

2025-2026 System Assessment

Local Planning Report



Metro Station, Spokane, Washington

Electric System Planning
 Avista Utilities
 PO Box 3727, MSC-16
 Spokane, WA 99220
 TransmissionPlanning@avistacorp.com
 DistributionPlanning@avistacorp.com

**Redacted
Version**

Prepared by: System Planning

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Metro Station, located in the heart of downtown Spokane, was originally constructed in 1976 and is currently being rebuilt with a planned in-service date of 2027. The rebuild increases transmission reliability in the downtown corridor by terminating the two overhead 115kV transmission lines into the new station along with doubling the 115kV underground connections between Metro Station and Post Street Station. Transmission reliability is also improved with the planned 115kV ring-bus configuration, enabling any 115kV circuit breaker to be taken out of service without a loss in network connectivity.

The new Metro Station also increases distribution reliability in the downtown network by incorporating a similar ring-bus configuration to connect the planned metal-clad switchgear. Distribution capacity is also increased with the upgrade to two 30MVA distribution transformers to serve the southern half of the downtown network. The planned six distribution feeders will serve approximately 6,000 residential, commercial, and governmental customers in the area.

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1. Executive Summary

The Avista System Assessment delivers two primary outcomes concerning the performance of the electric transmission and distribution system under both normal operating conditions and defined outage scenarios and contingencies:

- Comprehensive documentation of technical analysis results demonstrating system performance
- Conceptual solutions aimed at mitigating operational issues to ensure ongoing, reliable performance

The findings from the 2025-2026 System Assessment are based on models that incorporate current conditions as well as predictive forecasts. The underlying assumptions reflect anticipated changes in customer loads and system configurations, including newly completed and projected system assets. Across the Avista service area, customer peak loads are expected to increase an average of 1.12% in winter and 1.14% in summer. These projections account for future load modeling adjustments, such as forecasted electrification and localized growth. For the transmission system analysis, the load forecast includes a likely scenario with significant building and transportation electrification. Methods for integrating electrification forecasts into the distribution system are still in development and were not applied in this assessment. Notably, local load growth in Coeur d'Alene, Post Falls, North Spokane, West Plains, and Lewiston is contributing to new performance concerns and exacerbating previously identified system constraints.

Generation dispatch assumptions have also evolved, influenced by Avista's participation in the Energy Imbalance Market (EIM) since 2022. The EIM enables economic dispatch of resources across participants to optimize supply and demand balancing. As a result, generation dispatch now has a direct impact on electric system performance by altering infrastructure utilization patterns.

Projects not yet approved by the Avista Business Performance Team (BPT), as well as new initiatives to address identified performance issues, have been highlighted through analytical findings, internal collaboration, and external stakeholder input via the Attachment K and Distribution Planning Advisory Group process. Conceptual mitigation strategies for emerging concerns are outlined and will be further refined in coordination with stakeholders. New requests submitted to the BPT will include the following principal recommendations:

- Transmission reinforcements in the Palouse and Sandpoint areas
- Rebuilding Beacon Station to resolve fault duty and performance challenges
- Transmission voltage mitigation through installation of capacitor banks or battery energy storage systems
- Expanding distribution capacity in Coeur d'Alene, Lewiston, North Spokane, and Post Falls

The 2025-2026 System Assessment serves as a foundation for continued dialogue and planning regarding the future of Avista's electric system. The System Planning Team welcomes feedback and additional insights related to this report and will integrate stakeholder input into the development of comprehensive, forward-looking project solutions.

2. Introduction

The System Assessment document includes distribution and transmission contributions. For each, assumptions, corrective action plans, and technical analyses are created and produce current and forecasted system needs. Combined system needs for both distribution and transmission produce a holistic system view and provide transparency of contributions and effects of one focus area to another. The System Assessment document also provides a single point of reference for outside groups requiring system existing and forecasted information.

The *2025-2026 System Assessment* (Local Planning Report) is a deliverable from Phase 2 of a two-year process as defined in Avista's *Open Access Transmission Tariff (OATT) Attachment K*. The System Assessment identifies the Transmission System facility additions required to reliably interconnect forecasted generation resources, serve the forecasted loads of Avista's Network Customers and Native Load Customers, and meet all other Transmission Service and non-OATT transmission service requirements, including rollover rights, over a 10-year planning horizon. The Planning Assessment process is open to all Interested Stakeholders, including, but not limited to, Transmission Customers, Interconnection Customers, and state authorities. The Western Electric Coordinating Council (WECC) facilitates interconnection wide planning and development of wide area planning proposals.

The two-year planning process desired timeline is illustrated in Figure 1. The completion of Phase 2 includes providing the documented results of performing necessary technical studies. The state of the existing and future system is provided. Where the technical studies identified performance issues, conceptual projects have been proposed.

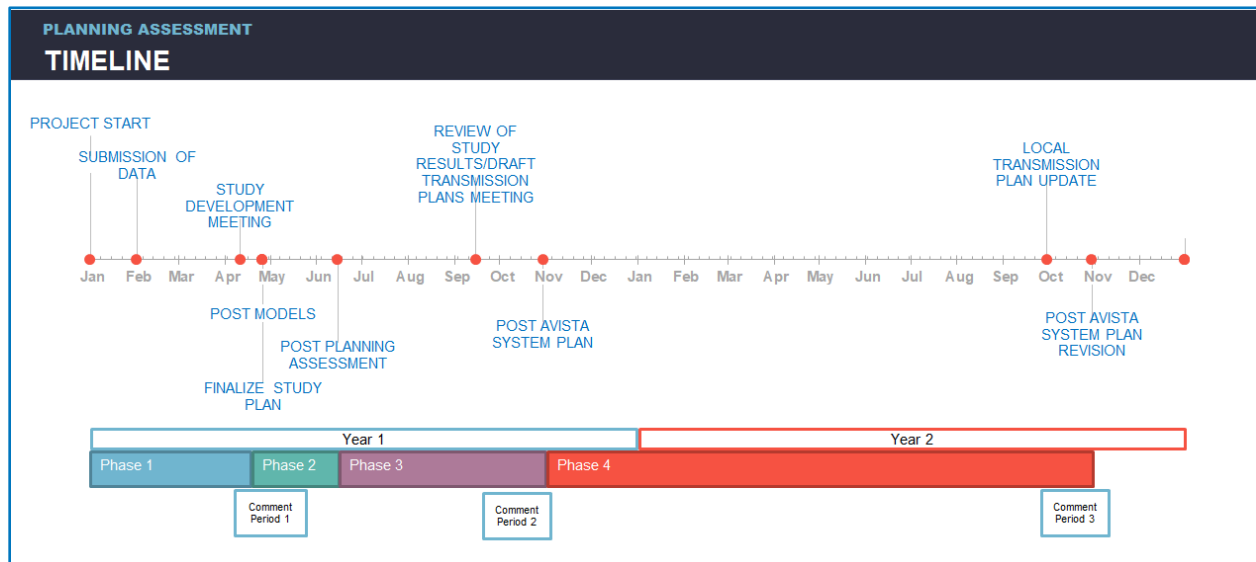


Figure 1: Planning Assessment Timeline

Phase 3 of the process will follow the completion of the System Assessment. Phase 3 includes providing the Avista System Plan report to stakeholders. The Avista System Plan will include documentation of the electrical infrastructure plan with preferred solution options. The resulting project list will include additional information regarding projects and system modifications developed through means other than the technical studies¹.

¹ Such other means may include, for example, generation interconnection or transmission service request study processes under the OATT, or joint study team processes under NorthernGrid.

2.1. Point of Contact

A Point of Contact for questions regarding this System Assessment and the projects described within it has been designated. Please contact the party named below with any questions:

Electric System Planning
Avista Utilities
PO Box 3727, MSC-16
Spokane, WA 99220
TransmissionPlanning@avistacorp.com
DistributionPlanning@avistacorp.com

3. Study Assumptions

The technical studies performed as part of this System Assessment were conducted according to the *2025-2026 Avista System Assessment Study Plan*. The following sections provide a summary of key assumptions regarding the representation of the electrical system and methodologies of analysis.

3.1. Transmission System

3.1.1. System Conditions

A set of transmission system models were developed to represent specific operating scenarios. The scenarios were selected to capture reasonably expected conditions which may stress the performance of the transmission system. Figure 2 and Figure 3 provide a comparison of the Summer and Winter models to the historical Balancing Authority Area (BAA) load and BAA interchange excluding dynamic imports. The model scenarios represented by green markers represent a 1-in-10 probability of occurrence.

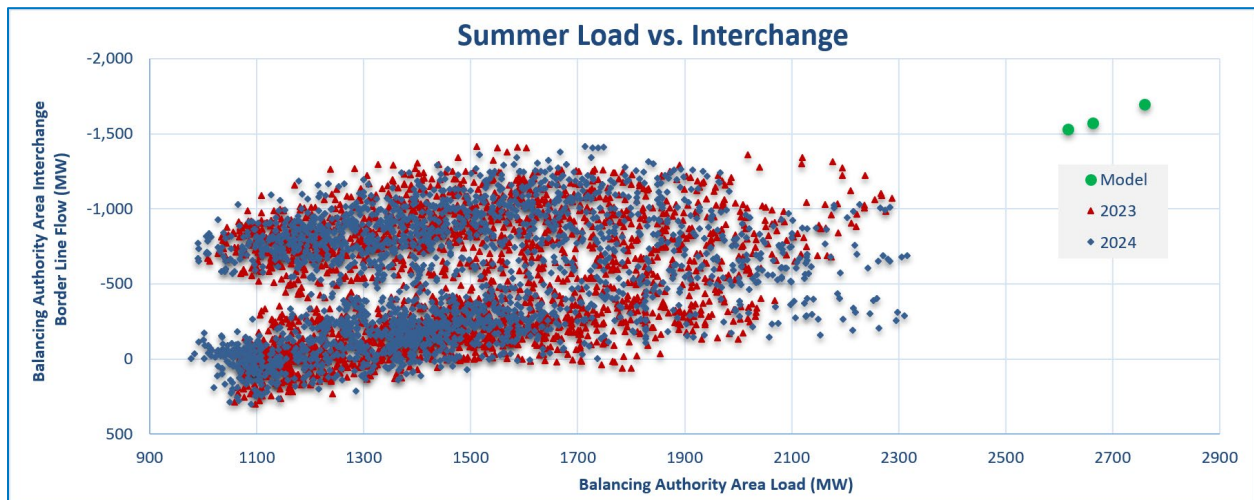


Figure 2: Historical Avista BAA Load Versus Interchange During Summer Months

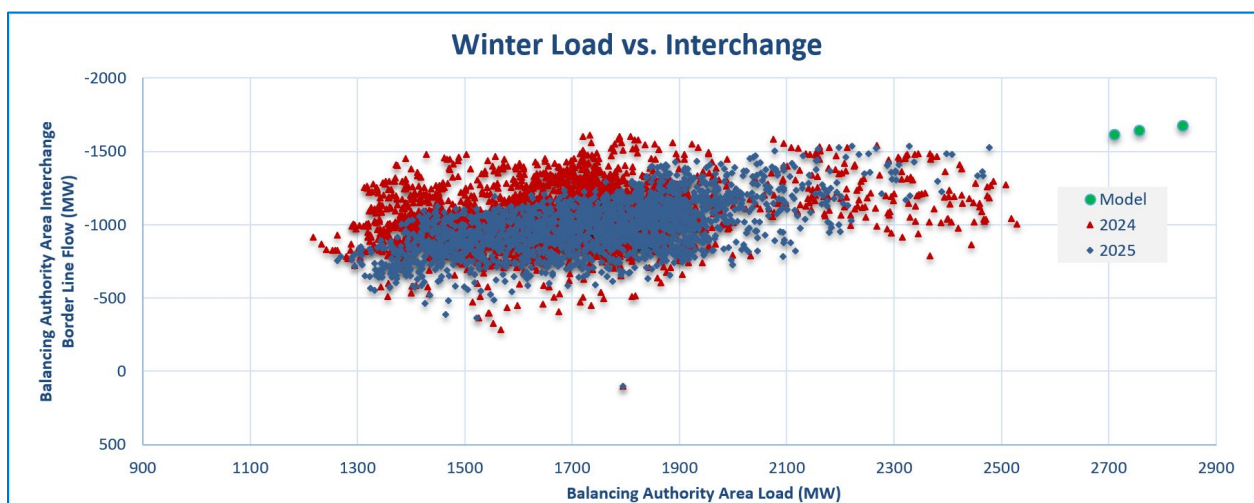


Figure 3: Historical Avista BAA Load Versus Interchange During Winter Months

A detailed summary of specific flows and loading levels modeled in the Planning Cases used for the *2025-2026 System Planning Assessment* is provided in Appendix B – Transmission Models.

3.1.2. Transmission Projects Modeled

The transmission system models include representation of projects expected to be constructed within the applicable planning horizon. The models are analyzed with and without these projects to demonstrate the impact of the projects on the performance of the system. Table 1 provides the list of projects included in the models. Included in Table 1 are designations for projects that are included in the one-, five-, and ten-year planning models. The Five-Year Planned Projects are significant because they represent the expected system configuration and performance in the near-term planning horizon. It should be noted the entire scope of each project is considered complete and operational when included in the designated planning model.

ERT #	Project Name	Driver	Scope	Status	Included in Model		
					1-year	5-year	10-year
12	Carlin Bay Station	Performance & Capacity	Construct new distribution station with one 20MVA xfmr and two feeders. Transmission integration includes constructing a new radial 115kV transmission line from O'Gara Station to Carlin Bay. The second phase of the project includes rebuilding the existing O'Gara Station to a switching station. New microwave communication paths will be established to O'Gara Station.	Construction		X	X
38	Metro Station Rebuild	Asset Condition	Rebuild existing station at new location. Six-position 115kV ring-bus with two 30MVA transformers, two 115kV UG lines from PST, two 115kV OH lines, and switchgear on the 13kV side with Network and Distribution feeders.	Construction		X	X
46	Poleline Station	Performance & Capacity	Construct new distribution station to replace Avista facilities at Prairie Station. New station includes two 30MVA transformers, four feeders, and looped-through transmission without circuit breakers.	Construction	X	X	X
56	Bronx Station Rebuild	Performance & Capacity	Rebuild station in green field location north of existing station. 115kV loop-through distribution station with circuit breakers, one 20MVA transformer, and two feeders. Station design will consider expansion of 115kV to breaker and a half for future reinforcement projects.	Budgeted		X	X
58	Westside Station Rebuild	Performance & Capacity	Replace the existing Westside 230/115kV Transformer and complete bus work to double bus, double breaker on both the 230kV and 115kV buses	Complete	X	X	X
60	Ninth & Central - Sunset 115kV Line Upgrade	Performance & Capacity	Replace the 795 AAC/ACSR conductor on the Ninth & Central – Sunset 115kV Transmission Line with 795 ACSS.	Complete	X	X	X
61	Post Falls Station Rebuild	Customer Requested	Rebuild existing Post Falls Station in green field location adjacent to existing station in ring-bus configuration with three transmission line positions, a metered GSU position, and two 115/13kV distribution transformers with two feeders each.	Budgeted			
62	Lolo Transformer Replacement	Performance & Capacity	Upgrade Lolo 230/115kV 125MVA transformers to 250MVA. 115kV circuit breakers, bus work and other capacity-limiting elements will be replaced. Circuit switchers at Clearwater, Lolo, and Sweetwater stations will be replaced.	Complete	X	X	X
96	Kettle Falls Protection System Upgrades	Mandatory & Compliance	Upgrade existing protection schemes on the Addy – Kettle Falls and Colville – Kettle Falls 115kV Transmission Lines. New relays at Kettle Falls Station and a new communication path from Kettle Falls to Mount Monumental are required.	Construction	X	X	X

ERT #	Project Name	Driver	Scope	Status	Included in Model		
					1- year	5- year	10- year
100	Melville Station	Performance & Capacity	New switching station near existing tap to Four Lakes Station off the South Fairchild Tap 115kV Transmission Line. Construct new transmission line from Airway Heights to Melville including passing through Russel Road and Craig Road Stations. Requires new 115kV terminal at existing Airway Heights Station. The scope also includes rebuilding sections of the Airway Heights – Garden Springs 115kV Transmission Line.	Budgeted		X	X
124	Pine Street – Rathdrum 115kV Transmission Line Upgrade	Performance & Capacity	Rebuild transmission line. Existing 556AAC remains on new structures.	Construction	X	X	X
131	Garden Springs Station	Performance & Capacity	Construct new 115kV portion of Garden Springs Station at the existing Garden Springs switching location. New station will terminate Airway Heights – Sunset and Sunset – Westside 115kV transmission lines including the South Fairchild Tap. Construct new 230kV portion of Garden Springs Station including two 250MVA nominal 230/115kV transformers. Construct new 230kV transmission line from Garden Springs to a new switching station, Bluebird, at an interconnection point on the BPA Bell – Coulee #5 230kV transmission line.	Construction		X	X
134	Craig Road Station	Customer Requested	Customer will construct a new distribution station. Avista will provide a new radial 115kV transmission line from Airway Heights Station as part of the Melville Station project.	Budgeted		X	X
N/A	Boulder-Irvin #1 115kV Transmission Line Upgrade	Performance & Capacity	Project updates the existing Boulder-Irvin #1 115kV Transmission Line from Boulder to SIP. Rebuild the 0.25-mile line section from 556AAC to 795ACSS.	Complete	X	X	X
156	Safely Interrupting Faults	Performance & Capacity	Replace Airway Heights A187 and A511 circuit switchers with 40kA or greater rated equipment. Replace Barker Road A316 circuit switcher with 40kA or greater rated equipment. Replace East Colfax A17 circuit switcher with 20kA or greater rated equipment. Replace Francis & Cedar A676 and A677 circuit switchers with 40kA or greater rated equipment. Replace Garfield EG-1 transformer fuse with 10kA or greater rated fuse. Replace Lakeview R330 circuit switcher with 20kA or greater rated equipment. Replace Leon Junction SMD-2B transformer fuse with 15kA or greater rated fuse. Replace Long Lake SMD-2B transformer fuse with 15kA or greater rated fuse. Replace North Moscow SMD-2B transformer fuse with 15kA or greater rated fuse. Replace Post Street A435 and A436 circuit switchers with 40kA or greater rated equipment. Replace South Othello A57 circuit switcher with 20kA or greater rated equipment.	Budgeted		X	X
158	North Spokane Transmission Reinforcement	Performance & Capacity	Project 1: Loop existing Boulder – Irvin #1 115kV Transmission Line into BPA's Trentwood Station. Project 2: Construct new Five Mile 115kV Station with loop through of Nine Mile – Westside 115kV requiring 3-miles of new 115kV line. New BPA interconnection at Bell Station to create Bell - Five Mile 115kV line using 1.5 miles of new line and portion of Beacon – Francis & Cedar 115kV line. New Five Mile – Francis & Cedar 115kV line using 1.5 miles of new line.	Budgeted		X	X

ERT #	Project Name	Driver	Scope	Status	Included in Model		
					1- year	5- year	10- year
159	Kootenai County Transmission Reinforcement	Performance & Capacity	Construct new 230/115kV station in Kootenai county to include the loop through of Lancaster – Rathdrum 230kV Transmission Line, two 250MVA 230/115kV transformers, and integration of three area 115kV transmission lines.	Budgeted			X
165	Lewiston 115kV Mitigation	Performance & Capacity	Construct new Bryden Canyon Station on green field site. Station consists of 115kV ring-bus to create transmission lines to North Lewiston, Dry Creek, and Lolo. Distribution facilities will include two 30MVA transformers and six feeders. Station replaces existing South Lewiston Station.	Budgeted		X	X
166	Lewiston 230kV Mitigation	Performance & Capacity	Construct second Hatwai – Lolo #2 230kV Transmission Line. Scope includes 230kV line positions at Hatwai and Lolo Stations.	Proposed			X
N/A	Pound Lane Bypass	Operational	Reconfigure Lolo – Pound Lane 115kV Transmission Line with the Pound Lane – South Lewiston section open at South Lewiston and the Holbrook – South Lewiston section closed.	In service	X	X	X
N/A	Lolo – Oxbow Rebuild	Asset Condition	Rebuild Lolo – Oxbow 230kV Transmission Line to address asset condition and achieve higher capacity.	Proposed			X

Table 1: Projects Represented in Transmission System Models

3.1.3. Performance Criteria

Avista's transmission system performance criteria are defined in *TP-SPP-01 – Transmission System Performance*. Specific criteria are provided for acceptable steady state voltage limits, post-contingency voltage deviations, transient voltage response, thermal performance, load loss limits and allowable operating plans for the system. Criteria for identifying system instability, weak systems, and acceptable short circuit equipment loading are also provided.

3.1.4. Studies Performed

Technical studies are performed as part of the System Assessment. The methodologies for each study are documented in *TP-SPP-01 – Transmission System Performance*². The defined set of technical studies include:

- Steady State Contingency Analysis
- Spare Equipment Analysis
- Short Circuit Analysis
- Stability Contingency Analysis
- Voltage Stability Analysis
- Protection System Failure Analysis

² TP-SPP-01 Transmission System Performance V8, December 5, 2023, Table 1, pages 5-6.

3.2. Distribution System

3.2.1. System Conditions and Modeling Assumptions

The power system model used to analyze the distribution system was based on a snapshot of the system as it existed in April 2025, with all lines and equipment in service. The loads characterized in the model used the peak load and load curve SCADA data from 2022, 2023, and 2024. A load forecast was developed using a multivariate regression analysis with each feeder assumed to have a decaying growth rate over the 10-year planning horizon. The highest growth rates were observed in the Coeur d'Alene, Rathdrum, and Post Falls areas.

Figure 4 shows an example of the multiple regression used to project a feeder's rate of load growth. The plot represents CW12F1, a feeder at College & Walnut station. The pink represents actual data, the teal is the tool's ability to replicate the load based on the data provided, and the orange is the difference between the actual and replicated data. The orange is used to validate the tool captures the patterns of loading on the feeder. The growth rate is shown in the left corner, and the curve fit is the R^2 value. The data uses heating and cooling degree days along with the day of week, season, and hour to forecast growth. Forecasted load is primarily based on 40-year average heating and cooling degree day data. All growth has an added decay rate over the 10-year planning horizon to fully represent the normal growth patterns over areas with many diverse loads.

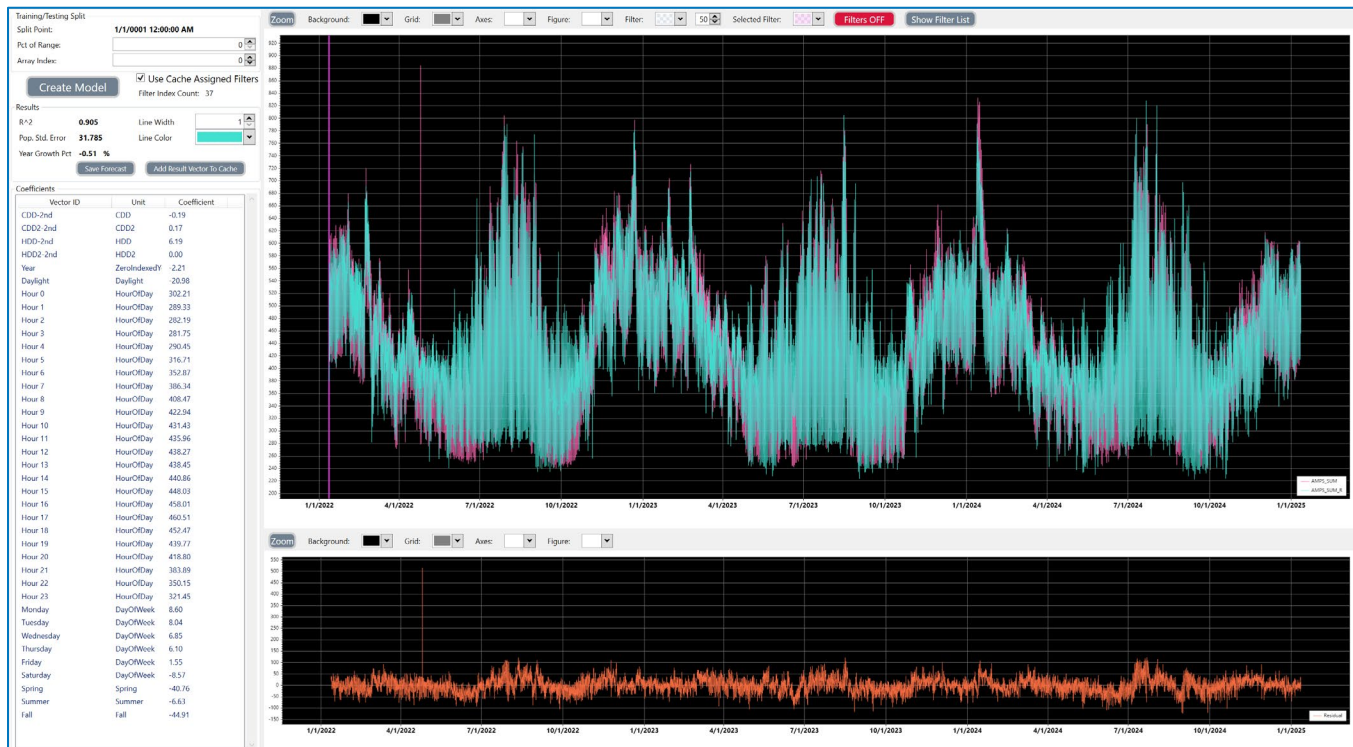


Figure 4: College & Walnut-Example Load Regression Analysis Forecast

Specific seasonal and loading scenarios are represented within the models and are used to evaluate if the system will meet the performance criteria defined in *DP-SPP-02 – Distribution System Performance*. When analysis indicates an inability of the system to meet the performance criteria for the scenarios listed in Table 2, projects will be developed addressing how the performance criteria will be met. Additional sensitivity scenarios may be studied in addition to those listed in Table 2.

Scenario	Description
Heavy Summer	Day-time peak load occurring between June and August with loads representing a 1-in-10 probability
Heavy Winter	Day-time peak load occurring between December and March with loads representing a 1-in-10 probability
Heavy Summer Sensitivity	Same scenario as Heavy Summer with loads representing the highest summer temperature on record
DER Adoption	PV and EV potential adoption by census block group

Table 2: Distribution System Scenarios

Historical weather data was reviewed to select the scenarios listed in Table 3. *DP-SPP-02 – Distribution System Performance V5* outlines the methodology and data for Table 3.

Location	Heavy Summer	Heavy Winter
Colville	103	-19
Sandpoint	102	-10
Lewiston	108	-10
St Maries	102	-14
Spokane	104	-17
Othello	108	-15
Silver Valley	102	-14

Table 3: Historical 1-in-10 Temperature (°F)

3.2.2. Projects Modeled

The distribution system models include representation of projects expected to be constructed within the applicable planning horizon. The models are analyzed with and without these projects to demonstrate the impact of the projects on the performance of the system. Table 4 provides a list of projects which will be included in the models when individual project analysis is performed.

ERT #	Project Name	Driver	Scope	Status	Included in Model		
					1-year	5-year	10-year
12	Carlin Bay Station	Performance & Capacity	Construct new distribution station to include single 20MVA transformer and two feeders. Transmission integration includes constructing a new radial transmission line from O'Gara Station to Carlin Bay. The second phase of the project includes rebuilding the existing O'Gara Station to a switching station. New microwave communication paths will be established to O'Gara Station.	Construction		X	X
38	Metro Station Rebuild	Asset Condition	Rebuild existing substation at new location. 115kV bus to be a 6-position ring; 2 – 30MVA xfmrs, 2 – 115kV UG lines from PST, 2 – 115kV OH lines; switchgear on the 13kV side, both Network and Distribution feeders	Construction		X	X
43	Valley Station Rebuild	Performance & Capacity	Rebuild existing Valley Station with one 20MVA transformer and three feeders.	Construction		X	X
46	Poleline (Prairie) Station Rebuild	Performance & Capacity	Construct new distribution station to replace Avista facilities at existing Prairie Station. New station includes two 30MVA transformers, four feeders, and looped-through transmission without circuit breakers.	Construction		X	X
56	Bronx Station Rebuild	Performance & Capacity	Reconstruct existing Bronx Station and green field loop through distribution station with 115kV circuit breakers, a 20MVA transformer, and two feeders. Station design will consider expansion of 115kV to breaker and a half for future reinforcement projects.	Budgeted		X	X

ERT #	Project Name	Driver	Scope	Status	Included in Model		
					1- year	5- year	10- year
61	Post Falls Station Rebuild	Customer Requested	Rebuild existing Post Falls Station in green field location adjacent to existing station. New station will be ring bus configuration with three transmission line positions, a metered GSU position, and two 115/13kV distribution transformers. The distribution transformers will have four feeders connected.	Proposed			
100	Melville Station	Performance & Capacity	Scope not complete. New switching station near existing tap to Four Lakes Station off the South Fairchild Tap 115kV transmission line. Construct new transmission line from Airway Heights to Melville including passing through Russel Road and Craig Road distribution stations. Requires new transmission line terminal at existing Airway Heights Station.	Budgeted		X	X
140	Bunker Hill Customer Capacity	Customer Requested	Install new 20MVA transformer to replace existing transformer and construct new dedicated customer distribution feeder.	Budgeted		X	X
151	Pleasant View Capacity Mitigation	Performance & Capacity	Expand existing station by installing new 30MVA transformer and two feeders.	Budgeted		X	X
160	Northeast Capacity Mitigation	Performance & Capacity	Replace two existing 20MVA transformers with 30MVA transformers and add new NE12F6 feeder. Transformer circuit switchers replacements are included in scope to eliminate existing fault blocking scheme. Distribution integration scope includes new switches and an express feeder truck.	Budgeted		X	X
161	Glenrose Capacity Mitigation	Performance & Capacity	Replace existing transformer with 30MVA and rebalance feeders. Regulator upgrades assumed to be an existing flex crew project.	Budgeted		X	X
163	Orin Capacity Mitigation	Performance & Capacity	Construct new distribution station connected to BPA's Colville – Republic 115kV Transmission line. New station will include a single 20MVA transformer and two distribution feeders.	Budgeted		X	X
147	Moscow Capacity Mitigation	Performance & Capacity	Construct new Selkirk distribution station to add capacity for unloading the existing Moscow Station and for future load growth on the south side of Moscow.	Proposed		X	X
164	Lewiston Capacity Mitigation	Performance & Capacity	Construct a portion of new station north of existing Tenth and Stewart Station with single 30MVA transformer and three feeders, leaving existing station in-service as needed. Upgrade existing Lolo transformer to be new 30MVA transformer and upgrade feeder regulators to 438A regulators.	Proposed			X
Flex	Rathdrum Distribution Expansion	Performance & Capacity	Construct new RAT234 13kV feeder at existing Rathdrum Station.	Budgeted		X	X

Table 4: Projects Represented in Distribution System Models

3.2.3. Performance Criteria

The performance criteria used in evaluating the performance of the distribution system is outlined in *DP-SPP-02 – Distribution System Performance V5* Table 1³.

3.2.4. Studies Performed

Technical studies are performed as part of the System Assessment. The methodologies for each study are documented in *DP-SPP-02 – Distribution System Performance*. The defined set of technical studies include:

- Load Forecast Development

³ DP-SPP-02 – Distribution System Performance V5, May 15, 2023, Table 1, page 5.

- Multi-Year Load-Flow Analysis
- Contingency Analysis (under development)
- Auto-Transfer Analysis
- Short Circuit Analysis (under development)

4. Corrective Action Plans

When technical studies demonstrate the system's inability to meet performance requirements, Corrective Action Plans are developed to address how the performance requirements will be satisfied. Revisions to Corrective Action Plans are allowed in subsequent System Assessments but the planned system must continue to meet performance requirements. Corrective Action Plans can be developed to meet the performance requirements for one or more sensitivity cases analyzed.

Corrective Action Plans developed to address performance issues identified on the transmission system must be implemented in accordance with TPL-001-5⁴ R2.7. If situations arise outside Avista's control that prevents the implementation of a Corrective Action Plan within the required timeframe, Avista is then permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation while providing documentation of the actions and resolution. Avista shall document the problematic performance issue, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service. (TPL-001-5, R2.7.3)

In some instances, performance requirements can be met using Operating Procedures, making Corrective Action Plans unnecessary. Operating Procedures may also introduce undesired risks to the system. Projects are developed and recommended to address the instances where expected system performance using Operating Procedures is not considered acceptable.

Corrective Action Plans for the transmission and distribution system are provided in the following sections.

4.1. Existing Projects

Included in Table 5 below are projects identified in prior years' technical studies that have been incorporated into Avista's Engineer Roundtable prioritized project list.

ERT #	Project Name	Driver	Scope	Status	TPL CAP
12	Carlin Bay Station	Performance & Capacity	Construct new distribution station with one 20MVA transformer and two feeders. Transmission integration includes constructing a new radial 115kV transmission line from O'Gara Station to Carlin Bay. The second phase of the project includes rebuilding the existing O'Gara Station to a switching station. New microwave communication paths will be established to O'Gara Station.	Construction	No
43	Valley Station Rebuild	Asset Condition	Rebuild existing Valley Station with 20MVA transformer and three feeders.	Construction	No
56	Bronx Station Rebuild	Performance & Capacity	Rebuild station in green field location north of existing station. 115kV loop-through distribution station with circuit breakers, one 20MVA transformer, and two feeders. Station design will consider expansion of 115kV to breaker and a half for future transmission reinforcement projects.	Construction	No
96	Kettle Falls Protection System Upgrades	Mandatory & Compliance	Upgrade existing protection schemes on the Addy – Kettle Falls and Colville – Kettle Falls 115kV Transmission Lines. New relays at Kettle Falls Station and a new communication path from Kettle Falls to Mount Monumental are required.	Construction	Yes

⁴ NERC Transmission Planning standard TPL-001-5, <https://nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.pdf>.

ERT #	Project Name	Driver	Scope	Status	TPL CAP
100	Melville Station	Performance & Capacity	New switching station near existing tap to Four Lakes Station off the South Fairchild Tap 115kV Transmission Line. Construct new transmission line from Airway Heights to Melville including passing through Russel Road and Craig Road Stations. Requires new 115kV terminal at existing Airway Heights Station. The scope also includes rebuilding sections of the Airway Heights – Garden Springs 115kV Transmission Line. Rebuild 7-mile section of Airway Heights - Garden Springs 115kV line.	Budgeted	No
131	Garden Springs Station	Performance & Capacity	Construct new 115kV portion of Garden Springs Station at the existing Garden Springs switching location. New station will terminate Airway Heights – Sunset and Sunset – Westside 115kV Transmission Lines including the South Fairchild Tap. Construct new 230kV portion of Garden Springs Station including two 250MVA nominal 230/115kV transformers. Construct new 230kV transmission line from Garden Springs to a new switching station, Bluebird, at an interconnection point on the BPA Bell – Coulee #5 230kV Transmission Line. Includes transmission rebuild of Garden Springs - Sunset 115kV line.	Budgeted	Yes
147	Moscow Capacity Mitigation	Performance & Capacity	Construct new Paradise Ridge distribution station to add capacity for unloading the existing Moscow Station and for future load growth on the south side of Moscow.	Budgeted	No
151	Pleasant View Capacity Mitigation	Performance & Capacity	Add a new 30MVA transformer and two feeders to the existing station.	Budgeted	No
156	Safely Interrupting Faults	Performance & Capacity	Replace Airway Heights A187 and A511 circuit switchers with 40kA or greater rated equipment. Replace Barker Road A316 circuit switcher with 40kA or greater rated equipment. Replace East Colfax A17 circuit switcher with 20kA or greater rated equipment. Replace Colville A297 circuit switcher with 20kA or greater rated equipment. Replace Francis & Cedar A676 and A677 circuit switchers with 40kA or greater rated equipment. Replace Garfield EG-1 transformer fuse with 10kA or greater rated fuse. Replace Lakeview R330 circuit switcher with 20kA or greater rated equipment. Replace Leon Junction SMD-2B transformer fuse with 15kA or greater rated fuse. Replace Long Lake SMD-2B transformer fuse with 15kA or greater rated fuse. Replace North Moscow SMD-2B transformer fuse with 15kA or greater rated fuse. Replace Post Street A435 and A436 circuit switchers with 40kA or greater rated equipment. Replace South Othello A57 circuit switcher with 20kA or greater rated equipment.	Budgeted	No
158	North Spokane Transmission Reinforcement	Performance & Capacity	Project 1: Loop existing Boulder – Irvin #1 115kV Transmission Line into BPA's Trentwood Station. Project 2: Construct new Five Mile 115kV Station with loop through of Nine Mile – Westside 115kV requiring 3-miles of new 115kV line. New BPA interconnection at Bell Station to create Bell - Five Mile 115kV line using 1.5 miles of new line and portion of Beacon – Francis & Cedar 115kV line. New Five Mile – Francis & Cedar 115kV line using 1.5 miles of new line.	Budgeted	Yes
159	Kootenai County Transmission Reinforcement	Performance & Capacity	Construct new 230/115kV station in Kootenai county to include the loop through of Lancaster – Rathdrum 230kV Transmission Line, two 250MVA 230/115kV transformers, and integration of three area 115kV transmission lines.	Budgeted	Yes
160	Northeast Capacity Mitigation	Performance & Capacity	Replace two existing 20MVA transformers with 30MVA transformers and add new NE12F6 feeder. Transformer circuit switchers replacements are included in scope to eliminate existing fault blocking scheme. Distribution integration scope includes new switches and an express feeder truck.	Construction	No

ERT #	Project Name	Driver	Scope	Status	TPL CAP
161	Glenrose Capacity Mitigation	Performance & Capacity	Replace two existing 20MVA transformers with 30MVA transformers and add new NE12F6 feeder. Transformer circuit switchers replacements are included in scope to eliminate existing fault blocking scheme. Distribution integration scope includes new switches and an express feeder truck.	Budgeted	No
163	Orin Capacity Mitigation	Performance & Capacity	Construct new distribution station connected to BPA's Colville – Republic 115kV Transmission line. New station will include a single 20MVA transformer and two distribution feeders.	Budgeted	No
164	Lewiston Capacity Mitigation	Performance & Capacity	Construct portion of new station north of existing Tenth and Stewart Station with single 30MVA transformer and three feeders, leaving existing station in-service as needed. Upgrade existing Lolo transformer to be new 30MVA transformer and upgrade feeder regulators to 438A regulators.	Budgeted	No
165	Lewiston 115kV Mitigation	Performance & Capacity	Construct new Bryden Canyon Station on green field site. Station consists of 115kV ring-bus to create transmission lines to North Lewiston, Dry Creek, and Lolo. Distribution facilities will include two 30MVA transformers and six feeders. Station replaces existing South Lewiston Station.	Budgeted	No
166	Lewiston 230kV Mitigation	Performance & Capacity	Construct second Hatwai – Lolo #2 230kV Transmission Line. Scope includes 230kV line positions at Hatwai and Lolo Stations.	Budgeted	No

Table 5: Existing Projects Included in Avista's Five-Year Capital Budget Plan

4.2. New Projects

Corrective Action Plans identified by technical analysis completed as part of the *2025-2026 System Assessment* are provided in this section. The Corrective Action Plans provided were not identified during previous years' technical analyses or they were identified in earlier System Assessments, but a comprehensive Corrective Action Plan has not been developed and/or approved through the Engineering Review Process. The following issues are not included in Avista's prioritized project list.

The project scope outlined for each Corrective Action Plan is preliminary and will require further study including the evaluation of alternatives (traditional and non-traditional) and coordination with stakeholders to confirm the appropriate scope is executed. Each Corrective Action Plan will be reviewed in subsequent System Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures. (TPL-001-5, R2.7.4)

The new required projects and associated performance issues, in addition to the planned projects included in the study assumptions, are summarized in Table 6 below.

Issue	Corrective Action Plan			System Impact			TPL?
	Project Name	Planning Scope	Desired In-service Timeline	Worst Performance Criteria Issue	Impacted Facilities	Impact Timeline	
1	Sandpoint Area Transmission Reinforcement	New 115kV transmission into the Sandpoint area or upgrades of existing facilities	5-10 years	N-1-1 (P6) of Cabinet & Libby 230/115kV transformers	ALFL-SDCK overload & voltage collapse	Existing	Yes
2	Beacon Transmission Reinforcement	Rebuild Beacon with higher capacity equipment and redundant bus design	5-10 years	Close-in fault on BEA 115/13kV transformer and Beacon breaker failures	BEA 115kV circuit breakers and Spokane 115kV system	Existing	Yes
3	Palouse Area Transmission Reinforcement	Under development	5-10 years	N-1-1 (P6) of Moscow & Shawnee 230/115kV transformers	M23-M15 115kV & voltage collapse	Existing	Yes, Ops Plan

Issue	Corrective Action Plan			System Impact			TPL?
	Project Name	Planning Scope	Desired In-service Timeline	Worst Performance Criteria Issue	Impacted Facilities	Impact Timeline	
4	Safely Interrupting Faults	Expand project scope to include: Replace Indian Trail A742 circuit switcher with 40kA or greater rated equipment. Update Third & Hatch A672 circuit switcher Fault Reduction Scheme Reduce project scope to exclude: East Colfax, Lakeview, Leon Junction, and Long Lake	2-5 years	Faults on distribution transformers	3HT & INT	Near-term	No
5	West of Lancaster Constraint	New 230kV line from Boulder to Rathdrum	2-5 years	N-2 (P7) of West of Lancaster lines	BLD-RAT, OTI-PF, PF-RAM	Existing	No, Ops Plan
6	Coeur d'Alene Station Voltage Support	New capacitor bank or BESS at Coeur d'Alene Station	4-6 years	N-1-1 (P6) of two lines into Coeur d'Alene Station	CDA	Existing	No
7	Grangeville Station Voltage Support	New capacitor bank or BESS at Grangeville Station	4-6 years	N-1-1 (P6) of two lines into the area	GRV, COT, WIK, KAM, ORO, KOO, EGV	Existing	No
8	Mead Station Voltage Support	Scope undetermined	9-10 years	N-1 (P2.1) of Bell end of Addy – Bell 115 line	LOO, CLY, DEP, MLN, TUM, HMN, COL, MEA	Long-Term	No
9	Northwest Transmission Reinforcement	Reconductor 3.5 miles of L&S-ROS 115kV	4-6 years	N-1-1 (P6) of two lines into the area	F&C-ROS 115kV	Existing	Yes
10	West Spokane Transmission Reinforcement	Scope undetermined	4-6 years	N-1-1 (P6) of BLU-GDN and GDN-WES	ROS-3HT	Near-term	Yes
11	Avondale Capacity Mitigation	Upgrade AVD151 regulator	7-8 years	Peak summer capacity	AVD151	Long-term	No
12	Coeur d'Alene Capacity Mitigation	Scope undetermined	4-5 years	Peak summer capacity	CDA124, CDA125	Near-term	No
13	Colbert Capacity Mitigation	Scope undetermined	4-5 years	Peak summer capacity	COB XFMR 1, COB12F2	Near-term	No
14	Deer Park Capacity Mitigation	Scope undetermined	4-5 years	Peak winter capacity	DEP XFMR 2, DEP12F1	Near-term	No
15	Downriver Capacity Mitigation	Phase balancing	4-5 years	Peak summer capacity	DRV XFMR 1, DRV12F3	Near-term	No
16	Glenrose Capacity Mitigation	Review existing project scope	6-8 years	Peak summer capacity	GLN12F2	Long-term	No
17	Idaho Road Capacity Mitigation	Post Falls station rebuild	9-10 years	Peak summer capacity	IDR XFMR 1, IDR253	Long-term	No
18	Indian Trail Capacity Mitigation	Scope undetermined	4-5 years	Peak summer capacity	INT12F1	Near-term	No
19	Kooskia 34 Capacity Mitigation	New feeder tie to transfer customer	1-2 years	Peak winter capacity	K34 XFMR 1	Existing	No
20	Lewiston Capacity Mitigation	New LOID Substation with two feeders	2-3 years	Peak summer capacity	TEN, LOL, SLW	Existing	No
21	Milan Capacity Mitigation	Coordinate mitigation with transfer customer	1-2 years	Peak winter capacity	MLN XFMR 2, MLN12	Existing	No

Issue	Corrective Action Plan			System Impact			TPL?
	Project Name	Planning Scope	Desired In-service Timeline	Worst Performance Criteria Issue	Impacted Facilities	Impact Timeline	
22	Northeast Capacity Mitigation	Scope undetermined	6-7 years	Peak summer capacity	NE12F1	Long-term	No
23	Pound Lane Capacity Mitigation	Scope undetermined	1-2 years	Peak summer capacity	PDL XFMR 1, PDL1201, PDL1203	Existing	No
24	Priest River Capacity Mitigation	Upgrade existing transformer	3-5 years	Peak winter capacity	PRV XFMR 1	Existing	No
25	South Lewiston Capacity Mitigation	Construct new Bryden Canyon Station	4-5 years	Peak summer capacity	SLW XFMR 1, SLW XFMR 2	Near-term	No
26	South Othello Capacity Mitigation	Add second transformer to SOT	4-5 years	Peak summer capacity	SOT XFMR 1	Near-term	No
27	Spangle Capacity Mitigation	Coordinate mitigation with transfer customer	1-2 years	Peak winter capacity	SPA XFMR 1, SPA441	Existing	No
28	Turner Capacity Mitigation	Scope undetermined	1-2 years	Peak winter capacity	TUR116	Existing	No

Table 6: Corrective Action Plans Identified in 2025-2026 System Assessment

4.2.1. Transmission Issues and Potential Mitigation

4.2.1.1. Sandpoint Transmission Reinforcement

The Sandpoint area load is served by one Avista 115kV transmission line and two Bonneville Power Administration (BPA) 115kV transmission lines. This area has multiple contingency overload issues during heavy loading conditions (230MW winter peak). Additionally, load increases in the area have resulted in these contingency issues being identified in both the summer and winter seasons.

BPA currently has an N-1 (P1) voltage issue for the loss of their Libby 230/115kV Transformer which they plan to mitigate with reactive support at their Troy Station in 2032.

The remaining issues involve multiple contingencies that result in thermal overloads and low voltage issues. The most impactful is an N-1-1 (P6 long lead) outage combination involving the Libby 230/115kV Transformer and the Cabinet 230/115kV Transformer, which overloads BPA's Albeni Falls – Sand Creek 115kV Transmission Line as it is left serving all the area load. This outage combination also results in low voltage, up to and including voltage collapse under peak loading conditions.

A reinforcement project needs to be developed to mitigate the observed transmission line overloads and low voltages during outage conditions. Several alternatives exist and vary in scope. The project may include the construction of a new 115kV transmission line to the Sandpoint area from Rathdrum or Albeni Falls Stations, providing a fourth transmission line into the area. Coordination of a project with BPA could include upgrades to the Albeni Falls – Sand Creek 115kV Transmission Line and the construction of additional reactive support in the area. The optimum long-term mitigation alternative has not been determined. Further analysis of the project is necessary and will be evaluated in subsequent system assessments.

The rebuild of Bronx Station adds distribution capacity and is planned to be an initial phase of a local 115kV transmission expansion to support the Sandpoint area. The Bronx Station capacity addition and preliminary scope for a future switching station is shown in Figure 5.

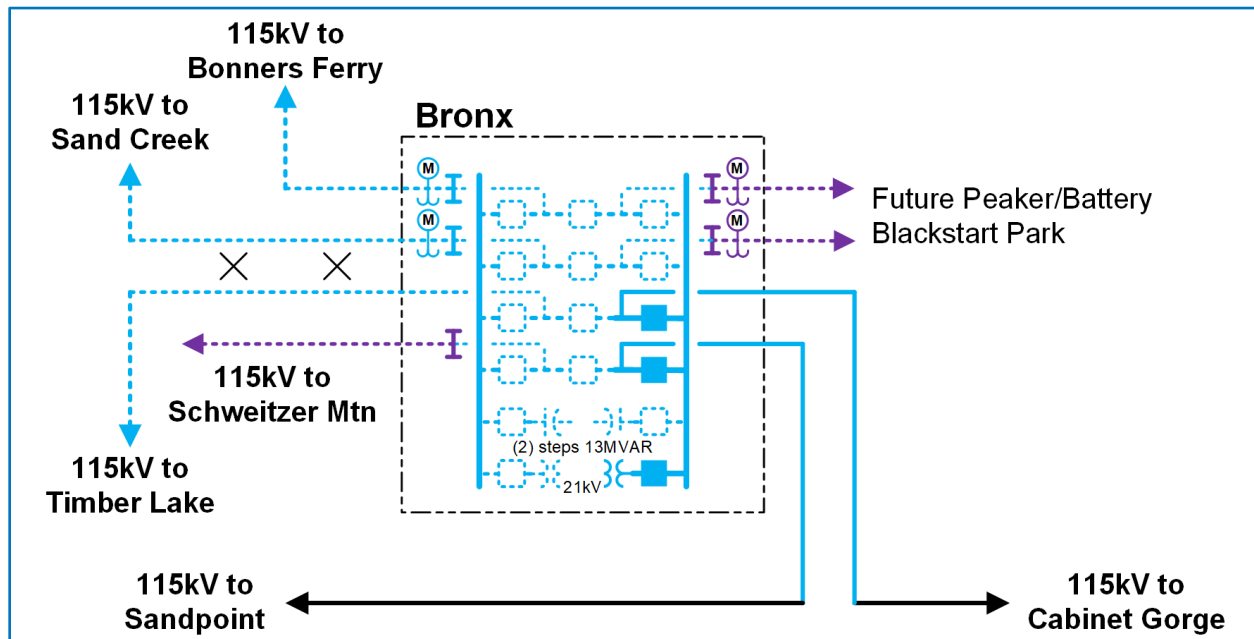


Figure 5: Bronx Station Rebuild - New Distribution Capacity and Space for 115kV Expansion

The need for the Sandpoint Transmission Reinforcement Project was identified through the transmission steady state near-term contingency analysis.

4.2.1.2. Beacon Transmission Reinforcement

The performance of the Beacon Station is a critical part of reliably for serving load in the Spokane area. Short circuit and contingency analysis indicate improvements are necessary to meet reliability requirements.

The available fault duties for high voltage circuit breakers at the Beacon Station presently exceed 95% of their interrupting ratings. The A-608 and A-614 positions, protecting Beacon 115/13kV Transformer 1 and 2 respectively, have an available fault current above 38kA. Several other 115kV transmission line positions have fault duties greater than 90% of their equipment rating or exceeding the equipment rating after planned projects are constructed in the area. Initial review of the mechanical capability of the bus indicated adequacy to the 40kA level. Further evaluation of the existing station's mechanical design for fault withstand is also necessary.

In addition to the underrated interrupting capabilities, a 115kV or 230kV bus-tie breaker failure (P2.4) causes performance issues in the area. Outages including either of the Beacon 230/115kV Transformers in combination with the Bell 230/115V Transformer also cause performance issues (P6 long lead) issues in the long-term horizon. Long-term outages of either Beacon transformers, even with an available spare, will cause possible load serving constraints during heavy system loading.

The protection system, single point of failure analysis, identified contingencies at Beacon as problematic. Evaluation of design alternatives is required.

A rebuild of the Beacon Station is proposed. Evaluation of a feasible construction plan for the rebuild needs to be developed. The resulting station rebuild will require circuit breakers rated at industry standard 50kA or greater, and bus configuration either as double bus double breaker or breaker and a half. Additional consideration on whether a third 230/115kV transformer or a larger class of transformers will also be necessary. A preliminary single line diagram is shown in Figure 6.

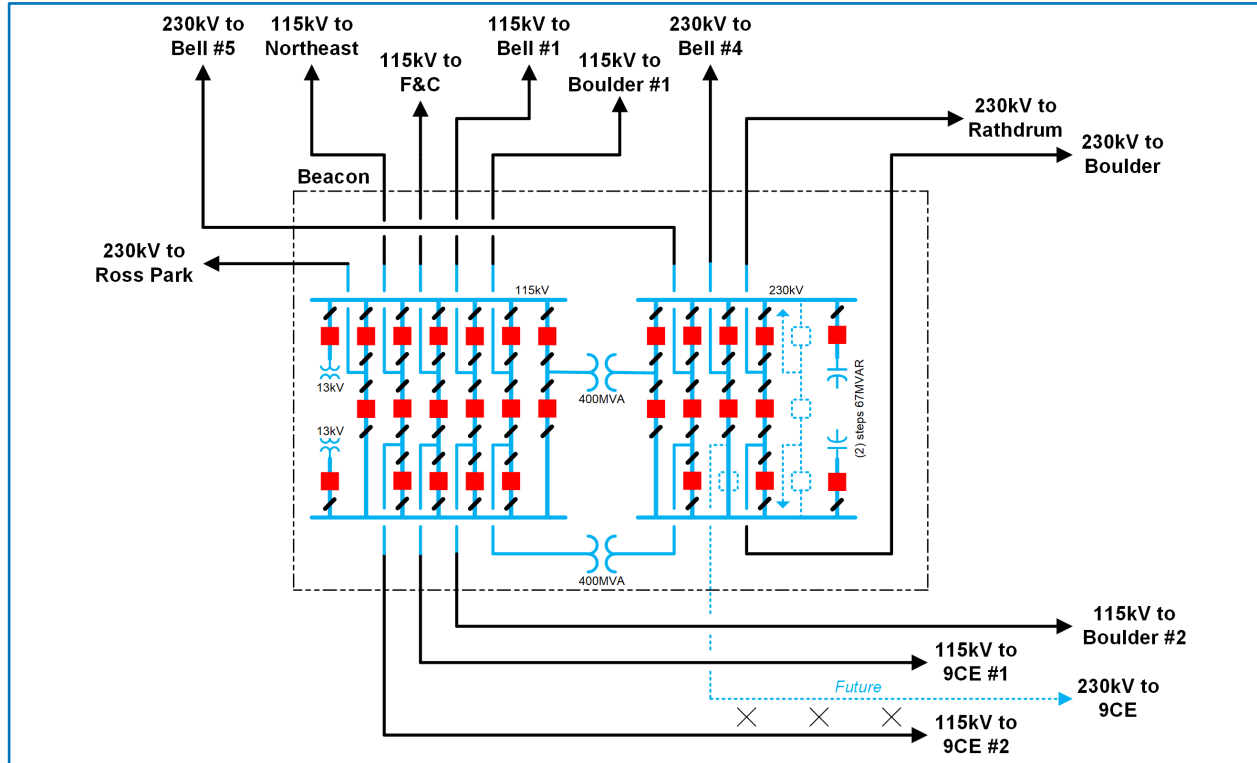


Figure 6: Preliminary Beacon Rebuild – Single Line Diagram

The need for the Beacon Transmission Reinforcement Project was identified through the transmission short circuit analysis, steady-state contingency analysis, spare equipment analysis, and single point of failure analysis. Further development of the scope for the Beacon Transmission Reinforcement Project is necessary and will be reviewed in subsequent system assessments.

4.2.1.3. Palouse Transmission Reinforcement

There are two primary deficiencies in the Palouse area resulting from outages of the 230/115kV transformers or the two 115kV transmission lines that connect Moscow Station to Shawnee Station.

First, the combined N-1-1 (P6 long lead) outage of the Moscow 230/115kV and Shawnee 230/115kV transformers cause low voltage, up to and including voltage collapse under peak loading conditions in the Palouse area if there are no mitigating actions taken following the outage of the first transformer. System deficiencies are observed in all scenarios studied but the worst performance occurs in the Heavy Winter scenario.

An Operating Procedure to open all 115kV ties during a 230/115kV transformer outage is in place today to mitigate this issue. Given a forced or planned outage of the first transformer, followed by a second transformer outage (N-1-1, P6 long lead) results in a system blackout

with up to 220MW of load loss, which is localized to the Palouse area. Some of the dropped load can be restored by transferring to neighboring 115kV sources, but up to 60MW of load would be permanently off-line during heavy load conditions until a 230/115kV transformer was restored. The Operating Procedure permits the deferral of a Corrective Action Plan to meet the TPL-001-5 requirements.

Secondly, the two 115kV transmission lines connecting Moscow Station to Shawnee Station are nearing their load serving capacity. The primary issue is low voltage being observed for an N-1-1 (P6) outage of the Shawnee 230/115kV Transformer followed by either an outage of the Moscow – South Pullman or Moscow 230 – Terra View 115kV Transmission Lines. A maintenance issue is the N-1-1 (A6) combination of either of these lines with an open point at Moscow, plus the loss of the Shawnee 230/115kV transformer results in thermal overloads on the remaining 115kV transmission line serving the loop.

These line issues occur during the heavy summer scenarios and can be addressed with an Operating Procedure to transfer Moscow City Station south to North Lewiston Station.

A preliminary concept to resolve these issues was explored. The first issue could be corrected with a third 230/115kV transformer in the area and the 115kV line issues could be corrected by extending the Moscow City – Leon Junction– North Lewiston 115kV Transmission Line into a new 115kV line position at Moscow 230 Station, leaving Moscow City station on the new networked line.

The requirement for the Palouse Transmission Reinforcement Project was identified through the transmission steady state, near-term, and long-term contingency analysis. A specific project scope will be provided in subsequent study documents.

4.2.1.4. Safely Interrupting Faults

The A-676 and A-677 circuit switchers at Francis & Cedar Station, plus the A-762 circuit switcher at Indian Trail will be overdutied given the increased system strength after the addition of the North Spokane Reinforcement Project. Replacement with appropriately rated circuit switchers or another design alternative is required.

The Fault Reduction Scheme at Post Street Station protecting circuit switchers A-435 and 436, plus the Fault Reduction Scheme at Third & Hatch Station protecting circuit switcher A-672 were determined to be insufficient to reduce fault current given the increased system strength after the addition of the Garden Springs Reinforcement Project. Both schemes could be changed to a Fault Blocking Scheme or the equipment replaced with appropriately rated circuit switchers.

The existing Safely Interrupting Faults Project needs to expand its scope to include updates at Indian Trail and Third & Hatch Stations. The additional project scope was identified through the transmission short circuit analysis.

4.2.1.5. West of Lancaster Constraint

The transmission system west of Lancaster Station is constrained during periods of high transfer and/or high generation. Outages of the 230kV transmission lines, including the P7 outage of the Beacon – Rathdrum and Lancaster – Rathdrum 230kV double circuit, will overload the underlying 115kV transmission lines.

This issue is currently mitigated via an Operating Procedure which manually reduces local generation when the Real-time Contingency Analysis (RTCA) results identify an issue.

From the last System Assessment, two projects were analyzed to mitigate the West of Lancaster performance issue.

- Building a new 230kV transmission line connecting Boulder and Lancaster. This would be a continuation of the planned Lancaster – Wyoming – Rathdrum 230kV Transmission Line and mitigate the N-1-1 issues identified.
- Mitigation of the overloads could be mitigated with a new West of Lancaster Remedial Action Scheme (RAS). Further evaluation of proposed arming levels, triggering events, and generation tripping is necessary, but preliminary studies indicate that the total of generation tripping would be undesirable.

Increased loading in the Kootenai County area helps to mitigate the west of Lancaster Station performance issues. Though any relief on this transmission constraint may be countered by increases in local generation and/or increases in east to west transfers.

The requirement for the West of Lancaster Reinforcement Project was identified through the transmission steady state near-term and long-term contingency analysis. A specific project scope will be provided in subsequent study documents.

4.2.1.6. Coeur d'Alene Station Voltage Support

Coeur d'Alene Station is served by three 115kV transmission lines. Continued load growth in the area has resulted in unacceptable low voltage for certain contingency combinations. The primary issue is low voltage being observed for an N-1-1 (P6) outage of the Coeur d'Alene – Ramsey 115kV and Dalton – Rathdrum 115kV Transmission Lines. The worst performance results from a maintenance N-1-1 (A6) outage combination of the Dalton – Wyoming 115kV Transmission Line open at Wyoming and the Coeur d'Alene – Ramsey 115kV Transmission Line. A Corrective Action Plan is necessary to mitigate the contingency issues as there is not a feasible Operating Procedure to address the performance requirements.

The requirement for the Coeur d'Alene Station Voltage Support Project was identified through the transmission steady state near-term and long-term contingency analysis. A specific project scope will be provided in subsequent study documents.

4.2.1.7. Grangeville Station Voltage Support

There are two primary deficiencies in the Clearwater area resulting from N-1-1 contingency outages to the 115kV lines feeding this load center and line end outages on the 115kV Grangeville loop. The contingency issue is only during winter peak loading conditions.

First, an N-1-1 (P6) outage of the Dworshak – Orofino 115kV Transmission Line and Lolo - Nez Perce 115kV Transmission Line results in unacceptable voltage across all the Clearwater area stations with similar results for an N-1-1 (P6) outage of the Dworshak – Orofino 115kV Transmission Line and the Moscow - Orofino 115kV Transmission Line. Additionally, an outage combination of a local capacitor bank with a 115kV line also results in low voltage issues.

Secondly, an N-1 (P2.1) line section outage on the Grangeville – Nez Perce #1 or #2 115kV Transmission Line, either 115kV line open at Nez Perce and closed through at Grangeville, results in unacceptable voltage at stations near the end of the loop.

Grangeville Station is on the list of stations that should be rebuilt based on age and condition but has been on hold until another project driver was established.

Preliminary concepts to resolve these issues were explored; including additional reactive support at Grangeville Station or the addition of an appropriately sized Battery Energy Storage System (BESS), which would offset load and add reactive support.

The requirement for the Grangeville Station Voltage Support Project was identified through the transmission steady state near-term and long-term contingency analysis. A specific project scope will be provided in subsequent study documents.

4.2.1.8. Mead Station Voltage Support

The loading on BPA's Addy – Bell 115kV Transmission Line has increased to the point where a line section outage (P2.1) at Bell results in low voltage at Avista's Mead Station in the long-term planning horizon. The bulk of the load is at the southern end of this line, so there is not a similar issue with a line section outage to the north. Avista has roughly 60% of the 106MW total load on BPA's 115kV line, predominately on the southern Bell end, which will result in Avista having to mitigate the low voltage issue. Note that Avista uses 0.95pu as a trigger to identify mitigation measures and potentially bring projects forward, where BPA uses 0.90pu to screen for N-1 issues.

Inland Power and Light (IPL) has requested BPA to study a new point of delivery at Staley Station south of Deer Park. That study identified the need for additional reactive support at BPA's Deer Park Station to integrate the new service. Given the Addy – Bell 115kV Transmission Line currently serves eight stations, nine including Staley Station, Avista plans to work with BPA on a more holistic solution for load service and reliability in this area.

A Corrective Action Plan is necessary to mitigate the contingency issues as there is not a feasible Operating Procedure to address the performance requirements.

The requirement for the Mead Station Voltage Support Project was identified through the transmission steady state long-term contingency analysis. A specific project scope will be provided in subsequent study documents.

4.2.1.9. Northwest Transmission Reinforcement

Francis & Cedar Station is served by three 115kV transmission lines and certain N-1-1 contingency combinations results in thermal violations. This is a current operational issue, and the North Spokane Reinforcement Project does not change this result. The primary issue is an overload on the Francis & Cedar – Ross Park Transmission Line for the N-1-1 (P6) outage of the Five Mile – Francis & Cedar 115kV and Northwest – Westside 115kV Transmission Lines. This N-1-1 outage also results in low voltage in the area. A Corrective Action Plan is necessary to mitigate the contingency issues as there is not a feasible Operating Procedure to address the performance requirements.

Northwest Station is on the list of stations that should be rebuilt based on age and condition but has been on hold until a capacity increase could be included as a driver. A capacity increase would include an uprate from 20MVA to 30MVA distribution transformers, which would also increase this contingency overload issue.

A reconductor of the 3.46-mile Lyons & Standard – Ross Park 115kV Line Section is a strait forward mitigation for this issue, but other alternatives will be investigated.

The requirement for the Northwest Transmission Reinforcement Project was identified through the transmission steady state near-term and long-term contingency analysis. A specific project scope will be provided in subsequent study documents.

4.2.1.10. West Spokane Transmission Reinforcement

The new Garden Springs Station and Melville Station increased capacity and reliability in the West Plains area, but it also resulted in a new contingency combination that strains the 115kV system during summer loading. The issue is an overload on the Ross Park – Third & Hatch 115kV Transmission Line for the N-1-1 (P6) outage of the Blue Bird – Garden Springs 230kV and the Garden Springs – Westside 115kV Transmission Lines. A Corrective Action Plan is necessary to mitigate this contingency issue as there is not a feasible Operating Procedure to address the performance requirements.

The requirement for the West Spokane Transmission Reinforcement Project was identified through the transmission steady state near-term and long-term contingency analysis. A specific project scope will be provided in subsequent study documents.

4.2.2. Distribution Issues and Potential Mitigation

4.2.2.1. Avondale Capacity Mitigation

The AVD151 feeder does not meet the performance criteria as identified in the distribution multi-year load flow analysis. This feeder is limited by the 250KVA regulator. Other feeders, including Dalton feeders and AVD152, potentially have spare capacity which can be used to offload AVD151. Growth on AVD151 is moderate and will factor into the solution. Options include:

- Upgrading the regulator on AVD151
- Transferring load to AVD152 (same transformer)
- Transferring load to Dalton Station feeders (adjacent)

4.2.2.2. Coeur d'Alene Capacity Mitigation

The CDA124 and CDA125 feeders do not meet the performance criteria identified in the distribution multi-year load flow analysis. These feeders have experienced moderate to significant growth in recent years. Although regulators at CDA124 have been replaced to address near-term capacity issues, anticipated growth in the area may result in loading concerns over the next ten years. Further analysis is required to determine a preferred solution; however, the robustness of this area and the potential utilization of existing feeder ties could contribute to an effective solution.

4.2.2.3. Colbert Capacity Mitigation

The COB12F2 feeder and Colbert 115/13kV Transformer 1 do not meet the performance criteria as identified in the distribution multi-year analysis. Both the feeder and transformer already exceed performance thresholds during peak summer loads. Further analysis of potential growth in the area and impacts of projects adjacent to the area are needed prior to identifying a preferred solution.

4.2.2.4. Deer Park Capacity Mitigation

The DER12F1 feeder and Deer Park 115/13kV Transformer 2 do not meet the performance criteria as identified in the distribution multi-year analysis. Area growth will cause peak winter overloading. With limited feeder tie options and a small substation (20MVA transformer, two feeders), evaluating unique solutions or upgrading the transformer is necessary.

4.2.2.5. Downriver Capacity Mitigation

The DRV12F3 feeder and Downriver 115/13kV Transformer 1 do not meet the performance criteria as identified in the distribution multi-year analysis. The loading issue appears to be a load imbalance issue which may have been resolved through load balancing following the 2024 summer peak. The capacity concern was not seen during summer of 2025 and may no longer be an issue.

4.2.2.6. Glenrose Capacity Mitigation

GLN12F2 does not meet the performance criteria as identified in the distribution multi-year analysis. Both feeders have the maximum standard capacity, and the transformer will be upgraded to a 30MVA as part of the existing Glenrose Capacity Mitigation project. The Glenrose Capacity Mitigation project will be reviewed to determine if an alternative project scope will be sufficient or if an additional project needs to be identified.

4.2.2.7. Idaho Road Capacity Mitigation

The Idaho Road 115/13kV Transformer 1 does not meet the performance criteria as identified in the distribution multi-year analysis. Proposed work at the Post Falls Station may provide adequate capacity relief. Further analysis, including the Post Falls scope of work, will be required to determine the most appropriate solution for this issue.

4.2.2.8. Indian Trail Capacity Mitigation

INT12F1 does not meet the performance criteria as identified in the distribution multi-year load flow analysis. Although a second lineup was added to Indian Trail Station and nearby feeders were shifted, INT12F1 still serves a large subdivision without feeder tie options. Further analysis is needed to either divide the subdivision or strengthen ties from Northwest Station.

4.2.2.9. Kooskia 34 Capacity Mitigation

The Kooskia 34kV transformer does not meet the performance criteria as identified in the distribution multi-year load flow analysis. The optimal solution depends on the contract with Idaho County Light & Power Cooperative (ICLP), which needs further review. The following initial options are being considered:

- Upsize the transformer at its present location
- Add a parallel transformer at the same site
- Relocate the K34 Substation to Kooskia Station and upgrade a portion of the KOO1299 feeder to 34.5kV
- Move the substation closer to the 115kV line and build a 115/34.5kV station
- Install a battery downstream of the transformer to provide peak shaving capability
- Reestablish tie to offload transformer

4.2.2.10. Lewiston Capacity Mitigation

Equipment at Lolo and Tenth and Stewart Stations does not meet the performance criteria as identified in the distribution multi-year load flow analysis unless work is done to mitigate the issue. The existing Lewiston Capacity Mitigation project includes upgrading a transformer at Tenth and Stewart providing capacity for an additional feeder, as well as upgrading both feeder regulators and the transformer at Lolo to provide capacity relief for these substations. The Lewiston Capacity Mitigation project is being reviewed to determine if an alternative project scope to construct a new LOID Station geographically located between Lolo and Tenth and Stewart will provide improved system performance.

4.2.2.11. Milan Capacity Mitigation

Milan 115/13kV Transformer 2 and MLN12 feeder serving IPL do not meet the performance criteria as identified in the distribution multi-year load flow analysis. While IPL owns the majority of the feeder equipment, some components are owned by Avista and are considered when setting operational limits. Mitigation will be required through coordination with IPL. Specific mitigation alternatives have not yet been determined.

4.2.2.12. Northeast Capacity Mitigation

NE12F1 does not meet the established performance criteria identified in the distribution multi-year analysis. The area is experiencing growth and contains multiple switching layers due to neighboring substation mitigation projects, which result in the feeder exceeding performance thresholds during peak summer loading. A review of the Northeast Capacity Mitigation project will be performed to address performance concerns.

4.2.2.13. Pound Lane Capacity Mitigation

Pound Lane 115/13kV Transformer 1 and its associated feeders do not satisfy the performance criteria outlined in the distribution multi-year analysis. Pound Lane Station currently has B phase SCADA monitoring only, with an assumed phase ratio applied to assess loading across all three phases. Calculations using this ratio indicate A-phase loading is significantly higher on both feeders and at the transformer. To conduct a thorough evaluation of the substation's conditions, it is necessary to gather data from all three phases prior to identifying possible solutions.

4.2.2.14. Priest River Capacity Mitigation

The Priest River 115/21kV Transformer 1 fails to meet performance standards based on multi-year load flow analysis. Permanent offloading or upgrading will be considered as mitigation options.

4.2.2.15. South Lewiston Capacity Mitigation

The transformers at South Lewiston Station do not meet the performance criteria as outlined in the distribution multi-year load flow analysis. Although there is low growth in the area, the transformers are close to or have already exceeded the specified criteria. The proposed Bryden Canyon Station identified to mitigate transmission-related performance issues provides a feasible alternative to partially or completely replace the existing South Lewiston Station.

4.2.2.16. South Othello Capacity Mitigation

The South Othello 115/13kV Transformer 1 does not meet performance standards per the multi-year load flow analysis. As a single 20MVA transformer with three feeders, there is potential for expansion or equipment upgrades. The recently rebuilt Othello Station offers additional feeders to help offload demand. Both expansion and offloading options will be considered to accommodate growth in the area.

4.2.2.17. Spangle Capacity Mitigation

Spangle 115/13kV Transformer 1 and SPA441 feeder serving IPL do not meet the performance criteria as identified in the distribution multi-year load flow analysis. Mitigation will be required through coordination with IPL. Specific mitigation alternatives have not yet been determined.

4.2.2.18. Turner Capacity Mitigation

TUR116 does not meet the performance criteria identified in the distribution multi-year analysis. This feeder has experienced some growth, previous issues with load imbalance, and extends as a long line with only a single feeder tie beyond the city of Colfax. Analysis is needed to determine the potential of balancing feeder loading to optimize capacity of the Turner Station.

5. Technical Analysis

- 5.1. Transmission Steady State Near-Term Analysis (R2.1)
- 5.2. Transmission Steady State Long-Term Analysis (R2.2)
- 5.3. Transmission Short Circuit Near-Term Analysis (R2.3)
- 5.4. Transmission Stability Near-Term Analysis (R2.4)
- 5.5. Transmission Stability Long-Term Analysis (R2.5)
- 5.6. Transmission Single Point of Failure Near/Long-Term Analysis
- 5.7. Distribution Multi-Year Load-Flow Analysis
- 5.8. Distribution Contingency Analysis
- 5.9. Distribution Auto-Transfer Analysis
- 5.10. Distribution Short Circuit Analysis
- 5.11. NERC Compliance Summary

6. Appendix A – System and Company Description

6.1. Overview

Avista is a publicly held energy company primarily involved in the production, transmission, and distribution of energy (natural gas and electricity). Avista, formerly known as The Washington Water Power Company, was founded on March 13, 1889, in Spokane, Washington, by ten enterprising men who saw the potential of one of the Northwest's most abundant natural resources – moving water.

Avista's primary market area covers more than 30,000 square miles, with energy generation, transmission, and distribution facilities in four Western states. The company serves more than 418,784 electric customers in eastern Washington and northern Idaho. Avista's electric power generation and transmission assets range in age from modern 21st century equipment to equipment that was patented and placed in service over 100 years ago.

The service territory served by the Avista electrical system is generally centered on the Spokane, Washington and Coeur d'Alene, Idaho load centers. Avista also serves a smaller southern load center located near Lewiston, Idaho and Clarkston, Washington. Figure 7 geographically displays the Avista service territory.



Figure 7: Avista Service Territory

6.2. Transmission System

6.2.1. Transmission Infrastructure

Avista owns and operates a system of over 2,300 miles of electric transmission facilities which include approximately 700 miles of 230kV and 1,600 miles of 115kV transmission lines. Figure 8 illustrates Avista's Transmission System on a regional map.



Figure 8: Avista Transmission Line Map

The Avista 230kV transmission lines are the backbone of Avista's Transmission System and consist of two "rings" centered near the Spokane and Coeur d'Alene areas. The northern ring connects generation in northwestern Montana to the larger load centers while the southern ring serves the Moscow-Pullman and Lewiston-Clarkston areas. Figure 9 shows a station-level drawing of Avista's 230kV transmission system including interconnections to neighboring utilities. Avista's 230kV transmission system is interconnected to the BPA 500kV transmission system at BPA's Bell, Hot Springs, and Hatwai Stations.

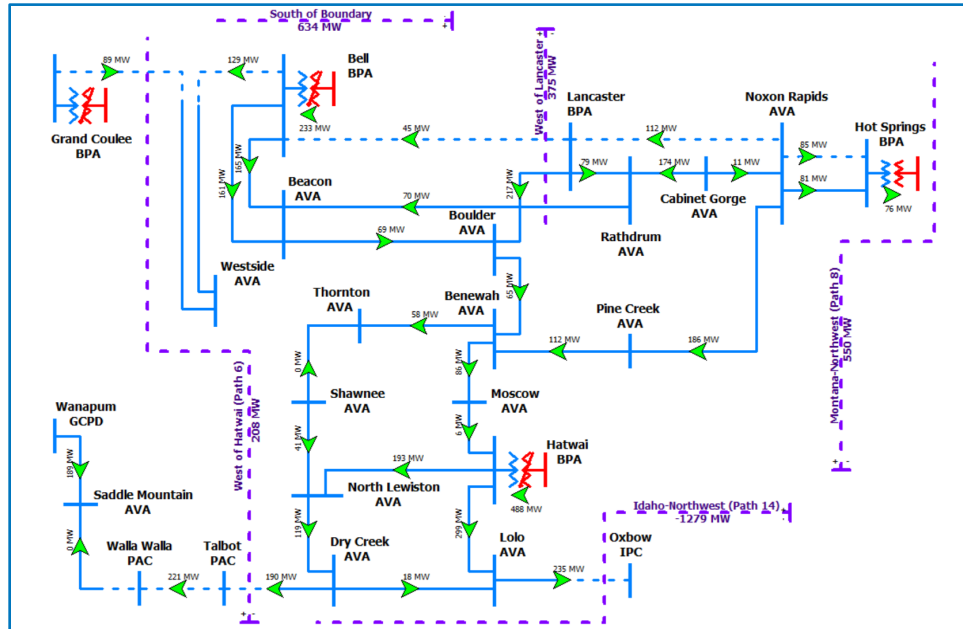


Figure 9: Avista 230kV Transmission System

6.2.2. Transmission System Areas

Avista has separated its transmission system into the five geographical areas, namely Spokane, Coeur d'Alene, Big Bend, Palouse, and Lewis-Clark. The areas are shown with their approximate boundaries in Figure 10.



Figure 10: Avista Transmission System Regions

6.2.3. WECC Rated Paths

Avista owns transmission assets along with capacity rights in the following WECC transfer paths:

- Path 6: West of Hatwai
- Path 8: Montana to Northwest
- Path 14: Idaho to Northwest

6.2.4. Points of Interconnection

Avista's BAA is directly interconnected to the BAAs operated by BPA, Public Utility District No. 2 of Grant County, Public Utility District No. 1 of Chelan County, Idaho Power Company, PacifiCorp, NorthWestern Energy, and Seattle City Light.

Significant points of interconnection are associated with the BPA 500/230kV transformers located at G.H. Bell Substation in Spokane, Washington, Hatwai Substation in Lewiston, Idaho, and Hot Springs Substation in Hot Springs, Montana.

Within Avista's BAA, Avista's transmission and distribution system is interconnected with Pend Oreille PUD's transmission system and several Load Serving Entities including Asotin County PUD, Big Bend Electric Cooperative, City of Cheney, City of Chewelah, Clearwater Power Company, Fairchild Air Force Base, Idaho County Light & Power Cooperative, Inland Power & Light Company, Kootenai Electric Cooperative, Modern Electric Water Company, Northern Lights, and City of Plummer. Avista-owned generation and distribution stations not connected directly to Avista's transmission system are typically telemetered into Avista's BAA.

6.3. Generation Resources

Avista has a diverse mix of generation resources with most of its generation being hydropower with various projects located on the Spokane and Clark Fork Rivers. Avista owns eight hydroelectric generating plants as well as coal (partial ownership), natural gas, and wood-

waste combustion plants in five Eastern Washington, Northern Idaho, Eastern Oregon, and Eastern Montana locations. Avista also utilizes power supply purchase and sale arrangements of varying lengths to meet a portion of its load requirements.

For more information on Avista's generation, please refer to Avista's latest Integrated Resource Plan (IRP).

6.4. Distribution System

Avista's distribution system consists of over 19,200 miles of distribution lines operated at voltages ranging from 12.5kV to 34.5kV. Most of the distribution system is configured as radial feeders with ties to adjacent feeders and stations for redundancy. The distribution system serving the downtown Spokane area is an exception and is operated in a networked configuration.

6.5. Customer Demand

Avista develops a biannual Electric IRP which is a thoroughly researched and data-driven document to guide responsible resource planning for the company.

6.5.1. Native Load

Avista historically experiences peak load in the winter months, between November and early February. Air conditioning loads have created some pockets where summer peak load can exceed the winter peak load. This phenomenon has transformed Avista into a dual peaking utility.

As documented in the IRP, Avista's 20-year native peak load growth rate was 0.35 percent in the winter and 0.42 percent in the summer.

6.5.2. Balancing Authority Area Load

The BAA load growth rate is expected to be consistent with the native load growth rate. The forecast data for the loads which are not Avista's native loads are provided by BPA on behalf of the Load Serving Entity of each load.

Avista's BAA load peaked at 2,515MW in the winter of 2024 and 2,380MW in the summer of 2021. Figure 11 and Figure 12 shows the BAA load historical winter and summer peaks from 2008-2020 and the forecasted monthly peaks for 2021-2030.

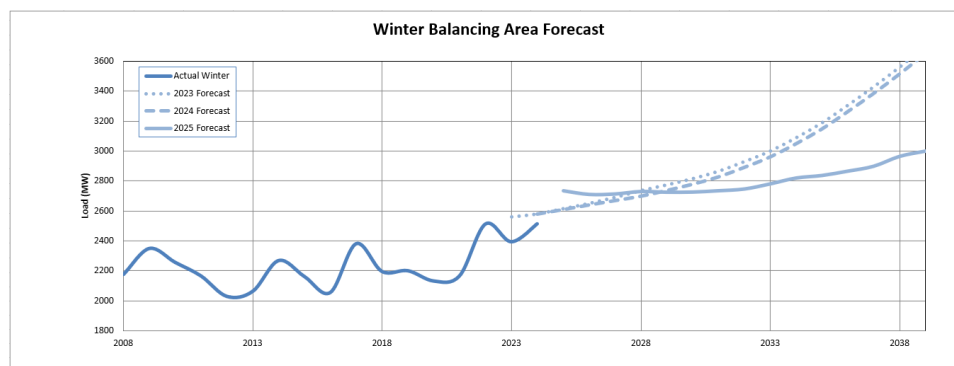


Figure 11: Winter Balancing Authority Area load forecast

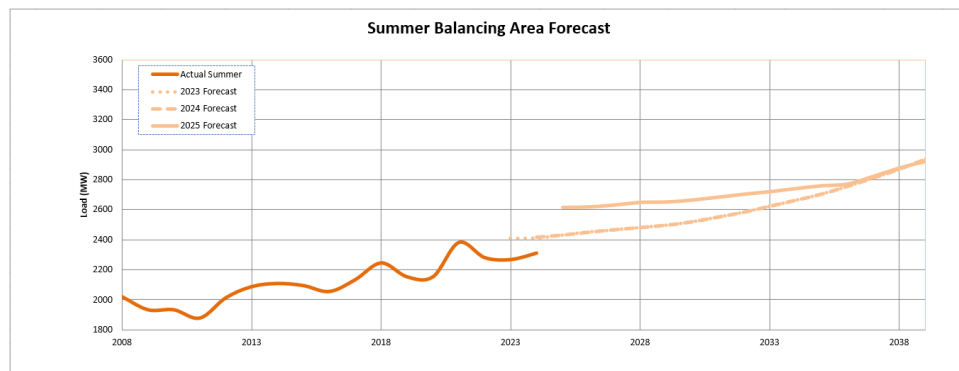


Figure 12: Summer Balancing Authority Area load forecast

7. Appendix B – Transmission Models

7.1. Planning Case Development

A set of transmission system models (Planning Cases) are developed biannually to model Avista's Transmission Planner and Planning Coordinator areas as well as the regional Transmission System. The Planning Case development process outlined in the internal document *TP-SPP-04 – Data Preparation for Steady State and Dynamic Studies* outlines the use of WECC-approved base cases and applying steady state and dynamic data modifications as required representing desired scenarios. Additional details are provided in *TP-SPP-01 – Transmission System Performance* and the *Avista System Planning Assessment - 2025 Study Plan*.

Planning Cases ensure that the WECC cases reflect Avista's respective study areas for performing the studies needed to complete its Planning Assessment. The Planning Cases use data consistent with the MOD-032 standard to represent projected system conditions, planned Corrective Action Plans, and projects supplemented by other sources as needed. These base cases set the normal system condition (P0) which represent existing facilities, new or updated facilities, real and reactive load forecasts, firm transmission service/interchange, and resources (supply or demand side) required for load service (TPL-001-5, R1).

The following scenarios are developed to represent various seasonal conditions over the near-term and long-term transmission planning horizons (TPL-001-5, R2):

- The Light Spring case represents typical April and May loading during early morning minimum load conditions, with moderate south to north transfers.
- The Heavy Summer cases represent a typical summer peak scenario where the Avista BAA is near peak load with local hydro generation at mid to late summer output. These scenarios model moderate transfers on Path 6 and Path 8 across Avista's BAA and heavy Path 14 transfers south into Idaho's BAA. These scenarios are limited by the summer thermal limits on various elements of the Transmission System, which helps to define where the system is near capacity for load service along with system transfers.
 - The first year is the latest Operations case projected out to the following year.
 - The fifth and tenth year are based on the latest WECC approved cases.
- The Heavy Winter case represents a typical winter peak scenario where the Avista BAA is near peak load and the local hydro generation is at moderate levels. These scenarios model significant transfers across Avista's BAA from regional thermal resources. The lower ambient temperature increases the operating limits of the various elements of the Transmission System and the reactive load is near unity power factor.
 - The fifth year is based on the latest WECC approved cases.
- The Light Summer case represents a typical light load scenario with High West of Hatwai Flows. During light summer (nighttime loading) with high Western Montana Hydro and high Montana thermal generation, the WECC rated path "West of Hatwai" (WECC Path 6) reaches its heaviest loading. During this scenario, portions of the Transmission System are nearing their stability limits. These limits define some of the operating constraints for the region and establish some of the arming levels for Remedial Action Schemes. This scenario is also limited by the summer thermal limits on

various elements of the transmission system, which helps to define where the system is near capacity.

8. Appendix C – Investment Driver Definitions

8.1. Customer Requested

Includes customer requests for new gas or electric service connections, line extensions, or system reinforcements to serve a single large customer. We have often referred to new service connections as “growth.” Prompt and efficient response to customer requests for service is a Commission requirement.

Example Projects and Programs:

1. Installing electric and natural gas distribution facilities in a new housing or commercial development.
2. Adding street or area lights per request from the City/County or private individual, respectively.
3. The costs associated with the first installation of electric and gas meters.

8.2. Customer Service Quality and Reliability

Investments required to maintain or improve service quality, to introduce new types of services and options to meet customer needs and expectations, to meet customer service quality requirements, and to achieve our electric system reliability objectives.

Example Projects and Programs:

1. Advanced Metering Infrastructure
2. Specific projects that are predominantly built to improve system reliability such as distribution automation, worst feeder program, or outage management system
3. Adding new customer products and services such as community solar, building energy management systems
4. Redeveloping our customer website – www.avistautilities.com

8.3. Mandatory and Compliance

Investments driven by compliance with laws, rules, and contractual obligations that are external to the Company such as State and Federal statutes, settlement agreements, FERC, NERC, and FCC rules, Commission Orders, among others.

Example Projects and Programs:

1. Investments to meet FERC hydro license conditions such as the mitigation of gas super-saturation, or environmental permit requirements including clean air and water.
2. Spending required to meet contract requirements, such as the owner/operator agreement for Colstrip, or tribal settlement agreements.
3. Transmission additions to meet NERC/WECC planning requirements.
4. To comply with regulatory requirements such as identifying and remediating gas overbuilds, natural gas cathodic protection, or hydro safety requirements.
5. Costs for relocating natural gas or electric facilities associated with road development projects,
6. To comply with franchise agreements or right-of-way permits including state, county, city franchise and tribal permits.
7. Investments required under regulatory settlements such as isolated steel pipe removal.

8.4. Performance and Capacity

Includes a range of system reinforcement projects to meet defined performance standards, typically developed by the Company, or to enhance the performance level of assets based on a demonstrated need or financial analysis.

Example Projects and Programs:

1. Upgrades to transmission, station, and distribution assets to relieve grid congestion or to mitigate thermal overloads.
2. Gas pipeline capacity needed to meet the Company's "design day" standard of -25F°.
3. Investments in hydro and thermal generation to maintain a level of unit availability or to achieve efficiency output objectives.
4. New employee training facilities to accommodate greater numbers of craft apprentices entering the workforce.
5. Ergonomic office equipment to reduce the incidence of employee health issues.
6. New engineering building at the Clark Fork River projects.
7. Purchase or expand office facilities to accommodate additional employees or special projects, including Project Atlas and Project Everest as examples.
8. New computer software and hardware to achieve work process and business continuity objectives.

8.5. Asset Condition

Investments to replace assets based on industry accepted, asset management principles and strategies. Asset management strategies are designed to optimize the overall lifecycle value for customers. Examples of common asset strategies include:

1. Run to failure (streetlights)
2. Inspection-based replacement (gas leak survey, pole test and treat)
3. Monitor-based replacement (power transformer gas monitoring)
4. Calendar-based replacement (PC refresh, cell phones)
5. Condition-based replacement (fleet replacement based on age, vehicle mileage, and operating expense)

Example Projects and Programs:

1. Personal computer (3-year) and cell phone (2-year) refresh cycles
2. Wood pole inspection and replacement (20-year)
3. HVAC replacement (condition based)
4. Aldyl-A pipe program
5. New replacement office furniture
6. Project Compass
7. New roof for office building
8. New microwave communications system (driven by FCC)
9. Replacement of fleet vehicles and equipment
10. Natural gas meter ERTs
11. Gantry crane replacement program
12. Spokane hydro redevelopment
13. Thermal plant "run-time" capital maintenance program
14. Distribution transformer change-out program (TCOP)

15. Station inspection and equipment replacement program (circuit breakers, voltage regulators, insulators, cables, and control systems)

8.6. Failed Plant and Operations

Requirements to replace failed equipment such as failed transformers, switches, poles, wires, cables, gas pipes, and meter sets. Also includes inspection-based replacements of natural gas and electric infrastructure identified by Operations.

Example Projects and Programs:

1. Cable, equipment, vaults, and manholes located in Avista's electric secondary district (Spokane business district)
2. Electric distribution minor blanket (capital maintenance and repairs of existing overhead and underground systems)
3. Electric and gas meter blanket (replacement of failed units)
4. Transmission blanket (storm response)
5. Electric distribution storm damage
6. Natural gas minor blanket (capital maintenance and repairs of existing gas plant)