WestConnect Regional Transmission Planning

2015 Abbreviated Cycle

Regional Transmission Plan

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(Contact admin@westconnect.com to Request Non-Redacted Version)

Contents

1.0 Summary and Introduction

The final step of the WestConnect Regional Transmission Planning Process involves the development and issuance of a Regional Transmission Plan (Regional Plan), which documents the transmission projects selected during the planning cycle and a description of why projects were either included or not included in the plan. This document reflects the Regional Plan for the one-year abbreviated 2015 planning cycle. Due to the abbreviated planning cycle and as clarified in the WestConnect 2015 Regional Study Plan (Study Plan), the Regional Plan was developed in Quarter 4 of the 2015 planning cycle rather than Quarter 8 of a regular biennial planning cycle as described in the WestConnect Regional BPM.

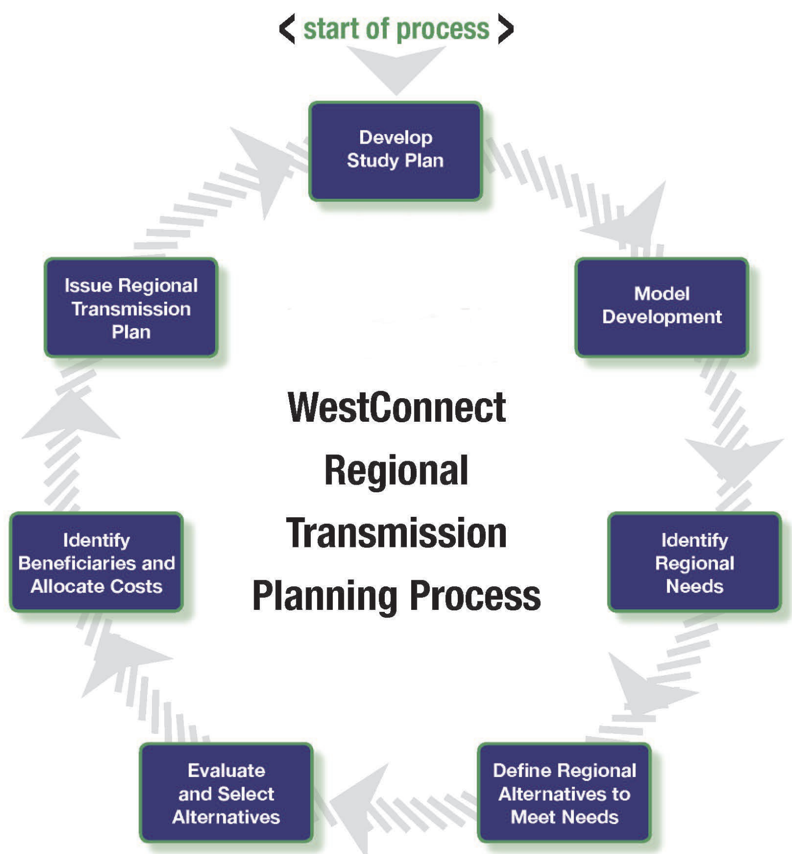
Based on the 2015 abbreviated cycle analysis performed for reliability, economic, and public policy transmission needs, there were no regional transmission needs identified in the 2015 assessment. Thus, alternatives to meet regional needs were not solicited and no additional projects, aside from those projects identified in the 2024 Regional Base Transmission Plan, were selected into the 2015 Regional Transmission Plan.

1.1 WestConnect Regional Transmission Planning Process

The WestConnect Regional Transmission Planning Process (planning process) was developed for compliance with Federal Energy Regulatory Commission (FERC) Order No. 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, (Order No. 1000).[1] The biennial planning process consists of seven primary steps as outlined in Figure 1.

[1] *All references to Order No. 1000 include any subsequent orders.*

Figure 1: WestConnect Regional Transmission Planning Process



The WestConnect Regional Transmission Planning Cycle (planning cycle) is biennial. Except for this abbreviated 2015 planning cycle, the biennial cycle will commence in even numbered years, resulting in the development of a Regional Transmission Plan every other year. During the biennial planning cycle, WestConnect will establish the region's reliability, economic, and public policy transmission needs. WestConnect will solicit alternatives (transmission or non-transmission alternatives (NTAs)) from WestConnect members and stakeholders to meet the regional needs. WestConnect will evaluate the alternatives submitted to or developed by WestConnect to determine which alternatives meet the region's needs more efficiently or cost effectively, and will identify those alternatives in the WestConnect Regional Transmission Plan. Those identified alternatives that were submitted for the purposes of cost allocation may go through the cost allocation process if they pass the cost/benefit thresholds established for the relevant category of project (reliability, economic, public policy) and if they are further determined to be eligible for regional cost allocation.

Additional details of the WestConnect Regional Transmission Planning Process can be reviewed in the WestConnect Regional BPM.

1.2 Management of the Regional Study Plan Activities

The WestConnect Planning Management Committee (PMC) has overall responsibility for all WestConnect regional planning activities. The planning process activities described within this Regional Plan have been conducted under the direction of the PMC by the Planning Subcommittee (PS) and Cost Allocation Subcommittee (CAS), and with input from WestConnect Transmission Owners (TOs), Subregional Planning Groups[2] (SPGs), and stakeholders as described in greater detail in subsequent sections of this document.

1.3 Study Plan Elements

WestConnect conducted an abbreviated one-year planning cycle in 2015, and the first full biennial planning cycle will commence in 2016. This Regional Plan documents the planning activities conducted during the abbreviated planning cycle, which included a portion of the activities contemplated in the full biennial planning process (Figure 1).

The planning process was performed in an open and transparent manner to attain objective analysis and results. WestConnect utilized its website and e-mail distributions to invite and encourage interested parties or entities to participate in and provide input to the planning process at all planning process committee levels.[3] Section 4.0 provides more details in this regard.

Due to the abbreviated nature of this first regional planning cycle, the planning activities were limited in scope to provide WestConnect the best opportunity to address all aspects of its planning process in a one-year timeframe. Major components of the 2015 regional transmission planning activities included:

1. Regional Model Development
    a. A 10-year, 2024 heavy summer regional power flow model (PFM) was developed from the Western Electricity Coordinating Council (WECC) power flow base cases with assistance from the Subregional Planning Groups (SPGs) and WestConnect Transmission Owners (TOs).
    b. A 10-year, 2024 regional production cost model (PCM) was developed from the WECC Transmission Expansion Planning Policy Committee (TEPPC) 2024 Common Case with assistance from the Subregional Planning Groups (SPGs) and WestConnect Transmission Owners (TOs).
2. Documentation of Local TO Transmission Plans[4]
    a. The regional 10-year models included transmission projects that TOs, SPGs, and others planned to be in service in the next ten years (i.e., 2015 through 2024). These projects were reviewed and approved for inclusion in the regional models by the PMC and are provided in Appendix C.
3. Identification of Regional Needs
    a. Reliability Assessment: WestConnect identified regional *reliability* transmission needs by evaluating the regional PFM N-0 conditions and N-1 contingencies to verify compliance with North American Electric Reliability Corporation (NERC) Transmission Planning (TPL) standards ("NERC TPL standards") for N-1 outages. Due to the abbreviated timeline, analyses were limited to steady-state system performance utilizing "post-transient" and "steady-state" methodologies.

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[2] The WestConnect Subregional Planning Groups consist of the Southwest Area Transmission (SWAT), the Sierra Subregional Planning Group (SSPG), and the Colorado Coordinated Planning Group (CCPG).

[3] Stakeholders had opportunities to participate in and provide input to local transmission plans as provided for in each Member TO's OATT. Further, stakeholders had opportunities to participate in and provide input into subregional planning efforts within the WestConnect Subregional Planning Groups.

[4] WestConnect TOs perform local planning studies to determine local reliability needs and identify new facilities to meet planning standards and satisfy native load and network customers' requirements. Facilities identified in these local planning processes are provided as input into the WestConnect Regional Transmission Planning Process.

b. Economic Assessment: Due to the abbreviated timeline, the economic assessment of the WestConnect system was limited. However, the TEPPC 2024 Common Case was reviewed from a WestConnect perspective to discern whether there were indications of congestion or other issues that might indicate regional economic needs. In addition, comments from WestConnect participants enabled the development of a 2024 regional PCM from the TEPPC model and WestConnect explored methodologies for assessing economic needs for use in future, full biennial planning cycles.

c. Public Policy Documentation: The regional power flow and production cost models were updated to reflect all enacted public policies. Due to the abbreviated timeline, the analysis of transmission needs driven by public policy requirements was limited to needs driven by renewable portfolio standard (RPS) requirements. A spreadsheet-based gap analysis was performed to ensure adequate renewable resources were included in the regional models so as to comply with enacted RPS requirements. The regional models were then used to evaluate whether adequate transmission facilities are available to access the renewable resources and thereby achieve RPS public policy requirements.

d. Local vs. Regional Transmission Needs: If the regional assessments revealed transmission performance issues, then a determination was made as to whether the issues were of a local or regional nature. Local issues included those that only impacted a single TO whereas, in general, regional issues were those that impacted multiple TOs. Issues that were determined to be local in nature were referred to the impacted TO to provide an appropriate project or mitigation to be included in the regional models.

4. Issuance of Regional Transmission Plan: This document.

The above activities are described in further detail in subsequent sections.

2.0 Regional Planning Model Development

During the first and second quarter of the abbreviated 2015 planning cycle, the Planning Subcommittee (PS) worked to develop the Regional Planning Models (RPMs) that were used in the identification of regional transmission needs. This was documented in the WestConnect 2015 Regional Model Development Report. Two types of studies (or models) were needed for the planning process: reliability (or "power flow model") and economic (or "production cost model"). Table 1 describes the two RPMs developed during the abbreviated 2015 planning cycle. A "top-down" approach was utilized in which the Western Electricity Coordinating Council (WECC) provided the foundational models and WestConnect updated its footprint. WECC provided the original foundation for both models.

Table 1. WestConnect Abbreviated 2015 Planning Cycle Models

Modeling Type	Case Name	Description
Power Flow Model (PFM) [Reliability]	2024 HS Regional PFM	10-year, 2024 heavy summer (HS) regional PFM based on the WECC 2024 Heavy Summer 1 Scenario Base Case (24HS1SA) and created with assistance from the SPGs and TOs
Production Cost Model (PCM) [Economic]	2024 Regional PCM	10-year, 2024 regional PCM dataset based on the WECC TEPPC 2024 Common Case and, per areas of improvement identified by the Planning Subcommittee, was developed throughout 2015

The 2024 HS Regional PFM was developed for use in the regional needs identification portion of the abbreviated 2015 planning cycle whereas the 2024 Regional PCM was developed to familiarize the WestConnect stakeholders with the complexity of the PCM dataset and the reporting capabilities of the PCM software. Also, the abbreviated cycle limited the reliability analysis to steady-state power flow studies, which meant that a matching set of dynamic power flow models was not maintained for the 2024 HS Regional PFM.

The development process for the PFM provided for the protection of confidential information (see Appendix A) and strove to ensure that sufficient data was collected from all transmission providers within the region to ensure sufficient regional topology. Section 2.1 through Section 2.6 provides the overarching assumptions and principles that were used in the development of both models as well as assumptions specific to each model. In developing the regional models, the Planning Subcommittee had strong participation by the non-FERC jurisdictional TOs in the WestConnect footprint that are not yet signatories to the Planning Participation Agreement (PPA), and Section 4.0 provides more details in this regard.

2.1 Study Area

The approximate footprint of both member and non-member TOs is shown in Figure 2. The WestConnect planning process evaluated the transmission needs of the WestConnect planning region, which is defined as the combined footprints of signatories to the Planning Participation Agreement within the TO Member Sector.[5] TO participants in the WestConnect planning process, and the systems reflected in the study area include:

- Arizona Public Service Company*
- Basin Electric*
- Black Hills Power, Inc.*
- Colorado Springs Utilities
- Sacramento Municipal Utility District*
- Salt River Project*
- Southwest Transmission Cooperative
- Transmission Agency of Northern California*

[5] *There are five PMC Member Sectors and they are defined in Section 6 of the WestConnect Planning Participation Agreement dated June 15, 2015. Certain TO Members may have transmission facilities located in a planning region other than the WestConnect Planning Region. If a transmission facility is located exclusively in a planning region other than WestConnect, then it will not be included in the WestConnect planning process. Such facilities may, however, be subject to interregional coordination.*

- El Paso Electric Company*
- Imperial Irrigation District*
- Los Angeles Department of Water and Power
- NV Energy*
- Public Service Company of New Mexico*
- Platte River Power Authority*
- Tucson Electric Power Company*
- Tri-State Generation and Transmission Association*
- Xcel Energy (Public Service Company of Colorado)*
- Western Area Power Administration*

**Denotes PMC TO Member*

Figure 2. Approximate Footprint of WestConnect Member TOs and Participating TOs

The following PMC members from the Independent Transmission Developer Member Sector and Key Interest Group Sector also participated in the planning effort:

- Southwestern Power Group
- TransCanyon
- Black Forest Partners
- Xcel Western Transmission Company
- American Transmission Company (ATC)
- Natural Resources Defense Council (NRDC)

2.2 Study Horizon

The 2015 Study Plan called for an assessment of the WestConnect region's transmission needs in the 10-year study timeframe. This would normally call for models that reflect a planning year of 2025; however, based on the availability of the starting (i.e., WECC) models, the PMC elected to develop regional models focused on 2024.

2.3 2024 Regional Base Transmission Plan

WestConnect establishes a base transmission plan during each planning cycle to inform the base transmission network topology that should be reflected in each of the RPMs in order to adequately identify regional transmission needs and assess alternatives to meet those needs. The base transmission plan consists of all existing transmission facilities as well as incremental transmission facilities expected to be on-line within the study timeframe and which meet the criteria in the "Base Transmission Plan" section of the WestConnect Regional BPM.[6] This criterion includes two tiers of projects:

1. Projects developed by the WestConnect SPGs and TO Members in accordance with their local Order No. 890 planning processes (including any assumptions they may have made with regard to other incremental regional transmission facilities in the development of their plans[7]).
2. Projects under development by merchants or Independent Transmission Companies (ITCs), located in the WestConnect footprint, and which have sufficient certainty to warrant their inclusion in the base transmission plan.

Appendix C provides the incremental projects in the 2024 Regional Base Transmission Plan (base transmission plan), which were the transmission facilities expected to be on-line in 2015 through 2024 and were included in the 2024 RPMs. The rest of this section describes how the list of these projects was developed.

The base transmission plan development began with the project information collected for the 2015 WestConnect Annual Ten-Year Transmission Plan[8] via the WestConnect Transmission Plan Project List (TPPL), which serves as a project repository for TO member and participant local transmission plans and non-incumbent developer projects. The TPPL data collection window for the abbreviated 2015 planning cycle opened on November 20, 2014, and closed on December 15, 2014.

All TO projects in the TPPL with "in-service," "under construction," and "planned" project development statuses were slated for inclusion in the base transmission plan. Conceptual transmission projects were not included. The "planned" designation was the most tentative and subjective of the inclusive projects, so all "planned" TPPL projects were subjected to additional criteria to ensure consistency with the WestConnect definition for planned projects:

- Project has a sponsor,

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[6] *The BPM is undergoing revisions and further development so that it reflects the current status of the regional transmission planning process in the form approved by FERC in the WestConnect dockets of the jurisdictional TO members of the region. In drafting this report, the Planning Subcommittee sought to honor the principles and the primary findings of FERC as reflected in the WestConnect orders.*

[7] *Other planning assumptions including load forecasts, planned resource additions, and non-transmission alternatives are documented separately from the base transmission plan.*

[8] *The 2015 WestConnect Annual Ten-Year Transmission Plan was approved by the WestConnect (Order 890) PMC on February 19, 2015. This was the last Annual Ten-Year Transmission Plan to be developed under the WestConnect Order 890 planning process. All future regional planning activities will now be conducted under the WestConnect Order 1000 Regional Planning Process.*

- Project has been incorporated in an entity's regulatory filings,
- Project has an agreement committing entities to participate in and construct the project, or
- Permitting has been or will be sought for the project.

The additional scrutiny of the "planned" projects was accomplished in two ways: (1) review by WestConnect members and non-member participants and (2) review by each WestConnect SPG who met individually and focused on the projects in each SPG footprint. This process ensured peer review of the criteria used for including projects in the base transmission plan. The NERC TPL standards require TOs, Transmission Planners, and Planning Coordinators[9] to plan the transmission system to meet certain performance requirements and there were "planned" TPPL projects driven by the sponsoring TO's need to meet the NERC TPL standards. These projects didn't necessarily have complete financial approvals in the TO's budgeting process, so there were some uncertainties regarding their design, costs, and in-service dates. In addition to the problem of these uncertainties, if these projects were included in the base transmission plan, it might have been difficult for members to recommend replacement projects that could be more efficient or cost effective. On the other hand, if the projects were not included in the base transmission plan, the regional analysis may have identified performance issues that had already been addressed by the TO's normal planning processes.

These considerations and discussions resulted in PS recommending that projects proposed to meet NERC TPL standards should be included in the base transmission plan as long as the projects had gone through an appropriate FERC 890 planning process. In addition, the treatment of projects for inclusion in the base transmission plan is consistent with FERC's findings in the WestConnect compliance dockets that only new projects are subject to evaluation under Order No. 1000, and that other projects are exempt from Order No. 1000 including, but not limited to, local or single system transmission projects that have been identified in individual transmission providers' TPL standards compliance assessments to mitigate reliability issues and planned transmission system upgrades to existing facilities, as well as projects that (as of the effective date of the Order No. 1000 compliance filings) have reached identified milestones (e.g., projects that have received approval through local or state regulatory authorities or board approval, and/or have been planned and submitted for inclusion in the Regional Plan or exist in the 10-year corporate capital project budgets of local TOs).

The PS also met on several occasions to review the list of non-incumbent projects in the TPPL to see if any of them met the threshold identified by the PMC for inclusion in the base transmission plan. These meetings were open to the public, and the non-incumbent project sponsors were invited to attend. Upon reviewing the project information submitted by the project sponsors, the PS did not identify any non-incumbent projects that warranted inclusion in the base transmission plan.

California Independent System Operator (CAISO) Projects

The CAISO and WestConnect transmission planning footprints have strong electrical and operational ties, which required close coordination on planning assumptions and information. Based on member and participant feedback, the PS considered two CAISO transmission projects for inclusion in the regional planning models that were recently approved by the CAISO Board of Directors and were going through the CAISO competitive solicitation process. These projects were:

- Delaney – Colorado River 500 kV, estimated in-service date 2020; and
- Harry Allen – Eldorado 500 kV, estimated in-service date 2020.

[9] NERC functional entities that the TPL Standard applies to are Transmission Planners and Planning Coordinators.

Both projects were included in the CAISO 10-year planning studies, so both were included in the WestConnect models to align the WestConnect 10-year planning studies with those of the CAISO.[10]

2.4 Public Policy Considerations

In the abbreviated 2015 cycle, the analysis of transmission needs driven by public policy requirements was limited to needs driven by enacted renewable portfolio standard (RPS) requirements. A spreadsheet tool was developed to calculate the TO RPS requirements and compare them with the TO RPS compliance plans (i.e., how each TO planned to comply with the RPS rules). Subsequently, a cross-check was performed during the development of the WestConnect 2024 HS Regional PFM to ensure that the model was consistent with all TO RPS compliance plans (see Section 2.5). The rest of this section provides more detail about how the TO RPS requirements and compliance plans were developed, and the final 2024 Public Policy Documentation is in Appendix D. Appendix D shows each utility's estimated 2024 RPS requirement, whether the necessary renewable resources were in the 2024 HS Regional PFM to meet the requirement, and relevant notes for individual TOs.

The development of the spreadsheet tool began by estimating enacted RPS requirements for each WestConnect TO member and participant in 2024 using a repeatable process and publicly available data sources. Calculating individual TO RPS requirements required reviewing state RPS requirements and forecasting TO retail sales in 2024. A single, uniform, and public source for 2024 retail sales estimates for each WestConnect TO member and participant did not exist, so WestConnect developed these by linking each TO with the 2024 load by TEPPC load area[11] defined in WECC's TEPPC 2024 Common Case:

1. Each TO's percentage of each TEPPC load area was determined by comparing actual 2012 retail sales for individual TOs[12] with the 2012 load data (by TEPPC load area) collected by WECC.[13]
2. Each TO's percentage of each TEPPC load area was applied to the 2024 load by TEPPC load area to estimate 2024 retail sales for each individual WestConnect TO.

Generally, the WestConnect TO members and participants agreed that the above, repeatable process provided reasonable estimates of their 2024 RPS requirements. However, six entities believed their own estimates were more accurate than those based on the above process, so they provided their own 2024 retail sales estimates.

The 2024 RPS requirements for each TO were initially calculated by applying a RPS percentage[14] to the TO's 2024 retail sales estimate; however, some TOs required special consideration because they either serve load in multiple states or serve multiple utilities that have different RPS requirements (even within a single state). For instance, El Paso Electric serves load in New Mexico and Texas, and Tri-State serves its members with RPS obligations in Arizona, Colorado, and New Mexico. For these cases a weighted-average RPS energy requirement was calculated, based on the location of retail sales in the

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[10] The Planning Subcommittee did not make any judgment with regard to any interregional aspects of these two projects. They were not submitted for the purposes of cost allocation.

[11] TEPPC load areas generally align with Balancing Authority Areas (BAAs). TEPPC's 2024 data provides load served, including losses. To estimate 2024 retail sales for each TEPPC load area, the transmission level losses calculated by GridView were removed and an additional 3% of load was removed to account for losses at the distribution level.

[12] 2012 Utility Bundled Retail Sales – Total, U.S. Energy Information Administration, Data from forms EIA-861-schedules 4A & 4D and EIA 861-S, available on the EIA website (http://www.eia.gov/electricity/data.cfm#sales).

[13] WECC 2012 Load and Resource Data was provided by WECC Staff. To convert this load data to retail sales equivalents, losses were removed using the same loss percentage estimated by load area by GridView and an additional 3% of load was removed to account for losses at the distribution level.

[14] Consolidated information on RPS requirements can be found on the Database of State Incentives for Renewables & Efficiency (DSIRE) website (http://www.dsireusa.org/).

2012 EIA data. Resource carve-outs (such as special requirements for distributed generation or solar resources) were also calculated for each TO.

In combination with the calculation of the 2024 RPS requirements, the TOs provided the PS with their RPS compliance plans (i.e., how each TO planned to comply with the RPS rules).[15] TOs provided information regarding which resources (existing, planned, and conceptual) were expected to be used for RPS compliance in 2024, including estimates of the resources' energy output. In addition, TOs provided information on other compliance vehicles allowed within the RPS rules, such as energy efficiency (e.g., permitted under the Nevada RPS), banked Renewable Energy Credits (RECs), and unbundled RECs. For each TO, the RPS compliance plans were compared with the 2024 RPS requirements to determine any RPS compliance gaps.

2.5 Regional Power Flow Model

For the abbreviated 2015 planning cycle, the PS developed one base scenario power flow model (PFM), representing a 2024 heavy summer system condition. The abbreviated timeline didn't allow enough time to develop or run assessments on additional PFM scenarios.

Base Case Selection

The WestConnect 2024 HS Regional PFM was developed from the WECC TSS 2024 Heavy Summer 1 Scenario Base Case (24HS1SA), approved by the WECC Planning Coordination Committee (PCC) on February 21, 2014. This WECC case (24HS1SA) was originally built to study the Remedial Action Schemes (RAS) arming in the Colorado/Utah/Northern Nevada area. Generation, interchange, and load conditions for RAS arming studies are near transmission limits for the studied paths, so 24HS1SA was chosen as the reference for the WestConnect Regional PFM because it was expected to need fewer generation or interchange modifications in the WestConnect footprint than a general 10-year planning case produced by WECC.

Power Flow Model Development Process

WestConnect TO Members, other PMC Members, and non-members (including member and non-member non-incumbent transmission developers) participated in the regional PFM development individually in their respective SPG meetings and collectively at the Planning Subcommittee (PS). Only data/models associated with WestConnect TO Members, participating TOs, and/or a neighboring planning region (to the extent such information was provided to WestConnect) were updated. The remaining systems within the Western Interconnection were maintained as originally modeled by WECC.

The regional PFM development was accomplished through several iterations of review and feedback:

1. Each SPG reviewed the WECC 24HS1SA PFM and updated the model while coordinating their internal area-to-area schedules. This produced three SPG footprint PFMs, which WestConnect combined to create the first iteration of the regional PFM.

2. The model was evaluated for N-0 branch rating and bus voltage limits and further tested with a preliminary, auto-generated contingency (N-1 only) analysis and the results and regional PFM were sent out for another round of review. Individual participants submitted further changes via

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[15] *Due to the potentially commercially sensitive nature of this information, individual TO data submittals are considered confidential.*

email and these changes were tested and incorporated into the model to create the second iteration of the regional PFM.

- The changes included updates to the Category B contingency definitions (removing invalid single branch outages and adding multi-element breaker-to-breaker outages).

3. The final draft WestConnect 2024 HS Regional PFM was released for PS review on April 30, 2015. Upon reviewing the case, the PS made some minor changes and the final model was made available to PMC and PS members and participants (with appropriate confidentiality agreements) on May 12, 2015.

The rest of this section provides more detail regarding the modeling assumptions in the final WestConnect 2024 HS Regional PFM. The regional PFMs, including the SPG footprint PFMs, were developed in a format accessible by users of the PowerWorld Simulator, General Electric Positive Sequence Load Flow (GE PSLF), and Siemens PTI PSS®E power flow applications.

Modeling Assumptions and Details Specific to 2024 HS Regional PFM

The SPG and TO participants reviewed and updated the WECC 24HS1SA PFM to ensure that the base transmission plan projects were included and adequately represented in the model. In addition, the participants were asked to review the model as a whole and recommend any additional changes to loads, generation, and transmission to reflect the expected 2024 future. The changes were primarily submitted using processes already established by the SPGs. Participants submitted changes to the model as well as project lists so the PS could readily identify the 2015 to 2024 incremental transmission facilities within the model.

Modeling Software

PowerWorld Simulator (Simulator) was used to develop the power flow model. Simulator imported and exported both PSS®E RAW and PSLF EPC formats so that data from the different applications could be compiled. Simulator also compiled the regional contingency definitions by importing such data developed via either the PSS®E ACCC tool (*.con files) or PSLF SSTools tool (*.otg files). The final case and interim review cases were released in a format accessible by users of GE PSLF, Siemens PTI PSS®E, and PowerWorld Simulator power flow applications.

Generation

The model was developed to ensure adequate generation resources to meet the forecasted 2024 load plus reserve requirements as well as the 2024 RPS obligations of the WestConnect member and participating TOs. In general, all existing, under construction, and planned generation that had received regulatory approval were included in the model.

A cross-check was performed during the development of the WestConnect 2024 HS Regional PFM to ensure that the model was consistent with all TO RPS compliance plans.[16] TOs either provided the location (i.e., bus number) of RPS resources explicitly included in the model or indicated where RPS resources (e.g., distributed generation) were modeled as reduced load. As a result of this cross-check,

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[16] *The Regional Plan assesses the needs solely of WestConnect TO Members in this regard. However, the data collected includes information from TOs who were not currently WestConnect members at the time of the data collection, but who were considering membership. Such information only factored into the determination of public policy requirement-driven transmission needs if any such TO became a member of WestConnect in time to be included in the regional needs assessment.*

approximately 290 MW of nameplate renewable generator capacity was added to the 2024 HS Regional PFM.

Transmission

The model was developed to include everything in the base transmission plan. As previously explained (Section 2.3), the base transmission plan included all existing (i.e., in-service), under construction, and planned transmission facilities, as well as two CAISO projects. Neither the model nor the base transmission plan included conceptual transmission projects.

A voltage range of 0.9 to 1.1 per unit was the default assumption for the normal and post-contingency voltage limits of all facilities in the model; however, some SPGs provided updates to these settings to the extent they assumed different voltage limits in their planning efforts.

Demand and System Support Devices

The forecast loads included in the model were based on the 2024 base load forecast for each TO Member and participant, including the impact of planned energy efficiency, demand side management (DSM) programs, and behind-the-meter distributed generation resources.

All in-service and planned reactive devices were included in the model.

Contingency Definitions, including Operating Procedures and Protection Systems

An initial list of Bulk Electric System (BES) single branch outages was auto-generated at the start of the model development as part of a test contingency analysis. WestConnect participants' review of and feedback on the test contingency analysis lead to modeling updates (i.e., unexpected results focused the investigation) and the complete contingency list used in the regional needs assessment.

Special operating procedures, such as switching procedures and remedial action schemes, required for compliance with NERC TPL standards were considered and included in the model's contingency definitions.

WECC Transfer Paths (Interchanges)

Area-to-area schedule changes between the three SPGs were not needed. Data errors flagged by the software were addressed by individual data owners/TOs and there were no significant adjustments to the interchange assumptions between WestConnect and neighboring regions.

Control Devices

Special control devices required for compliance with NERC TPL standards were considered and included in the model.

Confidentiality

The review and access to the WestConnect 2024 HS Regional PFM was limited to signatories of the WECC Confidentiality Agreement, which granted them access to WECC power flow models and their Critical Energy Infrastructure Information (CEII). An explanation of confidential information is provided in Appendix A.

2.6 Regional Production Cost Model

For the abbreviated 2015 planning cycle, the PS developed one base scenario production cost model (PCM) from the most recent WECC PCM. Its development was in conjunction with the development of the WestConnect 2024 HS Regional PFM. The abbreviated timeline did not allow enough time to develop or run assessments on additional PCM scenarios.

Production Cost Model Development Process

The WestConnect 2024 Regional PCM was developed from two iterations of the WECC 2024 Common Case PCM: Version 1.4 (dated January 19, 2015) and Version 1.5 (dated April 9, 2015). Only data/models associated with WestConnect TO Members, participating TOs, or a neighboring planning region (to the extent such information was provided) were updated. The remaining systems within the Western Interconnection were maintained as originally modeled by WECC.

The regional PCM development was accomplished through several iterations of review and feedback:

1. WestConnect participants reviewed the bus and generator information in Version 1.4 of the WECC 2024 Common Case and utilized a spreadsheet tool to submit recommended updates to the model. The model was updated per feedback received to create the first iteration of the regional PCM.
2. The second iteration of the regional PCM was created to reference Version 1.5 of the WECC 2024 Common Case while still reflecting the updates in the first iteration of the regional PCM that were additional to the updates included in Version 1.5 of the WECC 2024 Common Case. This iteration of the regional PCM was used for further PS review (see Section 3.2 for more details):
    - Metrics: PS reviewed congestion metrics used by other planning regions and considered them for the WestConnect planning process.
    - WECC results: PS reviewed congestion-related results from Version 1.5 of the WECC 2024 Common Case.
    - Discussion of TO-level results: PS discussed congestion results within individual WestConnect TOs and between WestConnect TO members.
3. Further updates were made to the model to create the third iteration of the regional PCM:
    - Corrections to branch ratings and an interface name,
    - Updating the model with preliminary ownership data, and
    - Updating the model with improved median hydro modeling.

The WestConnect 2024 Regional PCM was developed in the ABB GridView format.

3.0 Regional Transmission Needs Assessment

The PMC identifies the more efficient or cost-effective solutions for the region by first identifying regional transmission needs. This section describes the studies that were run on the Regional Planning Models (RPMs) in order to identify the region's transmission needs, which was first documented in the WestConnect 2015 Regional Transmission Needs Assessment Report.

The 2015 regional transmission needs assessment scope, as defined in the Study Plan, was limited in this abbreviated planning cycle given the reduced time to compile new models, run studies, vet results, and compile reports. The focus of the assessment was on the identification of regional reliability needs based on a reliability assessment of the WestConnect 2024 HS Regional PFM.

A more comprehensive review of potential economic-driven needs is expected for the first full biennial cycle (2016-2017), since the WestConnect Regional PCM was in the developmental stages throughout 2015.

In the abbreviated 2015 planning cycle, the assessment of regional transmission needs driven by public policy requirements was conducted using the same model and studies used to identify the regional reliability needs. Production cost modeling was not used to identify regional transmission needs driven by public policy requirements in 2015.

3.1 Regional Reliability Needs

As outlined in the Study Plan, the PMC may identify regional reliability needs in the 10-year (2024) planning horizon. An assessment of the 2024 HS Regional PFM was conducted to evaluate the WestConnect planning region as a whole. Performance was measured by monitoring compliance with applicable reliability standards and criteria, which are the steady-state requirements of the NERC TPL-001 and TPL-002 reliability standards. These reliability standards are defined as follows:

- TPL-001: System Performance Under Normal Conditions (Category A);
- TPL-002: System Performance Following Loss of a Single Bulk Electric System (BES) Element (Category B);

Any violations of NERC TPL-001 and/or TPL-002 reliability standards ("TPL standards") that the PMC determined to be regional in nature were identified as regional reliability needs. If such regional needs are identified, then potential solutions will be solicited by the PMC for evaluation and potential inclusion into the regional plan. By definition, regional reliability needs are identified by issues that impact more than one TO Member system. Specifically, in the event a simulated outage produces one or more NERC TPL violations in more than one member TO system, those violations may result in the identification of a regional reliability-driven transmission need.

Study Procedure and Assumptions

The reliability needs assessment study of the 2024 Heavy Summer Regional Power Flow Model included several iterations of disturbance simulations, participant review of the results, and incorporation of participant modifications and comments into the next round of simulations. Due to the abbreviated timeline, the Study Plan limited the scope of the reliability analysis to N-0 steady-state power flow conditions (Category A in the TPL standards) and N-1 contingencies (Category B in the TPL standards). Voltage stability and transient stability assessments were excluded.

Transmission planners primarily rely on three reliability assessment study methods to investigate a system's response to a contingency (i.e., disturbance). The timeframe for investigation, measured after the disturbance, is a common and practical way to distinguish the assessments. The three reliability assessment study methods are:

- Transient stability: first 30 seconds post-disturbance,
- Post-transient: system's condition at three minutes post-disturbance, and
- Steady-state: system's condition at 20 minutes post-disturbance.

Steady-state criteria (a set of performance requirements driven by TPL standards) are used to flag issues in the post-transient and steady-state assessments. Since system conditions during the three minutes after a contingency are typically volatile as the system attempts to recover from the disturbance, the post-transient assessment tends to flag more issues, making it useful as a means to screen out disturbances that do not need to be re-evaluated in the steady-state assessment.

In executing the studies described in the 2015 Study Plan, an initial contingency analysis was performed using the post-transient method,[17] including fast automatic[18] actions. Next, contingencies that flagged branch overloads or bus voltage limits in the post-transient method were repeated in a steady-state assessment with appropriate slow automatic and manual actions modeled to determine if these additional adjustments would mitigate the issues flagged by the post-transient method.

All BES branches and buses in the WECC model were monitored (> 100kV)[19] with contingency or "emergency" branch limits assumed as Rating 2 in the PFM and bus voltage limits specified by participants.[20] Additional reporting filters were included to minimize flagging issues with very low sensitivity to the contingencies (e.g., outside the WestConnect footprint). If a branch rating was exceeded, the branch was not reported as an issue unless its flow increases by 1% or more from its base case value. If a bus voltage limit was exceeded, the bus is not reported as an issue unless its voltage change is 0.5% or more from its base case value. The assessment contingencies included:

- Auto-generated BES single branch outages,
- Auto-generated outages of generator step-up transformers (GSU) connecting >20 megawatts (MW) of generating capability to the grid, and
- Participant-supplied contingency definitions to supplement the auto-generated outages.

Study Results

There were several iterations of analyses, which yielded preliminary results that were discussed by participants at Planning Subcommittee meetings. These preliminary results included a variety of potential performance "issues." Participants were encouraged to review the performance issues and provide feedback on how the issues could be resolved. Some of the issues were related to inaccurate transmission system modeling. Although the Planning Subcommittee made a diligent effort to ensure accuracy of models, transmission studies invariably uncover a limited number of minor inaccuracies. In preliminary analyses, prior to approval of the base model, corrections were made to the base model. Following PMC approval of the base model, subsequently identified inaccuracies and data updates were simply noted in the results. Other issues were related to remedial action schemes or operating procedures that were not captured in the disturbance simulations. Again, in preliminary stages of analyses, the Planning Subcommittee was able to incorporate the actions following the disturbance into

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[17] A failed power flow solution using the post-transient method often flags a contingency condition exceeding a voltage stability limit. A successful power flow solution can also exceed a local load level-caused voltage stability limit if the voltage solves very low, because the load will change from constant MVA to voltage sensitive below a user-defined threshold (0.70 per unit in this study).

[18] Examples of fast automatic actions modeled in the post-transient method include static var compensators (SVCs), generator line drop compensation or reactive current compensation voltage control, remedial action schemes (RAS), and post contingency load levels restored to pre-contingency constant MVA values. Examples of slow automatic and manual actions in the model include switchable VAR devices (SVDs), transformer under load tap changing (LTCs), phase shifter tap changing, generator remote bus voltage control, and participant supplied information for load tripping and generation shifts.

[19] With the following exceptions: lines greater than 90kV for IID and those greater than 69kV in zone 147 of the Arizona power flow area.

[20] The default was 0.90 to 1.10 if not specified by participants.

the “base” contingency modeling. However, once the base model was approved, the post-disturbance actions were noted in the tables of results.

Results from the final analysis are summarized below and a tabular summary is provided in Appendix B. The information in Appendix B represents the results of the steady-state analysis. A separate workbook comprised of publicly available work papers underlying the steady-state analysis, as well as the post-transient results and contingency definitions, is available in spreadsheet format among the Planning Subcommittee Reports posted on the WestConnect website.[21]

Post-Transient Method

The assessment first used a post-transient method to identify potential issues for further investigation and study. The post-transient method assessment included 6,190 total contingencies, which identified 135 contingencies causing 308 potential issues within the WestConnect footprint. Again, this was only an initial step and these flagged issues were only used to identify the contingencies that required further investigation using the steady-state method and additional feedback from study participants. Participant comments on the post-transient issues were used to improve the contingency definitions for the steady-state method, and the post-transient assessment was not re-run to incorporate participant comments, because the steady-state method was intended to become the final assessment. Accordingly, the post-transient analysis was not brought to completion, and the interim results it yielded (while helpful to the subsequent steady-state analysis) were not definitive results and should not be considered a reliability assessment of any member or participant.

Steady-State Method

As previously indicated, participants reviewed the issues identified in the post-transient study and provided additional data for the contingency definitions. During this review, individual TOs addressed flagged issues by incorporating more detailed data into the contingency definitions. After the additional data was included in the contingency definitions and redundant contingency definitions (same actions with different contingency name) were removed from the analysis, the steady-state method simulations were run, resulting in 17 contingencies flagging 33 potential issues within the WestConnect footprint. In other words, the steps taken in the steady-state assessment led to the resolution of 275 of the initial 308 potential issues identified using the post-transient method. The remaining 33 potential steady-state issues included both single- and multiple-system impacts. The multiple-system impacts did not include any member-to-member issues within the WestConnect planning region, as discussed below. Participants provided feedback on the steady-state results, which included mitigating actions that served to either remedy the issue(s) or correct for errors in the modeling assumptions. Any modeling corrections were noted and the Planning Subcommittee recommends that individual TOs verify that such corrections will fully mitigate the corresponding steady-state issue(s). The Planning Subcommittee did not re-run the steady-state analyses for these instances since the base model was finalized and approved by the PMC.

Single-System Issues

For the purposes of this study, a single-system issue is defined as a contingency that impacts only the TO-footprint in which it resides. Single TO issues and non-member issues are not within the scope of the WestConnect regional transmission planning process, and are not considered regional transmission needs. However, for the sake of completeness and study transparency, the study process included a review of single-system issues to ensure that in combination, none of the issues were regional in nature.

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[21] *https://doc.westconnect.com/Documents.aspx?NID=16584&dl=1*

Each of the 33 potential issues identified through the steady-state assessment ultimately was determined to be single-system in nature. Where the steady-state powerflow analyses conducted by the planning region revealed potential single-system issues, participants were invited to provide comments to document how each issue is currently being addressed by the affected entity. In some cases, comments included a description of planned or existing mitigating actions that would remediate the issue. In others, the identified issue was driven by modeling assumptions—in which case the issue is addressed through a comment (and depicted in the worksheet) that describes the modeling correction.

This regional planning analysis does not result in a determination or finding that there is any deficiency within the single system that requires action. Any single-system issues are the responsibility of the affected TO to resolve, if necessary. Since the Study Plan is directed towards the identification of regional transmission needs, no further inquiry or study was performed. The regional findings are discussed next.

Regional Reliability Study Findings

As described above, the regional reliability assessment identified 33 potential issues. After a detailed review of each potential issue, it was ultimately determined that none were regional in nature. Thirty of the 33 issues were clearly single-system in nature—meaning they were not within the scope of the WestConnect regional planning process, and thus were not considered as potential regional transmission needs. These issues were referred back to the respective TOs.

The remaining three issues were the result of one contingency that impacted more than one TO, and so this required additional investigation by the Planning Subcommittee. The contingency originated on one TO system and resulted in three low-voltage issues on another TO system. However, the voltage issues occurred on a local load-serving 115 kV system. Specifically, a single 115 kV line that is sourced from both ends has load-serving taps along the line (between the sourced ends). For a contingency at either end of the line, voltages drop because the loads are served radially. The contingency has no performance impacts outside the local area. Based on this review, the Planning Subcommittee determined that this potential issue was a local load-serving issue, and was referred back to the affected TOs.[22] Although the contingency impacted more than one TO, a more thorough review of the issue, as described above, reveals that it was not regional in nature.

To summarize, the regional reliability transmission needs assessment did not identify any simulated outages that either (a) resulted in potential regional issues in more than one member TO system, or (b) caused a regional issue on a member TO system that was different than the contingency/outage owner. This assessment also did not identify any simulated outages within WestConnect that resulted in any issues outside of the WestConnect footprint.

3.2 Regional Economic Needs

Due to the abbreviated timeline in 2015, WestConnect did not conduct the type of economic needs assessment contemplated for future biennial cycles. The Study Plan committed WestConnect to review the WECC 2024 Common Case (from a WestConnect perspective) to discern whether there were indications of congestion or other issues that might indicate regional economic needs. To complete this task, the WestConnect Planning Subcommittee took the following steps:

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[22] *As of the WestConnect 2015 Regional Transmission Needs Assessment Report approval, neither of the affected TOs were WestConnect signatory members. Therefore, in addition to this contingency and results not being a regional issue, it was also outside the WestConnect process, since there was no impact to signatory members of WestConnect.*

1. Metric review: The Planning Subcommittee reviewed congestion metrics used by other planning regions, which were discussed at length to determine the appropriateness of the metrics relative to the WestConnect planning process for identifying regional economic needs. Metrics considered by the group included:
    a. Congestion (hours)
    b. Congestion cost ($)
    c. Shadow pricing
    d. Locational Marginal Pricing (LMP) differentials
2. WECC results: The Version 1.5 of the WECC 2024 Common Case PCM was run and a number of congestion-related results were compiled for review by the PS.
3. WestConnect Planning Subcommittee review: During the June 15, 2015 PS meeting, the congestion results from the 2024 Common Case were reviewed, from a WestConnect perspective. The group used the preliminary study results to hold a discussion on line and interface congestion and congestion cost for all congested elements greater than 100 kV. The group also drilled down and discussed congestion results within and between WestConnect TOs.

During the review of the congestion metrics, the Planning Subcommittee discussed ways to implement an economic needs identification methodology. While this work was ongoing throughout 2015, the following general principles were developed within the abbreviated 2015 cycle:

- Strict metrics or thresholds are not desirable, as congestion identified in the model runs is a product of the input assumptions, and the quantitative analysis must be complemented by member review. A complete study cycle should allow for more complete analysis to determine the metric to establish economic need, and evaluation of factual considerations that are producing the model run results.
- Future WestConnect Regional PCMs will likely require significant data updates if they are to reasonably reflect member-to-member congestion. This should be a focus of discussion and model development in future planning cycles.
- The identification of economic needs should be considered across a number of possible futures, not just a single expected future. Since scenarios will need to be created to show the complete impact to the transmission system, one PCM cannot completely capture the full range of costs and benefits. Later cycles should include more than just one PCM to capture system characteristics.

3.3 Regional Public Policy Needs

WestConnect defines public policy requirements as enacted federal, state and local policies. In the abbreviated 2015 planning cycle, the analysis of regional transmission needs driven by public policy requirements for PMC members was limited to needs driven by enacted renewable portfolio standard (RPS) requirements. As previously mentioned in Section 2.4, the development of the 2024 HS Regional PFM included performing a gap analysis using a spreadsheet tool to ensure adequate renewable resources needed to achieve RPS requirements were included in the 2024 HS Regional PFM. Per Planning Subcommittee review, the 2024 HS Regional PFM contained adequate transmission facilities to support the amount of renewable resources within the model, thereby accomplishing the assessment of transmission needs driven by public policy requirements for PMC members.

The regional reliability needs assessment of the 2024 HS Regional PFM did not identify any regional reliability issues (see Section 3.1) and the 2024 HS Regional PFM reflected public policy (enacted RPS) requirements. As a result, there were no public policy-driven regional transmission needs identified in the abbreviated 2015 planning cycle.

4.0 Stakeholder Involvement and Regional Coordination

All WestConnect planning meetings were open to stakeholders, with the only exceptions being PMC closed sessions which were included in the agendas distributed prior to meetings and posted on the website. WestConnect also coordinated with the four established Planning Regions in the Western Interconnection as well as the Western Electricity Coordinating Council (WECC) as follows:

- Participation in interregional coordination meetings (see Appendix E)
- Publicly distributing WestConnect planning documents:
    - WestConnect Regional Planning Process Business Practice Manual (WestConnect Regional BPM)
    - WestConnect 2015 Regional Study Plan (Study Plan)
    - WestConnect 2015 Regional Model Development Report
    - WestConnect 2015 Regional Transmission Needs Assessment Report
    - WestConnect 2015 Regional Transmission Plan (i.e., this document)
- Sharing planning data and models upon request, with appropriate confidentiality (Appendix A)
- Requesting data and models from TOs outside of the WestConnect planning region during the development of the regional planning models
- Engaging in the development of the WECC 2026 Common Case production cost model

In developing the regional models, the Planning Subcommittee had strong participation by the non-FERC jurisdictional TOs in the WestConnect footprint not yet party to the PPA. These participating TOs updated the models following the same process and to the same extent as the member TOs. This invaluable participation in WestConnect model development will certainly be encouraged in future cycles.

Appendix E provides the activities conducted within the abbreviated 2015 planning cycle. Changes to the Study Plan's schedule of activities were announced in a timely manner via the WestConnect website, emails to stakeholder distributions lists, and discussions within committee meetings.

5.0 Conclusions

Based on the abbreviated cycle analysis performed for reliability, economic, and public policy transmission needs, there were no regional transmission needs identified in the 2015 assessment.

Appendix A – Information Confidentiality

The Planning Subcommittee handled confidential information in accordance with the protocols outlined in the BPM. Although the Regional Planning Process is open to all stakeholders, stakeholders are required to comply at all times with certain applicable confidentiality measures necessary to protect confidential information, proprietary information, or Critical Energy Infrastructure Information (CEII).

As it related to the model development portion of the process, confidentiality protections were accorded for the following:

- WestConnect power flow models are considered CEII. Based on this, during the case development process, only those entities having signed the appropriate WECC Confidentiality Agreement were granted access to the model. The WestConnect power flow models do not contain any information that is different from what would be typically contained in the original WECC-base case.
- Certain generator procurement and contract information gathered during the RPS evaluation was considered commercially sensitive. Based on this assessment, that data was considered confidential and was not shared.

Additional confidentiality protections were developed during the 2015 abbreviated planning cycle, including the use of non-disclosure agreements tailored to WestConnect's regional transmission planning process, and the data collections and distributions made pursuant to the WestConnect process.

Appendix B – Results of 2015 Reliability Needs Assessment: Final Issues Flagged in the Steady-State Analysis

Contingency Information		**Element(s) Which Had an Issue** Note that all potential issues were determined to be local/single-system in nature		**The issue and its magnitude - Voltages are per unit, all others are real numbers or percents**					**Data Owner's Comment**
Area/ Zone/ Owner	**Contingency Name**	**Area/ Zone/ Owner**	**Element Name**	**Category**	**% Change From Base Case**	**% Branch Loading**	**Value**	**Limit**	
ARIZONA/ APS/ Arizona Public Service	[redacted]	ARIZONA/ APS/ Arizona Public Service	"MAZATZAL" 345 kV Bus	Bus High Volts			[redacted]	[redacted]	Issue due to modeling of Bulk system only. Area owners are aware of higher voltages and studying future projects.
			"PRECHCYN" 345 kV Bus	Bus High Volts			[redacted]	[redacted]	
LADWP/ City of Los Angeles/ City of Los Angeles	[redacted]	LADWP/ City of Los Angeles/ City of Los Angeles	"MKTPSVC" 500 kV Bus	Bus High Volts			[redacted]	[redacted]	Missing shunt reactor in model at [redacted] will mitigate high voltage
			"MARKETPL" 500 kV Bus	Bus High Volts			[redacted]	[redacted]	
NEW MEXICO/ ZonePN/ PN1 New Mexico	[redacted]	NEW MEXICO/ ZonePN/ Aragonne Wind LLC	"ARGONNE3" 138 kV Bus	Bus Low Volts			[redacted]	[redacted]	Proprietary voltage control excluded from the model will mitigate low voltage
ARIZONA/ SWTC/ Southwest Transmission Coop.	[redacted]	ARIZONA/ SWTC/ Southwest Transmission Coop.	"AVRA" 115 kV Bus	Bus Low Volts			[redacted]	[redacted]	Mitigating alternative plans will be studied by affected TO
			"MARANA" 115 kV Bus	Bus Low Volts			[redacted]	[redacted]	
			"SNDARIO" 115 kV Bus	Bus Low Volts			[redacted]	[redacted]	
ARIZONA/ APS, SWTC, WAPA-DSW/ Southwest Transmission Coop., WAPA-DSW	[redacted]	ARIZONA/ SWTC/ Southwest Transmission Coop.	"MARANA" 115 kV Bus	Bus Low Volts			[redacted]	[redacted]	Mitigating alternative plans will be studied by affected TOs
			"AVRA" 115 kV Bus	Bus Low Volts			[redacted]	[redacted]	
			"SNDARIO" 115 kV Bus	Bus Low Volts			[redacted]	[redacted]	
ARIZONA/ APS, WAPA-DSW/ WAPA-DSW	[redacted]	ARIZONA/ APS,SWTC/ WAPA-DSW	"SAG.EAST-MARANATP" 115 kV Line #1	Branch Amp	[redacted]	[redacted]	[redacted]	[redacted]	Mitigating alternative plans will be studied by affected TO

Contingency Information		Element(s) Which Had an Issue Note that all potential issues were determined to be local/single-system in nature		The issue and its magnitude - Voltages are per unit, all others are real numbers or percents					Data Owner's Comment
Area/ Zone/ Owner	**Contingency Name**	**Area/ Zone/ Owner**	**Element Name**	**Category**	**% Change From Base Case**	**% Branch Loading**	**Value**	**Limit**	
WAPA R.M./ ZoneR4/ Tri-State G&T	[redacted]	WAPA R.M./ Zone69/ Tri-State G&T	"CORTZPIP-MAIN CO" 115 kV Line #1	Branch Amp	[redacted]	[redacted]	[redacted]	[redacted]	Open branch [redacted] in the model should be closed, which will eliminate flagged overload ([redacted])
WAPA R.M./ ZoneR4/ Tri-State G&T	[redacted]	WAPA R.M./ Zone69/ Tri-State G&T	"CORTZPIP-MAIN CO" 115 kV Line #1	Branch Amp	[redacted]	[redacted]	[redacted]	[redacted]	
WAPA R.M./ Zone69, ZoneR4/ Tri-State G&T	[redacted]	WAPA R.M./ Zone69/ Tri-State G&T	"ANASAZI-Y.JACK 2" 115 kV Line #1	Branch Amp	[redacted]	[redacted]	[redacted]	[redacted]	
WAPA R.M./ Zone69/ Tri-State G&T	[redacted]	WAPA R.M./ Zone69/ Tri-State G&T	"ANASAZI-Y.JACK 2" 115 kV Line #1	Branch Amp	[redacted]	[redacted]	[redacted]	[redacted]	
WAPA R.M./ Zone69, ZoneR4/ Tri-State G&T	[redacted]	WAPA R.M./ Zone69,ZoneR4/ Tri-State G&T	"CORTZPIP-TOWAOC" 115 kV Line #1	Branch Amp	[redacted]	[redacted]	[redacted]	[redacted]	
WAPA R.M./ ZoneR4/ Tri-State G&T	[redacted]	WAPA R.M./ Zone69,ZoneR4/ Tri-State G&T	"CORTZPIP-TOWAOC" 115 kV Line #1	Branch Amp	[redacted]	[redacted]	[redacted]	[redacted]	
WAPA R.M./ Zone69, ZoneR4/ Tri-State G&T	[redacted]	WAPA R.M./ ZoneR4/ Tri-State G&T	"DOECANYN-CAHONE" 115 kV Line #1	Branch Amp	[redacted]	[redacted]	[redacted]	[redacted]	
WAPA R.M./ ZoneR4/ Tri-State G&T	[redacted]	WAPA R.M./ Zone69,ZoneR4/ Tri-State G&T	"CORTZPIP-TOWAOC" 115 kV Line #1	Branch Amp	[redacted]	[redacted]	[redacted]	[redacted]	
WAPA R.M./ ZoneR4/ Tri-State G&T	[redacted]	WAPA R.M./ Zone69,ZoneR4/ Tri-State G&T	"CORTZPIP-TOWAOC" 115 kV Line #1	Branch Amp	[redacted]	[redacted]	[redacted]	[redacted]	
WAPA R.M./ Zone69/ Tri-State G&T	[redacted]	WAPA R.M./ ZoneR4/ Tri-State G&T	"DOECANYN-CAHONE" 115 kV Line #1	Branch Amp	[redacted]	[redacted]	[redacted]	[redacted]	
WAPA R.M./ ZoneR4/ Tri-State G&T	[redacted]	WAPA R.M./ Zone69,ZoneR4/ Tri-State G&T	"CORTZPIP-TOWAOC" 115 kV Line #1	Branch Amp	[redacted]	[redacted]	[redacted]	[redacted]	
WAPA R.M./ Zone69, ZoneR4/ Tri-State G&T	[redacted]	WAPA R.M./ Zone69/ Tri-State G&T	"CORTZPIP-MAIN CO" 115 kV Line #1	Branch Amp	[redacted]	[redacted]	[redacted]	[redacted]	

Contingency Information		**Element(s) Which Had an Issue** Note that all potential issues were determined to be local/single-system in nature		**The issue and its magnitude - Voltages are per unit, all others are real numbers or percents**					**Data Owner's Comment**
Area/ Zone/ Owner	**Contingency Name**	**Area/ Zone/ Owner**	**Element Name**	**Category**	**% Change From Base Case**	**% Branch Loading**	**Value**	**Limit**	
WAPA R.M./ Zone69, ZoneR4/ Tri-State G&T	[redacted]	WAPA R.M./ ZoneR4,Zone69/ Tri-State G&T	"DOECANYN-ANASAZI" 115 kV Line #1	Branch Amp	[redacted]	[redacted]	[redacted]	[redacted]	Open branch [redacted] in the model should be closed, which will eliminate flagged overload ([redacted])
WAPA R.M./ ZoneR4/ Tri-State G&T	[redacted]	WAPA R.M./ Zone69/ Tri-State G&T	"CORTZPIP-MAIN CO" 115 kV Line #1	Branch Amp	[redacted]	[redacted]	[redacted]	[redacted]	
WAPA R.M./ Zone69/ Tri-State G&T	[redacted]	WAPA R.M./ ZoneR4,Zone69/ Tri-State G&T	"DOECANYN-ANASAZI" 115 kV Line #1	Branch Amp	[redacted]	[redacted]	[redacted]	[redacted]	
WAPA R.M./ ZoneR4/ Tri-State G&T	[redacted]	WAPA R.M./ Zone69/ Tri-State G&T	"CORTZPIP-MAIN CO" 115 kV Line #1	Branch Amp	[redacted]	[redacted]	[redacted]	[redacted]	
PG AND E/ Conf Load (Western)/ WAPA - SNR	[redacted]	PG AND E/ Conf Load (Western)/ WAPA - SNR	"FLANAGAN" 230/115 kV Transformer #1	Branch MVA	[redacted]	[redacted]	[redacted]	[redacted]	Closed branch [redacted] in the model should be open, which will eliminate flagged overload
			"FLANAGAN" 230/115 kV Transformer #2	Branch MVA	[redacted]	[redacted]	[redacted]	[redacted]	
			"KESWICK-KNAUF" 115 kV Line #1	Branch Amp	[redacted]	[redacted]	[redacted]	[redacted]	
PSCOLORADO, WAPA R.M./ ZoneEC, ZoneRN/ PSColorado	[redacted]	PSCOLORADO/ ZoneRN/ PSColorado	"B.CRK_PS" 230/115 kV Transformer #T1	Branch MVA	[redacted]	[redacted]	[redacted]	[redacted]	Emergency rating of the transformer should be [redacted] in the model, so transformer is not actually overloaded.
PSCOLORADO/ ZoneWP/ West Plains G&T	[redacted]	PSCOLORADO/ ZoneWP/ West Plains G&T	"LAJUNTAW" 115 kV Bus	Bus Low Volts			[redacted]	[redacted]	Planned shunt capacitor not modeled will mitigate low voltage

Appendix C –2024 Regional Base Transmission Plan (2015-2024 Projects)

Southwest Area Transmission (SWAT) Projects (116 Total)

#	Sponsor	Project Name	Development Status	Voltage
1	Arizona Public Service	Mazatzal 345/69kV Substation	Planned	345 kV
2	Arizona Public Service	Morgan - Sun Valley 500kV Line	Planned	500 kV AC
3	Arizona Public Service	North Gila - Orchard 230kV Line	Planned	230 kV
4	Arizona Public Service	Ocotillo 230kV Generation Interconnections	Planned	230 kV
5	Arizona Public Service	Scatter Wash 230/69kV Substation	Planned	230 kV
6	Arizona Public Service	Sun Valley - Trilby Wash 230kV Line	Planned	230 kV
7	El Paso Electric Company	Afton North - Airport Transmission Line	Planned	115 kV
8	El Paso Electric Company	Afton North Autotransformer	Planned	345 kV
9	El Paso Electric Company	Airport - Jornada Transmission Line	Planned	115 kV
10	El Paso Electric Company	Felipe 69 kV Substation Capacitor Bank	Planned	Below 115 kV
11	El Paso Electric Company	Global Reach Substation Capacitor Bank	Planned	115 kV
12	El Paso Electric Company	Global Reach Substation Transformer (T2)	Planned	115 kV
13	El Paso Electric Company	Lane - Pendale - Copper (16900) 69 kV Line Rebuild & Reconductor	Planned	Below 115 kV
14	El Paso Electric Company	LE1 (Organ) - Jornada Transmission Line	Planned	115 kV
15	El Paso Electric Company	LE1 (Organ) Substation	Planned	115 kV
16	El Paso Electric Company	Leasburg Substation 33.6 MVA Transformer	Planned	115 kV
17	El Paso Electric Company	Leo - Dyer (6500) Transmission Line Upgrade to 115 kV	Planned	115 kV
18	El Paso Electric Company	Leo - Milagro (7800) Transmission Line Upgrade to 115 kV	Planned	115 kV
19	El Paso Electric Company	Leo Substation Upgrade from 69 kV to 115 kV	Planned	115 kV
20	El Paso Electric Company	NW2 (Verde) Substation 30 MVA Transformer	Planned	115 kV
21	El Paso Electric Company	NW3 (Transmountain) Substation Transformer	Planned	115 kV
22	El Paso Electric Company	Patriot Substation Transformer (T2)	Planned	115 kV
23	El Paso Electric Company	Picante Substation Capacitor Bank	Planned	115 kV
24	El Paso Electric Company	Pipeline Substation 33.6 MVA Transformer	Planned	115 kV
25	El Paso Electric Company	Rio Bosque Substation Transformer (T2)	Planned	Below 115 kV
26	El Paso Electric Company	Rio Grande - Asarco Tap (5500) 69 kV Line Reconductor	Planned	Below 115 kV
27	El Paso Electric Company	Rio Grande - Sunset (5600) 69 kV Line Reconductor	Planned	Below 115 kV

Southwest Area Transmission (SWAT) Projects (116 Total)

#	Sponsor	Project Name	Development Status	Voltage
28	El Paso Electric Company	Sol - Vista Transmission Line Upgrade	Planned	115 kV
29	El Paso Electric Company	Uvas Substation 12 MVA Transformer	Planned	115 kV
30	El Paso Electric Company	Wrangler - Sparks Transmission Line Reconductor	Planned	115 kV
31	Imperial Irrigation District	El Centro Switching Station (ECSS) - Dixieland - Bannister 230 kV Upgrade	Planned	230 kV
32	Imperial Irrigation District	El Centro Switching Station (ECSS) 161/92 kV Transformer Replacement	Planned	161 kV
33	Imperial Irrigation District	El Centro Switching Station (ECSS) to Fern Switching Station 230 kV Transmission Line	Planned	230 kV
34	Imperial Irrigation District	Highline to El Centro Switching Stations double circuit 230 kV Transmission Line	Planned	230 kV
35	Imperial Irrigation District	Hoober 230 kV Switching Station	Planned	230 kV
36	Imperial Irrigation District	Imperial Valley Substation (IV Sub) to Dixieland Switching Station 230 kV Transmission Line Project - Phase 2	Planned	230 kV
37	Imperial Irrigation District	Imperial Valley Substation (IV Sub) to Dixieland Switching Station 230 kV Transmission Line project - Phase 1	Planned	230 kV
38	Imperial Irrigation District	Midway - Devers Switching Stations 500 kV AC Line	Planned	500 kV AC
39	Imperial Irrigation District	Midway to Highline Switching Stations 230 kV Transmission Line Upgrade	Planned	230 kV
40	Imperial Irrigation District	Midway - Hoober - Bannister 230 kV Transmission Line	Planned	230 kV
41	Imperial Irrigation District	Niland Substation Transformer Replacement	Planned	161 kV
42	Imperial Irrigation District	North Gila to Highline 500 kV Transmission Line	Planned	500 kV AC
43	Imperial Irrigation District	Ramon Substation, 230/92 kV, 300 MVA Transformer Addition	Planned	230 kV
44	Los Angeles Department of Water and Power	Barren Ridge Renewable Transmission Project	Planned	230 kV
45	Los Angeles Department of Water and Power	Scattergood - Olympic 230 kV Cable A with Shunt	Planned	230 kV
46	Los Angeles Department of Water and Power	Northridge - Tarzana CB Upgrade	Planned	230 kV
47	Los Angeles Department of Water and Power	Valley - Rinaldi 230 kV Line Reconductor	Planned	230 kV
48	Los Angeles Department of Water and Power	Victorville 500/287 kV Auto-Transformer	Planned	230 kV
49	Los Angeles Department of Water and Power	Toluca 500/230 kV Transformer	Planned	230 kV

Southwest Area Transmission (SWAT) Projects (116 Total)

#	Sponsor	Project Name	Development Status	Voltage
50	Los Angeles Department of Water and Power	Haskell Canyon - Rinaldi 230 kV Line Reconductor	Planned	230 kV
51	Los Angeles Department of Water and Power	Castaic - Haskell Canyon 230 kV Line	Planned	230 kV
52	NV Energy	Arden - Haven 138 kV Line Upgrade	Planned	138 kV
53	NV Energy	Burnham - Pebble 138 kV Line Upgrade	Planned	138 kV
54	NV Energy	Equestrian - 2nd 230/69 kV XFMR Installation	Planned	230 kV
55	NV Energy	Iron Mountain - 3rd 230/138 kV Transformer	Planned	230 kV
56	NV Energy	McDonald 230/138 kV XFMR & Decatur - Arden 230kV Line Fold into McDonald	Planned	230 kV
57	NV Energy	Pecos - Craig 138 kV Line Upgrade (Reconductor/Re-Build)	Planned	138 kV
58	NV Energy	Pecos - Michael Way 138 kV Line Fold into Miller 138kV	Planned	138 kV
59	NV Energy	Tropical 138kV 24 MVAR Capacitor	Planned	138 kV
60	NV Energy	Winterwood - Cabana 138k V Line Upgrade (Reconductor/Re-Build)	Planned	138 kV
61	NV Energy	Garces - Mayfair 138 kV Line Upgrade	Planned	230 kV
62	Public Service Company of New Mexico	Alamogordo Voltage Support Phase II	Planned	115 kV
63	Public Service Company of New Mexico	Richmond 115 kV Switching Station	Planned	115 kV
64	Public Service Company of New Mexico	Second Yah-Ta-Hey 345/115 kV Transformer	Planned	345 kV
65	Salt River Project	Abel - Pfister - Ball 230 kV (formerly RS12-RS-24-Abel and Abel-Moody)	Planned	230 kV
66	Salt River Project	Browning - Corbell 230 kV Line Reconfiguration	Planned	230 kV
67	Salt River Project	Hassayampa - Pinal West #1 Jojoba Line Loop	Planned	500 kV
68	Salt River Project	Rogers - Santan 230 kV	Planned	230 kV
69	Salt River Project	RS28 Substation	Planned	230 kV
70	Salt River Project	Schrader - RS28 230 kV Transmission Line	Planned	230 kV
71	Southwest Transmission Cooperative	Bicknell Substation Capacitor Bank	Planned	115 kV
72	Southwest Transmission Cooperative	Butterfield Substation Capacitor Bank	Planned	230 kV

Southwest Area Transmission (SWAT) Projects (116 Total)

#	Sponsor	Project Name	Development Status	Voltage
73	Southwest Transmission Cooperative	Sahuarita Substation Capacitor Bank	Planned	230 kV
74	Southwest Transmission Cooperative	San Rafael Substation Capacitor Bank	Planned	230 kV
75	Southwest Transmission Cooperative	Three Points Substation Capacitor Bank	Planned	115 kV
76	Tri-State Generation and Transmission Association	NENM Reliability Improvement	Planned	115 kV
77	Tucson Electric Power	Corona 138/13.8 kV Substation	Planned	138 kV
78	Tucson Electric Power	Craycroft Barril 138/13.8 kV Substation	Planned	138 kV
79	Tucson Electric Power	Del Cerro - Tucson 138 kV Line Uprate/Reconductor	Planned	138 kV
80	Tucson Electric Power	DeMoss Petrie to North East Loop Reconductor	Planned	138 kV
81	Tucson Electric Power	Green Valley to Toro 138 kV Line Uprate	Planned	138 kV
82	Tucson Electric Power	Greenlee 345 kV, Conversion to Breaker-and-a-half Substation	Planned	345 kV
83	Tucson Electric Power	Griffith - N. Havasu 69/230 kV Transmission Line	Planned	230 kV
84	Tucson Electric Power	Harrison 138/13.8 kV Substation	Planned	138 kV
85	Tucson Electric Power	Hartt 138/13.8 kV Substation	Planned	138 kV
86	Tucson Electric Power	Hartt to Toro 138 kV Transmission Line Uprate	Planned	138 kV
87	Tucson Electric Power	Irvington - Drexel 138 kV Line Uprate	Planned	138 kV
88	Tucson Electric Power	Irvington - Tucson 138 kV Transmission Line Circuit 2	Planned	138 kV
89	Tucson Electric Power	Irvington 138 kV Breaker-and-a-half Substation	Planned	138 kV
90	Tucson Electric Power	Irvington to 22nd 138 kV Transmission Line Reconductor	Planned	138 kV
91	Tucson Electric Power	Kino 138/13.8 kV Substation	Planned	138 kV
92	Tucson Electric Power	Marana 138/13.8 kV Substation	Planned	138 kV
93	Tucson Electric Power	Marana 138 kV Transmission Line	Planned	138 kV
94	Tucson Electric Power	Midvale - Spencer 138 Transmission Line	Planned	138 kV
95	Tucson Electric Power	Naranja 138/13.8 kV Substation	Planned	138 kV
96	Tucson Electric Power	NL - NARANJA 138 kV Project	Planned	138 kV
97	Tucson Electric Power	NL EXP - Rancho Vistoso 138 kV Line Reconductor	Planned	138 kV
98	Tucson Electric Power	NL Expansion 138 kV Capacitor Bank upgrades, banks 1&2	Planned	138 kV
99	Tucson Electric Power	North Loop - DMP 138 kV Line Reconductor	Planned	138 kV

Southwest Area Transmission (SWAT) Projects (116 Total)

#	Sponsor	Project Name	Development Status	Voltage
100	Tucson Electric Power	North Loop - Rillito 138 kV Line Reconductor	Planned	138 kV
101	Tucson Electric Power	North Loop Expansion - West Ina Reconductor	Planned	138 kV
102	Tucson Electric Power	Orange Grove 138/13.8 kV Substation	Planned	138 kV
103	Tucson Electric Power	Toro 138kV Switchyard (Rosemont)	Planned	138 kV
104	Tucson Electric Power	Rancho Vistoso to La Canada 138 kV Line Uprate	Planned	138 kV
105	Tucson Electric Power	Rosemont 138 kV Line	Planned	138 kV
106	Tucson Electric Power	Series Capacitor Replacement at Greenlee 345kV Substation	Planned	345 kV
107	Tucson Electric Power	South Loop 138 kV Capacitor Upgrade	Planned	138 kV
108	Tucson Electric Power	South Loop 138 kV Disconnect Switch Replacement	Planned	138 kV
109	Tucson Electric Power	South Loop 345 kV, Conversion to Breaker-and-a-half Substation	Planned	345 kV
110	Tucson Electric Power	South Loop to Toro 138kV Line Uprate	Planned	138 kV
111	Tucson Electric Power	Tortolita - Rancho Vistoso 138kV Line Re-configuration: Tortolita - NL EXP / NL EXP - Rancho Vistoso	Planned	138 kV
112	Tucson Electric Power	Tortolita 500 kV Switchyard	Planned	500 kV AC
113	Western Area Power Administration - DSW	Gila 161 kV Substation Rebuild	Planned	161 kV
114	Western Area Power Administration - DSW	Glen Canyon Transformer Addition	Planned	230 kV
115	Western Area Power Administration - DSW	Mead Transformer Replacement	Planned	345 kV

Southwest Area Transmission (SWAT) Projects (116 Total)

#	Sponsor	Project Name	Development Status	Voltage
116	Western Area Power Administration - DSW	Tucson Substation	Planned	230 kV

Colorado Coordinated Planning Group (CCPG) Projects (45 Total)

#	Sponsor	Project Name	Development Status	Voltage
1	Black Hills Energy	Baculite Mesa-Overton 115 kV Line Rebuild	Planned	115 kV
2	Black Hills Energy	LaJunta Tri-State Interconnect	Planned	115 kV
3	Black Hills Energy	Overton 115 kV Substation	Planned	115 kV
4	Black Hills Energy	Portland 115/69 kV Transformer Replacement	Planned	115 kV
5	Black Hills Energy	West Station - Desert Cove 115 kV Line Rebuild	Planned	115 kV
6	Black Hills Power	Osage - Lange 230 kV Line	Planned	230 kV
7	Black Hills Power	Second 230/69 kV Yellow Creek Transformer	Planned	230 kV
8	Black Hills Power	Teckla - Osage 230 kV Line	Planned	230 kV
9	Cheyenne Light Fuel and Power	Second South Cheyenne 230/115 kV Transformer	Planned	230 kV
10	Cheyenne Light Fuel and Power	Swan Ranch 115 kV Substation	Planned	115 kV
11	Colorado Springs Utility	Kelker - Front Range 230 kV Transmission Line	Planned	230 kV
12	Intermountain Rural Electric Association	Brick Center - Kiowa 115 kV	Planned	115 kV
13	Intermountain Rural Electric Association	Delbert 115 kV Substation	Planned	115 kV
14	Intermountain Rural Electric Association	Citadel 115 kV Substation	Planned	115 kV
15	Intermountain Rural Electric Association	Compark 115 kV Substation	Planned	115 kV
16	Intermountain Rural Electric Association	Happy Canyon 11 5 kV Substation	Planned	115kV
17	Platte River Power Authority	Boyd 230/115 kV Substation Expansion	Planned	230 kV
18	Platte River Power Authority	Fort Collins Northeast 115/13.8 kV Substation	Planned	115 kV
19	Platte River Power Authority	Laporte 230kV Expansion	Planned	230 kV
20	Platte River Power Authority	Timberline 230/115 kV Transformer T3 Replacement	Planned	230 kV
21	Public Service Company of Colorado/ Xcel Energy	Avery Substation	Planned	230 kV
22	Public Service Company of Colorado/ Xcel Energy	Bluestone Substation	Planned	230 kV
23	Public Service Company of Colorado/ Xcel Energy	Happy Canyon Substation	Planned	115 kV

Colorado Coordinated Planning Group (CCPG) Projects (45 Total)

#	Sponsor	Project Name	Development Status	Voltage
24	Public Service Company of Colorado/ Xcel Energy	Moon Gulch 230/13.8 kV, 50 MVA Distribution Substation	Planned	230 kV
25	Public Service Company of Colorado/ Xcel Energy	Palmer Lake Series Reactor	Planned	115 kV
26	Public Service Company of Colorado/ Xcel Energy	Pawnee - Daniels Park 345 kV Transmission Project	Planned	345 kV
27	Public Service Company of Colorado/ Xcel Energy	Rifle - Parachute 230 kV Line #2	Planned	230 kV
28	Public Service Company of Colorado/ Xcel Energy	Thornton Substation	Planned	115 kV
29	Public Service Company of Colorado/ Xcel Energy	Wheeler - Wolf Ranch 230 kV Transmission Project	Planned	230 kV
30	Tri-State Generation and Transmission Association	Badwater - DJ 230 kV Line (Badwater - Casper 230 kV Line)	Planned	230 kV
31	Tri-State Generation and Transmission Association	Big Sandy - Calhan 230 kV Project	Planned	230 kV
32	Tri-State Generation and Transmission Association	Burlington - Lamar 230 kV Transmission Project	Planned	230 kV
33	Tri-State Generation and Transmission Association	Falcon - Midway 115 kV Line Uprate Project	Planned	115 kV
34	Tri-State Generation and Transmission Association	JM Shafer - Henry Lake 230 kV Line Project	Planned	230 kV
35	Tri-State Generation and Transmission Association	La Junta (TS) 2nd 115/69 kV, 42 MVA XFMR	Planned	115 kV
36	Tri-State Generation and Transmission Association	Lost Canyon - Main Switch 2nd 115 kV line	Planned	115 kV
37	Tri-State Generation and Transmission Association	Poncha - San Luis Valley 2nd 230 kV line	Planned	230 kV
38	Western Area Power Administration - RMR	Archer Transformer KV2A Replacement	Planned	230 kV
39	Western Area Power Administration - RMR	Badwater Reactor	Planned	230-kV
40	Western Area Power Administration - RMR	Curecanti Transformer Replacement	Planned	230 kV

Colorado Coordinated Planning Group (CCPG) Projects (45 Total)

#	Sponsor	Project Name	Development Status	Voltage
41	Western Area Power Administration - RMR	Estes - Flatiron 115-kV rebuild	Planned	115 kV
42	Western Area Power Administration - RMR	Granby - Windy Gap	Planned	138 kV
43	Western Area Power Administration - RMR	Lovell - Basin 115-kV Uprate	Planned	115 kV
44	Western Area Power Administration - RMR	Stegall Transformer	Planned	230 kV
45	Western Area Power Administration - RMR	Waterflow KU1A & KU1B Replacement	Planned	345 kV

Sierra Subregional Planning Group (SSPG) Projects (8 Total)

#	Sponsor	Project Name	Development Status	Voltage
1	NV Energy	California - Bordertown 120 kV Line	Planned	115 kV
2	NV Energy	Carlin Trend 120 kV Separation Scheme (RAS) to mitigate thermal overloading	Planned	345 kV
3	NV Energy	Carlin Trend 120 kV and 345 kV Reinforcement	Planned	345 kV
4	NV Energy	Emerson - Carson 120 kV Line Upgrade	Planned	115 kV
5	NV Energy	Falcon 345/120 kV Transformer Addition	In-service	345 kV
6	Western Area Power Administration - SNR	Install 230 kV Reactive Voltage Support	Planned	230 kV
7	Western Area Power Administration - SNR	Reconductor Keswick-Airport-Cottonwood 230 kV Lines	Planned	230 kV
8	Western Area Power Administration - SNR	Reconductor Olinda - Cottonwood #1 & #2 230 kV Lines	Planned	230 kV

Regional (in Multiple SPGs) Projects (2 Total)

#	Sponsor	Project Name	Development Status	Voltage
1	NV Energy	Harry Allen 500/230 kV Transformer	In-service	500 kV AC
2	Tri-State Generation and Transmission Association	San Juan Basin Energy Connect Project	Planned	230 kV

Non-Incumbent Developer Projects

The following projects were submitted into the WestConnect TPPL and evaluated for inclusion in the 2024 Base Transmission Plan, though none passed the threshold required by the WestConnect Planning Process for inclusion in the base transmission plan (note the third column). However, exclusion from the base plan does not mean that a project is ineligible to seek Order No. 1000 regional cost allocation. Eligibility for Order No. 1000 cost allocation is a separate analysis, and would have followed the identification of regional transmission needs had the abbreviated 2015 planning cycle identified any needs.

Non-Incumbent Developer Projects Evaluated for 2024 Base Transmission Plan (23 Total)

#	Sponsor	Project Name	In Base Plan Transmissio n Plan?	Voltage
1	CATS Sub-Regional Planning Group Participants	Palo Verde - Saguaro 500kV line	No	500 kV AC
2	Central Arizona Project	Harcuvar Transmission Project (HTP)	No	230 kV
3	Clean Line Energy Partners	Centennial West Clean Line	No	500 kV DC
4	Clean Line Energy Partners	Western Spirit Clean Line	No	345 kV
5	Duke-American Transmission Company	Zephyr	No	500 kV DC
6	Energy Capital Partners	WECC - Eastern Interconnection DC Upgrade Project	No	230 kV
7	Great Basin Energy Development, LLC	Great Basin HVDC	No	500 kV DC
8	Great Basin Transmission, LLC	Southwest Intertie Project or SWIP (SWIP Phase II)	No	500 kV AC
9	Longview Energy Exchange, LLC	Longview 500 kV Switchyard	No	500 kV AC
10	Longview Energy Exchange, LLC	Longview to Moenkopi-Eldorado 500 kV Line	No	500 kV AC
11	Longview Energy Exchange, LLC	Longview to Peacock 500 kV line	No	500 kV AC
12	Longview Energy Exchange, LLC	Longview to Yavapai 500 kV Line	No	500 kV AC
13	Lucky Corridor, LLC	Lucky Corridor Transmission Project	No	345 kV

Non-Incumbent Developer Projects Evaluated for 2024 Base Transmission Plan (23 Total)

#	Sponsor	Project Name	In Base Plan Transmissio n Plan?	Voltage
14	Public Service Company of Colorado/ Xcel Energy	High Plains Express Transmission Project	No	500 kV AC
15	San Luis River Colorado Project	SLRC Power Center, Transmission Line	No	230 kV
16	Southline Transmission, L.L.C.	Southline Transmission Project - Afton-Apache)	No	345 kV
17	Southline Transmission, L.L.C.	Southline Transmission Project - (Apache-Saguaro)	No	230 kV
18	Southwest Transmission Partners, LLC	North Gila - Imperial Valley #2	No	500 kV AC
19	SunZia Transmission, LLC	SunZia Southwest Transmission Project	No	500 kV AC
20	TransCanada	Chinook	No	500 kV DC
21	TransWest Express, LLC	TransWest Express Project	No	600 kV DC
22	Tres Amigas LLC	Tres Amigas Superstation	No	345 kV
23	Wyoming-Colorado Intertie, LLC	Wyoming-Colorado Intertie	No	345 kV

Appendix D – 2024 Public Policy Documentation

Member / Participant	Effective RPS Requirement in 2024	Estimated 2024 Retail Sales (MWh)	2024 RPS Requirement (MWh)	RPS Resources in Regional PFM?	Notes
Arizona Public Service	14%	33,418,210	4,678,549	Yes	Arizona's RPS includes a Distributed Generation (DG) carve out. In 2024, the DG carve out is 30% of the RPS or 4.2% of retail sales.
Basin Electric	0%	NA	NA	NA	Outside of BEHC members that are also members of Tri-State, BEHC members do not have enacted RPS requirements (requirements in North and South Dakota are only goals).
Black Hills Power	30%	2,010,775	603,233	Yes	Figures in this table are for Black Hills Colorado Electric (BHCE), as only BHCE has an enacted RPS requirement. Colorado RPS includes a DG carve out of 10% of the RPS (3% of retail sales). Colorado provides credit multiplier for in-state resources, community projects and solar in POU territory. 2024 retail sales figured adjusted based on BHP load forecast.
Colorado Springs Utilities	10%	4,840,011	484,001	Yes	Colorado provides credit multipliers for in-state resources, community projects and solar in a POU territory. 2024 retail sales figured adjusted based on CSU load forecast.
El Paso Electric	4%	9,959,332	437,260	Yes	Texas RPS is a capacity requirement that has been achieved. EPE's effective RPS requirement is a 20% RPS for New Mexico load. New Mexico requires a "fully diversified" RPS portfolio. Utilities will be excused from diversification targets and the RPS requirement if applicable cost thresholds are exceeded. Figures do not account for situations where large industrial load has been exempted from RPS compliance. Assessment did not include year-to-year RPS carryover or REC banking.
Imperial Irrigation District	33%	4,249,037	1,402,182	Yes	IID is subject to California's 33% RPS in 2024. California's RPS permits the use of banked RECs and a limited amount of unbundled RECs.
LA Department of Water and Power	33%	26,045,455	8,144,000	Yes	LADWP is subject to California's 33% RPS in 2024. California's RPS permits the use of banked RECs and a limited amount of unbundled RECs. 2024 retail sales figures adjusted based on LADWP forecast.

Member / Participant	Effective RPS Requirement in 2024	Estimated 2024 Retail Sales (MWh)	2024 RPS Requirement (MWh)	RPS Resources in Regional PFM?	Notes
NV Energy	22%	35,066,833	7,714,703	Yes	Nevada RPS has a solar carve out of 6% of RPS (or 1.3% of sales in 2024). Nevada RPS allows energy efficiency to count towards a portion of the RPS. Nevada RPS is based on a "credit" rather than energy standard, allowing station usage, RECs, banking and utility-rebated DG to be used for RPS compliance.
Public Service Company of New Mexico	20%	9,909,055	1,981,811	Yes	New Mexico requires a "fully diversified" RPS portfolio. Utilities will be excused from diversification targets and the RPS requirement if applicable cost thresholds are exceeded. Figures do not account for situations where large industrial load has been exempted from RPS compliance. Assessment did not include year-to-year RPS carryover or REC banking.
Platte River Power Authority	6%	3,423,000	212,226	Yes	Only certain PRPA members are subject to the Colorado RPS requirement. 2024 retail sales figures and effective RPS adjusted based on PRPA load forecast. Municipal utilities are not subject to a DG carve out under the Colorado RPS. Colorado provides credit multiplier for in-state resources, community projects and solar in a POU territory.
Sacramento Municipal Utility District	33%	11,001,136	3,630,375	Yes	SMUD is subject to California's 33% RPS in 2024. California's RPS permits the use of banked RECs and a limited amount of unbundled RECs.
Salt River Project	20%	37,888,449	7,577,690	Yes*	SRP is not subject to the Arizona Renewable Energy Standard. In 2011, SRP's Board of Directors established a target of 20% of SRP retail sales to be met through sustainable resources by 2020. Sustainable resources include energy-efficiency savings, hydroelectric generation and other renewable generation. *SRP provided information on its existing utility scale renewables resources that are part of SRP's sustainable portfolio goal and it was verified that existing, utility scale renewable resources were included in the powerflow base case.
Southwest Transmission Cooperative	0%	-	-	NA	Neither SWTC nor any of its members have state renewable goals; they only have reporting obligations.

Member / Participant	Effective RPS Requirement in 2024	Estimated 2024 Retail Sales (MWh)	2024 RPS Requirement (MWh)	RPS Resources in Regional PFM?	Notes
Transmission Agency of Northern California	33%	16,780,963	5,537,718	Yes*	Figures are only for Sacramento Municipal Utility District, Turlock Irrigation District, Modesto Irrigation District and City of Redding. TANC members are subject to California's 33% RPS in 2024. California's RPS permits the use of banked RECs and a limited amount of unbundled RECs. *There were some RPS resources for which bus numbers were not available and, thus, it could not be explicitly verified that those RPS resources were in the base case. However, those are existing resources and are almost certainly already included in the case.
Tucson Electric Power Company	14%	10,835,471	1,516,966	Yes	Arizona's RPS includes a DG carve out. In 2024, the DG carve out is 30% of the RPS or 4.2% of retail sales. 2024 retail sales figured adjusted based on TEP load forecast.
Tri-State Generation and Transmission	8%	20,584,568	1,745,718	Yes	Tri-State members are subject to RPS requirements in AZ, CO and NM. The AZ DG carve out is 30% of the RPS or 4.2% of retail sales. Colorado RPS includes a DG carve out of 10% of the RPS (1% of retail sales for Tri-State members). Colorado provides credit multiplier for in-state resources, community projects and solar in a POU territory.
UNS Electric	14%	1,964,320	275,005	Yes	Arizona's RPS includes a DG carve out. In 2024, the DG carve out is 30% of the RPS or 4.2% of retail sales. 2024 retail sales figured adjusted based on UNS load forecast.
Xcel Energy/Public Service Company of Colorado	30%	33,009,461	9,902,838	Yes	Figures in this table are for PSCo's Colorado RPS requirement. Colorado RPS includes a DG carve out of 10% of the RPS (3% of retail sales). Colorado provides credit multipliers for in-state resources, community projects and solar in a POU territory. 2024 retail sales figured adjusted based on PSCo load forecast. RPS generation figures are energy to be delivered.
Western Area Power Administration	0%	NA	NA	NA	WAPA does not have an RPS obligation.

Appendix E – WestConnect Meetings and Activities Conducted within the Abbreviated 2015 Planning Cycle

Dates & Links to Posting or Meeting Materials	2014-2015 Activity
November 20, 2014	WestConnect Annual Planning Meeting & TPPL data entry window opened
December 4, 2014	Draft Regional Study Plan posted to WestConnect website
December 12, 2014	Stakeholder comments on draft Study Plan were due
December 15, 2014	TPPL data entry window closed - TPPL Updates and WestConnect Plan maps were due
December 16, 2014	PMC meeting: Daft Study Plan and organizational activities
January 6, 2015	PMC meeting: Approval of the WestConnect 2015 Regional Study Plan
January 22, 2015	PMC meeting: Model Development and organizational activities
January 30, 2015	WestConnect 2015 Regional Study Plan posted to WestConnect website
February 3, 2015	PMC meeting: Model Development and organizational activities
February 17-18, 2015	PMC meeting: Model Development and organizational activities
February 19, 2015	WestConnect Regional Planning Process Stakeholder Meeting
February 20, 2015	SPG-footprint power flow models were due
February 26, 2015	Western Planning Regions Coordination Meeting
March 3, 2015	PMC meeting: Model Development and organizational activities
March 4, 2015	PS meeting: Model Development
March 10, 2015	PS meeting: Model Development
March 17, 2015	PMC meeting: Model Development and organizational activities
March 18, 2015	PS meeting: Model Development
March 26, 2015	PS meeting: Model Development
April 2, 2015	PS meeting: Model Development

Dates & Links to Posting or Meeting Materials	2014-2015 Activity
April 9, 2015	PMC meeting: Model Development
April 13, 2015	CAS meeting: Model Development, Needs Assessment, and Regional Study Plan considerations
April 15, 2015	PS meeting: Model Development
April 20, 2015	PS meeting: Model Development
April 21, 2015	PMC meeting: Model Development and organizational activities
May 5, 2015	PMC meeting: Model Development
May 5, 2015	PS meeting: Model Development
May 18, 2015	PS meeting: Model Development and Needs Assessment
May 18, 2015	CAS meeting: Model Development
May 19, 2015	PMC meeting: Approval of WestConnect 2015 Regional Model Development Report
May 27, 2015	PS meeting: Needs Assessment
June 1, 2015	CAS meeting: Needs Assessment and Cost Allocation options
June 2, 2015	PMC meeting: Needs Assessment
June 4, 2015	PS meeting: Needs Assessment
June 15, 2015	PS meeting: Needs Assessment
June 15, 2015	CAS meeting: Cost Allocation options
June 16, 2015	PMC meeting: Needs Assessment and organizational activities
June 25, 2015	Western Planning Regions Stakeholder Coordination Meeting
July 8, 2015	PMC meeting: Needs Assessment
July 8, 2015	PS meeting: Needs Assessment
July 21, 2015	PS meeting: Needs Assessment and Regional Transmission Plan
July 21, 2015	CAS meeting: Cost allocation options
July 22, 2015	PMC meeting: Needs Assessment and Regional Transmission Plan
July 29, 2015	PS meeting: Needs Assessment and Regional Transmission Plan
August 4, 2015	PMC meeting: Needs Assessment
August 5, 2015	WestConnect Regional Planning Process Stakeholder Meeting

Dates & Links to Posting or Meeting Materials	2014-2015 Activity
August 11, 2015	CAS meeting: Cost allocation options
August 13, 2015	PS meeting: Needs Assessment
August 17, 2015	PMC meeting: Approval of WestConnect 2015 Regional Transmission Needs Assessment Report
August 18, 2015	Western Planning Region (WPR) Group Order 1000 Interregional Coordination Procedures Stakeholder Conference Call
August 27, 2015	PS meeting Remaining Study Plan Activities
August 31, 2015	CAS meeting: Cost Allocation options
September 1, 2015	PMC meeting: Organizational activities
September 15, 2015	PS meeting: Remaining Study Plan Activities and Regional Transmission Plan
September 15, 2015	CAS meeting: Cost Allocation discussions
September 16, 2015	PMC meeting: Organizational activities
October 1, 2015	PS meeting
October 6, 2015	PMC meeting
October 20, 2015	PS meeting
October 20, 2015	PS meeting
October 21, 2015	PMC meeting
November 3, 2015	PMC meeting
November 4, 2015	PS meeting
November 10, 2015	CAS meeting
November 17, 2015	PS meeting
November 17, 2015	CAS meeting
November 18, 2015	PMC meeting
November 19, 2015	WestConnect stakeholder meeting
November 20, 2015	2015 Regional Transmission Plan released for stakeholder comment
December 1, 2015	PMC meeting
December 15, 2015	PS meeting

Dates & Links to Posting or Meeting Materials	2014-2015 Activity
December 15, 2015	CAS meeting
December 16, 2015	PMC meeting: Approval of 2015 Regional Transmission Plan

Appendix F – Other Regional Planning Process Activities

The PMC will identify transmission developers eligible to utilize cost allocation developed in the Regional Planning Process using the Transmission Developer Qualification Criteria. Transmission developers seeking eligibility for potential designation as the entity eligible to use the regional cost allocation for a transmission project selected in the Regional Plan for purposes of cost allocation must submit to the PMC information as specified in the tariff of each TO Member. The submittal window for this information as part of the 2015 planning cycle will be determined by the PMC.

Once projects have been selected for inclusion in the Regional Plan, WestConnect will select an eligible transmission developer (as determined by the Transmission Developer Qualification Criteria describe above) to utilize the cost allocation developed for each project selected for the purposes of cost allocation.

Please follow a link listed below to view the Transmission Developer Qualification Criteria and the developer selection process.

WestConnect TO Member	**OASIS Link to Tariff**
Arizona Public Service Company	http://www.oasis.oati.com/azps/index.html
Black Hills Power, Inc.	http://www.oatioasis.com/BHBE/index.html
Black Hills Colorado Electric Utility Company, LP	http://www.oatioasis.com/bhct/index.html
Cheyenne Light Fuel & Power Company	http://www.oatioasis.com/CLPT/index.html
El Paso Electric Company	http://www.oatioasis.com/epe/index.html
NV Energy	http://www.oatioasis.com/NEVP/index.html
Public Service Company of New Mexico	http://www.oatioasis.com/pnm/index.html
Tucson Electric Power Company	http://www.oatioasis.com/tepc/index.html
UNS Electric, Inc.	http://www.oatioasis.com/UNST/index.html
Xcel Energy – Public Service Company of Colorado	http://www.oasis.oati.com/psco/index.html