IDAHO POWER

2018-2019 LOCAL TRANSMISSION PLAN

STUDY PLAN

June 2018

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Objectives of the Plan

The objective of the 2018 – 2019 Local Transmission Plan (LTP) is to identify the upgrades and other investments to the Idaho Power Transmission System and Demand Resources necessary to reliably satisfy, over a 20 year planning horizon, the following: Network Customers' resource and load growth expectations for designated Network Load and Network Resource additions; Transmission Provider's resource and load growth expectations for Native Load Customers; Transmission Provider's transmission obligations for public Policy Requirements; and Transmission Provider's Point-to-Point Transmission Customers' projected service needs including obligations for rollover rights.

Please refer to the Idaho Power OATT Attachment K for definitions of capitalized terms herein and a description of the planning process.

Study Methodology

The methodology to develop the LTP is outlined below. Refer to Figure 1 for a quarterly breakdown of activities.

Step 1: Assemble needs from Q1 data submittals and requirements outlined in Attachment K, including:

i. Forecast load additions and locations. Forecast load additions will include impacts of Demand Side Management (DSM).

ii. Resource additions and locations.

iii. Any transmission needs driven by public policy.

iv. Other transmission obligations.

Step 2: Evaluate the resource additions and path loading/transfer requirements to determine where transmission deficiencies exist.

Step 3: Determine transmission infrastructure additions, and in combination, or as an alternative, the amount of demand response required to relieve the transmission deficiency.

Step 4: Select appropriate power flow base case from WECC base case archive. Incorporate forecasted loads, resource additions and transmission obligations into the case as well as transmission element additions and any demand response measures.

Step 5: Perform power flow studies under steady-state, single and multi-element outage conditions to determine if the future system with the proposed facility additions meets applicable system performance criteria.

Step 6: Refine and iterate Step 2 through Step 5 based on stakeholder input or modifications in resource portfolios based upon draft LTP transmission information or the current IRP process.

Step 7: Incorporate Idaho Power's 2019 IRP preferred resource portfolio and near-term action plan into a sensitivity case. Repeat steps 2-5 if the 2019 resource portfolio differs from the 2017 resource portfolio.

Step 8: Finalize the LTP.

The two-year planning cycle schedule is shown below in Figure 1.

Biennial Planning Cycle and Schedule

	Biennial Transmission Planning Cycle			Economic Study Cycle
	Months	Quarter	Activity	Activity
Even Years	JAN-MAR	Qtr 1	Information Gathering	Receive and Prioritize Requests
	APR-JUN	Qtr 2	Study Plan and Assumptions	Study
	JUL-SEP	Qtr 3	Draft Plan Analysis	Report/Review Results
	OCT-DEC	Qtr 4		
Odd Years	JAN-MAR	Qtr 5	Draft Study Results and Review	Receive and Prioritize Requests
	APR-JUN	Qtr 6	Economic Studies and Cost Allocation Process	Study
	JUL-SEP	Qtr 7	Final Plan Report and Review	Report/Review Results
	OCT-DEC	Qtr 8	Final Plan	

Figure 1: Planning Cycle Schedule

Plan and Assumptions

System Conditions to Study

Idaho Power will use scenario planning to evaluate the performance of the transmission system for different load and generation dispatch patterns in the future. Idaho Power will utilize one 20 year heavy load study case as its primary study scenario. A five year heavy load scenario and a 10 year heavy load scenario will also be incorporated as part of the overall evaluation. Further, Idaho Power will evaluate the year 2028 study cases developed as part of the 2018-2019 Northern Tier Transmission Group (NTTG) planning process and incorporate one or more of the system conditions into the LTP evaluation process.

Power Flow Cases

The 20 year study case will be the primary study scenario. This base case will be developed from the Western Electricity Coordinating Council (WECC) approved 2028 heavy summer (2028hs1a1) detailed power flow base case, approved by WECC on April 18, 2018. The loads in the 2028hs1a1 case will be scaled to forecasted 2038 levels. Resources additions and transmission obligations will be updated to the year 2038 based on the most recent projections.

The five year and ten year scenarios will utilize WECC approved power flow base cases. Idaho Power will cross reference its NERC Transmission Planning (TPL) compliance studies and will use the same power flow cases for both efforts. The following cases are proposed, but may change depending on the scope of Idaho Power's 2018 TPL compliance review and the WECC base case development and approval process:

- 2023 Heavy Summer case (23hs2a1), approved 07/19/2017
- 2028 Heavy Summer case (28hs1a1), approved 04/18/2018

As part of the biennial planning process, NTTG will develop multiple study cases representing different system conditions from the WECC 2028 production cost model. Idaho Power will utilize one or more of these cases developed by NTTG to evaluate the Idaho Power system for system conditions not modeled in the previously mentioned heavy summer load conditions.

Path Flows

The path flow levels in the 2038 base case will be adjusted, as necessary, to reflect expected summer resource and loading conditions, e.g. medium hydro, high thermal generation and moderate Northwest to Idaho (path 14) imports.

The path flows for the five and ten year scenarios will not be modified from the WECC base cases. Similarly, the path flows will not be modified from any case(s) developed by NTTG.

Native and Network Loads

For the 2038 case, the load in the Idaho Power service territory will be scaled to reflect forecasted 2038 native and network loads. The native and network loads will be adjusted based on the Idaho Power load forecast submitted to WECC in quarter one of 2018. The 10-year forecasts submitted to WECC will be scaled to 20 year levels. Network customer loads will be scaled to 20 year levels from the 10-year forecasts received during first quarter data submittals. Loads outside of the Idaho Power service territory will not be scaled from the 2028 base case. Table 1, below, summarizes the 10 and 20 year system load projections.

Table 1 - Idaho Power Balancing Area Load Forecasts

Year	***Load (MW)***
2017 Actual Peak	3,836
2028 Forecast Peak	4,412
2038 Forecast Peak	4,959

The loads will not be modified in the WECC study cases or any case(s) developed by NTTG.

Resources

Additional resources will be added to the 2038 study case based on the resources identified in Idaho Power's 2017 IRP and the resources present in Idaho Power's generator interconnection queue with executed power sales agreements as of the 2018 first quarter data gathering period. Table 2 summarizes the resource additions and subtractions from Idaho Power's 2017 IRP, and table 3 summarizes the resources in the Idaho Power interconnection queue with executed power sales agreements as of quarter 1, 2018.

Table 2 - 2017 IRP Preferred Portfolio

Date	*Resource*	*Capacity*
2019 Year-End	Retire North Valmy Unit 1	(~131 MW) IPC Share
2025 Year-End	Retire North Valmy Unit 2	(~131 MW) IPC Share
2026	Boardman to Hemingway	500 MW Transfer Capacity, Apr-Sep 200 MW Transfer Capacity, Oct-Mar
2028 Year-End	Retire Jim Bridger Unit 2	(~178 MW) IPC Share
2031	Reciprocating Engines	36 MW
2032	Reciprocating Engines	36 MW
2032 Year-End	Retire Jim Bridger Unit 1	(~178 MW) IPC Share
2033	CCCT (1x1)	300 MW
2035	Reciprocating Engines	54 MW
2036	Reciprocating Engines	54 MW

Table 3 - Summary of Resources in 2018 Q1 IPCO Interconnection Queue with Executed Power Sales Agreements

Year	*Capacity (MW)*
Hydro	2
Biomass	5
Solar	24

Idaho Power will incorporate the 2019 IRP resource information into a 2038 sensitivity base case once the 2019 Idaho Power IRP is published which is expected to occur late in the 6th quarter or early 7th quarter of the biennial cycle.

Additional Transmission Uses

The 2038 base case and the five and ten year cases will be modified to reflect the active long-term transmission services and any transmission services submitted during the 2018 quarter 1 data gathering period. Table 4, below, summarizes the long-term transmission services expectations. The table was compiled by summarizing the long-term transmission services (OASIS reservations) with a service end date of 2028 or later.

Table 4 – Summary of New Long Term Transmission Service

Year	*From*	***To***	***MW***
2026 (Summer)	Northwest	Idaho	500
2026 (Summer	Northwest	BPA SEID	250
2026 (Winter)	Northwest	Idaho	200
2026 (Winter)	Northwest	BPA SEID	550

Additionally, any identified needs driven by Public Policy Requirements will be reflected in the base case. Idaho Power evaluated Public Policy Requirements (PPRs) and Public Policy Considerations (PPCs) to determine any transmission needs driven by PPRs or PPCs. It was determined that PPRs and PPCs are already incorporated into Idaho Power's IRP process and that the preferred resource portfolio selection accounts for each noted requirement and consideration. Consequently, the Local Transmission Planning process will not extend analysis to explicitly consider transmission needs beyond those embedded into the IRP process. Further, no PPR or PPC sensitivity analysis will be conducted in the development of the Local Transmission Plan. Refer to Idaho Power's OASIS for further information on the PPRs and PPCs that were considered, https://www.oasis.oati.com/IPCO/IPCOdocs/Transmission_Needs_Driven_By_Public_Policy.pdf.

Assessment Criteria

Power flow studies will be evaluated under steady-state, single element outage and credible multi-element outage conditions to ensure the transmission system meets the system performance requirements defined in the NERC reliability standard NERC TPL-001-4. Further, voltage performance will be evaluated based on Idaho Power's FERC filed Reliability Criteria (FERC Form No. 715).

Outages of transmission facilities 100 kV and above will be considered. Specifically, loss of a single transmission circuit, loss of a single transformer, and loss of a single generator unit will be considered. Credible multi-element outages consist of transmission circuits that share common structures, bus section faults, or circuit breaker failures.

1. Steady-State Conditions

    a. Under steady-state conditions, bus voltages must be maintained between 0.95 p.u. and 1.05 p.u., unless specific minimum operating voltage requirements exist

    b. All line and transformer loadings must be below normal continuous ratings.

2. Contingency Conditions

    a. Changes in bus voltages from pre- to post-contingency conditions must be less than 8% for single P1 N-1 contingencies.. Idaho Power does allow for discretion for post

contingency deviations greater than 8% as long as the minimum voltage remains above 0.90 per unit and the distribution bus voltage is acceptable.

b. All system elements must be below their emergency ratings for both single and multi-element contingencies.

Evaluation Process

PowerWorld power flow software will be utilized to conduct the reliability assessment. If any system reliability issues arise, transmission and non-transmission alternatives will be considered on an equivalent basis.

Confidentiality

The transmission plan studies include data that have been classified by their providers as Critical Energy Infrastructure Information, Confidential Transmission Information, or Proprietary Market Information. Care will be taken to protect such data from unauthorized disclosure. Confidential and Critical Energy Infrastructure Information shall be handled in accordance with Attachment K or other rules and regulations as appropriate.

Revision History

Version	Date	Comment	Author
Revision 0	06/12/2018	Initial Draft	Curtis Westhoff (Idaho Power)