to central Oregon load. Without modifying the PTP agreements, the transmission path to central Oregon would still be constrained, and the usefulness of B2H to the Company would be reduced. This risk rests primarily on the Company since reduced usefulness would reduce its basis for cost recovery.

Staff believes the risk of this issue is low since the Company and BPA have signed the agreements. However, there are remaining risks given contingencies contained in the agreements, especially the need for FERC approval, which is outside of the Company's control.

Customer Notice and Public Comments

A telephonic Customer Workshop for Rocky Mountain Power's application was held on Wednesday, April 19, 2023. Customer participation was minimal. As of Thursday, May 25, 2023, there has been one (1) Customer Comment received, which was in support of this case.

STAFF RECOMMENDATIONS

Staff recommends that the Commission:

1. Issue an order granting a CPCN for the construction of the B2H project but make recovery contingent on the Commission's approval of all Asset Exchanges and a determination of the prudence of actual cost when the project is complete;
2. Direct that when the Company does file for recovery, it should include evidence of its pursuit of alternative funding sources for the project;
3. Establish a soft cap for the recoverable value of the project as discussed above; and
4. Require the Company to provide a detailed breakdown of the soft cap cost components in a subsequent compliance filing with input from Commission Staff on the components to include.

Respectfully submitted this 25th day of May 2023.

Chris Burdin
Deputy Attorney General

Technical Staff: Matt Suess
Jolene Bossard
Jon Kruck
Kevin Keyt
Kimberly Loskot

i:umisc/comments/pace23.1cbmsjkjbklkk comments

ATTACHMENT A IS CONFIDENTIAL AND PROTECTED UNDER THE PROTECTIVE AGREEMENT

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 25th DAY OF MAY 2023, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF TO,** IN CASE NO. PAC-E-23-01, BY E-MAILING A COPY THEREOF, TO THE FOLLOWING:

MARK ALDER
ROCKY MOUNTAIN POWER
1407 WEST NORTH TEMPLE STE 330
SALT LAKE CITY UT 84116
E-MAIL: mark.alder@pacificorp.com

JOHN HUTCHINGS
CARLA SCARSELLA
ROCKY MOUNTAIN POWER
1407 WEST NORTH TEMPLE STE 330
SALT LAKE CITY UT 84116
E-MAIL: john.hutchings@pacificorp.com
carla.scarsella@pacificorp.com

DATA REQUEST RESPONSE CENTER
E-MAIL ONLY:
datarequest@pacificorp.com

KATHERINE McDOWELL
ADAM LOWNEY
McDOWELL RACKNER GIBSON
419 SW 11TH AVE STE 400
PORTLAND OR 97205
E-MAIL: katherine@mrg-law.com
adam@mrg-law.com

ERIC L OLSEN
ECHO HAWK & OLSEN PLLC
PO BOX 6119
POCATELLO ID 83205
E-MAIL: elo@echohawk.com

LANCE KAUFMAN PhD
2623 NW BLUEBELL PLACE
CORVALLIS OR 97330
E-MAIL: lance@aegisinsight.com

THOMAS J BUDGE
RACINE OLSON PLLP
PO BOX 1391
POCATELLO ID 83204-1391
E-MAIL: tj@racineolson.com

BRIAN C COLLINS
GREG MEYER
BRUBAKER & ASSOCIATES
16690 SWINGLEY RIDGE RD, #140
CHESTERFIELD MO 63017
E-MAIL: bcollins@consultbai.com
gmeyer@consultbai.com

SECRETARY