



WENDY MCINDOO  
Direct (503) 290-3627  
wendy@mrg-law.com

December 8, 2017

**VIA EMAIL DELIVERY**

PUC Filing Center  
Public Utility Commission of Oregon  
PO Box 1088  
Salem, OR 97308-1088

**Re: Docket LC 68 - Idaho Power Company's 2017 Integrated Resource Plan ("IRP")**

Attached for filing in the above-identified docket is Idaho Power Company's Appendix D: B2H Supplement to the 2017 Integrated Resource Plan.

Please contact this office with any questions

Very truly yours,

Wendy McIndoo  
Office Manager

Enclosures

## CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing documents in Docket LC 68 on the following named persons on the date indicated below by e-mail addressed to said persons at his or her last-known address indicated below.

Gail Carbiener  
19506 Pond Meadow Ave  
Bend OR, 97702  
Mcgccarb@Bendbroadband.Com

### Coalition

Nancy Esteb  
PO Box 490  
Carlsborg WA, 98324  
Esteb44@Centurylink.Net

John Lowe  
Renewable Energy Coalition  
12050 SW Tremont St  
Portland OR, 97225-5430  
Jravenesanmarcos@Yahoo.Com

Irion A Sanger  
Sanger Law Pc  
1117 SE 53rd Ave  
Portland OR, 97215  
Irion@Sanger-Law.Com

### NIPPC

Robert D Kahn  
Northwest & Intermountain Power Producers  
Coalition  
PO Box 504  
Mercer Island, WA, 98040  
Rkahn@Nippc.Org

Carl Fink  
Blue Planet Energy Law Llc  
628 SW Chestnut St, Ste 200  
Portland OR, 97219  
Cmfink@Blueplanetlaw.Com

### Oregon Citizens Utility Board

Oregon Citizens' Utility Board  
610 SW Broadway, Ste 400  
Portland OR, 97205  
Dockets@Oregoncub.Org

Robert Jenks  
Oregon Citizens' Utility Board  
610 SW Broadway, Ste 400  
Portland OR, 97205  
Bob@Oregoncub.Org

Elizabeth Jones  
Oregon Citizens' Utility Board  
610 SW Broadway, Ste 400  
Portland OR, 97206  
Liz@Oregoncub.Org

**Oregon Department of Energy**

Jesse D. Ratcliffe  
\*Oregon Department of Energy  
1162 Court St NE  
Salem OR, 97301-4096  
Jesse.D.Ratcliffe@Doj.State.Or.Us

Diane Broad  
\*Oregon Department of Energy  
625 Marion St Ne  
Salem OR, 97301-3737  
Diane.Broad@State.Or.Us

Wendy Simons  
\*Oregon Department of Energy  
625 Marion St NE  
Salem OR, 97301  
Wendy.Simons@Oregon.Gov

**Sierra Club**

Alexa Zimbalist  
Sierra Club  
2101 Webster St Ste 1300  
Oakland CA, 94612  
Alexa.Zimbalist@Sierraclub.Org

Gloria D Smith  
Sierra Club Law Program  
2101 Webster St Ste 1300  
Oakland CA, 94612  
Gloria.Smith@Sierraclub.Org

Amy Hojnowski  
Sierra Club  
Amy.Hojnowski@Sierraclub.Org

**Staff LC 68**

Stephanie S Andrus  
PUC Staff--Department of Justice  
Business Activities Section  
1162 Court St NE  
Salem OR, 97301-4096  
Stephanie.Andrus@State.Or.Us

Nadine Hanhan  
Public Utility Commission of Oregon  
PO Box 1088  
Salem OR, 97308-1088  
Nadine.Hanhan@State.Or.Us

**Stop B2H**

Charles H Gillis  
Charles H. Gillis, Attorney at Law  
1306 Adams Ave  
La Grande OR, 97850  
Charlie@Gillis-Law.Com

F. Steven Knudsen  
FSK Energy  
2015 SE Salmon St  
Portland OR, 97214  
Fskenergy@Threeboys.Com

Jim Kreider  
Jkreider@Campblackdog.Org

DATED: December 8, 2017

  
Wendy McIndoo  
Office Manager

# 2017 IRP

APPENDIX D: B2H SUPPLEMENT

DECEMBER • 2017



## **SAFE HARBOR STATEMENT**

This document may contain forward-looking statements, and it is important to note that the future results could differ materially from those discussed. A full discussion of the factors that could cause future results to differ materially can be found in Idaho Power's filings with the Securities and Exchange Commission.

# 2017

## IRP

### APPENDIX D: B2H SUPPLEMENT

## ACKNOWLEDGEMENT

Resource planning is an ongoing process at Idaho Power. Idaho Power prepares, files, and publishes an Integrated Resource Plan (IRP) every two years. Idaho Power expects that the experience gained over the next few years will likely modify the 20-year resource plan presented in this document.

Idaho Power invited outside participation to help develop the 2017 IRP. Idaho Power values the knowledgeable input, comments, and discussion provided by the Integrated Resource Plan Advisory Council and other concerned citizens and customers.

It takes approximately one year for a dedicated team of individuals at Idaho Power to prepare the IRP. The Idaho Power team is comprised of individuals that represent many departments within the company. The IRP team members are responsible for preparing forecasts, working with the advisory council and the public, and performing all the analyses necessary to prepare the resource plan.

Idaho Power looks forward to continuing the resource planning process with customers, public-interest groups, regulatory agencies, and other interested parties. You can learn more about the Idaho Power resource planning process at [idahopower.com](http://idahopower.com).



## TABLE OF CONTENTS

Table of Contents .....	i
List of Tables .....	iv
List of Figures .....	v
List of Appendices .....	v
Executive Summary .....	1
Resource Need Evaluation .....	5
Capacity Needs .....	5
IRP Guideline Language—Transmission Evaluated on Comparable Basis .....	5
Boardman to Hemingway as a Resource .....	6
Capacity Costs .....	6
Energy Cost.....	7
Market Overview .....	8
Power Markets .....	8
Mid-C Market .....	8
Mid-C and Idaho Power.....	10
Modeling of the Mid-C Market in the IRP .....	11
B2H Comparison to Other Resources.....	11
Idaho Power’s Transmission System .....	12
Transmission Capacity Between Idaho Power and the Pacific Northwest.....	13
Montana–Idaho Path Utilization.....	15
Idaho to Northwest Path Utilization .....	16
Regional Planning—Studies and Conclusions.....	16
The B2H Project .....	17
Project History .....	17
Public Participation.....	17
Project Activities.....	20
2006.....	20



2007.....	20
2008.....	20
2009.....	20
2010.....	20
2011.....	20
2012.....	21
2013.....	21
2014.....	21
2015.....	21
2016.....	21
2017.....	21
Route History .....	22
B2H Capacity Interest.....	27
Capacity Rating—WECC Rating Process .....	28
B2H Design.....	29
Transmission Line Design .....	29
Transmission Line Structural Loading Considerations.....	31
Transmission Line Foundation Design .....	32
Lightning Performance .....	33
Earthquake Performance.....	33
Wildfire .....	34
Wind Gusts/Tornados .....	34
Ice .....	34
Landslide.....	34
Flood .....	35
Direct Physical Attack .....	35
B2H Design Conclusions.....	35
Project Co-Participants .....	35

PacifiCorp and BPA Needs.....	35
PacifiCorp.....	36
BPA.....	37
Co-Participant Expenses Paid to Date .....	37
Co-Participant Agreements.....	38
Cost.....	38
Cost Estimate .....	38
Transmission Line Estimate.....	39
Substation Estimates .....	39
Calibration of Cost Estimates .....	39
Costs Incurred to Date .....	40
Cost-Estimate Conclusions.....	40
Transmission Revenue .....	40
Potential BPA and Idaho Power Asset Swap.....	41
Benefits .....	42
Capacity .....	42
Avoid Constructing New Resources (and Potentially Carbon-Emitting Resources.....	43
Improved Economic Efficiency .....	44
Renewable Integration .....	44
Grid Reliability/Resiliency .....	45
Resource Reliability.....	46
Reduced Electrical Losses .....	47
Flexibility.....	47
EIM .....	48
B2H Complements All Resource Types.....	48
B2H Benefits to Oregon.....	49
Economic and Tax Benefits.....	49
Local Area Electrical Benefits.....	49

Risk .....	50
Capital-Cost Risk .....	51
Market Price Risk .....	52
Liquidity and Market Sufficiency Risk.....	52
Data Point 1. Peak Load Analysis from Table 6.....	53
Data Point 2. Pacific Northwest Power Supply Adequacy Assessment for 2022— Northwest Power Conservation Council Report.....	53
Data Point 3: 2016 Pacific Northwest Loads and Resources Study—BPA.....	54
Data Point 4: Northwest and California Renewable Portfolio Standards .....	57
Market Sufficiency and Liquidity Conclusions .....	57
Co-Participant Risks .....	57
Siting Risk.....	58
Schedule Risk.....	58
Catastrophic Event Risk.....	59
Project Activities.....	59
Schedule Update .....	59
Permitting.....	59
Post-Permitting .....	60
Conclusions.....	61

## LIST OF TABLES

Table 1.	Total capital \$/kW for select resources considered in the 2017 IRP
Table 2.	High-level differences between resource options
Table 3.	Pacific Northwest to Idaho Power import transmission capacity from the 2016 transmission forecast
Table 4.	The Idaho to Northwest Path (WECC Path 14) summer allocation
Table 5.	B2H joint permit funding capacity interests by funder
Table 6.	2026 peak load estimates—illustration of load diversity between western regions

Table 7.	NERC—AC transmission circuit sustained outage metrics
Table 8.	NERC forced-outage rate information for a fossil or gas power plant
Table 9.	Projected annual B2H tax expenditures by county
Table 10.	2027 data points from Figure 12

## LIST OF FIGURES

Figure 1.	Northwest regional forecast (Source: 2017 PNUCC)
Figure 2.	Idaho Power transmission system map
Figure 3.	Routes developed by the CAP advisory teams (2009 timeframe)
Figure 4.	B2H proposed route resulting from the CAP process (2010 timeframe)
Figure 5.	BLM final EIS routes
Figure 6.	BLM Agency Preferred route from the 2017 BLM ROD
Figure 7.	B2H route submitted in 2017 EFSC Application for Site Certificate
Figure 8.	Transmission tower components
Figure 9.	Comparison of total portfolio costs from 2017 IRP (Table 9.3 in 2017 IRP)
Figure 10.	Correlation between Mid-C market prices and natural gas prices
Figure 11.	2021–22 LOLP by month (Source: NWPCC northwest analysis)
Figure 12.	January, June, and July forecast Pacific Northwest resource surplus/deficit (Source: 2016 BPA White Book)

## LIST OF APPENDICES

Appendix D-1.	Transmission line alternatives to the proposed B2H 500-kV transmission line
Appendix D-2.	Detailed list of notable project milestones
Appendix D-3.	B2H funding agreement
Appendix D-4.	B2H MOU
Appendix D-5.	NTTG studies

This page left blank intentionally.

## EXECUTIVE SUMMARY

The Boardman to Hemingway Transmission Line Project (B2H) is a planned 500-kilovolt (kV) transmission project that would span between the Hemingway 500-kV substation near Marsing, Idaho, and the proposed Longhorn Substation near Boardman, Oregon. Once operational, B2H will provide Idaho Power increased access to reliable, low-cost market energy purchases from the Pacific Northwest. Idaho Power's planned capacity interest in B2H will increase the availability of capacity and energy of the Pacific Northwest market by 500 megawatts (MW) during the summer months, when energy demand from Idaho Power's customers is at its highest. B2H (including early versions of the project) has been a cost-effective resource identified in each of Idaho Power's integrated resource plans (IRP) since 2006 and continues to be a cornerstone of Idaho Power's 2017 IRP preferred resource portfolio. In the 2017 IRP, as has been the case in prior IRPs, the B2H project is not simply evaluated as a transmission line, but rather as a *resource* that will be used to serve Idaho Power load. That is, the B2H project, and the market purchases it will facilitate, is evaluated in the same manner as a new combined-cycle gas plant, or a new utility-scale solar complex.

As a resource, the B2H project is demonstrated to be the most cost-effective method of serving projected customer demand. In the 2017 IRP, B2H was identified as the least-cost and least-risk resource to serve peak-hour load deficits forecast to occur beginning in 2026. As can be seen in Table 9.3, page 111 of the 2017 IRP, the four lowest-cost resource portfolios (P1, P4, P7, and P10) each included B2H. The information presented in Table 9.3 also indicates that the next lowest-cost portfolio that does not include B2H had a present-value portfolio cost of approximately \$147 million dollars greater than Idaho Power's preferred resource portfolio, P7. When compared to other individual resource options, B2H is also the least-cost option in terms of both capacity cost and energy cost. B2H is expected to have a capacity cost that is 71 percent lower than either a combined-cycle gas plant or utility-scale solar alternatives.<sup>1</sup> B2H is also expected to have a levelized cost of energy that is 22 percent lower than a combined-cycle gas plant and 38 percent lower than utility-scale solar.<sup>2</sup> As a resource alone, B2H is the lowest-cost alternative to serve Idaho Power's customers in Oregon and Idaho. As a transmission line, B2H also offers incremental ancillary benefits and additional operational and resource integration flexibility.

In addition to being the least-cost, lowest-risk resource to meet Idaho Power's resource needs, the B2H project has received national recognition for the benefits it will provide. The B2H

---

<sup>1</sup> 2017 IRP, page 87, Figure 7.5.

<sup>2</sup> 2017 IRP, page 89, Figure 7.6.

Footnotes continued on the next page.

project was selected by the Obama administration as one of seven nationally significant transmission projects that, when built, will help increase electric reliability, integrate new renewable energy into the grid, create jobs, and save consumers money. Most recently, B2H was acknowledged as complementing the Trump Administration’s America First Energy Plan, which addresses all forms of domestic energy production. In a November 17, 2017, United States (US) Department of the Interior press release,<sup>3</sup> B2H was held up as “a Trump Administration priority focusing on infrastructure needs that support America’s energy independence...” The release went on to say, “This project will help stabilize the power grid in the Northwest, while creating jobs and carrying low-cost energy to the families and businesses who need it...” The benefits B2H is expected to bring to the region and nation have been recognized across both major political parties.

Under a 2012 B2H Permit Funding agreement, Idaho Power is allocated a 21.2-percent project interest, with PacifiCorp and Bonneville Power Administration (BPA) subscribed for the remainder of the line’s capacity. The agreement will allow Idaho Power customers to benefit from the project’s economies of scale and from load diversity between the project co-participants. While Idaho Power’s 21.2-percent share would provide for an annual average of 350 MW of west-to-east import capacity, the agreement is structured to provide Idaho Power with 500 MW of import capacity during the summer months, when Idaho Power experiences peak demand, and 200 MW of import capacity in the winter months, when the load-serving need is less.

The total cost estimate for the B2H project is \$1 to \$1.2 billion dollars, which includes Idaho Power’s allowance for funds used during construction (AFUDC). Co-participant AFUDC is not included in this estimate range. The total cost estimate includes a 20 percent contingency for unforeseen expenses. In the 2017 IRP, Idaho Power assumes a 21.2-percent share of the direct expenses, plus its entire AFUDC cost, which equates to approximately \$258 million in B2H project expenses. Idaho Power also included costs for local interconnection upgrades totaling \$16 million. The 2017 IRP was the first year for which the B2H route was relatively certain, resulting in a more accurate cost estimate compared to prior IRPs.

Idaho Power is the project manager for the permitting phase of the B2H project. The B2H project achieved a major milestone nearly 10 years in the making with the release of the Bureau of Land Management (BLM) Record of Decision (ROD) on November 17, 2017. The BLM ROD formalized the conclusion of the siting process at the federal level, as required by the *National Environmental Policy Act of 1969* (NEPA). The BLM ROD provides the ability to site the B2H project on BLM-administered land.

---

<sup>3</sup> [blm.gov/press-release/doi-announces-approval-transmission-line-project-oregon-and-idaho](https://www.blm.gov/press-release/doi-announces-approval-transmission-line-project-oregon-and-idaho)

For the State of Oregon permitting process, Idaho Power submitted the amended application for Site Certificate to the Oregon Department of Energy in summer 2017. Oregon’s Energy Facility Siting Council (EFSC) is tasked with establishing siting standards for energy facilities in Oregon and ensuring certain transmission line projects, including B2H, meet those standards.<sup>4</sup>

Before Idaho Power can begin construction on B2H, it must obtain a Site Certificate from EFSC. The Oregon EFSC process is a standards-based process based on a fixed site boundary. For a linear facility, like a transmission line, the process requires the transmission line boundary be established (a route selected) and fully evaluated to determine if the project meets established standards. Idaho Power must demonstrate a need for the project before EFSC will issue a Site Certificate authorizing the construction of a transmission line (non-generating facility). Idaho Power’s demonstration of need is based on the least-cost plan rule, for which the requirements can be met through a commission acknowledgement of the resource in the company’s IRP.<sup>5</sup> In this case, Idaho Power seeks to satisfy EFSC’s least-cost plan rule requirement through an acknowledgement of its 2017 IRP.

As of the date of this report, Idaho Power expects the Oregon Department of Energy (ODOE) to issue a Draft Proposed Order in 2018 and a Final Order and Site Certificate in 2020. To achieve an in-service date in the mid-2020s, preliminary construction activities must commence in parallel to EFSC permitting activities. Preliminary construction activities include, but are not limited to, geotechnical explorations, detailed ground surveys, sectional surveys, right-of-way (ROW) acquisition activities, and detailed design and construction bid package development. After the Oregon permitting process and preliminary construction activities conclude, construction activities can commence.

This B2H 2017 IRP Appendix D provides context and details that support evaluating this transmission line project as a supply-side resource, explores (qualitatively and quantitatively) many of the ancillary benefits offered by the transmission line, and considers the risks and benefits of owning a transmission line connected to a market hub in contrast to direct ownership of a traditional generation resource.

---

<sup>4</sup> See generally Oregon Revised Statute (ORS) 469.300-469.563, 469.590-469.619, and 469.930-469.992.

<sup>5</sup> OAR 345-023-0020(2).



This page left blank intentionally.

## RESOURCE NEED EVALUATION

### Capacity Needs

The entire Integrated Resource Plan (IRP) process is predicated on defining a need for resources in the future to serve projected customer demand.

The IRP analysis begins by developing a monthly load forecast, which incorporates the future electricity needs of our customers. The load forecast consists of both average monthly (energy) and monthly peak-hour (capacity) conditions. The existing Idaho Power resources (generating, demand side management [DSM], and transmission) are evaluated against the load forecast. The load less the available resources determines the load and resource balance. Times where the load exceeds the resources defines the need for resources to reliably serve our customers.

All resources on Idaho Power's system are considered in the load and resource balance, including hydro, gas, coal, existing cogeneration and small-power producer (CSPP) contracts, existing power purchase agreements (PPA) (including the *Public Utility Regulatory Policies Act of 1978* [PURPA]), and available import transmission capacity. All supply-side resources, all DSM and EE programs, and transmission import capacity are summed and subtracted from the appropriate load forecast—either peak hour or average monthly. If the result of load is greater than resources is, Idaho Power's system is resource insufficient and the need for a resource is established.

As detailed in Idaho Power's 2017 IRP, Idaho Power has a peak-demand capacity deficit in the year 2026. The Jim Bridger unit retirement evaluations in the 2017 IRP can accelerate the capacity deficit date depending on the retirement date assumptions.

Refer to Chapter 7 of Idaho Power's 2017 IRP for more information on the planning period forecasts and establishment of need.

### IRP Guideline Language—Transmission Evaluated on Comparable Basis

In Order No. 07-002, the Public Utility Commission of Oregon (OPUC) adopted guidelines regarding integrated resource planning.<sup>6</sup>

Guideline 5: Transmission. Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation *and electric transmission facilities as resource options*, taking into account their value

---

<sup>6</sup> [apps.puc.state.or.us/orders/2007ords/07-002.pdf](https://apps.puc.state.or.us/orders/2007ords/07-002.pdf)

for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.

## Boardman to Hemingway as a Resource

The Boardman to Hemingway Transmission Line Project (B2H) is one of the most cost-effective IRP resources Idaho Power has considered and proven through successive IRPs. When evaluating and comparing alternative resources, two major cost considerations exist: 1) the capacity cost of the project (fixed costs) and 2) the energy cost of the project (variable costs). The 2017 IRP details the results of each component of the various portfolios in Table 9.3 of the IRP. Capital costs are derived through cost estimates to install the various projects. Energy costs are calculated through a detailed modeling analysis, using the AURORA software. Energy prices are derived based on inputs into the model, such as gas price, coal price, nuclear price, hydro conditions, etc.

Illustrating the difference between capacity and energy, a diesel generator may have a very low cost to install; however, the cost of diesel fuel and the maintenance required would be significant. Alternatively, a utility-scale solar plant will have almost no energy cost; the fuel to run the plant—the sun—is free. However, in the case of a solar plant, the capacity cost to install the plant is quite expensive. The installed capacity needed to ensure the solar is available during the Idaho Power peak is even larger.

### Capacity Costs

Exploring the capacity costs of different resources, page 73 of the 2017 IRP *Appendix C—Technical Appendix* details the total capital cost per kilowatt (kW) for many various resources. This capital-cost data feeds into Table 9.3 of the main IRP report. Data from the technical appendix is copied into Table 1 below for illustrative purposes. Note that solar costs have been updated from those reported in the IRP with capital costs from the November 2017 Lazard energy cost report.<sup>7</sup> The capital costs for B2H in the table below reflect the inclusion of local interconnection costs for B2H, and consequently also differ from the per-kW cost reported in the IRP technical appendix. The local interconnection costs for B2H were included in portfolio cost modeling performed for the IRP.

**Table 1. Total capital \$/kW for select resources considered in the 2017 IRP**

Resource Type	Total Capital \$/kW	Total Capital \$/kw—peak	Depreciable Life
B2H	\$783*	\$548**	55 years
Combined-cycle combustion turbine (CCCT) (1x1) F Class (300 megawatts [MW])	\$1,344	\$1,344	30 years

<sup>7</sup> Lazard's Levelized Cost of Energy Analysis—Version 11.0, November 2017.

Simple-cycle combustion turbine —Frame F Class (170 MW)	\$995	\$995	30 years
Reciprocating Gas Engine	\$887	\$887	30 years
Solar Photovoltaic (PV)— Utility-Scale 1-Axis	\$1,382	\$2,692	25 years

\* Utilizes the B2H 350-MW average capacity

\*\* Utilizes the B2H 500-MW average capacity

The B2H total capital cost per kilowatt at peak is 62 percent of the cost of the next lowest-cost resource. Additionally, B2H, as a transmission line, will depreciate over 55 years compared to 30 years for a gas plant or 25 years for a solar plant. The low up-front cost and slower depreciation further reduces the cost impact to Idaho Power’s customers. Finally, the B2H cost estimate includes a 20 percent contingency, whereas none of the other resources evaluated in the 2017 IRP include a cost contingency. The summation of these factors suggest B2H is the lowest capital-cost resource by a substantial margin.

## Energy Cost

B2H provides Idaho Power with more capacity to the Pacific Northwest to purchase power from the Mid-Columbia (Mid-C) trading hub. Market power in the summer months is generally a function of the price of natural gas. Idaho Power, in a B2H future, would therefore pay a slight premium for market power compared to a future in which Idaho Power owned its own combined-cycle gas plant. This slight premium is reflected in the 2017 IRP by comparing the energy costs of B2H and the non-B2H gas portfolios: P1 and P3, P4 and P6, P7 and P9, and P10 and P12. In each of these cases, the B2H portfolio has a higher energy cost than the non-B2H portfolio. Higher energy costs for B2H portfolios are due to the following:

- Idaho Power will pay a slight premium to Pacific Northwest entities for purchased power (selling entities must recover some of their fixed costs).
- P3, P6, P9, and P12 include Idaho Power constructing power plants rather than B2H. In these portfolios, Idaho Power would have the opportunity to sell excess energy to the market and generate revenue to offset costs.
- Idaho Power must purchase transmission service (transmission wheeling) from a Pacific Northwest entity (likely Bonneville Power Administration [BPA]) to transmit the purchased power to the edge of Idaho Power’s system at Longhorn Substation (once B2H is built). If Idaho Power and BPA can complete an asset swap, these transmission wheeling costs may be avoided, which would reduce the energy cost component of B2H portfolios. Refer to Appendix D-4 for the Memorandum of Understanding (MOU) relating to the potential Idaho Power–BPA asset swap.

The B2H portfolios' capacity costs are so low that capacity installation savings far outweigh the additional energy costs, leading B2H portfolios to be the lowest-cost option for Idaho Power's customers.

## Market Overview

### *Power Markets*

A power market hub is an aggregation of transaction points (often referred to as bus points or buses). Hubs create a common point to buy and sell energy, creating one transaction point for bilateral transactions. Hubs also create price signals for geographical regions.

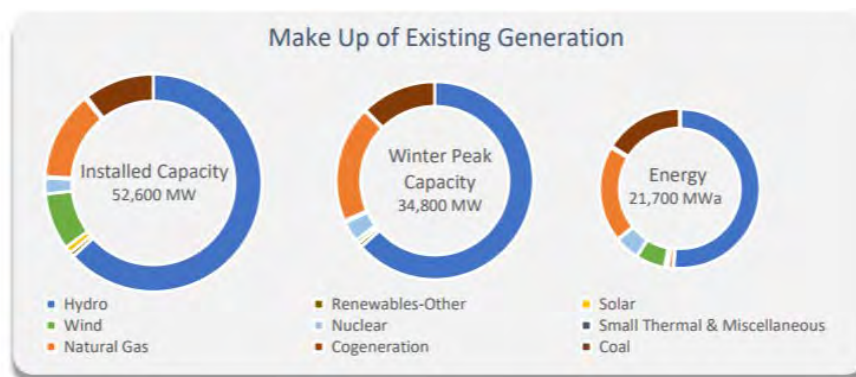
Six characteristics of successful electric trading markets include the following:

1. The geographic location is a natural supply/demand balancing point for a particular region with adequate available transmission.
2. Reliable contractual standards exist for the delivery and receipt of the energy.
3. There is transparent pricing at the market with no single player nor group of players with the ability to manipulate the market price.
4. Homogeneous pricing exists across the market.
5. Convenient tools are in place to execute trades and aggregate transactions.
6. Most importantly, there is a critical mass of buyers and sellers that respond to the five characteristics listed above and actively trade the market on a consistent basis. This is the definition of liquidity, which is clearly the most critical requirement of a successful trading hub.

### *Mid-C Market*

The Mid-C electric energy market hub is a hub where power is transacted both physically and financially (derivative). Power is traded both physically and financially in different blocks: long term, monthly, balance-of-month, day ahead, and hourly. Much of the activity for balance-of-month and beyond is traded and cleared through a clearing exchange, the Intercontinental Exchange (ICE). For short-term transactions, such as day-ahead and real time (hourly), trades are made primarily between buyers and sellers negotiating price, quantity, and point of delivery over the phone (bilateral transactions). In the Pacific Northwest, most of the price negotiations begin with prices displayed for Mid-C on the ICE trading platform.

The Mid-C market exhibits all six characteristics of a successful electric trading market discussed above. Figure 1 shows the relative volume of energy in the Northwest.



**Figure 1. Northwest regional forecast (Source: 2017 PNUCC)<sup>8</sup>**

In the western US, the other major market hubs are California–Oregon Border (COB), Four Corners (Arizona–New Mexico border), Mead (Nevada), Mona (Utah), Palo Verde (Arizona), and SP15 (California). The Mid-C market is very liquid. In 2017, on a day-ahead trading basis, daily average trading volume during heavy-load hours during June and July ranged from nearly 40,000 megawatt-hours (MWh) to over 51,000 MWh. When combining heavy-load hours with light-load hours, on a day-ahead trading basis, the monthly volumes for June and July were each approximately 2,000,000 MWhs. These volumes are in addition to month-ahead trading volumes. Mid-C is by far the highest volume market hub in the west; frequently, Mid-C volumes are greater than the other hubs combined.

The following market participants transact regularly at Mid-C. Additionally, numerous other independent power producers trade at Mid-C.

- Avista Utility
- BPA
- Chelan County Public Utility District (PUD)
- Douglas County PUD
- Eugene Electric Board
- Idaho Power
- PacifiCorp
- Portland General Electric

<sup>8</sup> [pnucc.org/system-planning/northwest-regional-forecast](http://pnucc.org/system-planning/northwest-regional-forecast)

- Powerex
- Puget Sound Energy
- Seattle City Light
- Tacoma City Light

Energy traded at Mid-C is not necessarily physically generated in the Mid-Columbia River geographic area. For instance, Powerex is a merchant of BC Hydro in British Columbia and frequently buys and sells energy at Mid-C. A trade at Mid-C requires that transmission is available to deliver the energy to Mid-C. Transmission wheeling charges must be accounted for when transacting at Mid-C. Sellers at Mid-C must pay necessary transmission charges to deliver power to Mid-C, and buyers must pay necessary transmission charges to deliver power to load.

### ***Mid-C and Idaho Power***

Historically, Idaho Power wholesale energy transactions have correlated well with the Mid-C hub due to Idaho Power's proximity to the market hub and because it is the most liquid hub in the region. Energy at Mid-C can be delivered to, or received from, Idaho Power through a single transmission wheel through the BPA or Avista. Additionally, long-term monthly price quotes are readily available for Mid-C, making it an ideal basis for long-term planning.

Idaho Power uses the market to balance surplus and deficit positions between generation resources and customer demand, and to take advantage of price differences across the region. For example, when market purchases are more cost-effective than generating energy within Idaho Power's generation fleet, Idaho Power customers benefit from lower net power supply cost through purchases instead of Idaho Power fuel expense. Idaho Power customers also benefit from the sale of surplus energy. Surplus energy sales are made when Idaho Power's resources are greater than Idaho Power customer demand and when the incremental cost of these resources are below market prices. Idaho Power customers benefit from these surplus energy sales as offsets to net power supply costs through the power cost adjustment (PCA).

In 2017, Idaho Power averaged approximately 55,000 MWh of Mid-C purchases in June and July. As stated previously, the average monthly volumes at Mid-C, on a day-ahead basis, were approximately 2,000,000 MWh. Based on these averages, Idaho Power's purchases represented less than 3 percent of the total market volumes in June and July. At 3 percent of total market volume on average in June and July, Idaho Power represents a very small fraction of the Mid-C volume during the months when Idaho Power relies on Mid-C the most.

The Mid-C market could be used more to economically serve Idaho Power customers, but Idaho Power's ability to transact at Mid-C is limited due to transmission capacity constraints between the Pacific Northwest and Idaho. In other words, sufficient transmission capacity is currently

unavailable during certain times of the year for Idaho Power to procure cost-effective resources from Mid-C for its customers, even though generation supply is available at the market.

### ***Modeling of the Mid-C Market in the IRP***

As part of the IRP analysis, Idaho Power uses the AURORA to derive energy prices at the Mid-C market. Energy prices are derived based on inputs into the model, such as gas price, coal price, nuclear price, hydro conditions, etc. Refer to Chapter 9 of the 2017 IRP for more information on AURORA and modeling.

Energy purchases from the market require transmission to wheel the energy from the source to the utility purchasing the energy. Purchases from the Mid-C market would need to be wheeled across the BPA system to get the energy to the proposed Longhorn Substation near Boardman, Oregon.

Transmission wheeling rates and wheeling losses are included in the AURORA database and are part of the dispatch logic within the AURORA modeling. AURORA economically dispatches generating units, which can be located across any system in the West. All market energy purchases modeled in Aurora include these additional transmission costs and are included in all portfolios and sensitivities.

### **B2H Comparison to Other Resources**

The 2017 IRP provides an in-depth analysis of the B2H project compared to alternative resource options. Table 2 summarizes some of the high-level differences between B2H and other notable resource options.



**Table 2. High-level differences between resource options**

	B2H	Reciprocating Engines	CCCT	Lithium batteries	1-axis solar PV
Intermittent renewable					✓
Dispatchable capacity providing	✓	✓	✓	✓	
Non-dispatchable (coincidental) capacity providing					✓
Balancing, flexibility providing	✓	✓	✓	✓	
Energy providing	✓	✓	✓	✓	✓
Variable costs (primary variable cost driver)	Mid-C market	Natural gas	Natural gas	Mid-C market	No variable costs
Capital costs	\$450/on-peak kW	\$775/kW	\$1,250/kW	\$1,750/kW	\$2,500/on-peak kW
Fuel price risk		✓	✓		
Wholesale power market price risk	✓			✓	
Other	Expanded access to market (Mid-C) providing abundant clean, renewable energy, highly reliable (low forced outage), as long-lived resources promote stability in customer rates, benefit to regional grid	Scalable (modeled generators 18.8-MW nameplate), relatively short-lead resource	Relatively short-lead resource with recent construction experience	Nascent, uncertainty related to performance (e.g., # of lifetime cycles), potential grid benefit depending on resource siting, scalable and potential for geographic dispersion	Renewable, clean, scalable (modeled plants 30-MW nameplate)

**Notes:**

1. Idaho Power's 2016 solar integration study suggests modest impacts from solar intermittency. Study based on synthetic solar data. Actual production from currently on-line solar projects will be reviewed in 2018 to verify study findings.
2. Solar is not dispatchable but tends to produce at fairly high levels during periods of high customer demand (on-peak capacity factor or contribution to peak equal to 51.3 percent of installed capacity).
3. Lithium battery is a net energy consumer (roundtrip efficiency = 86 percent). Lithium battery provides energy during heavy load hours or other high energy demand/high energy value periods; battery recharge costs tied primarily to Mid-C market costs or variable costs of Idaho Power's system resources during light load hours.
4. B2H capital-cost estimate includes a 20-percent contingency. Lithium battery capital costs are on a declining trend; 2017 Lazard reporting projects 10 percent per year annual rate of capital cost decline. Solar capital cost decline slowing. B2H and solar capital costs are expressed in terms of \$/on-peak kW, where on-peak kW for B2H are based on 500-MW summer capacity and for solar is based on on-peak capacity equal to 51 percent of installed capacity.

## Idaho Power's Transmission System

Idaho Power's transmission system is a key element to providing reliable, responsible, fair-priced energy services. A map of Idaho Power's transmission system is shown in Figure 6.1 on page 58 of the 2017 IRP and in Figure 2. Transmission lines facilitate the delivery of economic resources and allow resources to be sited where most cost effective. In most instances,

the most economic/best location for resources is not immediately next to major load centers (i.e., hydro along the Columbia River, wind in Wyoming, solar in the desert southwest). For much of its history, Idaho Power has taken advantage of resources outside of its major load pockets to economically serve its customers. The existing transmission lines between Idaho Power and the Pacific Northwest have been particularly valuable. Idaho Power has maximized its use of the transmission path between Idaho and the Pacific Northwest. Additional transmission capacity is required to access incremental resources to meet projected peak demand. The B2H project is the mechanism to increase capacity between the Pacific Northwest and Idaho Power's service area.

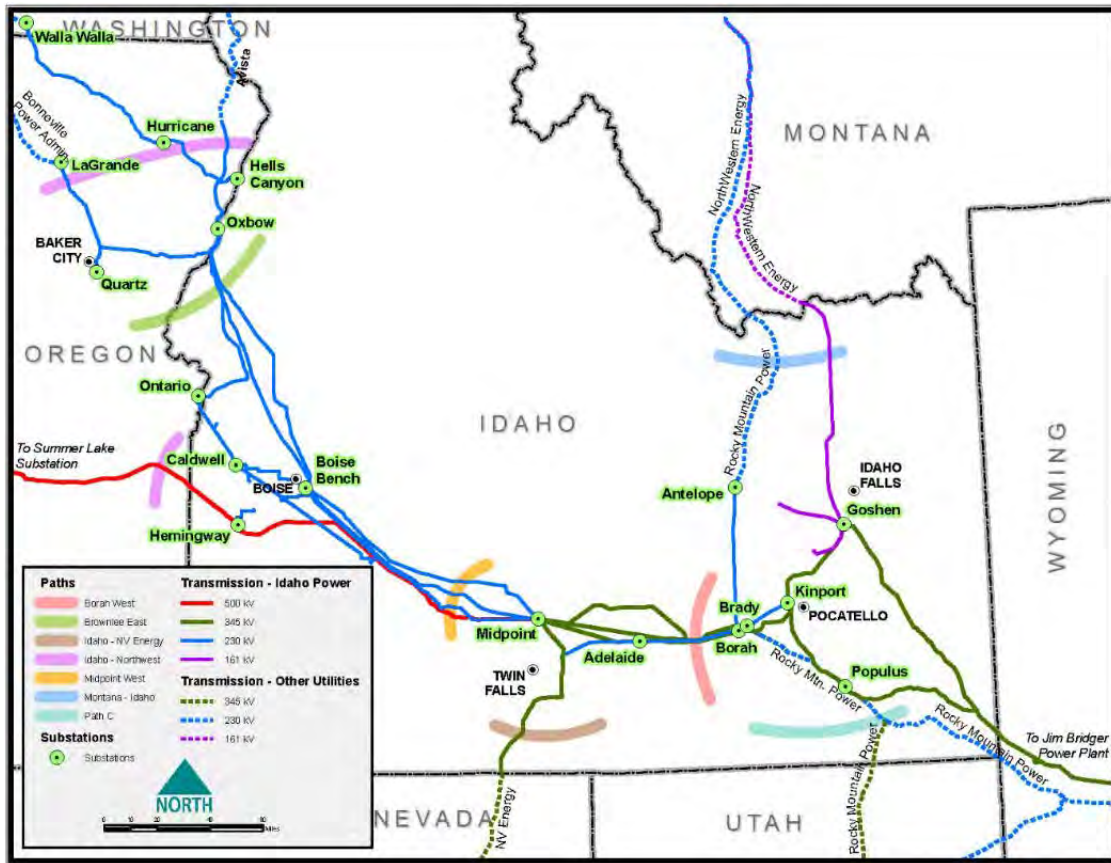
Transmission lines are constructed and operated at different operating voltages depending on purpose, location, and distance. Idaho Power operates transmission lines at 138 kV, 161 kV, 230 kV, 345 kV, and 500 kV. Idaho Power also operates sub-transmission lines at 46 kV and 69 kV, but these voltages will not be discussed further in this appendix; the focus of this appendix is on higher voltage transmission lines used for moving bulk electricity. The higher the voltage, the greater the capacity of the line, but also the greater the construction cost and physical size requirements.

The utility industry often compares transmission lines to roads and highways. Typically, lower-voltage transmission lines (138 kV) are used to facilitate delivery of energy to substations to serve load, like a two-lane highway. Much like roads and highways can become congested, so can transmission lines. High-voltage lines are used to facilitate the bulk delivery of power, sometimes referred to as backbone transmission. Depending on the capacity needs, economics, distance (higher voltages result in less losses for longer distances), and intermediate substation requirements, either 230-kV, 345-kV, or 500-kV transmission lines are used. A 230- or 345-kV line can be compared to a multi-lane interstate, whereas a 500-kV line can be compared to a major (6+ lane) freeway used to move as many vehicles as possible.

## Transmission Capacity Between Idaho Power and the Pacific Northwest

Idaho Power owns 1,280 MW of transmission capacity between the Pacific Northwest transmission system and Idaho Power's transmission system. Of this capacity, 1,200 MW are on the Idaho to Northwest path (Western Electricity Coordinating Council [WECC] Path 14), and 80 MW are on the Montana–Idaho path (WECC Path 18). A transmission path is one or more transmission lines that collectively transmit power to/from similar geographic areas. The Idaho to Northwest transmission path is comprised of three 230-kV lines, one 500-kV transmission line, and one 115-kV transmission line. The capacity limit on the path is established through a WECC rating process based on equipment overload ratings resulting from the loss of the most critical element on the transmission system. Collectively, these lines between Idaho and the Northwest have a transfer capacity rating that is greater than the individual rating of each line

but less than the sum of the individual capacity ratings of each line based on reliability limits. Figure 2 shows an overview of Idaho Power’s transmission system.



**Figure 2. Idaho Power transmission system map**

Table 3 details the capacity allocation between the Pacific Northwest and Idaho Power in 2017. The shaded rows represent capacity amounts that can be used to serve Idaho Power’s native load. Although Idaho Power owns 1280 MW of transmission capacity between the Pacific Northwest and Idaho Power’s system, after all other uses are accounted for, Idaho Power was only able to use 307 MW to serve Idaho Power’s native load in 2017. Idaho Power used 361 MW to serve BPA or PacifiCorp network load on Idaho Power’s system, 282 MW were allocated to transmission reserve margin (TRM), and 330 MW were allocated to capacity benefit margin (CBM).

**Table 3. Pacific Northwest to Idaho Power import transmission capacity from the 2016 transmission forecast**

Firm Transmission Usage (Pacific Northwest to Idaho Power)	Capacity (July MW)
BPA Load Service (Network Customer)	360
Boardman Generation	60
Fighting Creek (PURPA)	4

Palette Load (PacifiCorp—Network Customer)	1
TRM	282
CBM	330
<b>Subtotal</b>	<b>1,037</b>
Pacific Northwest Purchase (Idaho Power Load Service)	243
<b>Total</b>	<b>1,280</b>

TRM is transmission capacity that Idaho Power sets aside as unavailable for firm use, for the purposes of grid reliability. Idaho Power’s TRM methodology, approved by the Federal Energy Regulatory Commission (FERC) in 2002, requires Idaho Power to set aside transmission capacity based on the average loopflow on the Idaho to Northwest path. In the west, electrical power is scheduled through a contract-path methodology, which means if 100 MW is purchased and scheduled over a path, that 100 MW is decremented from the path’s total availability. Physics dictate the actual power flow over the path (based on the path of least resistance), so actual flows don’t always follow contract-path schedules. This unscheduled flow is sometimes referred to as loopflow. The average adverse loopflow across the Idaho to Northwest path during the month of July is 282 MW, which is equal to Idaho Power’s TRM in July. Idaho Power reserves TRM to ensure a safe and reliable transmission system.

CBM is transmission capacity Idaho Power sets aside as unavailable for firm use, for the purposes of recovering from severe unexpected generation outages. Reserve generation capacity is critical to being able to recover from unexpected outages. CBM allows a utility to reduce the amount of reserve generation capacity on its system by providing transmission availability to another market, such as the Pacific Northwest, which is rich with surplus capacity necessary for emergency conditions. Idaho Power’s 330 MW of CBM is based on Idaho Power’s share of the unplanned loss of two Jim Bridger units. The loss of two Jim Bridger units results in the removal of over 1,000 MW of generation in Wyoming, leaving Idaho Power and PacifiCorp searching to replace approximately 330 MW and 670 MW, respectively. Recovering from such an event, especially during peak summer load, can be extremely difficult without access to Pacific Northwest generation capacity, hence the reserve margin.

### **Montana–Idaho Path Utilization**

To utilize Idaho Power’s share of the Montana–Idaho 80 MW of capacity, Idaho Power must purchase transmission service from either Avista or BPA. This transmission system connects the purchased resource in the Pacific Northwest to Idaho Power’s transmission system. Avista or BPA transmits, or wheels, the power across their transmission system and delivers the power to Idaho Power’s transmission system. The Montana–Idaho path is identified in Figure 2 above.

## Idaho to Northwest Path Utilization

To utilize Idaho Power’s share of the Idaho to Northwest capacity, Idaho Power must purchase transmission service from Avista, BPA, or PacifiCorp. Table 4 details a typical summer allocation of the Idaho to Northwest capacity:

**Table 4. The Idaho to Northwest Path (WECC Path 14) summer allocation**

Transmission Provider	Idaho to Northwest Allocation (Summer West to East) (MW)
Avista (to Idaho Power)	340
BPA (to Idaho Power)	350
PacifiCorp (to Idaho Power)	510
<b>Total Capability to Idaho Power</b>	<b>1,200*</b>

\* During times of very low generation at Brownlee, Oxbow, and Hells Canyon hydro plants, the Idaho to Northwest path total capability can increase to as much as 1,340 MW; low generation at these power plants does not correspond with Idaho Power’s system peak.

Avista, BPA and PacifiCorp share an allocation of capacity on the western side of the Idaho to Northwest path, and Idaho Power owns 100 percent of the capacity on the eastern side of the Idaho to Northwest path. For Idaho Power to transact across the path and serve customer load, Idaho Power’s Load Servicing Operations must purchase transmission service from Avista, BPA, or PacifiCorp to connect the selling entity, via a contract transmission path, to Idaho Power.

Construction of B2H will add 1,050 MW of capacity to the Idaho to Northwest path in the west-to-east direction, of which Idaho Power will own 500 MW in the summer months (April–September), and 200 MW in the winter months (January–March and October–December). A total breakdown of capacity rights of the B2H permitting co-participants can be found in the Project Co-Participants section of this report. The Idaho to Northwest path is identified in Figure 2 above.

## Regional Planning—Studies and Conclusions

The Northern Tier Transmission Group (NTTG) and Columbia Grid are regional planning organizations that are organized and operate in compliance with FERC orders 890 and 1000. The purpose of these organizations is to consolidate each member’s local transmission plans and determine a regional plan that can meet the needs of the combined member footprint in a more efficient or cost-effective manner. The NTTG and Columbia Grid develop transmission plans biennially.

B2H is a committed project in the most recent Columbia Grid 10-year plan, and it is part of the projects compromising the NTTG 2014–2015 Biennial Plan and the soon-to-be-published NTTG 2016–2017 Biennial Plan. The identified need for the B2H project in these regional planning organizations is based on transmission needs submitted by BPA, Idaho Power, and PacifiCorp.

At NTTG, all member utilities submit their load forecasts, generation forecasts, and transmission needs. NTTG studies the members' transmission footprints to determine the more efficient or cost-effective plan to meet those needs.

B2H has been, and remains, an integral part of NTTG's 10-year plan. NTTG's analysis indicated B2H is the most cost-effective and efficient project to meet the needs of the NTTG footprint.

Appendix D-5 contains the latest NTTG materials. For the most recent updates related to Idaho Power's regional planning organization, please refer to the NTTG website at [nttg.biz/](http://nttg.biz/).

## THE B2H PROJECT

### Project History

The B2H project originated from Idaho Power's 2006 IRP. The 2006 IRP specified 285 MW of additional transmission capacity, increasing Idaho Power's connection to the Pacific Northwest power markets, as a resource in the preferred resource portfolio. A project had not been fully vetted at that time but was described as a 230-kV transmission line between McNary Substation and Boise. After the initial identification in the 2006 IRP, Idaho Power evaluated numerous capacity upgrade alternatives. Considering distance, cost, capacity, losses, and substation termination operating voltages, Idaho Power determined a new 500-kV transmission line between the Boardman, Oregon, area and the proposed Hemingway 500-kV substation would be the most cost-effective method of increasing capacity. Refer to Appendix D-1 for more information on the upgrade options considered.

Transmission capacity, especially at 500 kV, can be described as "lumpy" because capacity increments are relatively large between the different transmission operating voltages. In the 2009 IRP, Idaho Power assumed 425 MW of capacity, which was 50 percent of the assumed total rating. Idaho Power's long-standing preference was to find a partner or partners to construct B2H with to take advantage of economies of scale. In the 2011 IRP, Idaho Power assumed 450 MW of capacity. In 2012, Idaho Power achieved two major milestones: 1) PacifiCorp and BPA officially joined the B2H project as permitting co-participants and 2) Idaho Power received a formal capacity rating for the B2H project via the WECC Path Rating Process (more on this process in preceding section). In the 2013 IRP, Idaho Power began to use the negotiated capacity from the permitting agreement: 500 MW in the summer and 200 MW in the winter, a yearly average of 350 MW, for a cost allocation of 21 percent of the total project. Idaho Power used the same 21.2 percent interest in the 2015 and 2017 IRPs.

### Public Participation

The B2H project has involved considerable stakeholder involvement over the last 10 years. Idaho Power has hosted and participated in over 250 public and stakeholder meetings with an

estimated 3,000+ participants. After approximately a year of public scoping in 2008, Idaho Power paused the federal and state review process and initiated a year-long comprehensive public process to gather more input. This community advisory process (CAP) took place in 2009 and 2010. The four objectives and steps of the CAP were as follows:

1. Identify community issues and concerns.
2. Develop a range of possible routes that address community issues and concerns.
3. Recommend proposed and alternate routes.
4. Follow through with communities during the federal and state review processes.

Through the CAP, Idaho Power hosted 27 Project Advisory Team meetings, 15 public meetings, and 7 special topic meetings. In all, nearly 1,000 people were involved in the CAP, either through Project Advisory Team activities or public meetings. Additionally, numerous meetings with individuals and advocacy groups were held during and after the process.

Ultimately, the route recommendation from the CAP was the route Idaho Power brought into the *National Environmental Policy Act of 1969* (NEPA) process as the proponent-recommended route. The NEPA process included additional opportunities for public comment at major milestones, and Idaho Power worked with landowners and communities along the way. Ultimately, the route selected through the NEPA process was based on the Bureau of Land Management's (BLM) analysis and public input. For more information on the CAP, including the final report<sup>9</sup>, and Idaho Power's initial scoping activities, visit the documents section<sup>10</sup> on the [B2H website](#).

Throughout the BLM's NEPA process, including development of the Draft Environmental Impact Statement (EIS), issued Dec. 19, 2014, and prior to the Final EIS, issued Nov. 22, 2016, Idaho Power worked with landowners, stakeholders and jurisdictional leaders on route refinements and to balance environmental impacts with impacts to farmers and ranchers. For example, Idaho Power met with the original "Stop Idaho Power" group in Malheur County to help the group effectively comments and seek change from the BLM when the Draft EIS indicated a preference for a route across Stop Idaho Power stakeholder lands. BLM's decision was modified, and the route moved away from an area of highly valued agricultural lands in the Final EIS almost two years later.

---

<sup>9</sup> [boardmanto hemingway.com/documents/CAP%20Report-Final-Feb%202011.pdf](http://boardmanto hemingway.com/documents/CAP%20Report-Final-Feb%202011.pdf)

<sup>10</sup> [boardmanto hemingway.com/documents.aspx](http://boardmanto hemingway.com/documents.aspx)

Idaho Power worked with landowners in the Baker Valley, near the National Historic Oregon Trail Interpretive Center (NHOTIC), to move an alternative route along fence lines to minimize impacts to irrigated farmland, where practicable. This change was submitted by the landowners and included in the BLM's Final EIS and ROD (issued Nov. 17, 2017). Another change in Baker County was in the Burnt River Canyon and Durkee area, where Idaho Power worked with the BLM and affected landowners to find a more suitable route than what was initially preferred in the Draft EIS. Idaho Power is still working with landowners and local jurisdictional leaders to microsite in these areas to minimize impacts.

Unfortunately, the route preferences of Idaho Power and the local communities aren't always reflected in the BLM's Agency Preferred route. For example, Idaho Power had worked in the Baker County area to propose a route on the backside of the NHOTIC (to the east) to minimize visual impacts, and in the Brogan area, to avoid landowner impacts. However, both route variations went through priority sage grouse habitat and were not adopted in BLM's Agency Preferred route.

However, Idaho Power worked with Umatilla County, local jurisdictional leaders and landowners to identify a new route through the entire county, essentially moving the line further south and away from residences, ranches, and certain agriculture. This southern route variation through Umatilla County was included the BLM's Agency Preferred route.

At the urging of local landowners along Bombing Range Road in Morrow County, Idaho Power has been working with local jurisdictional leaders, delegate representatives, farmers, ranchers, and other interested parties to gain the Navy's consideration of an easement along the eastern edge of the Boardman Bombing Range. This cooperative effort with the local area has benefited the Project, providing an approach that meets the interests and common good for all in the area. Idaho Power is still working with the Navy to obtain that easement, but all indications point to receiving an authorization from the Navy in 2018.

Finally, in Union County Idaho Power worked with local jurisdictional leaders, stakeholder groups, such as the Glass Hill Coalition and some members of StopB2H (prior to that group's formation) to identify new route opportunities. The Union County B2H Advisory Commission agreed to submit a route proposal to the BLM that followed existing high-voltage transmission lines, which was later identified as the Millcreek Alternative. At the same time, Idaho Power met with a large landowner to adjust the Morgan Lake Alternative route to minimize impacts to the landowners. Idaho Power understood that both the Mill Creek and Morgan Lake route variations were favored over BLM's Agency Preferred Alternative (Glass Hill Alternative) by landowners, the Glass Hill Coalition, several stakeholders, and the Confederated Tribe of the Umatilla Indian Reservation due to concerns of impacts on areas that had no prior development. Idaho Power continued support of the community-favored routes in its amended preliminary Application for



Site Certificate. Idaho Power will work with Union County and local stakeholders to determine the route preference between the Morgan Lake and Millcreek alternatives.

## Project Activities

Below is a summary of notable activities by year since project inception. For more information about any of the activities, please visit the [B2H website](#).

### 2006

Idaho Power files its IRP with a transmission line to the Pacific Northwest identified in the preferred resource portfolio.

### 2007

Idaho Power analyzes the capacity and cost of different transmission line operating voltages and determines a new 500-kV transmission line to be the most cost-effective option to increase capacity and meet customer needs. Idaho Power files a Preliminary Draft Application for Transportation and Utility Systems and Facilities on Federal Lands. Idaho Power scopes routes.

### 2008

Idaho Power submits application materials to the BLM. Idaho Power submits a Notice of Intent to the EFSC. The BLM issues a Notice of Intent to prepare an EIS; officially initiating the BLM-led federal NEPA process. Idaho Power embarks on a more extensive public outreach program to determine the transmission line route.

### 2009

Idaho Power pauses NEPA and EFSC activities to work with community members throughout the route as part of the CAP to identify a proposed route that would be acceptable to both Idaho Power and the public. Forty-nine routes and/or route segments were considered through CAP.

### 2010

The CAP concludes. Idaho Power resubmits a proposed route to the BLM based on input from the CAP. The BLM re-initiates the NEPA scoping process and solicits public comments. Idaho Power publishes its [B2H Siting Study](#). Idaho Power files a Notice of Intent with EFSC.

### 2011

Additional public outreach resulted in additional route alternatives submitted to the BLM. The Obama Administration recognizes B2H as one of seven national priority projects<sup>11</sup>.

---

<sup>11</sup> [boardmantoohemingway.com/documents/RRTT\\_Press\\_Release\\_10-5-2011.pdf](http://boardmantoohemingway.com/documents/RRTT_Press_Release_10-5-2011.pdf)

## 2012

The ODOE conducts informational meetings and solicits comments. The ODOE issues a Project Order outlining the issues and regulations Idaho Power must address in its Application for Site Certificate. Additional public outreach and analysis resulted in route modifications and refinements submitted to the BLM. Idaho Power issues a [Siting Study Supplement](#). Idaho Power conducts field surveys for the EFSC application. WECC adopts a new Adjacent Transmission Circuits definition with a separation distance of 250 feet, which would later modify routes in the EIS process. Idaho Power receives a formal capacity rating from WECC.

## 2013

Public meetings are held. Idaho Power submits its Preliminary Application for Site Certificate to the ODOE. The BLM releases preliminary preferred route alternatives and works on a Draft EIS.

## 2014

The BLM issues a Draft EIS identifying an Agency Preferred Alternative. The 90-day comment period opens. Idaho Power conducts field surveys for EFSC application.

## 2015

The BLM hosts open houses for the public to learn about the Draft EIS, route alternatives, environmental analysis. The BLM reviews public comments. Idaho Power notifies the BLM of a preferred termination location, Longhorn Substation. Idaho Power submits an application to the Navy for an easement on the Naval Weapons System Training Facility in Boardman. Idaho Power conducts field surveys for the EFSC application.

## 2016

Idaho Power submits a Draft Amended Application for Site Certificate to the ODOE for review. The BLM issues a Final EIS identifying an environmentally preferred route alternative and an Agency Preferred route alternative. Idaho Power incorporates the Agency Preferred route alternative into the EFSC application material. Idaho Power collaborates with local area stakeholders in Morrow County to find a routing solution on Navy-owned land. Idaho Power submits a revised application to the Navy. Idaho Power conducts field surveys for the EFSC application.

## 2017

Idaho Power submits an Amended Application for Site Certificate to the ODOE. The BLM issues a ROD.

For a detailed list of project activities by year, please refer to Appendix D-2.

## Route History

As stated previously, the B2H project was first identified in the 2006 IRP. At that time, the transmission line was contemplated as a line between Boise and McNary. The project evolved into a 500-kV line between the Boardman area and the Hemingway Substation. Several northern terminus substations were considered over the years, including the Boardman coal plant 500-kV yard, the proposed Grassland Substation to be constructed by Portland General Electric to integrate the then-proposed Carty Plant, and the proposed Longhorn Substation, which at the time was proposed by BPA to integrate wind onto the BPA 500-kV transmission system. During scoping, a considerable number of routes were considered to connect Hemingway and the Boardman area. Figure 3 is a snapshot of a number of routes considered early on during the CAP process (2009 timeframe). Numerous alternatives were considered, including routes through Idaho and through central Oregon. This large number of routes was further refined during the CAP process.

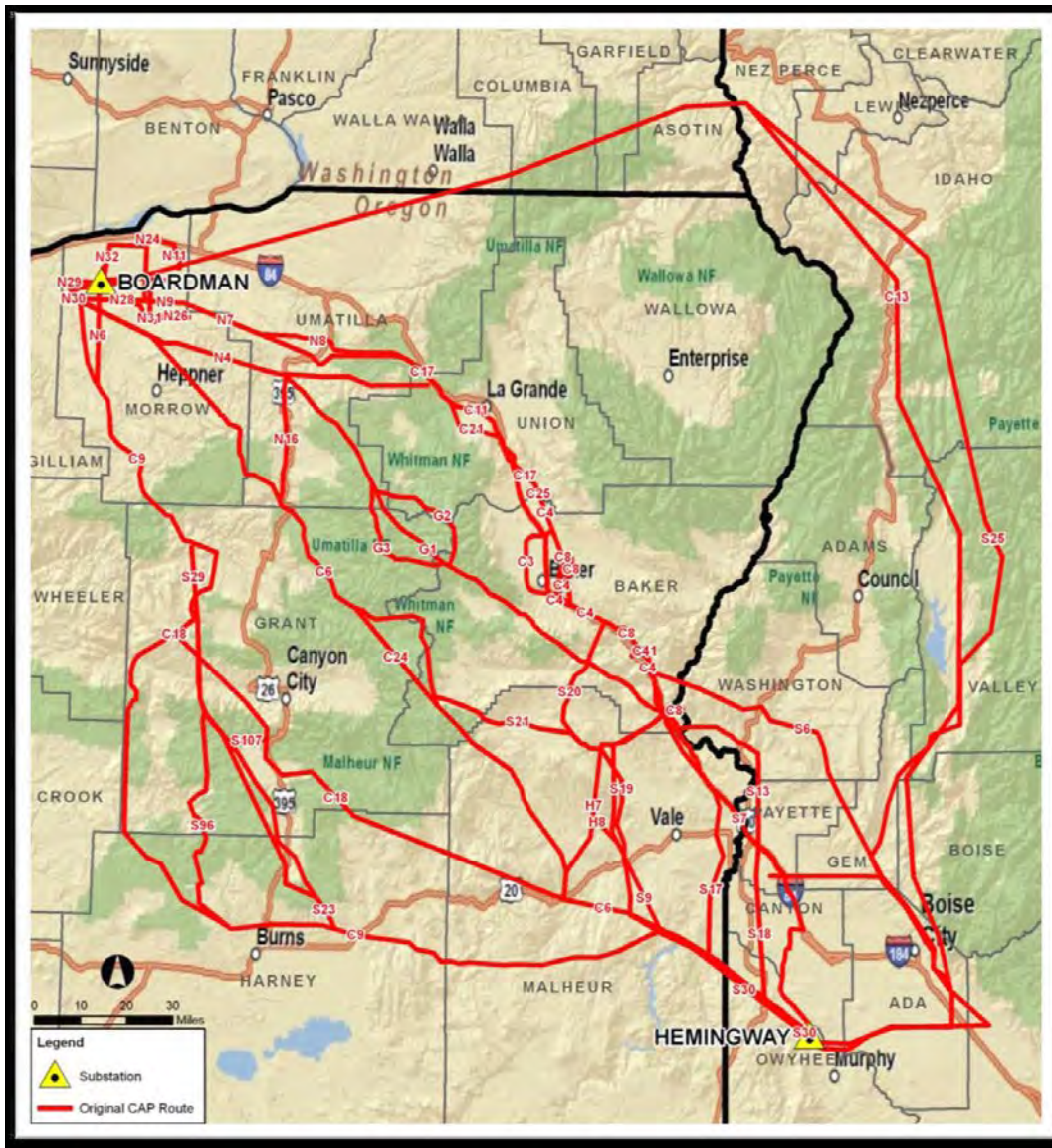


Figure 3. Routes developed by the CAP advisory teams (2009 timeframe)

The CAP process resulted in Idaho Power submitting the route shown in Figure 4 as the company’s proposed route in the BLM-led NEPA process.



Figure 4. B2H proposed route resulting from the CAP process (2010 timeframe)

The BLM considered Idaho Power’s proposed route, along with a number of other reasonable alternative routes, in the NEPA process. Figure 5 shows the route alternatives and variations considered in the BLM’s November 2016 Final EIS.

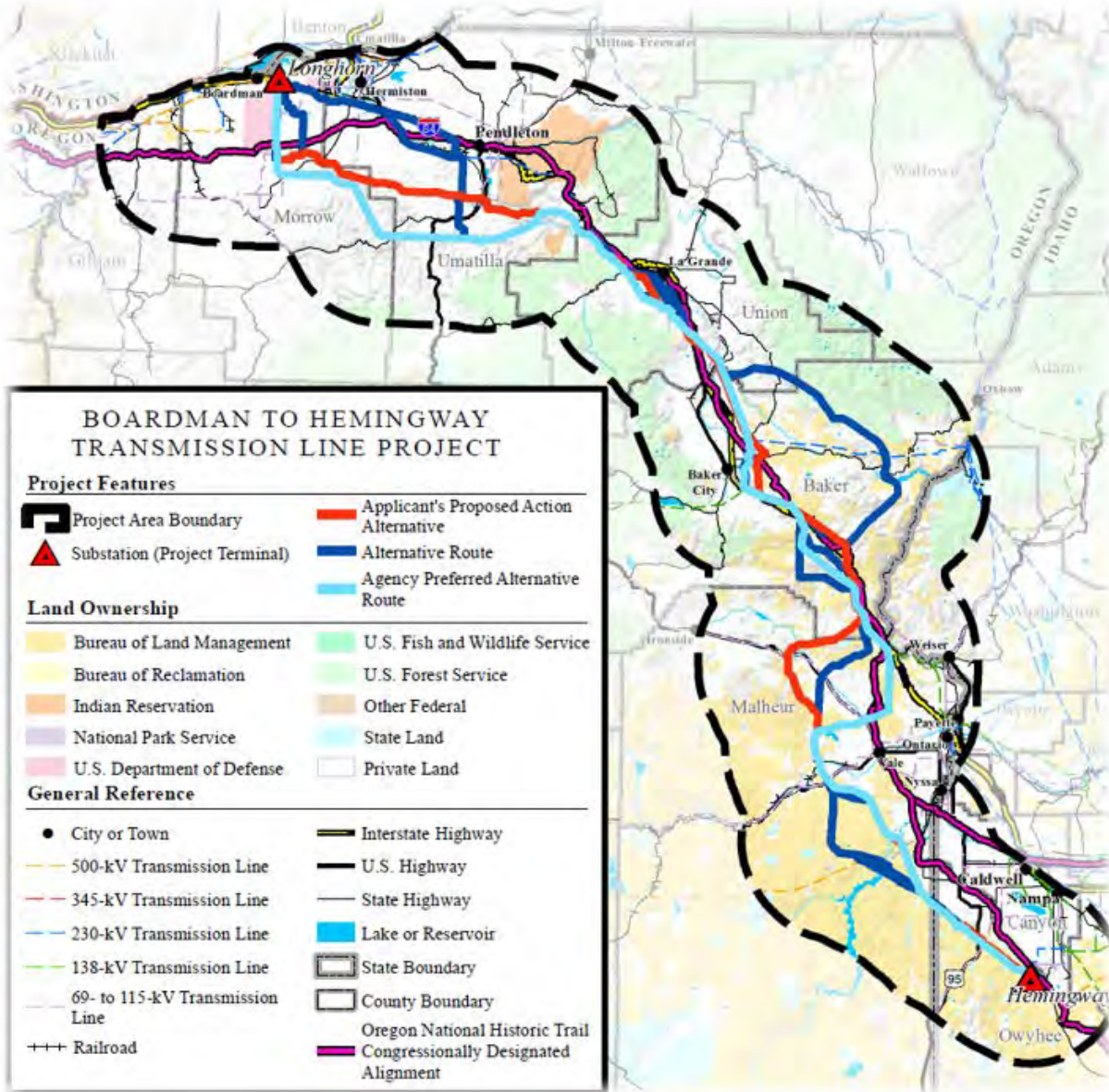
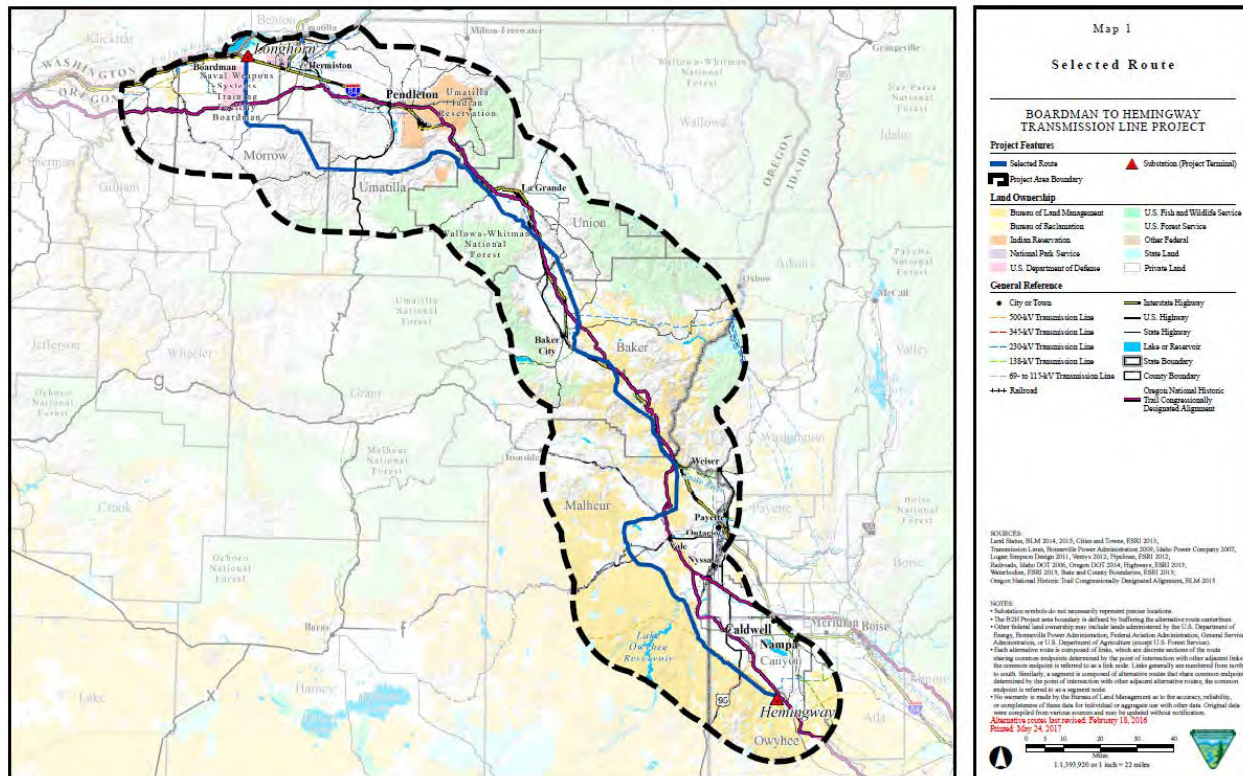


Figure 5. BLM final EIS routes

The conclusion of the BLM-led NEPA process, the BLM’s ROD, resulted in a singular route—the BLM’s Agency Preferred route. The 293.4-mile approved route will run across 100.3 miles of federal land (managed by the BLM, the U.S. Forest Service [USFS], the Bureau of Reclamation, and the U.S. Department of Defense), 190.2 miles of private land, and 2.9 miles of state lands. Figure 6 shows the BLM’s Agency Preferred route.



**Figure 6. BLM Agency Preferred route from the 2017 BLM ROD**

As discussed previously, the BLM-led NEPA process and the EFSC process are distinct processes. Idaho Power submitted its Amended Application for Site Certificate to the ODOE in summer 2017. The route Idaho Power submitted to the ODOE as part of the Application for Site Certificate is very similar to the BLM’s Agency Preferred route, except for a small section of private property west of La Grande. The BLM’s Agency Preferred route in this area was a surprise to Idaho Power and seemingly all stakeholders in the area. The section the BLM chose was not the county’s stated preference, nor was it the variation Idaho Power had worked with a large local landowner to modify to minimize impacts to his property.

At the time of EFSC application finalization (which was prior to the Final EIS release), Idaho Power did not feel as if there was a stakeholder consensus preference between the County’s preferred route and the modified route west of the City of La Grande. Therefore, Idaho Power brought both alternatives into the EFSC application. Idaho Power intends to continue to work with the community to finalize which of the two variations in this area will be constructed.

Figure 7 shows the route Idaho Power submitted in its 2017 EFSC Application for Site Certificate.

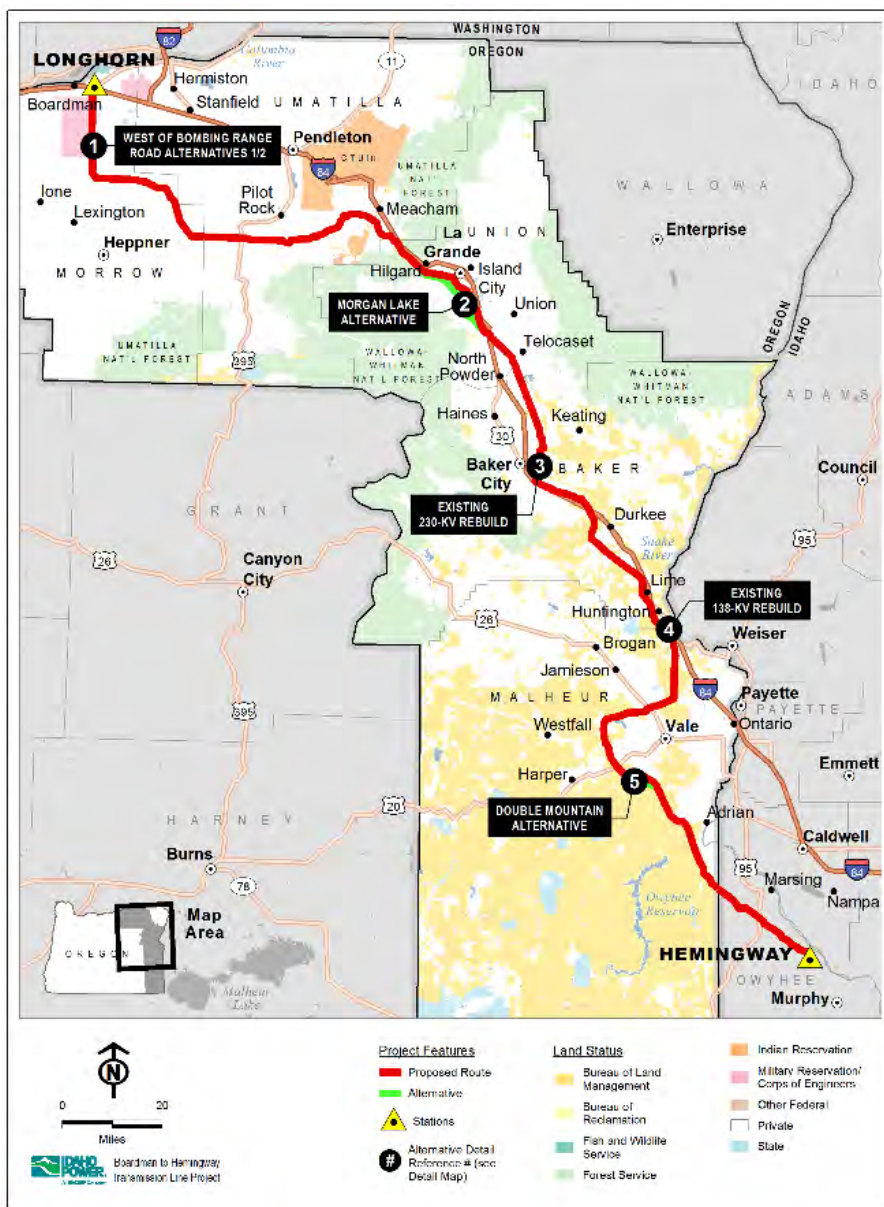


Figure 7. B2H route submitted in 2017 EFSC Application for Site Certificate

## B2H Capacity Interest

Per the terms of the Joint Permit Funding Agreement (see Appendix D-3), each co-participant (funder) is assigned a permitting interest based on the annual weighted capacity expressed in the project. The permitting interest is determined by the sum of a funder’s eastbound capacity interest and westbound capacity interest, divided by the total of all eastbound and westbound capacity interest. Table 5 details the capacity interest of each funder.



**Table 5. B2H joint permit funding capacity interests by funder**

	Capacity Interest (West-to-East)	Capacity Interest (East-to-West)	Ownership %
<b>Idaho Power</b>	350 MW (Average) 500 MW (Summer) 200 MW (Winter)	0 MW	21.2%
<b>PacifiCorp</b>	300 MW	600 MW	54.5%
<b>BPA</b>	400 MW (Average) 250 MW (Summer) 550 MW (Winter)	0 MW	24.2%
<b>Unallocated</b>	0 MW	400 MW	

Idaho Power’s capacity interest is seasonally shaped, with 500 MW of eastbound capacity from April through September and 200 MW of eastbound capacity from January through March and October through December. BPA’s capacity interest is seasonally shaped with 250 MW of eastbound capacity from April through September and 550 MW of eastbound capacity from January through March and October through December. PacifiCorp’s capacity is constant throughout the year. The sum of the capacity interest in the east-to-west direction is less than the rating (1,000 MW), so the unallocated capacity is divided among the funders based on their respective percentage permitting interest.

The seasonal capacity shaping is a great benefit for Idaho Power’s customers, and one of the reasons why the B2H project is such a competitive and cost-effective option in the IRP process. Idaho Power is effectively purchasing 500 MW of capacity (peak summer need) at a cost based on 350 MW of capacity.

## Capacity Rating—WECC Rating Process

Idaho Power coordinated with other utilities in the Western Interconnection via a peer-reviewed process known as the WECC Path Rating Process. Through the WECC Path Rating Process, Idaho Power worked with other western utilities to determine the maximum rating (power flow limit) across the transmission line under various stresses, such as high winter or high summer peak load, light load, high wind generation, and high hydro generation on the bulk power system. Based on industry standards to test reliability and resilience, Idaho Power simulated various outages, including the outage of B2H, while modeling these various stresses to ensure the power grid was capable of reliably operating with increased power flow. Through this process, Idaho Power also ensured the B2H project did not negatively impact the ratings of other transmission projects in the Western Interconnection. Idaho Power completed the WECC Path Rating Process in November 2012 and achieved a WECC Accepted Rating of 1,050 MW in the west-to-east direction and 1,000 MW in the east-to-west direction. The B2H project, when constructed, will add significant reliability, resilience, and flexibility to the Northwest power grid.

## ***B2H Design***

B2H is routed and designed to withstand catastrophic events, including, but not limited to, the following:

- Lightning
- Earthquake
- Fire
- Wind/tornado
- Ice
- Landslide
- Flood
- Direct physical attack

The following sections provide more information about the design of the B2H transmission line and address each of the catastrophic events listed above.

### **Transmission Line Design**

The details below are not inclusive of every design aspect of the transmission line but provide a brief overview of the design criteria. The B2H project will be designed and constructed to meet or exceed all required safety and reliability criteria.

The basic purpose of a transmission line is to move power from one substation to another for eventual distribution of electricity to end users. The basic components of a transmission line are the structures/towers, conductors, insulators, foundations to support the structures, and shield wires to prevent lightning from striking conductors. See Figure 8 for a cross-section of a transmission line.

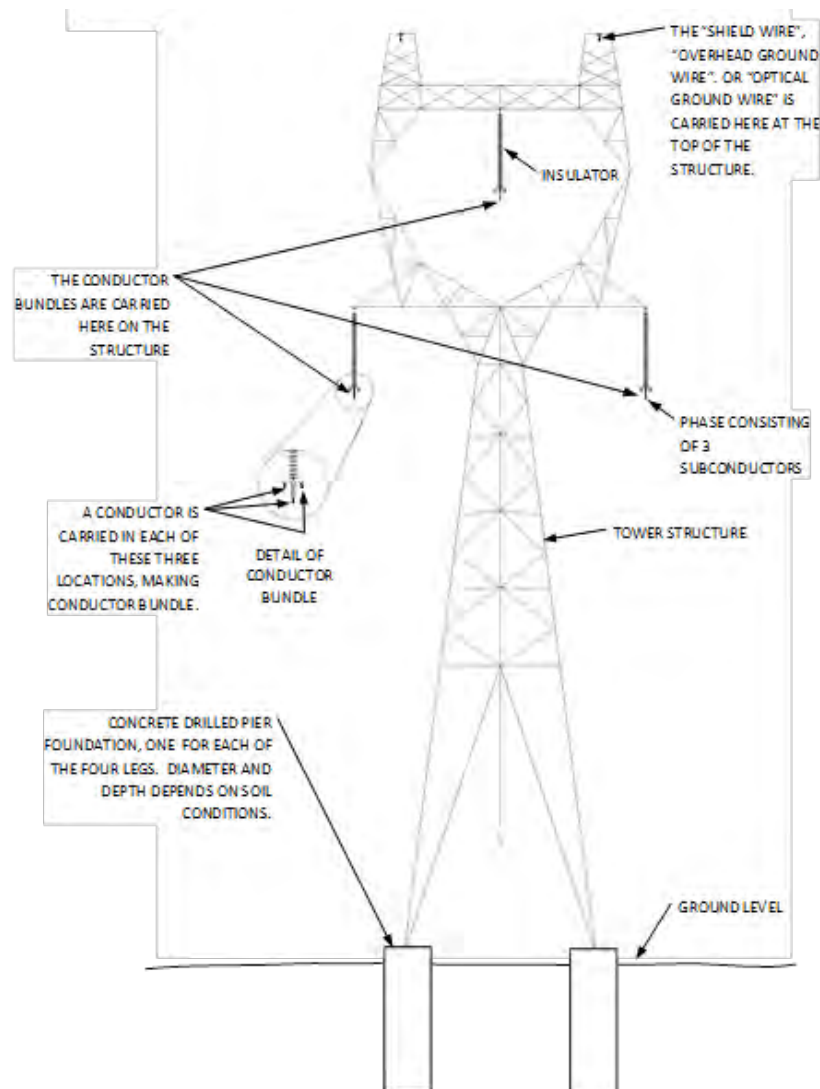
For a single-circuit transmission line, such as B2H, power is transmitted via three-phase conductors (a phase can also have multiple conductors, called a bundle configuration). These conductors are typically comprised of a steel core to give the conductor tensile strength and reduce sag and of aluminum outer strands. Aluminum is used because of its conductive properties, and it provides the ability to move more power using a smaller amount of material.

Shield wires, typically either steel or aluminum, and occasionally including fiber optic cables inside for communication between substation equipment, are the highest wires on the structure. Their main purpose is to protect the phase conductors from a lightning strike.

Structures are designed to support the phase conductors and shield wires and keep them safely in the air. For the B2H project, structures were chosen to be steel lattice tower structures,

which provide an economical means to support large conductors for long spans over long distances. The typical structure height for B2H is 135 feet tall (structure height will vary depending on location) with a structure located roughly every 1,200 feet on average. The tower height and span length were optimized to minimize ground impacts and material requirements; taller structures could allow for longer spans (less structures on average per mile) but would be costlier due to material requirements. Again, the B2H tower and conductors were engineered to maximize benefits and minimize costs and impacts.

Foundations are the support mechanism that bind the structures to the earth and safely keep the phase conductors and shield wires in the air. For the B2H project, the foundations at each lattice tower structure are planned to be concrete-drilled pier shafts. A cylindrical hole will be drilled at each tower footing of adequate diameter and depth to support the loads applied to the structure from the shield wires and phase conductors. The loads applied to structures via shield wires and conductors are discussed in further detail below.



**Figure 8. Transmission tower components**

### Transmission Line Structural Loading Considerations

Reliability and resiliency are designed into transmission lines. Overhead transmission lines have been in existence for over 100 years, and many codes and regulations govern the design and operation of transmission lines. Safety, reliability, and electrical performance are all incorporated into the design of transmission lines. Idaho Power's EFSC application includes an exhaustive list of standards. Several notable standards are as follows:

- American Concrete Institute 318—*Building Code Requirements for Structural Concrete*
- American National Standards Institute (ANSI) standards (for material specs)
- American Society of Civil Engineers (ASCE) Manual No.74—*Guidelines for Electrical Transmission Line Structural Loading*

- National Electrical Safety Code (NESC)
- Occupational Safety and Health Administration (OSHA) 1910.269 April 11, 2014 (for worker safety requirements)
- National Fire Protection Association (NFPA) 780—*Guide for Improving the Lightning Performance of Transmission Lines*

NESC provides for minimum guidelines and industry standards for safeguarding persons from hazards arising from the construction, maintenance, and operation of electric supply and communication lines and equipment. The B2H project will be designed, constructed, and operated at standards that meet, and in most cases, exceed, the provisions of NESC.

Physical loads induced onto transmission structures and foundations supporting the phase conductors and shield wires for the B2H project are derived from three phenomena: wind, ice, and tension. Under certain conditions, ice can build up on phase conductors and shield wires of transmission lines. When transverse wind loading is also applied to these iced conductors, it can produce structural loading on towers and foundations far greater than normal operating conditions produce. Design weather cases for the B2H project exceed the provisions in the NESC. As an example, for a high wind case, NESC recommends 90 miles per hour (mph) winds. The criteria proposed for this project is 100 mph wind on the conductors and 120 mph wind on the structures. There are multiple loading conditions that will be incorporated into the design of the B2H project, including unbalanced longitudinal loads, differential ice loads, broken phase conductors, broken sub-phase conductors, heavy ice loads, extreme wind loads, extreme ice and wind loads, construction loads, and full dead-end structure loads.

### **Transmission Line Foundation Design**

The 500-kV single-circuit lattice steel structures require a foundation for each leg of the structure. The foundation diameter and depth shall be determined during final design and are dependent on the type of soil or rock present. The foundations will be concrete pier foundations designed to comply with the allowable bearing and shear strengths of the soil where placed. Soil borings shall be taken at key locations along the project route, and subsequent soil reports and investigations shall govern specific foundation designs as appropriate.

Common industry practices design transmission line structures to withstand wind and ice loads of NESC or greater, and are accepted as more stringent than the potential loads resulting from ground motion due to earthquakes. The 2017 NESC Rule 250A4 observes the structure capacity obtained by designing for NESC wind and ice loads at the specified strength requirements is sufficient to resist earthquake ground motions. Additionally, ASCE Manual No. 74 states transmission structures need not be designed for ground-induced vibrations caused by earthquake

motion; historically, transmission structures have performed well under earthquake events,<sup>12, 13</sup> and transmission structure loadings caused by wind/ice combinations and broken wire forces exceed earthquake loads.

### **Lightning Performance**

The B2H project is in an area that historically experiences 20 lightning storm days per year.<sup>14</sup> This is relatively low compared to other parts of the US. The transmission line will be designed to not exceed a lightning outage rate of one per 100 miles per year. This will be accomplished by proper shield wire placement and structure/shield wire grounding to adequately dissipate a lightning strike on the shield wires or structures if it were to occur. The electrical grounding requirements for the project will be determined by performing ground resistance testing throughout the project alignment, and by designing adequately sized counterpoise or using driven ground rods with grounding attachments to the steel rebar cages within the caisson foundations as appropriate.

### **Earthquake Performance**

Experience has demonstrated that high-voltage transmission lines are very resistant to ground-motion forces caused by earthquake, so much so that national standards do not require these forces be directly considered in the design. However, secondary hazards can affect a transmission line, such as landslides, liquefaction, and lateral spreading. The design process considers these geologic hazards using multiple information streams throughout the siting and design process. The current B2H route evaluated geologic hazards using available electronic (geographic information system [GIS]) data, such as fault lines, areas of unstable and/or steep soils, mapped and potential landslide areas, etc. Towers located in potential geologic hazards are investigated further to determine risk. Additional analysis may include field reconnaissance to gauge the stability of the area and subsurface investigation to determine the soil strata and depth of hazard. At the time of this report, no high-risk geologic hazard areas have been identified. If, during the process of final design, an area is found to be high risk, the first option would be to micro-site—route around or span over the hazard. If avoidance is not feasible, the design team would seek to stabilize the hazard. Engineering options for stabilization include designing an array of sacrificial foundations above the tower foundation to anchor the soil or improving the subsurface soils by injecting grout or outside aggregates into the ground. If the geotechnical

---

<sup>12</sup> Risk Assessment of Transmission System under Earthquake Loading. J.M. Eidinger, and L. Kemper, Jr. Electrical Transmission and Substation Structures 2012, Pg. 183-192 © ASCE 2013.

<sup>13</sup> Earthquake Resistant Construction of Electric Transmission and Telecommunication Facilities Serving the Federal Government Report. Felix Y. Yokel. Federal Emergency Management Agency (FEMA). September 1990.

<sup>14</sup> USDA RUS Bulletin 1751-801.

investigation determines the problematic soils are relatively shallow, the tower foundations can be designed to pass through the weaker soils and embed into competent soils.

### **Wildfire**

The transmission line steel structures are constructed of non-flammable materials, so wildfires do not pose a physical threat to the transmission line itself. However, heavy smoke from wildfires in the immediate area of the transmission line can cause flashover/arcing between the phase conductors and electrically grounded components. Standard operation is to de-energize transmission lines when fire is present in the immediate area of the line. Transmission lines generally remain in-service when smoke is present from wildfires not in the immediate vicinity of the transmission line. Alternatively, solar PV is susceptible to smoke, which can move into areas even if fires are not in the immediate vicinity of the solar generation. For example, the forest fires in the Pacific Northwest in 2017 caused much smoke along the proposed B2H corridor and in the Pacific Northwest in general. The B2H line would likely still operate for the fires not in the immediate area, whereas solar PV would likely operate at a much-reduced capacity while heavy smoke is covering the area.

### **Wind Gusts/Tornados**

Tornados are unlikely along the B2H route. As noted in the Transmission Line Structural Loading Considerations section above, the B2H transmission line is designed to withstand extreme wind loading combined with ice loading.

### **Ice**

Ice formation around the phase conductors and around the shield wires can add a substantial amount of incremental weight to the transmission line, putting extra force on the steel structures and foundations. As described in the Transmission Line Structural Loading Considerations section above, the B2H transmission line is designed to withstand heavy ice loading combined with heavy wind loading.

### **Landslide**

The siting and design process considers geologic hazards, such as landslides, liquefaction, and lateral spreading. See the Earthquake Performance section above. Through the siting and design process, steep, unstable slopes are avoided, especially where evidence of past landslides is evident. During the preliminary construction phase, geotechnical surveys and ground surveys (light detection and ranging [LiDAR] surveys) help verify potentially hazardous conditions. If a potentially hazardous area cannot be avoided, the design process will seek to stabilize the area.

## **Flood**

The identification and avoidance of flood zones was incorporated into the siting process and will be further incorporated into the design process. Foundations and structures can be designed to withstand flood conditions.

## **Direct Physical Attack**

A direct physical attack on the B2H transmission line will remove the line's ability to deliver power to customers. In the case of a direct attack, B2H is fundamentally no different than any other supply-side resource should a direct physical attack occur on a specific resource. However, because the B2H project is connected to the transmission grid, a direct physical attack on any specific generation site in the Pacific Northwest or Mountain West region will not limit B2H's ability to deliver power from other generation in the region. In this context, B2H provides additional ability for generation resources to serve load if a physical attack were to occur on a specific resource or location within the region and therefore increases the resiliency of the electric grid as a whole.

If a direct physical attack were to occur on the B2H transmission line and force the line out of service, the rest of the grid would adjust to account for the loss of the line. Per the WECC facility rating process, the B2H capacity rating is such that an outage of the B2H line would not overload any other system element beyond equipment emergency ratings. Idaho Power also keeps a supply of emergency transmission towers that can be very quickly deployed to replace a damaged tower allowing the transmission line to be quickly returned to service.

## **B2H Design Conclusions**

As evidenced in this section, the B2H project is designed to withstand a wide range of physical conditions and extreme events. Because transmission lines are so vital to our electrical grid, design standards are stringent. B2H will adhere to, and in most cases, exceed, the required codes or standards observed for high voltage transmission line design. This approach to the design, construction, and operation of the B2H project will establish utmost reliability for the life of the transmission line. Additionally, as discussed in the Direct Physical Attack section, transmission lines add to the resiliency of the grid by providing additional paths for electricity should one or more generation resources or transmission lines experience a catastrophic event.

# **PROJECT CO-PARTICIPANTS**

## **PacifiCorp and BPA Needs**

PacifiCorp and BPA are co-participants on the B2H project (also referred to as funders). Collectively, Idaho Power, PacifiCorp, and BPA represent a very large electric service footprint in the western US. The fact that three large utilities have each identified the value of the B2H



project indicates the regional significance of the project and the value the project brings to customers throughout the West. Idaho Power, PacifiCorp, and BPA have worked closely to assign the capacity rights of the project to correlate with each party's needs. More information about PacifiCorp's and BPA's needs and interest in the B2H project can be found in the following sections.

### **PacifiCorp**

PacifiCorp is a locally managed, wholly owned subsidiary of Berkshire Hathaway Energy Company. PacifiCorp is a leading western US energy services provider and the largest grid owner/operator in the West, serving 1.8 million retail customers in six western states. PacifiCorp is comprised of two business units: Pacific Power (serving Oregon, Washington, and California) and Rocky Mountain Power (serving Utah, Idaho, and Wyoming). Visit [pacificorp.com](http://pacificorp.com) for more information.

PacifiCorp has invested in the permitting of the B2H project because of the strategic value of the B2H corridor, which connects the Pacific Northwest to the Intermountain West. The existing transmission path between the two regions is fully used during key operating periods. As a potential owner in the project, PacifiCorp would be able to use its bidirectional capacity to increase reliability and efficiency for its customers. The following is a list of additional B2H benefits identified for PacifiCorp.

- **Customers:** PacifiCorp continues to invest to meet customers' needs, making only critical investments now to ensure future reliability, security, and safety. The B2H project is identified as an investment that will ensure future reliability, security, and safety for PacifiCorp customers.
- **Renewables:** PacifiCorp continues to grow their renewable resources and transition to a lower-carbon future. The B2H project has been identified as a strategic project to facilitate PacifiCorp's use of renewable resources across their two balancing authority areas.
- **EIM:** PacifiCorp was a leader in implementing the western energy imbalance market (EIM). The real-time market helps optimize the electric grid, lowering costs, enhancing reliability, and more effectively integrating resources. PacifiCorp believes the B2H project will help advance the objectives of the EIM, benefitting PacifiCorp customers and the broader region.
- **Regional Benefit:** PacifiCorp, as a member of the regional planning entity Northern Tier Transmission Group (NTTG), supports the conclusion that the B2H project is as a cost-effective project providing regional solutions to identified regional needs.

- **Balancing Area Consolidation:** PacifiCorp operates/controls two balancing areas in the West. After the addition of B2H and portions of Gateway West, more transmission capacity will exist between PacifiCorp’s two balancing areas, providing the ability to increase operating efficiencies. B2H will provide PacifiCorp 300 MW of additional west-to-east capability and 600 MW of east-to-west capability to move resources between PacifiCorp’s two balancing authority areas.

## **BPA**

BPA is a nonprofit federal power marketing administration based in the Pacific Northwest. BPA provides approximately 28 percent of the electric power used in the Pacific Northwest, which has an estimated population of over 13 million people. BPA also operates and maintains about three-fourths of the high-voltage transmission in its service area. BPA’s area includes Idaho, Oregon, Washington, western Montana, and small parts of eastern Montana, California, Nevada, Utah, and Wyoming. For more information, visit [bpa.gov](http://bpa.gov).

Similar to the Idaho Power IRP process for identifying cost-effective service alternatives, BPA identified the B2H project plus associated asset exchange as its top priority for pursuit for serving customers in southeast Idaho. BPA’s load and resource mix in southeast Idaho results in a net winter peak demand that exceeds the summer peak demand. BPA’s winter peak load couples well with Idaho Power’s summer peak load to allow for seasonal shaping of the B2H capacity. Seasonal shaping of capacity would allow BPA to own 550 MW of B2H capacity in the winter and 250 MW of capacity in the summer, dramatically increasing the cost-effectiveness of the project for BPA customers. A recent analysis performed by BPA continues to support the B2H project plus the asset exchange as its top priority for pursuit. For more information about the southeast Idaho load service analysis, visit [bpa.gov](http://bpa.gov).<sup>15</sup>

As a federal agency, BPA has responsibilities to comply with NEPA and consider the environmental impacts of its actions, such as participating in transmission line construction. To that end, BPA was a cooperating agency in the development of the B2H EIS and continues to coordinate with the BLM and other federal agencies. BPA will ensure an appropriate environmental review has been conducted on any BPA-proposed action associated with the project and plans to prepare a ROD to the B2H EIS as appropriate and in accordance with the B2H project’s permitting schedule.

## **Co-Participant Expenses Paid to Date**

Approximately \$92 million, including allowance for funds used during construction (AFUDC), have been expended on the B2H project through September 30, 2017. Pursuant to the terms of

---

<sup>15</sup> Southeast Idaho Load Service analysis:

[bpa.gov/transmission/CustomerInvolvement/SEIdahoLoadService/Pages/default.aspx](http://bpa.gov/transmission/CustomerInvolvement/SEIdahoLoadService/Pages/default.aspx)

the joint funding arrangements, Idaho Power has received approximately \$48 million of that amount as reimbursement from the project participants as of September 30, 2017. Idaho Power has accrued in receivables approximately \$18 million more that will be billed by Idaho Power in the future to the project co-participants for expenses Idaho Power has incurred, for a total amount reimbursable by co-participants of \$66 million. Co-participants are obligated to reimburse Idaho Power for their share of any future project permitting expenditures incurred by Idaho Power.

## Co-Participant Agreements

Idaho Power, BPA, and PacifiCorp (collectively, the funders) entered a Joint Permit Funding Agreement on January 12, 2012, with the intent to be joint owners of the B2H line. The Joint Permit Funding Agreement provides for the permitting (state and federal), siting, and acquisition of right-of-way (ROW) over public lands. A copy of the Joint Permit Funding can be found in Appendix D-3.

Related to the project, but not specific to the B2H permitting activities, the B2H co-participants entered into an MOU on January 12, 2012, to 1) explore alternatives to establish BPA eastern Idaho load service from Idaho Power and PacifiCorp's Hemingway Substation and 2) consider whether to replace certain transmission arrangements involving existing assets with joint ownership transmission arrangements and other alternative transmission arrangements pursuant to definitive agreements mutually satisfactory to the co-participants. In other words, in conjunction with the project, the parties agreed to explore cost-effective methods to serve customers by jointly owning facilities other than the B2H project. A copy of the MOU can be found [here](#) or in Appendix D-4.

## COST

### Cost Estimate

The total cost estimate for the B2H project is \$1 to \$1.2 billion dollars, which includes Idaho Power's allowance for funds used during construction (AFUDC). Co-participant AFUDC is not included in this estimate range. The total cost estimate includes a 20-percent contingency for unforeseen expenses.

In IRP modeling, Idaho Power assumes a 21.2-percent share of the direct expenses, plus its entire AFUDC cost, which equates to approximately \$258 million. Idaho Power also included costs for local interconnection upgrades totaling \$16 million. The 2017 IRP was the first year for which the B2H route was relatively certain. In prior years, the estimate was based on uncertain route and terminus location information.

## ***Transmission Line Estimate***

Idaho Power has contracted with HDR to serve as the B2H project's third-party owners' engineer and prepare the B2H transmission line cost estimate. HDR has extensive industry experience, including experience serving as an owner's engineer for BPA for the last seven years. HDR has prepared a preliminary transmission line design that locates every tower and access road needed for the project. HDR used utility industry experience and current market values for materials, equipment, and labor to arrive at the B2H estimate. Material quantities and construction methods are well understood because the B2H project is utilizing BPA's standard tower and conductor design for 500-kV lines. BPA has used the proposed towers and conductor on hundreds of miles of lines currently in-service. HDR was the owner's engineer on recent BPA projects, so HDR is also familiar with the BPA towers and conductor the B2H project is using.

## ***Substation Estimates***

Idaho Power prepared the substation cost estimate for the Hemingway Substation, and BPA prepared the Longhorn Substation estimate. Idaho Power used experience designing and constructing the Hemingway Substation in 2013. The Hemingway Substation is designed to accommodate the B2H line terminal in the future. New equipment must be ordered and installed, but no station expansion will be required. The Longhorn Substation is a station proposed by BPA near Boardman, Oregon. BPA owns the land for the Longhorn Substation, but the station has yet to be constructed. BPA proposed the Longhorn Substation to integrate certain wind projects in the immediate area. BPA has extensive experience designing and constructing substations.

## ***Calibration of Cost Estimates***

The B2H estimate was reviewed and approved by BPA and PacifiCorp. BPA and PacifiCorp both have recent transmission line construction projects to calibrate against. The recent projects included the following:

- BPA: Lower Monumental–Central Ferry 500-kV line (38 miles, in-service 2015)
- BPA: Big Eddy–Knight 500-kV line (39 miles, in-service 2016)
- PacifiCorp: Sigurd to Red Butte 345-kV line (160 miles, in-service 2015)
- PacifiCorp: Mona to Oquirrh 500-kV line (100 miles, in-service 2013)

Additionally, in early 2017 Idaho Power visited with NV Energy and Southern California Edison to learn from each company's recent experience constructing 500-kV transmission lines in the West. As part of the discussions with each company, Idaho Power calibrated cost estimates and resource requirements.

The two projects were as follows:

- NV Energy: ON Line project (235 miles, 500 kV, in-service 2014)
- Southern California Edison: Devers to Palo Verde (150 miles, 500 kV, in-service 2013)

### **Costs Incurred to Date**

Approximately \$92 million, including AFUDC, has been expended on the Boardman-to-Hemingway project through September 30, 2017. Refer to the Co-Participant Expenses Paid to Date section for co-participant reimbursements. The \$92 million incurred through September 30, 2017, is included in the \$1 to \$1.2 billion total estimate. Idaho Power's share of the costs incurred to-date is included B2H IRP portfolio modeling.

### **Cost-Estimate Conclusions**

The cost estimate for B2H has been thoroughly vetted. Idaho Power used third-party contractors with industry experience, relied on PacifiCorp and BPA recent transmission line construction experience, and benchmarked against multiple recent high-voltage transmission line investments in the West to arrive at the B2H construction cost estimate. Material quantities and construction methods are well understood because the B2H project is using BPA's standard tower and conductor design for 500-kV lines. As a conservative measure, Idaho Power has added a 20 percent contingency to cover any unanticipated expenses. As a reminder, Idaho Power's IRP analysis escalates all resource costs at a 2.1-percent inflation rate into the future so future labor and material cost escalations are accounted for in B2H IRP portfolio modeling.

### **Transmission Revenue**

The B2H transmission line project is modeled in AURORA as additional transmission capacity available for Idaho Power energy purchases from the Pacific Northwest. In general, for new supply-side resources modeled in the IRP process, surplus sales of generation are included as a cost offset in the AURORA portfolio modeling. However, historically, additional transmission wheeling revenue has not been quantified for transmission capacity additions. For the 2017 IRP, Idaho Power modeled the additional transmission wheeling revenue for the B2H project. After the B2H line is in-service, the cost of Idaho Power's share of the transmission line will go into Idaho Power's transmission rate base as a transmission asset. Idaho Power's transmission assets are funded by native-load customers, network customers, and transmission wheeling customers based on a ratio of each party's usage of the transmission system. In the IRP modeling, the estimated incremental transmission wheeling revenue from non-native-load customers was modeled as an annual revenue credit for B2H portfolios.

In the B2H analysis, Idaho Power chose to conservatively assume that third-party use (network customers and transmission wheeling customers) across Idaho Power's transmission system would remain static following the construction of B2H. Idaho Power's FERC transmission rate is calculated as follows:

$$\text{Transmission Rate} = \frac{\text{Transmission Costs (\$)}}{\text{Transmission Usage (MW * year)}}$$

Per the formula above, since transmission costs will go up following the installation of B2H, and transmission usage is assumed to remain the same, Idaho Power's transmission rate will increase. Idaho Power's *existing* transmission customers will pay this higher transmission rate, resulting in incremental transmission revenue to Idaho Power.

As a specific example, based on current third-party long-term usage, Idaho Power forecasts 611 MW of third-party long-term transmission wheeling customers. Idaho Power also forecasts 250 average MW of network customers for a combined total of 861 MW usage. For each \$1,000 per MW per year increase to the transmission rate (transmission costs in the equation above), Idaho Power will gain about \$861,000 in transmission revenue. B2H will increase Idaho Power's rate by over \$6,000 per MW per year.

An alternative way to understand the FERC transmission rate, and B2H's impact, is to look at the transmission system from a total load prospective. Native load, network load, and transmission customers must pay their respective share based on their usage of the system. Native load and network load usage is measured in peak MW (averaged by month), and transmission customer usage is measured by reservation amount. The total transmission usage in 2026 is forecast to be approx. 3,900 MW (including Idaho Power's native load usage); therefore, the 861 MW of network load and transmission customer usage results in approximately 22 percent of the total transmission system usage. As such, non-Idaho Power customers are estimated to pay about 22 percent of the costs associated with B2H.

This transmission revenue will offset the cost of B2H for retail customers. In a similar manner, other portfolios include revenues from market sales of newly installed supply resources, which act to offset costs in those portfolios. This section provides a high-level explanation of the workings of Idaho Power's FERC transmission rate. When determining the annual transmission revenue credit for B2H portfolios, Idaho Power ran a full corporate financial model, including rate of return, depreciation expense, operation and maintenance (O&M), etc.

Idaho Power believes short-term usage of the Idaho Power transmission system by third parties could substantially increase because additional capacity is created, further reducing Idaho Power customer rates. However, to be conservative, Idaho Power assumed there would be no increased short-term or long-term third-party transmission usage and only applied the higher transmission rate to the existing usage.

## Potential BPA and Idaho Power Asset Swap

Corresponding with the construction of B2H, Idaho Power and BPA are working to complete an asset swap that would allow Idaho Power to directly access the Mid-C market and avoid a BPA transmission wheeling charge. Such a swap would result in lower purchased-power prices for

Idaho Power’s customers. In return, BPA would be able to directly serve their load in southeastern Idaho and avoid an Idaho Power wheeling charge. As part of the 2017 IRP analysis, Idaho Power conservatively assumed there would be a wheeling charge to access Mid-C resources across B2H. If an asset swap were to take place, the cost of energy in B2H portfolios would be further reduced and make B2H an even more attractive project. Refer to Appendix D-4 for the MOU relating to the potential Idaho Power–BPA asset swap.

## BENEFITS

High-voltage transmission lines, such as B2H, are used to serve customer demand and to move energy between major markets hubs in the Western Interconnection. If the existing western US were to be overlaid with thousands of new miles of high-voltage transmission lines, the entire WECC could be optimized such that all customers would be served with the most economic resources at all times of the year. The long-term need for new supply-side resources would greatly diminish due to the vast diversity of the loads and resources across the Western Interconnection. Such a grid, of course, is economically infeasible, but projects such as B2H are being developed to allow economic resources to be shared between regions. The existing transmission grid is not perfect and many areas of the transmission grid are congested. Transmission congestion causes both economic and reliability issues.

### Capacity

High-voltage transmission lines provide many significant benefits to the Western Interconnection. The most significant benefit of the B2H project is the capacity benefit of the transmission line. Idaho Power is developing the B2H project to create capacity to serve peak customer demand. The capacity benefit is described in more detail in the Resource Need section.

The Pacific Northwest is a winter peaking region. Pacific Northwest utilities continue to install and build generation capacity to meet winter peak regional needs. Idaho Power operates a system with a summer peak demand. Idaho Power’s peak occurs in the late June/early July timeframe, which aligns well with spring hydro runoff conditions when the Pacific Northwest is flush with surplus power capacity. The existing transmission system between the Pacific Northwest and Idaho Power is constrained. Constructing B2H will alleviate this constraint and add 1,050 MW of transfer capability between the Pacific Northwest and Idaho Power. Both the Pacific Northwest and Idaho Power will significantly benefit from the addition of transmission capacity between the regions. The Pacific Northwest has already built the power plants and would benefit from selling energy to Idaho Power. Idaho Power needs resources to serve peak load, and a transmission line to existing, underutilized power plants is much more cost effective than building a new power plant.

## Avoid Constructing New Resources (and Potentially Carbon-Emitting Resources)

In the early days of the electric grid, utilities built individual power plants to serve their local load. Utilities quickly realized that if they interconnected their systems with low-cost transmission, the resulting diversity of load reduced their need to build power plants. Utilities also realized transmission allowed them to build and share larger, more cost-effective and more efficient power plants. The same opportunities exist today. In fact, B2H is being developed to take advantage of existing diversity.

Table 6 illustrates peak-load estimates, by utility and season, for 2026. The shading represents winter-peaking utilities. As seen in the table, there is significant diversity of load between the regions. The Maximum (MW) column illustrates the minimum amount of generating capacity that would be required if each region were to individually plan and construct generation to meet their own peak load need: 69,000 MW. When all regions plan together, the total generating capacity can be reduced to 63,800 MW, a nearly 10 percent reduction. Transmission connections between the regions, such as B2H, are the key to sharing installed generation capacity.

**Table 6. 2026 peak load estimates—illustration of load diversity between western regions**

Region	Summer Peak (MW)	Winter Peak (MW)	Maximum (MW)
Avista	2,200	2,400	2,400
BPA	9,200	11,000	11,000
British Columbia	10,300	13,100	13,100
Chelan	600	800	800
Grant	900	900	900
Idaho Power	3,800	2,800	3,800
Nevada	9,000	6,500	9,000
Northwestern Energy	2,000	1,900	2,000
PacifiCorp—East	9,500	7,900	9,500
PacifiCorp—West	3,600	4,000	4,000
Portland General	4,000	4,100	4,100
Puget Sound	4,000	5,400	5,400
Seattle City	1,500	1,900	1,900
Tacoma	800	1,100	1,100
<b>Total</b>	<b>61,400</b>	<b>63,800</b>	<b>69,000</b>

Note: 2026 regional peak load data extracted from the WECC TEPPC 2026 Common Case.

Load diversity occurs seasonally, as illustrated in Table 6, but it also occurs sub-seasonally and daily. An additional major variable in the Northwest is hydroelectric generation diversity. Over the winter, water accumulates in the mountains through snowpack. As this snow melts, water



flows through the region's hydroelectric dams, and northwest utilities generate a significant amount of power. During the spring runoff, generation capacity available in the Pacific Northwest can be significantly higher than generation capacity available during the winter, or even during late summer. Idaho Power is fortunate to have a peak load that is coincident with the late spring / early summer hydro runoff. Idaho Power's peak load occurs in late June/early July, when hot weather causes major air-conditioning load coincident with agricultural irrigation/pumping load. Idaho Power's time window for a significant peak is quite short, with agricultural irrigation/pumping load starting to ramp down by mid-July.

Utilities have an obligation to serve customer load. This means that utilities are planning to meet peak load needs. As discussed previously, transmission congestion can cause utilities to build additional generation to serve load. Due to transmission congestion, utilities may be unable to leverage their transmission system to access dormant generation already constructed by their neighbors. The B2H project is an alternative to building new supply-side resources. As demonstrated in the 2017 IRP, the portfolios that are the most cost-effective other than B2H are portfolios with natural gas generation. In this case, B2H is an alternative to building a carbon-emitting supply-side resource.

## Improved Economic Efficiency

Transmission congestion causes power prices on opposite sides of the congestion to diverge. Transmission congestion is managed by dispatching less economically efficient resources to ensure the transmission system is operating securely and reliably. Congestion can have a significant cost. During peak summer conditions, the Idaho to Northwest path in the west-to-east direction becomes constrained and power prices in Idaho and to the east will generally be high, while power prices in the Pacific Northwest will be depressed due to a surplus of power availability without adequate transmission capacity to move the power out of the region. The construction of B2H will alleviate much of this constraint and create a win-win scenario where generators in the Pacific Northwest will be able to gain further value from their existing resource, and load-serving entities in the Mountain West region will be able to meet load service needs at a lower cost. The reverse situation could be true as well—the Pacific Northwest could benefit from economical resources from the Mountain West region during certain times of the years.

## Renewable Integration

Transmission capacity is critical to the integration of renewable generation that, at times, is curtailed due to a lack of transmission capacity to move the energy to load. Transmission is a facilitator for future generation development.

## Grid Reliability/Resiliency

Transmission grid disturbances do occur. B2H will increase the robustness and reliability of the regional transmission system by adding additional high-capacity bulk electric facilities designed with the most up-to-date engineering standards. Major 500-kV transmission lines, such as B2H, substantially increase the grid's ability to recover from major unexpected disturbances.

Unexpected disturbances are difficult to predict, but below are a few examples of disturbances whose impacts would be reduced with the addition of B2H:

1. Loss of the Hemingway–Summer Lake 500-kV line with heavy west-to-east power transfer into Idaho. The loss of the Hemingway–Summer Lake 500-kV transmission line, the only 500-kV connection between the Pacific Northwest and Idaho Power, during peak summer load is one of the worst possible contingencies the Idaho Power transmission system can experience. Once Hemingway–Summer Lake 500-kV disconnects, the transfer capability of the Idaho to Northwest path is reduced by over 700 MW in the west-to-east direction. After the addition of B2H, there will be two major 500-kV connections between the Pacific Northwest and Idaho Power. The Hemingway–Summer Lake 500-kV outage would become much less severe to Idaho Power's transmission system.
2. Loss of the Hemingway–Summer Lake 500-kV line with heavy east-to-west power transfer out of Idaho to the Pacific Northwest. In this disturbance, an existing remedial action scheme (power system logic used to protect power system equipment) will disconnect over 1,000 MW of generation at the Jim Bridger Power Plant to reduce path transfers and protect bulk transmission lines and apparatus. Due to the magnitude of the generation loss, recovery from this disturbance can be extremely difficult. After the addition of B2H, this enormous amount of generation shedding will no longer be required. With two 500-kV lines between Idaho and the Pacific Northwest, the loss of one can be absorbed by the other.
3. Loss of a single 230-kV transmission tower in the Hells Canyon area. Idaho Power owns two 230-kV transmission lines, co-located on the same transmission towers, that connect Idaho to the Pacific Northwest. Because these lines are on a common tower, Idaho Power must consider the simultaneous loss of these lines as a realistic planning event. Historically, such an outage did occur on these lines in 2004 during a day with high summer loads. By losing these lines, Idaho Power's import capability was dramatically reduced, and Idaho Power was forced to rotate customer outages for several hours due to a lack of resource availability. After the addition of B2H, the impact of this outage would be substantially reduced.

## Resource Reliability

Transmission unavailability and unexpected forced outages have historically been a fraction of a traditional generation resource. Availability, and contribution to resource adequacy on the power grid, vary significantly by resource type. The North American Electric Reliability Corporation (NERC) has historically tracked transmission availability through a Transmission Availability Data System (TADS) and generation availability through a Generation Availability Data System (GADS) in North America. A telling sign of the reliability of a resource is the equivalent forced outage rate (EFOR). The EFOR is calculated based on the amount of time a transmission line, or generator, is either de-rated, or forced out of service while needed. De-rating a generator would be considered a partial outage, based on the de-rate amount as a percentage of the total capacity.

Table 7 provides the NERC TADS data for different transmission operating voltages. From the NERC TADS data, a 300-mile, 500-kV transmission line (B2H) would be expected to have an outage rate of 0.4 percent. Stated differently, the B2H transmission line is expected to have 99.6 percent availability.

**Table 7. NERC—AC transmission circuit sustained outage metrics**

Voltage Class	Circuit Miles	No. of Circuits	No. of Outages	Total Outage Time (hr)	Frequency (SCOF) (per 100 CM per yr)	Frequency (SOF) (per circuit per yr)	MTTR or Mean Outage Duration (hr)
200–299 kV	103,558	4,477.5	876	14,789.6	0.8459	0.1956	16.9
300–399 kV	56,791	1,623.6	394	19,766.8	0.6938	0.2427	50.2
400–599 kV	32,184	594.7	141	3,957.9	0.4381	0.2371	28.1
600–799 kV	9,451	110.0	28	342.4	0.2963	0.2545	12.2
All Voltages	201,985	6,805.8	1,439	38,856.7	0.7124	0.2114	27.0

By comparison, Table 8, lists the average EFOR for traditional fossil fuel power plants (coal, oil, gas, etc.) and the average EFOR for gas power plants.

**Table 8. NERC forced-outage rate information for a fossil or gas power plant**

Generation Type	Unit Size	EFOR
Fossil (general)	All Sizes	7.96%
Fossil (general)	100–199 MW	7.49%
Fossil (general)	200–299 MW	5.85%
Gas	All Sizes	9.61%
Gas	1–99 MW	9.72%
Gas	100–199 MW	6.85%

A transmission line with an EFOR of less than 1 percent, on the high end, is significantly more reliable than a power plant, which has an EFOR of 7 to 10 percent. A transmission line, of

course, requires a resource to source the line and serve load. However, the resources purchased at the end of the transmission line can be purchased as firm, whereby the seller must be able to supply the generation no-matter what (which may require purchasing someone else's generation if the primary unit experiences an outage). Therefore, if the resource is purchased as firm, the purchased resource would have an EFOR consistent with the transmission line, which is much more reliable than traditional supply-side generation. In the management of cost and risk, B2H will provide Idaho Power's operators additional flexibility when managing the Idaho Power resource portfolio.

## Reduced Electrical Losses

During peak summer conditions, with heavy power transfers on the Pacific Northwest and Idaho Power transmission systems, the addition of the B2H project is expected to reduce electrical losses by more than 100 MW in the Western Interconnection. This is a considerable savings for the region; 100 MW of generation, that customers ultimately pay for, does not need produced to supply losses alone.

Losses on the power system are caused by electrical current flowing through energized conductors, which in turn create heat. Losses are equal to the electrical current squared times the resistance of the transmission line:

$$\text{Electrical Losses} = \text{Current}^2 \times \text{Resistance}$$

From the electrical losses equation above, if the current doubles, the electrical losses will increase by a factor of four. By constructing the B2H line, less efficient (i.e., lower voltage) transmission lines with very large transfers are relieved, reducing the electrical current through these lines and dramatically reducing the losses due to heat.

## Flexibility

Advances in technology are pushing certain existing generation resources toward economic obsolescence. Any supply-side resource alternative could face the same economic obsolescence in the future. B2H is an alternative to constructing a new supply-side resource and therefore, reduces the risk of technological obsolescence. B2H will facilitate the transfer of any generation technology, ensuring Idaho Power customers always have access to the most economic resources, regardless of the resource type.

B2H capacity, when not used by B2H owners, will be available (for purchase) to other parties to make economic interstate west-to-east and east-to-west power transfers for more efficient regional economic dispatch. This provides a regional economic benefit to utilities around Idaho Power that is not factored into the analysis. Specifically, the B2H project will make additional capacity available for Pacific Northwest utilities to sell energy to southern and eastern markets in the West, and for Pacific Northwest utilities to purchase energy from southern and eastern

markets to meet their winter peak load service needs (southern and eastern WECC entities are mostly summer peaking). Idaho Power customers benefit from any third-party transmission purchases as the incremental transmission revenue acts to offset retail customer costs.

The existing electric system is heavily used. Because the system is so heavily used, new transmission line infrastructure, like B2H, creates additional operational flexibility. B2H will increase the ability to take other system elements out of service to conduct maintenance and will provide additional flexibility to move needed resources to load when outages occur on equipment.

## EIM

Idaho Power views the regional high-voltage transmission system as critical to the realization of EIM benefits, and the expansion of this transmission system (i.e., B2H) facilitates the realization of these benefits. As fluctuations in supply and demand occur for EIM participants, the market system will automatically find the best resource(s) from across the large-footprint EIM region to meet immediate power needs. This activity optimizes the interconnected high-voltage system as market systems automatically manage congestion, helping maintain reliability while also supporting the integration of intermittent renewable resources and avoiding curtailing excess supply by sending it to where demand can use it.

Idaho Power notes that EIM participation does not alter its obligations as a balancing authority (BA) required to comply with all regional and national reliability standards. Participation in the western EIM does not change NERC or WECC responsibilities for resource adequacy, reserves, or other BA reliability-based functions for a utility.

## *B2H Complements All Resource Types*

Utility-scale resource installations allow economies of scale to benefit customers in the form of lower cost per watt. For instance, residential rooftop solar is growing in popularity, but the economics of rooftop solar are outweighed by the economics of utility-scale solar installation.<sup>16</sup> Large transmission lines allow the most economical resources to be sited in the most economical locations. As an example, single-axis tracking utility-scale solar in Salem, Oregon, is expected to have a capacity factor of approximately 15 percent (where the capacity factor is the amount of time the system generates over the course of a year). Comparatively, the same single-axis tracking utility-scale solar system in Boise, Idaho, has a capacity factor of approximately 19 percent<sup>17</sup>. If solar system prices are assumed to be equivalent in Salem and Boise, a Boise

---

<sup>16</sup> The National Renewable Energy Laboratory (NREL) estimates the cost of residential rooftop solar (PV) is approximately 2.5 times the cost of utility-scale solar on a \$/Watt basis (NREL, U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017).

<sup>17</sup> NREL, System Advisory Model

installation would generate over 30 percent more energy over the course of the year. Transmission lines provide the ability to move the most economical resources around the region.

Idaho Power views transmission lines like B2H as a complement to any resource type that allows access to the least-cost and most efficient resource, as well as regional diversity, to benefit all customers in the West.

## B2H Benefits to Oregon

### *Economic and Tax Benefits*

The B2H project will result in positive economic impacts for eastern Oregon communities in the form of new jobs, economic support associated with infrastructure development (i.e., lodging and food), and increased annual tax benefits to each county for project-specific property tax dollars. The annual tax benefit for the non-BPA owned portion of the line is shown in Table 9 below. BPA, as a federal entity, does not pay taxes, so BPA's 25 percent project interest is excluded from the estimates. Idaho Power anticipates the project will add about 500 construction jobs, which will provide a temporary increase in spending at local businesses.

**Table 9. Projected annual B2H tax expenditures by county**

Oregon County	Property Tax (excluding BPA's 25% ownership interest)
Morrow	\$270,295
Umatilla	\$569,656
Union	\$629,410
Baker	\$1,778,282
Malheur	\$893,567
<b>Total Oregon Tax Benefit</b>	<b>\$4,141,210</b>

### *Local Area Electrical Benefits*

The B2H project will add 1,050 MW of additional transmission connectivity between the BPA and Idaho Power systems. Currently, the transmission connections between BPA and Idaho Power are fully used for existing customer commitments. Idaho Power currently serves customers in Owyhee County, Idaho, and Malheur County and portions of Baker County in Oregon. PacifiCorp, through Pacific Power, serves portions of Umatilla County. BPA provides transmission service to local cooperatives in the remainder of the project area in Morrow, Umatilla, Union, and Baker counties. Below is a summary of how these areas will benefit directly from B2H.

La Grande and Baker City are served by the Oregon Trails Electric Cooperative (OTEC). Portions of Morrow County and Umatilla County are served by Umatilla Electric Cooperative (UEC) and Columbia Basin Electric Cooperative (CBEC). OTEC, UEC, and CBEC pay BPA's

network transmission rate to receive power and transmission service from the BPA system. If BPA finds less expensive solutions to meet service obligations to customers in southeast Idaho and Wyoming, costs are kept low for other BPA customers, including OTEC, UEC, and CBEC. In other words, BPA customers in Oregon benefit by finding a low-cost solution for customers in Idaho and Wyoming. BPA's financial analysis to date has projected that a share of the B2H project with asset exchange appears the most cost-effective, long-term solution to serve customers in southeast Idaho and eastern Wyoming. Correspondingly, OTEC, UEC, and CBEC customers would also benefit from this cost-effective solution.

The B2H project provides economic development opportunities. The cost of power is a major factor in economic development and, as discussed previously, B2H, as a low-cost resource alternative, will keep power costs low compared to more expensive alternatives.

Capacity must be available on the existing system for additional economic development to take place. In Union and Umatilla counties, BPA's McNary–Roundup–La Grande 230-kV line has limited ability to serve additional demand in the Pendleton and La Grande areas but is currently capable of meeting the 10-year load forecast. The B2H project will increase the transfer capability through eastern Oregon by 1,050 MW. This capacity will provide a significant regional benefit to the entire Northwest and specifically benefit load service to eastern Oregon and southern Idaho. It is possible this added capacity resulting from the B2H project could be used to serve additional demand in Union and Umatilla counties.

Portions of Baker County are served by Idaho Power, from Durkee to the east. BPA currently provides energy to OTEC, which serves Baker City via transmission connections between the Northwest and Idaho Power's transmission system. At this point, the existing transmission connections between the Northwest and Idaho Power are fully used for existing load commitments, with very little ability to meet load growth requirements. The B2H project will increase the transmission connectivity between the Northwest and Idaho Power by 1,050 MW, which will allow BPA to serve additional demand in Baker City.

Finally, additional transmission capacity can create opportunities for new energy resources, which can add to the county tax base and create new jobs.

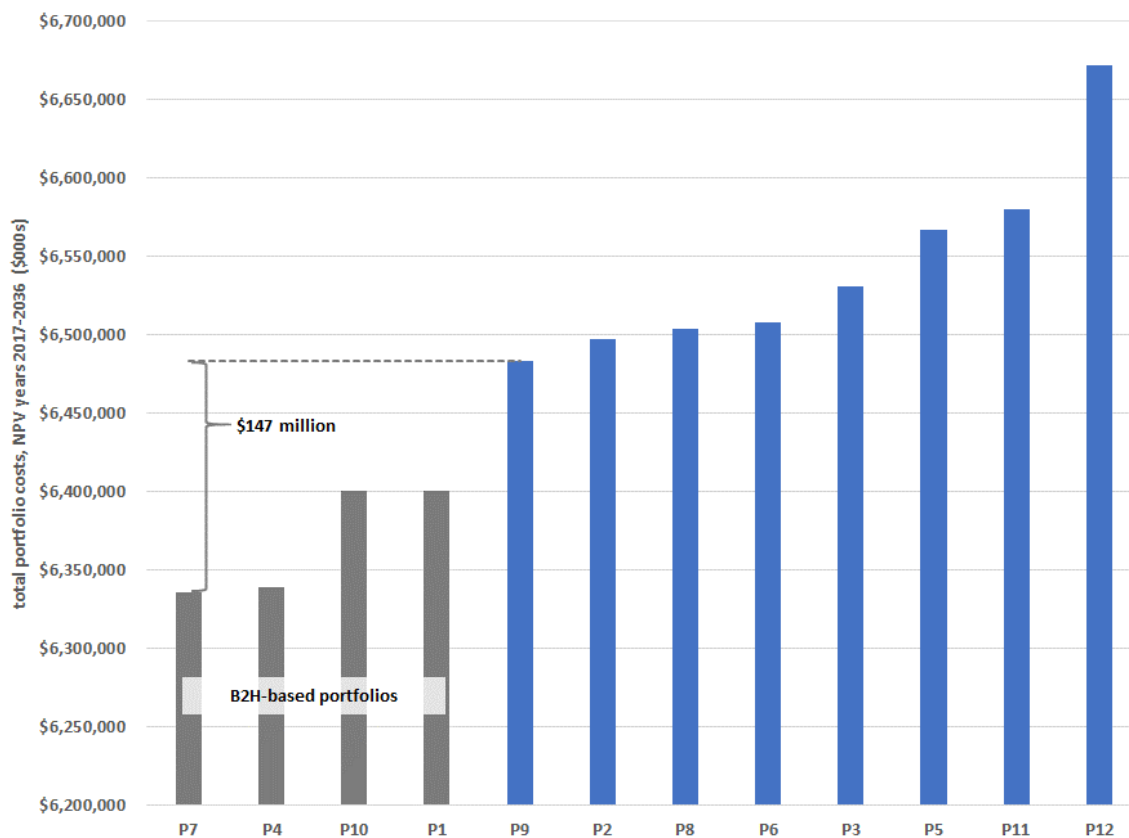
## RISK

Risk is inherent in any infrastructure development project. The sections below address various risks associated with the B2H project. Combining the analysis below with the risk analysis conducted in the 2017 IRP, Idaho Power believes B2H is the lowest-risk resource to meet Idaho Power's resource needs.

## Capital-Cost Risk

The capital-cost estimate for the B2H project has been well vetted. See the Cost section for an explanation of how the B2H project cost estimate was determined. Idaho Power’s share of the B2H project is \$274 million, including Idaho Power’s AFUDC and local interconnection costs. For illustrative purposes, Figure 9 compares total portfolio costs for the 2017 IRP 20-year planning horizon. To determine the fixed costs associated with each portfolio, costs for each resource are levelized over the asset life, and costs beyond 2036 are not included in the analysis. The information from Figure 9 was extracted directly from the IRP Table 9.3.

The B2H project has considerable capital-cost bandwidth. The least-cost B2H portfolio (Portfolio 7) outperforms the least-cost B2H-alternative portfolio (Portfolio 9) by a 2017 net present value (NPV) of \$147 million. Note that the B2H estimate already includes 20-percent capital-cost contingency. No other resources evaluated in IRP portfolios include a contingency. Based on NPV analysis over the 20-year planning horizon, Idaho Power’s cost share of the B2H project could more than double, and the least-cost B2H portfolio would still be more cost-effective than the least-cost B2H-alternative portfolio.

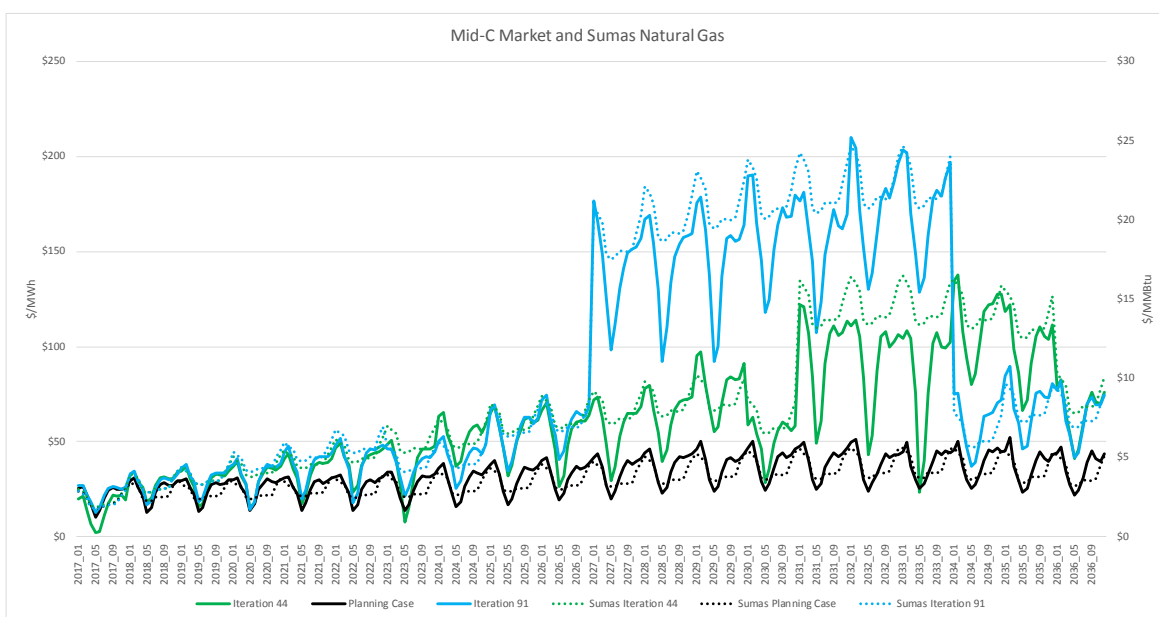


**Figure 9. Comparison of total portfolio costs from 2017 IRP (Table 9.3 in 2017 IRP)**



## Market Price Risk

The cost of dispatching gas-fired generation typically sets the market price of power at Mid-C. A stochastic risk analysis was conducted on all 2017 Idaho Power IRP portfolios, with natural gas prices ranging up to 400 percent of the planning case. Refer to IRP Table 9.4 and Table 9.5 for more information. The natural gas stochastic risk analysis in the 2017 IRP is a market price stochastic analysis because natural gas prices set the energy market prices. Figure 10 below shows three stochastic iterations comparing natural gas prices and Mid-C market prices. The solid lines represent Mid-C energy hub prices, and the dotted lines represent Sumas hub natural gas prices; the natural gas prices and market prices are very closely correlated.



**Figure 10. Correlation between Mid-C market prices and natural gas prices**

Based on the correlation of natural gas prices and market prices, market price risk analysis was considered for the B2H project in Idaho Power’s 2017 IRP. Results of the stochastic analysis show B2H portfolios remain the low-cost portfolios for all natural gas price sensitivities, except a 400 percent price sensitivity. However, Idaho Power believes a 400 percent energy market price increase is unlikely because a 400 percent increase in natural gas prices, along with the associated increase in energy prices, would likely result in the development of alternative resources in place of natural gas (that is, developers of more cost-effective resources would take advantage of financial opportunities if market prices increased 400 percent due to natural gas costs).

## Liquidity and Market Sufficiency Risk

The Pacific Northwest is a winter peaking region. Pacific Northwest utilities continue to install and build generation capacity to meet winter peak regional needs. Idaho Power operates a system

with a summer peak. Idaho Power's peak occurs in the late June/early July timeframe. The Idaho Power summer peak aligns with the Mid-C hydro runoff conditions when the Pacific Northwest is flush with surplus power capacity. The existing transmission system between the Pacific Northwest and Idaho Power is constrained. Constructing B2H will alleviate this constraint and add 1,050 MW of total transfer capability between the Pacific Northwest and the Intermountain West region. The Pacific Northwest and Idaho Power will significantly benefit from the addition of transmission capacity between the regions. The Pacific Northwest has constructed power plants to meet winter needs and would benefit from selling energy to Idaho Power in the summer. Idaho Power needs generation capacity to serve summer peak load, and a transmission line to existing underutilized power plants is much more cost-effective than building a new power plant.

See the Market Overview section of this appendix for more information about the Mid-C market hub liquidity. Based on the risk assessment, Idaho Power believes sufficient market liquidity exists.

The following data points will address the market sufficiency risk.

### ***Data Point 1. Peak Load Analysis from Table 6***

Referencing Table 6 from the Benefits section above, British Columbia and other utilities in the Pacific Northwest have forecast 2026 winter peaks that exceed their forecast 2026 summer peaks by a combined 7,600 MW. Given the difference in seasonal peaks, coupled with Columbia runoff hydro conditions aligning with Idaho Power's summer peak, resource availability in the Pacific Northwest during Idaho Power's summer peak is likely.

### ***Data Point 2. Pacific Northwest Power Supply Adequacy Assessment for 2022—Northwest Power Conservation Council Report***

The Northwest Power and Conservation Council (NWPCC) recently studied the Northwest power system to determine resource adequacy using a five-year forecast. In July 2017, the NWPCC published their 2022 Assessment.<sup>18</sup> The report suggests the Northwest must install 400 MW of new effective capacity by 2021 to meet the NWPCC standard.

The NWPCC, through their analysis, attempted to quantify resource adequacy through a loss-of-load probability (LOLP) analysis. In Figure 11 below, a higher LOLP indicates worse performance (more customer risk), and a lower LOLP indicates better performance. Idaho Power's peak load occurs in a narrow window in the late June/early July timeframe. Figure 11 illustrates the Northwest has a 0 percent LOLP for the June and July months. This indicates that

---

<sup>18</sup> [nwcouncil.org/media/7491213/2017-5.pdf](http://nwcouncil.org/media/7491213/2017-5.pdf)

the Northwest will continue to have sufficient resources available for Idaho Power to purchase and deliver to Idaho Power customers across the B2H line.

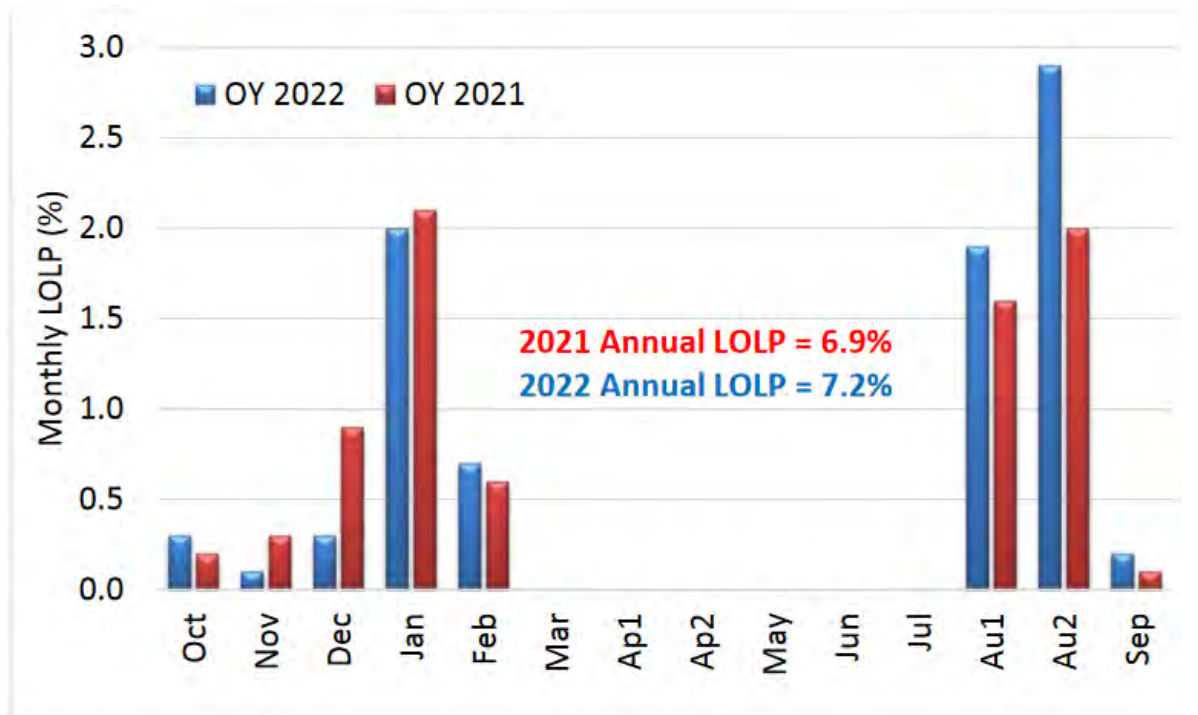


Figure 11. 2021–22 LOLP by month (Source: NWPC north west analysis)

Evaluating Figure 11 further, the NWPC information suggests the Northwest region, as a whole, must add resources to address deficiencies in the winter and late summer. Resource additions to address these needs will further increase resource availability in late June/early July. This argument is further stressed in Data Point 3.

### **Data Point 3: 2016 Pacific Northwest Loads and Resources Study—BPA**

The Pacific Northwest Loads and Resources Study<sup>19</sup>, commonly called “The White Book,” is BPA’s annual publication of the federal system and the Pacific Northwest regions loads and resources for the upcoming 10-year period.

Data detailing whether Pacific Northwest resources will be available to purchase post-2025 can be found in the 2016 Pacific Northwest Loads and Resources Technical Appendix, Volume 2,

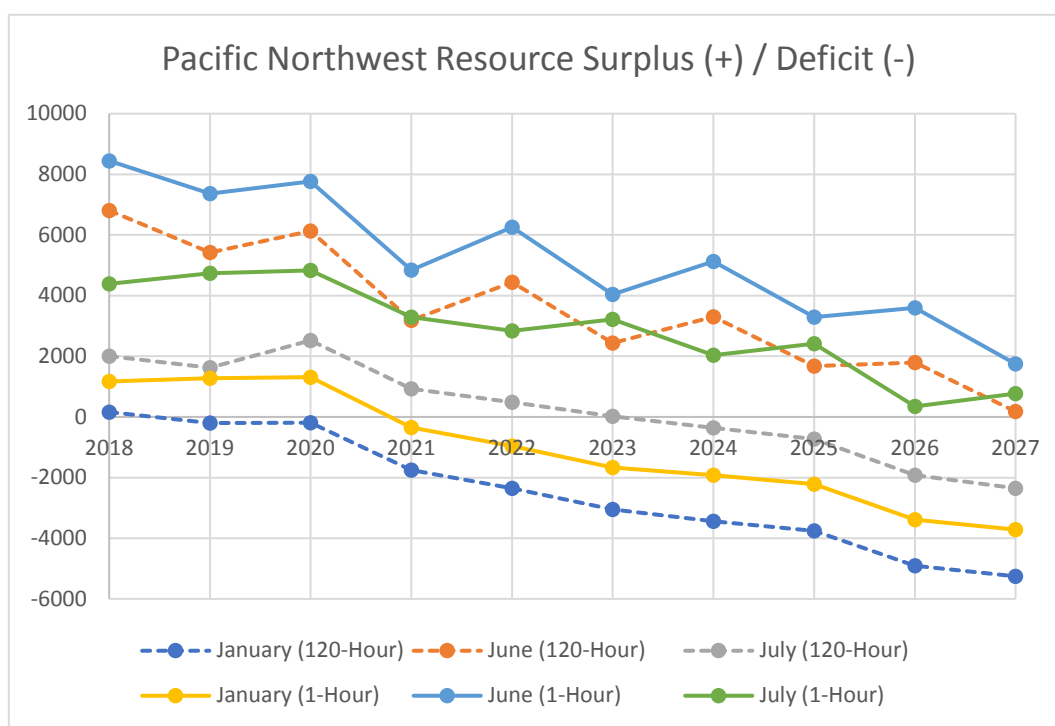
<sup>19</sup> [bpa.gov/power/pgp/whitebook/2016/index.shtml](http://bpa.gov/power/pgp/whitebook/2016/index.shtml)

Footnotes continued on the next page.

Capacity Analysis<sup>20</sup>. This appendix evaluates the Pacific Northwest resource and generation balance to determine a monthly surplus/deficit for the next 10 years. Given the importance of hydro generation in the Pacific Northwest, BPA makes a conservative assumption that there will be a water year equivalent to 1937, one of the worst water years on record.

The BPA capacity metrics are defined as follows:

- **120-Hour Capacity**—Calculated by averaging the generation forecasts from the six highest heavy load hours per day, five days per week, for four weeks per month (6 x 5 x 4 = 120 hours).
- **1-Hour Capacity**—Calculated using the highest single one-hour generation per month.



**Figure 12. January, June, and July forecast Pacific Northwest resource surplus/deficit (Source: 2016 BPA White Book)<sup>21</sup>**

Exploring Figure 12 further, Table 10 below lists the critical 2027 data points.

<sup>20</sup> [bpa.gov/power/pgp/whitebook/2016/2016-WBK-Technical-Appendix-Volume%20-2-Capacity-Analysis-20161222.pdf](https://www.bpa.gov/power/pgp/whitebook/2016/2016-WBK-Technical-Appendix-Volume%20-2-Capacity-Analysis-20161222.pdf)

<sup>21</sup> [bpa.gov/power/pgp/whitebook/2016/2016-WBK-Technical-Appendix-Volume%20-2-Capacity-Analysis-20161222.pdf](https://www.bpa.gov/power/pgp/whitebook/2016/2016-WBK-Technical-Appendix-Volume%20-2-Capacity-Analysis-20161222.pdf)

**Table 10. 2027 data points from Figure 12**

Month	120-Hour Capacity (MW)	1-Hour Capacity (MW)
January	-5,255	-3,716
June	177	1,748
July	-2,349	770

Assuming a critical water year equivalent to 1937, BPA forecasts a 2027 January deficit of 5,255 MW in the 120-hour capacity evaluation and a deficit of 3,716 MW in the one-hour capacity evaluation. July is much better than January; BPA forecasts a 2027 deficit of 2,349 MW in the 120-hour capacity evaluation and a surplus in the 1-hour capacity evaluation. BPA forecasts a surplus for June in both the 120-hour and 1-hour capacity evaluations.

Several BPA considerations are built into the analysis:

- Analysis includes a 1,000+ MW export to Canada (summer and winter). In practice, at peak, Canada is typically exporting to the Northwest.
- Renewables are assumed to have a capacity factor near zero.
- California solar exports to the Pacific Northwest are zero.
- Analysis includes committed generation retirements. There are no assumptions for replacement generation.

Given BPA's analysis, Idaho Power believes there will be sufficient resources in the future based on the following:

- Northwest utilities will need to address their severe January deficit. Adding resources to address this deficit will improve the July deficit. A similar argument was made in Data Point 2.
- Canada generally exports 1,000+ MW over summer peak, rather than importing over 1,000 MW per BPA assumptions in the analysis. This reduces the July deficit to almost zero.
- Solar resources should have a summer capacity factor (should not be zero). Idaho Power assumed a 51-percent summer capacity factor in the 2017 IRP for potential Idaho Power utility-scale solar resources.
- All signs point to California exporting solar output to the Pacific Northwest, especially if renewable portfolio standards (RPS) increase.

The 2016 Pacific Northwest Loads and Resources Study can be found on [BPA's website](#).

### **Data Point 4: Northwest and California Renewable Portfolio Standards**

The adoption of more aggressive RPS goals by states such as Oregon, California, and Washington will drive policy-driven resource additions. The RPS goals will also likely result in the addition of dispatchable flexible ramping resources, such as the recently constructed Port Westward 2 power plant installed by Portland General Electric.

### **Market Sufficiency and Liquidity Conclusions**

Based on the analysis summarized above and in the Markets section of this report, Idaho Power believes there will be sufficient resources in the future to source the B2H transmission line. Also, because the market balances supply and demand based on a market clearing price, liquidity risk can be modeled in economic terms. Should demand be greater than supply at the Mid-C energy hub in the future, market hub prices would reflect the scarcity accordingly (higher prices). As discussed in the Market Price Risk section, a sensitivity analysis conducted in the 2017 IRP indicates B2H remains the low-cost resource portfolio over a wide range of market price sensitivities.

### **Co-Participant Risks**

Idaho Power, BPA, and PacifiCorp, collectively referred to as co-participants or funders, are fully engaged in permitting activities but have not yet entered into construction and operating agreements. Per the 2012 Joint Funding Agreement, Idaho Power has 60 days following the publication of the BLM ROD to issue a Notice of Completion (Notice), which triggers the commencement of construction negotiations. The funders are allotted two 180-day periods (360 days total), following receipt of the Notice, to negotiate one or more definitive development and construction agreements. The BLM ROD was published on November 17, 2017. Idaho Power, PacifiCorp, and BPA have been in negotiations regarding a possible amendment to the Joint Funding Agreement that would clarify ongoing payment terms, update the milestone schedule, and modify construction agreement triggers and negotiation durations.

The funders may withdraw from the Joint Permitting Agreement at any time and for no reason, and the withdrawing funder(s) shall pay all costs up to the last day of the month of withdrawal. If one or more of these funders does not move forward with construction, withdrawals from the project, all rights, title, and interest will be transferred to the remaining funder(s) such that the remaining funder(s) shall have 100 percent of the permitting interest in the permitting project. The remaining funders may then seek other funder(s) and/or proceed with construction.

Although funder commitments are not a guarantee at this point, Idaho Power believes other parties may have interest in potential ownership in the project should one or more of the funders decide not to move forward with construction. At least one additional party was involved in the

original negotiations that ultimately lead to the current three-party 2012 Joint Funding Agreement. Additionally, Idaho Power has been approached by at least one entity that may have interest in the B2H project. Any consideration of additional project co-participants would be discussed and agreed on by current funders.

Changes in ownership structure could change cost allocation percentages. Refer to the Capital-Cost Risk section of this appendix for more information about capital-cost risk. For any potential changes in ownership structure, Idaho Power will evaluate the potential ownership cost and capacity allocation, and assuming cost-effective for Idaho Power customers, would request approval from the Oregon and Idaho public utility commissions for any modification in ownership.

## Siting Risk

Siting any new infrastructure projects comes with siting risk. The BLM ROD, which was released on November 17, 2017, was a significant milestone in the B2H project development and greatly minimized siting risk. It provided the project authorization to cross BLM land and provided the BLM Agency Preferred alternative for the remainder of the route. The USFS and Navy will tier off of the BLM's analysis to conclude their NEPA processes. The State of Oregon EFSC process is the next major step to ensure siting risk is minimized for privately owned land in Oregon.

## Schedule Risk

As of the date of this appendix, Idaho Power has schedule scenarios for B2H in-service dates in 2024 or later. At a high level, activities prior to energization are permitting, co-participant agreements, preliminary construction, and material procurement and construction.

The B2H project is currently in the permitting phase of the project. For federal permitting, the B2H project recently achieved the biggest schedule milestone to date with the release of BLM's ROD on November 17, 2017. The ROD formalized the BLM-led NEPA process and established a BLM Agency Preferred route on public and private property. The USFS ROD and a Navy ROD and easement are the next major federal permitting milestones. At this point, neither the USFS ROD nor Navy ROD are expected to be critical path schedule activities.

For the State of Oregon permitting process, the B2H project also achieved a considerable milestone in summer 2017 with the submittal of the amended Application for Site Certificate to the ODOE. The ODOE is expected to issue a Draft Proposed Order in 2018 and a Final Order and Site Certificate in 2020. The EFSC permitting process is a critical path schedule activity. Schedule risk exists for the EFSC permitting process if the ODOE does not issue a Site Certificate by late 2020.

With the receipt of the BLM ROD and submittal of the amended Application for Site Certificate, which is expected to be deemed complete in the near future, sufficient route certainty exists to begin preliminary construction activities. Assuming co-participant agreements are in place, the current B2H schedule plans to commence preliminary construction activities prior to the receipt of a Site Certificate to achieve an in-service date in the mid-2020s. The B2H co-participants have not formally decided on the contracting method for the project, so the preliminary construction and construction schedule activities remain preliminary until contracts are in place.

Idaho Power believes schedule flexibility exists if the EFSC process is delayed. For instance, certain schedule activities could be condensed by employing more resources or certain activities. Additionally, certain schedule activities could overlap if planned appropriately, such as ROW acquisition and construction.

Currently, Idaho Power believes there is sufficient schedule flexibility to achieve a 2026 in-service date. Idaho Power, BPA, and PacifiCorp plan to negotiate construction agreements in 2018, which should provide additional clarity to the schedule.

## Catastrophic Event Risk

As detailed in B2H Design section, the B2H transmission line is designed to withstand a variety of extreme weather conditions and catastrophic events. Like most infrastructure, the B2H project is susceptible to direct physical attack. However, unlike some other supply-side resources, B2H adds to the resiliency of the electrical grid by providing additional capacity to transfer energy throughout the region should a physical attack or other catastrophic event occur elsewhere on the system. Additionally, Idaho Power also keeps a supply of emergency transmission towers that can be quickly deployed to replace a damaged tower, allowing the transmission line to be quickly returned to service.

## PROJECT ACTIVITIES

### Schedule Update

#### *Permitting*

The B2H project achieved a major milestone with the release of the BLM ROD on November 17, 2017. The BLM ROD formalized the conclusion of the siting process and federally required NEPA. The BLM ROD provides the B2H project the ability to site the project on BLM-administered land. The BLM-led NEPA process took nearly 10 years to complete and involved extensive stakeholder input. Refer to the Project History and Route History sections of this report for more information on project history and public involvement. The next steps in the federal permitting process include a USFS ROD and Navy ROD; both are expected in 2018. Both the USFS and Navy will use the BLM's environmental analysis.



For the State of Oregon permitting process, Idaho Power submitted the amended application for Site Certificate to the ODOE in summer 2017. As of the date of this report, Idaho Power expects the ODOE to issue a Draft Proposed Order in 2018 and a Final Order and Site Certificate in 2020.

The NEPA and EFSC processes are very distinct permitting processes and not necessarily designed to work simultaneously. At a high level, the NEPA EIS process evaluates reasonable alternatives to determine the best alternative (the Agency Preferred Alternative) at the end of the process. Comparative analysis is conducted at a “desktop” level. Information is brought into the process on a phased-approach. Detailed analysis must be conducted on the final route prior to construction, generally once final design is complete.

The Oregon EFSC process is a standards-based process based on a fixed site boundary. For a linear facility, like a transmission line, the process requires the transmission line boundary to be established (a route selected) and fully evaluated to determine if the project meets established standards. The practical effect of the EFSC standards-based process required the NEPA process be far enough along to conduct field studies and other technical analysis to comply with standards. Idaho Power conducted field surveys and prepared the EFSC application in parallel with the NEPA process. The EFSC application is lengthy. Idaho Power estimates the application submitted in 2017 was roughly 17,000 pages long.

### ***Post-Permitting***

To achieve an in-service date in the mid-2020s, preliminary construction activities must commence parallel to EFSC permitting activities. Preliminary construction activities include, but are not limited to, the following:

- Geotechnical explorations
- Detailed ground surveys
- Sectional surveys
- ROW acquisition activities
- Detailed design
- Construction bid package development and construction contractor selection

After the Oregon permitting process and preliminary construction activities conclude, construction activities can commence. Construction activities include, but are not limited to, long-lead material acquisition, transmission line construction, and substation construction. The preliminary construction activities must commence several years prior to construction.

The material acquisition and construction activities are expected to take 3 to 4 years. The specific timing of each of the preliminary construction and construction activities will be coordinated with the project co-participants.

## CONCLUSIONS

This B2H 2017 IRP appendix provides context and details that support evaluating the B2H transmission line project as a supply-side resource, explores (qualitatively and quantitatively) many of the ancillary benefits offered by the transmission line, and considers the risks and benefits of owning a transmission line connected to a market hub in contrast to direct ownership of a traditional generation resource.

As discussed in this report, once operational, B2H will provide Idaho Power increased access to reliable, low-cost market energy purchases from the Pacific Northwest. B2H (including early versions of the project) has been a cost-effective resource identified in each of Idaho Power's Integrated Resource Plans (IRP) since 2006 and continues to be a cornerstone of Idaho Power's 2017 IRP preferred resource portfolio. In the 2017 IRP, B2H was identified as the least-cost and least-risk resource to serve peak-hour load to resource deficits that are forecast to occur beginning in 2026. When compared to other individual resource options, B2H is also the least-cost option in terms of both capacity cost and energy cost. B2H is expected to have a capacity cost that is 71 percent lower than either a combined-cycle gas plant or utility-scale solar alternatives.<sup>22</sup> B2H is also expected to have a levelized cost of energy that is 22 percent lower than a combined-cycle gas plant and 38 percent lower than utility-scale solar.<sup>23</sup>

B2H project brings additional benefits beyond cost-effectiveness. The B2H project will increase the efficiency, reliability, and resiliency of the electric system by creating an additional pathway for energy to move between major load centers in the West. The B2H project also provides the flexibility to integrate any resource type and move existing resources during times of congestion, benefiting customers throughout the region. Idaho Power believes B2H provides value to the system beyond any individual resource because it enhances the flexibility of the existing system and facilitates the delivery of cost-effective resources not only to Idaho Power customers, but also to customers throughout the Pacific Northwest and Mountain West regions.

The company must demonstrate a need for the project before EFSC will issue a Site Certificate authorizing the construction of a transmission line. The need demonstration can be met through a commission acknowledgement of the resource in the company's IRP.<sup>24</sup> In this case, Idaho Power

---

<sup>22</sup> 2017 IRP, Page 87, Figure 7.5.

<sup>23</sup> 2017 IRP, Page 89, Figure 7.6.

<sup>24</sup> OAR 345-023-0020(2).

seeks to satisfy EFSC's least-cost plan rule's requirement through an acknowledgement of its 2017 IRP.

**Appendix D-1. Transmission line alternatives to the proposed B2H 500-kV transmission line****Table D-1**

Comparison of Transmission Line Capacity Scenarios—New Lines from Longhorn to Hemingway

Scenario	Line Capacity <sup>1</sup>	Potential Path 14 West-East Increase <sup>2</sup>	Losses on New Circuit(s) <sup>3</sup>
a. Longhorn to Hemingway 230 kV single circuit	956 MW	525 MW	10.8%
b. Longhorn to Hemingway 230 kV double circuit	1,912 MW	915 MW	9.5%
c. Longhorn to Hemingway 345 kV single circuit	1,434 MW	730 MW	6.6%
d. Longhorn to Hemingway 500 kV single circuit	3,214 MW	1,050 MW	4.2%
e. Longhorn to Hemingway 500 kV—two separate lines	6,428 MW	2,215 MW	3.7%
f. Longhorn to Hemingway 500 kV double circuit	6,428 MW	1,235 MW	2.9%
g. Longhorn to Hemingway 765 kV single circuit	4,770 MW	1,200 MW	2.4%

<sup>1</sup> Line Capacity is the thermal rating of the assumed conductors and does not account for system limitations of voltage, stability, or reliability requirements.

<sup>2</sup> Potential Rating is based upon study results to date to meet reliability design requirements for the WECC ratings processes, not including simultaneous interaction studies.

<sup>3</sup> Estimated Losses are percent losses for the new line at the Potential Rating loading level. Annual energy losses are dependent on total system loss reductions. All of the scenarios would likely yield a total system loss reduction for the flow levels above.

**Table D-2**

Comparison of Transmission Line Capacity Scenarios – Rebuild Existing Lines to the Northwest

Scenario	Line Capacity <sup>1</sup>	Potential Path 14 Increase <sup>2</sup>	Losses on New Circuit(s) <sup>3</sup>	Length of Line/ New ROW <sup>4</sup>
h. Replace Oxbow-Lolo 230 kV with Hatwai - Hemingway 500 kV	3,214 MW	430 MW W-E 675 MW E-W	3.8%	255 Miles/136 Miles
i. Replace Oxbow-Lolo 230 kV with Hatwai - Hemingway 500 kV - No double circuiting with existing lines	3,214 MW	710 MW W-E 745 MW E-W	4.1%	255 Miles/167 Miles
j. Replace Walla Walla to Brownlee 230 kV with Sacajawea Tap-Hemingway 500 kV	3,214 MW	400 MW W-E 675 MW E-W	3.5%	288 Miles/150 Miles
k. Replace Walla Walla to Palette 230 kV with Sacajawea Tap-Hemingway 500 kV - No double circuiting with existing lines	3,214 MW	720 MW W-E 730 MW E-W	3.8%	288 Miles/181 Miles
l. Build double circuit 500 kV/230 kV line from McNary to Quartz. Build 500kV from Quartz to Hemingway.	3,214 MW	765 MW W-E 870 MW E-W	3.9%	298 Miles/168 Miles

<sup>1</sup> Line Capacity is the thermal rating of the assumed conductors and does not account for system limitations of voltage, stability, or reliability requirements.

<sup>2</sup> Potential Rating is based upon study results to date to meet reliability design requirements for the WECC ratings processes, not including simultaneous interaction studies.

<sup>3</sup> Estimated Losses are percent losses for the new line at the Potential Rating west-east loading level. Annual energy losses are dependent on total system loss reductions. All of the scenarios would likely yield a total system loss reduction for the flow levels above.

<sup>4</sup> In addition to utilizing existing 230 kV right-of-way (“ROW”), each of the scenarios above will require new ROW to be obtained.

This page left blank intentionally.

**Appendix D-2. Detailed list of notable project milestones**

- June, 2006 – Idaho Power files the 2006 IRP – Transmission line between Boise and Pacific Northwest identified in preferred resource portfolio (this transmission line eventually became the Boardman to Hemingway project)
- December 19, 2007 – Idaho Power Completes the B2H Preliminary Plan of Development
- 2008 – Idaho Power files the 2008 IRP Update
- August 28, 2008 – Idaho Power submits Notice of Intent to EFSC to submit an Application for Site Certificate.
- September 12, 2008 – Notice of Intent published in the Federal Register for BLM to prepare an Environmental Impact Statement for B2H
- April 10, 2009 – Public Scoping Report for B2H EIS completed by Tetra Tech
- December 30, 2009 – Idaho Power files the 2009 IRP – B2H Project identified in preferred resource portfolio
- June 2010 – Idaho Power completes the B2H Preliminary Plan of Development
- July 2010 – Idaho Power submits a NOI to apply for a Site Certificate for B2H to ODOE
- August 2010 – Idaho Power completes the B2H Siting Study
- August 2010- February 2011 – Idaho Power completes the Community Advisory Process
- February 2011 – Idaho Power completes a Revised Plan of Development for B2H
- June 30, 2011 – Idaho Power files the 2011 IRP – B2H Project identified in preferred resource portfolio
- October 5, 2011 – Obama administration recognizes B2H as one of seven national priority projects that when built, will help increase electric reliability, integrate new renewable energy into the grid, create jobs and save consumers money. See news release.
- November 2011 – Idaho Power completes a Revised Plan of Development for B2H
- January 12, 2012 – Idaho Power, BPA and PacifiCorp enter into Joint Permit Funding Agreement
- March 2, 2012 – ODOE issues a Project Order for B2H

- June 2012 – Idaho Power completes a Supplemental Siting Study for B2H
- October 2, 2012 – BPA identifies B2H as the best option for meeting load growth in southeastern Idaho
- November 27, 2012 – Idaho Power receives formal capacity rating from Western Electricity Coordinating Council (WECC)
- February 28, 2013 – Idaho Power submits Preliminary Application for Site Certificate to Oregon Department of Energy
- June 28, 2013 – Idaho Power files the 2013 IRP
- December 19, 2014 – Draft EIS and Land-use Plan Amendments Published in Federal Register
- December 22, 2014 – ODOE issues amended Project Order for B2H
- June 22, 2015 – Idaho Power submits easement application to Navy to site on Naval Weapons System Training Facility Boardman (aka “Bombing Range”)
- June 30, 2015 – Idaho Power files the 2015 IRP – B2H Project identified in the preferred resource portfolio
- November 25, 2016 – BLM issues the Final EIS for B2H
- November 18, 2016 – Idaho Power submits revised application to Navy, updating the route on Navy property based on collaborative routing solution
- January 20, 2017 – Donald Trump inaugurated as 45th President of the United State
- June 29, 2017 – Idaho Power submits electronic version of Amended Preliminary Application for Site Certification to ODOE
- June 30, 2017 – Idaho Power files the 2017 Integrated Resource Plan (IRP) – B2H Project identified in the preferred resource portfolio
- July 19, 2017 – Idaho Power submits hard copies of Amended Preliminary Application for Site Certification to ODOE.
- November 17, 2017 – BLM issues a Record of Decision (ROD) for the B2H. The Record of Decision was signed by the Assistant Secretary of Lands and Minerals, U.S. Department of Interior.

**Appendix D-3. B2H funding agreement**

See the attached document.



This page left blank intentionally.

**BOARDMAN TO HEMINGWAY TRANSMISSION PROJECT JOINT PERMIT  
FUNDING AGREEMENT**

This Boardman to Hemingway Transmission Project Joint Permit Funding Agreement (the “Agreement”) is entered into this 12th day of January, 2012 (the “Effective Date”), by and between Idaho Power Company, an Idaho corporation (“Idaho Power”), PacifiCorp, an Oregon corporation (“PAC”), and the Bonneville Power Administration (“BPA”), a United States government power marketing administration. Idaho Power, PAC, and BPA are hereinafter sometimes individually referred to as a “Funder” and collectively as the “Funders.”

**RECITALS**

WHEREAS, Idaho Power, PAC, and BPA have independent obligations to plan for and expand their respective transmission systems to provide safe, reliable and cost-effective service to their native load customers, network customers, and/or eligible customers;

WHEREAS, Idaho Power, PAC and BPA recognize the potential to fulfill their respective service obligations through the development of certain new transmission facilities;

WHEREAS, the proposed Boardman to Hemingway Transmission Project is a 500 kV single circuit transmission line located from the vicinity of Boardman, Oregon to the existing Hemingway substation near Melba, Idaho (as further described in Exhibit A, the “Boardman to Hemingway Transmission Project”), that if constructed could assist Idaho Power, PAC, and BPA in fulfilling their respective service obligations;

WHEREAS, Idaho Power, PAC, and BPA recognize that obtaining appropriate and necessary Governmental Authorizations and completing other necessary work is an essential component to developing the Boardman to Hemingway Transmission Project;

WHEREAS, Idaho Power, PAC, and BPA desire to support and contribute funds, with the intent to be joint owners subject to the terms of this Agreement, to the processes associated with obtaining the necessary Governmental Authorizations and completing other necessary work to develop, permit, site, and acquire Rights-of-Way over public lands for the Boardman to Hemingway Transmission Project;

WHEREAS, Idaho Power, PAC, and BPA are entering into this Agreement for the purposes of providing the definitive terms and conditions by which Idaho Power, PAC, and BPA will jointly support and contribute funds, with the intent to be joint owners subject to the terms of this Agreement, to permit, site and acquire Rights of Way over public lands for the development of Boardman to Hemingway Transmission Project;

WHEREAS, Idaho Power has submitted applications to the United States Department of Interior, Bureau of Land Management (“BLM”), serving as the lead permitting agency under the

National Environmental Policy Act (“NEPA”), to obtain authorizations for the Boardman to Hemingway Transmission Project to cross federal lands. The United States Forest Service, United States Department of the Navy and the United States Bureau of Reclamation are cooperating agencies with the BLM in preparing an Environmental Impact Statement (“EIS”) for the Boardman to Hemingway Transmission Project;

WHEREAS, Idaho Power has submitted its notice of intent to apply for an energy facility site certificate with the Oregon Department of Energy, Energy Facility Siting Council, to construct the portions of the Boardman to Hemingway Transmission Project located in the State of Oregon;

WHEREAS, Idaho Power, PAC, and BPA intend for the express purpose of this Agreement to facilitate the successful completion of the Project Permitting Objectives (as further defined herein);

WHEREAS, Idaho Power and PAC recognize that, although BPA is entering into this Agreement, BPA has certain obligations and responsibilities under NEPA and other federal laws that it must fulfill before it can make a decision concerning whether to participate in the development and construction of the Boardman to Hemingway Transmission Project, and BPA intends to be a cooperating agency under NEPA on the Environmental Impact Statement being prepared by the BLM and other federal agencies to facilitate completion of BPA’s obligations and responsibilities under NEPA;

WHEREAS, Idaho Power and PAC acknowledge that BPA is considering various transmission and other alternatives to meet its service obligations in eastern Idaho and that BPA’s decision whether to participate in the development and construction of the Boardman to Hemingway Transmission Project may be based on BPA’s evaluation of such alternatives;

WHEREAS, upon the completion of the Project Permitting Objectives, any of the Funders that decide to proceed with the development and construction of the Boardman to Hemingway Transmission Project intend to negotiate in good faith further agreement(s) for the purposes of providing the definitive terms and conditions by which such Funders may jointly design, engineer, procure, construct, commission, own and operate the Boardman to Hemingway Transmission Project (the “Definitive Development and Construction Agreements”); and

WHEREAS, nothing in this Agreement shall affect any other existing or proposed projects, expansions, or developments that are not a part of this Agreement.

NOW, THEREFORE, in consideration of the promises and the mutual covenants and agreements herein contained, the adequacy of which is hereby acknowledged, Idaho Power, PAC, and BPA agree as follows:

**ARTICLE I**  
**DEFINITIONS; RULES OF INTERPRETATION**

1.1 Definitions. As used in this Agreement, the following capitalized terms have the meanings specified in this Section 1.1:

“Advance Contribution” has the meaning set for in Section 4.2(a).

“Affected Party” has the meaning set forth in Section 9.1.

“Affiliate” means, with respect to a Person, each other Person that, directly or indirectly, controls, is controlled by or is under common control with, such designated Person; provided, however, that in the case of PAC “Affiliate” includes MidAmerican Energy Holdings Company and its direct and indirect subsidiaries. For the purposes of this definition, “control” (including with correlative meanings, the terms “controlled by” and “under common control with”), as used with respect to any Person, shall mean (a) the direct or indirect right to cast at least fifty percent (50%) of the votes exercisable at an annual general meeting (or its equivalent) of such Person or, if there are no such rights, ownership of at least fifty percent (50%) of the equity or other ownership interest in such Person, or (b) the right to direct the policies or operations of such Person.

“Agreement” has the meaning set forth in the Preamble.

“Bankrupt” means, with respect to any Person, that such Person: (a) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it, (b) makes an assignment or any general arrangement for the benefit of creditors, (c) otherwise becomes insolvent (however evidenced), (d) has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets, or (e) is generally unable to pay its debts as they fall due.

“BLM” has the meaning set forth in the Recitals.

“Boardman to Hemingway Transmission Project” has the meaning set forth in the Recitals.

“BPA” has the meaning set forth in the Preamble.

“Business Day” means any day other than Saturday, Sunday and any day which is not a federal holiday or a day on which banking institutions in New York, New York are authorized or obligated by Governmental Requirements to close.

“Claims” has the meaning set forth in Section 11.1.

“Commercially Reasonable Efforts” means the level of effort that a reasonable electric utility would take in light of the then known facts and circumstances to accomplish the required action at a then commercially reasonable cost (taking into account the benefits to be gained thereby).

“Completion Funding Payment” has the meaning set forth in Section 3.1(a)(ii) and Exhibit B.

“Completion Notice” has the meaning set forth Section 3.3(a).

“Defaulting Funder” has the meaning set forth in Section 8.1.

“Dispute” has the meaning set forth in Section 13.1.

“Dispute Notice” has the meaning set forth in Section 13.2.

“Disputing Party” has the meaning set forth in Section 13.2.

“Definitive Development and Construction Agreements” has the meaning set forth in the Recitals.

“Effective Date” has the meaning set forth in the Preamble.

“Environmental Impact Statement” has the meaning set forth in the Recitals.

“Event of Default” has the meaning set forth in Section 8.1.

“Executives” has the meaning set forth in Section 13.3(a).

“FERC” means the Federal Energy Regulatory Commission.

“Final Environmental Impact Statement” means the Final Environmental Impact Statement for the Boardman to Hemingway Transmission Project.

“Force Majeure” has the meaning set forth in Section 9.1.

“Funders” has the meaning set forth in the Preamble.

“Funding Committee Representative” has the meaning set forth in Section 3.2(b).

“Funding Invoice” has the meaning set forth in Section 3.1(b)(i).

“Final Expense True-Up” has the meaning set forth in Section 3.1(b)(iii) and Exhibit B.

“Good Utility Practice” means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, would have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act section 215(d).

“Governmental Authority” means any federal, state, local or municipal governmental body; any governmental, quasi-governmental, regulatory or administrative agency, commission, body or other authority exercising or entitled to exercise any administrative, executive, judicial, legislative, policy, regulatory or taxing authority or power, including FERC, NERC or any regional reliability council; or any court or governmental tribunal, in each case, having jurisdiction over any Funder (whether as Funder or as Permitting Project Manager) or any of its Affiliates or the development, permitting, siting, acquisition of Rights-of Way, or preliminary design of the Boardman to Hemingway Transmission Project.

“Governmental Authorizations” means any license, permit, order, approval, filing, waiver, exemption, variance, clearance, entitlement, allowance, franchise, or other authorization from or by a Governmental Authority.

“Governmental Requirements” means all laws, statutes, ordinances, rules, regulations, codes, and similar acts or promulgations or other legally enforceable requirements of any Governmental Authority.

“Idaho Power” has the meaning set forth in the Preamble.

“Joint Defense Agreement” has the meaning set forth in Section 11.1.

“Joint Defense Agreement Notice” has the meaning set forth in Section 11.2.

“Manager” has the meaning set forth in Section 13.3(a).

“Mandatory Payments” has the meaning set forth in Section 3.1(a) and Exhibit B.

“Negotiations End Date” has the meaning set forth in Section 3.3(b).

“NEPA” means the National Environmental Policy Act, as the same may be amended from time to time.

“NERC” means the North American Electric Reliability Corporation.

“Non-Defaulting Funders” means a Funder(s) that is not a Defaulting Funder(s).

“Non-Permitting Project Manager Funders” means PAC and BPA.

“Notice of Payment” has the meaning set forth in Section 3.1(b)(ii).

“PAC” has the meaning set forth in the Preamble.

“Person” means an individual, partnership, corporation, limited liability company, joint venture, association, trust, unincorporated organization, Governmental Authority, or other form of entity

“Permit Funding Committee” has the meaning set forth in Section 3.2.

“Permit Funding Payment Schedule” has the meaning set forth in Section 3.1(a)(iii) and Exhibit B.

“Permitting Interest” means, with respect to each of the Funders, their Permitting Interest as set forth in Exhibit D.

“Permitting Project” has the meaning set forth in Section 2.1.

“Permitting Project Manager” means Idaho Power.

“Private Property Interest” has the meaning set forth in Section 2.1.

“Project Costs” has the meaning set forth in Section 3.1(d)

“Project Cost Records” has the meaning set forth in Section 3.1(d).

“Project Permitting Objectives” has the meaning set forth in Section 2.2.

“Project Permitting Timetable” has the meaning set forth in Section 2.2.

“Purchase and Sale Date” has the meaning set forth in Section 3.3(c).

“Purchase and Sale End Date” has the meaning set forth in Section 3.3(c).

“Purchasing Funder” has the meaning set forth in Section 3.3(c).

“Representatives” means, in respect of a Funder or Permitting Project Manager, the directors, officers, shareholders, partners, members, employees, agents, consultants, contractors or other representatives of such Funder or Permitting Project Manager.

“Response Notice” has the meaning set forth in Section 3.3(c).

“Rights-of-Way” means all rights-of-way, easements, grants and other interests on which the Boardman to Hemingway Transmission Project is or will be constructed that are owned or to be owned by Funders or their Affiliates. Private Property Interests are expressly excluded from this Agreement.

“Selling Funder” has the meaning set forth in Section 3.3(c).

“Subchapter K” has the meaning set forth in Section 14.4(b).

“Term” has the meaning set forth in Section 6.1.

“WECC Rating Process” has the meaning set forth in Section 3.3(a)(iii)(A).

“Withdrawal Date” has the meaning set forth in Section 7.2(a).

“Withdrawal Payment” has the meaning set forth in Section 7.2(a).

“Withdrawing Funder” has the meaning set forth in Section 7.1.

1.2 Interpretation. The following rules of interpretation and construction shall apply in this Agreement:

- (a) The masculine shall include the feminine and neuter.
- (b) References to “Articles,” “Sections” and “Exhibits” shall be to articles and sections of and exhibits to this Agreement.
- (c) The Exhibits and Schedule 2.2 attached hereto are incorporated in and are intended to be a part of this Agreement.
- (d) This Agreement was negotiated and prepared by Idaho Power, PAC, and BPA with the advice and participation of counsel. Idaho Power, PAC, and BPA have agreed to the wording of this Agreement and none of the provisions hereof shall be construed against one Funder on the ground that such Funder is the author of this Agreement or any part hereof.
- (e) Each reference in this Agreement to any agreement or document or a portion or provision thereof shall be construed as a reference to the relevant agreement or document as amended, supplemented or otherwise modified from time to time with the written approval of Idaho Power, PAC, and BPA.



- (f) Each reference in this Agreement to Governmental Requirements and to terms defined in, and other provisions of, Governmental Requirements shall be references to the same (or a successor to the same) as amended, supplemented or otherwise modified from time to time.
- (g) The term “day” shall mean a calendar day, the term “month” shall mean a calendar month, and the term “year” shall mean a calendar year. Whenever an event is to be performed, a period commences or ends, or a payment is to be made on or by a particular date and the date in question falls on a day which is not a Business Day, the event shall be performed, or the payment shall be made, on the next succeeding Business Day; provided, however, that all calculations shall be made regardless of whether any given day is a Business Day and whether any given period ends on a Business Day.
- (h) Each reference in this Agreement to a Person includes its successors and permitted assigns; and each reference to a Governmental Authority includes any Governmental Authority succeeding to its functions and capacities.
- (i) In this Agreement, the words “include,” “includes” and “including” are to be construed as being at all times followed by the words “without limitation.” References to “or” shall be deemed to be disjunctive but not necessarily exclusive.
- (j) The words “hereof,” “herein” and “hereunder” and words of similar import when used in this Agreement shall, unless otherwise specified, refer to this Agreement as a whole and not to any particular provision of this Agreement.

## ARTICLE II THE PERMITTING PROJECT

2.1 Joint Permitting. The Funders desire to jointly fund and support, with the intent to be joint owners pursuant to this Agreement, the process of obtaining Governmental Authorizations and completing other necessary work directly related to the siting, permitting, preliminary designing and acquiring Rights-of-Way for the Boardman to Hemingway Transmission Project (collectively, the “Permitting Project”), in accordance with the terms of this Agreement. The planning, design, procurement, and acquisition of private rights of way, private easements, private licenses, and similar private property interests are expressly excluded from this Agreement (“Private Property Interests”). Neither the Funders nor the Permitting Project Manager shall acquire Private Property Interests for the Boardman to Hemingway Transmission Project without the written agreement, not to be unreasonably withheld, of the then current Funders. Idaho Power, BPA, and PAC will define the terms of any acquisition of Private Property Interests by

amending this Agreement in accordance with Section 14.7, entering into a separate agreement expressly for the purpose of acquiring Private Property Interests, or through the incorporation of Private Property Interests into one or more Definitive Development and Construction Agreements. The Funders intend the terms of the acquisition of Private Property Interests to be consistent with the Permitting Interests established in Exhibit D to this Agreement.

- 2.2 Project Permitting Objectives and Timetable. The objectives (the “Project Permitting Objectives”) and timetable (the “Project Permitting Timetable”) that Idaho Power, PAC, and BPA desire to achieve with respect to the Permitting Project pursuant to this Agreement are set forth in Schedule 2.2. Idaho Power, PAC and BPA agree to use Commercially Reasonable Efforts to achieve the Project Permitting Objectives and Project Permitting Timetable in accordance with Schedule 2.2.

### **ARTICLE III FUNDERS & PERMIT FUNDING COMMITTEE**

#### 3.1 Funders’ Rights & Obligations.

- (a) Payment Obligations. Subject to the provisions of Article VII and after the Effective Date:
- (i) Each Funder is required to pay the mandatory funding payments as set forth in Exhibit B (the “Mandatory Payments”). Any payment made by a Funder will accrue interest, per annum, on behalf of the Funder calculated in accordance with Idaho Power’s AFUDC rate to be credited to the Funder. Any credit shall be included in the funding invoice provided pursuant to Section 3.1(b)(i) and, as applicable, Section 3.1(b)(iii).
  - (ii) A Funder may elect, but is not required, to pay the final funding payment as set forth in Exhibit B (the “Completion Funding Payment”). A Funder that does not elect to pay the Completion Funding Payment set forth in Exhibit B consistent with Sections 3.1(b)(ii) and a Funder that pays such Completion Funding Payment but does not pay the Final Expense True-Up payment consistent with Section 3.1(b)(iii), shall be deemed a Withdrawing Funder under Article VII of this Agreement.
  - (iii) A Funder may, in its sole and absolute discretion, elect to make any of the Mandatory Payments or the Completion Funding Payment, in whole or in part, in advance of the date due identified in the Permit Funding Payment Schedule set forth in Exhibit B, in accordance with Section 3.1(b). In the event a Funder elects to make an early payment which includes an

AFUDC accumulation component, accumulation of AFUDC will cease upon receipt of the payment by the Permitting Project Manager.

- (b) Method of Payment. All payments required under the terms of this Agreement shall be made to an account or accounts designated by the Permitting Project Manager to which payment is owed by electronic transfer in immediately available funds in the lawful currency of the United States. The Permitting Project Manager shall invoice the payments set forth in Exhibit B of this Agreement as follows:
- (i) Mandatory Payments. The Permitting Project Manager shall deliver to the Funders an invoice (“Funding Invoice”) ten (10) days in advance of each of the Mandatory Payment dates as set forth in Exhibit B. The invoice shall provide a sufficient level of detail describing the activities to be performed by the Permitting Project Manager, as requested by the receiving Funder. With the exception of Mandatory Payment 1 which is due twenty (20) days after the Effective Date, Funders shall tender payments to the Permitting Project Manager within forty (40) days of receipt of the Funding Invoice. Any payment past due will accrue interest, per annum, calculated in accordance with Section 3.1(a)(i). The failure of the Permitting Project Manager to timely deliver an invoice shall not relieve any Funder of its payment obligations in respect to the Mandatory Payments or Completion Funding Payment shown on such invoice.
- (ii) Completion Funding Payment. The Permitting Project Manager shall provide the Funders with written notice of the expected date of completion of the Project Permitting Objectives and an invoice for the Completion Funding Payment within sixty (60) days after the publication of a Final Record of Decision by the BLM in the *Federal Register* for the Boardman to Hemingway Transmission Project (the “Final Payment Invoice”). The Final Payment Invoice shall provide a sufficient level of detail describing the activities performed or to be performed by the Permitting Project Manager, as requested by the receiving Funder. The Funders shall provide written notice to the Permitting Project Manager of its intent to pay the Completion Funding Payment within twenty (20) days from receipt of the Final Payment Invoice for the Completion Funding Payment (the “Notice of Payment”). Any Funder who fails to issue a Notice of Payment within such twenty (20) day period or issues a Notice of Payment within such twenty (20) day period but fails to tender payment to the Permitting Project Manager within forty (40) days of the Notice of Payment shall be deemed a Withdrawing Funder pursuant to Article VII, provided,

however, that Idaho Power may not withdraw from this Agreement pursuant to Article VII. The Funders electing to make the Completion Funding Payment shall tender payment to the Permitting Project Manager within forty (40) days of the Notice of Payment.

(iii) Final Expense True-Up Payment. Except where a Funder has withdrawn from this Agreement pursuant to Article VII, the Permitting Project Manager shall deliver to the Funders an invoice one hundred and eighty (180) days following the Notice of Payment relating to a Completion Funding Payment to include a final true up payment as provided in Exhibit B (the “Final Expense True-Up”). The Final Expense True-Up payment shall include all cost adjustments to Mandatory Payments 1, 2 and 4 approved by the Permit Funding Committee and not previously paid by the Funders to the Permitting Project Manager and any credit for any accrued interest not previously received by the Funders pursuant to Section 3.1(a)(i). The invoice shall provide the Funders sufficient level of detail describing the activities performed by the Permitting Project Manager, as requested by the receiving Funder. The Funders shall tender payment to the Permitting Project Manager within thirty (30) days of receipt of the invoice. The failure by the Permitting Project Manager to timely deliver an invoice shall not relieve any Funder of its payment obligations in respect to the Final Expense True-Up payment shown on such invoice. Any true up associated with a Funder’s withdrawal from the Agreement is subject to Article VII. In the case of any overpayment by the Non-Permitting Project Manager Funders, the Permitting Project Manager shall promptly return the amount of the overpayment to the Non-Permitting Project Manager Funder, together with interest for the period from the date of overpayment until such amount has been paid, calculated in the manner prescribed for calculating interest in Section 3.1(a).

(c) Disputed Amounts. If a Funder disputes any portion of any amount described in Exhibit B, the Funder shall pay its total amount of the invoice when due, and, if actually known at the time by the Funder, identify the disputed amount and state that the disputed amount is being paid under protest. Any disputed amount shall be resolved pursuant to the provisions of Article XIII. If it is determined pursuant to Article XIII that an overpayment or underpayment has been made by the Funder or any amount allocated to a Funder on an invoice is incorrect, then (i) in the case of any overpayment by a Funder, the Permitting Project Manager shall promptly return the amount of the overpayment (or credit the amount of the overpayment on the next invoice) to the Funder; and (ii) in the case of an underpayment by the Funder, the Funder shall promptly pay the amount of the

underpayment to the Permitting Project Manager (in each case, together with interest for the period from the date of overpayment, underpayment, or incorrect allocation, until such amount has been paid or credited against a future invoice calculated in the manner prescribed for calculating interest in Section 3.1(a)).

- (d) Audit Rights. Each Funder may, at its cost, at any time during normal business hours and with reasonable prior notice to the Permitting Project Manager and the other Funders, of not less than ten (10) Business Days, but not more often than twice in any twelve (12) month period, inspect and audit the books and records of the Permitting Project Manager and any of its Affiliates (and the Permitting Project Manager shall secure such rights for the Permitting Project Manager from its Affiliates) relating: (1) to the determination of the payments set forth in Exhibit B for which the Funders are responsible under this Agreement, including the costs set forth in Exhibit C (the “Project Costs”), within twelve (12) months prior to the date of the audit notice; and (2) directly related to and involved in formulating the Mandatory Payments, Completion Funding Payment, and any applicable true up payment pursuant to this Agreement (“Project Costs Records”). Audit findings shall be provided to each Funder to this Agreement. If any audit discloses that, during such twelve (12)-month period, an overpayment or underpayment of Project Costs has been made by the Funders or the amount of any Project Costs allocated to the Funders on an invoice is incorrect, then such overpayment, underpayment or incorrect amount shall be resolved pursuant to Article XIII. The Funders requesting the audit shall reimburse one hundred percent (100%) of all reasonable costs and expenses (including internal costs and expenses) incurred by or on behalf of the Permitting Project Manager and any of its Affiliates in complying with the provisions of this Section 3.1(d), provided, however, that such Funders shall not be required to reimburse any such costs if the audit determines that Funders, in combination, have made more than Twenty-Five Thousand Dollars (\$25,000) in overpayments of Project Costs or more than Twenty-Five Thousand Dollars (\$25,000) in Project Costs have been incorrectly allocated to Funders.
- (e) Access. The Permitting Project Manager shall, to the extent possible under any Rights-of-Ways, provide each Funder and its designees reasonable access to the Boardman to Hemingway Transmission Project sites to permit the Funders and their designees to inspect the development, preliminary design, siting, Rights-of-Way acquisition and permitting of the Boardman to Hemingway Transmission Project, provided that (i) the Funders and their designees do not interfere with the development, preliminary designing, siting, Rights-of-Way acquisition and permitting of the Boardman to Hemingway Transmission Project or any portion thereof or pose a safety hazard; (ii) the Funders and their designees comply with

any requirements of any Rights-of-Ways applicable to the Boardman to Hemingway Transmission Project; and (iii) the Funders and their designees performing the inspection comply with the Permitting Project Manager's or any other contractor's safety and security rules, notice of which the Permitting Project Manager shall provide to the Funders.

### 3.2 Permit Funding Committee.

- (a) Scope and Authority. The Permit Funding Committee shall consider, evaluate and take action with respect to mutually resolving the following matters: (1) any and all changes in the scope or schedule of the Permitting Project that directly affect the cost of the Mandatory Payments, Completion Funding Payment or the costs otherwise associated with the Permitting Project; (2) any and all proposed cost adjustments to the Mandatory Payments, Completion Funding Payment or costs otherwise described in Exhibit B; (3) any and all technical specifications and other matters related to the Permitting Project; (4) requests from and provide guidance to the Permitting Project Manager from time to time as necessary or when requested relating to the advancement of the Project Permitting Objectives and Project Timetable, or the Permitting Project; (5) general development of policy and strategy with respect to the Permitting Project; and (6) any and all direct or indirect effects of the development of other regional transmission projects (including project schedule and location of potential interconnection points), including, but not limited to, the Cascade Crossing Project and Gateway West Project, on the development and permitting of the Boardman to Hemingway Transmission Project.
- (b) Membership. The Permit Funding Committee shall be comprised of a representative of each Funder (each a "Funding Committee Representative"). Each Funder's Funding Committee Representative shall be a senior level representative or designee with authority to consider and act to resolve issues that arise between or among the Funders.
- (c) Permitting Project Manager. The Permitting Project Manager shall inform the Permit Funding Committee and the Funding Committee Representatives through formal and informal communication, of the ongoing progress and matters that impact the Governmental Authorizations or other necessary work relating to the Permitting Project. The Permitting Project Manager shall confer and communicate with the Permit Funding Committee and Funding Committee Representatives as to the matters described in Section 3.2(a) or as otherwise provided in this Agreement.

- (d) Funding Committee Meetings. The Permit Funding Committee will meet at least monthly, in person or telephonically, or as deemed necessary by the Funding Committee Representatives. Any Funding Committee Representative may request a meeting of the Permit Funding Committee at any time and for any reason. The Permitting Project Manager shall provide the Permit Funding Committee with regular statements, at least monthly, regarding the Permitting Project that include future expense projections.
- (e) Funding Committee Procedures. The Funding Committee Representatives shall work in good faith to consider, evaluate and make best efforts to mutually resolve any issues that are raised before the Permit Funding Committee. If the Funding Committee Representatives are unable to mutually resolve any issue, they shall refer the matter to the Executives that have the authority to settle the issue. If the Executives are unable to mutually resolve the issue, the Funders may move to dispute resolution as set forth in Article XIII. All communications and writings exchanged between and/or among the Permitting Project Manager, Funding Committee Representatives, and Executives in connection with the Permit Funding Committee shall be treated as Confidential Information in accordance with Article XII.
- (f) Joint Working Groups. Joint working groups may be established by the Permit Funders Committee on an ad hoc basis when the need arises to advance certain specific tasks related to the Permitting Project and the Boardman to Hemingway Transmission Project, including, but not limited to, consultation on technical specifications and other matters related to the Permitting Project.
- (g) Committee Conversion. Within sixty (60) days after one or more Funders tenders Mandatory Payment 3 and the Completion Funding Payment set forth in Exhibit B, the Funders shall amend this Agreement, or enter into a new agreement, that establishes a committee structure that is consistent with the Permitting Interests of the Funders.

### 3.3 Future Agreements

- (a) Negotiation Process
  - (i) Completion Notice. Unless this Agreement is terminated pursuant to Article VI, the Permitting Project Manager shall provide the Funders with written notice within sixty (60) days following the publication of a Final Record of Decision by the BLM in the *Federal Register* for the Boardman to Hemingway Transmission Project (the "Completion Notice") of the expected date of completion of the Project Permitting Objectives.

Notwithstanding the foregoing, any Funder may commence negotiations pursuant to this Section 3.3 for reaching Definitive Development and Construction Agreements at any time by providing written notice of its desire to do so to the other Funders pursuant Section 14.10.

- (ii) Negotiation Period. Upon receipt of the Completion Notice, the Funders shall meet, subject to Section 3.3(a)(iii), to negotiate one or more Definitive Development and Construction Agreements for up to one hundred eighty (180) days (the “Negotiation Period”). Upon the termination of the Negotiation Period, the Funders may agree to extend the Negotiation Period for an additional period not to exceed one hundred eighty (180) days.
- (iii) Negotiations. During the Negotiation Period, the Funders will attempt, to the greatest extent possible, but subject to the other provisions of this Section 3.3(a)(iii), to keep the Definitive Development and Construction Agreements consistent with the terms and conditions of this Agreement, including the Permitting Interests set forth in Exhibit D, as may be amended from time to time by mutual agreement of the Funders pursuant to Section 14.7. In negotiating the Definitive Development and Construction Agreement the Funders shall also consider the following:
  - (A) Path Rating. The Funders acknowledge and agree that the Permitting Interest set forth in Exhibit D may be impacted by the WECC Three Phase Project Rating Process (the “WECC Rating Process”) and that each Funder’s Permitting Interest is subject to the results of the WECC Rating Process. Subject to the outcome of the WECC Rating Process, the Funders may, using the Permitting Interests set forth in Exhibit D as a baseline for allocation, mutually agree to further negotiate, revise, or adjust the Permitting Interest set forth in Exhibit D for purposes of negotiating Definitive Development and Construction Agreements, including adjustments to Mandatory Payments, the Completion Funding Payment or the Final Expense True-Up paid pursuant to this Agreement. The Funders shall cooperate and support each other in the WECC Rating Process in a manner consistent with Section 4.5.
  - (B) Alternative Analysis. BPA is considering various transmission and other alternatives to meet their service obligations in eastern Idaho. BPA’s decision whether to participate in and timing associated with participation in the development and construction of the



Boardman to Hemingway Transmission Project may be based on BPA's evaluation of such alternatives.

- (C) BPA NEPA Requirements. BPA has certain obligations and responsibilities under NEPA and other applicable Governmental Requirements that must be fulfilled before it can make a definitive decision concerning whether to participate in development and construction of the Boardman to Hemingway Transmission Project. Nothing in this Agreement shall be construed as obligating or committing BPA to enter into the Definitive Development and Construction Agreement before the NEPA review process for the Boardman to Hemingway Transmission Project has been completed and BPA has made a decision regarding how to proceed. Additionally, PAC's participation in the Boardman to Hemingway Transmission Project may be impacted by the schedule and design specifications of the Cascade Crossing Project and/or the Gateway West Project. As a result, or for other reasons, BPA or PAC may decide not to proceed further and to withdraw from this Agreement in accordance with Article VII at any time.
  - (D) Additional Materials. The Funders may request the Permitting Project Manager or other Funders to make available, and the Permitting Project Manager or other Funders will make available, on mutually agreed to terms (such agreement not to be unreasonably withheld) additional information related to the design, engineering, construction, or procurement of materials related to the Boardman to Hemingway Transmission Project that are not part of this Agreement.
- (b) Negotiation Termination. Any negotiations pursuant to this Section 3.3 shall automatically terminate, unless the Negotiation Period is extended as provided in Section 3.3(a)(ii) (the "Negotiations End Date").
  - (c) Transfer of Interest. Following the Negotiations End Date and notwithstanding Article V herein, to the extent a Definitive Development and Construction Agreement is not executed, any Funder who has made all payments pursuant to Exhibit B may issue a written notice to proceed with the development and construction of the Boardman to Hemingway Transmission Project to the other Funders (the "Notice to Proceed"). Notwithstanding anything to the contrary in Article VII, within thirty (30) days of the receipt of the Notice to Proceed, each Funder shall notify the other Funders whether it does or does not desire to proceed with the development and construction of the Boardman to Hemingway

Transmission Project (each a “Response Notice”). Within two (2) years of receipt of the last Response Notice (the “Purchase and Sale End Date”) the Funders who desire to proceed with the development and construction of the Boardman to Hemingway Transmission Project (each a “Purchasing Funder”) shall purchase and the Funders who do not desire to proceed with the development and construction of the Boardman to Hemingway Transmission Project (each a “Selling Funder”) shall sell all of the Selling Funder’s rights, title, and interests in and to the Permitting Project, including all reports, studies, and Governmental Authorizations, Rights of Way, and any other property whatsoever of whatever nature and kind, whether real or personal, tangible or intangible, acquired or perfected by the Permitting Project Manager for the benefit of the Funder(s) pursuant to the terms of this Agreement. Purchasing Funders shall select the date for the purchase and sale (the “Purchase and Sale Date”) which shall occur before the Purchase and Sale End Date, written notice of which they shall provide to the Selling Funders. On the Purchase and Sale Date, the Purchasing Funders shall pay immediately available funds pro-rata (based on their Permitting Interest after giving effect to the sale) and the Selling Funders shall receive the aggregate amount of all payments made pursuant to Exhibit B. The Funders shall execute such agreements and documents as may be reasonably required to facilitate the purchase and sale contemplated pursuant to this Section 3.3 (c).

- (d) If two or more Purchasing Funders remain pursuant to Section 3.3(c), the Purchasing Funders shall meet to negotiate one or more Definitive Development and Construction Agreements pursuant to Sectiond 3.3(a)(ii), (a)(iii), (b), (c) and (d).
- (e) In the event no Funder has issued a Notice to Proceed, the Funders retain their respective right, title and interest in the Permitting Project pursuant to this Agreement.

3.4 Other Projects. Nothing in this Agreement shall preclude a Funder from taking any action (or having its Affiliates take any action) with respect to any other transmission project, including a transmission project that may compete with the Permitting Project.

## **ARTICLE IV PERMITTING PROJECT MANAGER**

4.1 Appointment of Permitting Project Manager.

- (a) Appointment. The Funders hereby appoint Idaho Power, and Idaho Power hereby accepts appointment, to serve as Permitting Project Manager of the Permitting

Project and will perform the obligations of the Permitting Project Manager expressly set forth in this Agreement, in accordance with the terms and conditions of this Agreement.

- (b) Duty. The Funders agree that the Permitting Project Manager shall not have any obligations, responsibilities or duties to the Funders other than as are expressly provided for in this Agreement.

#### 4.2 Authority of Permitting Project Manager.

- (a) Role of Permitting Project Manager. The Permitting Project Manager shall administer and oversee the Permitting Project and shall be responsible for the day to day activities involved in advancing the Permitting Project to achieve the Project Permitting Objectives and Project Permitting Timetable, including the responsibility for obtaining all required Governmental Authorizations, siting, and Rights-of-Way acquisition relating to the Boardman to Hemingway Transmission Project. The Permitting Project Manager will advance funds in anticipation of receiving the Mandatory Payments from Funders, as necessary, to fulfill the Permitting Project Objectives (“Advance Contributions”). Idaho Power’s Advance Contributions will accrue interest, per annum, calculated in accordance with Idaho Power’s AFUDC rate. The Advance Contributions and accrued AFUDC will be reimbursed as part of the Funder’s Mandatory Payments 2 or 4 as set forth in Exhibit B, as applicable. The Permitting Project Manager shall not collect payments other than those described in Exhibit B or as approved by the Permit Funding Committee. The Permitting Project Manager will exercise or enforce all benefits, rights and remedies under this Agreement for the benefit of the Funders pro rata (in accordance with their respective Permitting Interests) and without adverse distinction or undue discrimination between or against the Funder’s respective Permitting Interests. In furtherance and not in limitation of the immediately preceding sentence, the Permitting Project Manager agrees to transfer, assign, distribute, pay over or otherwise make available to the Non-Permitting Project Manager Funders, the Non-Permitting Project Manager Funder’s pro rata share (based on its respective Permitting Interests) in any payments or proceeds obtained pursuant to this Agreement.
- (b) Communication. The Permitting Project Manager shall have the duty to communicate the status of the Permitting Project, including the Project Permitting Objectives, on a regular basis with the Permitting Funding Committee in a manner consistent with Section 3.2(c).
- (c) Reporting. The Permitting Project Manager shall be responsible for preparing and distributing monthly reports to the Permitting Project Committee (or less

frequently if mutually required by the Permit Funding Committee) regarding (i) Project Costs paid and projected to be incurred, and, to the extent necessary, recommend to the Permit Funding Committee adjustments to the Permit Funding Schedule to satisfy expected Project Costs to be incurred in relation to the Project Permitting Objectives and (ii) activity and progress with respect to achieving the Project Permitting Objectives and the Project Permitting Timetable. The Permitting Project Manager shall be responsible for preparing and distributing reports to the Permit Funding Committee at such other times as any material change occurs or is contemplated that affects the achievement of the Project Permitting Objectives.

- (d) Project Coordination. Notwithstanding anything to the contrary contained in this Agreement, the Permitting Project Manager shall work diligently, consult with and obtain the express written approval of the Funders with respect to the location, technical design and engineering specifications relating directly to the interconnection point of the Boardman to Hemingway Transmission Project and the proposed Cascade Crossing Project and Gateway West Project.

#### 4.3 Funder's Ownership Interests.

- (a) Perfection of Existing Ownership Interests. Commencing on the Effective Date of this Agreement, the Permitting Project Manager will take all necessary and reasonable action, unless prohibited by applicable Governmental Requirements, to perfect and vest, on behalf and in the name of the Funders, in accordance with the Funders' Permitting Interest set forth in Exhibit D, an undivided ownership interest as tenants-in-common in all right, title, and interest in all reports, studies, Governmental Authorizations (including permits) and other property of whatever nature and kind, whether real or personal, tangible or intangible, purchased or acquired prior to the Effective Date by or on behalf of the Permitting Project Manager or Idaho Power for the Boardman to Hemingway Transmission Project, including all Governmental Authorizations and Rights-of-Way required for the Boardman to Hemingway Transmission Project and acquired by Idaho Power hereunder.
- (b) Perfection of Future Ownership Interests. Following the Effective Date of this Agreement, the Permitting Project Manager shall acquire, unless prohibited by applicable Governmental Requirements, on behalf and in the name of the Funders, in accordance with the Funders' respective Permitting Interests set forth in Exhibit D, an undivided ownership interest as tenants-in-common in all right, title, and interest in all reports, studies, Governmental Authorizations (including permits) and other property of whatever nature and kind, whether real or personal,

tangible or intangible, for the Boardman to Hemingway Transmission Project, including all Governmental Authorizations and Rights-of-Way required for the Boardman to Hemingway Transmission Project and acquired by the Permitting Project Manager hereunder. The Funders and the Permitting Project Manager agree that any reports, studies and Governmental Authorizations shall be issued in the names of all Funders. Notwithstanding any provision to the contrary contained in this Agreement, the Permitting Project Manager shall make all applications for Government Authorizations, and shall obtain all such Government Authorizations, reports, and studies, in the name of the Funders, to the extent permitted by applicable Governmental Requirements. In the event a Governmental Authorization, report or study is not issued in the name of all Funders, the Funders and Permitting Project Manager agree to take all necessary and reasonable actions to perfect and vest, on behalf and in the name of the Funders, in accordance with the Funders' respective Permitting Interests, an undivided ownership interest as tenants-in-common in all right, title and interest in all such Governmental Authorizations, reports, and studies.

- (c) Forfeiture of Ownership Interests. In the event any Funder elects not to make all of the payments set forth in Exhibit B, or otherwise withdraws from this Agreement pursuant to Article VII, the Withdrawing Funder shall convey to the remaining Funders all right, title, and interest in this Agreement, as well as all right title and interest in all reports, studies, Governmental Authorizations (including permits), Rights of Way, and any other property whatsoever of whatever nature and kind, whether real or personal, tangible or intangible, acquired or perfected by the Permitting Project Manager for the benefit of the Funders pursuant to the terms of this Agreement pursuant to Section 7.2. If and to the extent the right, title, or interest in any permit or Governmental Authorization is by its terms or pursuant to applicable law not assignable, the Withdrawing Funder shall execute such reasonable agreements, licenses, or other instruments as shall be deemed reasonably necessary by the remaining Funders to otherwise convey all use and enjoyment of the Withdrawing Party's right, title, and interest in such permit or Governmental Authorization.

- 4.4 Standard of Work. The Permitting Project Manager shall perform all of its obligations under this Agreement as an independent contractor and in accordance with Good Utility Practice and applicable Governmental Requirements and Governmental Authorizations and without adverse distinction among the Funders.
- 4.5 Assistance. Each Funder shall cooperate with the Permitting Project Manager promptly, as and when reasonably requested by the Permitting Project Manager, to assist the Permitting Project Manager in the performance of its duties, responsibilities and

obligations under this Agreement, including executing and delivering from time to time such additional documents, certificates or instruments, and taking such additional actions, as may be reasonably requested by the Permitting Project Manager. Each Funder shall bear its own costs for providing such cooperation and assistance as requested by the Permitting Project Manager unless all of the Funders agree otherwise in writing. Each Funder shall provide internal personnel, services, know how, intellectual property or other internal resources as may be reasonably necessary or appropriate to carry out the intent of and to perform the Funders' and Permitting Project Manager's obligations under this Agreement or as all of the Funders may otherwise agree to in writing; provided however, to the extent the Permitting Project Manager desires to use for the purposes of this Agreement services of a Funder that are the subject of a separate agreement, such Funder shall consent, in its sole and absolute discretion, to such use and be reimbursed by the other Funders and the Permitting Project Manager as mutually agreed to by all the Funders. No Funder (other than Idaho Power in its role as Permitting Project Manager) shall have the right to invoice the other Funders for the costs or expenses associated with the utilization of internal personnel, services, know how intellectual property or other internal resources necessary or appropriate to carry out the intent of and to perform its obligations under this Agreement, unless otherwise agreed upon in writing by the Funders. Nothing in this Agreement shall preclude a Funder from exercising any rights expressly granted it under this Agreement or taking any action (or having its Affiliates take any action) with respect to any other transmission project, including any such project that may compete with the Permitting Project. The Permitting Project Manager shall request assistance under this Section 4.5 without adverse distinction of the Funders.

#### 4.6 Remedies.

- (a) Notwithstanding any provision to the contrary contained in this Agreement, the Permitting Project Manager shall not have any liability to the Non-Permitting Project Manager Funders in connection with the performance of its covenants and obligations under this Agreement, provided, however, the Permitting Project Manager shall be liable for any direct actual damages resulting from its own negligence or breach of this Agreement. The Funders agree that each Funder has a duty to mitigate any damages and shall use Commercially Reasonable Efforts to minimize any damages it may incur as a result of the Permitting Project Manager's failure to perform or breach of any of its covenants or obligations under this Agreement.
- (b) The Funders and the Permitting Project Manager acknowledge that the obligations and covenants performed by the Permitting Project Manager hereunder are unique and that the Non-Permitting Project Manager Funders will be irreparably injured should such obligations and covenants not be performed in accordance with the

terms and conditions of this Agreement. Consequently, the Non-Permitting Project Manager Funders will not have an adequate remedy at law if the Permitting Project Manager shall fail to perform its obligations and covenants hereunder. The Non-Permitting Project Manager Funders shall have the right, in addition to any other remedy available under this Agreement, to specific performance of the Permitting Project Manager's obligations and covenants hereunder, and the Funders and the Permitting Project Manager agree not to take a position in any proceeding arising out of this Agreement to the effect that the Non-Permitting Project Manager Funder has an adequate remedy at law.

- 4.7 Injury to Third Parties. Idaho Power and PAC shall be responsible for obtaining and maintaining during the Term insurance covering their respective legal liabilities to third persons or the property of third persons related to their respective obligations under this Agreement in amounts consistent with Good Utility Practice and any applicable Governmental Requirements. Insurance coverage required by this Section 4.7 for Idaho Power and PAC may be through a carrier or self-insured, or any combination of carrier insured and self-insured. BPA shall be responsible for injury or damage to third persons or the property of third parties related to its obligations under this Agreement and caused by BPA in accordance with the provisions of the Federal Tort Claims Act.

## **ARTICLE V TRANSFER OF RIGHTS AND INTERESTS; ASSIGNMENT**

- 5.1 Prohibited Transfers and Assignments. Except as provided in Section 3.3(c) and Section 5.2, no Funder may, without the express written consent of the other Funders (such consent not to be unreasonably withheld, conditioned or delayed) sell, assign, transfer, convey or otherwise dispose of, directly, in whole or in part, any of its rights, titles or interest in and to (a) this Agreement including its rights, duties and obligations hereunder, or (b) the Permitting Project. Any sale, assignment, transfer, conveyance or other disposition in violation of this Article V shall be null and void.
- 5.2 Permitted Assignments and Transfers. Notwithstanding anything to the contrary contained in this Agreement, Section 5.1 shall not restrict:
- (a) the right of any Funder to transfer voluntarily (and without the consent of the other Funders) all of its Permitting Interest in the Permitting Project and all of its rights, titles and interests in and to this Agreement (including all of its rights and obligations in this Agreement as Permitting Project Manager, if any) in connection with any sale, merger or other transfer of substantially all of such Funder's electric transmission facilities as an operating entity; provided, however, that the effectiveness of such assignment shall be conditioned upon the assignee

agreeing in writing to assume all of the rights and obligations of the assigning Funder under this Agreement (including all of its rights and obligations in this Agreement as Permitting Project Manager, if any) as of the effective date of assignment;

- (b) the right of any Funder to transfer voluntarily (and without the consent of the other Funders) all of its Permitting Interest in the Permitting Project and all of its rights, titles and interests in and to this Agreement (including all of its rights and obligations in this Agreement as Permitting Project Manager, if any) to an Affiliate of the Funder; provided, however, that the effectiveness of such assignment shall be conditioned upon the assignee agreeing in writing to assume all of the rights and obligations of the assigning Funder under this Agreement (including all of its rights and obligations in this Agreement as Permitting Project Manager, if any) as of the effective date of assignment;
- (c) the right of any Funder to transfer voluntarily all of its Permitting Interest in the Permitting Project and all of its rights, titles and interest in and to this Agreement (including all of its rights and obligations in this Agreement as Permitting Project Manager, if any) to a third party that is financially and technically capable of performing the transferring Funder's (and, Permitting Project Manager's, if any) obligations under this Agreement; provided that: (i) the other Funders approve, in their sole discretion, such transfer, and (ii) the other Funders are offered the right of first refusal to purchase such Permitting Interest and all of the transferring Party' rights, titles and interests in and to this Agreement (including all of its rights and obligations in this Agreement as Permitting Project Manager, if any) at the amounts set forth in the Permitting Funding Schedule; provided, however, that the effectiveness of such assignment shall be conditioned upon the third-party purchaser agreeing in writing to assume all of the rights and obligations of the assigning Funder under this Agreement (including all of its rights and obligations in this Agreement as Permitting Project Manager, if any) as of the effective date of assignment.

5.3 Release. Upon any assignment or transfer pursuant to this Section 5.2, no Funder transferring or assigning its right, title and interest in this Agreement and the Permitting Project shall have any further obligations or responsibilities under this Agreement.

## ARTICLE VI TERM

6.1 Term. The term of this Agreement ("Term") shall commence on the Effective Date and shall continue in full force and effect until the successful completion of the duties and obligations under this Agreement in accordance with the terms of this Agreement, unless



terminated earlier as set forth in this Article VI. Notwithstanding the foregoing, this Agreement shall terminate not later than January 1, 2022.

6.2 Early Termination.

- (a) The Term of this Agreement shall terminate effective upon the occurrence of any of the following:
  - (i) Withdrawal of two (2) Funders, if there are three (3) Funders at the time, or one (1) Funder, if there are only two (2) Funders at the time, in each case, pursuant to Article VII;
  - (ii) the mutual written consent of the Funders; or
  - (iii) The effective date of a separate written agreement among all of the then current Funders which by its terms supersedes this Agreement.
- (b) If this Agreement is terminated pursuant to this Section 6.2, then, except as for those provisions that are expressly intended to survive termination pursuant to this Agreement, this Agreement shall terminate and become void and of no further force and effect, without further action by any Funder, provided that no Funder shall be relieved from any of its obligations or liabilities hereunder accruing prior thereto.
- (c) If this Agreement is terminated pursuant to Section 6.2(a)(i), then the Non-Withdrawing Funder may, in its sole and absolute discretion, proceed with the Permitting Project.

**ARTICLE VII  
WITHDRAWAL**

- 7.1 Withdrawal. PAC or BPA may withdraw from this Agreement at any time and for any reason, or for no reason, subject to the limitations of this Article VII (a “Withdrawing Funder”). Idaho Power shall have no right to withdraw from this Agreement under any circumstance or at any time, including if it is a Defaulting Funder pursuant to Article VIII. A Withdrawing Funder shall provide reasonable prior written notice to the other Funders of its intent to withdraw from this Agreement (“Notice of Withdrawal”), and the Notice of Withdrawal shall specify the effective date of withdrawal, which in no event shall be less than five (5) Business Days after the date of delivery of the Notice of Withdrawal.
- 7.2 Effect of Withdrawal. The Withdrawing Funder’s withdrawal from this Agreement shall be subject to the following:

- (a) Withdrawal will become effective as of the last day of the month the Withdrawing Funder provides its Notice of Withdrawal (“Withdrawal Date”). As of the Withdrawal Date, the Withdrawing Funder shall be obligated to pay the Permitting Project Manager any outstanding Mandatory Payments identified in Exhibit B, including a true up that shall include all cost adjustments to Mandatory Payments 1, 2 and 4 approved by the Funding Committee and not previously paid by the Withdrawing Funder as of the Withdrawal Date and any credit for any accrued interest pursuant to Section 3.1(a)(i) (the “Withdrawal Payment”). The Permitting Project Manager shall invoice, in a manner consistent with Section 3.1(b), the Withdrawing Funder for the Withdrawal Payment within one hundred twenty (120) days following the Withdrawal Date.
- (b) Except as otherwise provided in Article III of this Agreement, effective as of the Withdrawal Date, a Withdrawing Funder shall forfeit and transfer to the remaining Funders all of its right, title and interest in: (i) the Permitting Project, including all Governmental Authorizations, and amounts paid to the Permitting Project Manager through the Withdrawal Date; (ii) all Rights-of-Way issued by the BLM and other federal agencies (including any other permits, licenses, options, permissions); and (iii) any and all reports and studies. The Withdrawing Funder’s Permitting Interest (including all project investments associated therewith) shall be allocated to the remaining Funders at no cost to the remaining Funders, such that the remaining Funders shall have 100% of the Permitting Interest in the Permitting Project.
- (c) The Withdrawing Funder shall execute such documents and instruments as may be reasonably requested by the remaining Funders in connection with the withdrawal, including as may be necessary to evidence the Withdrawing Funder’s relinquishment of its rights, titles and interest in the Permitting Project; provided, however, that the remaining Funders shall not be obligated to pay or reimburse the Withdrawing Funders for any Project Costs or the Withdrawal Payment paid to the Permitting Project Manager through the Withdrawal Date or to otherwise compensate the Withdrawing Funder for its rights, titles and interest in the Project.

## **ARTICLE VIII EVENT OF DEFAULT**

- 8.1 Event of Default. Each of the following events shall constitute an event of default (“Event of Default”) by the defaulting Funder, including the Permitting Manager Funder, (a “Defaulting Funder”):

- (a) Subject to Section 3.1(b)(ii), the failure to make, when due, any payment required pursuant to this Agreement, if such failure is not remedied within ninety (90) days after written notice thereof from a Non-Defaulting Funder;
- (b) any material representation or warranty made by a Defaulting Funder herein that is false or misleading in any material respect when made, unless (i) the fact, circumstance or condition that is the subject of such representation or warranty is made true within thirty (30) days after notice thereof from a Non-Defaulting Funder, provided that if the fact, circumstance or condition that is the subject of such representation or warranty reasonably cannot be corrected within such thirty (30) day period, then the Defaulting Funder shall have an additional period of time (not to exceed sixty (60) days) in which to correct the fact, circumstance or condition that is the subject of such representation or warranty so long as the Defaulting Funder commences good faith activities to correct the fact, circumstance or condition that is the subject of such representation or warranty during the initial 30-day cure period and continues thereafter to utilize Commercially Reasonable Efforts to effect a cure, and (ii) (A) such cure removes any adverse effect on the Non-Defaulting Funders of such fact, circumstance or condition being otherwise than as first represented, or (B) such fact, circumstance or condition being otherwise than as first represented does not materially adversely affect the Non-Defaulting Funders;
- (c) a transfer, assignment or other disposition of its interest in this Agreement or its Permitting Interest in the Permitting Project, in each case, in violation of Article V;
- (d) the failure to perform or breach of any material covenant or obligation set forth in this Agreement (other than provided for in this Section 8.1), if such failure is not remedied within thirty (30) days after written notice thereof from a Non-Defaulting Funder, provided that if such failure or breach cannot reasonably be cured within thirty (30) days, then the Defaulting Funder shall have an additional period of time (not to exceed ninety (90) days) in which to cure such failure or breach so long as the Defaulting Funder commences good faith activities to cure the failure or breach during the initial 30-day cure period and thereafter continues to utilize Commercially Reasonable Efforts to effect a cure; or
- (e) the Defaulting Funder or the Permitting Project Manager becomes Bankrupt.

8.2 Cure by Non-Defaulting Funders. If a Defaulting Funder fails to cure an Event of Default, then the Non-Defaulting Funders may, individually or together, in their respective sole discretion, attempt to cure the Event of Default, provided that the

Defaulting Funder shall reimburse the Non-Defaulting Funders for all costs and expenses incurred by or on behalf of the Non-Defaulting Funders pursuant to this Section 8.2.

### 8.3 Remedies.

- (a) If an Event of Default occurs and is continuing, then each of the Non-Defaulting Funders shall be entitled to exercise any of its remedies provided for in this Agreement and any of its remedies at law or in equity, including recovery from the Defaulting Funder of any damages suffered as a result of the Event of Default, subject to Section 11.6. The Non-Defaulting Funders shall use Commercially Reasonable Efforts to mitigate any damages suffered as a result of the Event of Default.
- (b) If an Event of Default by BPA or PAC occurs and is not cured as provided in this Article VIII, then BPA or PAC, as the Defaulting Funder, shall be deemed to be a Withdrawing Funder under and subject to the terms of Article VII.
- (c) The Funders acknowledge that the obligations and covenants performed by Idaho Power (as a Funder and Permitting Project Manager) hereunder are unique. If an Event of Default by Idaho Power occurs and is not cured as provided in this Article VIII, BPA and PAC shall have the right, in addition to any other remedy available under this Agreement, at law, or in equity, to seek specific performance of Idaho Power's obligations and covenants hereunder, and the Non-Defaulting Funders agree not to take a position in any proceeding arising out of this Agreement to the effect that the Non-Defaulting Funders have an adequate remedy at law.

## **ARTICLE IX FORCE MAJEURE**

- 9.1 Force Majeure Defined. For purposes of this Agreement, "Force Majeure" means an event or circumstance beyond the reasonable control of, and without the fault or negligence of, a Funder or Permitting Project Manager claiming Force Majeure ("Affected Party"), which, despite the exercise of reasonable diligence, cannot be or be caused to be prevented, avoided or removed by such Affected Party including, to the extent satisfying the above requirements, acts of God; earthquake; abnormal weather condition; hurricane; flood; lightning; high winds; drought; peril of the sea; explosion; fire; war (declared or undeclared); military action; sabotage; riot; insurrection; civil unrest or disturbance; acts of terrorism; economic sanction or embargo; civil strike, work stoppage, slow-down, or lock-out that are of an industry or sector-wide nature and that are not directed solely or specifically at the Affected Party; the binding order of any Governmental Authority, provided that the Affected Party has in good faith reasonably

contested such order; the failure to act on the part of any Governmental Authority, provided that such action has been timely requested and diligently pursued; unavailability of equipment, supplies or products, but only to the extent caused by Force Majeure; failure of equipment, provided that the equipment has been operated and maintained in accordance with Good Utility Practice; and transportation delays or accidents, but only to the extent otherwise caused by Force Majeure; provided, however, that neither insufficiency of funds, financial inability to perform nor changes in market conditions shall constitute Force Majeure.

## 9.2 Effect of Force Majeure.

- (a) If an Affected Party is rendered wholly or partly unable to perform its obligations under this Agreement or its performance is delayed because of Force Majeure, such Affected Party shall be excused from, and shall not be liable for, whatever performance it is unable to perform or delayed in performing due to the Force Majeure to the extent so affected, provided that:
  - (i) The Affected Party, as soon as reasonably practical after the commencement of the Force Majeure, gives the other Funders (s) and/or the Project Manager prompt written notice thereof, including a description of the particulars of the Force Majeure;
  - (ii) The suspension of performance is of no greater scope and of no longer duration than is required by the Force Majeure; and
  - (iii) The Affected Party uses Commercially Reasonable Efforts to overcome and remedy its inability to perform as soon as reasonably practical after the commencement of the Force Majeure.
- (b) Notwithstanding anything in this Article IX to the contrary, no payment obligation arising under this Agreement prior to the date of an event of Force Majeure shall be excused by such event of Force Majeure.
- (c) Whenever an Affected Party is required to commence or complete any action within a specified period and is prevented or delayed by Force Majeure from commencing or completing such action within the specified period, such period shall be extended by an amount equal to the duration of such event of Force Majeure occurring or continuing during such period.

**ARTICLE X  
REPRESENTATIONS AND WARRANTIES**

10.1 Representations and Warranties of Idaho Power. Idaho Power represents and warrants to PAC and BPA as of the Effective Date as follows:

- (a) It is duly formed, validly existing and in good standing under the laws of the jurisdiction of its formation.
- (b) It has all requisite corporate power necessary to own its assets and carry on its business as now being conducted or as proposed to be conducted under this Agreement.
- (c) It has all necessary corporate power and authority to execute and deliver this Agreement and to perform its obligations under this Agreement, and the execution and delivery of this Agreement and the performance by it of this Agreement have been duly authorized by all necessary corporate action on its part.
- (d) The execution and delivery of this Agreement and the performance by it of this Agreement do not: (i) violate its organizational documents; (ii) violate any Governmental Requirements applicable to it; or (iii) result in a breach of or constitute a default of any material agreement to which it is a party.
- (e) This Agreement has been duly and validly executed and delivered by it and constitutes its legal, valid and binding obligation enforceable against it in accordance with its terms, except as the same may be limited by bankruptcy, insolvency or other similar laws affecting creditors' rights generally and by principles of equity regardless of whether such principles are considered in a proceeding at law or in equity.
- (f) All material Governmental Authorizations required by Governmental Requirements to have been obtained by it prior to the date hereof in connection with the due execution and delivery of, and performance by it of its obligations under, this Agreement, have been duly obtained or made and are in full force and effect.

10.2 Representations and Warranties of PAC. PAC represents and warrants to BPA and Idaho Power as of the Effective Date as follows:

- (a) It is duly formed, validly existing and in good standing under the laws of the jurisdiction of its formation.

- (b) It has all requisite corporate power necessary to own its assets and carry on its business as now being conducted or as proposed to be conducted under this Agreement.
- (c) It has all necessary corporate power and authority to execute and deliver this Agreement and to perform its obligations under this Agreement, and the execution and delivery of this Agreement and the performance by it of this Agreement have been duly authorized by all necessary corporate action on its part.
- (d) The execution and delivery of this Agreement and the performance by it of this Agreement do not: (i) violate its organizational documents; (ii) violate any Governmental Requirements applicable to it; or (iii) result in a breach of or constitute a default of any material agreement to which it is a party.
- (e) This Agreement has been duly and validly executed and delivered by it and constitutes its legal, valid and binding obligation enforceable against it in accordance with its terms, except as the same may be limited by bankruptcy, insolvency or other similar laws affecting creditors' rights generally and by principles of equity regardless of whether such principles are considered in a proceeding at law or in equity.
- (f) All material Governmental Authorizations required by Governmental Requirements to have been obtained by it prior to the date hereof in connection with the due execution and delivery of, and performance by it of its obligations under, this Agreement, have been duly obtained or made and are in full force and effect.

10.3 Representations and Warranties of BPA. BPA represents and warrants to PAC and Idaho Power as of the Effective Date as follows:

- (a) It is duly formed, validly existing and in good standing under the laws of the jurisdiction of its formation.
- (b) It has all requisite statutory and administrative power necessary to own its assets and carry on its business as now being conducted or as proposed to be conducted under this Agreement.
- (c) It has all necessary statutory and administrative power and authority to execute and deliver this Agreement and to perform its obligations under this Agreement, and the execution and delivery of this Agreement and the performance by it of this Agreement have been duly authorized by all necessary statutory or administrative action on its part.

- (d) The execution and delivery of this Agreement and the performance by it of this Agreement do not: (i) violate its organizational documents; (ii) violate any Governmental Requirements applicable to it; or (iii) result in a breach of or constitute a default of any material agreement to which it is a party.
- (e) This Agreement has been duly and validly executed and delivered by it and constitutes its legal, valid and binding obligation enforceable against it in accordance with its terms, except as the same may be limited by bankruptcy, insolvency or other similar laws affecting creditors' rights generally and by principles of equity regardless of whether such principles are considered in a proceeding at law or in equity.
- (f) All material Governmental Authorizations required by Governmental Requirements to have been obtained by it prior to the date hereof in connection with the due execution and delivery of, and performance by it of its obligations under, this Agreement, have been duly obtained or made and are in full force and effect.

**ARTICLE XI  
COMMON DEFENSE & LIMITATION OF LIABILITY**

11.1 Common Defense. The Funders shall, at such time as specified in this Section 11, enter into a Joint Defense Agreement that is consistent with applicable Governmental Requirements and that provides for the common defense, as well as payment for the common defense, including actual damages, for any and all suits, actions, liabilities, legal proceedings, claims, demands, losses, costs and expenses of whatsoever kind or character ( including reasonable attorneys' fees and expenses of third parties) of third parties, for injury or death of persons or physical loss of or damage to property of persons (other than of the Funders or the Permitting Project Manager) arising from the performance by the Permitting Project Manager of its obligations under this Agreement ("Claims"); provided, however, that the Funders shall not be obligated to enter into a Joint Defense Agreement or otherwise be responsible for any Claims arising from the Permitting Project Manager's own negligence or willful misconduct in connection with the performance of its obligations under this Agreement. The Joint Defense Agreement shall set forth the terms under which the Funders shall provide a common defense for the Claims described in this Section 11.1, including, but not limited to, the retention of appropriate legal counsel, advisors, and experts and the resolution of any such Claims. Each Funder shall contribute under the Joint Defense Agreement, in proportion to its Permitting Interest set forth in Exhibit D, or as otherwise mutually agreed to by the Funders in writing, to such common defense.



- 11.2 Notice and Participation. The Permitting Project Manager shall give the other Funders prompt written notice of any Claim upon the receipt of actual knowledge or information by the Permitting Project Manager of a Claim (the “Joint Defense Agreement Notice”). Upon the issuance of the Joint Defense Agreement Notice, the Funders and Permitting Project Manager shall use all Commercially Reasonable Efforts to agree to the terms of and enter into a Joint Defense Agreement consistent with the provisions of this Section 11 as soon as practicable. Except as otherwise provided in Section 11.1, during such period as the Funders shall not be a party to a Joint Defense Agreement but a Joint Defense Agreement Notice or Joint Defense Agreement Notices shall have been delivered, each of the Funders shall contribute funds and otherwise support the common defense of the Claims that are the subject of such Joint Defense Agreement Notice, in proportion to its Permitting Interest set forth in Exhibit D or as otherwise mutually agreed to by the Funders in writing, and during such period all costs incurred by or on behalf of the Permitting Project Manager for the defense or resolution of any such Claims (including, but not limited to, actual damages to be paid to resolve such Claims and reasonable attorneys’ fees and costs) shall be considered Project Costs and payable to the Permitting Project Manager in proportion to the Funders’ Permitting Interest set forth in Exhibit D and pursuant to the terms of this Agreement.
- 11.3 Control of Defense Prior to Joint Defense Agreement. After delivery of a Joint Defense Agreement Notice but before the Funders have entered into a Joint Defense Agreement, the Permitting Project Manager shall have the right to assume the defense of the Claim, with counsel designated by the Permitting Project Manager and reasonably satisfactory to the Funders, and contest or, with or without the prior consent of the Funders, settle such Claim, provided that the Permitting Project Manager shall not settle any Claim with respect to which it has sought or is entitled to seek recovery pursuant to Section 11.1 unless it has obtained the prior written consent of the Funders.
- 11.4 Failure to Provide Timely Joint Defense Agreement Notice. The Funders shall have no obligation to enter into a Joint Defense Agreement for any Claim for which a Joint Defense Agreement Notice is not timely provided, but only to the extent that such failure to give such notice materially and prejudicially impairs the ability of the Funders to jointly defend the applicable Claim. To the extent that failure to provide a timely Joint Defense Agreement Notice materially and prejudicially impairs a Funder’s ability to jointly defend the applicable Claim, the Permitting Project Manager shall not be entitled to recover any costs incurred by or on behalf of the Permitting Project Manager in respect of such Claim as such Claim shall not be considered a Project Cost.
- 11.5 Survival of Obligation. The duty to provide for the common defense and enter into a Joint Defense Agreement shall continue in full force and effect for a period of one year after the expiration or termination of this Agreement, unless a Funder withdraws pursuant to Article VII in which case the duties and obligations under Sections 11.1 and 11.2 shall

not apply to the Withdrawing Funder for any Claim where it receives the Joint Defense Agreement Notice after the Notice of Withdrawal.

11.6 Limitation on Liability.

- (a) In the case of breach or default by a Funder or Permitting Project Manager hereunder for which an express remedy or measure of damages is provided, such express remedy or measure of damages shall be the sole and exclusive remedy, and the Funder's or Permitting Project Manager's liability shall be limited as set forth in such provision and all other remedies or damages at law or in equity are hereby irrevocably waived, unless the provision in question provides that the express remedies are in addition to other remedies that may be available. Unless otherwise provided in this Agreement, if no remedy or measure of damages is expressly provided herein (and a remedy or damages is otherwise permitted), then the Funder's or Permitting Project Manager's liability shall be limited to direct actual damages only, and such direct actual damages shall be the sole and exclusive remedy and all other remedies or damages at law or in equity are hereby irrevocably waived.
- (b) Notwithstanding any provision in this Agreement to the contrary, no Funder, whether in its capacity as Funder or Permitting Project Manager, shall be liable under this Agreement in any action at law or in equity, whether based on contract, tort or strict liability or otherwise, for any special, incidental, indirect, exemplary, punitive or consequential damages or losses, including any loss of revenue, income, profits or investment opportunities, loss of the use of equipment, or the cost of temporary equipment or services, provided that any Claims shall not be excluded under this Section 11.6(b) as special, incidental, indirect, exemplary, punitive or consequential damages or losses.

**ARTICLE XII  
PROPRIETARY INFORMATION**

- 12.1 Disclosure of Proprietary Information Prohibited. The Funders agree that all information exchanged in connection with this Agreement (but not this Agreement) shall be treated as "Confidential Information" subject to the terms and conditions of the Nondisclosure Agreement, dated March 15, 2010, between the Funders (the "Confidentiality Agreement"), the provisions of which are incorporated herein by reference.
- 12.2 Publicity. Each Funder shall provide reasonable advance notice to, and shall consult with, the other Funders of any planned press release, public statement or meeting with the public or Governmental Authorities by such Funder in which discussion of the Permitting Project is expected to be a material part, provided that nothing herein shall prevent, limit, or delay any Funder from making any disclosure required by Governmental

Requirements or Governmental Authorizations. Each Funder shall provide notice to the other Funders as promptly as possible of the nature and content of any significant unplanned communications about the Permitting Project with the public or with Governmental Authorities. Notwithstanding the foregoing, when the information provided at a meeting is part of a previously agreed to public affairs plan or otherwise previously approved for disclosure by the Funders, notice of each such meeting or communication is not required.

### **ARTICLE XIII DISPUTE RESOLUTION**

- 13.1 Exclusive Procedure. Any dispute, controversy or claim arising out of or relating to this Agreement or the breach, interpretation, termination, performance or validity of this Agreement (each, a “Dispute”) shall be resolved pursuant to the procedures of this Article XIII.
- 13.2 Dispute Notices. If a Dispute arises between the Funders or between the Permitting Project Manager and the Non-Permitting Project Manager Funders, then any Funder or Permitting Project Manager to such Dispute (each, a “Disputing Party”) may provide written notice thereof to the other Disputing Parties, including a detailed description of the subject matter of the Dispute (the “Dispute Notice”). Any Disputing Party may seek a preliminary injunction or other provisional judicial remedy to the extent allowed by law if such action is necessary to prevent irreparable harm or preserve the status quo, in which case the Disputing Party nonetheless will continue to pursue resolution of the Dispute pursuant to this Article XIII.
- 13.3 Informal Dispute Resolution.
- (a) The Disputing Parties shall make a good faith effort to resolve the Dispute by prompt negotiations between and/or among each Disputing Party’s representative so designated in writing to the other Disputing Party or Disputing Parties (each a “Manager”). If the Managers are not able to resolve the Dispute within thirty (30) days after the date of the Dispute Notice, they shall refer the matter to the designated senior officers of the Disputing Parties (the “Executives”), who shall have authority to settle the Dispute. If the Executives are not able to resolve the Dispute within sixty (60) days after the date of the Dispute Notice, then the Dispute shall be resolved pursuant to Section 13.4.
  - (b) All communications and writings exchanged between and/or among the Disputing Parties in connection with these negotiations shall be confidential and shall not be used or referred to in any subsequent binding adjudicatory process between the

Disputing Parties, either with respect to the current Dispute or any future Dispute between the Funders and/or the Permitting Project Manager.

- 13.4 Remedies. If any Dispute arising under this Agreement cannot be resolved as provided in Section 13.3, then any Disputing Party may, in its sole discretion, pursue any available remedy at law or equity.
- 13.5 Continued Performance. During the pendency of any Dispute, each Funder and the Permitting Project Manager shall continue to perform all of its respective obligations under this Agreement.

#### **ARTICLE XIV MISCELLANEOUS**

- 14.1 Counterparts. This Agreement may be executed in counterparts, each of which shall be considered an original, but all of which together shall constitute the same instrument. Electronic transmission of any signed original document, and retransmission of any signed electronic transmission, shall be the same as delivery of an original. At the request of any Funder or the Permitting Project Manager, the other Funders or Permitting Project Manager, as applicable, will confirm electronically transmitted signatures by signing an original document.
- 14.2 Headings. The Article and Section headings used in this Agreement (including headings used in any Exhibits attached hereto) are for convenience of reference only and shall not affect the construction of the Agreement or limit the scope of the particular provisions to which they refer.
- 14.3 Waiver. No waiver by any Funder of any breach or default by any other Funder or the Permitting Project Manager of its obligations herein shall be construed as a waiver of any other breach or default whether of a like kind or different nature. Any delay by a Funder, less than any applicable statutory period of limitations, in asserting or enforcing any rights or remedies under this Agreement shall not be deemed a waiver of such rights or remedies. Failure of any Funder or Permitting Project Manager to enforce any provision hereof shall not be construed to waive such provision, or to affect the validity of this Agreement or any part hereof, or the right of any Funder thereafter to enforce each and every provision hereof.
- 14.4 Relationship of Funders.
- (a) Several and not Joint. The covenants, obligations, and liabilities of the Funders are intended to be several and not joint or collective, and nothing herein contained shall be construed to create an association, joint venture, trust or partnership, or to impose a trust or partnership covenant, obligation or liability on or with regard to

any of the Funders. Each Funder shall be individually responsible for its own covenants, obligations and liabilities as herein provided. No Funders shall be under the control of, or shall be deemed to control, the other Funders. No Funder shall have a right or power to bind any other Funder without such other Funder's express written consent.

- (b) No Partnership. None of the provisions of this Agreement shall be deemed to constitute a partnership among or between the Funders and none of the Funders shall have any authority to bind the other Funders in any way, and the Funders agree that the arrangement contemplated by this Agreement shall be excluded from subchapter K of the U.S. Internal Revenue Code of 1986, as amended ("Subchapter K"). Idaho Power and PAC agree to report their respective Permitting Interest of any items of income, deductions and credits of the arrangement contemplated by this Agreement in a manner consistent with the exclusion of such arrangement from Subchapter K beginning with the taxable year which includes the Effective Date.
- (c) Additional Funders. This Agreement may be amended to include one or more additional parties as Funders upon mutual written agreement of the then current Funders.

14.5 Severability. In the event that any provision of this Agreement or the application thereof becomes or is declared by a court of competent jurisdiction to be illegal, void or unenforceable, the remainder of this Agreement will continue in full force and effect and the application of such provision to other persons or circumstances will be interpreted so as reasonably to effect the intent of Idaho Power, PAC, and BPA. The Funders and Permitting Project Manager further agree to replace such illegal, void or unenforceable provision of this Agreement with a valid and enforceable provision that will achieve, to the maximum extent possible, the economic, business and other purposes of such illegal, void or unenforceable provision.

14.6 Binding Effect. Upon execution by all Funders, this Agreement shall be binding upon each of the Funders and the Permitting Project Manager and their respective successors and permitted assigns. This Agreement is null and void unless it is executed by all Funders.

14.7 Amendments. This Agreement shall not be modified, amended, supplemented or otherwise changed in any respect except by a written document signed by the Funders and the Permitting Project Manager.

14.8 No Third Party Beneficiary. This Agreement is for the exclusive benefit of the Funders and the Permitting Project Manager, and is not intended to nor shall be construed to

confer upon or give to any Person (other than the Funders and the Permitting Project Manager) any rights or remedies under or by reason of this Agreement or any transaction contemplated herein.

14.9 Entire Agreement. This Agreement, including the Exhibits and Schedule 2.2 attached hereto, constitutes the entire agreement of the Funders and the Permitting Project Manager with respect to the transactions contemplated by this Agreement and supersedes all prior agreements (other than the Confidentiality Agreement), oral or written, with respect thereto.

14.10 Notices.

- (a) Except as otherwise provided herein, any notice, demand, request or other communication required or permitted to be given pursuant to this Agreement shall be in writing and signed by the Funder or Permitting Project Manager giving such notice, demand, request or other communication and shall be hand delivered or sent by certified mail, return receipt requested, or overnight courier to the other Funders and/or Permitting Project Manager at the address set forth below:

If to Idaho Power

(as Funder or Permitting Project Manager)

Idaho Power Company  
1221 West Idaho Street  
Boise, ID 83702  
Attn: Manager, Delivery Projects  
Telephone: 208-388-2741

With a copy to:

Idaho Power Company  
1221 West Idaho Street  
Boise, ID 83702  
Attn: Legal Department  
Telephone: 208-388-2300

If to PAC

(as Funder)

PacifiCorp  
825 NE Multnomah Street, Ste. 1600  
Portland, OR 97232  
Attn: Vice President, Transmission  
Telephone: 503-813-6712

With a copy to:

PacifiCorp  
825 NE Multnomah Street, Ste. 1800  
Portland, OR 97232  
Attn: Legal Department  
Telephone: 503-813-5854

If to BPA

(as Funder)

Bonneville Power Administration  
5411 NE Highway 99  
Vancouver, WA 98663  
Attn: Senior Vice President,  
Transmission Services  
Telephone: 360-418-2122

With a copy to:

Bonneville Power Administration  
905 NE 11<sup>th</sup> Avenue  
Portland, OR 97232  
Attn: Office of General Counsel  
Telephone: 503-230-4201

- (b) Each Funder and the Permitting Project Manager shall have the right to change the place to which any notice, demand, request or other communication shall be sent or delivered by similar notice sent in like manner to the other Funder(s) and Permitting Project Manager. The effective date of any notice, demand, request or other communication issued pursuant to this Agreement shall be when: (i) delivered to the address of the Funders or Permitting Project Manager personally, by messenger, by a nationally or internationally recognized overnight delivery service or otherwise; or (ii) received or rejected by the Funders or Permitting Project Manager, if sent by certified mail, return receipt requested, in each case, addressed to the Funders or Permitting Project Manager at its address and marked to the attention of the person designated above (or to such other address or person as a Funders or Permitting Project Manager may designate by notice to the Funders and/or Permitting Project Manager effective as of the date of receipt by such Funders).

14.11 Choice of Law. This Agreement shall be governed by and construed in accordance with the laws of the State of Idaho, without giving effect to conflicts of laws principles. Notwithstanding the foregoing, for so long as BPA is a Funder, this Agreement shall be governed and construed in accordance with the laws of the United States.

- 14.12 Further Assurances. Each Funder and the Permitting Project Manager agrees to execute and deliver from time to time such additional documents, and to take such additional actions, as may be reasonably required by the other Funders or the Permitting Project Manager to give effect to the purposes and intent hereof.
- 14.13 Conflict of Interest. Nothing in this Agreement shall prohibit any Funder or the Permitting Project Manager from engaging in or possessing any interest in other projects or business ventures of any nature and description, independently or with others.

**[SIGNATURE PAGE TO FOLLOW]**



IN WITNESS WHEREOF, the Funders hereto have caused this Boardman to Hemingway Transmission Project Joint Permit Funding Agreement to be executed by their respective authorized representatives on the day and year first above written.

IDAHO POWER COMPANY,  
as Funder and Permitting Project Manager

By   
Date 1/12/12

PACIFICORP,  
as Funder

By \_\_\_\_\_  
Date \_\_\_\_\_

BONNEVILLE POWER ADMINISTRATION,  
as Funder

By \_\_\_\_\_  
Date \_\_\_\_\_

IN WITNESS WHEREOF, the Funders hereto have caused this Boardman to Hemingway Transmission Project Joint Permit Funding Agreement to be executed by their respective authorized representatives on the day and year first above written.

IDAHO POWER COMPANY,  
as Funder and Permitting Project Manager

By \_\_\_\_\_

Date \_\_\_\_\_

PACIFICORP,  
as Funder

By \_\_\_\_\_

Date \_\_\_\_\_

BONNEVILLE POWER ADMINISTRATION,  
as Funder

By Bruce Schuster

Date 1/12/12

IN WITNESS WHEREOF, the Funders hereto have caused this Boardman to Hemingway Transmission Project Joint Permit Funding Agreement to be executed by their respective authorized representatives on the day and year first above written.

IDAHO POWER COMPANY,  
as Funder and Permitting Project Manager

By \_\_\_\_\_

Date \_\_\_\_\_

PACIFICORP,  
as Funder

By  \_\_\_\_\_

Date 1/12/12 \_\_\_\_\_

BONNEVILLE POWER ADMINISTRATION,  
as Funder

By \_\_\_\_\_

Date \_\_\_\_\_

## Exhibit A

### Description of Boardman to Hemingway Transmission Project

The development, siting, and acquisition of permits and Rights-of-Way over public land, construction, operation, and maintenance of a single circuit 500kV overhead electric transmission line and facilities beginning near Boardman, Oregon, and terminating near Melba, Idaho

Exhibit B

Permit Funding Schedule

The cost allocation of the Payment Schedule is determined by each Funder's Permitting Interest as of the Effective Date, which shall be calculated using the methodology described in Exhibit D.

Table B.1. Permit Funding Payment Schedule

Payment	Type	Idaho Power Amount	BPA Amount	PAC Amount	Date
1	Mandatory Payment	\$1,608,839	\$ 1,838,673	\$4,137,015	Due Twenty (20) days following the Effective Date
2	Mandatory Payment	\$1,608,839	\$ 1,838,673	\$4,137,015	10/1/2012
3	Mandatory Payment*	\$2,255,155	\$ 2,577,320	\$5,798,969	3/1/2013
4	Mandatory Payment	\$804,420	\$ 919,337	\$2,068,508	10/1/2013
5	Completion Funding Payment*	\$3,945,498	\$ 4,509,141	\$10,145,567	Due One hundred twenty (120) days following publication of Final BLM Record of Decision in the <i>Federal Register</i>
6	Final Expense True-up	TBD	TBD	TBD	Two hundred ten (210) days following Notice of Payment

\* The payment amounts shown for Mandatory Payments 3 and Completion Funding Payment 5 include estimated AFUDC accruals. The actual invoice may differ from the amount shown based on the actual monthly AFUDC accrued during the period.

## Exhibit C

### Project Costs

Project Costs are included as part of the payments set forth in Exhibit B. Project Costs associated with Governmental Authorizations and other necessary work include as relating to the Permitting Project, but are not limited to:

- i. Governmental Authorization costs;
- ii. NEPA compliance activity;
- iii. public involvement activity;
- iv. reasonable attorney's fees;
- v. third party contractor work for EIS development and support of the Boardman to Hemingway Transmission Project, including, but not limited to, the NEPA process;
- vi. Preliminary design and engineering work in support of the Boardman to Hemingway Transmission Project, including, but not limited to, the NEPA process;
- vii. Any other costs approved by the Permit Funding Committee associated with services to be coordinated by the Permitting Project Manager (and not provided for above), as set forth in this Agreement; and
- viii. Overheads incurred by the Permitting Project Manager for the Permitting Project will be calculated at a 10% rate.

## Exhibit D

### Permitting Interest Work Paper

Each Funder is assigned a Permitting Interest based on the annual weighted capacity expressed in the Permitting Project. The Permitting Interest is determined by the sum of a Funder's eastbound capacity interest and westbound capacity interest, divided by the total of all Funders' eastbound and westbound capacity interests.

**Table 1: Boardman to Hemingway Weighted Interest**

	<b>Total Requested Capacity (MW)</b>	<b>Idaho Power Capacity Interest (MW)</b>	<b>BPA Capacity Interest (MW)</b>	<b>PacifiCorp Capacity Interest (MW)</b>
<b>West to East</b>	<b>1050</b>	350*	400*	300
<b>East to West</b>	<b>600</b>	0	0	600
<b>Permitting Interest</b>		21.21%	24.24%	54.55%

\* Seasonally shaped capacity.

The capacity interests are based on:

- Idaho Power's capacity interest is seasonally shaped with 500 MW of eastbound capacity during the months of April through September and 200 MW of eastbound capacity during the months of January through March and October through December.
- BPA's capacity interest is seasonally shaped with 250 MW of eastbound capacity during the months of April through September and 550 MW of eastbound capacity during the months of January through March and October through December.
- PacifiCorp's capacity interest is constant throughout the entire calendar year.
- The sum of all Permitting Interest will equal one hundred percent.
- The sum of capacity interest may or may not equal the total rated capacity of project.

Additional Considerations:

- If the capacity interests are less than the total rated capacity of the Boardman to Hemingway Transmission Project, the unallocated capacity will be divided among the Funders based on the Funders Permitting Interest.
- The total rated capacity of the Boardman to Hemingway Transmission Project is subject to the results of the WECC Rating Process.

**Assumed B2H Ratings and Unassigned Capacity**

	<b>Assumed Rating (MW)</b>	<b>Unallocated Capacity (MW)</b>
<b>West to East</b>	1050	0
<b>East to West</b>	1000	400

**Allocation of Unassigned Capacity**

	<b>Percentage</b>	<b>Allocation of W-E Unassigned Capacity (MW)</b>	<b>Allocation of E-W Unassigned Capacity (MW)</b>
<b>IPCO</b>	21.21%	0	85
<b>BPA</b>	24.24%	0	97
<b>PAC</b>	54.55%	0	218



## Schedule 2.2

### Project Permitting Objectives and Timetable

- National Environmental Policy Act (NEPA) – BLM Lead Agency
  - BLM Publishes Draft Environmental Impact Statement – Q1 of 2013
  - BLM Publishes Final Environmental Impact Statement – Q2 of 2014
  - BLM issues Record of Decision – Q4 of 2014
  - BLM issues Notice to Proceed – Q4 of 2014
- Oregon Energy Facility Siting Council (EFSC)
  - File preliminary Application for Site Certificate (ASC) – Q4 of 2012
  - File Complete ASC – Q2 of 2013
  - EFSC issues Proposed Order & Notice of Contested Case – Q3 of 2013
  - EFSC issues Final Order Issuing Site Certificate & Site Certificate Review – Q2 of 2014
  - EFSC issues Final Site Certificate – Q1 of 2015
  - EFSC issues Notice to Proceed – Q2 of 2015

**Appendix D-4. B2H MOU**

See the attached document.

This page left blank intentionally.

## MEMORANDUM OF UNDERSTANDING

This Memorandum of Understanding (this “MOU”) is entered into as of January 12th, 2012 (the “Effective Date”), by and among PacifiCorp, an Oregon corporation (“PacifiCorp”), Idaho Power Company, an Idaho corporation (“Idaho Power”), and the Bonneville Power Administration, a United States government power marketing agency (“BPA”). PacifiCorp, Idaho Power and BPA are sometimes referred to in this MOU individually as a “Party” and, collectively, as the “Parties”.

### RECITALS

- A. PacifiCorp owns and operates facilities for the transmission of electric power and energy in interstate commerce (“PacifiCorp Transmission System”);
- B. BPA owns and operates facilities for the transmission of electric power and energy in interstate commerce (“BPA Transmission System”);
- C. Idaho Power owns and operates facilities for the transmission of electric power and energy in interstate commerce (“Idaho Power Transmission System”);
- D. The PacifiCorp Transmission System, BPA Transmission System and the Idaho Power Transmission System, are sometimes referred to in this MOU individually as a “Transmission System” and, collectively, the “Transmission Systems”;
- E. PacifiCorp, BPA and Idaho Power each have an independent obligation or authority to plan for and expand their respective Transmission Systems based upon the needs of their native load customers, network customers, and eligible customers that agree to expand the Transmission System;
- F. The Parties are considering whether to permit and construct new transmission projects in the West, including, but not limited to, jointly owning the proposed Boardman to Hemingway Transmission Project, which is a 500kV single circuit transmission line that is proposed to run from Boardman, Oregon to Melba, Idaho that if constructed could assist Idaho Power, PacifiCorp, and BPA in fulfilling their respective service obligations;
- G. The Parties desire to (i) explore alternatives to establish eastern Idaho load service from Hemingway in exchange for similar service from the BPA Transmission System and (ii) consider whether to replace certain transmission arrangements involving existing assets with joint ownership transmission arrangements and other alternative transmission arrangements pursuant to definitive agreements mutually satisfactory to the Parties (collectively, the “Definitive Agreements”);
- H. Idaho Power and PAC acknowledge that BPA is considering various transmission and other alternatives to meet its service obligations in eastern Idaho, including alternatives that would involve Open Access Transmission Service, and that BPA’s decision whether to participate

in development and construction of the Boardman to Hemingway Transmission Project may be based on BPA's evaluation of such alternatives; and

- I. The Parties are entering into this MOU to set forth a process by which the Parties will negotiate in good faith to attempt to reach mutually satisfactory agreement on the terms and conditions of the Definitive Agreements.

**NOW THEREFORE**, the Parties agree as follows:

1. Effective Date; Term.

- (a) This MOU shall become effective on January 12<sup>th</sup> 2012 (the "Effective Date").

- (b) This MOU shall remain in effect until December 31, 2014, at which time it will terminate (the "Termination Date"), unless one of the following occurs:

- (i) All Parties execute and deliver each of the Definitive Agreements before the Termination Date, in which case the Termination Date shall be the date that the last Definitive Agreement is fully executed;

- (ii) The Parties, by mutual written agreement, agree to extend the Termination Date, in which case the Termination Date shall be a mutually agreed date after December 31, 2014;

- (iii) The Parties, by mutual written agreement, agree that the MOU will be terminated before December 31, 2014, in which case the Termination Date shall be a mutually agreed date before December 31, 2014; or

- (iv) Two Parties exercise their unilateral right to withdraw from this MOU pursuant to Section 2, in which case the Termination Date shall be thirty (30) days after the second withdrawing Party provides written notice of withdrawal.

- (c) Upon termination, this MOU shall have no further force or effect, provided that the rights and obligations set forth in Sections 3(f) and 4 shall survive the termination of this MOU and remain in full force and effect.

2. Unilateral Withdrawal Rights.

Any Party may withdraw from this MOU at any time, for any reason whatsoever or for no reason, after thirty (30) days written notice to the other Parties of the intent to do so.

3. Responsibilities of the Parties.

(a) During the term of this MOU, the Parties meet regularly (either by teleconference or in person), proceed diligently and in good faith to negotiate mutually satisfactory terms of the Definitive Agreements and all such other agreements and documents necessary to fully document the transactions contemplated by the Definitive Agreements by no later than December 31, 2014. The Parties seek to meet the following milestones:

- (i) By no later than January 15, 2012, the Parties commence regular meetings to discuss the subject matters described in Exhibit A hereto;
- (ii) By no later than March 31, 2012, the Parties identify scenarios and any potential assets, the methodology for valuing capacity and assets, and any required criteria or conditions for execution of Definitive Agreements to achieve the alternatives described in Exhibit A.
- (iii) By no later than September 30, 2012, BPA informs Idaho Power and PacifiCorp whether it intends to pursue a plan of service for its eastern Idaho load service requirements that would require the availability of project(s) contemplated herein.

(b) Each Party shall select a senior-level representative (each, a "Representative") to be responsible for coordinating activities under this MOU. Each Party commits to provide its Representative with the support and resources necessary to further the purposes of this MOU.

(c) Any Party would be free to use the rights granted it by another Party under a Definitive Agreement for any legitimate transmission service permitted by its respective OATT, provided, however, that rights granted under a Definitive Agreement would not include any additional rights to receive transmission service that would require use of any portion of the other's system not specifically acknowledged in a Definitive Agreement.

(d) Based on the information currently known to the Parties, it is proposed that negotiations of the Definitive Agreements include the alternatives set forth in Exhibit A. Exhibit A sets forth the Parties' current general understanding with respect to these alternatives, but is not intended to represent a binding agreement or final contractual language, or to address every provision which the Parties may wish to incorporate into the Definitive Agreements.

(e) Each of the Parties acknowledges and agrees that each other Party's decision to proceed with the Definitive Agreements and any other decision with respect to the Definitive Agreements is within such Party's sole and absolute discretion.

(f) The Parties agree that all information exchanged in connection with this MOU (but not this MOU) shall constitute, and be treated by the Parties as, “Confidential Information” subject to the terms and conditions of that certain Nondisclosure Agreement, dated as of March 15, 2010, between the Parties (the “Confidentiality Agreement”), the provisions of which are incorporated herein by reference.

4. General Provisions.

(a) This MOU is not a binding or enforceable contract but is instead an understanding that broadly states the expected responsibilities and objectives of the Parties.

(b) Nothing in this MOU shall limit, repeal, or in any manner modify the existing legal rights, privileges, and duties of each of the Parties as provided by agreement (including the Confidentiality Agreement), statute or any other law or applicable court or regulatory decision. Further, the concepts contemplated by this MOU and any Definitive Agreements, if any, are intended to be consistent with applicable statutes, rules, orders, regulations or other similar requirements or obligations.

(c) Each of the Parties acknowledges and agrees that no Party shall be liable to the other Parties for any claim, loss, cost, liability, damage or expense, including any direct damage or any special, indirect, exemplary, punitive, incidental or consequential loss or damage (including any loss of revenue, income, profits or investment opportunities or claims of third party customers), arising out of or directly or indirectly related to a Party’s decision to terminate this MOU, the other Parties’ performance or failure thereof under this MOU, or any other decision with respect to proceeding or not proceeding with the Definitive Agreements.

(d) This MOU may not be amended except in writing signed by the Parties.

(e) Any waiver on the part of a Party to this MOU of any provision or condition of this MOU must be in writing signed by each Party to be bound by such waiver, shall be effective only to the extent specifically set forth in such writing and shall not limit or affect any rights with respect to any other or future circumstance.

(f) This MOU is for the sole and exclusive benefit of the Parties and shall not create a contractual relationship with, or cause of action in favor of, any third party.

(g) Nothing in this MOU will be deemed to establish any right or provide a basis for any action, either legal or equitable, by any person or class of persons against the United States, its departments, agencies, instrumentalities or entities, or its officers or employees, challenging a government action or failure to act.

(h) Nothing in this MOU will be construed as limiting or affecting in any way the authority or responsibility of the Parties to perform within their authorities, and nothing in this MOU shall be construed as committing the Parties to take any action concerning the items identified in Exhibit A before they have complied with all applicable statutes and regulations such as the National Environmental Policy Act (“NEPA”).

(i) Each Party shall be solely responsible for and shall pay its own costs and expenses incurred by it in connection with the negotiation of this MOU, the Definitive Agreements and all other agreements, documents and instruments related hereto and thereto, including all legal fees and expenses and expenses associated with such Party's own due diligence activities.

(j) Whenever this MOU requires or provides that (i) a notice be given by a Party to another Party or (ii) a Party's action requires the approval or consent of the other Parties, such notice, consent or approval shall be given in writing and shall be given by personal delivery, by recognized overnight courier service, or by certified mail (return receipt requested), postage prepaid, to the recipient thereof at the address given for such Party as set forth below, or to such other address as may be designated by notice given by any Party to the other Parties in accordance with the provisions of this Section 4(j):

If to PacifiCorp:

PacifiCorp  
825 NE Multnomah Street, Suite 1600  
Portland, OR 97232  
Attention: Vice President Transmission Services  
Fax No.: (503) 813-6893

If to Idaho Power:

Idaho Power  
1221 West Idaho Street  
Boise, Idaho 83702  
Attention: Manager Delivery Planning  
Fax No.: 208-388-6647

If to BPA:

Bonneville Power Administration  
5411 NE Highway 99  
Vancouver, Washington 98663  
Attention: Senior Vice President, Transmission Service  
Fax No.: 360 418-8433

Each notice, consent or approval shall be conclusively deemed to have been given (A) on the day of the actual delivery thereof, if given by personal delivery or overnight delivery, and (B) date of delivery shown on the receipt, if given by certified mail (return receipt requested).

Each Party shall have the right to change the place to which any notice, demand, request or other communication shall be sent or delivered by similar notice sent in like manner to the other Parties.



(k) This MOU may be executed in one or more counterparts (including by facsimile or a scanned image), each of which when so executed shall be deemed to be an original, and all of which shall together constitute one and the same instrument.

(l) Nothing contained in this MOU shall be construed as creating a corporation, company, partnership, association, joint venture or other entity, nor shall anything contained in this MOU be construed as creating or requiring any fiduciary relationship between the Parties. No Party shall be responsible hereunder for the acts or omissions of the other Party. Nothing herein shall preclude a Party from taking any action (or have its affiliates take any action) with respect to any other transmission project, including any such project that may compete with the Project.

(m) Unless otherwise expressly provided, for purposes of this MOU, the following rules of interpretation shall apply:

(i) any reference in this MOU to gender includes all genders, and the meaning of defined terms applies to both the singular and the plural of those terms;

(ii) the insertion of headings are for convenience of reference only and do not affect, and will not be utilized in construing or interpreting, this MOU;

(iii) all references in this MOU to any "Section" are to the corresponding Section of this MOU unless otherwise specified;

(iv) words such as "herein," "hereinafter," "hereof," and "hereunder" refer to this MOU (including the Exhibits to this MOU) as a whole and not merely to a subdivision in which such words appear unless the context otherwise requires; and

(v) the word "including" or any variation thereof means "including, without limitation" and does not limit any general statement that it follows to the specific or similar items or matters immediately following it.

**[SIGNATURE PAGE TO FOLLOW]**

Execution Copy  
BPA Contract Number 12TX-15584

IN WITNESS WHEREOF, each of the Parties has caused its duly authorized officer to execute this Memorandum of Understanding as of the date first above written.

**PACIFICORP**

By: \_\_\_\_\_  
Name:  
Title:

**IDAHO POWER COMPANY**

By:  \_\_\_\_\_  
Name: David B. Winer  
Title: EVP & COO

**BONNEVILLE POWER ADMINISTRATION**

By: \_\_\_\_\_  
Name:  
Title:

Execution Copy  
BPA Contract Number 12TX-15584

IN WITNESS WHEREOF, each of the Parties has caused its duly authorized officer to execute this Memorandum of Understanding as of the date first above written.

**PACIFICORP**

By:   
Name: PATRICK REITEN  
Title: PRESIDENT/CEO

**IDAHO POWER COMPANY**

By: \_\_\_\_\_  
Name:  
Title:

**BONNEVILLE POWER ADMINISTRATION**

By: \_\_\_\_\_  
Name:  
Title:

Execution Copy  
BPA Contract Number 12TX-15584

IN WITNESS WHEREOF, each of the Parties has caused its duly authorized officer to execute this Memorandum of Understanding as of the date first above written.


**PACIFICORP**

By: \_\_\_\_\_  
Name:  
Title:

**IDAHO POWER COMPANY**

By: \_\_\_\_\_  
Name:  
Title:

**BONNEVILLE POWER ADMINISTRATION**

By:   
Name: Brian Silverstein  
Title: Senior Vice-President, Transmission Services

## EXHIBIT A

### PRELIMINARY ALTERNATIVES FOR NEGOTIATION

This Exhibit A identifies the preliminary alternatives to be explored in negotiations under this MOU of the Definitive Agreements. The preliminary alternatives described in this Exhibit A are intended to be consistent with and subject to (i) all applicable statutory and governmental obligations of the Parties, including, as relating to PacifiCorp and Idaho Power, state and Federal Energy Regulatory Commission rules, regulations and orders; (ii) stakeholder and customer interests; and (iii) the Western Electricity Coordinating Council Three-phase rating process.

The Parties envision that PacifiCorp and Idaho Power may agree to jointly purchase and sell assets to achieve the objectives of the alternatives described in this Exhibit A. Any purchase and sale of existing assets between PacifiCorp and Idaho Power may involve some or all of the assets currently defined in existing contracts between Idaho Power and PacifiCorp, including, but not limited to, the Second Restated and Amended Transmission Facilities Agreement, Restated Transmission Service Agreement and the Agreement for Interconnection and Transmission Services. The service arising from any alternative may or may not be contingent upon the timing or physical construction of new assets.

#### Alternative 1:

- BPA would obtain a network service option from the Hemingway substation to the existing BPA service points in eastern Idaho. Idaho Power would sell and PacifiCorp would acquire Idaho Power's existing assets necessary to provide BPA's long-term load service.
- The Parties' intent is to minimize potential rate pancakes.
- BPA would work to plan an amount of BPA Transmission System capacity sufficient to enable PacifiCorp and Idaho Power to utilize their capacity shares (up to 650 MW in total) of the Boardman to Hemingway transmission project pursuant to standard OATT terms and conditions.

#### Alternative 2:

- Idaho Power and PacifiCorp, in combination, would provide BPA 600 MW of firm eastbound ownership rights of assets or other terms and conditions associated with the combined systems of Idaho Power and PacifiCorp in southern Idaho for the primary purpose of serving the BPA service points in eastern Idaho.
- BPA would provide to PacifiCorp and Idaho Power equivalent value of capacity rights, ownership rights of assets or other terms and conditions associated with the BPA Transmission System to the western terminus of the Boardman to Hemingway

Transmission Project, or other interconnection points jointly determined by the Parties. Such rights would originate at BPA's NW Market Hub (Mid-C) unless alternatives can be accommodated to serve load elsewhere over the BPA Transmission System.

- To achieve the objectives described in Alternative 2, the Parties would evaluate and consider interim measures and final approaches, including but not limited to the joint ownership of portions of the Gateway West Project, with BPA's minimum eastbound firm ownership rights of 250 MW, combined with the balance of ownership rights on a combination of Idaho Power and PacifiCorp's existing systems, as required to establish ownership rights from the Hemingway substation to BPA's existing eastern Idaho load points.

This page left blank intentionally.

**Appendix D-5. NTTG studies**

See the attached document.



This page left blank intentionally.



**NTTG 2016-2017**  
**REVISED DRAFT FINAL**  
**REGIONAL TRANSMISSION PLAN**  
**Draft 09.01.17**

Note: this is a draft report and may change as a result of stakeholder comments or edits by NTTG

**Date, 2017**

**Executive Summary ..... 3**

**The Northern Tier Transmission Group ..... 4**

**Participating Utilities..... 6**

**Purpose of the Plan ..... 6**

**Plan Development Process..... 6**

**Biennial Cycle..... 7**

**Biennial Study Plan..... 7**

**Study Methodology ..... 8**

        Production-Cost Modeling ..... 9

        Power-Flow Cases ..... 9

**Data Submission ..... 10**

        Forecasted Loads ..... 11

**Public Policy Consideration Scenario Requests ..... 13**

**Regional Economic Study Requests ..... 13**

**Initial Regional Transmission Plan Development ..... 13**

**Interregional Project Coordination..... 15**

**Stress-conditioned Case Study Results ..... 17**

        Stressed Hours for Study with Production-Cost Modeling ..... 17

**Development of Change Cases ..... 20**

**Change Case Results ..... 20**

        High Southern Idaho Import Case..... 23

        High Southern Idaho Export Case ..... 23

        High Wyoming Wind Case..... 24

        Interregional Transmission Projects ..... 24

**Reliability Conclusions..... 24**

**Economic Evaluations..... 25**

        Capital-related Cost Metric..... 25

        Energy-loss Metric ..... 25

        Reserve Metric..... 25

        Economic Metric Analysis Conclusion..... 26

**Planning Process Flow Map (Coming)..... 27**

**Final Regional Transmission Plan ..... 27**

**Cost Allocation ..... 28**

**Next Steps..... 28**

**NTTG 2016-2017 Regional Transmission Plan Supporting Materials ..... 29**

**Glossary ..... 29**

## Executive Summary

Would it be more efficient or cost-effective to meet future transmission needs in the Northern Tier Transmission Group (NTTG) footprint through a regional planning framework rather than the aggregate of local planning processes<sup>1</sup>? The 2015-2017 NTTG Regional Transmission Plan (RTP) poses this question and seeks to answer it. Developed in accord with NTTG Transmission Providers' Attachment K, which includes FERC Order 1000 regional and interregional transmission planning requirements, the plan analyzes whether NTTG's transmission needs in 2026 could best be satisfied with projects of a regional or interregional scope.

To arrive at a conclusion, NTTG used a two-year process of identifying transmission requirements and performing reliability and economic analyses on several collections of transmission projects, or plans: the prior (2014-2015) RTP, an Initial RTP<sup>2</sup> made up of projects from the prior RTP and projects included in the Full Funders' Local Transmission Plans, and a number of Change Case plans. A Null Change Case, which tests the NTTG footprint's current transmission system stressed by the addition of loads and resources projected for 2026-27, showed that the NTTG system performed acceptably in only one of seven stressed conditions studied. All the other conditions suffered performance issues that required correction.

A technical study found that the 2014-2015 prior RTP, which included two Non-Committed Projects (Boardman to Hemingway and portions of Energy Gateway), was not fully reliable with the 2026-27 load and resource projections. The study then evaluated 23 Change Cases that explored ways to reliably meet the transmission system needs through various combinations of the Non-Committed Projects in the Initial RTP or three proposed Interregional Transmission Projects, or both.

Reliability analyses narrowed the potentially acceptable solutions to the Initial RTP. These Change Cases were created to explore the relationship of a build-out of wind generation in Wyoming to meet NTTG load with its impact on the transmission system west of Wyoming and a potential expansion of the transmission system (i.e., the Gateway West and Gateway South projects). The study also examined three Interregional Transmission Projects as Alternative Projects to determine whether these projects would yield a more efficient or cost-effective regional transmission plan for NTTG and as a part of interregional coordination and planning. The analysis found, however, that none of the Interregional Transmission Projects could replace or enhance the Non-Committed Projects more efficiently or cost effectively to satisfy NTTG's regional transmission needs.

Subsequent economic analyses identified one of the Change Cases as the more-efficient or cost-effective case. Known in the study as Change Case 23, this case includes Boardman to Hemingway, Gateway South, portions of Gateway West, and the Antelope projects.

---

<sup>1</sup> NTTG's regional transmission planning process is not intended to be a replacement for local transmission or resource planning.

<sup>2</sup> Terms are capitalized to be consistent with Attachment K. All capitalized terms are defined in the glossary.

36 Stakeholder input on the RTP was accepted and evaluated throughout the biennial planning  
37 cycle. NTTG posted the Draft RTP in December 2016 (Quarter 4) for stakeholder comment and  
38 the Draft Final RTP in Quarter 6 for public comment. The Planning Committee will vote to  
39 recommend submittal of the RTP to the NTTG Steering Committee in Quarter 7. Steering  
40 Committee approval of the RTP will be requested in Quarter 8.

## 43 The Northern Tier Transmission Group

44 The Northern Tier Transmission Group (NTTG) was formed in 2007 to promote effective  
45 planning and use of the multi-state electric transmission system within the Northern Tier  
46 footprint. NTTG provides a forum where all interested stakeholders, including transmission  
47 providers, customers and state regulators, can participate in planning, coordinating and  
48 implementing a robust transmission system.

49 NTTG fulfills requirements of the Federal Energy Regulatory Commission (FERC) Order 1000 for  
50 each public utility transmission provider to participate in a regional transmission planning  
51 process that produces a regional transmission plan and, if appropriate, includes a regional cost-  
52 allocation method.

53 NTTG evaluates transmission projects that move power across the regional bulk electric  
54 transmission system, serving load in its footprint and delivering electricity to external markets.  
55 The transmission providers belonging to Northern Tier serve more than 4 million retail

56

customers with more than 29,000 miles of high-voltage transmission lines. These



57

Figure 1. Map of western North America showing NTTG members' transmission lines.

58

59

60

61

62

members provide service across much of Utah, Wyoming, Montana, Idaho and Oregon, and parts of Washington and California.

63 NTTG works with other entities—the Western Electricity Coordinating Council (WECC) for  
64 reliability planning and neighboring Planning Regions (e.g., ColumbiaGrid, WestConnect and  
65 California Independent System Operator (CAISO)) for interregional project coordination.

### 66 Participating Utilities

67 Deseret Power Electric Cooperative  
68 Idaho Power  
69 Montana Alberta Tie Ltd. (MATL)  
70 NorthWestern Energy  
71 PacifiCorp  
72 Portland General Electric  
73 Utah Associated Municipal Power Systems (UAMPS)

### 74 Purpose of the Plan

75 The NTTG Regional Transmission Plan (RTP) aims to produce, if possible, a more efficient or  
76 cost-effective regional plan to transmit energy compared with a plan that rolls up the local  
77 Transmission Providers’ transmission plans and other Change Case transmission plans studied.  
78 This study process complies with FERC Order No. 1000, Attachment K—Regional Planning  
79 Process. This planning cycle marks the first time that NTTG implemented FERC Order 1000  
80 interregional project coordination with the other western regional transmission planning  
81 organizations.

### 82 Plan Development Process

83 The Regional Transmission Plan is developed through a two-year process:

- 84 1) Identification of the transmission requirement for the NTTG footprint, derived from the data  
85 submissions
- 86 2) Reliability analysis and evaluation of the Initial RTP and Alternative Projects (including  
87 interregional projects) through Change Cases
- 88 3) Economic analysis and evaluation comparing the annualized incremental costs of the Initial  
89 RTP and the two most-efficient Change Cases
- 90 4) Selection of the project or projects that yield a regional transmission plan that is more  
91 efficient or cost-effective than the other regional transmission plans studied
- 92 5) Any projects that were submitted for the purposes of cost allocation and selected into the  
93 RTP will go through the cost allocation process if they are deemed to be eligible for cost  
94 allocation.

## Biennial Cycle

NTTG follows a two-year, eight-quarter planning cycle to produce the 10-year Regional Transmission Plan. In the first step, the Planning and Cost Allocation Committees pre-qualify<sup>3</sup> Transmission Developers who properly submit their transmission project to be considered for regional cost allocation (should the sponsor's project be selected in the Regional Transmission Plan for cost allocation). The biennial cycle includes steps to collect, evaluate and analyze transmission and non-transmission data, produce and publish a draft plan, gather stakeholder and public input, update the plan and complete the cycle with the publishing of a RTP.



Figure 2. NTTG uses an eight-quarter biennial planning cycle.

## Biennial Study Plan

The Biennial Study Plan outlines the process that NTTG follows to develop its 10-year RTP. It provides the framework to guide plan development. It also describes NTTG's process to determine if a properly submitted Interregional Transmission Project (ITP) would yield a transmission plan that is a more cost-effective or efficient solution to NTTG's regional transmission needs.

The NTTG Planning Committee manages the study plan. The Planning Committee establishes the Technical Work Group (TWG) subcommittee to develop the study plan. The TWG also performs the necessary technical evaluations for the RTP and assesses any projects, including ITPs, submitted to NTTG. TWG members are NTTG Planning Committee members or their

<sup>3</sup> A project sponsor must have their project pre-qualified before the beginning of the 2016-2017 biennial planning cycle (i.e., the last quarter of the prior planning cycle) pursuant to Attachment K, Section Pre-Qualification for Cost Allocation.



116 designated technical representatives. They have access to and expertise in power-flow analysis  
117 for power systems or production-cost modeling, or both.

118 Developed during Quarter 2 of the biennial planning cycle, the study plan establishes the:

- 119 • Study methodology and criteria
- 120 • Study assumptions based on the loads, resources, point-to-point transmission requests,  
121 desired flows, constraints and other technical data submitted in Quarter 1 and updated  
122 in Quarter 5 of the regional planning cycle
- 123 • Software analysis tools
- 124 • 2026 production-cost-model database and hours to be selected for reliability analysis
- 125 • Evaluation criteria for reliability and transmission service obligations
- 126 • Capital cost, energy losses and reserve-sharing metric calculations
- 127 • Public policy requirements and considerations

128 The study plan was posted for stakeholder comment, recommended for approval by the  
129 Planning Committee and approved by the Steering Committee during Quarter 2 of the biennial  
130 cycle. Due to data submission changes provided in Quarter 5, the study plan was revised in  
131 Quarter 6. Any differences between what is stated in the study plan and the process stated in  
132 Attachment K of the NTTG FERC Order 1000 defer to Attachment K.

### 133 [Study Methodology](#)

134 To determine the more efficient or cost-effective transmission plan, the TWG subcommittee  
135 conducted reliability and economic studies in accordance with the 2016-2017 Study Plan. The  
136 Study Plan and ultimately the RTP reflect the Full Funder's Attachment K requirements to  
137 satisfy its transmission needs. NTTG's regional transmission planning does not investigate local  
138 transmission planning or generation decisions related to integrated resource planning. Rather,  
139 NTTG's methodology uses a regional perspective to question the Initial RTP's roll-up of Non-  
140 Committed regional transmission project(s) to identify, if possible, a regional transmission plan  
141 that is more efficient or cost effective than the aggregated Full Funder's transmission plans. In  
142 conducting its regional studies, NTTG uses regional transmission and non-transmission  
143 alternatives (if any) to honor the local transmission needs. As part of the study, NTTG assumed  
144 that the local existing and new generation additions have (or will have) firm transmission rights  
145 to move their power from the generator to load. NTTG's reliability studies did not re-dispatch  
146 existing generation down to relieve congestion such that the new generation additions could  
147 move their power to load without potentially creating congestion.

148 The reliability studies used production-cost modeling and power-flow studies. The production-  
149 cost and power-flow models represent data for the western interconnection load, resource and  
150 transmission topology. In developing the data for these two models, NTTG started with a WECC  
151 production cost model (version TEPPC CC1.3) and WECC power-flow model (version 25hs1a)  
152 and modified the modeling data in NTTG's footprint for its regional studies. For the studies  
153 including one or more interregional transmission project that relied on increased wind

154 generation within NTTG’s footprint (e.g., adding new wind resource in Wyoming), NTTG  
155 adjusted generation levels down in the region receiving the power. The goal of the adjustments  
156 was to ensure western interconnection load and resource balance. NTTG consulted with the  
157 planning region receiving the power (i.e., California ISO) for their generation reductions.

158 The results of the production-cost modeling were used to identify seven hours of high stress on  
159 the transmission system. These seven hours were then subjected to reliability analysis using a  
160 power-flow model. The input and output data for these selected hours were transferred from  
161 the production-cost model (i.e., GridView) to a power-flow model (i.e., PowerWorld) to  
162 perform the technical reliability analysis. By taking these steps, a consistent set of analysis tools  
163 can be engaged to evaluate the reliability performance.

164 Next, economic studies employed the Attachment K’s three metrics—capital-related costs,  
165 energy losses, and reserves—to analyze Change Case plans that were deemed reliable to  
166 further determine the cost effectiveness of the NTTG transmission plan.

### 167 [Production-Cost Modeling](#)

168 The TWG examined 8,760 hours of data using GridView<sup>4</sup> production-cost software to establish  
169 stressed conditions within the NTTG footprint. To set the stressed conditions, TWG used and  
170 modified a dataset from the Transmission Expansion Planning Policy Committee (TEPPC) of the  
171 Western Electricity Coordinating Council (WECC). The TEPPC case included a representation of  
172 the load, generation and transmission topology of the WECC interconnection-wide  
173 transmission system 10 years into the future.

174 The study plan identified seven stressed conditions that affect the NTTG area for study. After all  
175 hours of data were run through the GridView production-cost program, the results were  
176 analyzed and the hours representative of the seven stressed conditions were identified. For a  
177 more detailed discussion of the conditions and hours, see the section on stress-conditioned  
178 case study results.

### 179 [Power-Flow Cases](#)

180 For the next step in the process, the TWG used PowerWorld<sup>5</sup> simulation software to convert  
181 the production-cost model for the seven stressed hours into power-flow cases. Each of the  
182 stressed cases was then reviewed by the TWG to ensure that the case met steady-state system  
183 performance criteria (no voltage issues or thermal overloads). Bubble diagrams showing the  
184 inter-area flows for each of the stressed cases are included in the Draft Final RTP, available on  
185 the NTTG website.

---

<sup>4</sup> GridView is a registered ABB product

<sup>5</sup> PowerWorld is a registered trademark of PowerWorld Corp.

186  
187  
188  
189  
190  
191  
192  
193  
194  
195  
196  
197

### Data Submission

Information flows in to NTTG during quarters 1 and 5 of the biennial cycle. Transmission Providers and stakeholders may supply data on forecasted firm energy obligations and commitments required to support the transmission system within the NTTG footprint. The data may include load forecasts, resources, transmission topology, transmission service and public policy requirements submissions. Regional transmission projects submitted in Quarter 1 are shown in **Table LMJ** and include those from the prior Regional Transmission Plan, Full Funder Local Transmission Plans (LTP), Sponsored Projects, unsponsored projects and Merchant Transmission Developer projects. No projects that were eligible for cost allocation were submitted into NTTG’s 2016-17 regional planning process.

### JANUARY 2016 DATA SUBMITTAL – TRANSMISSION ADDITIONS BY 2026

Sponsor	From	To	Voltage	Circuit	Type	Regionally Significant <sup>6</sup>	Committed	Projects
Deseret G&T	Bonanza	Upalco	138 kV	2	LTP	No	No	New Line
Idaho Power	Hemingway	Boardman/Longhorn	500 kV	1	LTP & pRTP	Yes	No	B2H Project
	Hemingway	Bowmont	230 kV	2	LTP	Yes	No	New Line (associated with Boardman to Hemingway)
	Bowmont	Hubbard	230 kV	1	LTP	Yes	No	New Line (associated with Boardman to Hemingway)
	Cedar Hill	Hemingway	500 kV	1	LTP	Yes	No	Gateway West Segment #9 (joint with PacifiCorp East)
	Cedar Hill	Midpoint	500 kV	1	LTP	Yes	No	Gateway West Segment #10
	Midpoint	Borah	500 kV	1	LTP	Yes	No	(convert existing from 345 kV operation)
	King	Wood River	138 kV	1	LTP	No	No	Line Reconductor
	Willis	Star	138 kV	1	LTP	No	No	New Line
Enbridge	SE Alberta		DC	1	LTP	Yes	No	MATL 600 MW Back to Back DC Converter
PacifiCorp East	Aeolus	Clover	500 kV	1	LTP & pRTP	Yes	No	Gateway South Project – Segment #2
	Aeolus	Anticline	500 kV	1	LTP & pRTP	Yes	No	Gateway West Segments 2&3
	Anticline	Jim Bridger	500 kV	1	LTP & pRTP	Yes	No	345/500 kV Tie
	Anticline	Populus	500 kV	1	LTP & pRTP	Yes	No	Gateway West Segment #4
	Populus	Borah	500 kV	1	LTP	Yes	No	Gateway West Segment #5
	Populus	Cedar Hill	500 kV	1	LTP	Yes	No	Gateway West Segment #7
	Antelope	Goshen	345 kV	1	LTP	Yes	No	Nuclear Resource Integration
	Antelope	Borah	345 kV	1	LTP	Yes	No	Nuclear Resource Integration
	Windstar	Aeolus	230 kV	1	LTP & pRTP	Yes	No	Gateway West Segment #1W
Oquirrh	Terminal	345 kV	2	LTP	Yes	Yes	Gateway Central	

<sup>6</sup> Regionally significant transmission projects are generally those that effect transfer capability between areas of NTTG. Projects that are mainly for local load service are not regionally significant. Projects that are not regionally significant will be placed into all change cases and not tested for impact on the Regional Transmission Plan. The future facilities submitted in the LTP’s will be removed in the Null Case

	Cedar Hill	Hemingway	500 kV	1	LTP	Yes	No	Gateway West Segment #9 (joint with Idaho Power)
<b>PacifiCorp West</b>	Wallula	McNary	230 kV	1	LTP	Yes	Yes	Gateway West Segment A
<b>Portland General</b>	Blue Lake	Gresham	230 kV	1	LTP	No	No	New Line
	Blue Lake	Troutdale	230 kV	1	LTP	No	No	Rebuild
	Blue Lake	Troutdale	230 kV	2	LTP	No	No	New Line
	Horizon	Springville Jct	230 kV	1	LTP	No	No	New Line (Trojan-St Marys-Horizon)
	Horizon	Harborton	230 kV	1	LTP	No	No	New Line (re-terminates Horizon Line)
	Trojan	Harborton	230 kV	1	LTP	No	No	Re-termination to Harborton
	St Marys	Harborton	230 kV	1	LTP	No	No	Re-termination to Harborton
	Rivergate	Harborton	230 kV	1	LTP	No	No	Re-termination to Harborton
	Trojan	Harborton	230 kV	2	LTP	No	No	Re-termination to Harborton

**Table LMJ**

**Forecasted Loads**

Participating load-serving entities provide forecasts of loads for balancing authority areas internal to the NTTG footprint. These loads are generally the same as those found in the participants’ official load forecasts (such as those in integrated resource plans) and are similar to those provided to the Load and Resource Subcommittee of the WECC Planning Coordination Committee. **Chart CCC** summarizes the load forecast used in the 2016-2017 planning cycle.

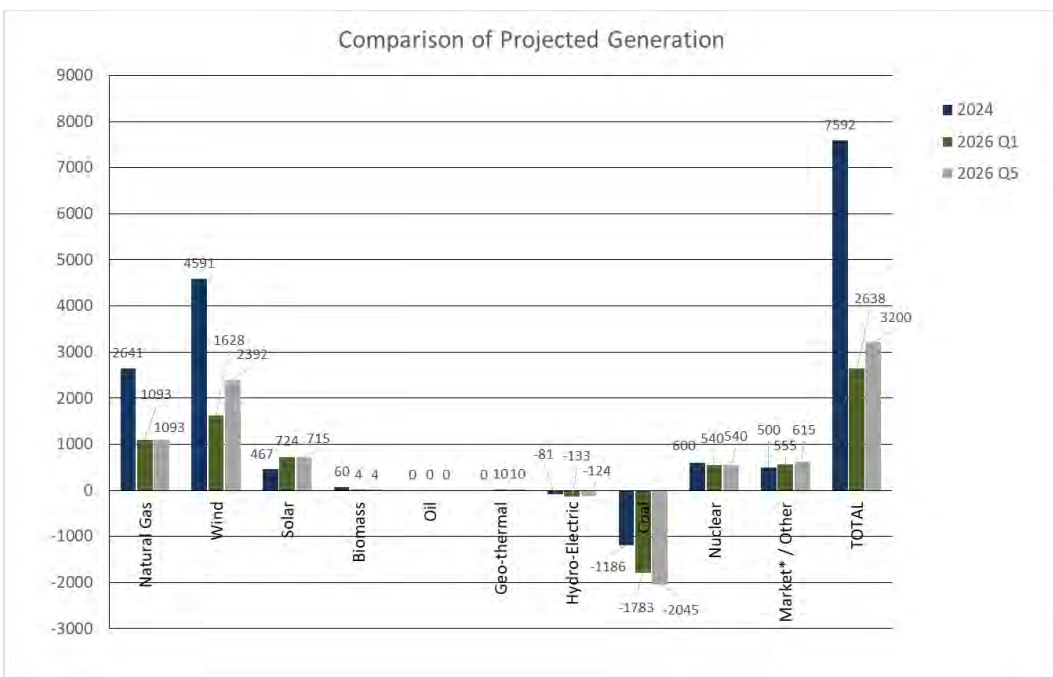
[Chart CCC: 2026 forecasted loads: bar graph to be created from Table 1, below, January 2016-2017 Data Submittal – Load Comparison, on page 8 of DFRTP, v2.6.]

SUBMITTED BY:	2015 Actual Peak Demand (MW)	2024 Summer Load Data Submitted in 2014-15 (MW)	2026 Summer Load Data Submitted in Q1 2016 (MW)	2026 Summer Load Data Submitted in Q5 2017 (MW)	Difference (MW) 2024-2026
<b>Idaho Power</b>	3,730	4,193	4,346	4,340	147
<b>NorthWestern</b>	1,790	1,774	1,992	1,992	218
<b>PacifiCorp</b>	12,634	14,002	13,414	13,414	-588
<b>Portland General</b>	3,958	3,933	3,885	3,874	-59
<b>TOTAL*</b>	22,112	23,902	23,637	23,620	-282
*	* Loads for Deseret G&T and UAMPS are included in PacifiCorp East				

NTTG received 3,200 MW of proposed new generation resources from its funding Transmission Providers for consideration in the RTP. Figure 3 displays these incremental resources within the

211  
212

NTTG footprint and compares submissions from the prior RTP with submissions for quarters 1 and 5 of the current cycle.



213  
214

Figure 3. Comparison of forecasted resources

215  
216  
217  
218  
219  
220  
221  
222  
223

In Quarter 5, Northwestern submitted 550 MW of new Montana wind generation. Also PacifiCorp indicated that its recently submitted integrated resource plan increased the amount of Wyoming wind power from 887 MW to 1,100 MW. As shown in Figure 3, the total resource forecast of 3,200 MW submitted this cycle was reduced by 392 MW, or 12.25 percent, from the 3,592 MW forecast in 2024. Following the Quarter 1 data submittal, the owners of the Colstrip 1 and 2 coal-fired plants announced a plan to retire the units before 2026. The owners of the Valmy 1 and 2 coal plants in Nevada also plan to decommission the plants by 2025, a decade earlier than originally planned. Both sets of retirements were assumed in the 2016-2017 studies and are reflected in Quarter 5 values shown in Figure 3.

224  
225  
226  
227  
228

In the 2014-15 study cycle, Power Company of Wyoming (PCW) submitted 3,000 MW of wind resources associated with the TransWest Express project. PCW asked that those resources not be included in the NTTG 2014-15 Regional Plan. Those resources, to serve loads outside the NTTG footprint in California, have been submitted with an Interregional Transmission Project in the 2016-17 study cycle.

229  
230  
231  
232

In support of the proposed transmission additions or upgrades, NTTG received four firm transmission-service-obligation submissions (contractual requirements to provide service)—two each from Idaho Power and PacifiCorp. These are shown in the following map. **Reference Report 2.6 Table 4. Map will need to be created. Use the map from page 9 of the 2014-15 RTP**

as a guide. Two vectors West to East across ID-Northwest to Boise area and to Idaho Falls area, another vector North to South from Arco to Utah, and a fourth vector east to west from Wyoming.]

Submitted by	MW	Start Date	POR	POD
Idaho Power	500/200	2021	Northwest	IPCo
	250/550	2022	LGBP	BPASEID
PacifiCorp East	540	2024	Antelope	Network
	1100	2026	Miners / Point of Rocks	Network

**Table 4 – Transmission Service Obligations**

### Public Policy Consideration Scenario Requests

In Quarter 1, Renewable Northwest (RNW) and the Northwest Energy Coalition (NWECC) jointly submitted a Public Policy Consideration request for a scenario analysis study. The group asked NTTG to study a faster phase-out of coal plants while developing utility-scale renewable resources and replacing Colstrip units 1, 2 and 3 with either wind only or a combination of wind and natural gas combustion.

Members of the TWG and representatives from RNW and NWECC reviewed the request and agreed to some modifications. These modifications, and the associated study assumptions, are documented in the NTTG 2016-2017 Study Plan, Attachment 3 of the Draft Final RTP.

The study results suggested that a replacement of wind or a combination of wind and gas for coal may be feasible. This study, however, neither constituted a path study nor conveyed or implied transmission rights. Additional analysis would be required to understand the full impacts of coal plant decommissioning.

Public Policy Considerations are considered to be relevant factors not established by local, state or federal laws or regulations. The results of PPC analysis may inform the RTP but do not result in the inclusion of additional projects in the RTP.

A full report of the study can be found in Appendix D of the NTTG 2016-2017 Draft Final RTP.

### Regional Economic Study Requests

NTTG received no regional economic study requests.

### Initial Regional Transmission Plan Development

The starting point for the biennial planning process was development of the Initial RTP. This exercise used a bottom-up approach to merge the projects in the prior RTP (2014-2015) and

the Full Funding Transmission Providers' local transmission plans into a single regional transmission plan. Next, the TWG analyzed the Initial RTP through Change Case plans, which included or excluded Non-Committed regional projects and Interregional Transmission Projects. These Change Case plans helped to determine whether Alternative Projects could be added or substituted, or if one or more Non-Committed Projects could be deferred, or both, to yield a regional transmission plan more efficient or cost effective than the Initial RTP. The results of this analysis led to the formation of the Draft RTP.

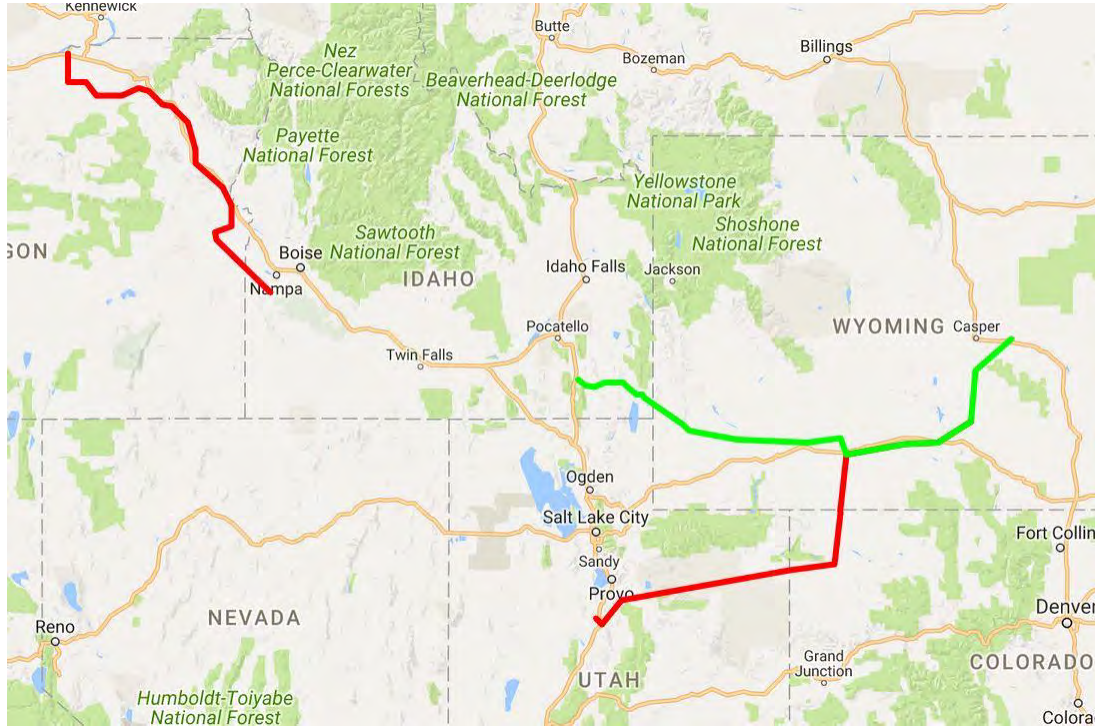


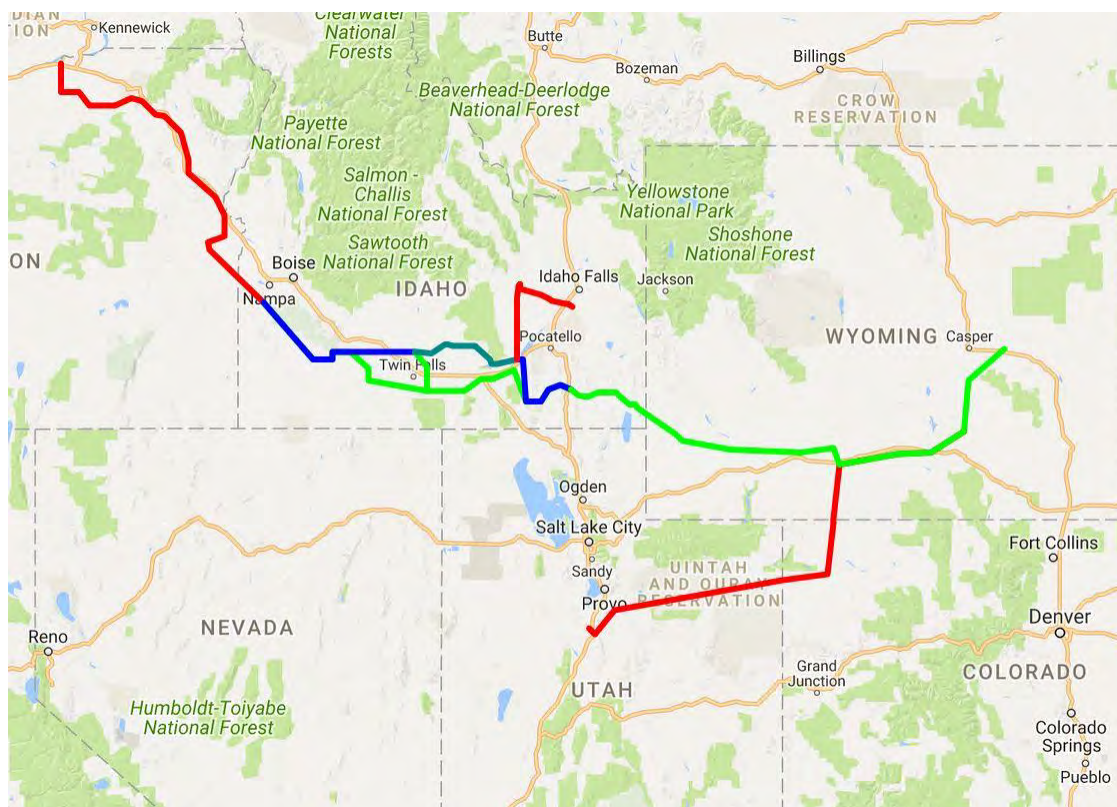
Figure 4. The red and green lines represent the projects comprising the prior RTP from 2014-2016. These include Boardman to Hemingway, in the northwest sector of the above map, and an Alternative Project with four transmission elements across four states.

The following Non-Committed regional projects comprised the Initial RTP:

- Boardman to Hemingway (Longhorn-Hemingway) 500 kV (red)
- Gateway West
  - Windstar-Aeolus 230 kV (green)
  - Aeolus-Anticline (Jim Bridger) 500 kV (green)
  - Anticline-Populus 500 kV (green)
  - Populus-Borah 500 kV (blue)
  - Populus- Cedar Hill 500 kV (green)
  - Cedar Hill-Hemingway 500 kV (green)
  - Cedar Hill- Midpoint 500 kV (green)
  - Borah-Midpoint 345 to 500 kV conversion (dark green)

282  
283  
284  
285  
286  
287  
288

- Midpoint-Hemingway #2 500 kV (blue)
- Gateway South
  - Aeolus-Clover 500 kV (red)
- Antelope
  - Goshen-Antelope 345 kV (red)
  - Antelope-Borah 345 kV (red)



289  
290

Figure 5. Map showing Non-Committed regional projects comprising the 2016-2017 Initial RTP.

291  
292

### Interregional Project Coordination

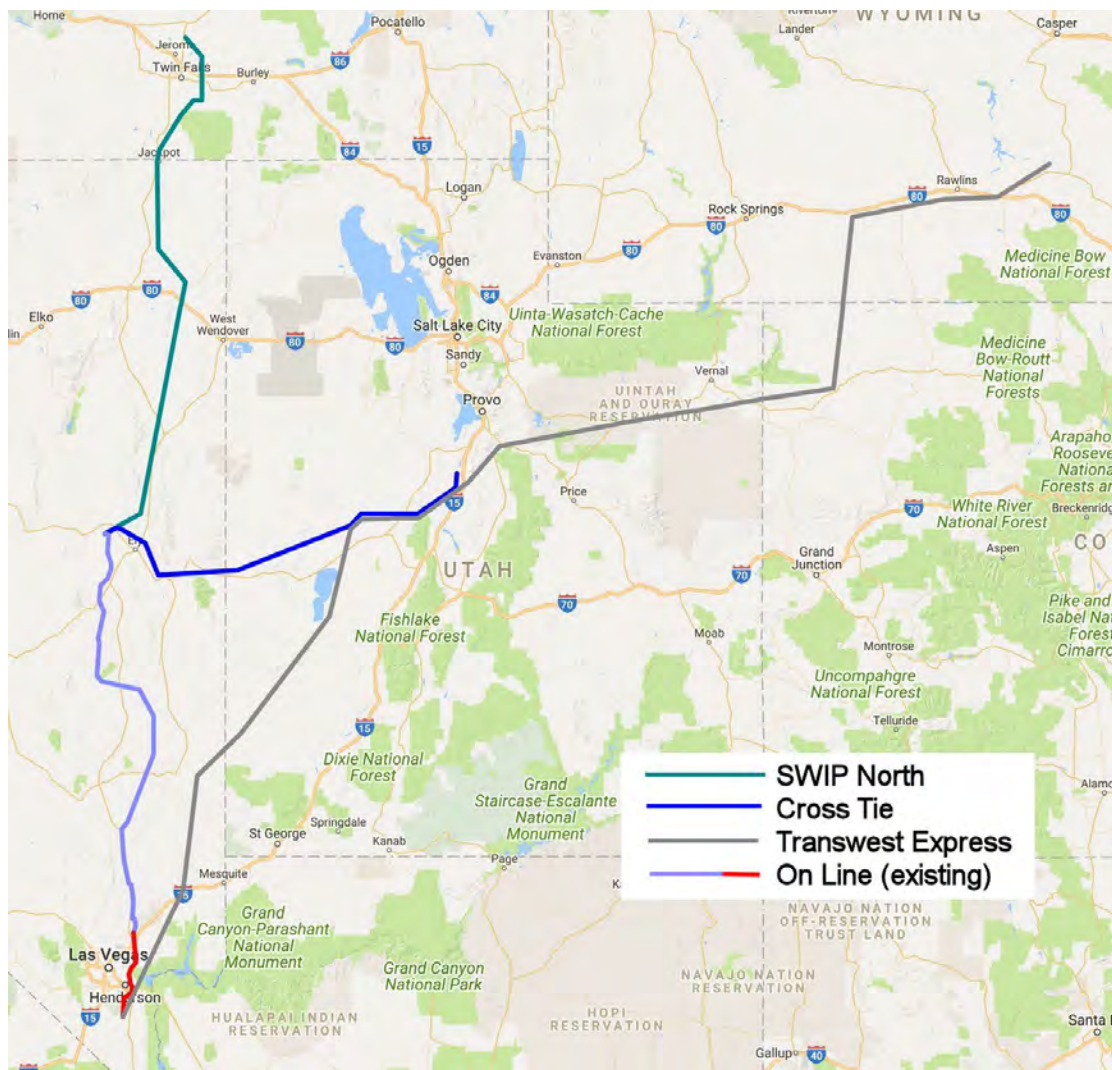
293  
294  
295  
296  
297  
298  
299  
300

As part of interregional coordination, NTTG and the other regional entities in the Western Interconnection collaborate during their transmission planning processes to coordinate their interregional transmission planning data. These coordination efforts inform each planning region’s transmission plans. A properly submitted Interregional Transmission Project is evaluated as an Alternative Project in NTTG’s regional planning process. The set of uncommitted projects (regional, interregional or both) that results in the more efficient or cost-effective regional transmission plan forms the basis of NTTG’s Regional Transmission Plan.



SUMMARY OF Q1-2016 INTERREGIONAL PROJECTS SUBMITTED TO NTTG						
Project Name	Company	Relevant Planning Region(s)	Termination From	Termination to	Status	In Service Date
Cross-Tie Transmission Project	TransCanyon, LLC	NTTG, WC	Clover, UT	Robinson Summit, NV	Conceptual	2024
SWIP-North	Great Basin Transmission LLC	NTTG, WC	Midpoint, ID	Robinson Summit, NV	Permitted	2021
TransWest Express Transmission Project	TransWest Express, LLC	NTTG, WC and CAISO	Sinclair, WY	Boulder City, NV	Conceptual	2020

**Table X.** Three Interregional Transmission Projects were submitted for consideration during formation of the Initial RTP in Quarter 1 of the biennial cycle.



**Figure 6.** Three Interregional Transmission Projects were evaluated during the planning cycle.

307 **Southwest Intertie Project (SWIP).** Great Basin Transmission, LLC (GBT), an affiliate of LS  
308 Power, submitted the 275-mile northern portion of the Southwest Intertie Project (SWIP) as an  
309 ITP. SWIP-North would connect the Midpoint 500-kV substation in NTTG’s planning area to the  
310 Robinson Summit 500-kV substation in the WestConnect area with a 500-kV single-circuit AC  
311 transmission line. The SWIP is expected to have a bi-directional WECC-approved path rating of  
312 approximately 2,000 MW. If GBT is selected to build SWIP-North, development, final design and  
313 construction activities could be completed to support energizing the project within an  
314 estimated 36-42 months.

315 **Cross-Tie Transmission Line.** TransCanyon submitted the 213-mile Cross-Tie Transmission Line  
316 for consideration as an ITP. TransCanyon proposes to build a 1500-MW, 500-kV high-voltage  
317 alternating current (HVAC) line between central Utah and east-central Nevada. The line would  
318 connect PacifiCorp’s proposed 500-kV Clover substation with the existing 500-kV Robinson  
319 Summit substation. TransCanyon expects the project to be in-service by the end of 2024.

320 **TransWest Express Transmission Project.** TransWest proposed a 730-mile, phased  
321 1,500/3,000 MW,  $\pm 600$  kV, high-voltage direct current (HVDC) transmission system with  
322 terminals in south-central Wyoming and southeastern Nevada. The federal Bureau of Land  
323 Management and Western Area Power Administration published the Final Environmental  
324 Impact Statement (FEIS) for the TWE Project in May 2015.

## 325 [Stress-conditioned Case Study Results](#)

### 326 [Stressed Hours for Study with Production-Cost Modeling](#)

327 The TWG used GridView production-cost software to review 8,760 hours of data to identify  
328 stressed conditions within the NTTG footprint. A case representing the year 2026 was obtained  
329 from the WECC TEPPC. This case included a representation of the load, generation and  
330 transmission topology of the WECC interconnection-wide transmission system 10 years in the  
331 future. The TWG identified corrections to the data needed to align with data submitted in the  
332 first quarter of the biennial planning cycle. TWG shared these changes with the other regional  
333 planning entities and WECC to include in their future studies. The TWG then agreed to use this  
334 modified TEPPC case in creating the stressed cases discussed below.

335 After processing all 8,760 hours through the production-cost program, the TWG analyzed the  
336 data and identified seven stressed conditions to study:

- 337 • High NTTG summer peak
- 338 • High NTTG winter peak
- 339 • High Montana-Northwest (Path 8) flows
- 340 • High southern Idaho import (Idaho-Northwest Eastbound)
- 341 • High southern Idaho-Northwest export (Idaho-Northwest westbound)
- 342 • High NE-SE (Path Tot2) flows
- 343 • Other conditions the might warrant transmission system reinforcement
- 344

Stressed Condition	Date	Hour	TWG Label
Max. NTTG Summer Peak	July 22, 2026	16:00	A
Max. NTTG Winter Peak	December 8, 2026	19:00	B
Max. MT to NW	September 10, 2026	Midnight	C
High Southern Idaho Import	June 11,2026	14:00	D1
High Southern Idaho Export	September 17, 2026	2:00	D2
High Tot2 Flows	November 11, 2026	17:00	E
High Wyoming Wind	September 17, 2026	2:00	F

**Table XYZ – Hours Selected from 2026 WECC TEPPC Case to Represent Different NTTG System Stresses**

High Summer Peak (NTTG Case A)

- 24,100 MW load
- 17,851 MW resources
- -6,250 import
- 4 p.m., July 22, 2026

This case showed a need to import energy during high summer air-conditioning loads. The transmission projects in the Initial RTP performed reasonably well; however, system performance proved inadequate without transmission system additions by 2026 to meet NTTG’s summer peak load. This case accounted for wind resources of 2,175 MW to check the performance of the set of projects comprising the Draft RTP.

High Winter Peak (NTTG Case B)

- 22,468 MW load
- 19,261 MW resources
- -3,208 MW import
- 7 p.m., Dec. 8, 2026

A few local system violations occurred when tested against the transmission projects comprising the Initial RTP. This case puts less stress on the NTTG system than did the summer peak. This case also accounted for wind resources of 2,175 MW to check the performance of the Draft RTP projects.

High Montana-NW (Path 8) Flows (NTTG Case C)

- 13,097 MW load
- 12,138 MW resources

376  
377  
378  
379  
380  
381  
382  
383  
384  
385  
386  
387  
388  
389  
390  
391  
392  
393  
394  
395  
396  
397  
398  
399  
400  
401  
402  
403  
404  
405  
406  
407  
408  
409  
410  
411  
412  
413  
414  
415  
416  
417  
418  
419  
420  
421

- -959 MW import
- 12:00 midnight, Sept. 10, 2026

This case tested transmission system capabilities with high electricity flows from Montana to the Northwest. This scenario was used for the public policy consideration study, which analyzed the impact of an accelerated phase-out of Colstrip units 1, 2 and 3 with either wind only or a combination of wind and gas. See the Public Policy Consideration Scenario Requests section for results of the study.

High Southern Idaho Import (NTTG Case D1)

- 16,382 MW load
- 9,159 MW resources
- -7,223 MW import
- 2 p.m., June 11, 2026

Under conditions with the eastbound path from the Northwest to Idaho operating at a 2,244 MW deficit, and the NTTG system importing 7,223 MW, the NTTG transmission topology could not import enough power to support load service obligations in southern Idaho. With the addition of transmission projects comprising the Initial RTP, however, the NTTG system would perform well, with a few local violations.

High Southern Idaho Export ( NTTG Case D2)

- 11,935 MW load
- 14,683 MW resources
- 2,748 MW export
- 2 a.m., Sept 17, 2026

In this export scenario, with the Idaho to Northwest Path 8 flow at 3,391 MW, the existing NTTG system would be incapable of supporting expected transfers and meeting transmission requirements in 2026. Adding in the projects from the Initial RTP, the system performed well, with one contingency that caused a series cap bank to overload. That bank, however, has reached the end of its useful life and is likely to be replaced before 2026.

High NE-SE (Path Tot2) flows (NTTG Case E)

- 16,625 MW load
- 16,620 MW resources
- 5 MW export
- 5 p.m., Nov. 11, 2026

This case evaluated the performance of the Interregional Transmission Projects in supporting transfers between regions. These additional interregional transfers were not identified in Q1 to meet or defer NTTG’s 2026 footprint resource requirements. The case showed near balance in the NTTG footprint between loads and resources, with a small 5 MW import, along with a Tot2

422 flow of 1,566 MW. This case accounted for wind resources of 2,175 MW to check the  
423 performance of the Draft RTP.

424  
425 High Wyoming wind production (NTTG Case F)

- 426 • 11,935 MW load
- 427 • 15,015 MW resources
- 428 • 3,081 MW export
- 429 • 2 a.m., Sept. 17, 2026

430  
431  
432 This case, as others, was studied at the 2,175-MW wind level, which includes the addition of  
433 1,100 MW of wind capacity. The added wind generation in the Wyoming area worsened  
434 reliability issues observed in Wyoming and confirmed the need for additional transmission to  
435 use these resources to their fullest extent. The RTP addresses these reliability concerns and  
436 relieves the transmission constraints.

### 437 438 Development of Change Cases

439 For each of the seven stress-conditioned cases, the TWG prepared a Null Change Case and  
440 analyzed reliability results. The Null case represents roughly today's transmission topology  
441 made to serve loads and resource requirements in 2026. Only the Heavy Winter case  
442 performed acceptably. All the other conditions revealed performance issues that required  
443 varying degrees of correction, with the heavy summer case needing the least correction and  
444 the high Wyoming wind case needing the most. In instances where the transmission system  
445 was not adequately stressed to historical norms, the TWG slightly modified system conditions  
446 to ensure that the transmission system was studied under reasonably stressed conditions.

### 447 448 Change Case Results

449 To efficiently study the wide range of potential combinations of Non-Committed Projects, the  
450 TWG proposed a Change Case matrix in the study plan. Once the stressed power-flow cases  
451 had been selected and developed, the TWG modified the matrix to better reflect the  
452 recommended analysis. The TWG provided stakeholders with the opportunity for input on  
453 whether a particular combination of uncommitted regional or interregional projects should be  
454 analyzed. No comments were received. The matrix was subsequently vetted through the  
455 Planning Committee and the Steering Committee.

456 **Table XX**, below, is the Change Case matrix used by the TWG.  
457  
458

Case	Gateway		Gateway	Antelope	SWIP N	Cross-	TWE	Case(s):
	B2H*	S*	W*	Projects		Tie		
null								A B D1 D2 F
pRTP	X	X	D					A B D1 D2 F
iRTP	X	X	X	X				A B D1 D2 E F
CC1	X							A B D1 D2 F
CC2		X		X				A D2 E F
CC3		X	X					A D1 D2 E F
CC4	X		X	X				A D1 D2 E F
CC5							X	A B D1 D2 F
CC6						X		A B D1 D2 F
CC7					X			A B D1 D2 F
CC8							X	E+RPS
CC9		X					X	E+RPS
CC20		X	X				X	E+RPS
CC10						X		E+RPS
CC11		X				X		E+RPS
CC18		X	X			X		E+RPS
CC12					X			E+RPS
CC13			X		X			E+RPS
CC19		X	X		X			E+RPS
CC14		X	X		X	X		E+RPS
CC15			X		X		X	E+RPS
CC16		X				X	X	E+RPS
CC17		X	X		X	X	X	E+RPS
CC21	X	X	A	X				D2 F
CC22	X	X	B	X				D2 F
CC23	X	X	C	X				F

\* B2H and Alternate P in the pRTP are similar to B2H, Gateway S and Gateway W in the 2016-17 Q1 data submittals

	The change case does not include the non-Committed Project
X	The change case includes the non-Committed Project
A	Gateway West without Midpoint-Hemingway #2 and Cedar Hill-Midpoint
B	Gateway West without Borah-Midpoint Uprate and Populus-Borah
C	Gateway West without Midpoint-Hemingway #2, Cedar Hill-Midpoint and Populus-Borah
D	Gateway West without Midpoint-Hemingway #2, Cedar Hill-Midpoint, Populus-Cedar Hill-Hemingway, Populus-Borah and Midpoint-Borah Uprate
	The change case was run with and without B2H

Figure 7. Change Case matrix used in the development of the RTP.

In all, the TWG performed more than 100 reliability studies on more than 410 contingencies. To better communicate the results of these studies, the TWG created heat maps, which present a

464  
465  
466

weighted<sup>7</sup> graphical performance of a Change Case on a specific flow condition. A full heat map analysis of the Change Cases is included in the final Draft RTP.

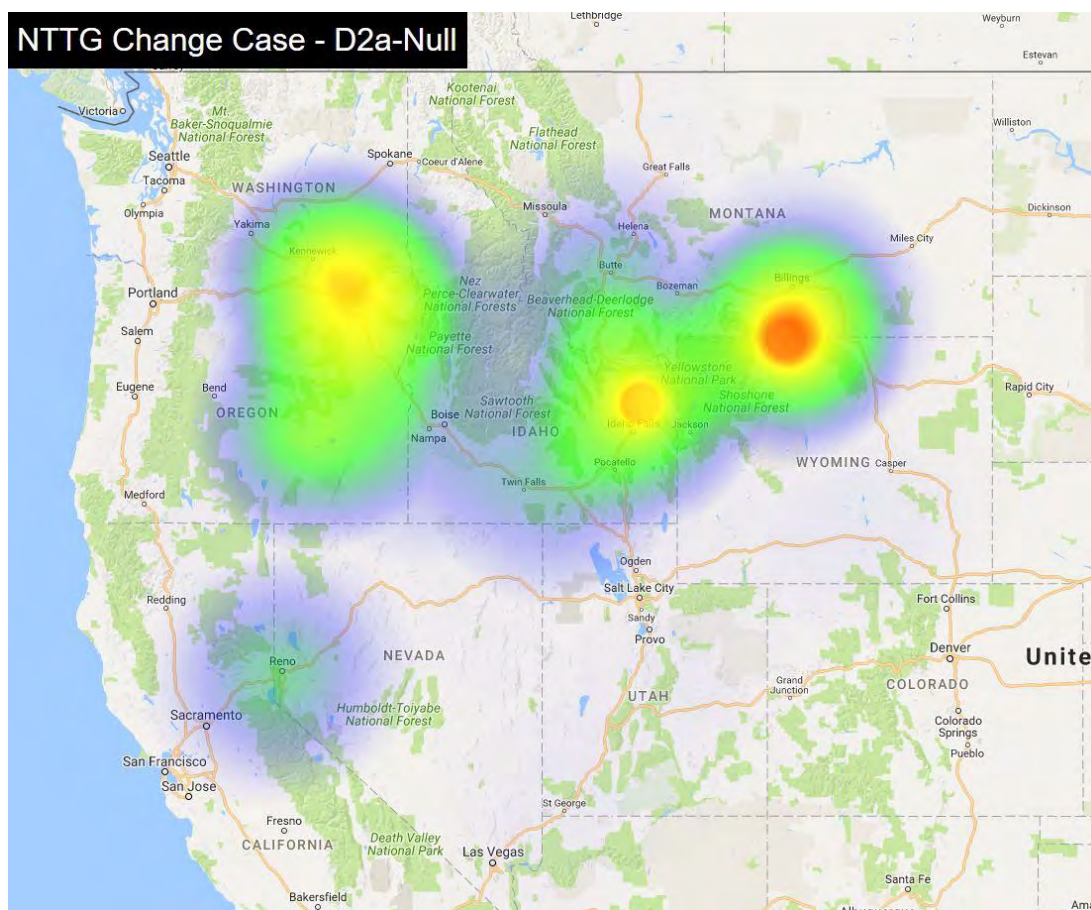


Figure 8. Heat map of the D2-Null Case

467  
468  
469  
470  
471  
472  
473  
474  
475  
476  
477

Figure 8, for example, shows the general location where performance issues (e.g., an overloaded transmission line) occurred for a contingency. The accumulation of overloads and voltage issues are represented by the color spectrum from blue to red, or “cooler” to “hotter.” These violations occur when transmission systems cannot handle anticipated transfers across that area’s transmission lines. In particular, this heat map, using existing Wyoming wind resources dispatched at about 600 MW, indicates that transmission additions are necessary to integrate the projected wind resources.

<sup>7</sup> High voltage conditions had a weighting of 1; Low voltage conditions had a weighting of 3; and overloads of branches had a weighting of 5. For example, a zone in which 10 contingencies caused an overload of one branch in that zone would receive a total weight of 50 (i.e., 10 x 5), which would then be translated into a color on the map. A blue color represents a weighted total of about 10, green is a count up to 30, yellow is a count up to 50 and red is for a weighted count exceeding about 70.

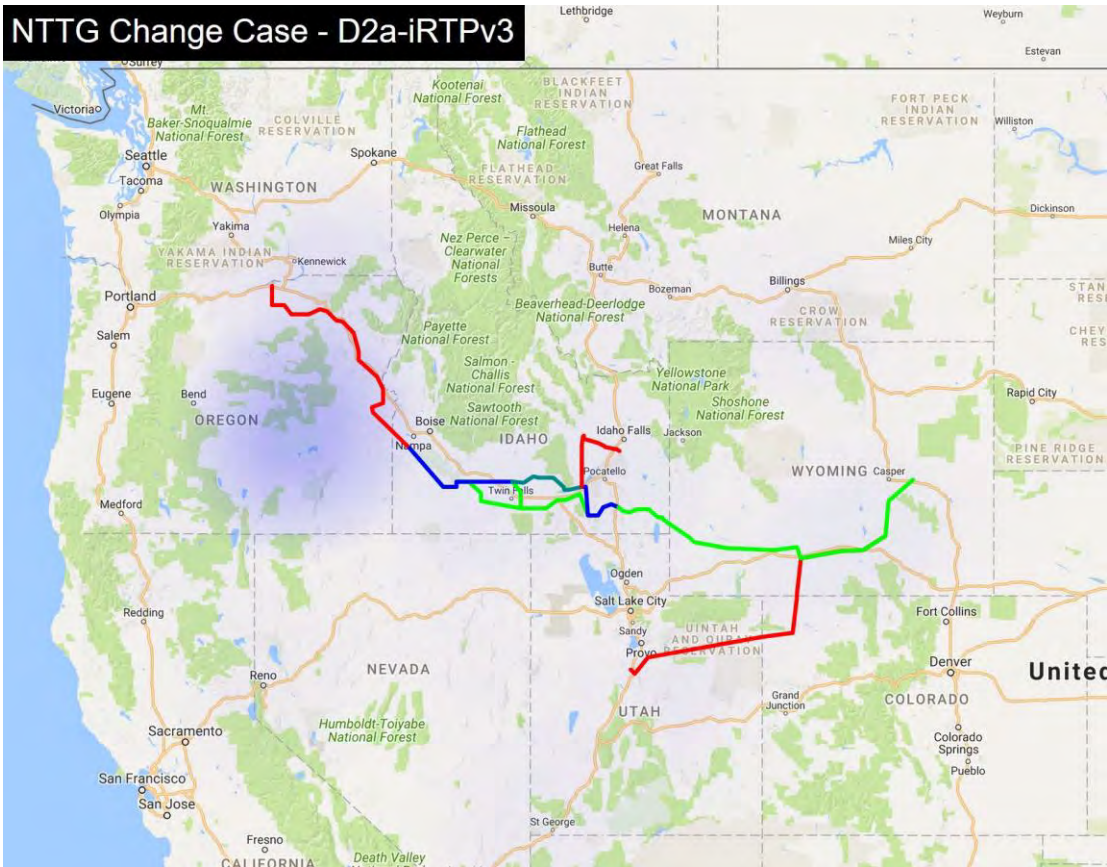


Figure 9. Heat map of the High Southern Idaho export case with the Initial RTP facilities included

The heat map in Figure 9 shows how the addition of the Initial RTP projects produced a dramatic improvement of transmission performance when compared with the Null Case.

High Southern Idaho Import Case

Combining the Boardman to Hemingway project with the Gateway West and Gateway South Non-Committed Projects eliminated violations in flow conditions visible in the Null Case. Change Case 3 tested whether Gateway West or Gateway South, or both, could replace or compare with the Boardman-to-Hemingway line. They couldn't. The projects contained in the prior RTP also failed to alleviate the violations.

High Southern Idaho Export Case

Adding the Boardman-to-Hemingway project relieved stress across the Idaho-Northwest cutplane, but significant issues remained east of Hemingway. Adding the eastern portion of Gateway West and Gateway South outlined in the prior RTP eliminated the performance issues in Wyoming and between Idaho and Montana, but those additions increased the stress across southern Idaho. The Initial RTP and Change Cases 21 and 23 resolved these issues.



### High Wyoming Wind Case

Without significant reinforcements, the transmission system in Wyoming could not handle both existing and future planned wind resources while maintaining all other Wyoming area generating resources at their typical high capability in an export scenario.

With wind production at the 1,300-MW level in the Null Case (no new transmission supporting 2026 loads), the system performed poorly. Nor did the projects in the prior RTP solve problems. Adding the Initial RTP projects resolved all violations except for a series capacitor bank. That bank has reached the end of its useful life, however, and is due for replacement.

In Quarter 6, the case was tested to see if Change Cases 1 through 4 would support the increased level of Wyoming wind. The Null Case (no new transmission) was unable to be solved with wind above 1,800 MW. Testing Change Case 4 required adding the Aeolus-Anticline 500-kV line to eliminate a number of contingencies that failed to solve in Wyoming. Change Case 23, which is essentially Change Case 4a with Gateway South added, performed well with Wyoming wind modeled at 2,175 MW.

### Interregional Transmission Projects

Change Cases 5 through 20 tested whether the three Interregional Transmission Projects (ITP)—alone, in combination with other ITPs or in combination with the Non-Committed Projects—could satisfy NTTG’s transmission needs on a regional or interregional basis more efficiently or cost effectively than through local planning processes. The ITPs were added to the null cases without any additional resources to serve NTTG load beyond those resources identified in the Quarter 1 and Quarter 5 data submittals. The ITPs did not provide the NTTG footprint with regional benefits, the testing showed, either by significantly reducing performance issues or by displacing NTTG Non-Committed Projects.

The Initial RTP also was analyzed to determine whether it would be capable of supporting the interregional resource transfers proposed by the ITPs. Given the relatively long distances of the ITPs, the local integration performance issues identified in Wyoming were solvable.

### Reliability Conclusions

Based on the above study results, the TWG concluded that both Change Cases 21 and 23 and the Initial RTP satisfy NTTG reliability criteria. In Quarter 5, the TWG tested Change Case 23 and the wind resource additions at various load and flow levels on the Heavy Summer, Heavy Winter, High Tot2 and High Wyoming wind cases. The TWG study found the NTTG area would be reliably served in the year 2026 only by including the following Non-Committed regional projects:

- Boardman to Longhorn (formerly Hemingway)
- The Energy Gateway projects including segments:
  - Windstar-Aeolus 230 kV
  - Aeolus-Clover 500 kV
  - Aeolus-Anticline 500 kV
  - Anticline-Populus 500 kV
  - Populus-Cedar Hill-Hemingway 500 kV

- 541       ▪ Antelope Transmission Project including:
  - 542           • Antelope – Borah 345 kV
  - 543           • Antelope – Goshen 345 kV
  - 544           • Antelope 345/230 kV transformers and interconnection facilities

545  
546 The ITPs were evaluated to determine whether one or more of them could defer or replace  
547 NTTG’s Non-Committed Projects. The TWG concluded that none of the ITPs solved NTTG’s  
548 reliability performance issues and, thus, were included in the final NTTG RTP.  
549

## 550 Economic Evaluations

551 To determine whether the Initial RTP or a Change Case transmission plan was more cost  
552 effective, the TWG used three economic metrics, as determined in the Biennial Study Plan. The  
553 three metrics—capital-related costs, power flow losses and reserves—and results are discussed  
554 below.

### 555 Capital-related Cost Metric

556 Development of the capital-related cost metric required three steps. The first step validated  
557 the capital cost of the Project Sponsor’s Q1 submitted project. The second step used those  
558 results to estimate the annual capital-related costs. The third step levelized the net present  
559 value annual capital-related costs for the Initial RTP and the Change Case plans.

### 560 Energy-loss Metric

561 The energy-loss metric captures the change in energy generated, based on system topology, to  
562 serve a given amount of load. A reduction in losses for a Change Case would represent a  
563 benefit, since less energy would be required to serve the same load. The two Change Cases  
564 with fewer Gateway West transmission segments—Change Cases 21 and 23—had losses higher  
565 than, or in some cases equal to, the Initial RTP. Losses were higher in the two Change Cases  
566 because the electrical flows in the Initial RTP were redistributed to fewer lines. From a loss  
567 perspective alone, the Initial RTP case had fewer losses and as such was the more efficient  
568 case.

### 569 Reserve Metric

570 The reserve metric evaluates the opportunities for two or more parties to save money by  
571 sharing a generating resource that would be enabled by transmission. The metric is a 10-year  
572 look at the increased load and generation additions in the NTTG footprint and the incremental  
573 transmission additions that may be included in the Draft RTP.

574 In the study cycle, the TWG analyzed Gateway West, Gateway South, Boardman to Hemingway,  
575 SWIP North and the Cross-Tie projects. To evaluate these projects, the NTTG footprint was  
576 segmented into five zones, and a sixth external zone was included to study the SWIP North and  
577 the Cross-Tie projects. The six zones produced 122 viable sharing combinations. Of those, the  
578 analysis of the annual net savings over each theoretical participant’s standalone alternative  
579 suggested that only 34 viable combinations were economic.

Note that this metric includes generation capital costs in its evaluation and, as such, may only be appropriate for cost allocation purposes. It should not drive the selection of a Draft RTP. Whether these cost savings warrant jointly sharing the costs of reserve capacity is up to the parties to decide.

For the NTTG metric analysis, the Initial RTP and the two alternative Change Cases each supported viable economic combinations. Since these Change Cases could contain the same benefit value, the Change in Reserve metric did not factor into the Draft RTP selection decision.

#### Economic Metric Analysis Conclusion

The sum of the annual capital-related cost metric, loss metric (monetized) and reserve metric (monetized) yielded an incremental cost for the Initial RTP and the Change Case plans. The set of projects with the lowest incremental cost, after adjustment by the plan's effects on neighboring regions—Change Case 23 (see Figure 10, below)—was then incorporated into the Draft RTP. Note that the incremental cost was computed as the levelized annual capital-related cost, minus NTTG loss benefit, minus monetized reserve benefit.

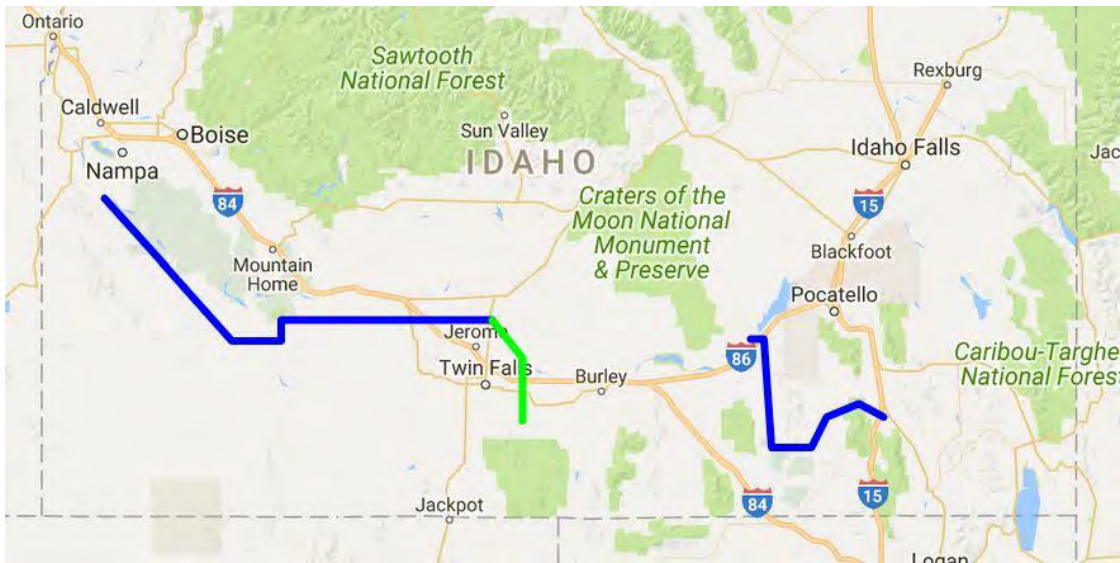


Figure 10. Change Case 23, comprising Boardman to Hemingway, Gateway South, portions of Gateway West, and the Antelope projects, produced the lowest incremental cost.

598 Planning Process Flow Map (Coming)

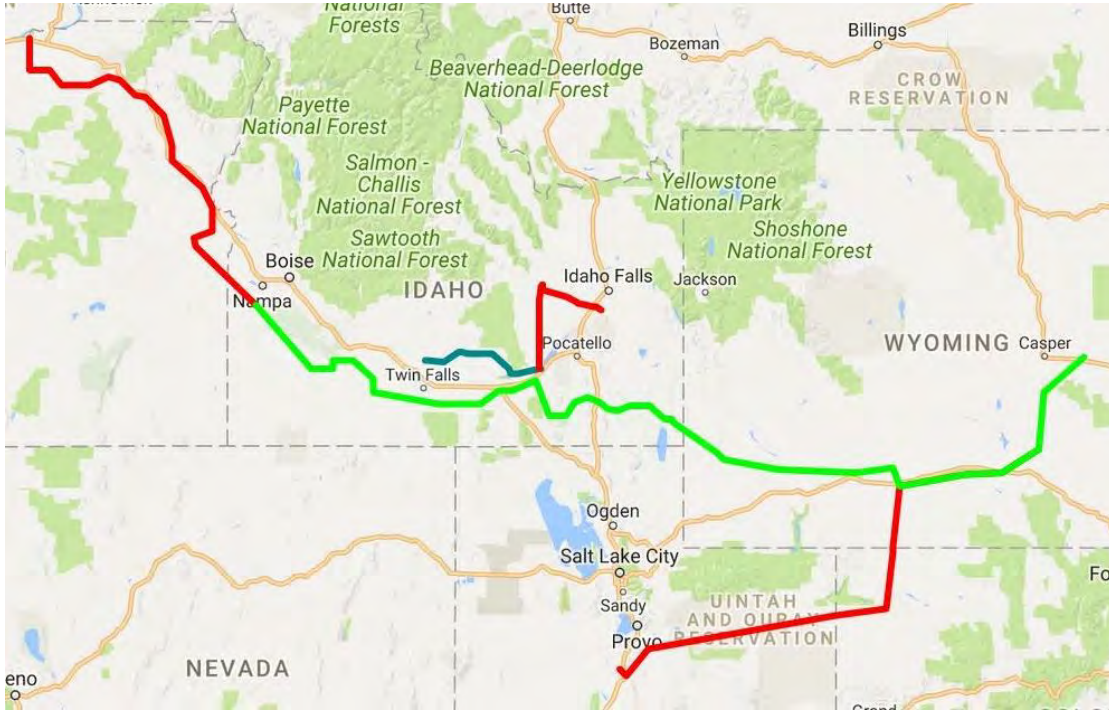
599  
600 Final Regional Transmission Plan

601 Based on the study assumptions and reliability and economic conclusions discussed above, the  
602 more efficient or cost-effective plan is Change Case 23. Change Case 23 is a staged variant of  
603 the Initial RTP. For the transfers submitted in Quarter 1 and Quarter 5, the facility segments  
604 shown in Figure 11, below, were not necessary for the transfers studied in the Change Cases.  
605 These segments would likely be necessary at higher transfer levels.



606  
607 Figure 11. These transmission line segments from the Initial RTP were not included in the final RTP.

608 NTTG's final Draft RTP emerged after a rigorous reliability analysis of the NTTG Transmission  
609 Providers' rollup of their local area plans and assumption of Non-Committed regional  
610 transmission projects, augmented with stakeholder Interregional Transmission Projects. This  
611 technical analysis was followed by an economic metric analysis that selected NTTG's more  
612 efficient and cost-effective regional transmission plan, shown below in Figure 12.



613  
614 **Figure 12.** These projects comprise NTTG's final RTP. See the legend for the identity of individual projects.

615 Legend for Fig. 12

616 Red in upper left: Boardman to Hemingway

617 Green: Gateway West

618 Red at bottom: Gateway South Gate

619 Dark green in middle: Gateway West—upgrade of existing line from 345 kv to 500 kv

620 Red at center: Antelope projects

621  
622 **Cost Allocation**

623 The SWIP-North project sponsors were the only project sponsors to request cost allocation;  
624 however, they failed to comply with the requirement to submit pre-qualification data by Oct.  
625 31, 2015. As a result, no projects that were eligible for cost allocation were submitted into  
626 NTTG's 2016-17 regional planning process.

627  
628 **Next Steps**

629 Publication of the NTTG Regional Transmission Plan completes the two-year planning process  
630 begun in January 2016. The 2016-2017 NTTG RTP identified a need for new transmission  
631 capacity to serve forecasted load in 10 years. The plan also identified a set of transmission

632 projects known in this report as Change Case 23 as the more efficient or cost-effective  
633 transmission plan to meet that need. While the RTP is not a construction plan, it provides  
634 valuable regional insight and information for all stakeholders (including developers) to consider  
635 and use in their respective decision-making processes.

636 The next biennial regional transmission planning cycle for NTTG started October 1, 2017 and  
637 will culminate with the publication of the 2018-2019 RTP in December 2019.

### 638 639 [NTTG 2016-2017 Regional Transmission Plan Supporting Materials](#)

640 The supporting materials referenced in this report have been posted on the NTTG website and  
641 can be found using the following link:

642 [https://www.nttg.biz/site/index.php?option=com\\_docman&view=list&slug=2016-2017-nttg-](https://www.nttg.biz/site/index.php?option=com_docman&view=list&slug=2016-2017-nttg-planning-cycle&Itemid=31)  
643 [planning-cycle&Itemid=31](https://www.nttg.biz/site/index.php?option=com_docman&view=list&slug=2016-2017-nttg-planning-cycle&Itemid=31)

644 A list and link to each of the individual supporting documents is also provided below:

- 645 1. [Amended Quarter 6 NTTG 2016-17 Biennial Study Plan Approved 08.02.17](#)
- 646 2. [Stakeholder Comments on NTTG 2016-2017 Draft Study Plan & NTTG Response - FINAL 07-](#)  
647 [13-2016](#)
- 648 3. [NWECC & RNW Comments Submitted on NTTG 2016-2017 Draft Study Plan](#)
- 649 4. [NTTG 2016-2017 Draft Final Regional Transmission Plan - 06-30-2017](#)
- 650 5. [2016-2017 NTTG Public Policy Consideration Scenario Report](#)
- 651 6. [Draft NTTG Study Report for 2016-2017 PPC Scenario For Stakeholder Comment](#)

### 652 653 [Glossary](#)

654 Note: This Glossary is for the benefit of readers and neither supplements nor modifies any  
655 defined terms contained in any entity's filed Open Access Transmission Tariff (OATT), including  
656 the Attachment K to that tariff. To the extent that a term diverges from any entity's OATT,  
657 defer to the OATT.

658 **Alternative Project** Alternative Project refers to Sponsored Projects, projects submitted by  
659 stakeholders, projects submitted by Merchant Transmission Developers and unsponsored  
660 projects identified by the Planning Committee (if any).

661 **Change Case** A Change Case is a scenario where one or more of the Alternative Projects is  
662 added to or replaces one or more Non-Committed projects in the Initial RTP. The deletion or  
663 deferral of a Non-Committed Project in the Initial RTP without including an Alternative Project  
664 can also be a Change Case.

665 **Committed Project** A Committed Project is a project that has all permits and rights of way  
666 required for construction, as identified in the submitted development schedule, by the end of  
667 Quarter 1 of the current regional planning cycle.

668 **Draft Regional Transmission Plan** Draft Regional Transmission Plan refers to the version of the  
669 Regional Transmission Plan that is produced by the end of Quarter 4 and presented to  
670 stakeholders for comment in Quarter 5.

671 **Draft Final Regional Transmission Plan** Draft Final Regional Transmission Plan refers to the  
672 version of the Regional Transmission Plan that is produced by the end of Quarter 6, presented  
673 to stakeholders for comment in Quarter 7 and presented, with any necessary modifications, to  
674 the Steering Committee for adoption in Quarter 8.

675 **Initial Regional Transmission Plan** Initial Regional Transmission Plan comprises projects  
676 included in the prior Regional Transmission Plan and projects included in the Full Funders Local  
677 Transmission Plans and accounts for future generation additions and deletions (e.g.,  
678 announced coal retirements).

679 **Interregional Transmission Project** An Interregional Transmission Project is a proposed new  
680 transmission project that would directly interconnect electrically to existing or planned  
681 transmission facilities in two or more planning regions and that is submitted into the regional  
682 transmission planning processes of all such planning regions.

683 **Merchant Transmission Developer** Merchant Transmission Developer refers to an entity that  
684 assumes all financial risk for developing and constructing its transmission project. A Merchant  
685 Transmission Developer recovers the costs of constructing the proposed transmission project  
686 through negotiated rates instead of cost-based rates.

687 **Non-Committed Project** A project that is not a Committed Project

688 **Sponsored Project** A Sponsored Project is a project proposed by a Project Sponsor.