WestConnect Regional Transmission Planning 2018-19 Cycle

Regional Transmission Plan Report

Approved by the WestConnect Planning Management Committee
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Updated July 27, 2021 to Redact Non-Public Information
(Contact admin@westconnect.com to Request Non-Redacted Version)

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1 Executive Summary

The WestConnect 2018-19 Regional Transmission Plan Report ("Regional Plan Report") is based on an evaluation of the transmission network in the WestConnect region for the 10-year timeframe. This report summarizes the processes, assumptions, and technical methods used to develop the WestConnect 2018-19 Regional Transmission Plan ("Regional Transmission Plan"); this involves the evaluation of the transmission network across the WestConnect region to determine regional reliability, economic, and public-policy driven transmission needs and seeks to identify the more efficient or cost-effective solutions for the needs.

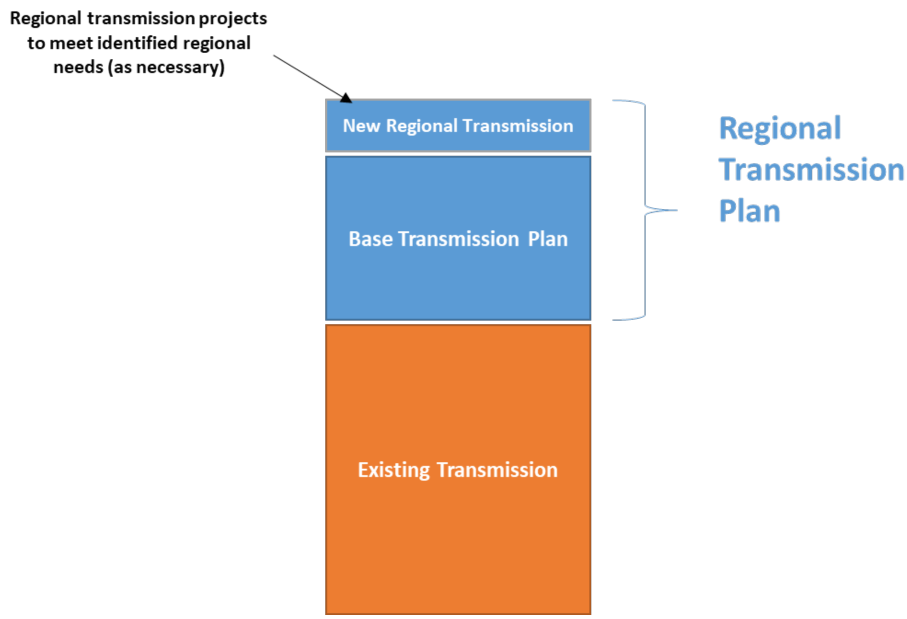
This Regional Plan Report is the final step of the WestConnect biennial Regional Transmission Planning Process ("Planning Process") and is intended to provide the reader with an overview of the core elements of the 2018-19 Planning Process. During the two-year planning cycle, the WestConnect Planning Management Committee ("PMC") produces detailed interim reports at the conclusion of each phase of the Planning Process, which are drawn from to create this Regional Plan Report. The interim reports contain significantly more detail than this Regional Plan Report and are made available on the WestConnect website. Their contents are summarized in **Table 1**.

Table 1: Summary of Interim Planning Documents for 2018-19 Planning Process

Interim Report	PMC Approval Date	Hyperlink	Contents
2018-19 Study Plan	March 14, 2018	Link	• Summary of study methods, models, tools, and analyses • Base Transmission Plan identified • Process schedule
2018-19 Model Development Report	January 16, 2019	Link	• Detailed assumptions and processes used to create models used to perform regional assessment • Analysis of Base Transmission Plan contents
2018-19 Regional Transmission Needs Assessment Report	March 20, 2019	Link	• Study results and findings from regional needs assessment
2018-19 Scenario Assessment Report	June 19, 2019	Link	• Study results and findings from scenario studies

The Regional Transmission Plan reflects the planned transmission that is necessary to meet the region's needs. The Regional Transmission Plan consists of the Base Transmission Plan, which is created at the beginning of each planning cycle to establish the assumed transmission network reflected in planning models for the 10-year timeframe, along with any regional transmission projects selected as the more efficient or cost effective alternative to a regional need identified during WestConnect's regional assessments, as illustrated in Figure 1.

Figure 1: Regional Transmission Plan



The 2018-19 Base Transmission Plan includes 191 planned transmission projects, spanning 843 miles with a total estimated capital investment of $933.2 Million. 66% of these projects involve facilities below 230 kV. Since the 2016-17 WestConnect Regional Transmission Plan, the WestConnect region has seen 95 new planned projects, 36 previously planned projects go into service, 9 previously planned projects begin construction, and 13 previously planned projects which are no longer planned. As defined by WestConnect, "planned" facilities include projects that have a sponsor, have been incorporated in an entity's regulatory filings, have an agreement committing entities to participate and construct, or for which permitting has been or will be sought.

In evaluating the need for new regional transmission projects in the Regional Transmission Plan, WestConnect first determines the system's needs. WestConnect uses three types of assessments to identify regional needs: reliability, economic, and public policy. These assessments were respectively dependent on power flow models, a production cost model ("PCM"), and confirmation from each Transmission Owner with Load Serving Obligation ("TOLSO") member that these models reflect plans to meet enacted public policies impacting the region. **Table 2** summarizes the WestConnect Planning Models developed and analyzed in the 2018-19 Planning Process, which include "Base Case" models used to identify regional needs, and a "Sensitivity Case" used to evaluate the impact of wheeling charge modeling assumptions on the economic model results.

Table 2: WestConnect Planning Models for Regional Assessment

Case Name	Case Description and Scope
2028 Heavy Summer Base Case	Expected peak load for June - August during 1500 to 1700 hours MDT, with typical flows throughout the Western Interconnection
2028 Light Spring Base Case	Light-load conditions in spring months during 1000 to 1400 hours MDT with solar and wind serving a significant, but realistic portion of the WECC total load
2028 Base Case	Business-as-usual, expected-future case with median load and hydro conditions and representation of resources consistent with enacted public policies
2028 50% Wheeling Charge Sensitivity Case PCM	Created from the 2028 Base Case by reducing the regular, inter-area wheeling charges to 50% of what was assumed in the 2028 Base Case

The reliability assessment for regional needs was based on reliability standards adopted by the North American Electric Reliability Corporation ("NERC") TPL-001-4 Table 1 (P0 and P1) and TPL-001-WECC-CRT-3.1 (Transmission System Planning Performance WECC Regional Criterion), and supplemented with any more stringent TOLSO planning criteria based on TOLSO member feedback. Regional issues subject to deeper investigation were defined as system performance issues impacting more than one Transmission Owner ("TO") Member system. The results of the reliability analyses identified 14 voltage issues within multi-TO systems, along with 7 branch overloads and 105 voltage issues within single-TO systems, all of which WestConnect determined to be local issues and not regional.

The economic assessment for regional needs involved reviewing the 2028 Base Case simulation results for regional congestion (i.e., number of hours) and congestion cost (i.e., the cost to re-dispatch more expensive generation because of transmission constraints) in order to determine a set of congested elements that warranted testing for the economic potential for a regional project solution, while also recognizing that the presence of congestion does not always equate to a regional need for congestion relief at a particular location. Similar to the reliability assessment, the review focused on the congestion issues impacting more than one TO Member system. The 2028 Base Case results identified 9 congested elements or paths in multi-TO systems and 21 congested elements or paths in single-TO systems, all of which WestConnect determined to be local issues and not regional.

The public policy assessment was intended to identify any regional issues driven by enacted public policy requirements (i.e. renewable portfolio standards). As part of the model development phase of the Planning Process, each TOLSO member provided express confirmation that the developed WestConnect 2028 economic and power flow models met all enacted public policies' conditions for study year 2028. WestConnect took an additional step during the 2018-19 Planning Process to determine whether the WestConnect economic models indicated a renewable energy penetration trajectory consistent with enacted public policies. This additional work was driven by stakeholder interest and was performed by comparing the region's modeled load and renewable energy in the 2028 Base Case to that of the 2026 Base Case from the 2016-17 Planning Cycle. WestConnect found a reasonable trend towards WestConnect members meeting enacted public policy requirements. During the regional reliability and economic assessments, no regional issues driven by enacted public policy requirements were identified and no stakeholders suggested or recommended the identification of a public policy-driven transmission need based on TO's local transmission plans. As a result, there are no identified public policy-driven needs in the WestConnect 2018-19 Regional Planning Process.

Based on the findings from the 2018-19 cycle analyses performed for reliability, economic, and public policy transmission needs, **no regional transmission needs were identified in the 2018-19 assessment**. As a result, the PMC did not collect transmission or non-transmission alternatives for evaluation since there were no regional transmission needs to evaluate the alternatives against and the 2018-19 Regional Transmission Plan is identical to the 2018-19 Base Transmission Plan.

The evaluations of multi-TO issues identified in the regional assessments are summarized in **Table 3** and **Table 4**.

Table 3. Evaluation of Reliability Multi-TO Issues

Reliability Multi-TO Issue	Rationale provided for why this should not identify a regional need
1. An EPE P1 contingency ([redacted]) caused high voltage decrease and low voltage issues on 14 buses in the EPE, TSGT, and PNM systems in the 2028 Heavy Summer Base Case.	PNM, TSGT, & EPE: The issue is local in nature. The voltage deviation is largely representative of the radial nature of a small remote area off the Bulk Electric System leading to the characterization of this being a local problem. PNM has voltage support tentatively scheduled for 2023 that will address the excessive voltage drop in the area. It should be noted that this solution has been addressed in previous PNM planning cycles and does not result in customer voltages operating outside facility or service limits or a system operating near a voltage stability limit.

Table 4. Evaluation of Economic Multi-TO Issues

Economic Multi-TO Issue	Rationale provided for why this should not identify a regional need
1. WECC Transfer Path 66 (California-Oregon Intertie, COI) was congested for 69 hours in the 2028 Base Case, amounting to $3,795K in congestion cost.	TANC and WAPA-SNR: Congestion cost is low and hours are also low.
2. San Juan – Waterflow 345 kV #1 line was congested for 74 hours in the 2028 Base Case, amounting to $2,209K in congestion cost.	WAPA-RM, Xcel/PSCO, and TSGT: Investigation into the congestion shown for the San Juan phase shifting transformers revealed a modeling error in how Path 31 (TOT2A) flows were calculated, allowing TOT2A to flow beyond its limit. After correcting the branch definition, Path 31 (TOT2A) congests in a direction (south-to-north) in which it has historically never flowed. This observation warrants further exploration in a future cycle.

Economic Multi-TO Issue	Rationale provided for why this should not identify a regional need
3. Sawmill Creek– Laramie River 230 kV #1 line was congested for 4 hours in the 2028 Base Case, amounting to $941K in congestion cost.	BEPC and TSGT: Only 4 hours of congestion is very minor (<<1% of the year) and can be considered noise, and the cost is relatively small.
4. WECC Transfer Path 30 (TOT 1A) was congested for 8 hours in the 2028 Base Case, amounting to $828K in congestion cost.	TSGT & WAPA & PRPA: Only 8 hours of congestion is very minor (<<1% of the year) and can be considered noise.
5. WECC Transfer Path 47 (Southern New Mexico) was congested for 42 hours in the 2028 Base Case, amounting to $690K in congestion cost.	PNM, EPE, and TSGT: Congestion is not high enough to be identified as a need. The number of hours of congestion identified in the model simulation is de minimis and the vetting process gave rise to questions about the model results. There was not a high degree of confidence in the congestion results with respect to this path. This factor, coupled with the trivial number of hours of congestion produced in the model simulation, resulted in the conclusion that it did not give rise to an economic-driven regional transmission need.
6. Dave Johnston – Sawmill Creek 230 kV #1 line was congested for 3 hours in the 2028 Base Case, amounting to $490K in congestion cost.	BEPC and TSGT: Only 3 hours of congestion is very minor (<<1% of the year) and can be considered noise, and the cost is relatively small.
7. WECC Transfer Path 32 (Pavant – Gonder 230 kV; Intermountain – Gonder 230 kV) was congested for 36 hours in the 2028 Base Case, amounting to $311K in congestion cost.	NVE and LADWP: (1) modeling issue on Intermountain – Gonder 230kV Line (correct rating for Intermountain – Gonder 230kV Line #1 ([redacted] MVA, i.e., [redacted] MW in PCM sim) wasn't modeled); (2) the observed congestion is in W-E direction, which has not been observed historically and thus is likely a modeling issue. Furthermore, the [redacted] MW path 32 W-E rating is based on the "capacity need" and "flowability" & not the facility ratings or other reliability constraints; therefore, there's a clear potential for its increase in the future, which could be recommended to be pursued by the path owners; and (3) the congestion is insignificant both by hours and by cost.
8. Intermountain – Gonder 230 kV #1 line was congested for 1 hour in the 2028 Base Case, amounting to $6K in congestion cost.	NVE and LADWP: Modeling issue. Correct rating for Intermountain – Gonder 230kV Line #1 ([redacted] MVA, i.e., [redacted] MW in PCM sim) wasn't modeled.
9. WECC Transfer Path 36 (TOT 3) was congested for 2 hours in the 2028 Base Case, amounting to $3K in congestion cost.	TSGT and WAPA-RM: Only 2 hours of congestion is very minor (<<1% of the year) and can be considered noise.

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The 2018-19 Planning Process also included "Scenario Case" models, which are used for information-only scenario studies that considered alternate, but plausible futures. The Scenario Cases are not used to identify regional needs and they do not impact the Regional Transmission Plan. The Scenario Cases, shown in **Table 5,** include Load Stress and the California Independent System Operator ("CAISO") Export Stress scenario assessments. They used the same analyses as the reliability needs assessment and focused, respectively, on the robustness of the Base Transmission Plan to load levels beyond those in the 2028 Heavy Summer Base Case and the reliability of the WestConnect regional transmission system during high export conditions from the CAISO to WestConnect. The Load Stress Scenario Case development leveraged the TOLSO member's expertise to scale the loads in the 2028 Heavy Summer Base Case to higher values and fill any generation-load gap with capacity while the CAISO Export Stress Scenario Case development leveraged the condition with the highest CAISO-to-WestConnect flow observed in the WestConnect 2028 Base Case economic model. The scenario assessments indicated several multi-owner issues. However, none of the issues observed indicated deficiencies in the Base Transmission Plan since they were radial in nature, easily addressed through system adjustments, or (in the CAISO export condition) remote from the study's focus area and caused by flows occurring in entirely new directions than what is observed historically. As a result, the regional system was found to be robust under higher than expected load conditions as well as during high CAISO export conditions. These studies were performed for informational purposes and did not impact the Regional Transmission Plan.

Table 5: WestConnect Planning Models for Scenario Studies

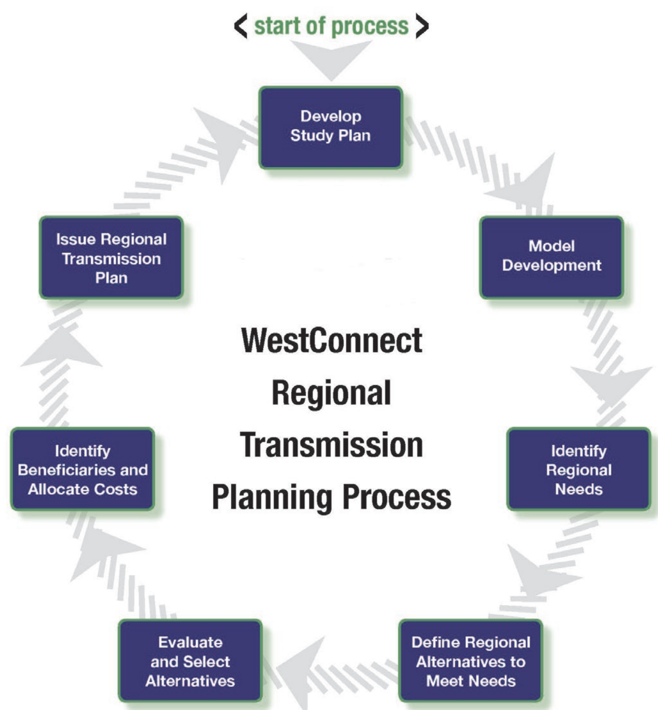
Case Name	Case Description and Scope
2028 Load Stress Scenario Case	WestConnect-wide load larger than the expected peak in the 2028 Heavy Summer Base Case
2028 CAISO Export Stress Scenario Case	Hour 15 of June 18th in the 2028 Base Case simulation, in which both (1) exports from the CAISO to WestConnect are high and (2) flows west-to-east across Path 49 and Path 46 are high

2 Planning Management and Process

This WestConnect 2018-19 Regional Transmission Plan Report ("Regional Plan Report") is the final step of the WestConnect 2018-19 biennial Regional Transmission Planning Process ("Planning Process") and summarizes the processes, assumptions, and technical methods used to develop the WestConnect 2018-19 Regional Transmission Plan ("Regional Transmission Plan"), which identifies the more efficient or cost-effective transmission solutions for the region. The document also explains why projects were either included or not included in the Regional Transmission Plan.

The WestConnect Planning Process was developed for compliance with Federal Energy Regulatory Commission ("FERC") Order Number 1000 ("Order No. 1000"), Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities. The Planning Process consists of seven primary steps as outlined in **Figure 2**.

Figure 2: WestConnect Regional Transmission Planning Process



The Planning Process commences in even numbered years, resulting in the development of a Regional Transmission Plan every odd-numbered year. During the planning cycle, WestConnect seeks to identify regional reliability, economic, and public policy transmission needs. If regional transmission needs are identified, WestConnect solicits alternatives (transmission or non-transmission alternatives) from WestConnect members and stakeholders to meet the regional needs. WestConnect then evaluates the alternatives to determine which meet the region's needs more efficiently or cost-effectively. The selected alternatives are then identified in the Regional Plan Report. Identified alternatives submitted for the purposes of cost allocation may go through the cost allocation process if they are eligible and pass the cost/benefit thresholds established for the relevant category of project (reliability, economic, or public policy).

Additional details of the WestConnect Regional Transmission Planning Process can be reviewed in the WestConnect Regional Business Practice Manual ("BPM").

2.1 Planning Management

The WestConnect Planning Management Committee ("PMC") has overall responsibility for all WestConnect regional planning activities. The Planning Process activities are conducted under the direction of the PMC by the WestConnect Planning Subcommittee ("PS") and WestConnect Cost Allocation Subcommittee ("CAS"), and with input from PMC members and stakeholders, as described in greater detail in subsequent sections of this document.

2.2 Planning Region

The WestConnect planning process evaluates regional transmission needs of the WestConnect planning region, which is defined as the combined footprints of signatories to the Planning Participation Agreement within the Transmission Owner with Load Serving Obligation ("TOLSO") Members. TOLSO Members participating in the WestConnect 2018-19 planning process and the systems considered in the regional assessment included:

- Arizona Electric Power Cooperative
- Arizona Public Service
- Basin Electric
- Black Hills Energy
- Colorado Springs Utilities
- El Paso Electric
- Imperial Irrigation District
- Los Angeles Department of Water and Power
- NV Energy
- Platte River Power Authority
- Public Service of New Mexico
- Sacramento Municipal Utility District
- Salt River Project
- Tucson Electric Power Company
- Transmission Agency of Northern California
- Tri-State Generation and Transmission
- Western Area Power Administration
- Xcel Energy – Public Service Company of Colorado

WestConnect conducts FERC Order No. 1000 regional transmission needs assessments for Transmission Owner ("TO") entities that are WestConnect members.[1] The approximate footprint of both member and participating TOs is shown in **Figure 3**.

[1] *All references to Order No. 1000 include any subsequent orders. (see http://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf)*

Figure 3: Approximate Footprint of WestConnect Member TOs and Participating TOs

In addition to the TOLSO members, the following PMC members from the Independent Transmission Developer Member Sector and Key Interest Group Sector also participate in the planning effort:

- American Transmission Company
- Black Forest Partners
- Exelon
- ITC Grid Development, LLC
- Southwestern Power Group
- TransCanyon, LLC
- Western Energy Connection, LLC
- Xcel Western Transmission Company
- Natural Resources Defense Council

2.3 Local and Regional Transmission Issues

For the purposes of the regional transmission needs assessment, a single-TO need impacts only the TO footprint in which it resides. Single-TO transmission 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 PS reviews all identified single-TO system transmission issues to ensure that in combination, none of the issues are regional in nature. Single-TO system issues are the responsibility of the affected TO to resolve, if necessary.

Regional needs are generally defined by impacts to more than one TO. However, the PMC may determine that in some instances, transmission issues that impact more than one TO are still local, rather than regional, in nature. In such cases, WestConnect will provide an explanation as to how impacts are classified.

2.4 Documentation of the 2018-19 Planning Process

This Regional Plan Report is intended to stand on its own, providing an overview of the core elements of the 2018-19 Planning Process. However, this report does not include all details pertaining to the Planning Process. The PMC produces interim reports at the conclusion of each phase of the Planning Process. These interim reports are drawn from to create this Regional Plan Report. The interim reports contain significantly more detail than this Regional Plan Report and are made available on the WestConnect website. Specifically, the interim reports contain technical appendices that are referenced to but are not repeated in this document.

2.4.1 Study Plan

The scope of work for the 2018-19 Planning Process is documented in the 2018-19 Regional Study Plan ("Study Plan"), which was approved by the PMC on March 14, 2018. The Study Plan describes the Base Transmission Plan as well as the reliability, economic, and public policy assessments to be performed in the planning cycle. It covers the scope of work for model development, and provides technical guidance regarding the identification of regional needs.

2.4.2 Model Development Report

The regional model development process and the input assumptions for the regional planning models is documented in the 2018-19 Model Development Report ("Model Development Report"), which was approved by the PMC on January 16, 2019. The report describes the development process of the regional base models and details key model assumptions and parameters, such as study timeframe, study horizon, study area, the Base Transmission Plan, and how public policy requirements were considered. Along with the Model Development Report, the PMC approved the regional base models for use in regional assessments.

2.4.3 Regional Assessment Report

The methods used to identify regional needs are documented in the 2018-19 Regional Transmission Needs Assessment Report ("Needs Assessment Report"), which was approved by the PMC on March 20, 2019. The Needs Assessment Report details the methods, assumptions, and results of the three types of regional needs assessments: reliability, economic, and public policy.

2.4.4 Scenario Assessment Report

In addition to describing the Base Case planning assessments used to identify regional transmission needs, the Study Plan also describes information-only scenario studies that consider alternate but plausible futures. Scenarios represent futures or system conditions with resource, load, and public policy assumptions that are different in one or more ways than what is assumed in the regional base models. The 2018-19 Scenario Assessment Report ("Scenario Assessment Report"), which was approved by the PMC on June 19, 2019, details the development process, study method, and results of the scenarios identified in the Study Plan.

3 2018-19 Base Transmission Plan

WestConnect creates the regional Base Transmission Plan at the beginning of each planning cycle to establish the transmission network that is reflected in planning models for the 10-year timeframe and evaluated in the regional transmission needs assessments. The Base Transmission Plan is one of the most important assumptions in the Planning Process as it consists of the "planned" incremental transmission facilities included by TOs in local transmission plans,[2] as well as regional transmission facilities identified in previous regional transmission plans that are not subject to reevaluation.[3] "Conceptual" transmission projects are not included in the Base Transmission Plan. As defined by WestConnect, "planned" facilities include projects that have a sponsor, have been incorporated in an entity's regulatory filings, have an agreement committing entities to participate and construct, or for which permitting has been or will be sought.

The Base Transmission Plan may also include projects under development by independent transmission company ("ITC") entities in the WestConnect planning region, to the extent there is sufficient likelihood of completion associated with these projects to warrant their inclusion in the Base Transmission Plan.[4] For the 2018-19 Regional Process, no ITC projects met the criteria for inclusion.

The Base Transmission Plan was developed using project information collected via the WestConnect Transmission Plan Project List ("TPPL"), which serves as a project repository for TO Member local transmission plans as well as ITC projects. The TPPL data used for the 2018–19 planning cycle was based on updates submitted as of January 26, 2018, with subsequent updates to the data made by members in the following weeks.

The full list of approved 2018-19 Base Transmission Plan ("Base Transmission Plan") projects can be found in Appendix A of the Study Plan.

3.1 2018-19 Regional Base Transmission Plan Projects

The Base Transmission Plan includes 191 planned transmission projects that consist of 75 new or upgraded transmission lines, 61 substations, 21 transmission line and substations, 22 transformers, and 12 other planned projects. From the data reported in the TPPL, these projects span 843 miles and add up to a total capital investment of $933.2 Million.[5] **Table 6**, **Table 7**, and **Table 8** summarize the Base Transmission Plan by project type and voltage. **Figure 4** illustrates the percentage breakout for the 2018-19 regional Base Transmission Plan projects by voltage.

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[2] *Developed in accordance with Order No. 890 local planning processes. The Base Transmission Plan also includes any non-Bulk Electric System (non-BES) assumptions TO members may have made with regard to other incremental regional transmission facilities in the development of their local transmission plans.*

[3] *There were no regional transmission projects identified to meet regional need(s) in the 2016-17 Planning Cycle.*

[4] *A description of the criteria used to identify projects for inclusion in the Base Transmission Plan is in the BPM.*

[5] *29% of the projects listed in the 2018-19 Base Transmission Plan did not report line mileage in the TPPL data and 65% of the projects did not report cost information in the TPPL data.*

232 **Table 6. Regional Base Transmission Plan Projects by Type, Reported Mileage, and Reported Investment ($K)**

Type of Project	Number of Projects	Length (Miles)	Planned Investment ($K)
Substation	61	-	$ 220,021
Transmission Line	75	647	$ 357,005
Transmission Line and Substation	21	197	$ 256,732
Transformer	22	-	$ 29,080
Other	12	-	$ 70,309
Total	**191**	**843**	**$ 933,147**

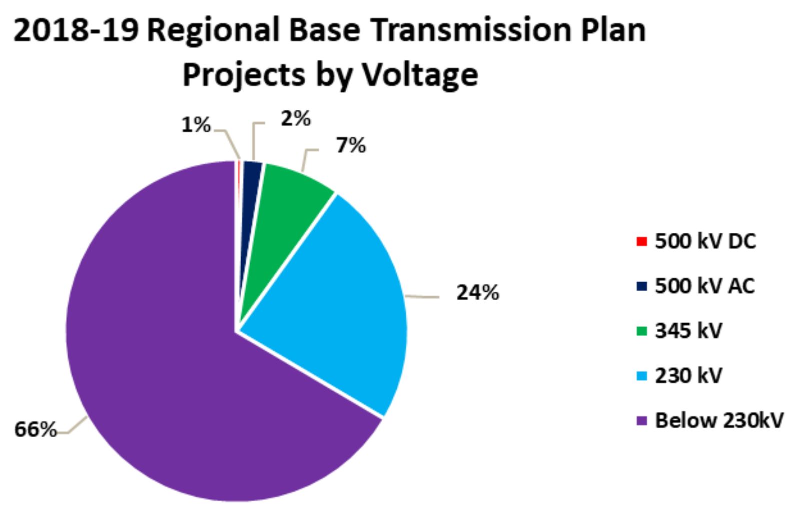
233 **Table 7. Number of TOLSO Regional Base Transmission Plan Projects by Voltage and TOLSO**

TOLSO	< 230 kV	230 kV	345 kV	500 kV AC	500 kV DC	Total
Arizona Public Service	-	2	-	-	-	**2**
Black Hills Energy	4	-	-	-	-	**4**
Black Hills Power	-	4	-	-	-	**4**
Cheyenne Light Fuel and Power	4	-	-	-	-	**4**
Colorado Springs Utilities	1	1	-	-	-	**2**
El Paso Electric Company	21	-	2	-	-	**23**
Imperial Irrigation District	1	-	-	-	-	**1**
Los Angeles Department of Water and Power	1	14	-	3	1	**19**
NV Energy	16	3	5	-	-	**24**
Platte River Power Authority	-	1	-	-	-	**1**
Public Service Company of Colorado/ Xcel Energy	4	1	1	-	-	**6**
Public Service Company of New Mexico	1		2	-	-	**3**
Sacramento Municipal Utility District		5	-	-	-	**5**
Salt River Project	2	3	-	-	-	**5**
Tri-State Generation and Transmission Association	13	2	1		-	**16**
Tucson Electric Power	48	2	2	1	-	**53**
Western Area Power Administration - DSW	4	1	-	-	-	**5**
Western Area Power Administration - RMR	7	3	1	-	-	**11**
Western Area Power Administration - SNR	-	3	-	-	-	**3**
Total Projects	**127**	**45**	**14**	**4**	**1**	**191**

Table 8. Regional Base Transmission Plan Projects by Voltage, Reported Mileage, and Reported Investment ($K)

Type of Project	Number of Projects	Length (Miles)	Planned Investment ($K)
500 kV DC[6]	1	-	$ -
500 kV AC[7]	4	0	$ -
345 kV	14	45	$ 212,030
230 kV	45	282	$ 236,946
Below 230kV	127	517	$ 484,171
Total Projects	**191**	**843**	**$ 933,147**

Figure 4. 2018-19 Regional Base Transmission Plan Projects by Voltage, based on the TPPL data



3.2 Regional Base Transmission Plan Projects by State

The Base Transmission Plan includes projects in multiple states in the WestConnect footprint and in some instances, projects span multiple states. **Table 9** summarizes the number of projects by states with aggregated capital investment. **Figure 5** illustrates the breakout of projects by voltage and state.

Table 9. Regional Base Transmission Plan Projects by State, Reported Mileage, and Reported Investment ($K)

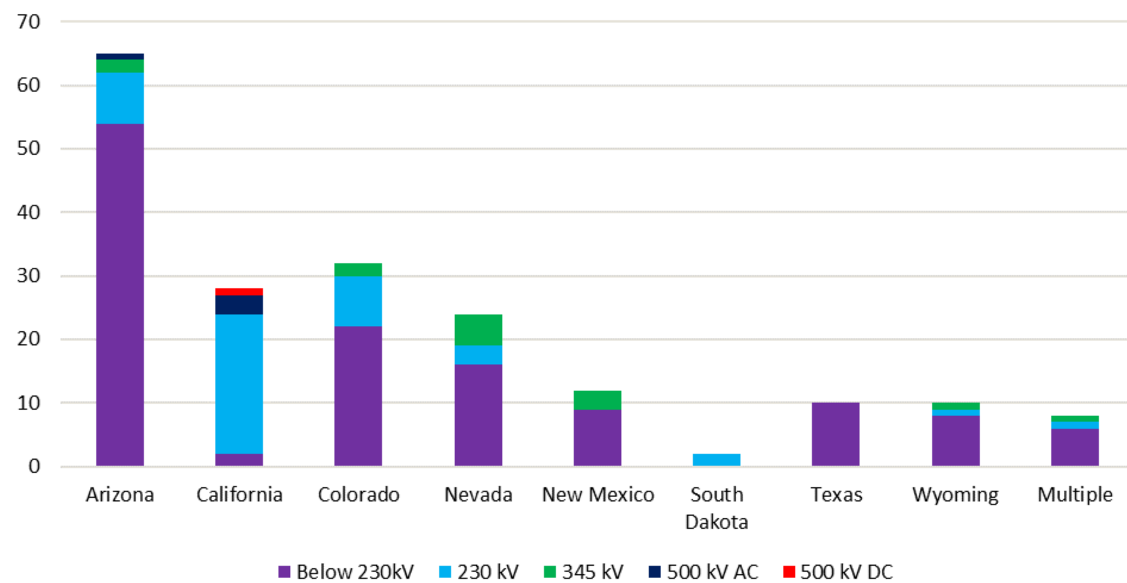
State	Number of Projects	Length (Miles)	Planned Investment ($K)
Arizona	65	237	$ 263,017
California	28	7	$ 22,423
Colorado	32	254	$ 350,296
Nevada	24	11	$ 31,000

[6] *500 kV DC project cost information was not provided from TOs.*

[7] *500 kV AC project cost information was not provided from TOs.*

State	Number of Projects	Length (Miles)	Planned Investment ($K)
New Mexico	12	127	$ 138,109
South Dakota	2	48	$ 23,400
Texas[8]	10	14	$ -
Wyoming	10	20	$ 52,902
Multiple	8	127	$ 52,000
Total Projects	**191**	**843**	**$ 933,147**

Figure 5. 2018-19 Regional Base Transmission Plan Projects by Voltage and State, based on the TPPL data



3.3 Regional Base Transmission Plan Projects by Driver

Nearly all of projects (90%) in the 2018-19 Base Transmission Plan are driven by local reliability needs, 7% are driven by public policy requirements and the remaining 3% are economically driven. **Table 10**, **Table 11**, and **Figure 6** below breakout the projects by length, planned investment costs and voltage.

Table 10. Regional Base Transmission Plan Projects by Driver, Reported Mileage, and Reported Investment ($K), based on the TPPL data

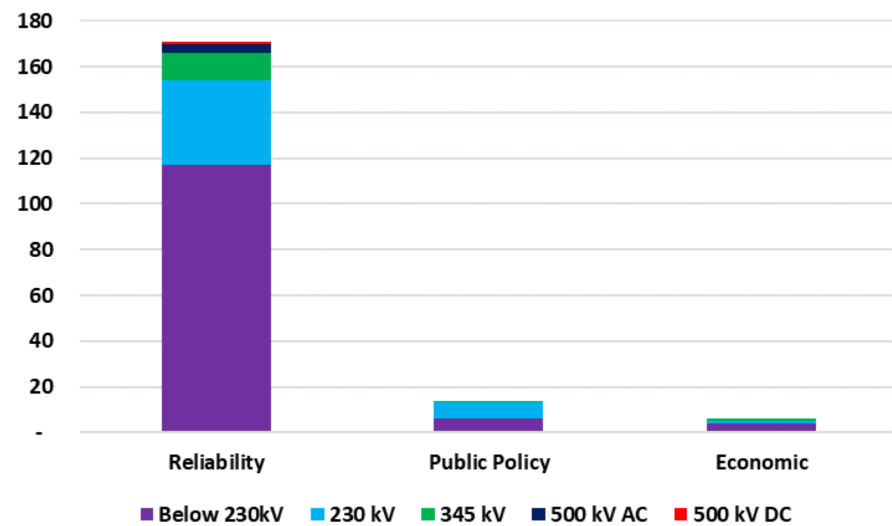
Driver	Number of Projects	Length (Miles)	Planned Investment ($K)
Reliability	171	826	$ 858,148
Public Policy	14	4	$ 46,749
Economic	6	13	$ 28,250
Total Projects	**191**	**843**	**$ 933,147**

[8] *No cost information was provided for the projects in Texas*

Table 11. Regional Base Transmission Plan Projects by Driver and Voltage, Reported Mileage, and Reported Investment ($K), based on the TPPL data

Driver	< 230kV	230 kV	345 kV	500 kV AC	500 kV DC
Reliability	117	37	12	4	1
Public Policy	6	7	1	-	-
Economic	4	1	1	-	-
Total Projects	**127**	**45**	**14**	**4**	**1**

Figure 6. 2018-19 Regional Base Transmission Plan Number of Projects by Driver and Voltage, based on the TPPL data



3.4 Updates to the 2016-17 Regional Base Transmission Plan Projects

Since the 2016-17 Base Transmission Plan was finalized during the prior 2-year Planning Process, a number of projects have had changes to their development status, as summarized below:

- 36 projects were placed in service;
- 9 projects were updated to “under construction” development status;
- 7 projects were changed from “planned” to “conceptual” development status;
- and 6 projects were withdrawn.

The balance of the planned projects in the 2016-17 Base Transmission Plan continue in the 2018-19 Base Transmission Plan. Additionally, 95 new planned projects were added to the TPPL and included in the 2018-19 Base Transmission Plan.

4 Reliability Assessment

The purpose of the reliability assessment is to identify regional transmission needs in the 10-year timeframe. WestConnect conducted the 2018-19 regional reliability assessment on two Base Cases: a 2028 Heavy Summer case and a 2028 Light Spring case. The reliability assessment for regional needs was based on reliability standards adopted by the North American Electric Reliability Corporation ("NERC") TPL-001-4 Table 1 (P0 and P1) and TPL-001-WECC-CRT-3.1 (Transmission System Planning Performance WECC Regional Criterion), and supplemented with any more stringent TO planning criteria based on TO Member feedback. Regional issues subject to deeper investigation were defined as system performance issues impacting, or between, more than one TO Member system.

4.1 Case Development

The information in this section summarizes each reliability model and provides details about the major assumptions incorporated into the reliability cases.

4.1.1 2028 Heavy Summer Base Case

Description: The case is designed to evaluate the Base Transmission Plan under heavy summer conditions. The seed case was the WECC 2028 Heavy Summer 1 Base Case dated December 20, 2017 (28HS1a), which was updated with the latest topology (i.e., generator, load, and transmission) information from WestConnect participants. The load level and generator dispatch were updated to account for these updates while still representing typical heavy summer load conditions and generator dispatch. After the Base Case was approved, the PMC granted PSCo the opportunity to update the 2028 Heavy Summer Base Case to reflect the latest "Colorado Energy Plan Portfolio". These changes included Comanche unit #1 and #2 retirements and replacement with planned renewable generation.

Generation: Within WestConnect, the case features a dispatch of 62,075 MW of thermal and hydro resources and 5,637 MW of wind and solar resources.

Load: The aggregate coincident peak load level for the WestConnect footprint is 65,274 MW. The original WECC case represented the system coincident peak for a heavy summer condition between the hours of 1500 to 1700 MDT during the months of June – August. WestConnect's intent was to continue these assumptions.

Transmission: No major planned transmission additions beyond the Base Transmission Plan were included in the case.

Other assumptions: Northern Tier Transmission Group (NTTG) submitted updates to the WECC 28HS1a power flow case to WECC in late June 2018. The NTTG power flow changes were reviewed and select updates that impacted WestConnect, as determined by the PS, were incorporated in the power flow cases. A summary of the changes is below.

- Retirement of Valmy unit #1 and rebalance of the Sierra area by re-dispatching generation in Sierra, scheduling an import from the Southern California Edison to Sierra, and adjusting reactive control devices.
- Incorporation of minor transmission rating updates in the NTTG area
- Retirement of Dave Johnston and Naughton units.

- Incorporation of PacifiCorp renewables from their 2020 Energy Vision plan and recommend changes to re-balance the PacifiCorp area by re-dispatching the Hunter and Huntington units.

4.1.2 2028 Light Spring Base Case

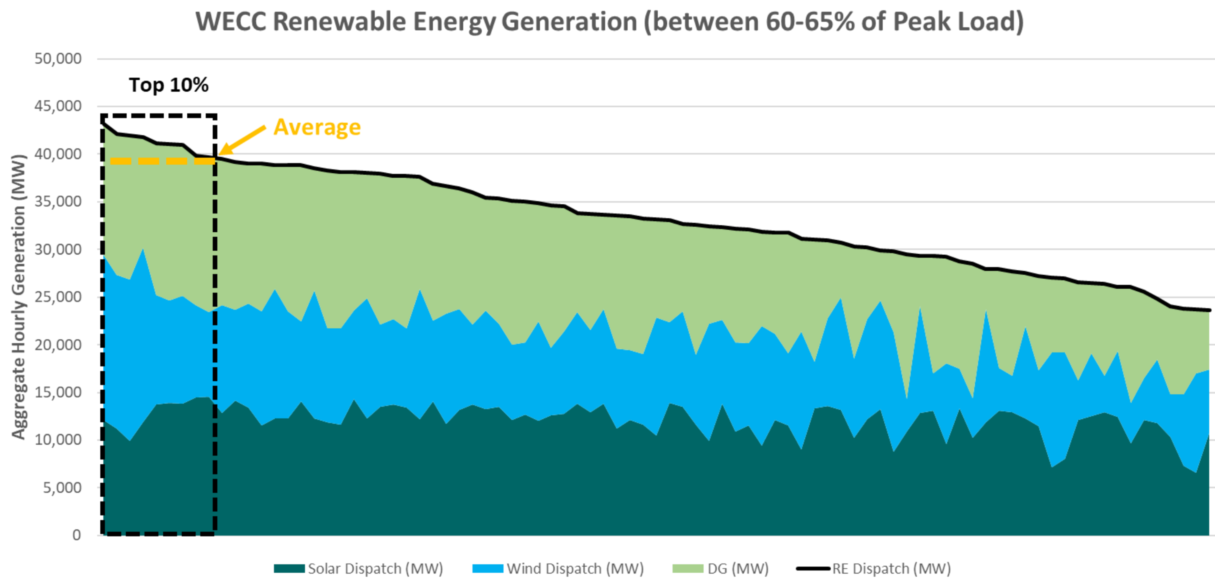
Description: The purpose of the case is to assess Base Transmission Plan performance under light-load conditions with solar and wind serving a significant but realistic portion of WestConnect's total load. The case does not include renewable resource capacity additions beyond what is already planned and included in the WestConnect 2028 Summer Base Case – the case intends to represent likely and expected system conditions. The seed case was the WECC "2028 Light Spring 1 for WestConnect" Scenario Case dated December 1, 2017 (28LSP1-S). After the Base Case was approved, the PMC granted PSCo the opportunity to update the 2028 Light Spring Base Case to reflect the latest "Colorado Energy Plan Portfolio". These changes included Comanche unit #1 and #2 retirements and replacement with planned renewable generation.

Generation: Within WestConnect, the case features 2,826 MW of wind and 4,377 MW of solar resources. The case description of the WECC 28LSP1-S included wind and solar dispatch targets recommended by WestConnect, the background of which are described below.

During the 2016-17 cycle, WestConnect used the WECC 2024 Common Case PCM to develop a likely instance of off-peak loading and high renewable generation. Simulated historical weather data was used to adjust the dispatch level for all wind and solar resources in the WestConnect footprint.[9] The use of hourly wind and solar production data ensured a realistic and weather-based dispatch of non-thermal resources across the WestConnect footprint. To identify the wind and solar dispatch level, the hourly wind and solar production data described above was filtered to only include data corresponding to hours between 1000 and 1400 MDT when load was 60-65% of the WECC peak. The reduced set of hourly wind and solar production data for WECC during these hours is shown in **Figure 7**. WestConnect opted to represent a wind and solar dispatch consistent with the average of the top 10% of generation hours (after ranking by combined MW output). These dispatch targets were provided to WECC for the development of the WECC 28LSP1-S case, so that areas outside of WestConnect would also have coincidently high levels of renewables.

[9] *The National Renewable Energy Laboratory (NREL) has created hourly solar and wind meso-scale production data for about 30,000 sites throughout the Western Interconnection. The shapes are based on meteorological modeling that produces historical wind speed and irradiance data for locations across the West. These shapes are used by WECC to develop energy production profiles for wind and solar generation resources in their Common Case production cost modeling dataset. The 2024 Common Case, whose data was used for the analysis described herein, used NREL profiles representing the 2005 historical weather year.*

Figure 7: Hourly Production Data used to Estimate Wind and Solar Dispatch



After the wind and solar generators were re-dispatched, as outlined above (based on their geographically-specific generation profiles), the thermal fleet was re-dispatched by PMC members to balance load and resources, keeping interchange between regions and areas roughly the same as in the original WECC case.

The roughly 7,200 MW of wind and solar energy dispatched across WestConnect, as modeled in this case, is intended to represent a realistic and likely future. This level of renewables served 19% of the total WestConnect load in this hour, as noted above.

Load: WestConnect member loads were adjusted slightly from the seed case to attempt to more closely correlate the load forecast to the wind and solar dispatch. The nature of the adjustment (i.e., up, down) was specific to each transmission owner. The total WestConnect load in the case was 41,894 MW, which is 64% of the WestConnect peak load in the WestConnect 2028 Heavy Summer Base Case. The load levels represent the system during 1000 to 1400 hours MDT, the same hours used to develop the wind and solar generator dispatch.

Transmission: Identical transmission assumptions as the 2028 Heavy Summer Base Case – see above for details.

Other assumptions: Identical other assumptions as the 2028 Heavy Summer Base Case – see above for details.

4.1.3 Other Data

The PS also considered the following when developing the reliability cases:

- **Operating Procedures** – Any special operating procedures required for compliance with NERC reliability standards were considered and included in the power flow cases.

- **Protection Systems** – The impact of protection systems including Remedial Action Scheme (RAS) required for compliance with NERC reliability standards were included in the power flow cases.
- **Control Devices** – Any special control devices required were included in the power flow cases.

The quality of the Base Cases and contingency definitions were improved by iteratively developing draft cases with contingency definitions and performing test simulations. After each draft and test simulation, data owners had the opportunity to examine and submit corrections. This procedure resulted in six review drafts of the base reliability models.

4.2 Study Method

The scope of the reliability assessment was based on a list of comprehensive N-1 contingencies at bulk electric system ("BES") level, plus TOLSO additions, in order to identify a regional need, as determined by the PS.[10] The intent was to minimize flagging and processing, local or "non-regional" issues. Contingency definitions for the steady-state contingency analysis were limited to N-1 contingencies for elements 230 kV and above, generator step-up ("GSU") transformers for generation with at least 200 MW capacity, and member-requested N-2 contingencies. All BES branches and buses in the WECC model were monitored and violations reported.

WestConnect also performed transient stability simulations. Select TOLSO Members provided transient stability outages were performed. The transient stability outages are provided in Section 2.1 of the Needs Assessment report.

System performance issues impacting or between more than one TO Member system were identified for further review by the PS. Local issues were reported and provided to members for informational purposes. The local issues were not the focus of this assessment.

4.3 Study Results and Findings

Upon a comprehensive review of the regional reliability assessment results in public meetings, no regional needs were identified. This conclusion was reached because neither the Heavy Summer nor the Light Spring assessments identified reliability issues that were regional in nature and impacting two or more TO Members. The evaluation of each multi-TO system issue is summarized below, and more details along with the transient stability results are provided in Appendix B.

- An EPE P1 contingency ([redacted]) caused high voltage decrease and low voltage issues on 14 buses in the EPE, TSGT, and PNM systems in the 2028 Heavy Summer Base Case. PNM, TSGT, & EPE provided the rationale for why these issues should not identify a regional need:
    - The issue is local in nature. The voltage deviation is largely representative of the radial nature of a small remote area off the BES leading to the characterization of this being a local problem. PNM has voltage support tentatively scheduled for 2023 that will address the excessive voltage drop in the area. It should be noted that this solution has been addressed in previous PNM planning cycles and does not result in customer voltages

[10] An initial list of automatically generated single branch ("N-1") outages for 230 kV and higher elements was created, and participants submitted multi-element contingency definitions not automatically created.

operating outside facility or service limits or a system operating near a voltage stability limit.

Single-TO system results are provided in Appendix B of the Needs Assessment Report.

5 Economic Assessment

WestConnect performed the 2018-19 regional economic assessment by conducting a production cost model ("PCM") study on a 2028 Base Case along with one sensitivity case. The goal of the assessment was to test the Base Case and the Base Transmission Plan for economic congestion between more than one TO Member's area.

5.1 Case Development

The economic Base Case originated from the WECC 2028 Anchor Dataset (ADS) PCM Version 1.0, and was reviewed and updated by WestConnect members. The reliability base models and economic base models had consistent electric topologies (e.g., matching load, generator, and branch models). [11] What follows is a description of the key assumptions used to form the 2028 Base Case used to evaluate regional economic needs.

5.1.1 2028 Base Case

Description: The case is a PCM dataset designed to represent a likely, median 2028 future. The WECC 2028 Anchor Dataset (ADS) interconnection-wide 10-year PCM ("2028 ADS PCM V1.0"), dated June 29, 2018, served as the seed case for the WestConnect economic model 2028 Base Case. The 2028 ADS PCM V1.0 was reviewed and updated by WestConnect consistent with the process described below.

Generation:

- WestConnect's updates to the database included but was not limited to: generator type, commission and retirement date, forced outage rate, outage duration, minimum and maximum capability with applicable de-rates for plant load or seasonal ambient temperature, minimum up and down times, fuel assignments, variable operations and maintenance and start-up costs, linkage to reserve modeling and regional/remote scheduling, linkage to operational nomograms, hydro fixed shape or load/price-driven scheduling, and hourly shapes. **Table 12** provides a summary by fuel category of the generation updates made to the WECC 2028 ADS PCM V1.0. The positive (or negative) values represent the capacity (in MWs) and resulting generated energy (in GWh) added to (or removed from) the WECC 2028 ADS PCM V1.0 in order to create the WestConnect 2028 Base Case.

[11] *There was one exception to this. The planned Apache ST4 generator was dispatched in the 2028 Heavy Summer Base Case but was turned off in the economic models.*

Table 12: Generation Changes Made to WECC 2028 ADS PCM V1.0. Percentages are in reference to the totals in the WECC 2028 ADS PCM V1.0

Fuel Category	Annual Generation		Capacity	
	GWh	%	MW	%
Coal	(24,859)	-26.3%	(4,334)	-28.8%
Gas	4,267	3.3%	(213)	-0.5%
Water	(201)	-1.0%	(10)	-0.1%
Uranium	(2,205)	-7.0%	0	0.0%
Solar PV	1,056	8.5%	1,278	24.7%
Solar Thermal	4	0.4%	0	0.0%
Wind	7,484	43.6%	1,557	26.3%
Bio	286	96.9%	8	7.1%
Geothermal	(3,210)	-31.7%	138	10.7%
DG/EE/DR	(9,803)	-54.2%	(4,584)	-50.8%
Other	104	100.9%	249	13.6%
Overall	(27,076)		(5,911)	

- The behind-the-meter distributed generation (BTM-DG) assumptions were retained from the WECC 2028 ADS PCM V1.0 which modeled them on the resource-side, with the exceptions listed below. **Table 13** summarizes the amount of BTM-DG by area represented in the WestConnect 2028 Base Case.
    - AZPS: A new hourly load shape was provided which represented the combination of the load, BTM-DG, and demand response (DR).
    - TEPC: The BTM-DG and DR shapes were merged with the load shapes to model the BTM-DG and DR on the load-side.
    - EPE: BTM-DG and DR shapes were removed since EPE's behind the meter generation was already accounted for as an adjustment in EPE's load numbers.

Table 13: Behind-the-Meter Distributed Generation

Area Name	Capacity (MW)	Generation (GWh)	Capacity Factor (%)	Dispatch at Area Peak Demand (% of Capacity)
AZPS	3,461	5,979	20%	16%
BANC	574	1,373	27%	50%
EPE	0	0	0%	0%
IID	130	291	26%	83%
LDWP	630	1,438	26%	56%
NEVP	599	1,339	25%	70%
PNM	132	289	25%	51%

Area Name	Capacity (MW)	Generation (GWh)	Capacity Factor (%)	Dispatch at Area Peak Demand (% of Capacity)
PSCO	522	1,191	26%	72%
SPPC	83	192	26%	71%
SRP	438	967	25%	64%
TEPC	433	927	24%	29%
WACM	60	139	26%	16%
WALC	324	702	25%	74%

Load: WestConnect made minor modifications to the load shapes and forecasts included in the WECC 2028 ADS PCM V1.0. No changes were made to the load forecasts for areas outside of WestConnect. **Figure 8** and **Figure 9** provide the annual load energy, various load snapshots (peak load and load during system/WECC peak), and the average load on a "PCM Area" basis. The PCM Areas are generally analogous to Balancing Authorities rather than specific utilities. The "PF Load" – load in the 2028 Heavy Summer Base Case – is provided for a frame of reference, though, some difference between the PCM and PF load snapshots is typical given:

- The Heavy Summer reliability model focuses on an extreme or more-stressed-than-normal system peak load condition whereas the economic load shapes do not contain extremely high or low load values since they are developed to support a median year-long simulation.
- The economic model load values include losses whereas the sum of the power flow model loads does not include losses.
- The economic model load shapes do not include the impact of BTM-DG except for AZPS and TEPC whereas the power flow model loads may or may not contain BTM-DG.
- The economic model loads in the charts below include exports out of Western Interconnection via the direct current interties along the east side of the Western Interconnection whereas they may or may not be included in the power flow load in the chart below.

Figure 8: WestConnect PCM Areas' Annual Load (GWh) [with Losses] in WestConnect 2028 Base Case (PCM)

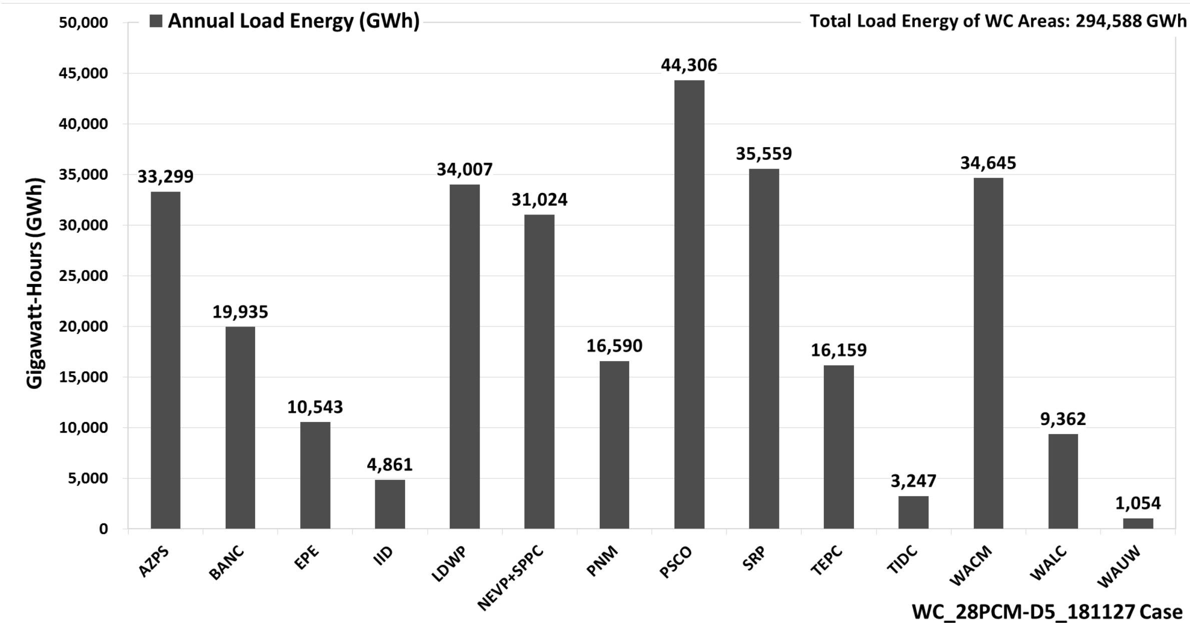
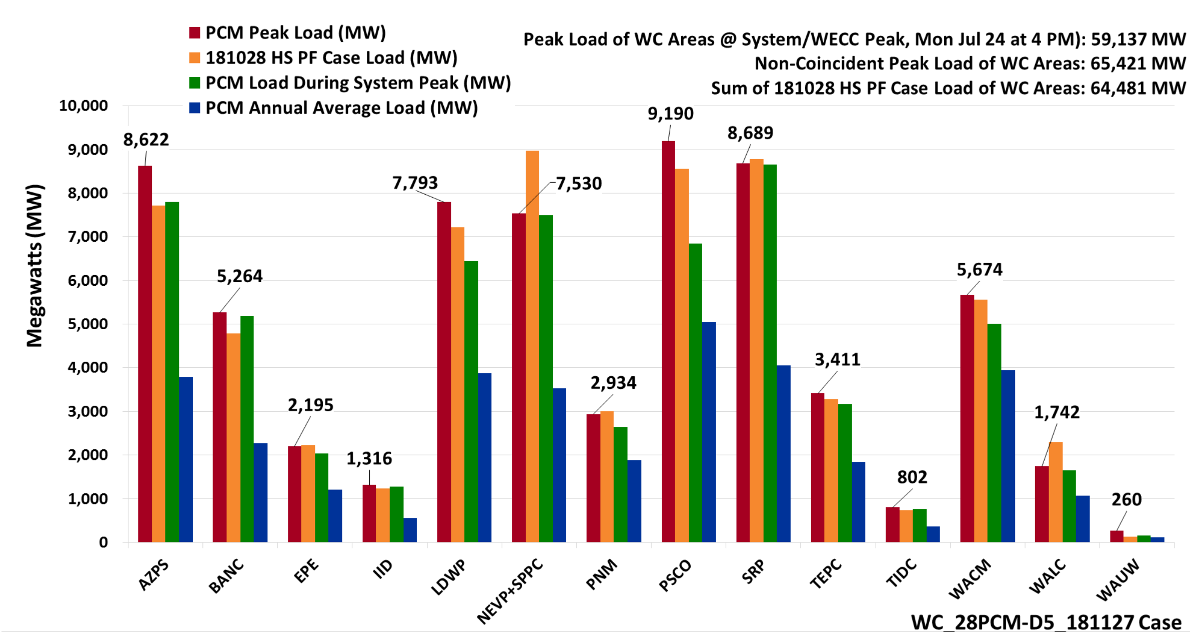


Figure 9: WestConnect PCM Areas' Peak, Load During System Peak, and Average Load (MW) in WestConnect 2028 Base Case [with Losses], shown with the Load from the 2028 Heavy Summer Base Case [No Losses] ("181028 HS PF Case")



Transmission: The WECC 2028 ADS PCM V1.0 was updated with the WestConnect member topology to be consistent with the WestConnect Base Transmission Plan and the reliability model topology. WestConnect also reviewed the case for seasonal branch ratings, interfaces, and nomograms – making the below listed changes in each of these categories. The transmission topology outside of WestConnect, including the Common Case Transmission Assumptions, was not modified.

- Increased branch monitoring in the WestConnect footprint: Monitored transmission lines ≥ 200 kV, transformers ≥100 kV, and all phase shifting transformer ("PST") branches, less BES exceptions in WestConnect (based on the branch monitoring in the reliability models)
- Updated interface definitions

Other Assumptions:

- Any opportunity to more closely align the economic Base Case model with the reliability Base Case model was taken. For example, the summer and winter branch ratings and load distribution factors were aligned with the 2028 Heavy Summer case.
- Fuel price forecasts and emission rate assumptions were consistent with the WECC 2028 ADS PCM V1.0. These assumptions are included in Appendix A of the Model Development Report.
- Reserve requirements modeling was consistent with the WECC 2028 ADS PCM V1.0.
- Variable Operations and Maintenance cost modeling was consistent with the WECC 2028 ADS PCM V1.0.
- Wheeling charges, which represent the transmission service charges associated with transferring power between areas were revised from the original WECC 2028 ADS PCM V1.0 values to peak and off-peak wheeling charges based on the latest Open Access Transmission Tariff ("OATT") rate. These assumptions are provided in Appendix A of the Model Development Report. The WECC 2028 ADS PCM V1.0 also contained additional wheeling charges associated with modeling carbon emission charges applicable to California, and these rates were maintained. WestConnect members reviewed these updates through draft model releases. Additional details for the wheeling charge modeling assumptions are included below:
    - The regular, inter-area wheeling charges were based upon the OATT on-peak and off-peak non-firm point-to-point transmission service charges (Schedule 8) as well as Schedule 1 (Scheduling System Control and Dispatch Service) and Schedule 2 (Reactive Supply and Voltage Control) charge components of transmission providers in the Western Interconnection.
    - Emission-related wheeling charges: The carbon emission charges applicable to California were representing the California Global Solutions Act ("AB 32") modeling and its modeling in the WECC 2028 ADS PCM V1.0 was retained.
- Nomograms and transmission interfaces were modeled by starting with the WECC 2028 ADS PCM V1.0, and then enhanced with additional nomograms and conditional constraints provided by WestConnect members. These input conditions aim to address the operational needs of individual member systems, such as voltage support and other factors, including must run and must take conditions, that drive the need for certain generation resources to be committed in a particular way, consistent with the existing operational practices of the WestConnect member systems. The names of monitored interfaces are included in Appendix A of the Model Development Report, and the "SMUD Op Nomogram", "EPE Balance", and "TEP Local Gen" were nomograms added to the model to commit local generation.

5.1.2 2028 Wheeling Charge Sensitivity Case

Description: The case was created from the 2028 Base Case by reducing the regular, inter-area wheeling charges to 50% of what was assumed in the 2028 Base Case. The other, emission-related (AB

32) wheeling charges were not changed from what was assumed in the 2028 Base Case. The inclusion of this sensitivity was based on backcast benchmarking studies WestConnect performed in 2017.

5.2 Study Method

The PS conducted the study and reviewed the 2028 Base Case results for regional congestion (i.e., number of hours) and congestion cost (i.e., the cost to re-dispatch more expensive generation because of transmission constraints). Given the regional focus of the WestConnect process, the PS limited its congestion analysis to:

- Transmission elements (or paths/interfaces) between multiple WestConnect member TOs;
- Transmission elements (or paths/interfaces) owned by multiple WestConnect member TOs; and
- Congestion occurring within the footprints of multiple TOs that has potential to be addressed by a regional transmission project or non-transmission alternative.[12]

As with the reliability assessment, the economic assessment included extensive testing and multiple iterations of model refinements, simulations, participant review of results, and incorporation of modifications and comments into the subsequent round of simulations.

As the work plan for the base economic model was being developed, there was considerable discussion around the wheeling charge modeling assumptions. A 50% Wheeling Charge Sensitivity Case was created from the 2028 Base Case by reducing the regular, inter-area wheeling charges to 50% of what was assumed in the 2028 Base Case. The other, emission-related (AB 32) wheeling charges were not changed from what was assumed in the 2028 Base Case.

5.3 Study Results and Findings

The objective of the economic assessment was to arrive at a set of congested elements that warranted testing for the economic potential for a regional project solution, while also recognizing that the presence of congestion does not always equate to a regional need for congestion relief at a particular location.

The Base Case economic assessment did not identify congestion significant enough to support the identification of a regional economic need. For completeness, the PS conducted the 50% wheeling charge sensitivity study described above and confirmed that the wheeling charge assumptions were not hiding potential regional congestion. Evaluations of each multi-TO system congestion issue in the Base Case results are summarized below. The PS determined all issues to be local and not regional in nature. More details, including the congestion results of the sensitivity case, are provided in Appendix C.

1. WECC Transfer Path 66 (California-Oregon Intertie, or COI) was congested for 69 hours in the 2028 Base Case, amounting to $3,795K in congestion cost. TANC and WAPA-SNR provided the rationale for why this should not identify a regional need:
    - Congestion cost is low and hours are also low.

[12] Congestion within a single TO's footprint (and not reasonably related or tied to other TO footprints) is out of scope of the regional planning effort and is alternatively subject to Order 890 economic planning requirements.

2. San Juan – Waterflow 345 kV #1 line was congested for 74 hours in the 2028 Base Case, amounting to $2,209K in congestion cost. WAPA-RM, Xcel/PSCO, and TSGT provided the rationale for why this should not identify a regional need:

    - Investigation into the congestion shown for the San Juan PST's revealed a modeling error in how Path 31 (TOT2A) flows were calculated, allowing TOT2A to flow beyond its limit. After correcting the branch definition, Path 31 (TOT2A) congests in a direction (south-to-north) in which it has historically never flowed. This observation warrants further exploration in a future cycle.

3. Sawmill Creek – Laramie River 230 kV #1 line was congested for 4 hours in the 2028 Base Case, amounting to $941K in congestion cost. BEPC and TSGT provided the rationale for why this should not identify a regional need:

    - Only 4 hours of congestion is very minor (<<1% of the year) and can be considered noise, and the cost is relatively small

4. WECC Transfer Path 30 (TOT 1A) was congested for 8 hours in the 2028 Base Case, amounting to $825K in congestion cost. TSGT provided the rationale for why this should not identify a regional need:

    - Only 8 hours of congestion is very minor (<<1% of the year) and can be considered noise

5. WECC Transfer Path 47 (Southern New Mexico) was congested for 42 hours in the 2028 Base Case, amounting to $690K in congestion cost. PNM, EPE, and TSGT provided the rationale for why this should not identify a regional need:

    - Congestion is not high enough to be identified as a need. The number of hours of congestion identified in the model simulation is de minimis and the vetting process gave rise to questions about the model results. There was not a high degree of confidence in the congestion results with respect to this path. This factor, coupled with the trivial number of hours of congestion produced in the model simulation, resulted in the conclusion that it did not give rise to an economic-driven regional transmission need.

6. Dave Johnston – Sawmill Creek 230 kV #1 line was congested for 3 hours in the 2028 Base Case, amounting to $490K in congestion cost. BEPC and TSGT provided the rationale for why this should not identify a regional need:

    - Only 3 hours of congestion is very minor (<<1% of the year) and can be considered noise, and the cost is relatively small

7. WECC Transfer Path 32 (Pavant – Gonder 230 kV; Intermountain – Gonder 230 kV) was congested for 36 hours in the 2028 Base Case, amounting to $311K in congestion cost. NVE and LADWP provided the rationale for why this should not identify a regional need:

    - Modeling issue on Intermountain – Gonder 230kV Line (rating for Intermountain – Gonder 230kV Line #1 ([redacted] MVA, i.e., [redacted] MW in PCM sim) wasn't modeled);
    - The observed congestion is in W-E direction, which has not been observed historically and thus is likely a modeling issue. Furthermore, the [redacted] MW path 32 W-E rating is based on the "capacity need" and "flowability" & not the facility ratings or other reliability

constraints; therefore, there's a clear potential for its increase in the future, which could be recommended to be pursued by the path owners; and

  - The congestion is insignificant both by hours and by cost.

8. Intermountain – Gonder 230 kV #1 line was congested for 1 hour in the 2028 Base Case, amounting to $6K in congestion cost. NVE and LADWP provided the rationale for why this should not identify a regional need:

  - Modeling issue. Correct rating for Intermountain – Gonder 230kV Line #1 ([redacted] MVA, i.e., [redacted] MW in PCM sim) wasn't modeled.

9. WECC Transfer Path 36 (TOT 3) was congested for 2 hours in the 2028 Base Case, amounting to $3K in congestion cost. TSGT and WAPA-RM provided the rationale for why this should not identify a regional need:

  - Only 2 hours of congestion is very minor (<<1% of the year) and can be considered noise

Single-TO congestion results are provided in Appendix C of the Needs Assessment Report.

6 Public Policy Assessment

Enacted public policy was considered in the WestConnect Regional Planning Process as a part of the Base Case development. Enacted public policies were incorporated into the base models through the roll-up of local TO plans and their associated load, resource, and transmission assumptions. Given this, regional public policy needs can be identified one of two ways:

1) New regional economic or reliability needs driven by enacted Public Policy Requirements (from local and state levels); or

2) Stakeholder review of local TO Public Policy Requirements-driven transmission projects and associated suggestions as to whether one or more TO projects may constitute a public policy-driven regional transmission need.

6.1 Study Method

WestConnect began the evaluation of regional transmission needs driven by public policy requirements by identifying a list of enacted public policies that impact local TO plans in the WestConnect planning region. This list was developed by the PS in public meetings and posted in meeting materials. It was agreed that enacted public policies including but not limited to state RPS and distributed generation goals/set-asides would be represented in the Base Cases.

Table 14 summarizes the enacted public policies that were reflected in regional base economic and power flow models. This table was originally in the Study Plan and incorporates two revisions made during the model development: 1) NV Energy's clarifications regarding the Nevada Renewable Portfolio Standard and 2) the additional of the SRP 2020 20% Sustainable Energy Goal. After their review of the models, each TOLSO member provided expressed confirmation that the WestConnect 2028 economic and power flow models met the conditions of these public policies' for study year 2028.

Table 14. Enacted Public Policies Incorporated into 2028 WestConnect Planning Models

Enacted Public Policy	Description
Arizona Renewable Energy Standard	Requires IOUs and retail suppliers to supply 15% of electricity from renewable resources by 2025), with a minimum of 30% of the renewable resources provided by distributed generation.
California SB350	Requires IOUs and municipal utilities to meet a 50% RPS by 2030 and also requires the establishment of annual targets for energy efficiency savings.
California AB398/SB32	Requires the California State Air Resources Board to approve a statewide greenhouse gas emissions limit equivalent to the statewide greenhouse gas emissions level in 1990 to be achieved by 2020 and to ensure that statewide greenhouse gas emissions are reduced to at least 40% below the 1990 level by 2030.
Colorado SB 07-100	Requires IOUs to identify Energy Resource Zones, plan transmission to alleviate constraints from those zones, and pursue projects according to the timing of resource development in those zones.
Colorado HB10-1001	Established Colorado Renewable Energy Standard (RES) to 30% by 2020 for IOUs (Xcel & Black Hills).
Colorado SB13-252	Requires cooperative utilities to generate 20% of their electricity from renewables by 2020.
Colorado HB10-1365	Requires rate regulated utilities in CO with coal-fired generation to reduce emissions on the smaller of 900 MW of generation of 50% of a company's coal generation fleet. Full implementation to be achieved by 12/31/2017
Nevada SB123	To reduce emissions from coal-fired generators, requires reduction of at least 800 MW generation capacity from coal-fired generation plants, addition of at least 350 MW of generating capacity from renewable energy facilities, and construction of at least 550 MW of generating capacity from other types of generating plants by 2020.
Nevada SB374	Requires net metering be available to each customer-generator who submits a request to the company.
Nevada Renewable Portfolio Standard	The percentage of renewable energy[13] required. Increases every two years until it reaches 25 percent by 2025.
New Mexico Efficient Use of Energy Act	Require utilities to include cost-effective EE and DR programs in their resource portfolios and establish cost-effectiveness as a mandatory criterion for all programs.
New Mexico Renewable Energy Requirements	Subject to the Reasonable Cost Threshold (RCT), the RPS Rule outlines renewable energy requirements that are a function of PNM's retail energy sales. • No less than 10% of retail energy needs for calendar years 2011 through 2014; • No less than 15% of retail energy needs for calendar years 2015 through 2019;

[13] *Is calculated based on number of renewable energy credits; reference Nevada Revised Statute ("NRS") 704.7821*

Enacted Public Policy	Description
	• No less than 20% of retail energy needs for calendar year 2020 and subsequent years
SRP 2020 20% Sustainable Energy Goal	SRP has established a goal that by 2020, SRP will meet a target of 20% of its expected retail energy requirements with sustainable resources. Among them are a diversified resource mix of wind, geothermal, large hydro and low-impact hydro, and solar.

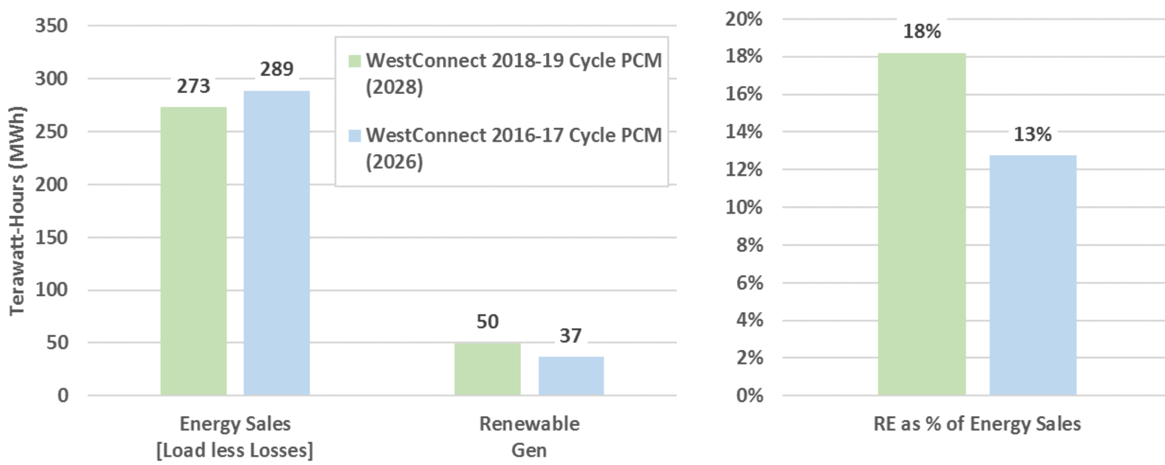
6.2 Case Development

During the model development process, there was interest in seeing whether the WestConnect economic models indicated a renewable energy penetration trajectory consistent with enacted public policies. To address this interest WestConnect conducted a renewable energy check, i.e., a high-level accounting and comparison of each PCM Area's energy sales and renewable energy via the process outlined below.

1. Annual generation of bio-fueled, geothermal, solar PV, solar thermal, & wind resources were summed for each PCM Load Area as "Renewable Energy" ("RE"). The RE for the SRP PCM Area also included specific hydro and combined solar & battery generation in the SRP PCM Area based on SRP's plan to meet its public policy requirements, but hydro was otherwise not counted as RE. The Reserve Capacity Distribution settings in the 2028 Base Case were used to allocate resources to their appropriate remote load area.
2. Each PCM Load Area's "Energy Sales" was determined by taking the "Served Load Includes Losses", subtracting losses, adding the magnitude of negative generation (e.g., pumping or motor loads with hourly profiles), and subtracting behind-the-meter generation (e.g., distributed generator or DG-BTM, energy efficiency or EE, demand response or DR).
3. The RE was divided by the "Energy Sales" to compute the "RE as % of Energy Sales" for the 2028 Base Case and the 2026 Base Case PCM from the 2016-17 cycle (to allow for comparison between cycles).

Only the single year results from each study year were used in this renewable energy check and no banking of renewable energy from other years was assumed. **Figure 10** shows the results of the renewable energy check. Since the 2018-19 case developed for 2028 has more renewable energy than the 2016-17 planning cycle case developed for 2026, the PS determined that this was a reasonable trend towards WestConnect members meeting enacted public policies.

Figure 10. Sum of Energy Sales, Renewable Generation, and overall RE as % of Energy Sales based on Single-Year Results from the 2028 Base Case and 2026 Base Case PCM.



6.3 Results and Findings

In conducting the regional reliability and economic assessments the PS did not find any regional issues driven by enacted public policy requirements. Furthermore, stakeholders did not suggest or recommend the identification of a public policy-driven transmission need based on TO's local transmission plans. Based on these two findings, there are no identified public policy needs in the WestConnect 2018-19 regional Planning Process.

7 Regional Transmission Plan

Based on the findings from the 2018-19 planning cycle analysis performed for reliability, economic, and public policy transmission needs as described in this report, no regional transmission needs were identified in the 2018-19 assessment.

Since no regional transmission needs were identified, the PMC did not collect transmission or non-transmission alternatives for evaluation since there were no regional transmission needs to evaluate the alternatives against. Given this, the 2018-19 Regional Transmission Plan is identical to the 2018-19 Base Transmission Plan and it does not include any additional regional projects.

8 Stakeholder Involvement and Interregional Coordination

8.1 Stakeholder Process

The WestConnect regional planning process is performed in an open and transparent manner to attain objective analysis and results. WestConnect invites and encourages interested parties or entities to participate in and provide input to the regional transmission planning process at all planning process stages. Stakeholders have opportunities to participate in and provide input to local transmission plans as provided for in each TO Member's OATT. Further, stakeholders have opportunities to participate in and provide input into subregional planning efforts within Colorado Coordinated Planning Group ("CCPG"), Sierra Subregional Planning Group ("SSPG"), and Southwest Area Transmission ("SWAT"). Finally, all WestConnect planning meetings are open to stakeholders with the exception of PMC closed sessions which were identified in agendas distributed prior to meetings and posted on the WestConnect website. Stakeholders' opportunities for timely input and meaningful participation are available throughout the WestConnect planning process. More specifically, the PS and PMC meetings held to support the regional transmission planning process were open to the public, and each meeting provided an opportunity for stakeholder comment. Notice of all meetings and stakeholder comment periods were posted to the WestConnect Calendar webpage and distributed via email. In addition, WestConnect accepted stakeholder comments on the interim reports created throughout the 2018-19 planning cycle. Further, open stakeholder meetings to discuss the WestConnect regional Planning Process were conducted on February 14, 2018, November 15, 2018, and February 13, 2019, and November 21, 2019. The meetings were announced through WestConnect's website and stakeholder distribution lists, and all stakeholders were invited to attend.

In response to stakeholder feedback during the 2018-19 cycle, the PMC is developing a new Stakeholder Tracking Document and an accompanying Stakeholder Comments webpage through which the PMC can better collect, track, and resolve stakeholder comments and concerns going forward.

8.2 Interregional Coordination

WestConnect coordinates its planning data and information with the three other established Planning Regions in the Western Interconnection (California Independent System Operator, ColumbiaGrid, and Northern Tier Transmission Group) by:

- Participating in annual interregional coordination meetings;
- Distributing regional planning data or information such as:
  - Draft and Final Regional Study Plan
  - Regional Transmission Needs Assessment Report
  - List of Interregional Transmission Projects ("ITP") submitted to WestConnect
  - Assessments and selection of ITPs into Regional Transmission Plan
  - Draft and Final Regional Transmission Plan
- Sharing planning assumptions if and when requested and subject to applicable confidentiality requirements; and
- Participating in a coordinated ITP evaluation process, as necessary, when an ITP is submitted to WestConnect as an alternative to meet an identified regional need. [14]

To the extent WestConnect received updated modeling data from TOs outside of the WestConnect planning region during the development of the regional models, it was considered, and if appropriate,

[14] *Additional details regarding the ITP submittal and evaluation process can be found in the BPM*

incorporated into the regional models. The goal in seeking input from neighboring planning regions and TOs outside of the WestConnect planning footprint is to maintain external model consistency and align planning assumptions as closely as possible.

The process WestConnect utilizes to conduct its interregional coordination activities is described in the WestConnect Regional Planning Process BPM which is posted on the WestConnect website.

8.3 Interregional Project Submittals

An ITP is defined in the common tariff language developed for the Order No. 1000 interregional compliance filings as "a proposed new transmission project that would directly interconnect electrically to existing or planned transmission facilities in two or more planning regions and that is submitted into the regional transmission planning processes of all such planning regions." ITP proponents seeking to have their project included in the WestConnect Base Transmission Plan had the opportunity to do so at the beginning of the planning cycle. ITP proponents that wanted their ITP considered for cost allocation and/or to have their project evaluated to meet an identified regional need needed to submit their project to WestConnect via the WestConnect Regional Project Submittal Form no later than March 31, 2018, so that WestConnect could coordinate the ITP evaluation process with all other Relevant Planning Regions.

WestConnect received the following ITP submittals for the 2018-19 Planning Process:

- Cross-Tie Transmission Line
- North Gila-Imperial Valley #2 Line
- SWIP North Project
- SDGE HVDC Conversion Project
- TransWest Express DC Project
- TransWest Express AC and DC Project

Details for each ITP submittal can be found on the Interregional Coordination webpage. WestConnect does not evaluate ITP submittals until regional transmission needs are identified. If regional needs are identified, then the ITPs have an opportunity to indicate which need they would seek to address, and the ITP would be studied alongside any other regional project submittals. However, since there were no regional transmission needs identified by WestConnect in the 2018-19 Planning Process, the submitted ITPs were not studied in this cycle.

9 Scenario Studies

Members or stakeholders proposed scenarios for consideration in the WestConnect Planning Process through an open submittal window. WestConnect held the open window from December 1, 2017 through January 5, 2018. Several proposed scenarios were received and subsequently reviewed by the PS during public meetings on January 19, 2018 and on February 13, 2018. During the meetings the PS discussed the proposed scenarios, member feedback, and the number of scenarios that would be appropriate to study. These conversations led to the inclusion of two scenarios in the final Study Plan: a Load Stress scenario and a California Independent System Operator ("CAISO") Export Stress scenario. Both scenarios were reliability assessments. The purpose of the Load Stress scenario was to test the robustness of the Base Transmission Plan against significant unforeseen load growth. The intent of the CAISO Export scenario was to evaluate the reliability of the WestConnect regional system during conditions in which physical power flows from the CAISO to WestConnect during CAISO overgeneration conditions.

The PS finalized the study scopes and developed the models required to complete the two scenario assessments. **Table 15** summarizes each scenario and the core questions that the studies were designed to investigate.

Table 15: Scenario Case Descriptions & Core Questions

Scenario	Description of Case	Core Questions to Investigate
Load Stress	The WestConnect-approved 2028 Heavy Summer Base Case conforming loads were scaled for each TOLSO based on feedback received during the scenario development process and the generation-load gap was filled with existing generator capacity not already dispatched in the Base Case. In one area, renewable capacity was added and dispatched to meet the load increase.	How robust is the Base Transmission Plan when peak load is higher than expected?
CAISO Export	Using the WestConnect-approved 2028 Base Case PCM, a power flow snapshot was developed based on system conditions identified for Hour 15 on June 18th. This hour was selected by the PS during the January 15, 2019, meeting as a system condition representative of high CAISO export to WestConnect. The CAISO export to WestConnect was approximately 6,280 MW during that hour.[15]	During high export conditions from the CAISO to WestConnect, how reliable is the WestConnect regional transmission system?

[15] *The CAISO Export to WestConnect interface was defined using all monitored "seam" branches between the CAISO and WestConnect Load Areas in the PCM. The flow on unmonitored and non-BES "seam" branches was not included in the interface definition.*

9.1 Case Development

The information in this section summarizes each scenario model and provides details about the major assumptions incorporated into the cases.

9.1.1 Load Stress Scenario

The Load Stress Scenario Case was developed by scaling load conditions modeled in the 2028 Heavy Summer Base Case to higher load levels as specified by TOLSOs during the case development phase. The generation-load gap created by the load increase was filled with existing generator capacity not already dispatched in the Base Case, with one exception. In the PNM area renewable capacity was added and dispatched to meet the load increase. The transmission topology did not change from the 2028 Heavy Summer Base Case and reflected the 2018-19 Base Transmission Plan additions. Detailed load, import, and generator dispatch assumptions, from the perspective of the WestConnect footprint, are provided in **Table 16**.

Table 16: High Load Stress Scenario Base Case Assumptions

WestConnect Metric	2028 Heavy Summer Base Case	2028 Load Stress Scenario	Change
WestConnect Load (MW)[16]	65,274	69,348	Increased 6.24%
WestConnect Import/Export (MW)	Export: 2,438	Export: 1,853	Decreased 24.0%
WestConnect Generation Dispatch (MW)	Thermal: 53,179 Hydro: 6,902 Wind/Solar: 5,637 Other: 1,994 Total: 67,712	Thermal: 55,596 Hydro: 7,022 Wind/Solar: 6,350 Other: 2,233 Total: 71,200	Increased 5.15%
WestConnect Transmission	2018-19 Base Transmission Plan		No change

9.1.2 CAISO Export Stress Scenario

Today and historically, net flow is almost always from WestConnect into the CAISO. This is especially true on the major interfaces between California and Arizona, including Path 46 (West of River) and Path 49 (East of River), which flow in the east-to-west direction. As the CAISO adds more solar onto its

[16] *Represents the system coincident peak for a heavy summer conditions between the hours of 1500 to 1700 MDT during the months of June – August.*

system, certain conditions cause the CAISO system to have more generation than it needs, particularly in light-load conditions in the spring and fall. This creates the opportunity for economic (transactional) exports out of the CAISO into WestConnect, as well as physical exports of power (i.e., actual power flow, which are different than energy transactions).

The CAISO Export Stress Scenario Case was based on conditions observed in the WestConnect 2028 Base Case economic model. The modeling results were filtered for hours in which there were power flows from the CAISO into WestConnect. In total, the export condition was observed in 13% of the hours in the study 2028 year. The PS focused on a review of hours in which both (1) exports from the CAISO to WestConnect are high, and (2) flows west-to-east across Path 49 and Path 46 are high. **Table 17** identifies the condition selected by the PS for study: Hour 15 of June 18th. During this condition, flows from the CAISO to WestConnect are 6,284 MW and flows on Path 46 and Path 49 are in the west-to-east direction at 4,231 MW and 5,463 MW, respectively.[17]

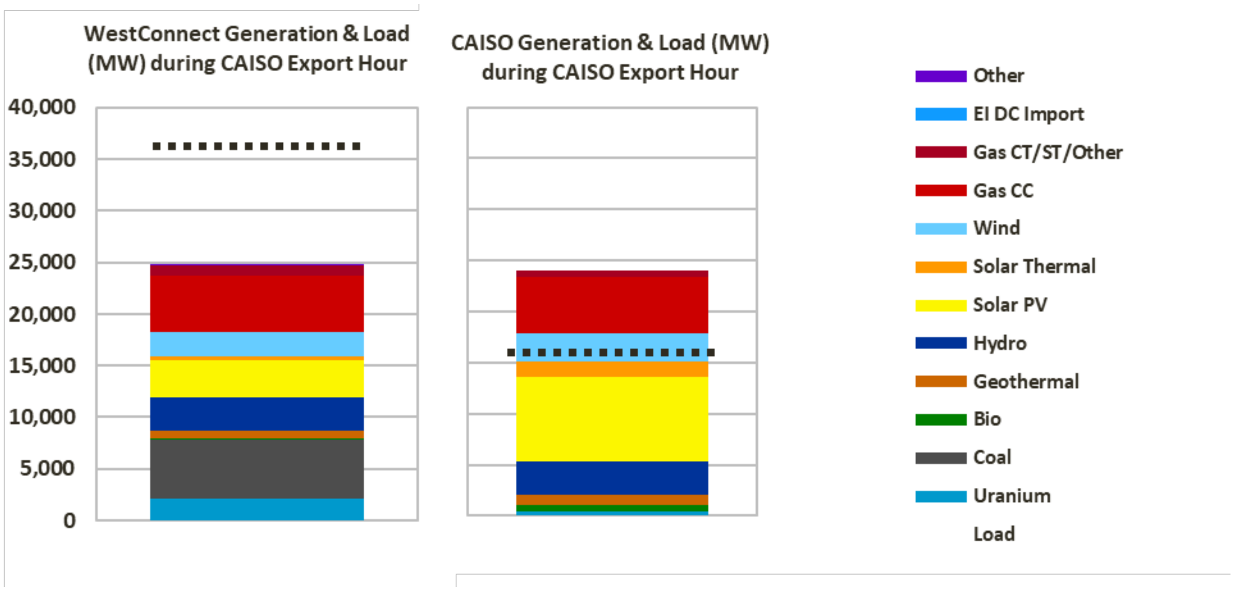
Table 17: June 18th Hour 15 Flows from the CAISO to WestConnect

		Flow (MW)		
Date	Hour	P46 [E->W]	P49 [E->W]	CAISO Export to WC (Approx.)
6/18/2028	15	-4,231	-5,463	6,284

The simulated WestConnect and the CAISO load levels and generation dispatch are summarized in **Figure 11**. The gap between the load and the top of the generation stack represents imports into the given region. When the stack is above the load level, this represents exports.

[17] Note that the interface between the CAISO and WestConnect was defined as all monitored seam branches between the CAISO and WestConnect Load Areas. This means that branches between WestConnect loads in California and the CAISO were included in the interface. Non-bulk electric system (Non-BES) branches and unmonitored branches were not included in the seam.

Figure 11: WestConnect & the CAISO Load & Generation During Selected CAISO Export on June 18th Hour 15



The transmission topology did not change from the Base Case assessments and reflects the 2018-19 Base Transmission Plan additions. The seed case was the approved WestConnect 2028 Heavy Summer Base Case. The load, imports, and generator dispatch assumptions are provided in **Table 18.**

Table 18: June 18th Hour 15 CAISO Export Scenario Base Case Assumptions

WestConnect Metric	2028 CAISO Export Scenario
WestConnect Load (MW)	35,872[18]
WestConnect Import/Export (MW)	Import: 7,273
WestConnect Generation Dispatch (MW)	Thermal: 18,621 Hydro: 3,187 Wind/Solar: 6,120 Other: 671 Total: 28,599
WestConnect Transmission	2018-19 Base Transmission Plan

[18] *Note that this load forecast is based on 1-in-2 load forecasts contained in the production cost model.*

9.2 Study Method

The PS performed the same Study Method as in the Reliability Assessment described in Section 4.2.

9.3 Results and Findings

The information in this section summarizes the results and findings of the scenario studies. The detailed results of the Load Stress Scenario and CAISO Export Stress Scenario are provided in Appendix A and Appendix B (respectively) of the Scenario Assessment Report.

9.3.1 Load Stress Scenario

This scenario's results included 15 voltage issues on multi-TO systems. The identified multi-TO issues were geographically isolated. None of the multi-TO issues indicate deficiencies in the Base Transmission Plan. There were single-TO system issues, all of which the PS determined to be local issues and not regional in nature.

The Load Stress scenario did not materially impact regional-level flows. Average branch loading increased by roughly 1% when compared to the 2028 Heavy Summer Base Case. Contingency analysis identified few multi-TO voltage issues. These multi-TO issues are informational, radial in nature, and do not indicate deficiencies in the Base Transmission Plan. Therefore, the study results indicate that the Base Transmission Plan is sufficiently robust under higher than expected load conditions.

9.3.2 CAISO Export Stress Scenario

This scenario's results included 6 branch overloads and 9 voltage issues on multi-TO transmission. The thermal branch overloads were located in the Colorado and Wyoming area. Single-TO system issues were reviewed and the PS determined that these single-TO system issues were not regional in nature.

The case development was successful in that a CAISO export condition was identified in the 2028 Base Case, and this condition was replicated in reliability models in terms of load, generation dispatch, and system flows. Reliability analysis of the condition identified several multi-TO voltage issues that can be easily addressed through system adjustments. The analysis also identified a few thermal overloads in the Colorado area, but these issues were remote from the CAISO-WestConnect interface(s) and caused by flows occurring in entirely new directions than what has been observed historically. WestConnect concluded that, at a high-level, scenario does not significantly stress the regional transmission system beyond levels identified in the Base Cases and the regional system is robust during CAISO export conditions.

Appendix A – 2018-19 Regional Transmission Plan[19]

The tables below include the planned projects in the 2018-19 Regional Transmission Plan, organized by Subregional Planning Group (SPG).

SWAT Base Transmission Plan Projects for 2018-19 Regional Planning Cycle

Sponsor	Project Name	Development Status	Voltage	2016-2017 Plan?	In-Service Date
Arizona Public Service	North Gila - Orchard 230kV Line	Planned	230 kV	**Y**	2021
Arizona Public Service	TS4 230/69kV Substation	Planned	230 kV	**N**	2020
El Paso Electric Company	Add 345 kV ring bus to VADO substation. Split Newman 345 kV to Afton_N 345 kV line tapping in-and-out to VADO 345 kV bus.	Planned	345 kV	**N**	2025
El Paso Electric Company	Afton North - Airport Transmission Line	Planned	115 kV	**Y**	2019
El Paso Electric Company	Afton North Autotransformer	Planned	345 kV	**Y**	2019
El Paso Electric Company	Anthony to VADO 115 kV transmission line Ckt 3. Created from existing Anthony to Arroyo 115 kV transmission line being tapped in and out of new VADO 115 kV substation.	Planned	115 kV	**N**	2023
El Paso Electric Company	East side loop expansion Phase 2	Planned	115 kV	**Y**	2021
El Paso Electric Company	East side loop expansion Phase I	Planned	115 kV	**Y**	2020
El Paso Electric Company	Eastside Loop Expansion Phase I	Planned	115 kV	**Y**	2020
El Paso Electric Company	Lane-Pendale-Copper (16900) 69 kV Line Rebuild & Reconductor	Planned	Below 115 kV	**Y**	2018
El Paso Electric Company	Leasburg Substation 33.6 MVA Transformer	Planned	115 kV	**Y**	2019
El Paso Electric Company	MOONGATE - Jornada Transmission Line	Planned	115 kV	**N**	2020
El Paso Electric Company	MOONGATE Substation	Planned	115 kV	**N**	2020
El Paso Electric Company	Move Sparks 115/69 kV autotransformer to Felipe substation	Planned	115 kV	**Y**	2021
El Paso Electric Company	New Afton_N to VADO 115 kV transmission line.	Planned	115 kV	**N**	2022

[19] *The project information provided in Appendix A is dated March 14, 2018, the approval date of the WestConnect 2018-19 Regional Study Plan*

Sponsor	Project Name	Development Status	Voltage	2016-2017 Plan?	In-Service Date
El Paso Electric Company	New Anthony to VADO 115 kV transmission line Ckt 2	Planned	115 kV	**N**	2024
El Paso Electric Company	New transmission line from VADO 115 kV to Salopek 115 kV Ckt 2	Planned	115 kV	**N**	2023
El Paso Electric Company	New VADO 115 kV switching station.	Planned	115 kV	**N**	2022
El Paso Electric Company	NW2 (Verde) Substation 30 MVA Transformer	Planned	115 kV	**Y**	2019
El Paso Electric Company	Patriot Substation Transformer (T2)	Planned	115 kV	**Y**	2018
El Paso Electric Company	Pipeline Substation 33.6 MVA Transformer	Planned	115 kV	**Y**	2022
El Paso Electric Company	Sol – Vista Transmission Line Upgrade	Planned	115 kV	**Y**	2017
El Paso Electric Company	Sparks to Felipe 69 kV to 115 kV line upgrade	Planned	115 kV	**Y**	2021
El Paso Electric Company	Uvas Substation 12 MVA Transformer	Planned	115 kV	**Y**	2024
El Paso Electric Company	VADO 115 kV to Arroyo 115 kV transmission line Ckt 1. Created from existing Anthony to Arroyo 115 kV transmission line being tapped in and out of new VADO 115 kV substation.	Planned	115 kV	**N**	2023
Imperial Irrigation District	CI-line reconductoring	Planned	Below 115 kV	**N**	Q4 2018
Los Angeles Department of Water and Power	Add voltage support in the LA Basin	Planned	138 kV	**N**	2021
Los Angeles Department of Water and Power	Apex-Crystal Transmission Line	Planned	500 kV AC	**N**	2022
Los Angeles Department of Water and Power	Castaic-Haskell Canyon 230 kV Line 3	Planned	230 kV	**Y**	2022
Los Angeles Department of Water and Power	Convert PP1&PP2-Olive 115kV Lines to 230kV Lines	Planned	230 kV	**N**	2022
Los Angeles Department of Water and Power	Lugo-Victorville Upgrades	Planned	500 kV AC	**N**	2021
Los Angeles Department of Water and Power	New Haskell Canyon-Sylmar 230 kV Line 2	Planned	230 kV	**N**	2022

Sponsor	Project Name	Development Status	Voltage	2016-2017 Plan?	In-Service Date
Los Angeles Department of Water and Power	New Rosamond Station	Planned	230 kV	**N**	2022
Los Angeles Department of Water and Power	New Scattergood-Olympic 230 kV Cable A	Planned	230 kV	**Y**	2018
Los Angeles Department of Water and Power	Re-conductor Rinaldi-Tarzana 230kV Line 1 & 2	Planned	230 kV	**N**	2022
Los Angeles Department of Water and Power	Re-conductor Valley-Rinaldi 230 kV Lines 1&2	Planned	230 kV	**Y**	2018
Los Angeles Department of Water and Power	Re-conductor Valley-Toluca 230 kV Lines 1&2	Planned	230 kV	**Y**	2020
Los Angeles Department of Water and Power	Scattergood-Olympic Cable B	Planned	230 kV	**N**	2020
Los Angeles Department of Water and Power	Springbok Solar III	Planned	230 kV	**N**	2019
Los Angeles Department of Water and Power	Upgrade Haskell Canyon-Olive 230 kV Line	Planned	230 kV	**Y**	2018
Los Angeles Department of Water and Power	Upgrade Olive-North Ridge 230 kV Line	Planned	230 kV	**Y**	2018
Los Angeles Department of Water and Power	Upgrade Rinaldi 230 kV CBs	Planned	230 kV	**Y**	2022
Los Angeles Department of Water and Power	Upgrade Toluca 500/230 kV Bank H	Planned	500 kV DC	**Y**	2021
Los Angeles Department of Water and Power	Upgrade Transformer Bank E and F	Planned	230 kV	**N**	2021
Los Angeles Department of Water and Power	Victorville 500/287 kV auto-transformer installation	Planned	500 kV AC	**Y**	2020
NV Energy	Arden - McDonald 230 kV Line upgrade	Planned	230 kV	**N**	2019
NV Energy	Avera - Tomsik 138 kV Reconductor	Planned	138 kV	**N**	2027
NV Energy	Burnham - Fold 138 kV fold into Pebble	Planned	138 kV	**N**	2018
NV Energy	Craig - LV Cogen 138 kV line upgrade	Planned	138 kV	**N**	2018

Sponsor	Project Name	Development Status	Voltage	2016-2017 Plan?	In-Service Date
NV Energy	East Tracy 345/120kV XFMR #2	Planned	345 kV	**N**	2020
NV Energy	Faulkner - Wilson 138 kV Reconductor	Planned	138 kV	**N**	2027
NV Energy	McDonald 230/138 kV Transformer Addition	Planned	230 kV	**N**	2019
NV Energy	Replace Wave-Traps on Humboldt-Midpoint 345kV	Planned	345 kV	**N**	2018
NV Energy	Wild Horse 120kV	Planned	115 kV	**N**	2020
Public Service Company of New Mexico	Alamogordo Voltage Support Phase II	Planned	115 kV	**Y**	2019
Public Service Company of New Mexico	Albuquerque-Clines Corners 345 kV Line	Planned	345 kV	**N**	2020
Public Service Company of New Mexico	Blackwater Synchronous Condenser	Planned	345 kV	**N**	2019
Salt River Project	Abel - Pfister - Ball 230kV	Planned	230 kV	**Y**	2021
Salt River Project	Coolidge - Hayden Reroute 115kV	Planned	115 kV	**N**	2020
Salt River Project	Copper Crossing - Abel	Planned	230 kV	**N**	2024
Salt River Project	Price Road Corridor	Planned	230 kV	**N**	2021
Salt River Project	Superior - Silver King 115kV Reroute	Planned	115 kV	**N**	2027
Tri-State Generation and Transmission Association	Hernandez 115/69kV T2 Transformer Replacement	Planned	115 kV	**N**	2021
Tri-State Generation and Transmission Association	NENM Reliability Improvement	Planned	115 kV	**Y**	2023
Tri-State Generation and Transmission Association	Rowe 115/24.9kV Transformer Replacement	Planned	115 kV	**N**	2020
Tucson Electric Power	22nd Capacitor Bank Addition	Planned	138 kV	**N**	2020
Tucson Electric Power	Corona 138/13.8 kV Substation	Planned	138 kV	**Y**	2026
Tucson Electric Power	Craycroft Barril 138/13.8 kV Substation	Planned	138 kV	**Y**	2023
Tucson Electric Power	Del Cerro - Tucson 138 kV Line Re-conductor	Planned	138 kV	**Y**	2020
Tucson Electric Power	DeMoss Petrie (DMP) Capacitor Bank Addition	Planned	138 kV	**N**	2022

Sponsor	Project Name	Development Status	Voltage	2016-2017 Plan?	In-Service Date
Tucson Electric Power	Drexel Capacitor Bank Addition	Planned	138 kV	**N**	2021
Tucson Electric Power	Gateway 138 kV Transmission Line	Planned	138 kV	**N**	2019
Tucson Electric Power	Gateway 138 kV Transmission Line (phase 2)	Planned	138 kV	**N**	2022
Tucson Electric Power	Gateway 230/138 kV Substation	Planned	230 kV	**N**	2019
Tucson Electric Power	Gateway to US/Mexico Border 230 kV Transmission Line	Planned	230 kV	**N**	2019
Tucson Electric Power	Greenlee 345 kV, Conversion to breaker-and-a-half substation	Planned	345 kV	**Y**	2019
Tucson Electric Power	Harrison 138/13.8 kV Substation	Planned	138 kV	**Y**	2020
Tucson Electric Power	Harrison Capacitor Bank Addition	Planned	138 kV	**N**	2028
Tucson Electric Power	Hartt 138/13.8 kV Substation	Planned	138 kV	**Y**	2022
Tucson Electric Power	Irvington - Kino 138kV Transmission Line	Planned	138 kV	**N**	2021
Tucson Electric Power	Irvington 138 kV breaker-and-a-half substation	Planned	138 kV	**Y**	2019
Tucson Electric Power	Irvington Capacitor Bank Addition	Planned	138 kV	**N**	2020
Tucson Electric Power	Irvington to 22nd Street 138 kV Line Re-Conductor	Planned	138 kV	**N**	2019
Tucson Electric Power	Irvington to South 138 kV Line Re-Conductor	Planned	138 kV	**N**	2020
Tucson Electric Power	Irvington to Vail 138 kV Line Re-Conductor	Planned	138 kV	**N**	2020
Tucson Electric Power	Kantor Capacitor Bank Addition	Planned	138 kV	**N**	2019
Tucson Electric Power	Kino 138kV Substation	Planned	138 kV	**Y**	2021
Tucson Electric Power	La Canada to Orange Grove 138 kV Line Re-Conductor	Planned	138 kV	**N**	2020
Tucson Electric Power	La-Canada Line Switch	Planned	138 kV	**Y**	2020
Tucson Electric Power	Line 125 Re-conductor & Conversion to Double Circuit	Planned	138 kV	**N**	2022
Tucson Electric Power	Loop-in of Hassayampa to Pinal West 500 kV Line with existing Jojoba Substation	Planned	500 kV AC	**N**	2019

Sponsor	Project Name	Development Status	Voltage	2016-2017 Plan?	In-Service Date
Tucson Electric Power	Loop-in of Irvington to Robert Bills 138 kV line with new Sonoran substation	Planned	138 kV	**N**	2021
Tucson Electric Power	Loop-in of Irvington to Sount 138 kV Line to Sonoran Substation	Planned	138 kV	**N**	2020
Tucson Electric Power	Loop-in of Irvington to Vail 138 kV Line to Sonoran Substation	Planned	138 kV	**N**	2021
Tucson Electric Power	Loop-in of North Loop to Rancho Vistoso 138 kV Line to Naranja Substation	Planned	138 kV	**Y**	2025
Tucson Electric Power	Marana 138/13.8 kV Substation	Planned	138 kV	**Y**	2024
Tucson Electric Power	Marana 138 kV Transmission Line	Planned	138 kV	**Y**	2024
Tucson Electric Power	Naranja 138/13.8 kV Substation	Planned	138 kV	**Y**	2025
Tucson Electric Power	Naranja Capacitor Bank Addition	Planned	138 kV	**N**	2025
Tucson Electric Power	North Loop Capacitor Bank Addition (#3)	Planned	138 kV	**N**	2022
Tucson Electric Power	North Loop Capacitor Bank Addition (#4)	Planned	138 kV	**N**	2024
Tucson Electric Power	Orange Grove Capacitor Bank Addition	Planned	138 kV	**N**	2019
Tucson Electric Power	Orange Grove to Rilito 138 kV Line Re-Conductor	Planned	138 kV	**N**	2020
Tucson Electric Power	Pantano Capacitor Bank Addition	Planned	138 kV	**N**	2020
Tucson Electric Power	Point of Interconnection 138kV Switchyard (Rosemont)	Planned	138 kV	**Y**	2019
Tucson Electric Power	Q59 138/13.8 kV Substation	Planned	138 kV	**N**	2022
Tucson Electric Power	Rancho Vistoso to La Canada 138 kV Line Re-Conductor	Planned	138 kV	**N**	2020
Tucson Electric Power	Re-Conductor Nogales to Kantor 138 kV Transmission Line	Planned	138 kV	**N**	2019
Tucson Electric Power	Sonoran 138/46/13.8 kV Substation	Planned	138 kV	**N**	2020
Tucson Electric Power	Sonoran to NextEra 138 kV Line	Planned	138 kV	**N**	2022
Tucson Electric Power	South Loop 345 kV, Conversion to breaker-and-a-half substation	Planned	345 kV	**Y**	2020

Sponsor	Project Name	Development Status	Voltage	2016-2017 Plan?	In-Service Date
Tucson Electric Power	South to NextEra 138 kV Line	Planned	138 kV	**N**	2022
Tucson Electric Power	Toro - Rosemont 138 kV Line	Planned	138 kV	**Y**	2019
Tucson Electric Power	Tortolita Capacitor Bank Addition (#2)	Planned	138 kV	**N**	2019
Tucson Electric Power	Tortolita Capacitor Bank Addition (#3)	Planned	138 kV	**N**	2021
Tucson Electric Power	Tortolita Capacitor Bank Addition (#4)	Planned	138 kV	**N**	2022
Tucson Electric Power	Tucson to El Camino del Cerro 138 kV Line Re-Conductor	Planned	138 kV	**N**	2020
Tucson Electric Power	West Ina Capacitor Bank Addition	Planned	138 kV	**N**	2021
Western Area Power Administration - DSW	Coolidge - Valley Farms	Planned	115 kV	**N**	2020
Western Area Power Administration - DSW	Dome Tap-Gila	Planned	161 kV	**N**	2020
Western Area Power Administration - DSW	Gila 161 kV substation rebuild	Planned	161 kV	**Y**	2020
Western Area Power Administration - DSW	Kofa – Dome Tap	Planned	161 kV	**N**	2020
Western Area Power Administration - DSW	Liberty - Rudd 230 kV Facility Uprate	Planned	230 kV	**N**	2019

CCPG Base Transmission Plan Projects for 2018-19 Regional Planning Cycle

Sponsor	Project Name	Development Status	Voltage	2016-2017 Plan?	In-Service Date
Black Hills Energy	Boone-La Junta 115 kV Rebuild	Planned	115 kV	**N**	2020
Black Hills Energy	LaJunta 115kV Substation	Planned	115 kV	**Y**	2019
Black Hills Energy	Portland 115/69kV Transformer Replacement	Planned	115 kV	**Y**	2019
Black Hills Energy	West Station - West Cañon 115kV	Planned	115 kV	**N**	2021
Black Hills Power	Sagebrush 230/69 kV Substation	Planned	230 kV	**N**	2019
Black Hills Power	Second 230/69kV Yellow Creek Transformer	Planned	230 kV	**Y**	2021
Black Hills Power	South Rapid City - Westhill 230kV Rebuild	Planned	230 kV	**Y**	2018
Black Hills Power	Westhill-Stegall 230 kV Line Rebuild	Planned	230 kV	**N**	2019
Cheyenne Light Fuel and Power	Archer - Cheyenne Prairie 115kV Reconductor	Planned	115 kV	**Y**	2019
Cheyenne Light Fuel and Power	East Business Park - Cheyenne Prairie 115kV Line Reconductor	Planned	115 kV	**Y**	2020
Cheyenne Light Fuel and Power	Happy Jack-North Range 115 kV Rebuild	Planned	115 kV	**N**	2018
Cheyenne Light Fuel and Power	Swan Ranch 115 kV Substation	Planned	115 kV	**Y**	2021
Colorado Springs Utility	Series Reactor - 115kV system	Planned	115 kV	**N**	2019
Colorado Springs Utility	Cottonwood 230/115kV Autotransformer Replacement	Planned	230 kV	**N**	2019
Platte River Power Authority	Timberline 230/115kV Transformer T3 Replacement	Planned	230 kV	**Y**	2021
Public Service Company of Colorado/ Xcel Energy	Ault-Cloverly 115 kV Transmission Project	Planned	115 kV	**Y**	2020
Public Service Company of Colorado/ Xcel Energy	Gilman-Avon 115 kV Transmission Line and Cap Bank	Planned	115 kV	**Y**	2022
Public Service Company of Colorado/ Xcel Energy	Monument 115 kV Phase Shifter	Planned	115 kV	**N**	2020

Sponsor	Project Name	Development Status	Voltage	2016-2017 Plan?	In-Service Date
Public Service Company of Colorado/ Xcel Energy	Thornton Substation	Planned	115 kV	**Y**	2019
Public Service Company of Colorado/ Xcel Energy	Avery Substation	Planned	230 kV	**Y**	2019
Public Service Company of Colorado/ Xcel Energy	Badgers Hills 345 kV Substation	Planned	345 kV	**N**	2020
Tri-State Generation and Transmission Association	Burlington - Burlington (KCEA) 115kV Line Rebuild	Planned	115 kV	**N**	2020
Tri-State Generation and Transmission Association	Falcon - Paddock - Calhan 115kV Line	Planned	115 kV	**N**	2022
Tri-State Generation and Transmission Association	Falcon-Midway 115 kV Line Uprate Project	Planned	115 kV	**Y**	2021
Tri-State Generation and Transmission Association	La Junta (TS) 2nd 115/69kV, 42 MVA XFMR	Planned	115 kV	**Y**	2020
Tri-State Generation and Transmission Association	Lost Canyon - Main Switch 115 kV Line	Planned	115 kV	**Y**	2022
Tri-State Generation and Transmission Association	Rolling Hills Substation	Planned	115 kV	**N**	2024
Tri-State Generation and Transmission Association	Santa Fe Springs Substation	Planned	115 kV	**N**	2022
Tri-State Generation and Transmission Association	Shaw Ranch Substation	Planned	115 kV	**N**	2024
Tri-State Generation and Transmission Association	White Rock 115/34.5kV Transformer #2	Planned	115 kV	**N**	2021
Tri-State Generation and Transmission Association	Wind River 115kV Reliability Upgrade	Planned	115 kV	**Y**	2022
Tri-State Generation and Transmission Association	Fuller 230/115kV Transformer #2	Planned	230 kV	**N**	2020
Tri-State Generation and Transmission Association	San Luis Valley-Poncha 230 kV Line #2	Planned	230 kV	**Y**	2022

Sponsor	Project Name	Development Status	Voltage	2016-2017 Plan?	In-Service Date
Tri-State Generation and Transmission Association	Wayne Child Phase II - (Formerly Arrow Transmission Project)	Planned	345 kV	**N**	2021
Western Area Power Administration - RMR	Big Horn Transmission Improvement	Planned	115 kV	**N**	2023
Western Area Power Administration - RMR	Blue Mesa	Planned	115 kV	**N**	2025
Western Area Power Administration - RMR	Estes-Flatiron 115 kV rebuild	Planned	115 kV	**Y**	2021
Western Area Power Administration - RMR	Kimball Substation	Planned	115 kV	**N**	2023
Western Area Power Administration - RMR	Sand Creek Tap	Planned	115 kV	**N**	2022
Western Area Power Administration - RMR	Granby - Windy Gap	Planned	138 kV	**Y**	2018
Western Area Power Administration - RMR	Midway KV1A Replacement	Planned	230 kV	**N**	2020
Western Area Power Administration - RMR	Pole Creek Tap	Planned	230 kV	**N**	2020
Western Area Power Administration - RMR	Stegall Bus Sectionalization	Planned	230 kV	**N**	2024
Western Area Power Administration - RMR	Ault 345/230 kV XFMR Replacement	Planned	345 kV	**Y**	2020
Western Area Power Administration - RMR	Badwater Reactor	Planned	Below 115 kV	**Y**	2019

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827 **SSPG Base Transmission Plan Projects for 2018-19 Regional Planning Cycle**

Sponsor	Project Name	Development Status	Voltage	2016-2017 Study?	In-Service Date
NV Energy	Brunswick Rebuild	Planned	115 kV	**N**	2018
NV Energy	California – Bordertown 120kV Line	Planned	115 kV	**Y**	2019
NV Energy	California Substation upgrade	Planned	115 kV	**N**	2018
NV Energy	Carson - Emerson Line Rebuild	Planned	115 kV	**N**	2019
NV Energy	Cortez South Pipeline Capacitor Bank	Planned	115 kV	**N**	2018
NV Energy	Dove - East Tracy 120 kV Line Reconductor	Planned	115 kV	**N**	2019
NV Energy	Dove Capacitor Bank	Planned	115 kV	**N**	2019
NV Energy	North Valley Road - Penny's Tap 120 kV line Uprate	Planned	115 kV	**N**	2018
NV Energy	Silver Lake 120 kV Capacitor Bank	Planned	115 kV	**N**	2021
NV Energy	Tracy - Patrick 120 kV Line Uprate	Planned	115 kV	**N**	2018
NV Energy	Turquoise Solar	Planned	115 kV	**N**	2018
NV Energy	Dixie Meadows I	Planned	230 kV	**N**	2020
NV Energy	East Tracy - Valmy 3422 Line Wavetrap Removal	Planned	345 kV	**N**	2019
NV Energy	Mira Loma Transformer #1 and #2 Rating Increase	Planned	345 kV	**N**	2018
NV Energy	Replace Wave Traps on Valmy-Coyote-Humboldt 345 kV Line	Planned	345 kV	**N**	2020
Sacramento Municipal Utility District	Carmichael 230 kV Shunt Capacitor	Planned	230 kV	**N**	2019
Sacramento Municipal Utility District	Franklin 230 kV Substation	Planned	230 kV	**N**	2018
Sacramento Municipal Utility District	Hurley - Procter 230 kV Line Re-conductor	Planned	230 kV	**N**	2018
Sacramento Municipal Utility District	Hurley 230 kV bus-tie breaker	Planned	230 kV	**N**	2020

Sponsor	Project Name	Development Status	Voltage	2016-2017 Study?	In-Service Date
Sacramento Municipal Utility District	Orangevale 230 kV Shunt Capacitor	Planned	230 kV	**N**	May, 2020
Western Area Power Administration - SNR	Install 230 kV Reactive Voltage Support	Planned	230 kV	**Y**	May, 2019
Western Area Power Administration - SNR	Reconductor Keswick-Airport-Cottonwood 230 kV Lines	Planned	230 kV	**Y**	May, 2019
Western Area Power Administration - SNR	Reconductor Olinda-Cottonwood #1 & #2 230 kV Lines	Planned	230 kV	**Y**	2020

Appendix B – Results of Reliability Assessment

Full results, including the local/single-system issues and transient stability results, are provided in Appendix B of the Needs Assessment Report.

Table 19: Multi-TO Results of Regional Reliability Assessment Contingency Analysis

Base Case PF	Disturbance(s) [Multiple if affected elements were the same]	Affected Element					Regional Need	Determination
		Owner/ Operator(s)	Affected Element	Value under (Worst) Disturbance	Limit	Issue		
HS	EPE's P1 ([redacted])	EPE	AMRAD 345kV Bus	[redacted]	[redacted]	High % V Decrease	NO	PNM, TSGT, & EPE: the issue is local in nature. The voltage deviation is largely representative of the radial nature of a small remote area off the BES leading to the characterization of this being a local problem. PNM has voltage support tentatively scheduled for 2023 that will address the excessive voltage drop in the area. It should be noted that this solution has been addressed in previous PNM planning cycles and does not result in customer voltages operating outside facility or service limits or a system operating near a voltage stability limit.
			AMRAD_B 345kV Bus	[redacted]			NO	
			ALA_5 115kV Bus	[redacted]			NO	
			HOLLOMAN 115kV Bus	[redacted]			NO	
			MAR 115kV Bus	[redacted]			NO	
			WHITE_SA 115kV Bus	[redacted]			NO	
		TSGT	BLAZER_T 115kV Bus	[redacted]			NO	
			C_CANYON 115kV Bus	[redacted]			NO	
			JARILLA1 115kV Bus	[redacted]			NO	
		PNM	ALAMOGCP 115kV Bus	[redacted]			NO	
			RUIDOSO 115kV Bus	[redacted]			NO	
			TULAROSA 115kV Bus	[redacted]			NO	
			GAVILAN 115kV Bus	[redacted]			NO	
				[redacted]	[redacted]	Low V	NO	

Figure 12. Frequency at All WestConnect Load Buses with WECC Voltage Criteria, for All Transient Stability Simulated Contingencies in Each Reliability Base Case

[redacted]

Figure 13. Per Unit Voltage at All WestConnect Load Buses with WECC Voltage Criteria, for All Transient Stability Simulated Contingencies in Each Reliability Base Case

Table 20. Summary of Transient Stability Simulations Which Show No Violations. The Unrestored Load & Tripped Generation Reported by The Simulations Is Acceptable Per TPL standards. [20] For the contingency definitions, refer to the Needs Assessment Report.

[redacted]

[20] *See TPL-001-4 references noted below:*

- *Note "b." in [TPL-001-4](): Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.*
- *Note "c." in [TPL-001-4](): Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.*

Appendix C – Results of Economic Assessment

Full results, including the local/single-system issues, are provided in Appendix C of the Needs Assessment Report.

Table 21: Multi-TO Results of Regional Economic Needs Assessment

Element Information		Congestion Hours (% Hrs) / Cost ($)		Regional Need	Determination
Owner/ Operator(s)	Branch/Path Name	2028 Base Case	50% Wheeling Charge Sensitivity Case		
TANC|WAPA-SNR|BPA|PACW|PGE|CAISO	P66 COI	69 (0.79%) / 3,795K	99 (1%) / 5,481K	No	TANC & WAPA-SNR: Congestion cost is low and hours are also low.
WAPA-RM|PSCO	SANJN PS-WATRFLW 345kV Line Ckt 1	74 (0.84%) / 2,209K	213 (2%) / 8,118K	No	WAPA-RM, PSCO, & TSGT: Investigation into the congestion shown for the San Juan PST's revealed a modeling error in how Path 31 (TOT2A) flows were calculated, allowing TOT2A to flow beyond its limit. After correcting the branch definition, Path 31 (TOT2A) congests in a direction (south-to-north) in which it has historically never flowed. This observation warrants further exploration in a future cycle.
BEPC|TSGT	SAWMILLCK-LAR.RIVR 230kV Line Ckt 1	4 (0.05%) / 941K	4 (0.05%) / 739K	No	BEPC & TSGT: Only 4 hours of congestion is very minor (<<1% of the year) and can be considered noise, and the cost is relatively small
WAPA-RM|TSGT|DG&T	P30 TOT 1A	8 (0.09%) / 828K	10 (0.11%) / 434K	No	TSGT & WAPA & PRPA: Only 8/10 hours of congestion is very minor (<<1% of the year) and can be considered noise

Element Information		Congestion Hours (% Hrs) / Cost ($)		Regional Need	Determination
Owner/ Operator(s)	Branch/Path Name	2028 Base Case	50% Wheeling Charge Sensitivity Case		
TSGT|EPE|PNM	P47 Southern New Mexico	42 (0.48%) / 690K	73 (0.83%) / 1,376K	No	PNM, EPE, & TSGT: congestion is not high enough to be identified as a need. The number of hours of congestion identified in the model simulation is de minimis and the vetting process gave rise to questions about the model results. There was not a high degree of confidence in the congestion results with respect to this path. This factor, coupled with the trivial number of hours of congestion produced in the model simulation, resulted in the conclusion that it did not give rise to an economic-driven regional transmission need.
BEPC|TSGT|PACE	DAVEJOHN-SAWMILLCK 230kV Line Ckt 1	3 (0.03%) / 490K	34 (0.39%) / 720K	No	BEPC & TSGT: Only 3 hours of congestion is very minor (<<1% of the year) and can be considered noise, and the cost is relatively small

Element Information		Congestion Hours (% Hrs) / Cost ($)		Regional Need	Determination
Owner/ Operator(s)	**Branch/Path Name**	**2028 Base Case**	**50% Wheeling Charge Sensitivity Case**		
NVE|LADWP	P32 Pavant-Gonder InterMtn-Gonder 230 kV	36 (0.41%) / 311K	38 (0.43%) / 298K	No	NVE & LADWP: 1. Modeling issue on Intermountain – Gonder 230kV Line (see comment for P29). 2. The observed congestion is in W-E direction, which has not been observed historically and thus is likely a modeling issue. Furthermore, the 235MW path 32 W-E rating is based on the "capacity need" and "flowability" & not the facility ratings or other reliability constraints; therefore, there's a clear potential for its increase in the future, which could be recommended to be pursued by the path owners. 3. The congestion is insignificant both by hours and by cost.
LADWP|NVE	INTERMT-GONDER 230kV Line Ckt 1	1 (0.01%) / 6K		No	NVE & LADWP: Modeling issue. Correct rating for Intermountain – Gonder 230kV Line #1 (402MVA, i.e., 382 MW in PCM sim) wasn't modeled.
TSGT|WAPA-RM	P36 TOT 3	2 (0.02%) / 3K	13 (0.15%) / 220K	No	TSGT & WAPA-RM: Only 2 or 13 hours of congestion is very minor (<<1% of the year) and can be considered noise
	Multi-Owner Congestion Cost:	**$9,270K**	**$17,390K**		

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