WestConnect Regional Transmission Planning

2024-25 Planning Cycle

Model Development Report

Approved by WestConnect Planning Management Committee on

December 18, 2024

Contents

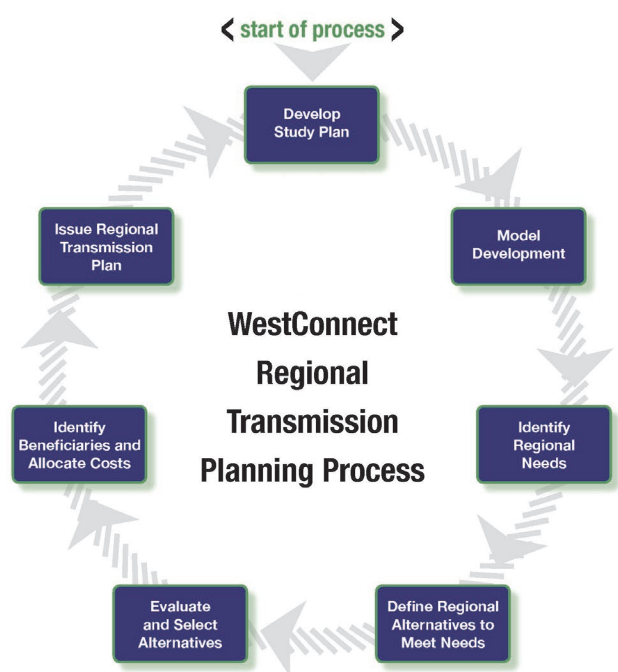
1.0 Introduction

The purpose of this report is to summarize the model development phase of the WestConnect 2024-25 Regional Planning Process. The Planning Subcommittee, which is responsible for developing the WestConnect regional models, has compiled this report to document major assumptions that have been incorporated into the models. The objective of model development is to support the overall purpose of the Regional Planning Process, which is to identify regional transmission needs and the more efficient or cost-effective solutions to satisfy those needs. The Planning Management Committee (PMC), which has decision-making authority over the overall WestConnect planning process, approves the regional models that are used during the transmission assessment. The PMC approved the base models described in this report on October 16, 2024. The results of the regional transmission assessment will be documented in the 2024-25 Regional Transmission Needs Assessment Report.

1.1 WestConnect Regional Transmission Planning Process

The development of regional models is the second step in the WestConnect Regional Transmission Planning Process (Planning Process). The Planning Process was developed for compliance with Federal Energy Regulatory Commission (FERC) *Order No. 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, (Order No. 1000).[1] The planning process is performed biennially, beginning in even-numbered years, and consists of seven steps as outlined in **Figure 1** .

Figure 1: WestConnect Regional Transmission Planning Process



Additional details of the Planning Process can be reviewed in the WestConnect Regional Planning Process Business Practice Manual (BPM) posted to the WestConnect website (link). Readers can access

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

the text of the FERC Order No. 1000 compliance documentation on the WestConnect website (link) and are encouraged to consult the compliance documentation and BPM for additional process information.

1.2 WestConnect 2024-25 Regional Study Plan

The first step in the planning process is the development of a Regional Study Plan. The 2024-25 WestConnect Study Plan (Study Plan) was approved by the PMC on March 20, 2024. The Study Plan identifies the scope and schedule of planning activities to be conducted during the planning cycle. The Study Plan also describes the models to be developed in the model development portion of the Planning Process.

2.0 Model Development Overview

During the second and third quarters of 2024, the Planning Subcommittee developed the regional models to be used in the identification of regional transmission needs for the 2024-25 Planning Process. Two types of studies are performed in the Planning Process: Reliability (power flow or PF) and Economic (Production Cost Model or PCM) studies. WestConnect conducts an assessment of regional transmission needs using models developed for the 2034 timeframe, approximately 10 years into the future. WestConnect may also perform information-only scenario studies, as outlined in the Study Plan, which are designed to evaluate alternate but plausible futures.

Table 1 lists the reliability and economic models developed for the 2024-25 cycle for the purposes of identifying regional transmission needs.

Table 1: WestConnect Regional Needs Assessment Planning Models

WestConnect Base Case Name	Case Description	Seed Case(s)
2034 Heavy Summer Base Case	Summer peak load conditions, with typical flows throughout the Western Interconnection.	WECC 2034 Heavy Summer 1 Planning Base Case (34HS1)
2034 Light Spring Base Case	Light load conditions during spring months of March, April, or May with solar and wind serving a significant but realistic portion of the Western Interconnection total load.	WestConnect Heavy Summer Base Case
2034 Base Case PCM	Business-as-usual, expected-future case with (1) median load, (2) median hydro conditions and (3) representation of resources consistent with TOLSO-approved resource plans as of March 2024.	WECC 2034 Anchor Data Set (ADS)

Study Area

The WestConnect planning process evaluates the regional transmission needs solely for the WestConnect planning region, which is defined as the combined footprints of signatories to the Planning Participation Agreement (PPA) within the Transmission Owner (TO) Member Sector. A list of Members participating in the WestConnect 2024-25 planning process is available on the WestConnect website (link). WestConnect Members and participants updated the models, as described in more detail below, to create a more accurate representation of the WestConnect footprint in each case.

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, 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 a reasonable level of model consistency and align planning assumptions as closely as possible. Details about the types of information received from external participants (e.g., planning regions, other TOs) are included in the model descriptions in the sections that follow.

3.0 Reliability Model Descriptions

The information in this section summarizes each reliability model and provides details about the major assumptions incorporated into the reliability cases. Note that the cases have detailed change records documenting specific data changes made to the original starting point case. This report summarizes each case and does not document each specific assumption.

2034 Heavy Summer Base Case

Description: The case is designed to evaluate the Base Transmission Plan under peak summer loading conditions. The seed case was the WECC 2034 Heavy Summer 1 Planning Base Case (34HS1), which was approved October 25, 2023. The 34HS1 case was updated with the latest topology (i.e. generator, load, and transmission) information from WestConnect participants while still representing typical heavy summer load conditions and generator dispatch.

Generation: Within WestConnect, the case features a dispatch of 37,143 MW of thermal, 6,034 MW of hydro, 8,645 MW of wind, 15,564 MW of solar, and 3,606 MW of Battery Storage resources.

Load: The aggregate coincident peak load level for the WestConnect footprint is 65,928 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. The intent was to continue these assumptions during its case development.

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

2034 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 the WestConnect total load. The seed case was intended to be the WECC 2034 Light Spring 1 Specialized Case (34LSP1-S). However, since the case was delayed, the WestConnect 2034 Heavy Summer powerflow case wase used to create the Light Spring model.

Generation: Within WestConnect, the case features a dispatch of 20,995 MW of thermal, 3,423 MW of hydro, 6,678 MW of wind, 12,794 MW of solar, and 506 MW of Battery Storage resources.

Load: The total WestConnect load in the case is 39,357 MW, which is 55% of the WestConnect peak conforming load in the WestConnect 2034 Heavy Summer Base Case. The load levels represent the system from 1200 to 1400 hours MDT during spring months of March, April, and May.

Transmission: Identical transmission assumptions as the 2034 Heavy Summer Base Case – see above for details.

Contingency Definitions, Dynamic Data, and Other Considerations

The regional reliability models identified as “base cases” are used to identify regional transmission needs. Scenarios will be limited to identifying regional opportunities. Both assessments are conducted using contingency definitions that were designed to limit the analysis to identify regional transmission issues.

An initial list of automatically created single branch (N-1) outages 230 kV and higher was created and participants also submitted multi-element contingency definitions not automatically created. Participants reviewed the outage list and (a) identified invalid single branch outages to remove, and (b) identified other contingencies not included in the list that could potentially flag regional transmission issues.

The dynamic data needed to support the transient stability simulations was developed by first taking the dynamic data from the WECC seed cases and appending additional or revised dynamic data per participant submittals.

The Planning Subcommittee also considered the following when developing the cases:

- **Operating Procedures** – Any special operating procedures required for compliance with NERC reliability standards are considered and included in the power flow (PF) cases.
- **Protection Systems** – The impact of protection systems including Remedial Action Scheme (RAS) required for compliance with NERC reliability standards will be included in the PF cases.
- **Control Devices** – Any special control devices required will be included in the PF 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 four review drafts of the base reliability models.

4.0 Economic Model Descriptions

The reliability and economic base models maintained consistent electric topologies (e.g., matching load, generator, and branch models) throughout their development.

2034 Base Case

Description: The case is a production cost model (PCM) dataset designed to represent a likely, median 2034 future. The WECC 2034 ADS Version 1 (V1), released on July 5, 2024, PCM served as the seed case for the WestConnect economic model 2034 Base Case. That case was then reconciled with the WestConnect 2032 PCM and the case updated as needed during Quarters 2 and 3 of the 2024-25 planning cycle. The WestConnect PCM was then compared with the WECC 2034 ADS PCM Version 2 (V2), which was released on July 29, 2024. These updates were consistent with the process described below, which focuses on what updates were completed with the WECC 2034 ADS PCM V2 dataset as the reference.

Generation:

- The WestConnect latest generator-specific modeling was developed and used to update the dataset. This 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 2** provides a summary by fuel category of the generation updates made to the WECC 2034 ADS PCM V2. The positive (or negative) values represent the capacity (in MWs) and resulting generated energy (in GWh) added to (or removed from) the WECC 2034 ADS PCM V2 in order to create the WestConnect 2034 Base Case PCM.

Table 2: Generation Differences from WECC 2034 ADS PCM V2
Percentages are in reference to the totals in the WECC 2034 ADS PCM V2

Fuel Category	Differences, WestConnect less WECC PCM				Annual Generation (GWh)		Capacity (MW)	
	Annual Generation		Capacity					
	GWh	%	MW	%	WestConnect	WECC	WestConnect	WECC
Coal	18,776	38.73%	290	2.62%	48,486	29,709	8,004	7,714
Gas	53,244	20.52%	-1,654	-1.55%	259,434	206,190	106,585	108,239
Water	-889	-0.33%	134	0.16%	266,416	267,305	84,257	84,123
Uranium	-4,735	-10.56%	-1,013	-19.57%	44,825	49,560	5,177	6,190
Solar PV	30,131	10.93%	1,890	1.52%	275,713	245,581	124,008	122,118
Solar Thermal	80	2.56%	0	0.00%	3,128	3,047	1,167	1,167
Wind	-29,625	-15.10%	-16,996	-25.04%	196,172	225,797	67,886	84,882
Bio	1,547	12.22%	-3	-0.14%	12,654	11,108	2,239	2,242
Geothermal	129,	0.53%	-142	-4.19%	24,434	24,305	3,395	3,537
BESS	-22,819	-31.38%	2,968	3.97%	72,725	95,543	74,778	71,809
Other	3,728	47.02%	1	0.01%	7,928	4,200	6,375	6,374
Overall	**49,568**		**-14,527**		**1,211,915**	**1,162,347**	**483,869**	**498,396**

- The behind-the-meter distributed generation (BTM-DG) assumptions were retained from the WECC 2034 ADS PCM V2which modeled them on the resource-side. **Table 3** summarizes the amount of BTM-DG by area represented in the WestConnect 2034 Base Case PCM.

Table 3: Behind-the-Meter Distributed Generation

Area Name	Capacity (MW)	Generation (GWh)	Capacity Factor (%)	Dispatch at Area Peak Load (% of Capacity)
AZPS	2,888	5,483	20%	31%
BANC	915	1,600	20%	47%
EPE	332	645	22%	45%
IID	109	208	22%	55%
LDWP	800	1,455	21%	61%
PNM	409	781	22%	33%
PSCO	1,721	2,896	20%	46%
SRP	264	501	22%	68%
TEPC	682	1,325	22%	29%
WACM	28	50	19%	60%
WALC	47	92	20%	84%

Load: WestConnect Members carefully reviewed the load forecasts provided with the WECC 2034 ADS PCM V2.0 (derived from the WECC 2024 Loads and Resources Data Collection Process) and made no modifications internal to WestConnect. No changes were made to the load forecasts for areas outside of WestConnect. **Figure 2** and **Figure 3** 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 BAAs rather than specific utilities. The "PF Load" – load in the WestConnect 2034 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 below-listed considerations.

- The PF model focuses on an extreme or more-stressed-than-normal system condition whereas the economic model 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 shapes do not include the impact of BTM-DG whereas the PF model loads may or may not contain BTM-DG.

Figure 2: WestConnect PCM Areas' Annual Demand (GWh) in WestConnect 2034 Base Case (PCM)

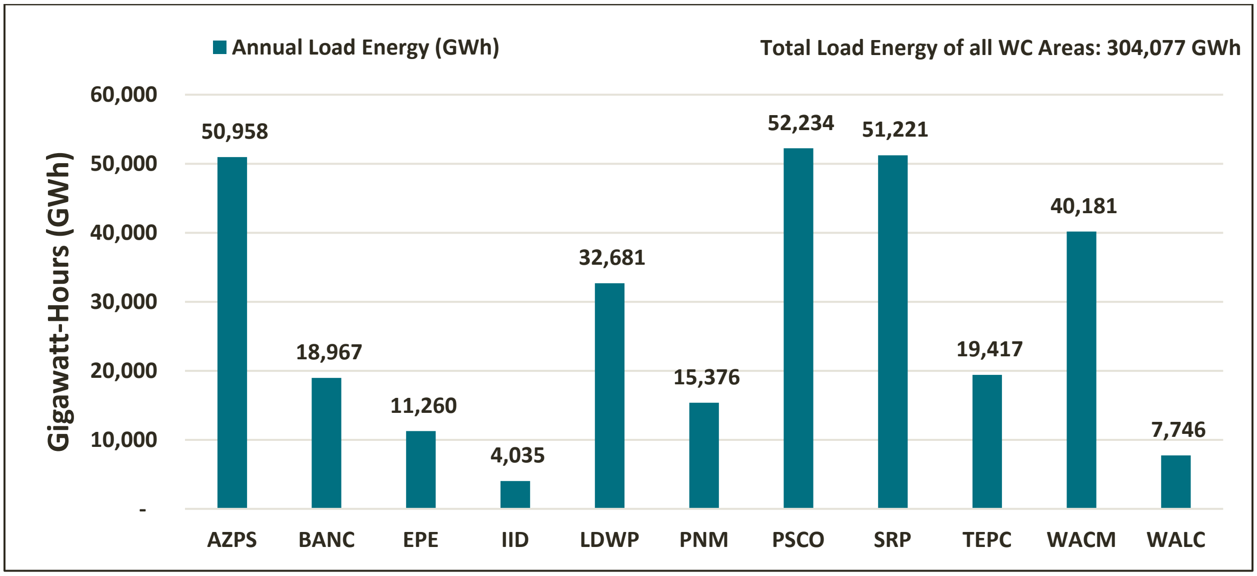
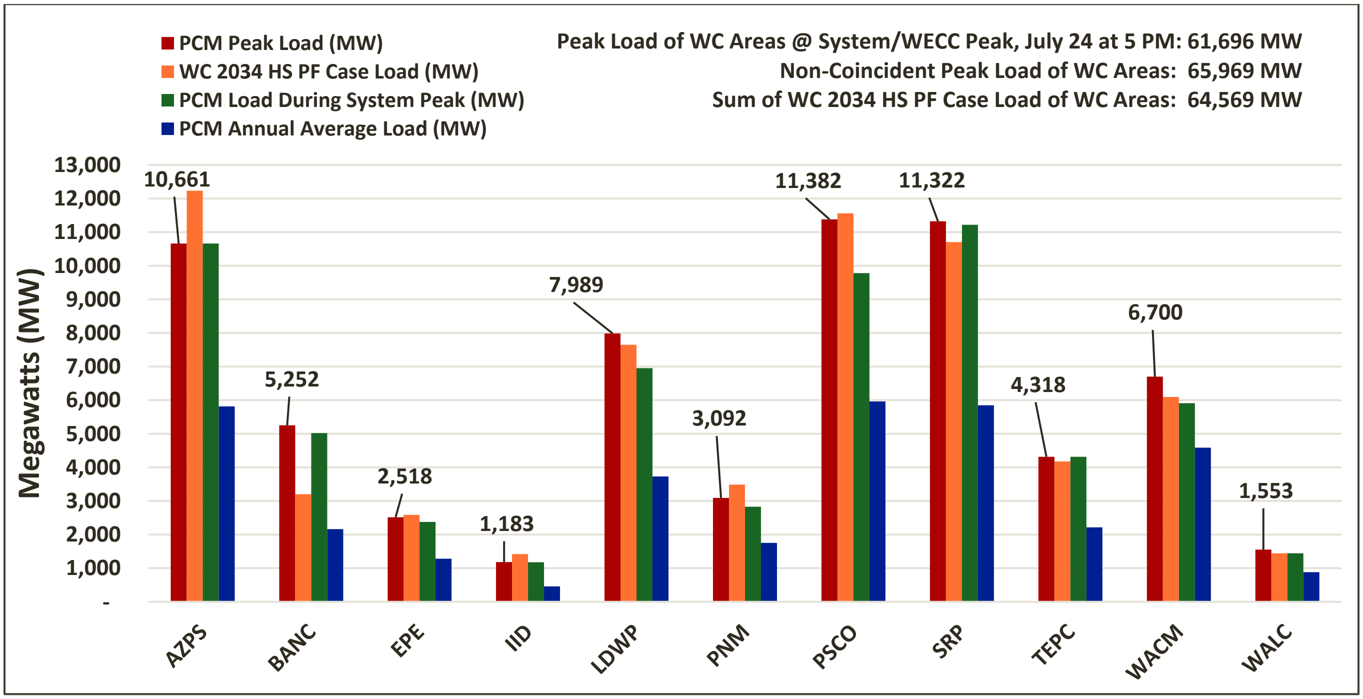


Figure 3: WestConnect PCM Areas' Peak Demand, Demand During System Peak, and Average Demand (MW) in WestConnect 2034 Base Case (PCM), shown with the Demand of the 2034 Heavy Summer Base Case



Transmission: The WECC 2034 ADS PCM V2.0 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.

- Branch monitoring in the WestConnect footprint: Monitored transmission elements greater than 90 kV in WestConnect, greater than 200 kV outside of WestConnect, and all phase shifting transformers (PST) (phase angle regulators, or PAR).
- Updated interface definitions and ratings.

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 2034 Heavy Summer Base Case.
- Fuel price forecasts and emission rate assumptions were pulled from the WECC 2034 ADS PCM V1.0 and subsequently updated with new fuel prices approved by the WECC PCDS and included in the WECC 2034 ADS PCM V2.0. These assumptions are included in Appendix A.
- Reserve requirements modeling was updated from what was represented in the WECC 2034 ADS PCM V2.0. These assumptions are summarized below:

- The reserves included in the production cost modeling include spinning reserves, regulation and load following reserves, and frequency response reserves. In modeling these reserve requirements, GridView sets aside generating capacity within a given footprint sufficient to meet the hourly reserve requirement, subject to eligible unit's ramping rates, which vary by technology type.
- Contingency Reserves (Spinning Reserves):
  - Modeling spinning reserves in the production cost model is typically done in tiers to best capture the sharing of reserves across the system. The total hourly reserve requirement is carried at the Reserve Sharing Group level, as applicable to a given BA, with sub-constraints layered on at the BA-level to ensure that a portion of the total reserves are carried locally at the participating BA-level.
  - Consistent with BAL-002-WECC-2, the spinning reserve requirement is set to 3% of hourly load for a given reserve sharing group area. Assumed that NW and SW BA's locally meet 25% and 90% (respectively) of their contingency reserve requirement based on previous WECC models citing WECC EDT Phase 2 Benefits Analysis Methodology (October 2011 Revision).
  - The Northwest Reserve Sharing Group (Western Power Pool – formerly Northwest Power Pool) was modified to include new entrants that joined in Q4 2023.
  - Assumed a 50/50 split between spinning and non-spinning reserves, leading to 1.5% load and 1.5% generation requirement at the RSG-level and a 0.375% load and 0.375% generation requirement at the underlying BA-level
- The model did not include modeling for non-spinning requirements since neither dataset currently has quick-start generator designations. Flexibility Reserves:
  - Regulation Ancillary Service (AS) assumptions shown in **Table 4** were based on the CPUC Unified Resource Adequacy and Integrated Resource Plan Inputs and Assumptions – Guidance for Production Cost Modeling and Network Reliability Studies, February 20, 2019 (link).
  - Load Following AS assumptions shown in **Table 4** were based on the CPUC SERVM model for their 2018-19 IRP.

Table 4. Reserve Requirement and Ancillary Service Assumptions in WestConnect 2034 Base Case

Reserve Requirement/AS	Ramping Response Requirement (minutes)	Requirement (at RSG level)	What it represents	What can contribute
Contingency/Spinning	10	1.5% of load and generation	Actions that can be taken to maintain system balance during an unexpected loss of generation or transmission	• Dispatchable thermals (excludes biomass/geothermal/nuclear/co-gen) generators subject to available headroom and ramp rate • Storage and hydro resources as constrained by headroom
Regulation Up	10	1.0% of load, 0.5% of generation	Security against unexpected loss of generation.	• Dispatchable thermals (excludes biomass/geothermal/nuclear/co-gen) generators subject to available headroom and ramp rate • Storage and hydro resources as constrained by headroom

Reserve Requirement/AS	Ramping Response Requirement (minutes)	Requirement (at RSG level)	What it represents	What can contribute
Contingency/Spinning	10	1.5% of load and generation	Actions that can be taken to maintain system balance during an unexpected loss of generation or transmission	• Dispatchable thermals (excludes biomass/geothermal/nuclear/co-gen) generators subject to available headroom and ramp rate • Storage and hydro resources as constrained by headroom
Regulation Down				***Same as Reg Up contributors*** **+** ***Wind & Solar (no more than 20% of Maximum Capacity)***
Load Following Up	20	1.5% of load and generation	Capacity reserved to accommodate load and/or renewable forecast error and sub-hourly deviations in forecasts. Not an actual product in most areas – proxy product to maintain reliability.	***Same as Reg Up contributors***
Load Following Down	20	1.5% of load and generation		***Same as Reg Down contributors***

- Frequency Response AS assumptions were based on system-wide values from the [CAISO SB350 Study Assumptions]This and the related assumptions are summarized in **Table 5**.

Table 5. Frequency Response Ancillary Service Assumptions in WestConnect 2034 Base Case

AS	Ramping Response Requirement (minutes)	Requirement (at RSG level)	What it represents	What can contribute
Frequency Response	1	385/1,753	• Response to frequency changes within one minute • 50% of constraint assumed to be met by hydro and renewable resources (full constraint is 2505 MW)	• Storage, coal, and gas only • Limit gas-fired contribution to 8% of their capacity/headroom (via Ancillary Max Contribution)

- The below listed thermal generation modeling assumptions were taken from the WECC Intertek report dated May 12, 2020, "Update of Reliability and Cost Impacts of Flexible Generation on Fossil-fueled Generators for Western Electricity Coordinating Council."
  - Cost per start: used the warm, median values
  - Ramping limits
  - Minimum up and down times
  - Variable Operations and Maintenance (VOM) cost
- Wheeling charges, which represent the transmission service charges associated with transferring power between areas, were revised from the original WECC 2034 ADS PCM V2.0 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. The WECC 2034 ADS PCM

V2 also contained additional wheeling charges associated with modeling carbon emission charges applicable to California, Oregon, and Washington, and these rates were updated. Planning Subcommittee 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 representing the California Global Solutions Act (AB 32) modeling and supplemental updates to the WECC 2034 ADS PCM V2 by the WECC Production Cost Data Subcommittee (PCDS) were implemented. Refer to the "Carbon emission charges updates" topic below for more details.
    - The WECC 2034 ADS PCM V2 included tiered wheeling constraints – zero wheeling charges up to a MW threshold and non-zero wheeling charges thereafter – on the Nevada, Idaho, Montana, and Canadian borders of the NW footprint as well as the PACE/APS border, and these wheeling charges were retained.

- Nomograms and transmission interfaces were modeled by starting with the WestConnect 2032 PCM, pulling in updates based on the WECC 2034 ADS PCM V2, 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. The "SMUD Op Nomogram", "EPE Balance", and "TEP Local Gen" were nomograms added to the model to commit local generation. In addition, other nomograms were added for generating plants containing a combination of solar PV and battery storage to ensure their combined output did not exceed their contractual limits, and others were added to ensure the battery storage only charged via the solar PV output for certain plants.
- Carbon emission charges updates: Details are below, in 2024 dollars.
    - California: Updated to \$64/MT based on the WECC PCDS recommendation (Final 2023 CEC IEPR GHG Allowance Price Projections) (California Carbon Price Assumption)
        - In addition, the reduced emission factor for NW imports was also updated to 0.0174 MT CO_2e/MWh based on CARB Mandatory GHG Reporting - Asset Controlling Supplier. This affected the above-mentioned updates to the emission-related wheeling charges.
    - Oregon: Added emissions allowance per WECC PCDS recommendation at \$64/MT (same as California) with updates planned following WECC stakeholder feedback.
    - Washington: Added emissions allowance per WECC PCDS recommendation at \$64/MT (same as California) with updates planned following WECC stakeholder feedback.
    - Alberta: Updated to \$37/MT based on WECC PCDS recommendation.
    - British Columbia: Updated to \$37/MT based on WECC PCDS recommendation

4.1 Economic Sensitivity Models

Models were developed for sensitivity studies on the 2034 Base Case economic model to better understand whether regional transmission congestion may be impacted by adjusting certain input assumptions subject to significant uncertainty. The sensitivity analysis is intended to make relatively minor adjustments that would still remain within the expected future framework of the base models. The Planning Subcommittee determined four sensitivities of interest, and their assumptions are described below.

2034 High Load Sensitivity Case

Description: Scaled up the hourly load shape of BAAs within WestConnect so their annual peak and energy is a 100%+ percentage of their value in the 2034 Base Case:

- All WestConnect Areas: 120% of both peak and energy

2034 Low Hydro Sensitivity Case

Description: Replaced hydro modeling with WECC 2001-based hydro modeling data developed by WECC in conjunction with their 2024 Common Case PCM dataset.

2034 High Gas Price Sensitivity Case

Description: Increased all the natural gas prices to 140% of their value in the 2034 Base Case.

2034 System-Wide Carbon Emission Cost Sensitivity Case

Description: Applied CO_2 emission charges to all generators in WECC via the below updates to the 2034 Base Case:

- Applied a reduced carbon emission price of $20/MT ($9/MWh) for all generation in California, Oregon, and Washington so the net change for units internally to these States remain the same ($20/MT + $44/MT = $64/MT)
- Kept the Alberta and British Columbia carbon emission prices unchanged at $37/MT
- Removed the carbon emission wheeling charges from all California borders except with Baja California (CFE)
- Applied a carbon emission price of $44/MT (2024 dollars) for all other generation in the WECC system.

5.0 Modeling Public Policy

Enacted public policies are considered early in the planning process and are incorporated into the base models (both reliability and economic) through the roll-up of local TO plans and their associated load, resource, and transmission assumptions. In this context, enacted public policies are state or federal laws or regulations, meaning enacted statutes (i.e., passed by the legislature and signed by the executive) and regulations promulgated by a relevant jurisdiction, whether within a state or at the federal level. Enacted public policies that are subject to significant uncertainty within the planning horizon are also considered, but only as a part of a scenario.

Table 6 summarizes the enacted public policies that were driving local transmission projects reflected in regional base economic and PF models. This table was originally in the WestConnect 2024-25 Regional Study Plan and has been scaled down in this report to show the enacted public policies driving local transmission needs. After their review of the models, each TOLSO member provided confirmation that the WestConnect 2034 economic and PF models met these public policies' conditions for the study year 2034 to the extent a plan for compliance with the enacted public policies was completed prior to the model development phase of the WestConnect 2024-25 planning cycle.

Table 6. Enacted Public Policies Considered and/or Incorporated into 2034 WestConnect Planning Models

Public Policy Requirement	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 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
California SB100	Requires Investor-owned utilities (IOUs) and municipal utilities to meet a 60% renewable portfolio standard ("RPS") by 2030
California SB350	Requires IOUs and municipal utilities to meet a 50% RPS by 2030 and requires the establishment of annual targets for energy efficiency savings
Colorado HB 18-1270 ("Energy Storage Procurement Act")	Directs the Commission to develop a framework to incorporate energy storage systems in utility procurement and planning processes. See C.R.S. § 40-2-201, et seq. The legislation broadly addresses resource acquisition and resource planning, and transmission and distribution system planning functions of electric utilities. Energy storage systems may be owned by an electric utility or any other person. Benefits include increased integration of energy into the grid; improved reliability of the grid; a reduction in the need for increased generation during periods of peak demand; and, the avoidance, reduction, or deferral of investment by the electric utility
Colorado HB 19-1261 and SB 1261 ("GHG Reduction Bills")	HB 19-1261 requires the Air Quality Control Commission ("AQCC") to promulgate rules and regulations for statewide greenhouse gas ("GHG") pollution abatement. Section 1 of SB 1261 states that Colorado shall have statewide goals to reduce 2025 greenhouse gas emissions by at least 26%, 2030 greenhouse gas emissions by at least 50%, and 2050 greenhouse gas emissions by at least 90% of the levels of statewide greenhouse gas emissions that existed in 2005. A clean energy plan filed by a utility is deemed approved if the plan demonstrates an 80% reduction by 2030.
Colorado HB10-1001	Established Colorado Renewable Energy Standard ("RES") to 30% by 2020 for IOUs (Xcel & Black Hills)
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 SB 18-009 ("Energy Storage Rights Bill")	Protects the rights of Colorado electricity consumers to install, interconnect, and use energy storage systems on their property without the burden of unnecessary restrictions or regulations and without unfair or discriminatory rates or fees.

Public Policy Requirement	Description
Colorado SB 19-077 (“Electric Vehicles Bill”)	The bill enables a regulatory approval process for electric utilities to invest in charging facilities and provide incentive rebates; thus, the investments and rebates may earn a return at the utility’s authorized weighted-average cost of capital. Where approved, the costs for the investments and rebates may be recovered from all customers of the electric utility similar to recovery of distribution system investments. Natural gas public utilities may provide fueling stations for alternative fuel vehicles as non-regulated services only.
Colorado SB 19-236 ("PUC Sunset Bill”)	The primary purpose of this bill is to reauthorize the CPUC, by appropriations, for a seven-year period to September 1, 2026. Reauthorization is required by the sunset process. Additionally, the bill carries numerous requirements for utilities and the CPUC to achieve an affordable, reliable, clean electric system. Included in the bill are requirements to reduce the qualifying retail utility’s carbon dioxide emissions associated with electricity sales to the qualifying retail utility’s electricity customers by eighty percent from 2005 levels by 2030, and that seeks to achieve providing its customers with energy generated from one-hundred-percent clean energy resources by 2050. The bill also subjects co-ops to Colorado Public Utility Commission rulemaking.
Colorado SB13-252	Requires cooperative utilities to generate 20% of their electricity from renewables by 2020
Colorado SB21-072	This bill requires electric transmission utilities in Colorado to join an organized wholesale market (“OWM”) by January 1, 2030, provided that the OWM meets certain criteria set forth in the statute. This bill also creates the Colorado Electric Transmission Authority, a governmental entity that is authorized to independently develop and finance transmission projects.
Colorado HB21-1266	This bill is a broad policy measure to promote environmental justice in disproportionately impacted communities through the creation of an Environmental Justice Task Force. The bill requires wholesale generation and transmission cooperatives to file with the Public Utilities Commission a Clean Energy Plan to achieve 80% emissions reductions by 2030.
Colorado SB 21-246	The primary purpose of this bill is to direct the approval of plans for the electrification of buildings that use fossil fuel-based systems through existing demand side management programs.
Colorado HB21-1238	The primary purpose of this bill is to update the PUC’s rules and decision-making process with respect to natural gas demand-side management programs including the use of the Social Cost of Carbon and Social Cost of Methane.
Colorado SB21-272	The primary purpose of this bill is to update the PUC’s rules and decision-making process to better incorporate the impacts and benefits to underserved or disproportionately impacted communities and groups including workforces impacted by generation acquisition and retirement. Other requirements include how utilities finance resources or investments, the retirement of renewable energy credits, and the inclusion of the Social Cost of Carbon in resource planning decisions.
Colorado SB23-016	This legislation updates the State of Colorado’s statutory greenhouse gas emissions goals (HB19-1261) to add a 65% reduction goal for 2035, an 80% reduction goal for 2040, and a 90% reduction goal for 2045, as well as amending the state’s 2050 goal from a 90% reduction goal to 100%.
Public Policy Requirement: California SB 1020	• Description: Under SB 1020, at least 90% of all retail sales of electricity in California must be supplied by eligible renewable and zero-carbon energy resources by December 31, 2035. By December 31, 2040, 95% of all retail electricity sales must be supplied by eligible renewable and zero-carbon energy resources. Additionally, all electricity resources by the end of 2035.

Public Policy Requirement	Description
Executive Order 14057 (EO 14057), Catalyzing Clean Energy Industries and Jobs Through Federal Sustainability (Dec. 8, 2021)	The President's executive order directs the federal government to use its scale and procurement power to achieve five ambitious goals: • 100 percent carbon pollution-free electricity ("CFE") by 2030, at least half of which will be locally supplied clean energy to meet 24/7 demand; • 100 percent zero-emission vehicle ("ZEV") acquisitions by 2035, including 100 percent zero-emission light-duty vehicle acquisitions by 2027; • Net-zero emissions from federal procurement no later than 2050, including a Buy Clean policy to promote use of construction materials with lower embodied emissions; • A net-zero emissions building portfolio by 2045, including a 50 percent emissions reduction by 2032; and Net-zero emissions from overall federal operations by 2050, including a 65 percent emissions reduction by 2030.
New Mexico Efficient Use of Energy Act	Require utilities to include cost-effective energy efficiency ("EE") and demand response ("DR") programs in their resource portfolios and establish cost-effectiveness as a mandatory criterion for all programs
New Mexico Energy Transition Act (2019 SB 489)	Subject to the Reasonable Cost Threshold ("RCT"), the Energy Transition Act defines renewable energy requirements that are a percentage of a utility's retail energy sales and the type of utility: • By 2020, 20% for public utilities and 10% for cooperatives • By 2025, 40% for public utilities and cooperatives • By 2030, 50% for public utilities and cooperatives • By 2040, 80% for public utilities with provisions associated with carbon free generation • 100% carbon-free by 2045 for public utilities and by 2050 for cooperatives
New Mexico Title 17-Public Utilities and Utility Services Part 574 Applications to Expand Transportation Electrification	"The purpose of this rule is to implement Section 62-8-12 NMSA 1978, applications to expand transportation electrification, and to bring to New Mexico the economic development and environmental benefits of expanded electrification of the State's transportation modalities and transportation infrastructure. Three-year plan with a planning outlook for two-years beyond the proposed three-year plan"

Public Policy Requirement	Description
New Mexico Title 17-Public Utilities and Utility Services Part 588 Grid Modernization Grant Program	Grid modernization roadmap and grant program is focused on improvements to electric distribution or transmission infrastructure, including related data analytics equipment, that are designed to accommodate or facilitate the integration of renewable electric generation resources with the electric distribution grid or to otherwise enhance electric distribution or transmission grid reliability, grid security, demand response capability, customer service or energy efficiency or conservation and includes:(a) advanced metering infrastructure that facilitates metering and providing related price signals to users to incentivize shifting demand;(b) intelligent grid devices for real time system and asset information at key substations and large industrial customers;(c) automated control systems for electric distribution circuits and substations;(d) communications networks for service meters;(e) distribution system hardening projects for circuits and substations designed to reduce service outages or service restoration times;(f) physical security measures at key distribution substations; (g) cybersecurity measures;(h) energy storage systems and microgrids that support circuit-level grid stability, power quality, reliability or resiliency or provide temporary backup energy supply;(i) electrical facilities and infrastructure necessary to support electric vehicle charging systems;(j) new customer information platforms designed to provide improved customer access, greater service options and expanded access to energy usage information; and (k) other new technologies that may be developed regarding the electric grid.
New Mexico Advanced Clean Car Rule	Starting in calendar year 2026, 43% of all new passenger cars and light-duty trucks shipped to New Mexico auto dealerships by national auto manufacturers must be zero emission vehicles. Similarly, beginning in calendar year 2026, 15% of all new commercial heavy-duty trucks shipped to New Mexico auto dealerships by national auto manufacturers must be zero emission vehicles. These percentages gradually increase over time.
SRP Sustainable Energy Goal	Reduce the amount of CO_2 emitted per megawatt-hour (MWh) by 65% from 2005 levels by 2035 and by 90% by fiscal year 2050.
Texas RPS	Texas RPS requires a total renewable capacity of 5,880 MW (which has already been achieved) by 2025 be installed in the state which is in turn converted into a renewable energy requirement. The renewable energy requirements are allocated to load serving entities based on their amount of retail energy sales as a percent of the total Texas energy served
Texas Substantive Rule 25.181 (Energy Efficiency Rule)	Require utilities to meet certain energy efficiency targets

Renewable Energy Check

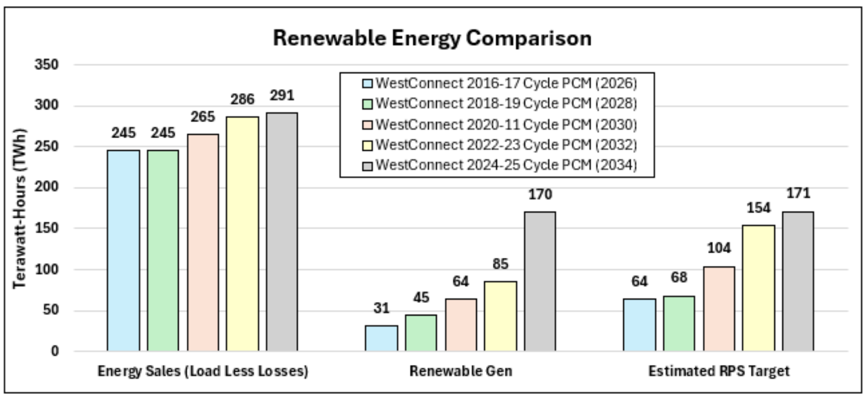
During the model development process, there was interest in seeing if the WestConnect economic models indicated a renewable energy penetration trajectory consistent with enacted public policies. To address this interest, WestConnect conducted a high-level accounting and comparison of the energy sales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

1. Annual generation consisting of Bio, Geothermal, Solar PV, Solar Thermal, & Wind were summed for each PCM Load Area as "Renewable Energy" (RE). The RE for the SRP PCM Area also included specific hydro and a combined solar & battery generation that was counted as RE based on the SRP plan to meet its public policy requirements, but hydro was otherwise not counted as RE. The Reserve Capacity Distribution settings in the 2034 Base Case PCM were used to allocate resources to their appropriate remote load area.

2. The "Energy Sales" from each PCM Load Area was determined by taking the "Served Load Includes Losses", subtracting losses, adding the magnitude of negative generation (e.g., pumping 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 "Renewable Energy" was divided by the "Energy Sales" as the "RE as % of Energy Sales" for the 2034 Base Case PCM and compared with these same values from the 2032 Base Case PCM and the 2030 Base Case PCM from the previous two cycles (to allow for comparison between cycles).

Only the single year results from each study year were used in the RE check and no banking of renewable energy from other years was assumed. **Figure 4** shows the results of the renewable energy check, which the Planning Subcommittee determined show a reasonable trend towards WestConnect members meeting enacted public policies. **Table 7** shows the losses and load, including losses used to calculate the WestConnect Energy Sales.

Figure 4. Sum of Energy Sales, Renewable Generation, and Overall RE as % of Energy Sales Based on Single-Year Results from the 2034 Base Case PCM and the Base Case PCM's from previous cycles



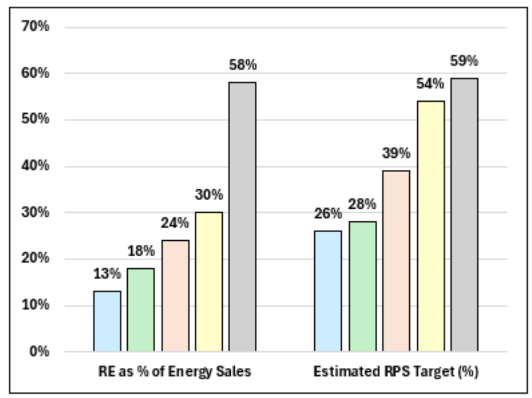


Table 7. BAA Losses and Served Load Including Losses used to calculate the WestConnect Energy Sales in the Renewable Energy Check

BAA	Estimated Losses (MWh)	Served Load Includes Losses (MWh)
AZPS	1,484,715	52,442,396
BANC	879,741	19,847,191
EPE	412,715	11,672,739
IID	128,466	4,163,605
LDWP	1,662,608	34,344,010
PNM	519,662	15,895,189
PSCO	1,526,414	53,760,901
SRP	1,460,360	52,681,826
TEPC	582,520	19,417,345
WACM	606,357	40,786,927
WALC	312,739	8,059,103

Total	**9,576,298**	**313,071,232**

6.0 Summary of Regional Base Transmission Plan

WestConnect created the regional base transmission plan at the beginning of the 2024-25 Planning Process to establish the transmission network topology that is reflected in the regional planning models for the 10-year timeframe and evaluated in the regional needs assessments. The base transmission plan consists of the "planned" incremental transmission facilities included by TOs in local transmission plans, as well as regional transmission facilities identified in previous regional transmission plans that are not subject to reevaluation.[2] It also includes any assumptions member TOs may have made with regard to other incremental regional transmission facilities in the development of their local transmission plans. "Conceptual" transmission projects are not included in the base transmission plan.

The base transmission plan was developed using project information collected via the WestConnect Transmission Plan Project List (TPPL), which is the tool that WestConnect uses for a project repository for TO member and TO participant local transmission plans as well as independently developed projects. The TPPL data used for the 2024-25 Planning Process was based on updates submitted as of February 2024, with subsequent updates to the data made by members through the Model Development Process. The full list of approved regional base transmission plan projects – prior to updates made during model development – can be found in Appendix B of the 2024-25 Regional Study Plan.

6.1 2024-25 Regional Base Transmission Plan Projects

The 2024-25 Base Transmission Plan project list includes 260 planned transmission projects that consist of 116 new or upgraded transmission lines, 116 substations, and 28 other planned projects. These projects span a reported total of 3,105 miles and add up to a total capital investment of $8,498.8 Million. **Table 8** and **Table 9** summarize the Base Transmission Plan by project type and voltage.

Table 8. Regional Base Plan Projects by Type, Reported Mileage, and Reported Investment ($K), based on TPPL data

Type of Project	Number of Projects	Length (Miles)	Planned Investment ($K)
Substation	116	-	$2,133,581
Transmission Line	116	3,105	$5,363,210
Other	28	-	$1,001,975
Total	260	3,105	$8,498,766

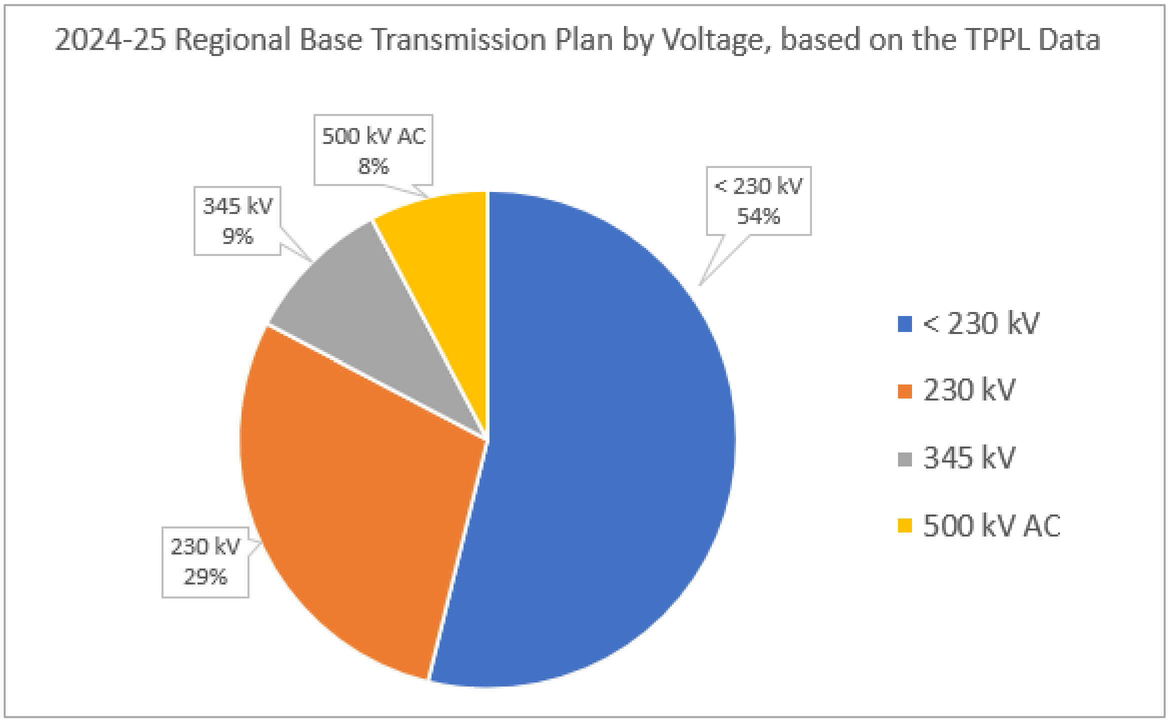
[2] *There are not any re-evaluation projects in the 2024-25 Base Transmission Plan.*

Table 9. Number of TOLSO Regional Base Transmission Plan Projects by Voltage and TOLSO, based on TPPL data

TOLSO	< 230 kV	230 kV	345 kV	500 kV AC	TBD	Total
Arizona Electric Power Cooperative	1	1	1	-	-	3
Arizona Public Service	-	13	2	5	-	20
Black Hills Energy	5	-	-	-	-	5
Black Hills Power	-	-	-	-	-	0
Cheyenne Light Fuel and Power	10	6	-	-	-	16
Colorado Springs Utility	8	3	-	-	-	11
Deseret Power	-	-	-	-	-	0
El Paso Electric Company	56	-	14	-	-	70
Imperial Irrigation District	2	2	-	-	-	4
Los Angeles Department of Water and Power	3	14	1	5	-	23
Platte River Power Authority	1	2	-	-	-	3
Public Service Company of Colorado/ Xcel Energy	3	4	2	-	-	9
Public Service Company of New Mexico	-	-	2	-	-	2
Sacramento Municipal Utility District	1	4	-	-	-	5
Salt River Project	1	9	-	9	-	19
Transmission Agency of Northern California	-	-	-	-	-	0
Tri-State Generation and Transmission Association	8	4	1	-	-	13
Tucson Electric Power	31	7	2	1	-	41
Western Area Power Administration - DSW	3	2	-	-	-	5
Western Area Power Administration - RMR	7	4	-	-	-	11
Western Area Power Administration - SNR	-	-	-	-	-	0
Total Projects	140	75	25	20	0	260

Review of the of the 2024-25 regional base transmission plan projects showed that 54% were classified as below 230 kV, 29% were classified as 230 kV, 9% were classified as 345 kV; and 8% were classified as the 500 kV. **Figure 5** illustrates the percentage breakout for the 2024-25 regional base transmission plan projects by voltage.

Figure 5. 2024-25 Regional Base Transmission Plan Transmission Line by Voltage, based on the TPPL data



6.2 Updates to the 2022-23 Regional Transmission Plan Projects

Review of the 2022-23 Regional Study plan base transmission projects showed several projects have gone into service, started construction, or have had other updates to their development status. The full list of 2022-23 regional base transmission plan projects can be found in the 2022-23 Regional Transmission Plan, Appendix B. Updated information provided to the TPPL showed that 32 projects were placed in service, 25 projects were updated to under construction development status, 10 projects were updated to conceptual development status and 14 projects were withdrawn from the 2022-23 Regional Transmission Plan. The remaining 2022-23 regional base transmission plan projects continued as planned projects in the 2024-25 regional base transmission plan. Additionally, 116 new planned projects were added to the TPPL and included in the 2024-25 regional base transmission plan. **Table 10** and **Table 11** summarize the updates to the 2022-23 regional base transmission plan projects.

Table 10. 2022-23 Regional Base Transmission Plan Projects In-Service, Reported Mileage, and Reported Investment ($K), based on the TPPL data

Type of Project	Number of Projects	Length (Miles)	Planned Investment ($K)
Substation	8	-	$42,057
Transmission Line	10	145	$160,630
Transmission Line and Substation	9	92	$213,172
Transformer	3	-	$5,500
Other	2	-	$10,500
Total Projects	**32**	**237**	**$431,859**

Table 11. 2022-23 Planned Regional Transmission Plan Projects Withdrawn or Changed to Conceptual by Voltage, based on the TPPL data

New Status	Type	< 230 kV	230 kV	345 kV	Total
Conceptual	Substation	4	-	1	5
	Transmission Line	3	-	-	3
	Transmission Line and Substation	1	-	1	2
	Transformer	-	-	-	0
	Other	-	-	-	0
Withdrawn	Substation	3	-	-	3
	Transmission Line	4	1	-	5
	Transmission Line and Substation	-	-	-	0
	Transformer	2	-	1	3
	Other	3	-	-	3
	Total	**20**	**1**	**3**	**24**

6.3 Regional Base Transmission Plan Projects by State

The 2024-25 regional base transmission plan has projects in multiple states in the WestConnect footprint and in some instances, projects span multiple states. **Table 12** summarizes the number of projects by states with aggregated capital investment.

Table 12. 2024-25 Regional Base Transmission Plan Projects by State, Reported Mileage, and Reported Investment ($K), based on the TPPL data

State	Number of Projects	Length (Miles)	Planned Investment ($K)
Arizona	87	745	$1,724,868
California	29	394	$2,011,180
Colorado	47	861	$2,449,321
Nebraska	2	-	$10,883
Nevada	1	13	$82,000
New Mexico	22	57	$492,165
Texas	47	144	$879,488
Wyoming	18	281	$360,299
Multiple	7	611	$488,563
Total Projects	**260**	3,105	$8,498,766

Review of the 2024-25 regional base transmission plan projects by state showed that many (33%) of the projects are located in Arizona, 18% of the projects are located in Colorado, 11% are located in California, and 3% span multiple states. The remaining projects are located in in Nebraska, Nevada, New Mexico, Texas, and Wyoming.

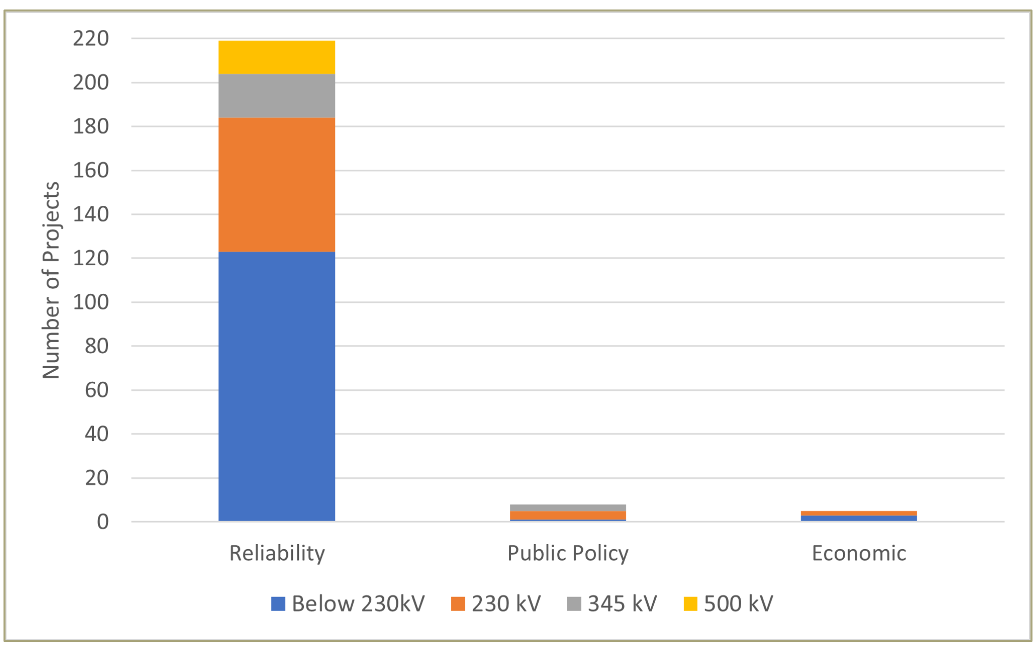
6.4 Regional Base Transmission Plan Projects by Driver

Review of the 2024-25 regional base transmission planned projects showed that nearly all of projects (84%) are primarily driven by reliability needs, 4% are primarily driven by public policy, and 2% are primarily economic driven. **Table 13**, and **Figure 6** below break out the projects by length, planned investment costs, and voltage.

Table 13. 2024-25 Regional Base Transmission Plan Projects by Driver and Voltage, Reported Mileage, and Reported Investment ($K), based on the TPPL data

Driver (Primary/Secondary)	< 230kV	230 kV	345 kV	500 kV	TBD	Total
Reliability	116	55	19	11	-	201
Reliability/Public Policy	6	6	1	4	-	17
Public Policy	1	3	4	-	-	8
Public Policy/Reliability	-	2	-	-	-	2
Other	13	7	1	5	-	26
Economic	3	1	-	-	-	4
Economic/Reliability	-	1	-	-	-	1
Reliability/Economic	1	-	-	-	-	1
Total Projects	140	75	25	20	0	260

Figure 6. 2024-25 Regional Base Transmission Plan Number of Projects by Primary Driver and Voltage, based on the TPPL data



7.0 Scenario Studies

Three scenario studies are included in the Study Plan, which WestConnect will perform on an "information-only" basis. Details regarding the process used to develop the scenarios and their purpose in the planning process is located in the 2024-25 Study Plan and provided below for quick reference:

Decreased Facility Rating Scenario: The purpose of the Decreased Facility Rating Scenario is to evaluate the impacts of an overall decrease in facility ratings by a given percentage. The thought behind the proposal is that transmission facility ratings can be adversely impacted by several factors, including higher ambient temperatures. The purpose of this study is to provide a relative view of how decreased facility ratings might impact reliability. The development of these models and the analyses they will undergo are described in more detail below.

Extreme Cold Weather Scenario: The purpose of the Extreme Cold Weather Scenario is to evaluate the reliability of the WestConnect footprint for a 10-year, heavy winter condition, with higher-than-expected loads and reduced resource availability that would be the result of extremely cold weather throughout the region. The thought behind the request is that an extreme cold weather event will result in higher loads than expected, combined with shortages of resources. For example, historical cold weather conditions have led to shortages in natural gas availability. Renewable resources could also be unavailable. As a result, such a scenario could have an impact on the reliability of the system. The scenario may provide valuable information into system import or export capabilities, and potential reliability issues, including how to serve load, which could result in the need for transmission or resource enhancements.

20-Year Increased Renewable Scenario: The purpose of this scenario is to perform regional reliability and economic assessments using models that represent a 20-year timeframe with aggressive renewable energy penetration. A 20-year scenario can help WestConnect members understand transmission-related issues associated with a 20-year future that attempts to capture current policy requirements throughout the Planning Region, as well as public policy requirements that are likely to change in the 20-year planning horizon and are expected to trend towards more aggressive objectives for carbon reduction. The study can provide both quantitative and qualitative perspectives of how the WestConnect transmission system could be affected, and the magnitude of transmission buildout that might be required to mitigate reliability and economic issues.

As stated in the Study Plan, the Planning Subcommittee will need to develop specific study methodologies for the scenarios at the beginning of 2025.

8.0 Next Steps

The Planning Subcommittee compiled this report to document major assumptions that have been incorporated into the base regional models and their sensitivity cases. Both draft and final versions of the regional models are made available to PMC Members and others that have executed the WestConnect Confidentiality Agreement.

The regional needs assessment was conducted in parallel with the later stages of the model development process and will culminate with a report from the Planning Subcommittee to the PMC. That report will document the findings of the regional assessments and the determination of regional transmission needs for the current planning cycle.

The scenario assessment will be conducted after the regional needs assessment and will culminate with a report from the Planning Subcommittee to the PMC. That report will document the findings of the scenario assessments and propose recommendations on any potential regional *opportunities*.

9.0 Appendix A: 2034 Base Case (PCM) Assumptions

This appendix contains select modeling assumptions reflected in the WestConnect 2034 Base Case.

Table 14. Annual Average of Fuel Price Assumptions (2024$/mmBtu) in WestConnect 2034 Base Case PCM

Fuel Name	Annual Average of Fuel Prices (2024$/mmBtu)	Fuel Name	Annual Average of Fuel Prices (2024$/mmBtu)
Bio_Agri_Res	0.608	Coal_Springerville3-4	2.518
Bio_Blk_Liquor	0.011	Coal_Springerville	2.518
Bio_Landfill_Gas	2.543	Coal_Sunnyside	1.591
Bio_Other	3.263	Coal_UT	2.377
Bio_Sludge_Waste	0.001	Coal_Valmy	3.222
Bio_Solid_Waste	0.001	Coal_WY_SW	1.951
Bio_Wood	3.241	Coal_Wygen	1.075
Coal_Alberta	1.411	Coal_Wyodak	1.426
Coal_Apache	3.236	Geothermal	0.001
Coal_AZ	2.867	NG_AB	4.346
Coal_Battle_River	1.414	NG_AZ North	5.516
Coal_Boardman	1.869	NG_AZ South	5.370
Coal_Bonanza	2.653	NG_BC_Sumas	4.259
Coal_CA_South	3.328	NG_CA PGaE BB	6.791
Coal_Centennial_Hard	1.133	NG_CA PGaE LT	8.010
Coal_Centralia	2.150	NG_CA SDGE	6.946
Coal_Cholla	2.836	NG_CA Rosarito	5.381
Coal_CO_East	2.006	NG_CA SoCalGas	6.952
Coal_CO_West	2.006	NG_CA Kern	5.212
Coal_Colstrip	1.313	NG_Colorado_Cheyenne	4.635
Coal_Comache	1.668	NG_Colorado_WhiteR	3.838

Fuel Name	Annual Average of Fuel Prices (2024$/mmBtu)	Fuel Name	Annual Average of Fuel Prices (2024$/mmBtu)
Coal_Coronado	3.091	NG_ID_Opal	5.102
Coal_Craig	2.556	NG_MT	4.635
Coal_Dave_Johnston	1.189	NG_NM North	5.350
Coal_Dry_Fork	0.906	NG_NM South	5.457
Coal_Escalante	1.867	NG_NV North	5.355
Coal_Four_Corners	3.586	NG_NV South	5.186
Coal_Hayden	2.493	NG_OR_Sumas	5.529
Coal_Hunter	2.081	NG_OR Malin	5.238
Coal_Huntington	2.234	NG_TX West	5.375
Coal_ID	2.266	NG_UT_Opal_Kern	5.086
Coal_Intermountain	2.645	NG_WA_King	4.916
Coal_Jim_Bridger	3.166	Oil_DistFuel_L	13.042
Coal_LRS	1.313	Oil_DistillateFuel_2	26.262
Coal_Naughton	2.807	Petroleum Coke	1.586
Coal_Neil_Simpson	1.076	Propane	26.498
Coal_NM	3.046	Purchased_Steam	1.125
Coal_Pawnee	1.473	Refuse	0.001
Coal_Rawhide	1.629	Synthetic Gas	7.865
Coal_San_Juan	2.147	Uranium	0.788
Coal_Springerville1-2	2.518	Waste_Heat	0.001

Table 15. Fuel Emission Rates by Type (lb/mmBtu) in WestConnect 2034 Base Case PCM

Fuel Groups or Fuel Name	Fuel Emission Rates by Type (lb/mmBtu)			Fuel Groups or Fuel Name	Fuel Emission Rates by Type (lb/mmBtu)		
	SO_2	NO_X	CO_2		SO_2	NO_X	CO_2
"Bio" Fuels	0.00579	0.17663	130	NG_AZ_North-South	0.0006	0.08	117
"NG" Fuels	0.0006	0.08	117	NG_AZ_Opal Kern	0.0006	0.08	117
Coal_Alberta	0.35	0.5	205	NG_BC_Sumas	0.0006	0.08	117
Coal_Apache	0.571	0.459146	205	NG_BC_Westcoast	0.0006	0.08	117
Coal_AZ	0.571	0.459146	205	NG_Cal_Kern	0.0006	0.08	117
Coal_Battle_River	0.35	0.5	205	NG_Cal_PG&E BB	0.0006	0.08	117
Coal_CA_South	0.330309	0.382413	204	NG_Cal_PG&E LT	0.0006	0.08	117
Coal_Centennial_Hard	0.691174	0.552889	205	NG_Cal_Rosarito	0.0006	0.08	117
Coal_Centralia	0.621817	0.288333	205	NG_Cal_SDG&E	0.0006	0.08	117
Coal_Cholla	0.571	0.459146	205	NG_Cal_SoCalGas	0.0006	0.08	117
Coal_CO_East	0.691174	0.552889	205	NG_Colorado_Cheyenne	0.0006	0.08	117
Coal_CO_West	0.691174	0.552889	205	NG_Colorado_WhiteR	0.0006	0.08	117
Coal_Colstrip	0.691147	0.552889	205	NG_Idaho_Opal	0.0006	0.08	117
Coal_Comache	0.691174	0.552889	205	NG_Montana	0.0006	0.08	117
Coal_Coronado	0.571	0.459146	205	NG_Nevada_North	0.0006	0.08	117
Coal_Craig	0.691174	0.552889	205	NG_Nevada_South	0.0006	0.08	117
Coal_Escalante	0.330309	0.382413	204	NG_New Mexico_North	0.0006	0.08	117
Coal_Four_Corners	0.571	0.459146	205	NG_New Mexico_South	0.0006	0.08	117
Coal_Hayden	0.691174	0.552889	205	NG_Oregon_Malin	0.0006	0.08	117
Coal_ID	0.691174	0.552889	205	NG_Oregon_OR and WA	0.0006	0.08	117
Coal_Intermountain	0.691174	0.552889	205	NG_Oregon_Sumas	0.0006	0.08	117
Coal_Jim_Bridger	0.07	0.1	205	NG_Oregon_Washington	0.0006	0.08	117
Coal_LRS	0.07	0.1	205	NG_Utah_Opal Kern	0.0006	0.08	117
Coal_Naughton	0.07	0.1	205	NG_Washington_King	0.0006	0.08	117
Coal_NM	0.330309	0.382413	204	NG_Washington_Oregon	0.0006	0.08	117
Coal_Springerville	0.571	0.459146	205	NG_Washington_Sumas	0.0006	0.08	117
Coal_Sunnyside	0.69117	0.552889	205	NG_West Texas_Waha	0.0006	0.08	117
Coal_UT	0.691174	0.552889	205	NG_Wyoming	0.0006	0.08	117
Coal_Valmy	0.112818	0.3485	203	Oil_DistillateFuel_2	0.00579	0.176636	156.3
Coal_WY_SW	0.07	0.1	205	Oil_DistillateFuel_L	0.0006	0.116	161.3
Coal_Wyodak	0.07	0.1	204	Petroleum Coke	0	0.028	224
DefaultFuel	0.35	0.276	200	Propane	0.00579	0.176636	123.11
Geothermal	0.00579	0.176636	20	Purchased_Steam	0	0.028	224
NG_Alberta_NOVA	0.0006	0.08	117	Refuse	0.00579	0.176636	130
NG_AZ/CAL_Blythe	0.0006	0.08	117	Synthetic Gas	0.0006	0.08	117

NG_AZ_North	0.0006	0.08	117	Waste_Heat	0	0	0

Table 16. WestConnect Inter-Area Wheeling Rate Assumptions in WestConnect 2034 Base Case PCM. Non-public wheeling charges provided by WestConnect members are excluded from this table: WACM export wheel.

From Zone	To Zone	From PCM Area(s)	To PCM Area(s)	Wheeling Charge ($/MWh)	
				Peak Hours	Off-Peak Hours
AB_AESO	BC_BCHA	AESO	BCHA	2.338	2.338
AB_AESO	NW_NWMT+	AESO	NWMT, WAUW	5.2	5.2
BC_BCHA	AB_AESO	BCHA	AESO	9.915 up to 590 MW, then 3.131	9.915 up to 590 MW, then 3.131
BC_BCHA	NW_BPAT+	BCHA	BPAT, CHPD, DOPD, GCPD, SCL, TPWR	0 up to 1571 MW, then 7.755	0 up to 1571 MW, then 7.755
BS_IPCO	NW	IPFE	AVA, BPAT, CHPD, DOPD, GCPD, PACW, PGE, SCL, TPWR	0 up to 2160 MW, then 2.912	0 up to 2160 MW, then 2.912
BS_IPCO	SW_NVE	IPFE	NEVP	4.64	2.59
BS_PACE	<Any>	PAID	<Any>	6.902	3.283
CA_BANC+	<Any>	BANC, TIDC	<Any>	2.3	2.3
CA_CFE	CA_CISO	CFE	CIPB, CIPV, CISC, CISD, VEA	12.2	12.2
CA_CISO	<Any>	CIPB, CIPV, CISC, CISD, VEA	<Any>	11.5	11.5
CA_IID	<Any>	IID	<Any>	3.06	3.06
CA_LDWP	<Any>	LDWP	<Any>	9.31	4.42
NW	BS_IPCO	AVA, BPAT, CHPD, DOPD, GCPD, PACW, PGE, SCL, TPWR	IPFE	0 up to 1080 MW, then 2.103	0 up to 1080 MW, then 2.103
NW	NW_NWMT+	AVA, BPAT, CHPD, DOPD, GCPD, PACW, PGE, SCL, TPWR	NWMT, WAUW	0 up to 1215 MW, then 2.103	0 up to 1215 MW, then 2.103
NW_BPAT+	<Any>	BPAT, CHPD, DOPD, GCPD, SCL, TPWR	<Any>	3.99	3.99
NW_BPAT+	BC_BCHA	BPAT, CHPD, DOPD, GCPD, SCL, TPWR	BCHA	0 up to 1201 MW, then 2.103	0 up to 1201 MW, then 2.103
NW_BPAT+	SW_NVE	BPAT, CHPD, DOPD, GCPD, SCL, TPWR	NEVP	0 up to 120 MW, then 2.103	0 up to 120 MW, then 2.103

From Zone	To Zone	From PCM Area(s)	To PCM Area(s)	Wheeling Charge ($/MWh)	
				Peak Hours	Off-Peak Hours
NW_NWMT+	<Any>	NWMT, WAUW	<Any>	4.56	4.56
NW_NWMT+	BS_PACE	NWMT, WAUW	PAID	0 up to 192 MW, then 5.166	0 up to 192 MW, then 5.166
NW_NWMT+	NW	NWMT, WAUW	AVA, BPAT, CHPD, DOPD, GCPD, PACW, PGE, SCL, TPWR	0 up to 2016 MW, then 5.166	0 up to 2016 MW, then 5.166
NW_PACW	<Any>	PACW	<Any>	6.902	3.283
NW_PGE	<Any>	PGE	TH_Malin	1.02	1.02
RM_PSCO	<Any>	PSCO	<Any>	8.238	4.753
SW_AZPS	<Any>	AZPS	<Any>	7.338	4.102
SW_AZPS	BS_PACE	AZPS	PAID	0 up to 300 MW, then 7.338	0 up to 300 MW, then 4.102
SW_EPE	<Any>	EPE	<Any>	5.95	3.40
SW_NVE	<Any>	NEVP	<Any>	7.09	4.28
SW_PNM	<Any>	PNM	<Any>	6.042	5.448
SW_SRP	<Any>	SRP	<Any>	4.36	2.48
SW_TEPC	<Any>	TEPC	<Any>	7.1	3.686
SW_WALC	<Any>	WALC	<Any>	1.811	1.811

Table 17. Names of Monitored Interfaces in WestConnect 2034 Base Case PCM

Monitored Interface Names	
_IPP DC pole balancing	P62 Eldorado-McCullough 500 kV Line
Delisted-P22 Southwest of Four Corners	P65N Pacific DC Intertie (PDCI)
Delisted-P23 Four Corners 345/500 Qualified Path	P65S Pacific DC Intertie (PDCI)
Delisted-P50 Cholla-Pinnacle Peak	P66 COI
Delisted-P51 Southern Navajo	P71 South of Allston
FlowMonitor_18009_180514_1	P73 North of John Day
P01 Alberta-British Columbia	P75 Hemingway-Summer Lake
P02 Alberta-Saskatchewan	P76 Alturas Project
P03 Northwest-British Columbia	P77 Crystal-Allen
P03East Side NW-BC	P78 TOT 2B1
P03West Side NW-BC	P79 TOT 2B2
P04 West of Cascades-North	P80 Montana Southeast
P05 West of Cascades-South	P81 Southern Nevada Transmission Interface (SNTI)
P06 West of Hatwai	P82 TotBeast
P08 Montana to Northwest	P83 Montana Alberta Tie Line
P14 Idaho to Northwest	P84 Harry Allen - Eldorado (HAE)
P15 Midway-LosBanos	P45 SDG&E-CFE
P16 Idaho-Sierra	P46 West of Colorado River (WOR)
P17 Borah West	P47 Southern New Mexico (NM1)
P18 Montana-Idaho	P48 Northern New Mexico (NM2)
P19 Bridger West	P49 East of Colorado River (EOR)
P20 Path C	P52 Silver Peak-Control 55 kV
P24 PG&E-Sierra	P54 Coronado-Silver King 500 kV
P25 PacifiCorp/PG&E 115 kV Interconnection	P55 Brownlee East
P26 Northern-Southern California	P58 Eldorado-Mead 230 kV Lines
P27 Intermountain Power Project DC Line	P59 WALC Blythe - SCE Blythe 161 kV Sub

Monitored Interface Names	
P28 Intermountain-Mona 345 kV	P60 Inyo-Control 115 kV Tie
P29 Intermountain-Gonder 230 kV	P61 Lugo-Victorville 500 kV Line
P30 TOT 1A	P89 SNTI + HAE
P31 TOT 2A	Palo Verde East
P32 Pavant-Gonder InterMtn-Gonder 230 kV	SeriesRctrLine_10231_12038_1
P33 Bonanza West	SeriesRctrLine_12008_12007_1
P35 TOT 2C	SeriesRctrLine_30560_30527_1
P36 TOT 3	SeriesRctrLine_30692_30690_1
P37 TOT 4A	SeriesRctrLine_30700_30527_1
P38 TOT 4B	SeriesRctrLine_30700_30697_1
P39 TOT 5	SeriesRctrLine_34727_34700_1
P40 TOT 7	SeriesRctrLine_34742_34704_1
P41 Sylmar to SCE	SeriesRctrLine_60275_60278_1
P42 IID-SCE	SeriesRctrLine_73414_78664_1