PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

March 20, 2023

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Salem, OR 97301-3398

RE: PCN 5—PacifiCorp's Rebuttal Testimony

PacifiCorp d/b/a Pacific Power encloses for filing its Rebuttal Testimony in the above referenced docket. Confidential information is provided subject to Order No. 22-309 in this docket.

If you have questions about this filing, please contact Cathie Allen, Regulatory Affairs Manager, at (503) 813-5934.

Sincerely,

Matthew McVee
Vice President, Regulatory Policy and Operations

Enclosure

Docket No. PCN 5
Exhibit PAC/200
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Rebuttal Testimony of Rick T. Link

March 2023

TABLE OF CONTENTS

ATTACHED EXHIBITS

Q. Are you the same Rick T. Link who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

I. PURPOSE AND SUMMARY

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to respond to the opening testimony of the Public Utility Commission of Oregon (Commission) Staff witness Sudeshna Pal. Specifically, I respond to Staff witness Pal's testimony regarding the benefits of the Boardman-to-Hemingway transmission line (B2H or Project) to PacifiCorp customers.

Q. What do you recommend?

A. PacifiCorp continues to support Idaho Power Company's (IPC) Application for Certificate of Public Convenience and Necessity (CPCN) for B2H. B2H provides significant risk-adjusted net benefits to, and is necessary to reliably and cost effectively serve, PacifiCorp's customers.

II. REPLY TO STAFF

Q. To evaluate B2H, Staff states that it needs a better understanding of the benefits of B2H to PacifiCorp customers, in particular its Oregon customers.[1] Is B2H necessary to meet PacifiCorp's need to reliably and cost effectively serve PacifiCorp customers, in particular its Oregon customers?

A. Yes. The 2021 Integrated Resource Plan (IRP) and 2021 IRP Update showed that B2H is necessary to meet the Company's need to reliably and cost effectively serve

[1] Staff/100, Pal/38:3-8.

customers, and it was part of the preferred portfolio in both plans. Both the 2021 IRP and 2021 IRP Update specifically examined the portfolio impacts and system cost implications of not participating in B2H relative to the preferred portfolio outcome that included it. Both analyses showed that building B2H was the least-cost, least-risk outcome. In the 2021 IRP, B2H was projected to result in $453 million in risk-adjusted net benefits during the study horizon of 2021 through 2040.[2] Similarly, the 2021 IRP Update projected risk-adjusted net benefits of $439 million during the same period.[3]

Since the 2021 IRP Update was prepared, several key changes have occurred. First, the Company's most recent load forecast has significantly increased, reflecting both new load and the impact of climate change. Second, the United States Environmental Protection Agency (EPA) proposed its "Ozone Transport Rule" (also called the Good Neighbor Rule or Cross-State Air Pollution Rule) to establish allowance-based emissions limits for nitrogen oxides (NOx) that will impact PacifiCorp's thermal resources in Utah and Wyoming. Third, the enactment of the federal Inflation Reduction Act (IRA) has extended and expanded tax incentives for clean generation and energy storage resources. Finally, PacifiCorp's transmission service requirements have evolved considering that the Bonneville Power Administration (BPA) may be unable to reasonably accommodate some of the modifications to PacifiCorp's existing transmission service arrangements contemplated in the non-binding B2H Term Sheet, dated January 18, 2022, attached as

[2] PacifiCorp's 2021 Integrated Resource Plan. Volume I. September 1, 2021. Pg. 271-272. Available at: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf

[3] PacifiCorp's 2021 Integrated Resource Plan Update. March 31, 2022. Pg. 89-91. Available at: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021_IRP_Update.pdf

Exhibit PAC/201.[4] After incorporating these and other associated changes, B2H is now projected to result in $1.713 billion in risk-adjusted net benefits during a study horizon of 2023 through 2042, assuming medium natural gas and carbon prices.

The Project significantly enhances the capability of the regional electric grid, and the current B2H benefit estimate has three distinct aspects. First, B2H will increase the bidirectional transfer capability between PacifiCorp's east and west balancing authority areas (BAA). Second, B2H enables lower-cost and more reliable transmission service to PacifiCorp's central Oregon loads. Third, B2H allows for lower cost transmission service to PacifiCorp loads in the vicinity of BPA's planned Longhorn substation, which is the western terminus of B2H.[5]

In the Company's economic analysis, PacifiCorp evaluated the change in revenue requirement associated with B2H using the PLEXOS model under a range of natural gas price and carbon dioxide (CO_2) policy assumptions (price-policy scenarios). PacifiCorp calculated the change in system revenue requirement between cases with and without B2H, where capital revenue requirement is levelized.

The change in annual nominal revenue requirement through 2042 was also calculated to provide some perspective around potential rate pressures relative to a case that does not include B2H.

---

[4] The Term Sheet is also available at: https://docs.idahopower.com/pdfs/B2H/B2H-termsheet-bpapacIPCSigned-IP.pdf
[5] The Longhorn substation is approximately four miles east of the city of Boardman, Oregon.

Q. How is the remainder of your testimony structured?

A. In Section III, I discuss how B2H was modeled in the 2021 IRP. In Section IV, I explain how B2H was modeled in the 2021 IRP Update. Finally, in Sections V through VIII, I discuss PacifiCorp's updated economic analysis.

III. 2021 INTEGRATED RESOURCE PLAN

Q. Does the 2021 IRP identify a need for additional resources and transmission to serve PacifiCorp's customers?

A. Yes. The primary focus of any IRP is to forecast customer demand and to evaluate different combinations of resources and transmission to meet that customer demand over time. In the 2021 IRP, the preferred portfolio represents the least-cost, least-risk portfolio of resources and transmission options, as presented in Tables 9.16 and 9.17 in Chapter 9 of Volume I. Consistent with prior IRPs, in the 2021 IRP, all resource portfolios that were considered as candidates for the preferred portfolio contain new supply-side, demand-side, market resources, and transmission upgrades necessary to meet customer demand.

Q. Was B2H included in the 2021 IRP preferred portfolio?

A. Yes. In the 2021 IRP, after a variety of price-policy and coal retirement scenarios were considered, the P02-MM[6] portfolio was identified as top-performing and B2H was included in that portfolio. At that point, eight variants of P02-MM were prepared to analyze key resource and transmission decisions. As B2H was already part of the P02-MM portfolio, a "No B2H" portfolio was prepared that excluded B2H. The

[6] In the 2021 IRP, the P02 series of portfolios reflect fully optimized coal unit retirements using the best available input data and assumptions regarding requirements and constraints. The P02-MM portfolio was selected assuming medium gas prices and a medium CO2 price proxy for future federal policy.

P02-MM portfolio, which includes B2H, was identified as the top-performing portfolio among all variants, including the variant that removed B2H.[7]

Q. Did the 2021 IRP modeling account for the interdependence of resources and transmission, like B2H?

A. Yes. The PLEXOS model used to develop the 2021 IRP, which I discuss in more detail below, has the ability to endogenously view costs and transmission capability associated with transmission upgrades and allows for selection of specific transmission investments that coincide with new resource options. Endogenous transmission modeling capabilities in the PLEXOS model include the consideration of 1) new incremental transmission options tied to resource options; 2) existing transmission rights tied to the use of post-retirement brownfield sites; 3) estimated costs associated with these transmission options; and 4) transmission options that interact with multiple or complex elements of the IRP transmission topology. When the 2021 IRP modeling evaluated transmission investments, it accounted for the assumed cost for those investments and the value generated by those investments by enabling low-cost resource options and better optimization of resources needed to serve load or to lower system costs.

[7] The 2021 IRP also identified additional resources related to compliance with Washington's Clean Energy Transformation Act ("CETA") that were added to establish the 2021 IRP preferred portfolio (P02-MM-CETA). The additional resources necessary to comply with CETA, however, are not treated as system resources for purpose of the IRP and had no impact on the need for B2H.

Q. Please describe the reliability benefits from B2H that were identified in the 2021 IRP.

A. The 2021 IRP indicated that energy not served (ENS) would be slightly higher in the absence of B2H. ENS is reported as an output of the PLEXOS model and it indicates the volume of load that could not be met do to a shortfall of supply in modeled load areas across PacifiCorp's system.

Q. Does the 2021 IRP fully capture the expected system reliability benefit associated with B2H?

A. No. The 2021 IRP reflects PacifiCorp's load, resources, and transmission rights, plus limited access to market purchases. In light of regional reliability concerns, discussed in Chapter 5 of the 2021 IRP, the maximum amount of market purchases available was reduced significantly from the level in the 2019 IRP. These reductions were applied in the summer season for the California-Oregon Border (COB), Nevada-Oregon Border (NOB), and Mona markets whose participants typically experience peak demand in the summer. For the Mid-Columbia (Mid-C) market, the maximum amount of market purchases was reduced in both seasons, but by a larger amount in the winter season, as the Pacific Northwest is generally winter peaking. By enhancing the connection between the summer and winter-peaking areas of PacifiCorp's system, B2H will make it more likely that purchases can be procured from markets that are not experiencing peak conditions and delivered where they are needed (i.e., purchases imported to PacifiCorp's East BAA in the winter and purchases imported into PacifiCorp's West BAA in the summer). While modeled market purchase limits are representative of what might be available during peak demand conditions, there are many hours within summer and winter seasons in which regional demand is likely to support market transactions well in excess of those limits. Due to the market purchase limits, the reported results do not account for the entire improvement in reliability that B2H is likely to facilitate by providing additional access to distant markets.

Q. Will B2H increase PacifiCorp's reliance on market purchases?

A. No. Access to market purchases is not the same as reliance on market purchases. The P02-MM portfolio, which includes B2H has more resources as a result of higher interconnection capability provided by the Project. The addition of more resources generally reduces the need to rely on market purchases to serve customer load. This does not mean that market purchases will necessarily decline, as reduced congestion allows for more cost-effective market purchases to support customer load rather than more expensive dispatchable resources. To the extent dispatchable resources are called upon less often, but remain available as indicated by the increase in resources in the portfolio that includes B2H, PacifiCorp would not be reliant upon such purchases to meet its peak loads and reliability requirements.

IV. 2021 IRP UPDATE

Q. Has the Company prepared an update to the 2021 IRP?

A. Yes. On March 31, 2022, the Company issued its 2021 IRP Update.

Q. What is the purpose of the 2021 IRP Update?

A. The 2021 IRP Update serves as a checkpoint to the action plan contained in the 2021 IRP to ensure that changes in the planning environment are considered in between the full IRP planning process, which is completed every two years. The 2021 IRP Update assesses whether evolving trends and events that may ultimately impact customers merit a shift in the action plan to deliver resources and transmission investments that might be needed to reliably serve customers. As relevant here, the 2021 IRP Update reflects resource planning and procurement activities that have occurred since the 2021 IRP and presents an updated load-and-resource balance and an updated resource portfolio consistent with changes in the planning environment.

Q. Was B2H considered in the Company's 2021 IRP Update?

A. Yes. B2H and associated resource interconnections it will enable were included in the preferred portfolio identified in the 2021 IRP Update.

Q. Did the 2021 IRP Update continue to show a need for additional transmission resources?

A. Yes. In fact, the need increased relative to the 2021 IRP, primarily due to an increase in forecast load. While the same transmission options were available in the 2021 IRP Update as the 2021 IRP, the 2021 IRP Update included two new options and accelerated four others from the 2021 IRP.[8] This was partially offset by one delay and the removal of one option from the final year of the study horizon. There were no changes in the timing and need for B2H.

Q. Did the 2021 IRP Update continue to show a need for additional generation resources?

A. Yes. The resource need also increased due to an increase in forecast load. The 2021 IRP Update shows a resource need in all years of the planning horizon—starting at 1,584 megawatts (MW) in 2022 and increasing to 6,755 MW in 2040.[9] In 2027, the first full year that B2H will be in service, the resource need is 2,403 MW, an increase

[8] *See* 2021 IRP Update, Table 6.2
[9] *See* 2021 IRP Update, Table 4.2.

of 273 MW, or approximately 13 percent, relative to the resource need identified in the 2021 IRP. The higher load reflected in the 2021 IRP Update approaches the level analyzed in the high-load sensitivity conducted in the 2021 IRP.[10] And, as discussed later in my testimony, the most recent load forecast is even higher than what was assumed in the 2021 IRP Update.

Q. What other important updates were included in the 2021 IRP Update modeling?

A. As discussed in Chapter 5 – Modeling and Assumptions Updates of the 2021 IRP Update, key updates in addition to the load-and-resource balance include the resource changes due to activity resulting from the 2020 All Source Request for Proposal. Importantly, the EPA's pre-publication version of its Ozone Transport Rule, which was released on March 11, 2022, was not modeled in the 2021 IRP Update.

Q. Did the 2021 IRP Update include the same with-and-without B2H analysis that you describe for the 2021 IRP?

A. Yes. Through 2040, the resource portfolio with B2H was $439 million lower cost on a risk-adjusted basis as compared to the portfolio without B2H.

V. MODELING ASSUMPTIONS

Q. Please summarize the natural gas and CO_2 price assumptions used in the updated economic analysis of B2H in this case.

A. The updated economic analysis of B2H includes four price-policy scenarios, as summarized in Table 1:

- Medium natural gas prices paired with medium CO_2 prices, which I refer to as the "MM" price-policy scenario;

[10] *See* 2021 IRP Update, Pg. 2.

- Medium natural gas prices without a CO_2 price, which I refer to as the "MN" price-policy scenario;
- Low natural gas prices without a CO_2 price, which I refer to as the "LN" price-policy scenario; and
- High natural gas prices with a high CO_2 price, which I refer to as the "HH" price-policy scenario.

These assumptions can influence the value of system energy, the dispatch of system resources, and PacifiCorp's resource mix. Consequently, wholesale-power prices and CO_2 policy assumptions affect net power cost (NPC) benefits, non-NPC variable-cost benefits, and system fixed-cost benefits associated with B2H. Because wholesale-power prices and CO_2 policy outcomes are both uncertain and important drivers to the economic analysis, it is important to evaluate a range of assumptions for these variables. Table 1 summarizes the price-policy scenarios used to analyze B2H.

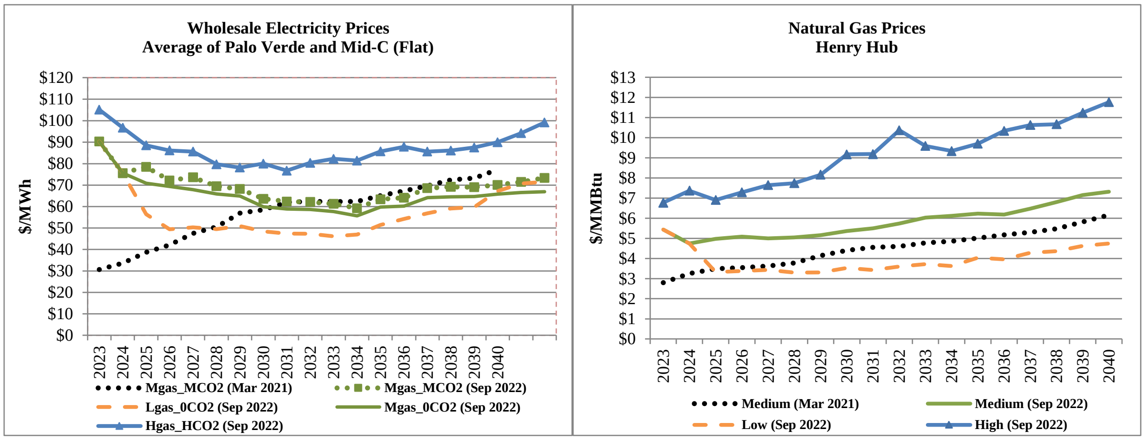
Table 1. Price-Policy Scenario Assumption Overview

Price-Policy Scenario	Henry Hub Natural Gas Price (Levelized $/MMBtu)*	CO_2 Price Description
MM	Medium Gas: $5.67	$12.10/ton starting 2025 rising to $51.40/ton in 2040
MN	Medium Gas: $5.67	None
LN	Low Gas: $3.67	None
HH	High Gas: $8.94	$44.34/ton starting 2025 rising to $120.48/ton in 2040
*Nominal levelized Henry Hub natural gas price from 2025 through 2040.		

Q. **Please describe the natural gas price assumptions used in the price-policy scenarios.**

A. The medium natural gas price assumptions are from PacifiCorp's official forward price curve (OFPC) dated September 30, 2022, which was the most current OFPC available when PacifiCorp prepared its modeling inputs. The first 36 months of the OFPC reflect market forwards at the close of a given trading day (September 30, 2022, in this case). As such, these 36 months represent market forwards as of September 2022. The blending period (months 37 through 48) is calculated by averaging the month-on-month market forwards from the prior year with the month-on-month fundamentals-based price from the subsequent year. The fundamentals portion of the natural gas OFPC reflects an expert third-party price forecast. The fundamentals portion of the electricity OFPC reflects prices as forecast by a third-party using AURORAXMP (Aurora), a WECC-wide market model. Aurora uses the expert third-party natural gas price forecast to produce a consistent electricity price forecast for market hubs in which PacifiCorp participates. Figure 1 shows Henry Hub natural-gas price assumptions for the medium, high, and low natural gas price scenarios compared to the medium price used in the 2021 IRP forecast from March 2021. The electric prices comparison is also shown. The September 2022 price forecast reflects updates to natural gas prices that are higher in the near term from recent market price trends. The updated gas prices also account for limitations in west coast states to add new natural gas.

Figure 1. Nominal Electric and Natural Gas Price Assumptions



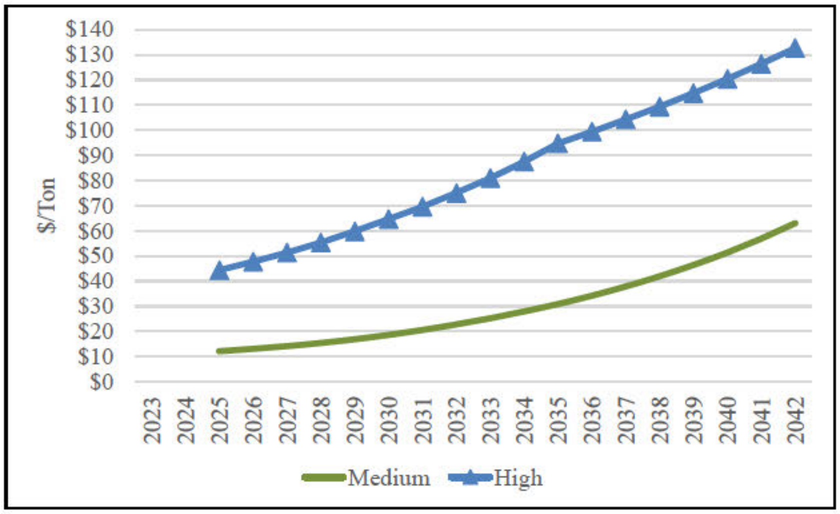
Q. Please describe the CO_2 price assumptions used in the price-policy scenarios.

A. PacifiCorp used three different system-wide CO_2 price scenarios—zero, medium, and high. The medium and high scenarios are derived from a survey of third-party industry experts, including IHS CERA, and Wood Mackenzie and the Energy Information Administration as well as CO_2 price assumptions used by peer utilities. The resulting CO_2 price is applied as a tax beginning in 2025, as shown in Figure 2.[11] In addition, the Company's Chehalis natural gas-fired plant is located in Washington and is subject to Washington's cap-and-invest program established in the Climate Commitment Act, which became effective January 1, 2023. As a proxy for the auction and trading process in this program, in all CO_2 scenarios the cost of emissions from the Chehalis plant reflect the social cost of greenhouse gases used for compliance with Revised Code of Washington (RCW) 19.280.030 and incorporates the updated inflation forecast in the Washington Utility and Transportation Commission's August 24, 2022, order in

[11] While the CO_2 price assumptions are applied as a tax, the inclusion of CO_2 prices in this way does not necessarily mean that future policies will specifically be implemented via a tax. Inclusion of a CO_2 price represents that there is a high likelihood that future policies will impute a cost on fossil-fired generation that is incremental to the cost of existing policies known today. Considering the difficulties in projecting future policy mechanisms, this incremental cost is applied for modeling purposes as a tax.

docket U-190730.

Figure 2. CO_2 Price Assumptions



Q. Does inclusion of potential future CO_2 costs reflect prudent utility planning?

A. Yes. The Company's price-policy scenarios include varying levels of assumed CO_2 costs to reflect the fact it is more likely than not that some policy will exist that will drive reduced emissions over the life of B2H and that these policies will introduce an incremental cost to fossil-fired generation. When determining CO_2 costs used for planning purposes, the Company strives to ensure that it is not an outlier. As discussed above, the medium price is within a reasonable range used by the industry to assess risk and conduct sound resource planning. The most recent example of this trend is the EPA's proposed Ozone Transport Rule restricting NO_x emissions from power plants and other industrial sources.[12] This rule could impose new and significant environmental compliance obligations, resulting in upward pressure on system costs, on PacifiCorp's coal units in Wyoming and Utah.

[12] *See* https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs.

Q. Are the modeled CO_2 costs intended to represent a literal carbon tax?

A. No. The modeled CO_2 costs are not intended to explicitly account for a future tax on CO_2 emissions. Rather, these costs capture the effect of policies incentivizing reduced emissions through benefits or imposing costs through penalties or other costs resulting from market dynamics driving the need for reduced emissions from fossil-fired generation.

Q. Did PacifiCorp update its load forecast in its economic analysis of B2H?

A. Yes. The sales and load forecast used in preparation of this filing was completed in September 2022. It is the same load forecast that was presented at the October 13, 2022, public-input meeting for the 2023 IRP.

Q. How does this load forecast compare to the load forecast used in the 2021 IRP?

A. Figure 3 and Figure 4 show the load and peak forecast relative to the 2021 IRP forecast, both before accounting for incremental energy efficiency savings. The higher load forecast is being driven by new industrial and commercial customer growth, increased air conditioning saturations and miscellaneous devices and electric vehicle adoption expectations. The updated load forecast also includes updates to weather, temperature, and line losses to account for the progression of historical data since the load forecast that informed the 2021 IRP. The updated load forecast also incorporates certain tax changes resulting from the passage of the IRA.

On average, over the 2023 through 2040 timeframe, forecast system load is up 12.9 percent per year and forecast coincident system peak is up 13.6 percent per year when compared to the 2021 IRP. Over that same timeframe, the average annual growth rate for the September 2022 forecast, before accounting for incremental energy efficiency improvements, is 2.00 percent for load and 1.6 percent for peak.

Figure 3. Forecast Annual System Load

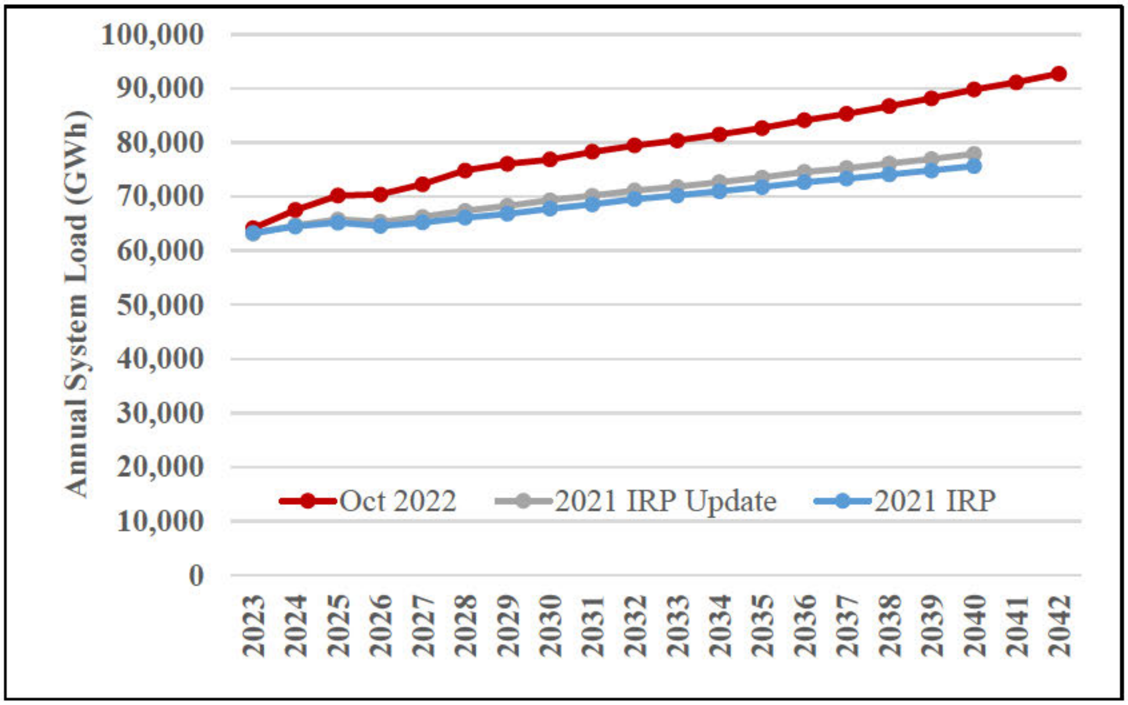
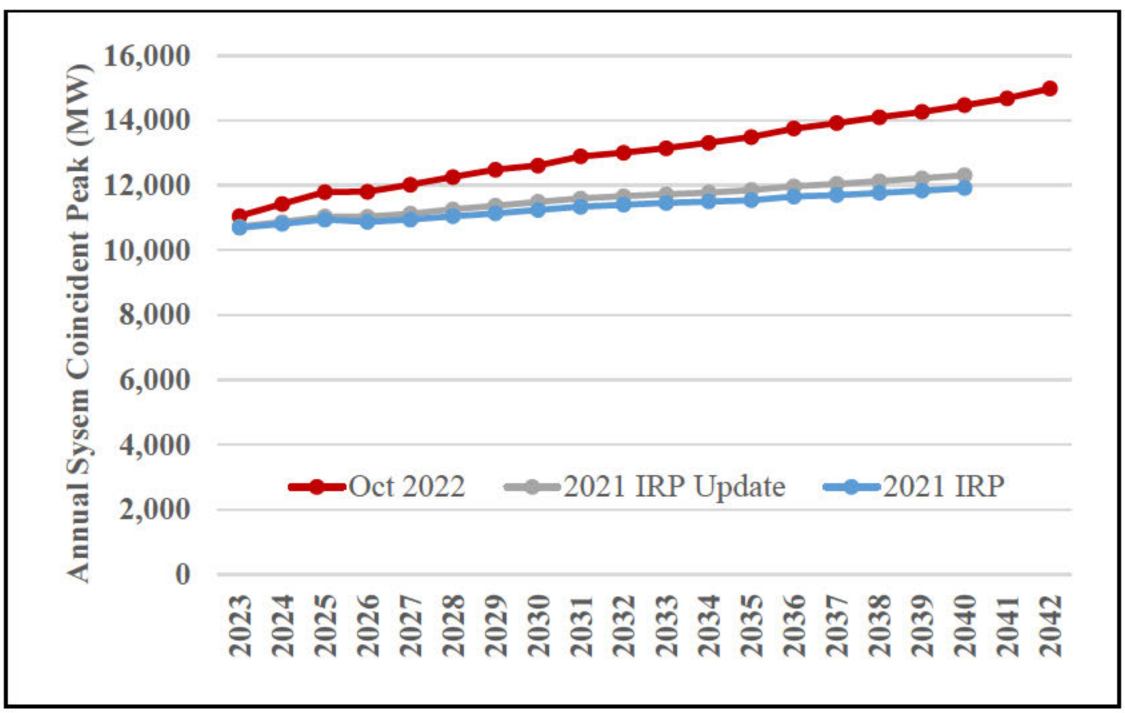


Figure 4. Forecast Annual System Coincident Peak



Q. Has PacifiCorp incorporated EPA's proposed Ozone Transport Rule in its analysis of B2H?

A. Yes. PacifiCorp modeled two primary components to reflect the Ozone Transport Rule: NOx allowance requirements for each of its units including penalties for units with high emissions rates, and a market price for NOx allowances, based on the allowance price used in the third-party forecast to develop the September 2022 OFPC. After running the model, PacifiCorp compared the results to a forecast of its dynamic annual allocation of NOx allowances for Utah and Wyoming based on operations in earlier years.

Q. Please describe how the annual allocation of NOx allowances would work under the proposed rule.

A. The proposed rule calls for dynamic budgeting of NOx allowances in 2025 and beyond, with available allowances allocated among resources within a state based on the recent historical heat input and emissions rates of each resource. Under EPA's proposed rule, the forecast allocation of NOx allowances drops significantly in 2026, as EPA assumed that selective catalytic reduction (SCR) installations at eligible facilities would significantly reduce emissions by that year. PacifiCorp's thermal facilities in Utah and Wyoming would be covered by the rule.

While trading of NOx allowances among participating states is allowed, the proposed Ozone Transport Rule includes significant penalties if a state's emissions exceed 121 percent of its annual allocation, including three-for-one allowance surrender for emissions in excess of 121 percent. Limited banking of NOx allowances is also allowed, but emissions met via banked allowances may also be subject to penalties if a state's emissions exceed 121 percent of its annual allocation. To avoid such penalties, PacifiCorp's NOx emissions during the ozone season (May-September) in each state cannot exceed 121 percent of PacifiCorp's forecast allocation of NOx allowances for that state.

Q. Please describe how PacifiCorp developed NOx allowance requirements for each of its units.

A. In general, an allowance for one ton of NOx emissions would allow the holder of the allowance to emit one ton of NOx. However, starting in 2027,[13] the proposed Ozone Transport Rule also imposes a daily NOx emissions rate limit of 0.14 lb/MMBtu for each coal-fired facility, and requires emitters to provide an equivalent of triple allowances for any emissions that exceed that rate. For example, a resource with an emissions rate of 0.20 lb/MMBtu would have an effective allowance requirement equivalent to an emissions rate of 0.32 lb/MMBtu.[14] In order to calculate PacifiCorp's NOx allowance requirements under the Ozone Transport Rule, starting in 2027 the modeled emission rates for coal resources whose emissions exceed 0.14 lb/MMBTU were grossed up to account for the additional surrender of allowances. Note that incremental allowances do not count toward the 121 percent state emissions limit, which is based on actual emissions, and not allowance requirements.

[13] Coal units that currently have SCR installed must meet the daily backstop limit in 2024. Coal units that do not currently have SCR installed must meet the daily backstop limit in 2027.

[14] Effective allowance requirement for resource with emissions rate of 0.20 lb/MMBTU: 100% * 0.20 lb/MMBtu + 200% * (0.20 – 0.14) lb/MMBtu = 100% *0.20 + 200% * 0.06 = 0.32 lb/MMBtu.

Q. Please describe how PacifiCorp's modeling represents its NOx allowance requirements.

A. PacifiCorp's September 2022 market price forecasts incorporate a regional NOx allowance price, and this price is incorporated in several ways. First, PacifiCorp calculated its share of EPA's proposed allowance allocation for Utah and Wyoming in 2023 and 2024, and a projection of its share thereafter. To the extent emissions in a state are projected to exceed 121 percent of its estimated allocation, any incremental emissions are assumed to be subject to the three-for-one allowance surrender requirement, which is reflected in a cost per ton that is three times the September 2022 allowance price forecast. Because the state limits are based on emissions, the modeled emissions rates are not grossed-up starting in 2027 as described above. In addition, to the extent that overall allowances (not emissions) exceed 100 percent of PacifiCorp's projected allocation, then any incremental allowances are assumed to have a cost per ton that is equal to the September 2022 allowance price forecast. Because the PacifiCorp total requirement is based on allowances (not emissions), a distinct emissions rate is modeled which is grossed-up for emissions over 0.14 lb/MMBtu starting in 2027 as described above.

Under EPA's proposed rule, PacifiCorp will receive specified free allowances in 2023 and 2024. Starting in 2025 PacifiCorp will receive free allowances that are dynamically calculated based on heat input and emissions rates two years prior. Said another way, heat input and emissions that require an allowance today will result in a share of future allowances two calendar years later. The net present value of each unit's current year allowance requirement and its share of future year allowances is translated into an effective emissions rate for dispatch, ensuring that resources that will yield higher future benefits are dispatched ahead of those with lower future benefits, to the extent that those benefits outweigh any difference in fuel and variable costs.

Q. Please describe how PacifiCorp's NOx allowance requirements are incorporated in the reported system cost results.

A. The dynamic nature of the proposed Ozone Transport Rule complicates the modeling, because the feedback from prior year dispatch decisions is difficult to incorporate. However, after a study is complete, it is possible to calculate allowance needs and future year allowance allocations that are specific to the dispatch and emissions results in that study. Allowance requirements (inclusive of the gross-up for emissions over 0.14 lb/MMBTU starting in 2027) are summed up, and two additional allowances are added for any emissions in excess of 121 percent of the dynamically calculated emissions requirement for each state. After subtracting off the allowance allocation, unused allowances are banked up to the specified limits, and any remaining allowances are assumed to be sold at the September 2022 forecast of the allowance price. If the allowance allocation is lower than the allowance requirement, banked allowances are used and the remaining balance is assumed to be purchased at the September 2022 forecast of the allowance price.

VI. MODELING METHODOLOGY

Q. Please describe the modeling methodology PacifiCorp used in its analysis of B2H.

A. PacifiCorp calculated a system present-value revenue requirement (PVRR) by identifying least-cost resource portfolios and dispatching system resources through 2042, which aligns with the 20-year forecast period used in PacifiCorp's forthcoming

2023 IRP. Net customer benefits are calculated as the present-value revenue requirement differential (PVRR(d)) between different simulations of PacifiCorp's system. One simulation includes B2H and the other simulation excludes it, and the resulting differences in PacifiCorp's modeled transmission rights between the two simulations are summarized in Table 2 below.

1 **Table 2. Modeled Transmission Associated with B2H**

Maximum Transfer Capability (MW)	**No B2H**	**With B2H**
B2H Transfers		
Existing PAC Westbound	1090	1090
IPC PTP Westbound	510	510
B2H Westbound	0	818
Total Westbound	**1600**	**2418**
IPC PTP Eastbound	100	300
B2H Eastbound	0	300
Total Eastbound	**100**	**600**
IPC Asset Transfer		
Borah to Hemingway Westbound	n/a	To PacifiCorp
Borah to Hemingway Eastbound	n/a	To PacifiCorp
To Goshen (BPA load service)	n/a	To IPC
Borah to Four Corners Southbound	n/a	To IPC
Borah to Four Corners Northbound	n/a	To IPC
Central Oregon Load Service		
Southbound to Central Oregon load	340	340
Northbound to Central Oregon load	340	340
Enabled by:	*Southern Oregon Battery & implementation of flow-based scheduling*	*B2H*
Total Central Oregon	**680**	**680**
Longhorn Area Load Service		
West to Longhorn area load	*100%**	300
East to Longhorn area load	0	818

**Longhorn load is confidential. The associated costs are identified in Confidential Exhibit PAC/202.*

Q. Why is PacifiCorp's share of B2H westbound capacity higher than its subscribed allocation of 600 MW?

A. The unsubscribed portion of B2H westbound capacity will be allocated between PacifiCorp and IPC based on their respective shares of the overall project. The value of 818 MW in Table 2 includes PacifiCorp's share of that unsubscribed capacity.

Q. Please describe the costs associated with the B2H transfer capability summarized above.

A. The cost of B2H, including associated equipment such as the Midline series compensation, is the largest element. While this cost will be included in PacifiCorp's rate base, it will also be recovered from third-party transmission customers of PacifiCorp Transmission, as part of its Open Access Transmission Tariff (OATT) and annual formula rate update. As a result, approximately 80 percent of these costs are expected to be recovered from PacifiCorp's retail customers. This same percentage applies to all transmission upgrade options evaluated in PacifiCorp's IRP modeling. In the same way, because PacifiCorp uses IPC point-to-point (PTP) transmission service to serve its retail customers, it will also pay for a portion of IPC's costs for the B2H project, through IPC's OATT rates and annual formula rate update process. This will be reflected in the rates for PacifiCorp's existing PTP reservations, and in the pending reservations that will be granted contingent upon B2H going into service. Unlike transmission capital costs for PacifiCorp-owned assets, which are partly recovered through OATT rates, the expense for third-party wheeling reservations is part of NPC and is recovered from PacifiCorp's retail customers only.

Q. Please describe the costs associated with the IPC asset transfers summarized above.

A. PacifiCorp does not have sufficient available transfer capability from its PacifiCorp East BAA at Borah to the southern terminus of B2H at Hemingway. To access the incremental transfer capability associated with B2H, PacifiCorp is negotiating an asset transfer with IPC. Many of the associated transmission assets between Borah and Hemingway are already jointly owned by PacifiCorp and IPC, and PacifiCorp would receive a greater share both eastbound and westbound that is in line with its share of the transfer capability associated with the Project itself. In return, IPC would receive a share of transmission assets to provide bidirectional rights between Borah and Four Corners, as well as to reach BPA loads in the Goshen area. As a result of the transfer, BPA would take transmission service from IPC, rather than PacifiCorp, which would result in a loss of OATT transmission revenue for the Company. The associated change in long-term transmission reservations would flow through PacifiCorp's annual formula rate update and result in higher OATT rates. While PacifiCorp's retail customers would be a larger share of the remaining long-term reservations, it is still projected to be approximately 80 percent of the total. As a result, 80 percent of the lost revenue from BPA would be attributable to PacifiCorp retail customers, and the remainder would be collected from remaining OATT customers.

Q. Please describe the costs associated with the central Oregon load service as summarized above.

A. PacifiCorp currently has rights to serve up to 340 MW of central Oregon load via transfers on the Buckley-Summerlake 500-kilovolt line either northbound or southbound. Because of growing loads in central Oregon, PacifiCorp is seeking to serve up to 680 MW of central Oregon load by scheduling both northbound and southbound concurrently, each at up to 340 MW. To provide this service, a series capacitor bank will be required at the Meridian substation, either with or without B2H being placed in service.

With B2H in service, no additional transmission upgrades would be required; however, PacifiCorp would be able to consolidate certain PTP reservations on BPA's system that are used to reach central Oregon loads, resulting in a reduction in its BPA wheeling expense. Because the expense for third-party wheeling reservations is part of NPC, one hundred percent of these savings would be attributed to PacifiCorp's retail customers.

In the absence of B2H, providing this level of central Oregon load service would require at least 725 MW of dispatchable generation in southern Oregon.[15] This dispatchable generation in southern Oregon would need to be deployed when power flows from PacifiCorp to central Oregon loads across paths operated by BPA exceeded specified levels. As this is based on regional load and resource conditions, which are likely to evolve over time, there is no specific duration that can be assured of maintaining central Oregon load service at 680 MW. For this analysis, the No B2H case included an additional 725 MW of eight-hour battery storage with estimated annual fixed costs of $230 million in 2027, after accounting for the 30 percent investment tax credit available to energy storage resources in the IRA. Because the IRP

[15] A non-wires analysis performed by BPA, IPC, and PacifiCorp indicated that obtaining 680 MW of central Oregon load service capability in the absence of B2H would require dispatchable generation in Southern Oregon ranging from 725 MW to 1,450 MW to prevent impacts to other existing rated paths.

analysis only includes PacifiCorp's transmission rights and forecast usage, it cannot identify periods in which dispatchable southern Oregon generation would need to be deployed to address flows on regional transmission paths. Given this uncertainty, the battery storage duration was increased to eight hours from the four-hour assumption used for this element of the analysis in the 2021 IRP and the 2021 IRP Update. Considering these uncertainties, the 725 MW storage resource was not assumed to be available for economic dispatch within the PLEXOS model.

Q. Please describe the costs associated with the Longhorn area load service summarized above.

A. PacifiCorp's load in the vicinity of the Longhorn substation is anticipated to grow significantly. Serving this load will require PTP transmission service with BPA, Portland General Electric Company (PGE), and/or Umatilla Electric Cooperative (UEC). The expense for such third-party wheeling reservations is part of NPC, so one hundred percent of these costs would be attributed to PacifiCorp's retail customers. Because of their location in proximity to B2H, these loads could instead be served via a connection to B2H. Once B2H is completed, such a connection is forecast to be in service in May 2027, and when it is in place, third-party PTP transmission service would no longer be required. Because the transmission system costs would be recovered as part of PacifiCorp's OATT and annual formula rate update, approximately 80 percent of these costs are expected to be recovered from PacifiCorp's retail customers.

Q. Please describe how third-party transmission expenses and revenues are calculated.

A. Table 3 below summarizes the assumptions used for each of the third-party transmission providers as well as PacifiCorp's revenue from BPA, under its OATT. The rates for PGE and UEC are relatively straightforward, reflecting escalation of the current rates at inflation. The rates for BPA reflect escalation of its current PTP and Schedule 1 rates (Scheduling, System Control and Dispatch) at 3.75 percent per year (7.5 percent over each two-year rate-effective period). The cost for BPA reservations is reduced by applicable short-distance discounts. For IPC and PacifiCorp, formula rate calculations also incorporate adjustments to include the cost of B2H (for both) and Gateway South (GWS) for PacifiCorp, as these major transmission investments appreciably increase these rates. In addition, the formula rate calculations for both IPC and PacifiCorp are also adjusted for changes in long-term contractual demand, adding PacifiCorp's additional PTP reservations to IPC's calculation and removing BPA's load from PacifiCorp's calculation.

Table 3: Third-party Transmission Service Assumptions

Provider	Service	Schedules	Escalation	Adjusted Rate Base	Adjusted Demand
BPA	PTP+SCHED	PTP+ACS	3.75%	n/a	n/a
PGE	PTP	7	2.27%	n/a	n/a
UEC	PTP	11	2.27%	n/a	n/a
IPC No B2H	PTP	7	2.27%	n/a	+100 MW
IPC w/ B2H	PTP	7	2.27%	+B2H	+100 MW
PAC No B2H	NITS	NITS	2.27%	+GWS	n/a
PAC w/ B2H	NITS	NITS	2.27%	+GWS+B2H	-314 MW

Q. What modeling tool did PacifiCorp use to evaluate the B2H project?

A. Consistent with the 2021 IRP modeling, PacifiCorp used the PLEXOS model.

Q. Please describe the PLEXOS model.

A. The PLEXOS model provides three platforms of the PLEXOS tool (referred to as long-term (LT), medium-term (MT) and short-term (ST)), which work on an integrated basis to inform the optimal combination of resources by type, timing, size, and location over PacifiCorp's 20-year planning horizon. The PLEXOS tool also allows for endogenous modeling of resource options simultaneously, greatly reducing the volume of individual portfolios needed to evaluate impacts of varying resource decisions.

Q. Please describe how PacifiCorp used the LT model.

A. PacifiCorp used the LT model to produce a unique resource portfolio under MM price-policy conditions. The LT model portfolio is informed by an hourly review of reliability based on ST model simulations (described below). This ensures that each portfolio meets minimum reliability criteria in all hours. While the 2021 IRP and 2021 IRP Update both assumed that B2H would enable 600 MW of generator interconnection capability, recent generator interconnection study results do not indicate that the B2H project is directly required for pending interconnection requests. Therefore, PacifiCorp did not assume any generating resources would be enabled by B2H and did not make any resource changes between cases that included B2H and cases without it. While there are currently no pending interconnection requests that require B2H, future interconnection requests in the vicinity of B2H could still be contingent upon its completion.

Q. Please describe how PacifiCorp used the MT model.

A. PacifiCorp used the MT model to perform stochastic risk analysis of the portfolios. Each portfolio was evaluated for cost and risk for each price-policy scenario. A primary function of the MT model is to calculate an optimized risk-adjustment, representing the relative risk of a portfolio under unfavorable stochastic conditions for that portfolio.

Q. Please describe how PacifiCorp used the ST model.

A. PacifiCorp used the ST model to evaluate each portfolio to establish system costs over the entire 20-year planning period. The ST model accounts for resource availability and system requirements at an hourly level, producing reliability and resource value outcomes as well as a PVRR, which serves as the basis for selecting least-cost, least-risk portfolios. As noted above, ST model simulations were also used to identify the potential need for resources in the portfolio to maintain system reliability.

Q. How did each of the three PLEXOS models work together to inform the economic analysis presented here?

A. In the first step, a resource portfolio without B2H was developed using the LT model. The LT model operates by minimizing operating costs for existing and prospective new resources, subject to system load balance, reliability, and other constraints. Over the 20-year planning horizon, the model optimizes resource additions subject to resource costs and load constraints. These constraints include seasonal loads, operating reserves, and regulation reserves plus a minimum capacity reserve margin for each load area represented in the model.

To accomplish these optimization objectives, the LT model performs a least-cost dispatch for existing and potential planned generation, while considering cost and performance of existing contracts and new demand-side management (DSM) alternatives within PacifiCorp's transmission system. Resource dispatch is based on representative data blocks for each of the 12 months of every year. Dispatch also determines optimal electricity flows between zones and includes spot market transactions for system balancing. The model minimizes the system PVRR, which includes the net present-value cost of existing contracts, market purchase costs, market sale revenues, generation costs (fuel, fixed and variable operation and maintenance, decommissioning, emissions, unserved energy, and unmet capacity), costs of DSM resources, amortized capital costs for existing coal resources and potential new resources, and costs for potential transmission upgrades.

Each portfolio developed by the LT model must have sufficient capacity to be reliable over the IRP's 20-year planning horizon. The resource portfolios reflect a combination of planning assumptions such as resource retirements, CO_2 prices, wholesale power and natural gas prices, load growth net of assumed private generation penetration levels, cost and performance attributes of potential transmission upgrades, and new and existing resource cost and performance data, including assumptions for new supply-side resources and incremental DSM resources.

Q. What is the next step in the modeling process?

A. In the second step, the Company conducted a reliability assessment using the ST model. The ST model begins with a portfolio of resources and transmission from the LT model that has not yet benefited from a reliability assessment conducted at an hourly level. The ST model is first run at an hourly level for 20 years in order to retrieve two critical pieces of data: 1) shortfalls by hour; and 2) the value of every potential resource to the system. This information is then used to determine the most cost-effective resource additions needed to meet reliability shortfalls, leading to a reliability-modified portfolio. The ST model is then run again with the modified portfolio to calculate an initial PVRR, which is risk-adjusted by outcomes of MT model stochastics that occurs in the third step of the process.

Q. Please describe how the MT model is used to conduct cost and risk analysis.

A. In the third step, the resource portfolios developed by the LT model and adjusted for reliability by the ST model are simulated in the MT model to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. The stochastic simulation in the MT model produces a dispatch solution that accounts for chronological commitment and dispatch constraints. The MT simulation incorporates stochastic risk in its production cost estimates by using the Monte Carlo sampling of stochastic variables, which include load, wholesale electricity and natural gas prices, hydro generation, and thermal unit outages. The MT results are used to calculate a risk adjustment which is combined with ST model system costs to achieve a final risk-adjusted PVRR.

Q. Is the PLEXOS model appropriate for analyzing the customer benefits of B2H?

A. Yes. The PLEXOS model is the appropriate modeling tool when evaluating significant capital investments that influence PacifiCorp's portfolio and affect least-cost dispatch of system resources. The LT model is needed to understand how the type, timing, and location of future resources might be coordinated to cost-effectively serve customer load. The ST and MT models provide additional granularity on how B2H is projected to affect system operations, including its impact on stochastic risks. Together, the LT, MT, and ST models are well suited to perform a benefit analysis for B2H that is consistent with long-standing least-cost, least-risk planning principles applied in PacifiCorp's IRP and resource procurement activities.

Q. When developing resource portfolios with the PLEXOS model, did you perform a reliability assessment?

A. Yes. As described above, the ST model was used to establish system costs for the entire 20-year planning period. The ST model accounts for resource availability and system requirements at an hourly level, producing reliability and resource value outcomes that will reveal whether an initially reliable portfolio selected by the LT model leaves shortfalls at an hourly level, which can then be addressed.

Q. Did PacifiCorp analyze how other assumptions affect its economic analysis of the B2H project?

A. Yes. PacifiCorp analyzed the B2H project under four price-policy scenarios.

VII. PRICE-POLICY SCENARIO RESULTS

Q. Please summarize the PVRR(d) results calculated from the PLEXOS model.

A. Table 4 summarizes the risk-adjusted PVRR(d) results for each price-policy scenario. The data that was used to calculate the PVRR(d) results shown in the table are provided as Confidential Exhibit PAC/202

Table 4. PVRR(d) Cost/(Benefit) of B2H ($ million), 2023-2042

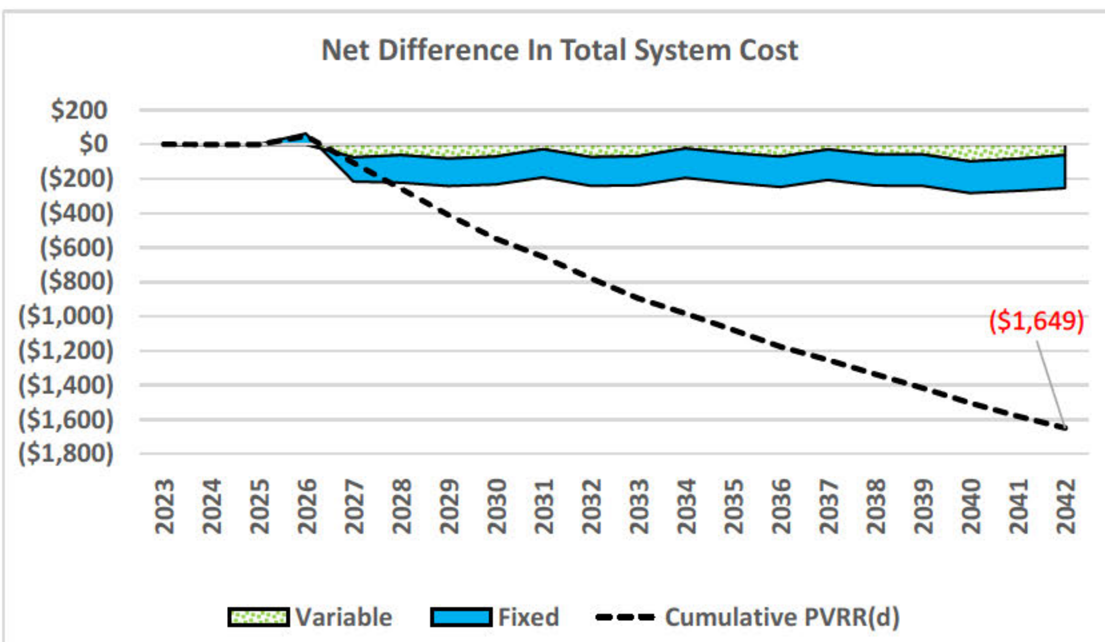
Price-Policy Scenario	B2H	Asset and Reservation Exchange	System Dispatch Impacts	Central Oregon Load Service	Longhorn Area Load Service	Total
MM	$454	$308	($520)	($1,811)	($143)	($1,713)
MN	$454	$308	($594)	($1,811)	($143)	($1,786)
LN	$454	$308	($488)	($1,811)	($143)	($1,680)
HH	$454	$308	($295)	($1,811)	($143)	($1,487)

As shown above, system costs are lower when B2H is included in the portfolio in all price-policy scenarios. The majority of the benefits are derived from the fixed cost of providing central Oregon load service, which are substantially lower as a result of B2H being placed into service. Both central Oregon load service and Longhorn area load service are solely comprised of fixed costs that are not impacted by system dispatch or the price-policy scenario assumptions.

Q. How do system costs change with and without B2H over time?

A. Figure 5 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when B2H is eliminated from the portfolio. The graph shows annual net changes in fixed and variable costs and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that the portfolio that includes B2H is $1,649 million lower cost than the portfolio without B2H, before accounting for risk.

Figure 5. Increase/(Decrease) in System Costs when B2H is Included in the Portfolio ($ millions) Medium Gas/Medium CO_2



VIII. ANNUAL REVENUE REQUIREMENT

Q. In addition to the modeling used to calculate present-value net benefits over a 20-year planning period, has PacifiCorp forecast the change in nominal revenue requirement due to B2H?

A. Yes. The system PVRR from the PLEXOS model was calculated from an annual stream of forecast revenue requirement over the period 2023 through 2042. The annual stream of forecast revenue requirement captures nominal revenue requirement for non-capital items (*i.e.*, NPC, fixed operations and maintenance, PTCs, etc.) and levelized revenue requirement for capital expenditures. To estimate the annual revenue-requirement impacts of B2H, capital costs need to be considered in nominal terms (*i.e.*, not levelized).

Q. Why is the capital revenue requirement used in the calculation of the system PVRR from the PLEXOS model levelized?

A. Levelization of capital revenue requirement is necessary in these models to avoid potential distortions in the economic analysis of capital-intensive assets that have different lives and in-service dates. Without levelization, this potential distortion is driven by how capital costs are included in rate base over time. Capital revenue requirement is generally highest in the first year an asset is placed in service and declines over time as the asset depreciates. In the context of long-term resource planning that is conducted over a finite planning horizon, this can inappropriately favor less capital-intensive assets or assets with longer lives even if those assets might increase system costs over their remaining life.

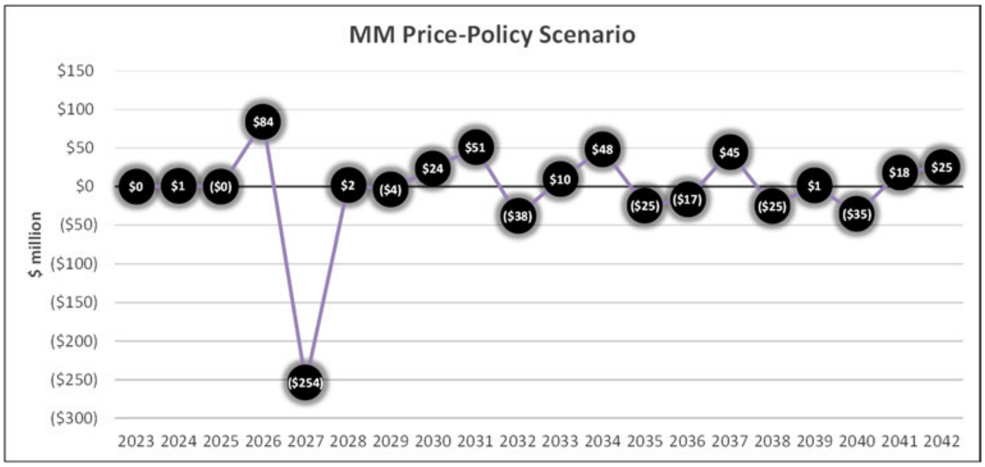
Q. How did PacifiCorp forecast the annual revenue-requirement impacts of B2H?

A. For each simulation, the annual stream of levelized revenue requirement associated with the initial capital for each resource and transmission addition, including B2H, is recalculated as a nominal revenue requirement through 2042, which aligns with the modeled study horizon. Since this change only applies to the cost stream associated with initial capital, all other costs that are part of the annual revenue requirement (e.g. fuel, market transactions, emissions), are unchanged from the modeled results.

Q. Please describe the change in annual nominal revenue requirement from B2H.

A. Figure 6 shows the estimated change in annual nominal-revenue requirement due to B2H for the MM price-policy scenario on a total-system basis. The annual revenue requirement shown in the figure reflects all costs for B2H, including capital revenue requirement (*i.e.*, depreciation, return, income taxes, and property taxes), operations and maintenance expenses, net of avoided transmission costs, changes to wheeling expenses and revenues, and transmission revenue credits. The project costs are netted against system impacts of B2H, reflecting the change in NPC, emissions, non-NPC variable costs, and system fixed costs that are enabled by, but not directly associated with, the incremental transfer capability from B2H.

Figure 6. Total-System Change in Annual Revenue Requirement Due to B2H ($ million)



In 2027, the first full year that B2H is in service, the total-system nominal revenue requirement decreases by $254 million. Thereafter, while the net change in revenue requirement from year to year shows modest variation, B2H continues to enable a lower overall revenue requirement through the end of the study horizon.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Docket No. PCN 5
Exhibit PAC/201
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Rick T. Link

B2H Term Sheet Dated January 18, 2022

March 2023

Contract No. 22TX-17207

TERM SHEET

THIS TERM SHEET IS INTENDED SOLELY TO FACILITATE DISCUSSIONS AMONG IDAHO POWER COMPANY ("***IDAHO POWER***" or "***IPC***"), PACIFICORP ("***PACIFICORP***" or "***PAC***"), AND THE BONNEVILLE POWER ADMINISTRATION ("***BPA***") (EACH REFERRED TO HEREIN AS A "***PARTY***" AND COLLECTIVELY REFERRED TO HEREIN AS THE "***PARTIES***") RELATED TO THE CONSTRUCTION, OWNERSHIP, OPERATION, ASSET EXCHANGES, AND SERVICE AGREEMENTS REGARDING THE BOARDMAN TO HEMINGWAY TRANSMISSION LINE PROJECT ("***B2H PROJECT***" OR "***PROJECT***") AND OTHER TRANSMISSION FACILITIES. EXCEPT FOR SECTION 5 OF THIS TERM SHEET WHICH SHALL BE LEGALLY BINDING UPON THE PARTIES UPON THE EXECUTION AND DELIVERY OF THIS TERM SHEET BY ALL OF THE PARTIES (THE "***EFFECTIVE DATE***"), (I) THIS TERM SHEET IS NOT INTENDED TO CREATE, NOR SHALL IT BE DEEMED TO CREATE, A LEGALLY BINDING OR ENFORCEABLE AGREEMENT OR OFFER, AND (II) NO PARTY SHALL HAVE ANY LEGAL OBLIGATION WHATSOEVER PURSUANT TO THIS TERM SHEET.

1. **BPA Requirements.** The Parties acknowledge and agree that in order to negotiate the Agreements (as defined below) and before BPA can make a definitive final decision regarding whether to enter into the Agreements, BPA must (1) engage in customer and stakeholder outreach, share information about this Term Sheet during the outreach, and solicit feedback; (2) fulfill all requirements under the National Environmental Policy Act (NEPA), the National Historic Preservation Act (NHPA) and other applicable environmental laws, and (3) make a definitive decision in an Administrator's final record of decision. Nothing in this Term Sheet shall be construed as indicating that BPA has engaged in customer and stakeholder outreach; completed its NEPA and other environmental review processes or made a decision regarding how to proceed.

2. **Term.** This Term Sheet shall terminate the earlier of (a) energization of the B2H Project, or (b) execution of all agreements identified in the Term Sheet, or (c) mutual written agreement of all Parties. This Term Sheet may be extended by mutual written agreement of all Parties.

3. **Agreements.** Upon execution of this Term Sheet, the Parties intend to negotiate in good faith toward the execution of the definitive, binding agreements and amendments between or among the Parties described below consistent with the terms and conditions described below ("***Agreements***"). Each of the Parties intends to prepare and deliver to the other Parties initial drafts of the Agreements it is designated as responsible for below by no later than the date identified for each agreement. The Parties further intend, subject

to the BPA requirements in Section 1, that they will endeavor to complete negotiation of and execute the Agreements by no later than the date identified for each agreement; provided, however, that the effectiveness of any such Agreement may be subject to one or more conditions precedent, including state or federal regulatory approvals.

a) Asset Exchanges, Transmission Service Agreements, and Amended and Restated Existing and Future Agreements: The table below defines the transactions contingent on completion of the B2H Project including, without limitation, regulatory approval associated with IPC's acquisition of BPA's interest in the Amended and Restated Boardman to Hemingway Transmission Project Joint Permit Funding Agreement ("Joint Permitting Agreement"), asset exchanges, transmission service agreements, and amended and restated existing and future agreements. Each of the Parties will prepare an initial draft of the Agreements and Amendments below for which it is designated as the Primary Drafter, consistent with the following terms:

	Parties / Agreement / Action / Primary Drafter	***General Terms / Details***
1.	***PAC, BPA*** ***Agreement on Principles and Timelines*** ***Prepare First Draft – BPA: Quarter 2 of Calendar Year 2022*** ***Target Execution Date: Quarter 3 of Calendar Year 2022***	PAC and BPA are parties to the Amended and Restated Midpoint-Meridian Agreement, originally executed June 1, 1994 (the "Midpoint-Meridian Agreement"), which provides PAC with 340 MW of bidirectional scheduling rights over the Buckley-Summer Lake 500kV line (the "Buckley-Summer Lake Line"). In connection with the Goshen Area Asset Exchange (as referenced in Section 3(a)(7) of this table) and the B2H Midline Series Capacitor Project (as referenced in Section 3(a)(12) of this table), PAC and BPA are discussing options to allow PAC the ability to schedule 340 MW from the Buckley substation to the 500kV side of the Ponderosa Transformer Bank 500/230 kV #1 ("Ponderosa 500") and to concurrently schedule 340 MW from the Summer Lake substation to Ponderosa 500 upon energization of the B2H line and the B2H Midline Series Capacitor Project. I. Contingent upon the conditions set forth below, PAC and BPA desire for the concurrent bidirectional scheduling rights over the Buckley-Summer Lake line to be provided as firm point-to-point transmission service ("PTP service") pursuant to the terms and conditions in BPA's Tariff and rate schedules upon energization of the B2H line

		and the B2H Midline Series Capacitor Project. As of the Effective Date, the PAC and BPA understand that such PTP service remains subject to further BPA evaluation. a. BPA's offer of PTP service may include conditions if such conditions are identified during BPA's evaluation. Conditions for PTP service are at BPA's sole discretion and, if required, will be developed consistent with the principles set forth in Section 3(a)(1)(II)(b) so that flows associated with the PTP service over the Buckley-Summer Lake line do not exceed 340 MW in the north-to-south direction and concurrently does not exceed 340 MW in the south-to-north direction during all lines in service. b. As part of the PTP service evaluation, PAC and BPA will also explore options to combine an offer of PTP service with the modification to points of receipt and points of delivery in PAC's existing PTP service tables ("redirect") within the Long Term Firm Point-to-Point Service Agreement (No. 04TX-11722) between PAC and BPA, subject to BPA's Tariff and related business practices including available transfer capability ("ATC"), with a goal to optimize PAC's transmission service over the Federal transmission system to serve its central Oregon loads (*e.g.*, using a single wheel from a network point of receipt to PAC's load at Ponderosa 230 or Pilot Butte 230). BPA will apply its long-standing practice to evaluate the ATC impacts of the new PTP service against the ATC impacts of existing service, to include the bidirectional scheduling rights and redirected service. c. BPA may request additional information from PAC. PAC will make good faith efforts to provide such information within 30 days of BPA's request. d. PAC will submit applicable transmission service request(s) ("TSR") within 30 days

		of BPA's notice to PAC that such requests should be submitted. e. If BPA determines, in its sole discretion, that BPA can convert the bidirectional scheduling rights to PTP service, BPA agrees to offer PTP service pursuant to BPA's Tariff and rate schedules. i. The PTP service will be contingent upon and will not be effective before (A) the energization of the B2H line and the installation of the B2H Midline Series Capacitor Project; (B) approval by the Federal Energy Regulatory Commission ("FERC") of the proposed amendments to the Midpoint-Meridian Agreement discussed in this Section 3(a)(1), per subpart (iii below; and (C) the Goshen Area Asset Exchange set forth in Section 3(a)(7) of this table is completed and all associated agreements are in effect. ii. PAC and BPA will adhere to the applicable requirements set forth in BPA's Tariff and related business practices, including timelines for execution or amendment of a service agreement. iii. Concurrent with the execution of the PTP service agreements contemplated in this Section 3(a)(1)(I), PAC and BPA will amend Section 4(a) of the Midpoint-Meridian Agreement to remove and otherwise terminate PAC's bidirectional scheduling rights over the Buckley-Summer Lake Line. f. If BPA offers PTP service that satisfies PAC's objectives as expressed in this Term Sheet, PAC intends to accept such service subject to the condition regarding FERC approval described below. If following FERC acceptance without material conditions of the arrangements negotiated between BPA and PAC in this Section 3(a)(1)(I), PAC nonetheless fails to submit applicable TSRs or otherwise

		declines to accept the PTP service or execute a PTP service agreement, then BPA will have no further obligations to provide PAC with the PTP service described in this Section 3(a)(1)(I) or the scheduling rights described in Section 3(a)(1)(II) below. g. PAC and BPA will negotiate in good faith to complete and enter into agreements needed to complete the other conditions set forth in Sections 3(a)(2) through (14) and 3(c) of this Term Sheet, as such conditions are applicable to either Party. h. PAC will seek FERC guidance as necessary and file the proposed amendment to the Midpoint-Meridian Agreement with FERC for acceptance. BPA will reasonably coordinate with PAC to prepare for FERC meetings and submissions. FERC's unconditioned acceptance shall be a condition to PAC's obligations as contemplated under this Term Sheet. II. Following either (1) BPA's determination that it is unable to provide the PTP service to PAC consistent with Section 3(a)(1)(I) above, or (2) FERC's failure to accept without material conditions the arrangements negotiated between PAC and BPA under Section 3(a)(1)(I) above, BPA will, effective upon energization of the B2H line and the B2H Midline Series Capacitor Project provided that all conditions described below are met, provide PAC with bidirectional scheduling rights over the Buckley-Summer Lake line which give PAC the ability to (A) schedule 340 MW from the Buckley substation to Ponderosa 500 ("North to South schedules") and (B) concurrently schedule 340 MW from the Summer Lake substation to Ponderosa 500 ("South to North schedules") (collectively referred to as "scheduling limits"). The concurrent, bidirectional scheduling rights described in the immediately preceding sentence will be

		provided pursuant to an amendment to the Midpoint-Meridian Agreement and one or more separately negotiated agreements, that will be effective upon acceptance by FERC and after all conditions set forth in this Section 3(a)(1)(II) are met and will remain in effect until BPA offers PTP service as set forth in Section 3(a)(1)(I). PAC and BPA will work in good faith to satisfy all such conditions consistent with the principles articulated in Section 3(a)(1)(II)(b) below by energization of the B2H line. a. Transmission service to move from the Ponderosa 500 substation. The utilization of the concurrent bidirectional scheduling rights at the Ponderosa substation described in this Section 3(a)(1)(II) is limited to Ponderosa 500. PAC must reserve PTP service from BPA pursuant to BPA's Open Access Transmission Tariff ("OATT"), business practices, and rate schedules in effect at the time of such reservation to move from Ponderosa 500 to the 230 kV side of Ponderosa transformer bank #1 for delivery to PAC load in central Oregon. b. Principles to guide satisfaction of conditions. i. North to South schedules, South to North schedules, and the associated directional power flows may not exceed the scheduling limits (*e.g.*, 340 MW North to South and, concurrently, 340 MW South to North, under all lines in service). A Power Transfer Distribution Factor ("PTDF") based methodology ("PTDF algorithm") and calculator will be used to determine directional power flow. The PTDF algorithm will sum positive flows in the North to South and South to North directions (*i.e.*, schedules and flows are not netted). ii. If, at any time, North to South schedules, South to North schedules, or the associated directional power

		flows exceed the scheduling limits, PAC shall reduce the schedules so that the schedules and directional power flows are within the scheduling limits. BPA can, at BPA's sole discretion, curtail the schedules in whole or in part to maintain the scheduling limits and to mitigate congestion, such as during outages. iii. Schedules (E-Tags) must contain a single granular source and sink. Sources and sinks (1) cannot be consolidated on a single E-Tag; and (2) must be granular enough to determine the PTDF impact. Sources and sinks that are scheduling points, hubs, or nodes are not sufficiently granular to determine the PTDF impact. iv. PAC may not schedule from sources and sinks for which the PTDF impact has not been determined. PAC will provide BPA with advance notice of sources and sinks with sufficient time for BPA to determine the PTDF impact and, if necessary, to accommodate modifications to tools, systems, and contracts. v. The terms, tools, and protocols associated with the concurrent bidirectional scheduling rights will be structured to minimize to the maximum extent possible any impacts exceeding the scheduling limits (*e.g.*, 340 MW North to South and, concurrently, 340 MW South to North, under all lines in service) that the physical flows associated with the concurrent bidirectional scheduling rights have on the Pacific Northwest AC Intertie (as such transmission facilities are defined in the various PNW AC Intertie-related agreements among PAC, BPA and the other PNW AC Intertie owners, the "NW AC Intertie") or the Federal transmission

		system, as reasonably determined by BPA. c. Conditions to Effectiveness of 3(a)(1)(II) Scheduling Rights i. PTDF calculator. BPA will develop a PTDF algorithm to calculate the directional power flow associated with each source and sink that PAC intends to schedule. PAC and BPA will coordinate to develop, at PAC's expense, a PTDF calculator that uses the PTDF algorithm and related communication equipment. ii. Agreement on operational terms. After the PTDF calculator is developed, PAC and BPA will work in good faith to develop operational terms, to include the protocols and requirements for monitoring, dispatch, curtailment, reduction of scheduling limits due to outages, and future modifications to stay current with reliability standards, automation, and technological abilities. The operational terms will remain in effect for the duration of the concurrent bidirectional scheduling rights described in this Section 3(a)(1)(II) and will be incorporated into the proposed amendments to the Midpoint-Meridian Agreement or such other agreement as mutually agreed by PAC and BPA. iii. Energization of the B2H Project, including the B2H Midline Series Capacitor Project. iv. The agreements set forth in Section 3(a)(1)(III) below are, to the extent required, accepted for filing at FERC without material conditions. v. The Goshen Area Asset Exchange set forth in Section 3(a)(7) of this table is completed and all associated agreements are in effect. III. Agreements.

		a. Agreement on Principles and Timelines. Following execution of the Term Sheet, PAC and BPA will negotiate and execute an agreement to reflect the objectives, commitments, principles, conditions, and timelines, including negotiation of applicable follow-on agreements for the PTP service described in Section 3(a)(1)(I), and the concurrent, bidirectional scheduling rights described in Section 3(a)(1)(II). With regard to the concurrent, bidirectional scheduling rights described in Section 3(a)(1)(II), the Agreement on Principles and Timelines would include the principles and conditions set forth in Section 3(a)(1)(II) above, and the timelines for development of the PTDF calculator and negotiation of operational terms and protocols. b. Follow-on Agreements. Before energization of B2H and subject to the conditions described above in this Section 3(a)(1) being met, PAC and BPA will negotiate and execute (1) the agreements and amendments referenced in Section 3(a)(1)(I) above, or (2) if BPA is not yet providing PTP service upon B2H energization consistent with Section 3(a)(1)(I) above, then an amendment to the Midpoint-Meridian Agreement to reflect the addition of the concurrent bidirectional scheduling rights, including term, scheduling and directional power flow requirements, usage of the PTDF calculator, and operational terms, all as consistent with Section 3(a)(1)(II) above. PAC and BPA understand that PAC may be required to file amendments to the Midpoint-Meridian Agreement with FERC for acceptance and that the effective date for the agreements referenced above will be upon FERC acceptance without material conditions. IV. Consistent with the "Phase II Joint Study Report (2020-2021), Boardman to

		Hemingway (B2H) and Incremental Central Oregon Load" completed on March 23, 2021, upon notice from BPA, PAC will upgrade the existing Meridian Series Capacitor on the 500 kilovolt bus or install an electrically equivalent series capacitor on the PAC section of the Dixonville-Meridian-Klamath Falls-Captain Jack lines in southern Oregon within a reasonable time after receiving the notice. PAC shall be responsible for all costs associated with the upgrade. V. PAC and BPA agree that the proposed modifications to the Midpoint-Meridian Agreement described above are limited in scope to PAC's bidirectional scheduling rights over the Buckley-Summer Lake line under Section 4 of the Midpoint-Meridian Agreement and do not include BPA's bidirectional scheduling rights over the Summer-Lake Malin line under Section 4 of the Midpoint-Meridian Agreement. PAC and BPA do not intend to modify, change, alter, or terminate BPA's bidirectional scheduling rights over the Summer Lake-Malin line set forth in Section 4 of the Midpoint-Meridian Agreement or the General Transfer Agreement between PAC and BPA, originally executed May 4, 1982, as amended.
2.	***IPC & PAC & BPA*** ***New operational agreement between IPC, PAC & BPA*** ***Prepare First Draft – BPA: Quarter 3 of Calendar Year 2022*** ***Target Execution Date: Quarter 4 of Calendar Year 2022***	IPC, PAC and BPA agree to negotiate in good faith and draft a tri-party operational agreement that will: a. Consider Midpoint-Meridian Agreement Section 5(f); and b. Define the curtailment procedures between NW AC Intertie, Western Electricity Coordinating Council (WECC) Path 14 (Idaho to Northwest), and WECC Path 75 (Hemingway – Summer Lake); and c. Identify conditions for revising the tri-party operational agreement including, but not limited to: i. Engagement with NW AC Intertie partners;

		ii. In the event the B2H Project and the B2H Midline Series Capacitor Project are not complete and energized by 2027. The Parties will make best efforts to negotiate and target execution of the tri-party operational agreement within one year of the Effective Date of this Term Sheet, with an effective date for the tri-party operational agreement a reasonable time thereafter.
3.	***PAC & BPA*** ***Termination of Existing NITSAs:*** ***PAC Trans – BPA Merchant NITSAs (SA Nos. 746, 747)*** ***Incorporate into Agreement on Principles and Timelines under 3(a)(1)***	BPA Network Integration Transmission Service Agreements ("NITSAs") (PacifiCorp Service Agreement No. 746 and No. 747): BPA and PAC agree to terminate the aforementioned NITSAs upon (1) the completion of the asset purchase and sale between IPC and PAC as detailed in Section 3(a)(5) through Section 3(a)(7) of this table – the Goshen Area Asset Exchange, and (2) the commencement of network service as described in Section 3(b)(1).
4.	***IPC & BPA & PAC*** ***New Agreement:*** ***Longhorn Substation Agreements*** ***Prepare First Draft – BPA: Quarter 2 of Calendar Year 2022*** ***Target Execution Date: Quarter 3 of Calendar Year 2022***	IPC and PAC will fund a portion of the proposed Longhorn substation near Boardman, Oregon, if B2H interconnects at Longhorn. This funding will occur as specified in one or more negotiated Longhorn Substation Agreements between the Parties that is consistent with BPA's Line and Load Interconnection Business practices and allows for recovery of the network portion of these funds through incremental transmission wheeling revenue. The agreement will: a. include provisions for IPC and PAC to pay a use of facilities charge or other charge pursuant to BPA's OATT and applicable rate schedules to transact across the Longhorn bus in the future; b. include provisions for IPC and PAC to potentially own, operate and maintain B2H equipment, which shall include: the

B2H series capacitor at Longhorn, the B2H shunt line reactors at Longhorn, any ancillary equipment required to support those devices, such as switches, bypass breakers (series cap), and insertion breakers (shunt reactor); and

c. be contingent upon BPA completing its obligations and responsibilities under NEPA, NHPA, and other requisite environmental compliance laws and making a decision regarding how to proceed (including provisions for IPC and PAC funding upfront at a prorated amount based on cost allocation of Longhorn, BPA's NEPA, NHPA, and environmental compliance costs).

Non-binding cost estimates identified for the potential Longhorn aspects of the B2H Project as of the Effective Date of this Term Sheet are as follows, which all Parties acknowledge and agree are preliminary and may be modified and revised prior to and upon B2H energization:

These are estimated costs, charges to be trued up with actual costs.

a. Longhorn (base substation) network costs ~$59M. Costs subject to transmission credit.
   i. IPC 21% ~ $12M (BPA to cover up to $14M of IPC cost)
   ii. PAC 55% ~ $33M
   iii. BPA 24% ~ $14M (plus IPC ~ $12M, for total ~ $26M)
b. B2H connection to Longhorn Network Bay~$11M. Constructed/Owned/Maintained by BPA. Develop bay 3 with (2) 500kV circuit breakers & (5) 500kV disconnects. Costs subject to transmission credits.
   i. IPC & PAC 100%
c. Customer built (not subject to transmission credits). Including civil work with the reactor and cap costs.

5.	***IPC & PAC*** ***New Agreement:*** ***Purchase and Sale Agreement for Asset Exchange -potentially utilize the previously developed Joint Purchase and Sale Agreement*** ***Prepare First Draft – IPC: Quarter 2 of Calendar Year 2022*** ***Target Execution Date: Quarter 4 of Calendar Year 2022***	PAC and IPC would purchase and sell to each other various assets to achieve the objectives identified in Section 3(a)(6) and Section 3(a)(7) of this table. PAC and IPC will seek to first balance the purchase and sale of the transferred assets through the depreciated net book value of such assets and allocation of upgrade costs and, finally, if necessary, will be balanced between IPC and PAC through cash considerations. Details related to Populus – Four Corners assets: These assets will provide IPC ownership on the existing PAC transmission system from Four Corners substation in New Mexico to Populus substation in Idaho. This will include 345 kV transmission lines between the following substations and assets to create a path through each substation: Four Corners, Pinto, Huntington, Camp Williams, Mona, Terminal, 90th South, Ben Lomond and Populus. Consistent with federal processes, IPC and PAC will complete required studies to determine if recent system upgrades result in a possible increase in existing transmission capacity between Borah and Populus to facilitate IPC's incremental transfer needs associated with this exchange. If determined necessary, IPC and PAC will identify revisions to the JOOA (as defined in Section 3(a)(6) of this table), upgrades, modifications, or other options to meet each party's commercial needs between Borah and Populus. Details related to Borah/Kinport to Hemingway and Midpoint to Borah/Kinport assets: These assets will provide PAC ownership on the existing IPC transmission system from Borah/Kinport to Hemingway and from Midpoint 500 to Borah/Kinport. This will include 500 kV and 345 kV transmission lines between the following substations and assets to create a path through each substation: Borah, Kinport, Adelaide, Midpoint and Hemingway. Upgrades are required across the Borah West and Midpoint West paths to facilitate this portion of the

		proposed asset exchange transaction. The cost of these upgrades will be determined in the course of negotiating the proposed asset exchange transaction described in this Section 3(a)(5). <u>Details related to Goshen Area assets</u>: As described in more detail in Section 3(a)(7) of this table, PAC will transfer to IPC certain to-be-determined Goshen areas transmission assets that would allow IPC to provide transmission service to all BPA customers in southeast Idaho currently served by PAC. These assets are being transferred to IPC, from PAC, as part of the negotiations between PAC and BPA as described in Section 3(a)(1) of this table, with the consideration for these assets being the transmission service provided by BPA to PAC as detailed in Section 3(a)(1) of this table. IPC and PAC intend for these Goshen assets to be incorporated into the broader purchase and sale agreement described in this Section 3(a)(5) with a goal of minimizing changes to each company's transmission rate base. This goal is intended to be facilitated through the allocation of the costs associated with the Borah West and Midpoint West upgrades.
6.	***IPC & PAC*** ***Amendment to Existing Agreement:*** ***IPC – PAC Joint Ownership and Operating Agreement ("JOOA")*** ***Prepare First Draft – IPC: Quarter 2 of Calendar Year 2022*** ***Target Execution Date: Quarter 4 of Calendar Year 2022***	As part of a transaction transferring assets described in Section 3(a)(5) of this table, IPC and PAC may expand their existing Joint Ownership and Operating Agreement, as amended and restated August 22, 2019 ("JOOA"), to include the following: I. PAC owning 300 MW of west-to-east transmission assets between Midpoint 500 and Borah (transferred from IPC); and II. PAC owning an additional 600 MW of east-to-west transmission assets between Borah and Hemingway (transferred from IPC) - total increases from the current 1,090 MW to 1,690 MW; and III. IPC owning 200 MW of bi-directional transmission assets between Populus, Mona and Four Corners (transferred from PAC); and IV. Other revisions as necessary to facilitate other asset exchanges (*e.g.*, for Goshen area, as

		described in Section 3(a)(5) and Section 3(a)(7) of this table).
7.	***IPC & PAC*** ***Goshen Area Asset Exchange*** ***Part of 3(a)(5)***	As referenced in Section 3(a)(5) and Section 3(a)(6) of this table, IPC and PAC would negotiate an asset exchange to be effective no later than (i) energization of the B2H line and (ii) commencement of the NITSA between BPA and IPC, as referenced in Section 3(b)(1), that enables BPA to to serve its loads currently in PAC's East transmission system (Lower Valley Elec., Idaho Falls, Fall River Rural Elec., Lost River Electric, Salmon River Electric, Soda Springs,) ("Southeast Idaho Load Service (SILS) Customers") with one leg of firm IPC network transmission service. As referenced in Section 3(a)(6) of this table, the Goshen area asset exchange may be wrapped into the existing JOOA framework. IPC, PAC, and BPA agree to make best efforts to plan for service to Idaho Falls that requires only one leg of network transmission from the BPA transmission system, provided such best efforts among the Parties must (1) respect and retain the existing services arranged for Idaho Falls load service between BPA and Utah Associated Municipal Power Systems (UAMPS); and (2) be in line with FERC orders in similar circumstances and accepted by FERC.
8.	***IPC & BPA*** ***New Agreement:*** ***Point to Point TSA*** ***Prepare First Draft – BPA: Quarter 2 of Calendar Year 2022*** ***Target Execution Date: Quarter 3 of Calendar Year 2022***	IPC will acquire up to 500 MW of PTP transmission service from Mid-C to Longhorn subject to the terms of BPA's OATT, business practices and applicable rate schedules. The duration of the new service must be for an initial service duration of at least 5 years, and sufficient to compensate BPA for BPA's revenue requirement associated with BPA capital investments to facilitate the transmission service, with the right to rollover service in accordance with the BPA's OATT and business practices in effect at the conclusion of the initial term.

9.	***IPC & PAC***	Upon energization of the B2H Project, PAC would not renew its current 510 MW of east-to-west rights on the IPC system (which rights are found in IPC 1st Revised Service Agreement (SA) Nos. SAs 344-346 and 383-384). Consistent with and pursuant to IPC's OATT, PAC and IPC will coordinate to extend any remaining IPC SAs, enter into new SAs, or take other action as necessary to bridge any SA expiration dates until such time as the B2H project is in-service.
10.	***IPC & PAC*** ***B2H Construction Funding Agreement-related Commitments***	The B2H Construction Funding Agreement, between IPC and PAC as referenced in Section 3(d) below, and any additional agreements as the Parties determine necessary, will include terms necessary to implement the Agreement to Reimburse BPA's Removal and Replacement Related Transaction Costs, among IPC, PAC and BPA, dated March 18, 2020 (BPA Contract No. 20TX-16835). IPC, on behalf of the B2H Project, will assure that it coordinates construction of the B2H Project with BPA in a manner consistent with the terms of BPA's Use Agreement, as amended by Amendment Two (2) to NF(R)-9617, including Exhibits A, B and C, between the United States of America, Dept. of the Navy and the United States of America, Bonneville Power Administration Ptn Secs 13, 23 and 24-T2N-R25E, W.M. IPC and PAC acknowledge that the Removal and Replacement Related Transactions described in Contract No. 20TX-16835 are contingent upon (1) BPA obtaining acceptable service from Umatilla Electric so that BPA may continue to serve Columbia Basin Electric's load; (2) BPA completing its obligations and responsibilities under NEPA, NHPA, or other requisite environmental compliance laws and making a decision regarding how to proceed; and (3) IPC and PAC moving forward with construction of the B2H Project.
11.	***IPC & PAC & BPA***	In conjunction with the termination of the NITSAs identified in Section 3(a)(3) of this table (*i.e.*, PAC

	BPA Redirect and Assignment of existing PTP transmission service ***Incorporate into Agreement on Principles and Timelines under 3(a)(1)***	SAs 746 & 747), following the energization of B2H, BPA will redirect its two 100 MW PTP transmission service agreements (91629850 and 91629500, or any applicable AREFs that supersede or replace them) that it takes from IPC (*i.e.*, IPC 1st Revised SAs 324 & 342) such that the new POR of each SA will be Walla Walla and the new POD for each SA will be Borah. Consistent with and pursuant to IPC OATT, following approval of such redirects by IPC as described above, BPA will assign those redirected reservations to PAC. This redirect and assignment will be delayed by BPA if B2H energization is delayed past 07/01/2026. PAC shall be responsible to pay for all costs associated with 91629850 and 91629500, or any applicable AREFs that supersede or replace them, upon approval of such redirect by IPC and assignment by BPA.
12.	***IPC & PAC & BPA, with respect to B2H Plus Facilities Expectations*** ***IPC & PAC, with respect to B2H Construction Funding Agreement***	The B2H Project will include the installation of the B2H Midline Series Capacitor Project and development of a remedial action scheme ("RAS"). When considering BPA's study methodology, the B2H midline series capacitor reduces simultaneous interactions between the NW AC Intertie, central and southern Oregon load service, and WECC Path 14 (Idaho to Northwest). The Parties agree to funding of the B2H Midline Series Capacitor Project as follows: a. IPC: funding 45% of the cost. b. PAC: funding 55% of the cost c. BPA: funding 0% of the cost The Parties will work in good faith to have the B2H Midline Series Capacitor Project in-service when the B2H Project is energized and to document expectations of operation, maintenance, and future reinforcements and upgrades.
13.	***IPC & PAC*** ***B2H Grant or Additional Funding***	Under IPC and PAC's existing OATT rate procedures, IPC and PAC will include any United States Department of Energy ("DOE") grant or additional funding received for the B2H project in the appropriate FERC account provided such account is allocated 100% to Transmission. Nothing in this Term Sheet limits or waives any party's right to participate, review, comment, or challenge the other

		party's rate case or formula rate inputs through their respective update processes.
14.	***IPC & PAC & BPA*** ***Permit Funding Agreement Amendment***	Upon transfer of BPA's Permitting Interest to IPC identified in 3(b)(3) below, the Permit Funding Agreement will be amended to recognize the re-allocation of the Parties' Permiting Interests and related funding obligations.

b) NITSA Terms and Conditions, NITSA Security Agreement, NITSA Backstop

1.	***IPC & BPA*** ***New Agreements:*** ***Network Integration Transmission Service Agreement to serve BPA customers at Goshen*** ***Network Integration Transmission Service Agreement to service BPA's customer at Burley*** ***Amendment to currently effective Network Integration Transmission Service Agreements*** ***Prepare First Draft – IPC: Quarter 2 of Calendar Year 2022***	IPC and BPA will enter into two NITSAs for IPC to provide firm network transmission service to BPA. One NITSA will serve BPA customers at Goshen (replacing what is, as of the Effective Date of this Term Sheet, provided under PAC Service Agreement 746) and one NITSA will serve Idaho Falls (replacing what is, as of the Effective Date of this Term Sheet, provided under PAC Service Agreement 747) ("New NITSAs"). The New NITSAs will be in addition to the existing NITSAs BPA currently holds with IPC for service to BPA's customers located on IPC's system ("Existing NITSAs"). The term of BPA's New NITSAs will be 20-years from energization of the B2H Project, with a renewal or rollover option at BPA's discretion as required and permitted by FERC a. The NITSA Security Agreement (as referenced in Section 3(b)(2) of this table), and any related other agreements necessary, between BPA and IPC will be updated once the energization of B2H has occurred to document the term and the repayment periods with the actual energization date. b. The New NITSAs, NITSA Security Agreement, and any related other agreements necessary, are conditioned on the Goshen Area Asset Exchange set forth in Section 3(a)(7) being completed and all associated agreements being in effect by the energization of the B2H line.

	Target Execution Date: Quarter 3 of Calendar Year 2022	The New NITSAs and the Existing NITSAs will be updated to include three Points of Receipt (PORs) over which BPA can deliver energy to its customers located on IPC's system. The three PORs are as follows: AMPS POR, LaGrande POR, and Longhorn POR. The New NITSAs shall reflect the following provisions: a. Under the New NITSAs, IPC will plan for and reserve transmission capacity for the continued network service to BPA's SILS Customers' loads and ensure that it can reliably serve the load for the term of the contract prior to BPA assigning the PTP service agreements to PAC pursuant to Section 3(a)(11) above. b. The New NITSAs between BPA and IPC will permit BPA to assign service to specific Points of Delivery (PODs) to BPA's wholesale customers who take service at those PODs. Such assigned PODs will be served by a separate NITSA agreement between BPA's wholesale customer and IPC. The New NITSA between BPA and IPC will state that the customer requesting a separate NITSA for its POD must meet credit rating standards consistent with IPC's OATT. Notwithstanding assignment of the NITS service, BPA would remain entitled to all outstanding credits associated with the Funded Amounts (as defined in Section 3(b)(2) below) as long as BPA continues to be a NITS customer. c. IPC will maintain the current practice of letting BPA choose through the annual delivery allocation process the PODs where BPA will deliver power to serve its loads. The current PODs include LaGrande and AMPS. Once B2H is in service, the PODs will include LaGrande, Longhorn, and AMPS. d. BPA would pay the NT rate as established by IPC's OATT transmission formula rate. There shall be no adders or segmentation

		like actions which result in a rate above the NT rate and the amount BPA pays to IPC under the NT service agreement will be reduced as discussed in the NITSA Security Agreement. e. IPC will not charge BPA IPC's system losses for energy from BPA's Palisades resource used to serve load behind Goshen.
2.	***IPC & BPA*** ***New Agreement:*** ***NITSA Security and Risk Backstop Agreement*** ***Prepare First Draft – IPC: Quarter 2 of Calendar Year 2022*** ***Target Execution Date: Quarter 3 of Calendar Year 2022***	IPC and BPA will enter into an NITSA security and risk backstop agreement ("NITSA Security Agreement"), concurrently with the New NITSA and the purchase and sale agreement referenced in Section 3(b)(3) of this table. <u>Reimbursement If IPC Receives all Permits and Certificates of Public Convenience and Necessity (CPCN) for Construction of B2H</u> IPC will reimburse BPA for the transfer of BPA's Permitting Interest under the Joint Permitting Agreement in an amount consisting of BPA's investment in B2H prior to the transfer date (~$25m). BPA will also pay to IPC an additional $10 million upon execution of the New NITSAs and the NITSA Security Agreement with the intent of offsetting overall B2H project costs in IPC's rate base. The additional $10 million plus BPA's investment in B2H will be collectively referred to as the "Funded Amount." IPC will retain the Funded Amount as follows: If and when IPC obtains all necessary CPCNs and permits for the B2H Project (and all appeals, if any, have been resolved), IPC shall have until January 1, 2026 ("Commencement Date") to commence construction of B2H or to inform BPA of its intent to not pursue construction of B2H. (1) If IPC commences construction of B2H by or before the Commencement Date, then: a. Interest on the Funded Amount (~$35m) payable by IPC to BPA will accrue from the date of energization of B2H at the rate

		established in the applicable IPC tariff for customer funded projects; b. The Funded Amount and all accrued interest will be repaid to BPA starting year 11 following the energization date (the "Refund Commencement Date"), with repayment amortized over the remaining 10 years of the New NITSAs. i. IPC and BPA will incorporate the interest schedule and payment amortization as an exhibit to the NITSA Security Agreement; ii. If during the term of the New NITSAs BPA defaults on its payment obligations under the New NITSAs, IPC will be entitled to retain for its own account an amount equal to the defaulted payment obligation not to exceed the amount not reimbursed to BPA as of the default date; iii. BPA will not be considered in default for any amount not paid subject to a billing dispute; and iv. IPC may prepay the Funded Amount and interest thereon at any time without penalty. (2) If IPC does not commence construction of B2H by or before the Commencement Date or if IPC informs BPA before the Commencement Date of its intent to not proceed with B2H, then: a. IPC shall have 180 days from the Commencement Date (or notice to BPA of its intent to not proceed, whichever is earlier) to sell its Permitting Interests in the B2H Project; b. No later than the close of the above mentioned 180 days, IPC shall i. pay to BPA BPA's proportional share of any proceeds received from the sale of its Permitting Interest in the B2H Project (if any), and

		ii. Pay to BPA the $10 million BPA provided to IPC upon execution of the New NITSAs. <u>Risk Backstop if IPC does not Receive all Permits or CPCNs Necessary for constructing B2H.</u> If IPC does not obtain all necessary CPCNs and permits for the B2H Project, or any such CPCNs or permits are overturned on appeal, then (a) IPC will return to BPA the $10 million BPA provided to IPC upon execution of the New NITSAs; and (b) BPA will reimburse IPC for funding the additional 24.24% share of all B2H Permitting and Preconstruction Costs incurred after BPA transfers its 24.24% Permitting Interest to IPC. The reimbursement obligation will not include any costs related to Right of Way option acquisition or exercising Right of Way Options. The risk backstop commitment will remain in place until IPC obtains all necessary CPCNs and permits for the Project (and all appeals, if any, have been resolved). The intent of the backstop is only to assist IPC in mitigating the risk associated with receiving the approvals for the B2H Project; not to assist in mitigating business risk. The risk backstop commitment will be as follows: a. IPC will not compensate or reimburse BPA for costs expended by BPA on B2H prior to the transfer of the Permitting Interest to IPC (*i.e.*, ~$25m BPA has expended to date); b. BPA will reimburse 24.24% of actual B2H Project Permitting Costs incurred after IPC takes over funding 45% of the project. (Current estimates for 2021-2024 – Total B2H Project estimated at $9,125,466 with 24.24% of these costs estimated at $2,212,234); and c. BPA will reimburse 24.24% of actual B2H Project Pre-Construction Costs incurred after IPC assumes funding 45% of the project. (Current estimates for

		2021-2024 – Total B2H Project estimated at $9,403,564 with 24.24% of these costs estimated at $2,279,652). Collectively, these amounts set forth in a. through c. above will be the "Risk Backstop Amount." The Risk Backstop Amount will be adjusted, as necessary, to the extent that IPC receives grants or forms of other financial assistance from sources other than BPA or PAC. For example, if IPC received a government grant that defrayed the pre-construction costs of B2H, BPA's 24.24 % share of the pre-construction costs would be reduced accordingly.
3.	***Transfer of Interest in Joint Permitting Agreement:*** ***Prepare First Draft – IPC: Quarter 2 of Calendar Year 2022*** ***Target Execution Date: Quarter 3 of Calendar Year 2022***	IPC and BPA will execute a purchase and sale agreement, assignment, and other applicable transfer documents, concurrently with the New NITSAs, NITSA Security Agreement, and any related other agreements necessary, to transfer all of BPA's Permitting Interest under the Joint Permitting Agreement (and all of BPA's interest in the assets associated therewith) to IPC in exchange for IPC's agreement for repayment to BPA of BPA's investment in B2H through the Joint Permitting Agreement through the effective date of the definitive purchase and sale agreement contemplated in this Section 3(b) (or other date specified therein). The proposed purchase and sale agreement contemplated in this Section 3(b)(3) will contain representations, warranties, and covenants typical of a transaction of the nature contemplated by these proposed terms. The definitive agreements transferring BPA's Permitting Interest under the Joint Permitting Agreement and related assets will be executed prior to any activities BPA has indicated could impact federal environmental regulatory requirements under NEPA, so as to prevent additional delay in the development of B2H. Following the transfer of BPA's Permitting Interest (and associated assets) under the Joint Permitting Agreement to IPC, IPC will be solely responsible for funding an additional 24.24% share of all B2H Project Costs thereafter under Joint Permitting Agreement

		(which includes permitting and preconstruction costs), and IPC will be entitled to all rights, title, and interests and assets that BPA would otherwise obtain under the Joint Permitting Agreement if it were a remaining funding party thereto.

c) Ownership, Operation, and Maintenance Agreement: Defines IPC's and PAC's capacity and property ownership, and their roles and responsibilities for operating and maintaining the B2H Project ("***Ownership and Operation Agreement***"). IPC will prepare an initial draft of the Ownership and Operation Agreement based on the ownership interests below and otherwise consistent with the terms of the JOOA between IPC and PAC. Alternatively, in lieu of a new agreement, IPC and PAC may decide to amend the existing JOOA to cover the B2H Project assets.

Idaho Power	**PacifiCorp**	**BPA**
Project ownership: 45.45%	Project ownership: 54.55%	Project ownership: 0%

d) Construction Funding Agreement: Defines IPC's and PAC's roles and responsibilities in construction of the B2H Project ("***Construction Funding Agreement***"). IPC will prepare an initial draft of the Construction Funding Agreement consistent with the following terms:

1. Project In-Service Date	June 1, 2026
2. Scope	The Construction Funding Agreement covers all work necessary to construct the B2H Project by the Project In-Service Date, including any associated residual work after the Project In-Service Date, but excluding any work already covered by the Joint Permitting Agreement.
3. Project Delivery System	A competitive process is being completed to hire a Construction Manager / Constructability Consultant ("CM") for the B2H Project in 2022 to: (1) provide constructability feedback to the design engineer; and (2) collaborate with PAC and IPC to complete the BLM Construction Plan of Development and the Oregon Energy Facility Siting Council's Site Certificate amendments. The hiring process of the CM will be structured such that the CM may be retained to construct the B2H Project.

	IPC and PAC may mutually agree to modify the CM's role through the Construction Funding Committee (as defined in Section 10 below -***Project Funding and Committee***) without amending the Construction Funding Agreement.
4. Project Manager	IPC is the overall Project Manager for all B2H Project permitting, design, procurement, construction, except that BPA will be responsible for designing, procuring, and constructing the Longhorn substation as described in Section 3(a)(4) and relocating and replacing the BPA 69 kV line off Navy property as described in Section 3(a)(10). Although IPC is the Project Manager, PAC is not precluded from taking project management responsibilities for all or selected tasks associated with the B2H Project; provided that these delegations must be made by the Construction Funding Committee.
5. Construction Project Manager	IPC's role as Construction Project Manager will be generally consistent with the roles and responsibilities of the Permitting Project Manager set forth in Article IV of the Joint Permitting Agreement, provided that the permitting responsibilities not relevant to construction will be removed. IPC, as the Construction Project Manager, will provide monthly project updates, including updates on project activities, financials, forecasts, and invoices detailing costs incurred with breakdowns demonstrating all Parties' cost responsibilities based on their percentage shares. To provide the necessary flexibility to avoid delay/additional costs, the Construction Project Manager will administer and oversee all work necessary to construct the B2H Project within the approved budget, schedule and scope, and also have authority to approve any non-material changes to the B2H Project resulting in a price difference of less than $500k, so long as the overall B2H Project costs remain within the approved budget with the price change. All changes to the B2H Project resulting in a change in the approved budget, will require approval of the Construction Funding Committee.

6. Component Specifications	All B2H Project construction specifications shall meet or exceed all applicable state and federal design requirements and standards; provided that, such specifications may be modified by the Construction Funding Committee so long as the project complies with all applicable state and federal design requirements and standards.
7. Real Property Ownership	<u>B2H real property, except Longhorn substation</u>: IPC will acquire rights of way, grants, easements, or other interests in real property necessary to construct, operate and maintain the B2H transmission line and grant to PAC perpetual and sufficient rights of access, to be set forth in the Ownership and Operation Agreement. <u>Longhorn Substation</u>: Upon completion of BPA's obligations and responsibilities under NEPA, NHPA, and other requisite environmental compliance laws and if BPA decides to proceed with construction of Longhorn substation, BPA will continue to own all real property associated with the Longhorn substation, and in relation to the B2H Project equipment BPA shall grant to IPC and PAC perpetual and sufficient rights of access, to be set forth in one or more Longhorn Substation Agreements as described in Section 3(a)(4).
8. Equipment and Facilities Ownership	Equipment and facilities ownership will be consistent with the Ownership and Operation Agreement. <u>B2H equipment/facilities, except Longhorn substation</u>: IPC and PAC will jointly own as tenants in common the transmission line and all associated facilities and equipment, including all associated facilities located in Hemingway Substation as well as supporting communication facilities and B2H Project substation equipment. <u>Longhorn Substation</u>: Upon completion of BPA's obligations and responsibilities under NEPA, NHPA, and other requisite environmental compliance laws and if BPA decides to proceed with construction of Longhorn substation, BPA will own all equipment and facilities in the Longhorn substation, except the B2H specific equipment and facilities which will be jointly owned by IPC and PAC as tenants in common. BPA will grant IPC and PAC access rights to the equipment

	and facilities in Longhorn substation that are constructed as part of and necessary to the operation of the B2H transmission line facilities, to be set forth in one or more Longhorn Substation Agreements as described in Section 3(a)(4).
9. Material Procurement	All material specifications shall be in accordance with IPC's procurement policies and standards, unless otherwise agreed by the Construction Funding Committee to exceed the same.
10. Project Funding and Committee	Funding: IPC and PAC will fund the B2H Project consistent with their respective ownership shares. Construction Funding Committee: The Construction Funding Agreement shall create a Construction Funding Committee consistent with IPC and PAC's ownership interests in the B2H Project, and generally consistent with the Permit Funding Committee created by the Joint Permitting Agreement (Article III). The Project Manager's reporting requirements set forth in the above Section 5 (***Construction Project Manager)*** will be delivered to all members of the Construction Funding Committee prior to, and discussed during, each of the Committee's regularly-scheduled monthly meetings. Obligations, disputed amounts, and audit rights will be generally consistent with Article III of the Joint Permitting Agreement. The Project Manager will have flexibility to make day-to-day decisions associated with construction of the Project but will be required to seek resolution/approval from the Construction Funding Committee on larger dollar/impact decisions, consistent with that set forth in the above Section 5 (***Construction Project Manager***). BPA will be responsible for designing, procuring, and constructing the Longhorn substation as described in Section 3(a)(4) and relocating and replacing the BPA 69 kV line off Navy property, as described in Section 3(a)(10).
11. Payment Schedule	Costs Accrued Prior to Agreement Execution: Prior to executing the Construction Funding Agreement, IPC

	and PAC will have the opportunity to audit all accrued construction-related expenses included therein that have not otherwise been funded under the Joint Permitting Agreement. IPC and PAC will align on ownership shares prior to execution of the Construction Funding Agreement and pay their respective portions of accrued expenses within 30 days of the effective date of the Construction Funding Agreement. Until which time BPA fully divests its ownership interest in the B2H Project, the Parties acknowledge that the B2H Project is bound to compliance with NEPA, NHPA, and other environmental laws associated with federal agency action. Costs Incurred After Execution: Following execution of the Construction Funding Agreement, the Project Manager will invoice the Construction Funding Agreement participants monthly, requiring payment within 30 days of the invoice date.
12. Transfer/Assignment of Rights/Interests *(Some or all of these terms may be instead placed in the Ownership Agreement)*	IPC and PAC may sell some or all of their respective ownership interests in the B2H Project, together with associated capacity, subject to the Construction Funding Committee's agreement and approval of the terms of any such transaction; provided that, such approval will not be unreasonably withheld. IPC will not transfer or assign rights or interests in the B2H Project that would materially impact the BPA load service commitments set forth in Section 3(b) of this Term Sheet.
13. Term ***Early Termination*** ***Withdrawal***	Term: The term of the Construction Funding Agreement will extend through completion of B2H Project construction, as well as final billing and any reconciliation or mitigation associated with the final expenses, unless otherwise agreed by the Construction Funding Committee. Early Termination/Withdrawal: Absent approval of the Construction Funding Committee, no Party shall have a right to withdraw from the Construction Funding Agreement following the earlier of (1) awarding the B2H Project construction contract, or (2) commencing procurement of long-lead items and equipment.

	Assignments of IPC's or PAC's rights and obligations under the Construction Funding Agreement shall be managed pursuant to the above Section 12 (***Transfer/Assignment of Rights/Interests***).
14. Event of Default	Generally consistent with Article VIII of the Joint Permitting Agreement.
15. Force Majeure	Generally consistent with Article IX of the Joint Permitting Agreement.
16. Reps and Warranties	Generally consistent with Article X of the Joint Permitting Agreement.
17. Common Defense & Limitation of Liability	Generally consistent with Article XI of the Joint Permitting Agreement, except that the Article will be expanded to address construction claims.
18. Proprietary Information/Confidentiality	Generally consistent with Article XII of the Joint Permitting Agreement, except that the Article will provide IPC the ability to share information as necessary to work with potential and selected engineers and contractors.
19. Dispute Resolution	Generally consistent with Article XIII of the Joint Permitting Agreement.
20. Miscellaneous	Generally consistent with Article XIV of the Joint Permitting Agreement and including any standard terms that are necessary for PAC agreements (e.g. assignment and jury trial waiver provisions).

4. Additional Agreements. The Parties agree that they may consolidate any or all of the above-described Agreements and are not precluded from pursuing additional agreements, or amending existing agreements as needed, related to the B2H Project besides those discussed herein.

5. Expenses. Each Party will bear its own expenses (including attorneys' fees) incurred in connection with preparation, negotiation, and execution of this Term Sheet, including preparation, negotiation and execution of the Agreements described herein.

ACKNOWLEDGED AND AGREED TO BY THE PARTIES:

IDAHO POWER COMPANY

Signature: ______________________

Printed Name: RYAN N ADELMAN

Title: VP, POWER SUPPLY

Date: 1/18/22

PACIFICORP

Signature: Rick Link Digitally signed by Rick Link Date: 2022.01.18 11:11:21 -08'00'

Printed Name: Rick Link

Title: Senior Vice President, Resource Planning, Procurement and Optimization

Date: 01/18/2022

Signature: Rick Vail Digitally signed by Rick Vail Date: 2022.01.18 11:59:50 -08'00'

Printed Name: Rick Vail

Title: Vice President, Transmission

Date: 01/18/2022

BONNEVILLE POWER ADMINISTRATION

Signature: TINA KO Digitally signed by TINA KO Date: 2022.01.18 04:25:04 -08'00'

Printed Name: Tina Ko

Title: Vice President, Transmission Marketing a

Date: 1/18/2022

Signature: Digitally signed by KIM THOMPSON Date: 2022.01.18 07:32:28 -08'00'

Printed Name: Kim Thompson

Title: Vice President, Requirements Marl

Date: 1/18/2022

Docket No. PCN 5
Exhibit PAC/202
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Confidential Exhibit Accompanying Rebuttal Testimony of Rick T. Link

PVRR(d) Calculations

March 2023

THIS EXHIBIT 202 IS CONFIDENTIAL AND HAS BEEN PROVIDED IN EXCEL FORMAT ONLY

CERTIFICATE OF SERVICE

I certify that I delivered a true and correct copy of **PacifiCorp's Rebuttal Testimony** on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

Service List
PCN 5

KAYE BISHOP FOSS 7JBLIVINGTRUST 774 PHEASANT RD ADRIAN, OR 97901 Onthehoof1@gmail.com	MEG COOKE WHITETAIL FOREST LLV 1601 OAK ST LA GRANDE, OR 97850 meganlatebird@hotmail.com
JAMES FOSS 7JBLIVINGTRUST 774 PHEASANT RD ADRIAN, OR 97901 Onthehoof1@gmail.com	JASON GASKILL OWYHEE OASIS 914 TUPELO DR NYSSA, OR 97913 jgaskill@providedholdings.capital
SUSAN GEER WHITETAIL FOREST LLC 906 OENN AVE LA GRANDE, OR 97850 susanmgeer@gmail.com	F STEVEN KNUDSON **(C)** FSK ENERGY 2015 SE SLAMON ST PORTLAND, OR 97214 sknudson@threeboys.com
GREG LARKIN **(C)** Larkingreg34@gmail.com	MARGIE MARIE LYON **(C)** 878 COYOTE GULCH RD ADRIAN, OR 97901 Marie.lyon@gmail.com
CARL MORTON MORTON CATTLE & HAY 1248 KLAMATH AVE NYSSA, OR 97913 cnjmorton@gmail.com	JULIE MORTON MORTON CATTLE & HAY 1248 KLAMATH AVE NYSSA, OR 97913 cnjmorton@gmail.com
SAM MYERS GENERATION FARM COMPANY Sam.myers84@gmail.com	SKYLAN MYERS GENERATION FARM COMPANY 68477 LITTLE BUTTE CREEK RD HEPPNER, OR 97836 myers.skylan@gmail.com
TIMOTHY PROESCH **(C)** OWYHEE OASIS 2104 OWYHEE LAKE ROAD NYSSA, OR 97913 owyheeoasis@gmail.com	JOHN WILLIAMS (USPS DELIVERY) PO BOX 1384 LA GRANDE, OR 97850

PACIFICORP	
PACIFICORP, DBA PACIFIC POWER 825 NE MULTNOMAH ST, STE 2000 PORTLAND, OR 97232 oregondockets@pacificorp.com	MATTHEW MCVEE **(C)** PACIFICORP 825 NE MULTNOMAH ST, STE 2000 PORTLAND, OR 97232 matthew.mcvee@pacificorp.com
CARLA SCARSELLA **(C)** PACIFICORP 825 NE MULTNOMAH ST, STE 2000 PORTLAND, OR 97232 carla.scarsella@pacificorp.com	
STAFF	
SUDESHNA PAL **(C)(HC)** PUBLIC UTILITY COMMISSION OF OREGON PO BOX 1088 SALEM, OR 97308 Sudeshna.pal@puc.oregon.gov	YASSIR RASHID **(C)(HC)** PUBLIC UTILITY COMMISSION OF OREGON PO BOX 1088 SALEM, OR 97308 yassir.rashid@puc.oregon.gov
JOHANNA RIEMENSCHNEIDER **(C) (HC)** PUC STAFF - DEPARTMENT OF JUSTICE BUSINESS ACTIVITIES SECTION 1162 COURT ST NE SALEM, OR 97301-4796 johanna.riemenschneider@doj.state.or.us	
IDAHO POWER	
JOCELYN C. PEASE **(C)(HC)** MCDOWELL RACKNER & Gibson 419 SW 11th AVE STE 400 PORTLAND, OR 97205 jocelyn@mrg-law.com ; dockets@mrg-law.com	DONOVAN E. WALKER **(C)** IDAHO POWER COMPANY PO BOX 70 BOISE, ID 83707 dockets@idahopower.com; dwalker@idahopower.com
STOP B2H	
JIM KREIDER **(C)** 60366 MARVIN RD LA GRANDE, OR 97850 jkreider@campblackdog.org	

Dated this 20th day of March 2023.

Santiago Gutierrez
Coordinator, Regulatory Operations