10-Year Regional Transmission Plan

Plan Summary

September 2011

Approved by the WECC Board of Directors on September 22, 2011.

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Executive Summary

The Western Electricity Coordinating Council (WECC) 10-Year Regional Transmission Plan (Plan) is an Interconnection-wide perspective on 1) expected future transmission and generation in the Western Interconnection, 2) what transmission capacity may be needed under a variety of futures, and 3) other related insights. The objective of the Plan is to provide information to stakeholders for their decision-making processes regarding where and when to build new transmission or take other related actions to help ensure the Western Interconnection is reliable, low-cost, efficient, and environmentally sound. In support of this objective, WECC's analyses are aimed toward:

- understanding transmission system needs over a broad range of potential futures;
- recognizing the potential economic benefits of transmission expansion, and;
- identifying transmission additions that, if foregone or delayed, will result in diminished opportunities to realize infrastructure benefits over a likely range of futures.

The Plan is informational in nature and is intended to advise and guide, rather than instruct. WECC does not have authority or jurisdiction over the construction of transmission lines, nor does WECC have any authority or jurisdiction over siting, permitting, or cost-allocation.

The Transmission Expansion Planning Policy Committee (TEPPC), a WECC Board of Directors (WECC Board) committee, guides the Regional Transmission Expansion Planning (RTEP) process that was used to create the Plan. RTEP is funded, in part, by a grant from the U.S. Department of Energy (DOE). The RTEP process is a bottom-up process with information flowing to TEPPC from stakeholders throughout the Western Interconnection. WECC would like to express its sincere appreciation to the many individuals and organizations that have contributed to the Plan. The volunteers who comprised the RTEP committees and workgroups have been fundamental in assuring that the best information was made available, comprehensive analysis was performed, and thorough review was conducted.

The Plan represents the continuing evolution of WECC's planning activities. This is WECC's first Interconnection-wide transmission plan and was produced in the using a broad stakeholder process. The Plan's limitations are based on the modeling capabilities, granularity of assumptions, and level of detail of the analyses performed.

The following are key assumptions regarding load, generation, and transmission that are germane to the observations and recommendations described in the Plan.

- The Plan assumes all 44 regionally-significant transmission projects identified in the Foundational Projects List will be completed by 2020. These projects add roughly 5,500 miles of transmission lines to the Western Interconnection.
- The Plan assumes retired and added generation will be sufficient to obtain full compliance with enacted State Renewable Portfolio Standards (RPS) and Once-Through-Cooling (OTC) regulations in California.
- The Plan assumes that enacted energy efficiency (EE) and Demand-Side Management (DSM) programs will be fully realized.

Given these assumptions, there are key regional transmission insights in the Plan.

- There are a number of regional transmission projects (further described in Section 4.1), coupled with changes to renewable generation assumptions, that have the potential to reduce the cost of meeting the RPS by accessing renewable resources that are located remote to major load centers.
- The assumed transmission additions provide sufficient transmission capacity in the Plan's Expected Future network to enable the Western Interconnection to meet its load and RPS requirements over the next 10-year planning period.[1]
- Two transmission paths – Montana to Northwest and the Pacific-Tie Paths – merit further evaluation for possible upgrades or expansion based on the levels of utilization and congestion that were observed in the Plan analyses. The future evaluation of these and other paths should consider impacts on reliability, system costs, economic benefits, market demand, and environmental considerations.

Expanding on these insights, the Plan includes the following observations and recommendations based on the analyses performed and stakeholder input.

1. *Cost-effective remote renewable resources – Section 4.1*

Some long-distance transmission to access remote renewable resources appears to be cost-effective when compared to some of the local renewable generation assumed in the Plan's Expected Future. Based on the high level of analysis performed, results from the resource relocation plus transmission expansion alternatives evaluated as part of the 10-year planning studies suggest total cost savings result under the alternative resource futures when compared with generation assumed in the Expected Future case.

2. *Montana to Northwest (Path 8) – Section 4.2*

The utilization of and congestion on the Montana to Northwest transmission path (Path 8) remain consistently high and increase under a variety of conditions (e.g., renewable generation relocation in Montana) analyzed in the 10-year planning studies. WECC recommends consideration by decision-makers for transmission upgrades or other mitigating measures that relieve congestion on Path 8 as renewable or other types of generation are expanded in Montana.

3. *Pacific-Tie Paths (Paths 65, 66) – Section 4.3*

The utilization of and congestion on the Pacific DC Intertie (Path 65) and California-Oregon Intertie (Path 66) continue to increase under most conditions analyzed in support of the Plan. WECC recommends consideration by decision-makers for transmission upgrades or other mitigating measures that relieve congestion on Paths 65 and 66.

4. *Operational impacts of variable generation– Section 4.4*

All of the cases analyzed in 10-year planning studies had high levels of variable generation. This caused significant and unprecedented levels of conventional generation ramping and cycling in the production cost models (PCM) used to complete the studies. WECC recommends

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[1] The lines listed on the Foundational Projects List do not necessarily address local reliability issues.

that future transmission and resource planning studies at all levels include a comprehensive review of variable integration issues. The review should also include an identification of how recent-related activities (e.g., energy imbalance market, intra-hour scheduling) can reduce operational impacts of variable generation.

5. *Planning cooperation – Section 4.5*

WECC recommends decision-makers accept the challenges of increased regional cooperation in transmission planning and development. WECC recognizes that integrated resource planning (IRP), RPS statues, generation procurement, and DSM policies are state- and provincial-centered. However, results presented in the Plan suggest there are opportunities for regional transmission and renewable resource development that should not be overlooked as states implement their own energy policies. Local and state jurisdictions should consider the compatibility of these opportunities with pertinent energy policies so as not to forego potential economic and environmental benefits that may accrue to their ratepayers.

6. *Environmental and cultural considerations in planning processes – Section 4.6*

As part of the RTEP project, the Scenario Planning Steering Group (SPSG) Environmental Data Task Force (EDTF) conducted a case study of selected transmission projects. The task force interviewed dozens of stakeholders to further understand how environmental information might be incorporated into regional transmission planning. The EDTF created a classification of land areas describing four tiers of suitability with respect to environmental and cultural constraints and sensitivities. It also provided recommendations on how these tiers can be incorporated into future RTEP processes. The EDTF produced an environmental and cultural data catalog for use in transmission planning processes.

7. *Water resource impacts on the future generation mix – Section 4.7*

The Western Governors' Association (WGA), along with the Western States Water Council and a consortium of national laboratories conducted a case study in which they compared water withdraw and consumption of various RTEP study cases. In future RTEP cycles, the WGA will provide information on water supply constraints, drought, and climate change in order to assist WECC in evaluating the impacts and options for electric generation in transmission planning activities.

8. *Future regional transmission planning processes – Section 4.8*

Great strides have been made recently in regional planning processes, but opportunities to improve the RTEP process exist. TEPPC intends to make the following enhancements to the RTEP process.

- Define a common set of key questions to be answered in the next set of regional transmission plans. This will be accomplished through discussions and other forums with utilities, policy-makers, utility regulators, permitting agencies, and other key stakeholders.
- Develop a list of questions regarding proposed transmission projects to better understand the project purpose and other parameters of the stages of transmission project development, and post the information to WECC's Transmission Project Information Portal.

- Expand WECC's analytic capabilities and activities to assure the future regional transmission plans continue to support stakeholders' needs.
- Encourage greater stakeholder participation in defining load, generation, and transmission assumptions used to construct regional transmission planning studies. Identify and evaluate the challenges of integrating the variable generation assumed in the Plan and identify possible options to address the challenges.

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1 Preface

From its inception, the electric power industry has recognized that using transmission to interconnect large groups of generators and loads makes it makes it possible to substantially reduce the cost and increase the reliability of serving the needs of consumers. Transmission interconnections grew steadily during the 20th Century until about 1979, when the electric power transmission networks in North America took on the characteristics and topology they have today. Sharing resources within an interconnection makes it possible to capture energy diversity across a wide area. Being the largest and most geographically diverse interconnection, the Western Interconnection has:

- usage diversity — varying amounts of use by consumers across an hour, a day, a week, or a season;
- production diversity — energy from hydro, wind, solar, geothermal, biomass, nuclear, and fossil-fired generation.

Leveraging diversity through a transmission-enabled interconnection has both reliability and economic value.

Transmission planning activities in the Western Interconnection serve to address the future needs of the transmission system. The wide ranges of climate, consumer demographics, and distances between loads and resources require division as well as coordination among the planning duties. These planning activities are divided by geographic reach and by planning-time horizons.

Transmission project development, driven by retail Load-Serving Entities' (LSE) resource decisions, is accomplished in various ways depending on the project developer, the purpose of the project, and the location of the proposed facility. Transmission planning activities serve the project development process by providing key information regarding system needs and the impact of proposed projects that, in turn, inform the entity making the project financing, siting, and regulatory approval decisions.

2 Introduction

The Western Electricity Coordinating Council (WECC) 10-Year Regional Transmission Plan (Plan) is a Western Interconnection-wide perspective. The Plan provides information on an Expected Future Western Interconnection, what transmission capacity may be needed under a variety of plausible futures, and other insights.

The objective of the Plan is to provide information to stakeholders for their decision-making processes regarding where and when to build new transmission or take other related actions to help ensure the Western Interconnection is reliable, low-cost, efficient, and environmentally sound.

The Transmission Expansion Planning Policy Committee (TEPPC), a WECC Board committee, guides the Regional Transmission Expansion Planning (RTEP) process used to create the Plan. The RTEP process used to identify planning needs in a 10-year timeframe, described in the TEPPC Planning Protocol, is a bottom-up process with information flowing to TEPPC from stakeholders throughout the Western Interconnection. RTEP is funded, in part, by a grant from the U.S. Department of Energy (DOE).

The Plan represents the continuing evolution of WECC's planning activities. This is WECC's first Interconnection-wide transmission plan and was produced in the using a broad stakeholder process. The Plan's limitations are based on the modeling capabilities, granularity of assumptions, and level of detail of the analyses performed.

2.1 Acknowledgements

WECC would like to express its sincere appreciation to the many individuals and organizations that have contributed to the Plan. The volunteers who comprised the RTEP committees and workgroups have been fundamental in assuring that the best information was made available, comprehensive analysis was performed, and broad review was conducted. A complete list of organizations and persons involved in the RTEP process is found on the Plan Web page.

2.2 Uses

The WECC 10-Year Regional Transmission Plan is informational. It has been designed specifically to provide high-quality, stakeholder-driven integrated analysis using regionally consistent data and processes that reflect statutory requirements.[2] It provides information on an Expected Future Western Interconnection and what Interconnection-wide transmission capacity or other transmission solutions may be needed under a variety of alternative futures.

The Western Electricity Coordinating Council (WECC) does not have authority or jurisdiction over the construction of transmission lines, nor does WECC have any authority or jurisdiction over siting, permitting, or cost-allocation.

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[2] Statutory requirements included State and Provincial renewable mandates (e.g., Renewable Portfolio Standards) and once-through-cooling retirements known at the time the analysis was conducted.

2.2.1 Energy Policy-makers

The Plan provides information on the impacts of implementing existing and potential energy policy decisions. The Plan includes an analysis that compares the cost of in-state vs. regionally-centered renewable energy procurement policy mandates. In addition, the Plan illustrates areas where different types of generation, including renewable, may be located and takes into account the transmission that could be used to deliver that generation to major load centers in the Western Interconnection. This information can be used by state, provincial, and federal policy-makers to support future energy policy decisions.

2.2.2 Utility Industry Regulators

The Plan shows the potential regional impacts of what are mostly state- and provincial-approved energy infrastructure decisions and what additional infrastructure may still be required in the 10-year timeframe. The Plan also highlights transmission projects assumed constructed in the Expected Future, many of which are currently in regulatory processes. If these projects are not constructed, it will impact observations and recommendations in the Plan.

The Plan highlights transmission paths that, even with the assumed transmission additions, still appear to be highly utilized or congested in 2020 under most conditions studied. Regulators should give consideration to infrastructure additions, transmission or otherwise, that serve to reduce congestion and monitor actions that may impact future congestion on these paths.

The Plan also identifies potentially lower cost renewable resource options that can be accessed by regional transmission additions. Regulators should consider this observation in their state resource and transmission planning activities.

2.2.3 Utility Industry Procurement Decision-makers

The Plan provides a regional perspective of known procurement decisions, both generation and transmission, which are detailed below in Section 3.2. As mentioned, all of these are assumed constructed in the Expected Future and if not constructed will impact observations and recommendations in the Plan.

Industry procurement decision-makers should consider the regional recommendations provided in the Plan with their future decisions on procurement and planning coordination.

2.3 Limitations

Observations and recommendations reported in the Plan are based on the analysis completed as part of the 2010 TEPPC Study Program and past TEPPC study reports. The data and modeling assumptions used to create the 10-year planning studies were developed using a collaborative stakeholder process. They reflect stakeholder consensus on available information regarding energy policies, load forecasts, transmission project status, and resource procurement trends at the time each case was developed.

The Plan uses a Production Cost Model (PCM) as its primary analytical tool. The PCM simulates the hourly operation of the entire Western Interconnection for the study year and provides important information about the utilization of generation and transmission. The PCM is useful for economic evaluation but does not evaluate capital costs, transmission reliability, or sub-hourly operational impacts. Additionally, it does not recognize the limitations of ownership or contractual rights on a generator's ability to access transmission. Of particular concern, the increasing amounts of variable generation analyzed in the 10-year planning studies indicate the need for sub-hourly and stability analyses and other evaluations outside the capacity of the PCM.

An investigation into how DC lines are modeled indicates that the PCM tends to favor loading AC lines prior to DC lines. This is due to the different algorithms used for calculating and applying transmission losses for DC lines, as described in the TEPPC 2019 Study Report. It is believed that this issue resulted in the underutilization of the DC lines modeled in the 10-year planning studies and may have caused congestion on the AC system near the DC lines to be overstated. As a result, it is difficult for the PCM to fully value the benefits of a two-terminal DC line. This issue is exacerbated when evaluating a three-terminal DC line.

While hourly production cost modeling provides useful information about hourly transmission congestion and utilization, this information alone is not sufficient to drive new investment. The Western Interconnection has a decentralized market and transmission ownership structure. Major new transmission investment is likely to be driven by the LSE's desire to access renewable generation resources with a high-degree of delivery assurance, which requires firm, long-term transmission contracts.

The data and assumptions used in the 10-year planning studies were based on public information. This increased the transparency of the planning process and results and it limited the level of detail that could be incorporated into studies. WECC did not use confidential data such as current or future procurement contracts, bilateral agreements, or other commercially sensitive information.

Cost comparisons of different renewable resources and potential transmission additions are an important part of the analyses and results described in the Plan. The comparisons were based on capital cost estimates for different renewable resources and the transmission projects needed to access those resources. The capital cost estimates reflect generic characterizations of renewable technologies and transmission projects. They were used for a wide-range of conditions and for large prospective transmission projects that would have to undergo extensive siting and permitting processes.

Alternative resource and transmission capital cost comparisons presented in this Plan generally reflect point (median) estimates of resource and transmission costs. Actual future costs must be viewed as covering a significant range of uncertainty (see Figures 14–17) and this risk will factor prominently into investment decisions. Resource-plus-transmission comparisons informing the Plan are based on certain factors for which capital cost estimates are the most important. However, they do not include other factors critical to renewable resource procurement decisions, some of which are identified in Figure 12. This Plan's high-level comparison of resource-plus-transmission options should be viewed as indicative of potential alternative resource options. These options need to be assessed at a greater detail at the state/provincial and LSE decision-making level.

2.4 Supporting Documents

The observations and recommendations described in the Plan Summary are supported by, and detailed in a number of WECC-authored reports as well as reports authored by various stakeholder groups. Key supporting reports include:

2019 TEPPC Study Report
2020 TEPPC Study Report
2010 TEPPC Study Program
2009 TEPPC Transmission Path Utilization Study
2008 TEPPC Transmission Path Utilization Study
2007 TEPPC Transmission Path Utilization Study
TEPPC Regional Transmission Expansion Planning Protocol
WECC 10-Year Regional Transmission Plan Whitepaper
EDTF Environmental Recommendations for Transmission Planning
WGA Water-Energy Analysis of the 10-year WECC Transmission Planning Study Cases
Subregional Coordination Group (SCG) Foundational Project List

All documents related to the Plan are available on the WECC website at http://www.wecc.biz/10yrPlan.

3 Summary of Analyses

The summary section provides a picture of the Western Interconnection in 2020, and alternative futures considered as part of the Plan analyses. The Plan's observations and recommendations are supported by the analyses performed by TEPPC as well as assumptions, analyses, and results brought to TEPPC by stakeholders through WECC's open processes.

3.1 Assumptions

As with any analysis, assumptions drive the results. The analyses conducted to support the Plan are no different. The key assumptions are summarized below and explained in more detail in the respective study cases.

Renewable Portfolio Standards (RPS) Will Be Met

The Plan assumes full state-mandated RPS compliance in all the 10-year planning studies and did not evaluate cost-based or other off-ramps that could reduce the actual amount of renewable resources constructed by 2020. The assumptions followed state requirements regarding participation and in-state/out-of-state qualifications.

Foundational Transmission Projects Will Be Constructed

The SCG Foundational Transmission Project List (see Figure 7) is a subset of the projects currently in the Subregional Planning Groups' (SPG) 10-year plans that have a very high probability of being built over the next 10 years. The purpose of the SCG Foundational Transmission Projects List (List) is to provide a basic set of transmission facilities that TEPPC can use as a starting point for the transmission topology assumed in its 10-year planning studies. The List is not intended to verify what will be built, but to be used as a set of assumed transmission projects for the purpose of case comparisons. The Expected Future assumed the 44 transmission projects in the List will be constructed before 2020. Many of the projects relieved congestion on key WECC paths in the study cases that, without the projects, would have been included in path upgrade recommendations below. Other projects that were not studied may have provided the same benefits.

Fuel Prices

Fuel prices for natural gas, coal, and nuclear were obtained from specialized price forecasting services and approved by Technical Advisory Subcommittee (TAS). Although some of the cases studied could have a significant impact on the electric sector natural gas usage, the same fuel prices were used for all of the 2020 study cases.

Wind and Solar Generation Profiles

The wind and solar generation profiles used for the resources modeled in various study cases and the resulting capacity factors of these resources were based on modeled locational wind and solar data obtained from the National Renewable Energy Laboratory (NREL). The highest capacity factor sites available in the NREL data were selected to create the TEPPC wind and solar generation profiles. No validation of the NREL data using actual projects has been conducted by TEPPC, but is anticipated in the future.

Transmission Operation

The PCM observes transmission flow limits as upper and lower bounds for utilization, and will operate lines and paths at or near their limits for prolonged periods if warranted by the hourly solution. In contrast, transmission operators prefer to leave some room for unscheduled fluctuations in actual system operation.

Financial Agreements and Power Contracts

Confidentiality issues and the inability to predict future commercial arrangements and contracts prevent the comprehensive modeling of long-term power purchase contracts in the 10-year planning studies with the exception of generation located at the north end of the Intermountain DC line.[3] As such, generation is assumed to be available to serve load in its assigned area, but may also be used to serve load outside its assigned area as determined by the economic dispatch. Modeling contract rights and schedule use of transmission capacity by contract holders would produce different results within the PCM.

The key observations and findings below are supported by the analyses conducted by TEPPC. Further detail is found in subsequent sections of the Plan and supporting appendices.

3.2 The Expected Future Network

The 'Expected Future' Western Interconnection electrical network (i.e., 2020 SPSC Reference Case) is based on stakeholder-provided assumptions regarding loads, generation, and transmission 10 years into the future (2020). The information was provided to WECC by LSEs, state, and provincial regulatory agencies via the State-Provincial Steering Committee (SPSC), SPGs, and directly to TEPPC through its open stakeholder meetings. The subsections below

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[3] The Intermountain Generating Station is modeled internal to the extended balancing authority boundary for LADWP that follows the IPP DC line north into Utah. For the purposes of the model, this applies the Intermountain Generating Station directly to the load/resource balance equation for the LADWP area.

describe the major load, generation, and transmission assumptions in the Expected Future network.

The analyses of the Expected Future network yielded the following observations.

First — the transmission network, including assumed additions, enabled energy to flow without significant congestion with the exception of two major transmission paths: the Montana to Northwest (Path 8) and Pacific-Tie Paths (Paths 65 and 66). The Intermountain Power Project DC Line (IPP DC) was also highly utilized, but this is by design. There have been major paths highlighted in past WECC transmission utilization reports that did not appear to be congested in the Expected Future network. This is due to transmission additions assumed in the analysis (i.e., lines identified in the List). These include Northwest-Canada (Path 3), Borah West (Path 17), and Bridger West (Path 19).

Second — the generation mix in the Expected Future case represents a significant departure from the past. With the exception of generation to replace units retired under Once-Through-Cooling (OTC) regulations in California in response to the federal Clean Water Act, additions were dominated by renewables to fulfill state-mandated RPS. The increase in variable and mostly non-dispatchable generation caused an increase in the utilization and ramping of conventional generators. The impact of this is two-fold. 1) Intra-day generator volatility sometimes results in non-economical day-ahead commitment of generators (carrying additional capacity for a few hours). 2) Transmission flows are changing more often and by larger amounts. This will also impact the management of system voltages and could have an impact on future path ratings.[4]

There are a number of assumptions in the Expected Future network that, if not realized, will have impacts on transmission utilization and costs. The Alternative Futures Section below highlights the impacts of alternative load and generation assumptions investigated as part of the Plan.

If transmission additions (i.e., Foundational Transmission Projects) are not constructed, congestion on key transmission paths will increase. Depending on the situation, it could impede the delivery of renewable or lower-cost generation and cause an increase in costs due to the use of higher-cost gas-fired generation. In addition, if one or more of the assumed transmission project additions is canceled, it could have a corresponding impact on a generation assumption.

Changes in loads, from what was assumed, will impact transmission utilization and costs. Key drivers for load include energy efficiency (EE), economic conditions, and technology changes (e.g., electric vehicles). Lower-than-expected load growth in exporting areas (e.g., Pacific Northwest and interior states) or higher-than-expected load growth in importing areas (e.g., California and the Desert Southwest) will increase regional transmission congestion. Conversely, higher-than-expected load growth in exporting areas or lower-than-expected load growth in importing areas will lower transmission utilization.

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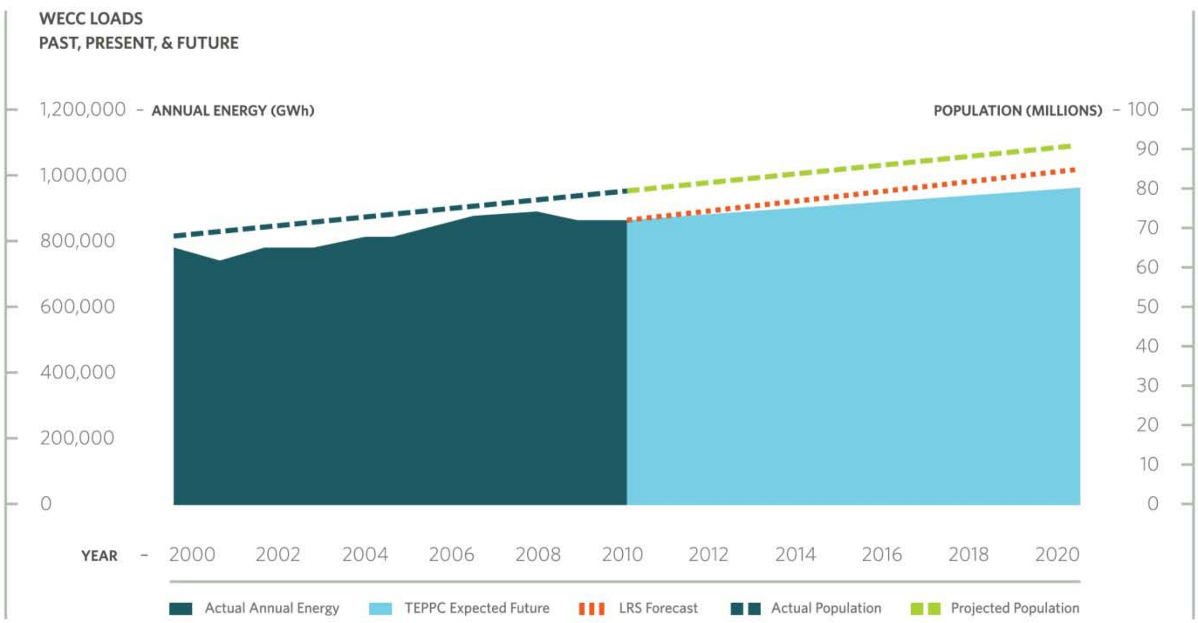
[4] A number of entities in the Western Interconnection are investigating the impact of increasing transmission flow changes, specifically changes to Dynamic Transfer Capacity Limits. http://www.columbiagrid.org/DTCTF-overview.cfm

Changes in assumed generation will also impact transmission utilization and costs. Hydro generation due to snowpack in key river basins greatly impacts transmission utilization and costs. More hydro increases transmission congestion but decreases costs, while less hydro decreases transmission congestion but increases costs. If renewable generation assumed in the analysis is not constructed, RPS targets may not be met. If the renewable generation is constructed differently than assumed (e.g., rapid shift to solar), transmission utilization, conventional generation dispatch, and costs will change. Another key driver to generation choices is the impact of carbon reduction regulations. How (or if) carbon reduction regulations are enacted will compel changes in existing coal- and gas-fired generation operations, as well as future generation additions and retirements.

3.2.1 Loads

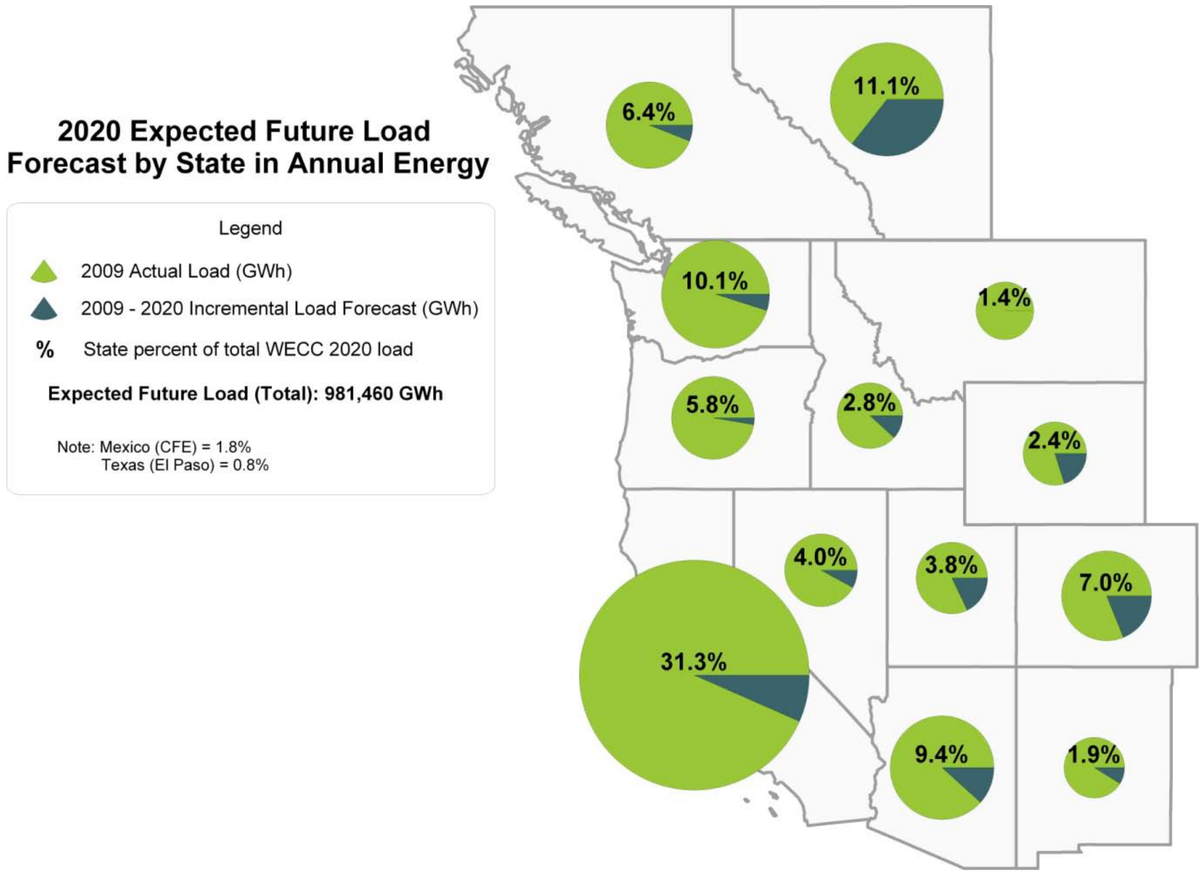
Loads are projected to increase 14 percent from 2009 to 2020 (1.2 percent compound annual growth rate). These projections were provided by LSEs via Balancing Authority (BA) reports to the WECC Load and Resource Subcommittee (LRS) data submittal process and adjusted by the SPSC to reflect existing EE and DSM programs and policies not included in LSE projections. The population of the Western Interconnection continues to increase and is projected to grow 13 percent to 90.7 million people from 2009 to 2020 (Figure 1).

Figure 1: Western Interconnection Load



The geographic location of the load, illustrated in Figure 2, has a major influence on study results. Over 53 percent of the load (by annual energy) is located in coastal states and British Columbia, with 31 percent of the total being located in California. Trends in load growth rates are skewed toward interior states and Alberta. This is due to a combination of higher population growth rates, less-aggressive EE programs, and energy development (e.g., oil sands in Alberta).

Figure 2: 2020 Loads by State and Province



3.2.2 Generation

The existing and future generation retirements and additions detailed in Figure 3 were provided to WECC via the LRS data submittal process and an extensive Integrated Resource Plan (IRP) review by Lawrence Berkeley National Laboratory. Generation projects that did not meet certain development status criteria reported to the LRS or were not reported in the IRPs were not included in the Expected Future. In addition, retirements and replacements due to OTC regulations in California were incorporated based on information provided to TEPPC by the impacted entities. Additional renewable generation was added using the Western Renewable Energy Zone (WREZ) tool to ensure the Expected Future network was consistent with enacted RPS. Based on the capital cost estimator used by TEPPC, the capital cost of the resource additions totaled approximately $179 billion in year 2010 dollars. Resources located in California were 54 percent of this estimated capital investment.

The future generation assumptions are among the most unpredictable elements of an Interconnection-wide planning effort. Generation plans are a moving target and plans have undoubtedly changed since the data was collected by WECC in early 2010. Table 1 represents the generation snapshot used for the Expected Future. Recent changes will be incorporated into future studies.

Figure 3 illustrates two important generation trends between now and 2020 relative to the generation assumptions. First, there are not significant increases in dispatchable generating capacity – most of the gas-fired additions in California merely offset the OTC retirements. Second, there are over 33,000 MW of assumed renewable generation additions. Combined, these developments raise significant questions around having adequate dispatchable resources to balance the large increase in variable generation (wind and solar). Some integration problems could be resolved by using complementary renewable resources, demand response programs, distributed generation, and energy storage projects. Renewable generation includes such non-variable types such as small hydro, geothermal, or biomass.

Figure 3: Generation Additions and Retirements

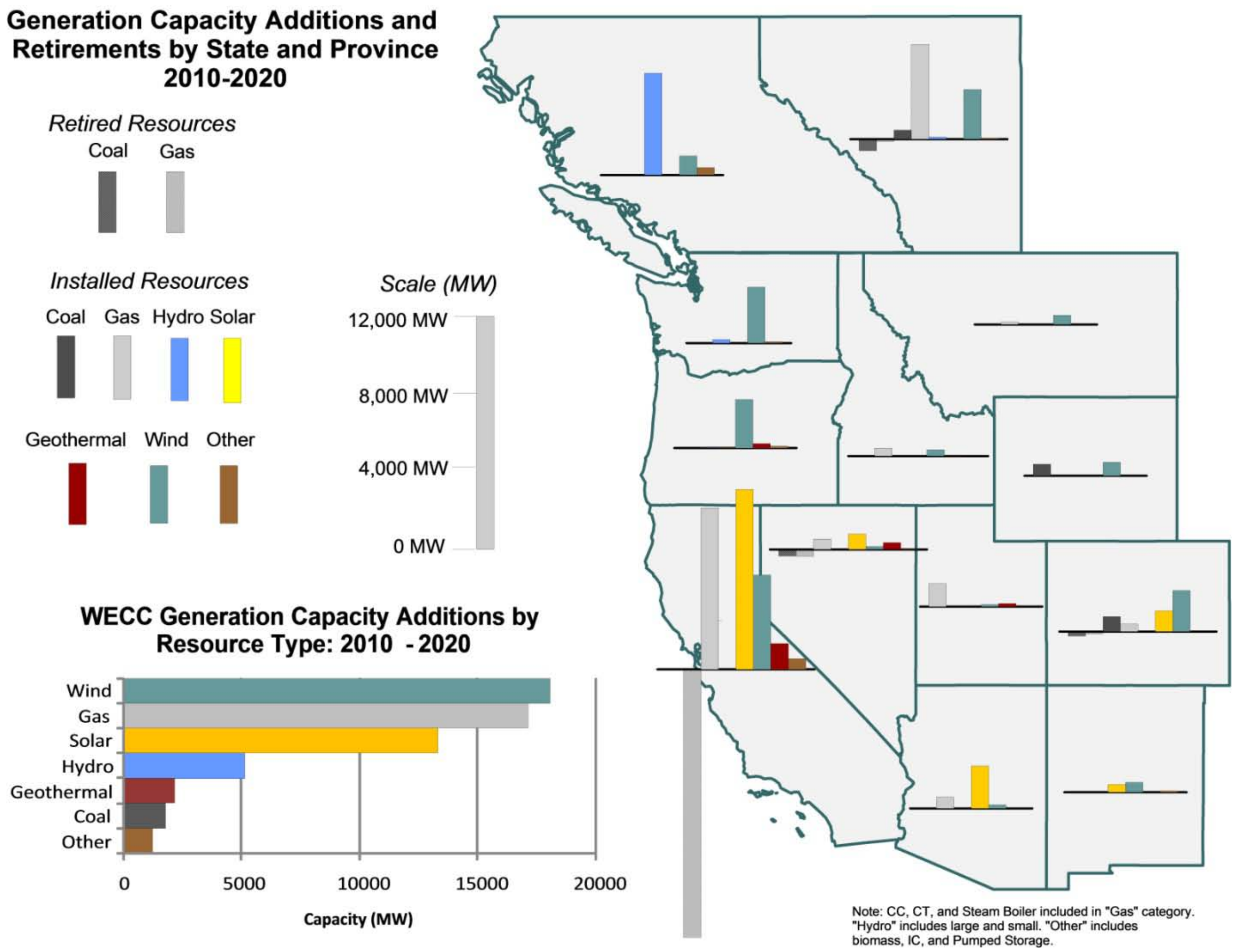


Table 1: Generation – Existing, Additions, and Retirements

Retirements (MW) through 12/31/2020

Resource	AB	AZ	BC	CA	CO	ID	MX	MT	NB	NV	NM	OR	SD	TX	UT	WA	WY	**WECC**
Coal	586	0	0	0	226	0	0	0	0	330	0	0	0	0	0	0	0	1,142
Combined Cycle	0	0	0	47	0	0	0	0	0	0	0	0	0	0	0	0	0	47
CT - nonOTC	118	0	0	337	0	0	39	0	0	0	0	0	0	0	0	0	0	494
CT - OTC	0	0	0	156	0	0	0	0	0	0	0	0	0	0	0	0	0	156
Steam - nonOTC	0	0	0	0	115	0	0	0	0	338	0	0	0	0	0	0	0	453
Steam - OTC	0	0	0	12,862	0	0	0	0	0	0	0	0	0	0	0	0	0	12,862
TOTAL	704	0	0	13,402	341	0	39	0	0	668	0	0	0	0	0	0	0	15,154

Existing (MW) as of 12/31/2009

Resource	AB	AZ	BC	CA	CO	ID	MX	MT	NB	NV	NM	OR	SD	TX	UT	WA	WY	**WECC**
Biomass RPS	262	24	165	641	0	94	0	0	0	0	0	0	0	0	0	197	0	1,382
Geo-thermal	0	0	0	1,878	0	10	699	0	0	334	0	0	0	0	48	0	0	2,968
Solar PV	0	0	0	21	8	0	0	0	0	10	0	0	0	0	0	0	0	39
Solar Thermal	0	0	0	454	0	0	0	0	0	75	0	0	0	0	0	0	0	529
Wind	712	0	147	2,327	1,171	204	0	354	0	0	394	1,699	0	0	223	1,856	1,064	10,149
Small Hydro RPS	30	30	0	1,199	0	258	0	0	0	0	0	80	0	0	0	45	28	1,670
Pumped Storage	0	146	0	3,041	560	0	0	0	0	0	0	0	0	0	0	0	0	3,747
Hydro	913	2,787	10,830	9,266	616	3,207	0	2,496	0	1,045	79	8,469	0	0	250	22,074	263	62,295
Nuclear	0	4,035	0	4,486	0	0	0	0	0	0	0	0	0	0	0	1,160	0	9,681
Coal	5,431	6,131	0	232	4,806	15	0	2,511	0	1,043	3,992	510	25	0	5,062	1,456	5,402	36,615
Combined Cycle	2,002	10,635	240	17,435	2,778	0	2,120	0	0	4,818	888	3,080	0	222	1,275	3,624	0	49,117
CT	2,263	1,926	66	6,805	2,822	607	281	0	300	1,560	700	172	339	69	405	704	79	19,097
IC	12	0	0	92	116	0	0	54	0	289	0	0	20	0	0	24	0	607
Steam Other	78	1,295	904	2,917	107	0	304	65	0	225	343	79	0	247	238	131	0	6,932
TOTAL	11,701	27,009	17,352	50,793	12,983	4,394	3,404	5,480	300	9,399	6,396	14,090	384	538	7,501	31,270	6,835	209,829

Additions (MW) 1/1/2010 - 12/31/2020

Resource	AB	AZ	BC	CA	CO	ID	MX	MT	NB	NV	NM	OR	SD	TX	UT	WA	WY	**WECC**
Biomass RPS	35	11	377	336	0	0	0	0	0	26	68	98	0	0	0	64	0	1,014
Geo-thermal	0	0	0	1,289	0	27	107	0	0	345	15	220	0	0	155	0	0	2,158
Solar PV	0	1,699	0	4,093	770	0	0	0	0	136	240	20	0	0	0	0	0	6,957
Solar Thermal	0	417	0	4,914	264	0	0	0	0	637	150	0	0	0	0	0	0	6,382
Wind	2,475	179	958	4,725	2,054	319	260	455	0	150	494	2,431	0	0	100	2,800	675	18,075
Small Hydro RPS	0	0	90	0	0	0	0	13	0	0	0	19	0	0	0	172	0	294
Pumped Storage	0	0	0	40	0	0	0	0	0	0	0	0	0	0	0	0	0	40
Hydro	100	0	5,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5,100
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal	450	0	0	0	750	0	0	0	0	0	0	0	0	0	0	0	485	1,685
Combined Cycle	2,518	0	0	4,329	200	300	381	120	0	524	0	0	0	288	1,143	0	0	9,803
CT	2,215	560	0	3,746	180	100	524	0	0	0	0	0	0	0	0	0	0	7,325
IC	0	0	0	163	0	0	0	0	0	0	0	0	0	0	0	0	0	163
Steam Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	7,793	2,866	1,425	23,634	4,218	746	1,272	588	0	1,818	967	2,788	0	288	1,398	3,036	1,160	58,995

As shown in Figure 4, the Western Interconnection is projected to generate 17 percent of its energy from non-hydro renewable sources in 2020. This, along with hydro and nuclear equates to non-carbon emitting resources generating roughly one-half of the Western Interconnection's total annual energy.

Figure 4: 2020 Annual Generation by Energy and Type in the Expected Future

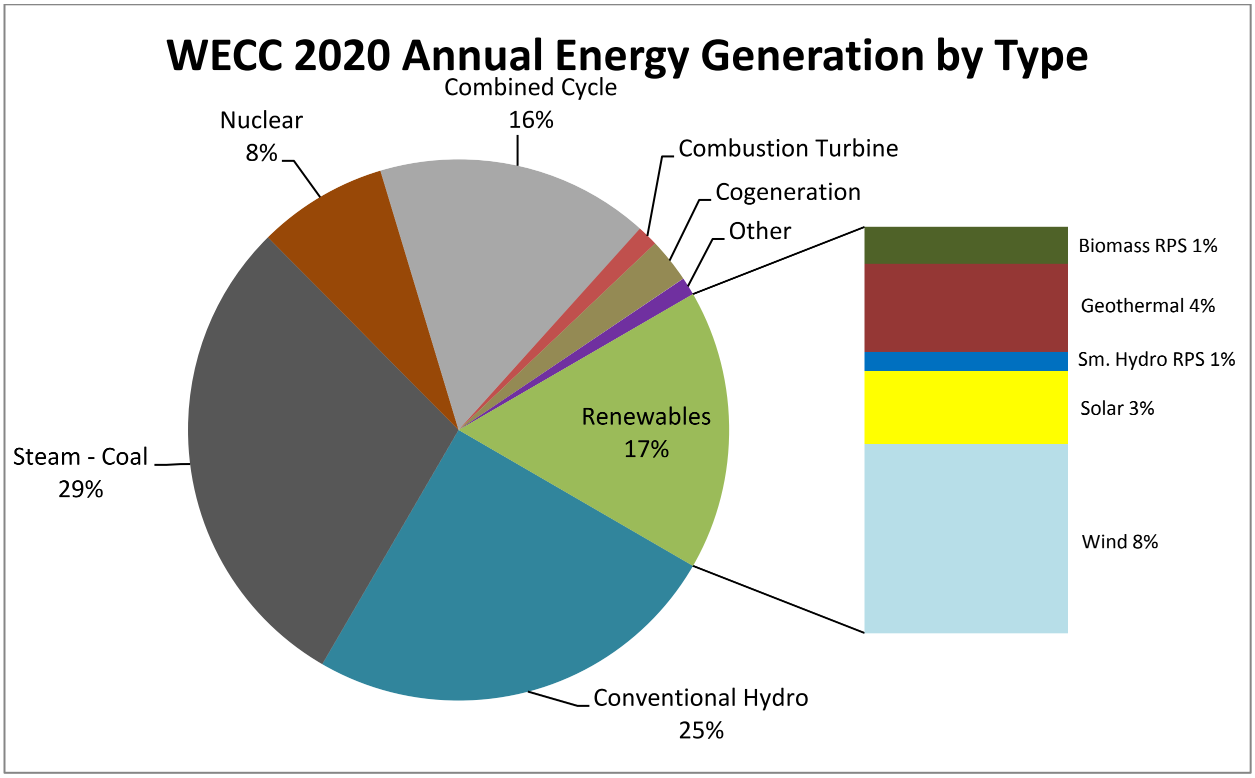
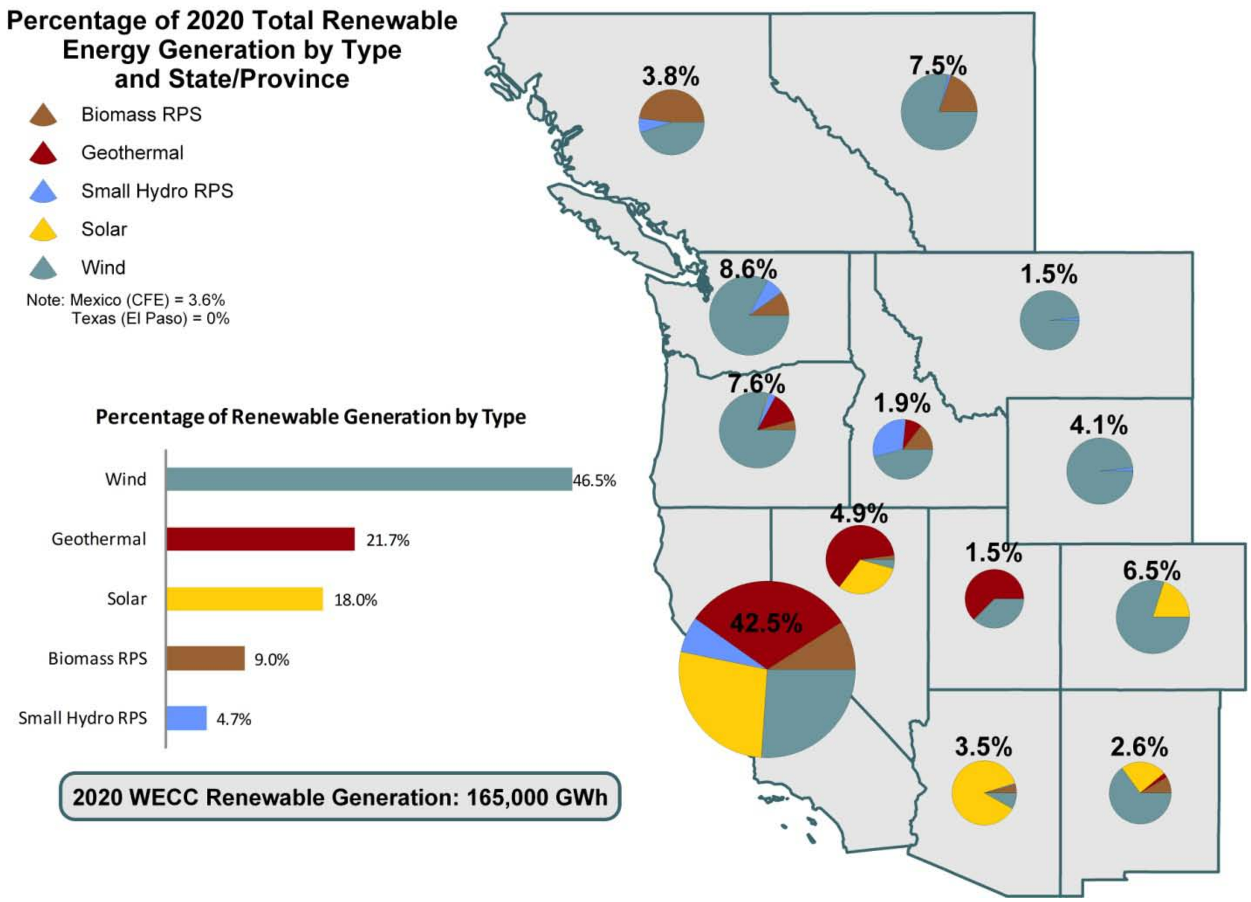


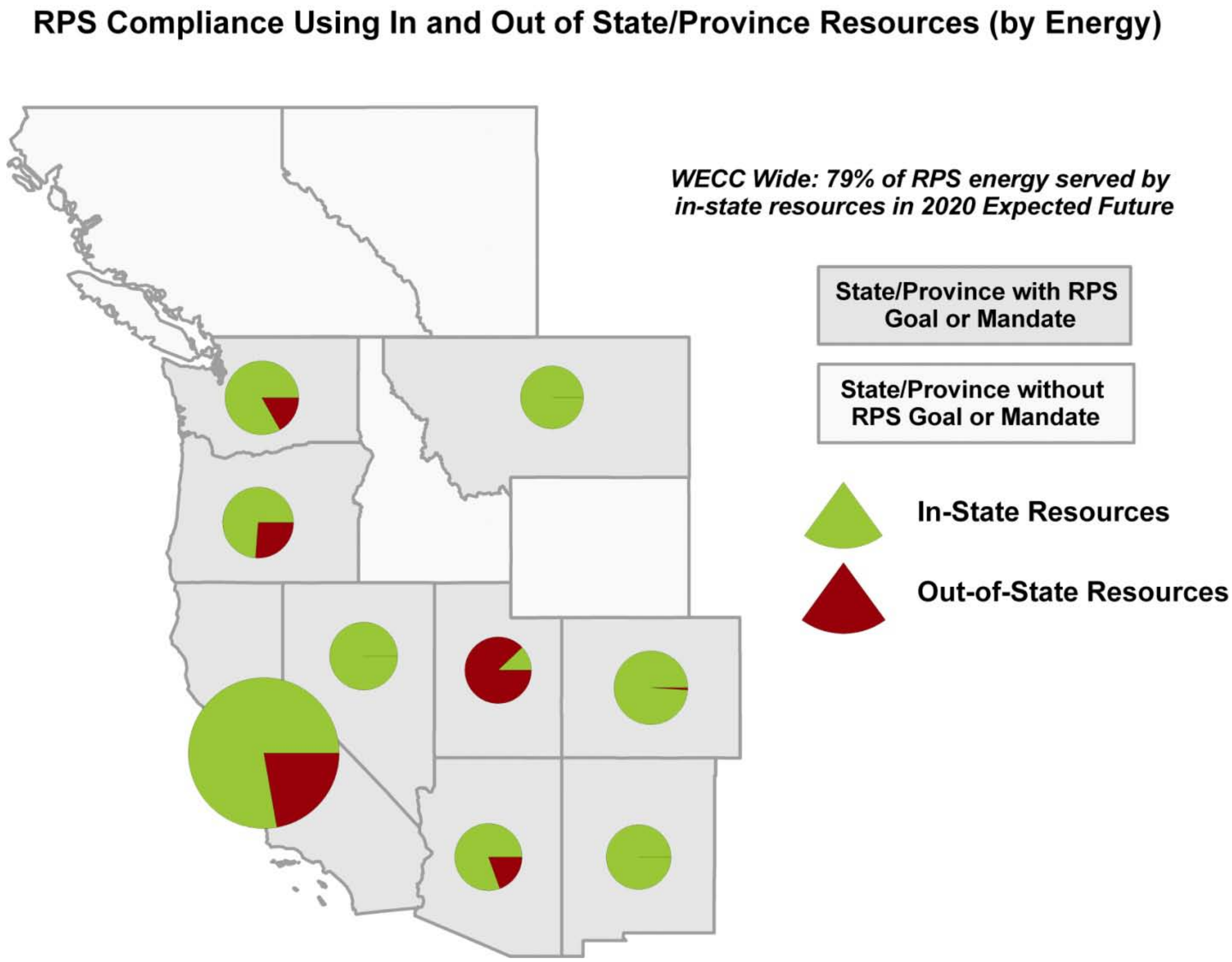
Figure 5 represents the mix of renewable generation in 2020, which continues to be dominated by wind. However, strong growth in solar is anticipated. Of the solar resources assumed in the 2020 Expected Future, 50 percent (by capacity) is photovoltaic (PV). Of the PV generation, 23 percent (by capacity) is distributed PV (19 percent by energy).

Figure 5: Renewable Energy Generation



Current renewable energy development trends are centered on accessing resources close to load. This is being driven by state mandates, regulatory and financial uncertainty around long-distance transmission development, and the development time-frame differences between generation (2-3 years) and transmission (7-10 years). The tendency to procure in-state (local) renewable resources is shown in Figure 6. In the 2020 Expected Future network, every state with a renewable energy portfolio mandate or goal, other than Oregon and Utah, receives over 75 percent of its RPS energy from in-state resources.

Figure 6: In and Out of State Resources for 2020 Expected Future[5]



3.2.3 Transmission

Assumptions regarding future transmission additions, shown in Figure 7, were provided by the SCG Foundational Transmission Projects List Report. The 44 major transmission projects on the list were selected by analyzing the development status of known subregional transmission projects and determining projects that have a high probability of being constructed by 2020. In total, the Foundational Projects add over 5,500 line-miles to the existing 75,000 line-miles of existing transmission above 200 kV. Local transmission additions (under 200 kV) were based on transmission provider submissions to the WECC Planning Coordination Committee (PCC). Based on the capital cost estimator used in the Plan and publicly available capital cost information, the estimated capital cost of the Foundational Projects totaled \$20 billion.[6]

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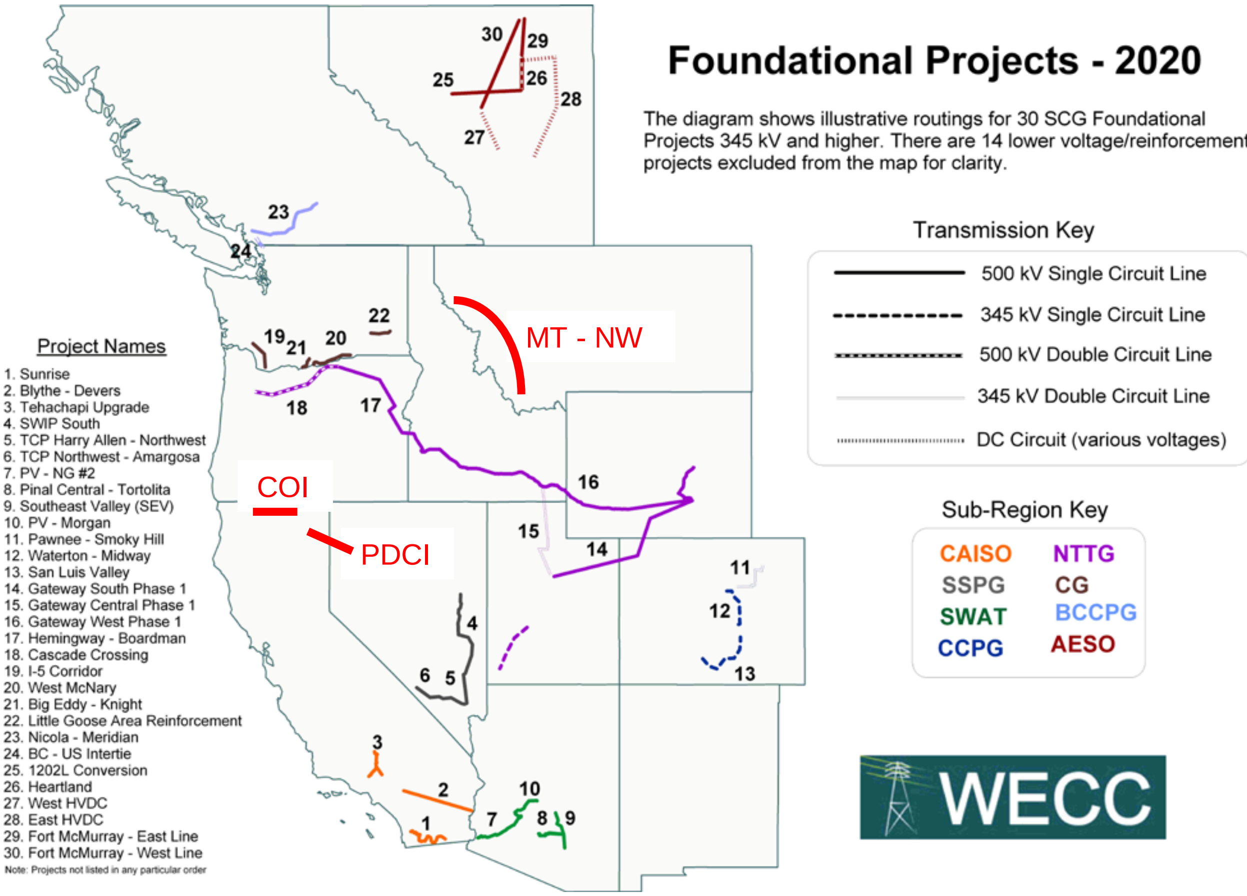
5 British Columbia has a clean and renewable generation standard of 93 percent by 2020, all of which is to be met by renewable resources located within the province.

6 Publicly available developer costs were used whenever possible. Costs not publicly available were estimated and only line-mileage and line-termination costs were included in the estimation. The reported value is likely less than actual costs.

Figure 7: Foundational Transmission Projects



With the addition of the Foundational Projects, most of the major transmission paths highlighted in past utilization studies do not appear to be significantly congested in 2020. The exceptions are the Montana to Northwest Path (Path 8) and the Pacific-Tie Paths (Paths 65 and 66). These paths are discussed in detail in the Observations and Recommendations Section and the WECC Path Reports.

The Montana to Northwest Path (Path 8), the largest of the Montana export paths, consists of the lines running between western Montana and the northwest U.S. It is the only major WECC Path available to export resources out of Montana and by design is almost fully subscribed to deliver shares of thermal generation. By combining the historical utilization analysis and forward-looking trends describing how the path may be used in 2020, analyses supporting the Plan assessed the need for additional transmission capacity out of Montana as discussed in Section 4.1.

The paths that bring energy from the Northwest down into California, the Pacific DC Intertie (PDCI) – Path 65 and the California-Oregon Intertie (COI) – Path 66, also continue to be areas of concern. The historical utilization analysis and forward-looking trend in path utilization in

2020[7] point to the possible need for additional transmission capacity between the Northwest and California. This will depend on the level of renewable development in the Northwest used to satisfy the RPS in California.[8] This is further supported by a recent report authored by the owners of the lines that comprise Path 66.[9]

A cursory reliability screening of the Expected Future network was performed and is the first time this has been attempted by WECC. This entailed performing a first-order (N-1) power flow analysis on 10 hours of interest in the Expected Future case to assess elements of the Plan for major reliability criteria violations. The hours selected were based on SCG input and were designed to capture diversity in load, generation, and transmission flows. The reliability screening methodology is detailed in Section 5.1.8. Although there were many lessons learned regarding the screening methodology and how to evaluate PCM study cases against reliability criteria, no specific conclusions about the reliability of the Expected Future case could be drawn. A report detailing lessons learned and next steps will be provided in a separate report.

3.3 Alternative Load and Resource Future Networks

In addition to the Expected Future network, the RTEP process analyzed alternative load, resource, and transmission scenarios. The purpose of this work was to 1) identify the relative impact on future transmission needs and 2) compare the estimated cost differences between the Expected Future and the alternative futures. The RTEP process analyzed two alternative load cases, eight resource relocation cases, and two aggressive wind cases.

The alternative load scenarios are focused on understanding 1) high-load-growth and 2) aggressive EE and DSM. Results for these scenarios are detailed in the TEPPC 2020 Study Report in 2020 PC2 and 2020 PC3, respectively.

The high-load growth case (2020 PC2) assumed a 10 percent increase in the load projections (as compared to the Expected Future) with no other changes to resources except that additional renewable generation was added to maintain RPS compliance. This case showed that the increase in load was served mostly by local gas-fired generation and that major flows between areas of the Western Interconnection decreased. However, flows into southern California increased as did a few isolated flows elsewhere. The lower flows were due to lower-cost resources in the Northwest and inland that were being utilized to serve local loads and thus not available to displace higher-cost resources in California. Gas-fired generation in California increased in order to replace these lost imports from the Northwest, as did combined cycle generation in Arizona, which contributed to an increase in transmission flows into southern

[7] This is based on assumptions of further generation expansion in Idaho, Montana, Oregon, and Washington that have the potential to provide surplus economy energy for export to California.

[8] The CAISO 2010-2011 Transmission Plan can be found at http://www.caiso.com/Documents/Board-approvedISO2010-2011TransmissionPlan.pdf and the California Transmission Planning Group Statewide Transmission Plan at http://www.ctpg.us/images/stories/ctpg-plan-development/2011/02-Feb/2011-02-09_final_statewide_transmission_plan.pdf. Both plans indicate that the need for such additional capacity would be driven by particular resource scenarios that assumed high reliance on Northwest renewables to meet California's 33 percent RPS.

[9] The Transmission Utilization Group, COI Utilization Report can be found at http://www.columbiagrid.org/download.cfm?DVID=2189.

California. This case had a large impact on variable (operating) costs, which were 25 percent higher than in the Expected Future case. The higher costs are attributed to the 40 percent increase in natural gas-fired generation.

The high EE/DSM case (2020 PC3) reduced load projections based on aggressive demand response assumptions and the implementation of all cost-effective EE programs.[10] This resulted in a decrease of 8.6 percent in the coincident Western Interconnection peak demand and a 10 percent reduction in total energy relative to the Expected Future. The distribution of additional EE/DSM was not equal across the states and provinces. Loads were decreased less significantly in areas that already had more aggressive programs, while loads in areas with less aggressive programs were decreased more significantly on the basis that there was a greater potential for savings from EE/DSM programs in these areas. The result of this case showed significant increases in flows from the Intermountain West and Northwest into California. The study showed the opposite impact demonstrated in the high load case. Due to the decrease in loads, lower-cost generation was available to flow into higher-cost markets in California. In addition, there was a 25 percent decrease in variable costs driven by the reduced need for gas-fired generation.

The remaining alternative futures focused on understanding the interplay between transmission and renewable resource location, specifically local vs. remote generation to load centers. To explore the transmission utilization and cost implications of some particular resource location tradeoffs, a series of change cases based on the 2019 10-year planning case (i.e., 2019 PC1A Base Case) were analyzed. In the 2019 PC1A case, 12,000 GWh of the lowest-ranking[11] renewable generation located in California was replaced with alternative renewable resource portfolios at eight different locations throughout the Western Interconnection.

As shown in Figure 8, California is home to 66 percent of the WECC-wide incremental RPS energy from 2010 to 2020. The 12,000 GWh of relocated resources represent about 20 percent of California's forecasted incremental RPS energy requirement in 2020. The locations and resource fuel types studied in these eight resource relocation alternative futures are illustrated in Figure 9. They reflect input from the WREZ Peer Analysis Tool, from utility planners, and from the NREL meso-scale wind profiles regarding the resources selected for each case.

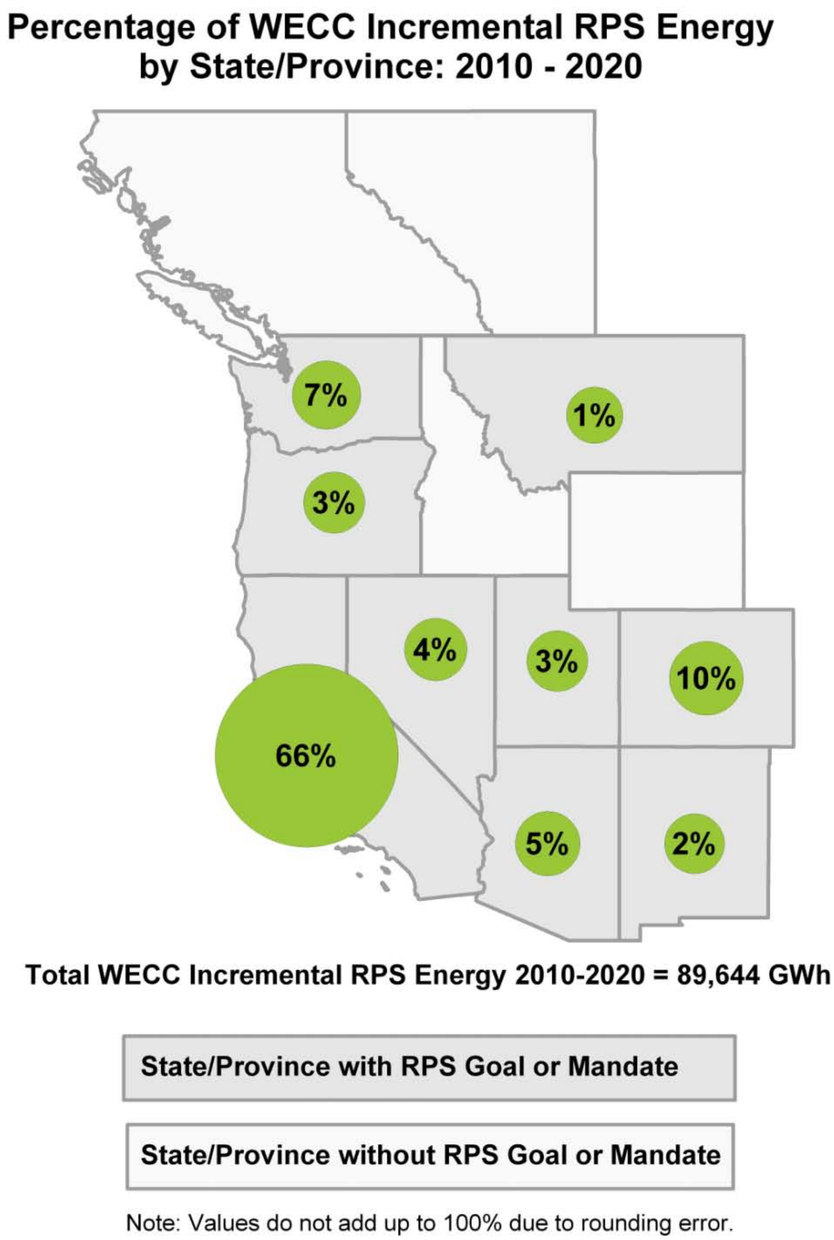
The installed capacity of the renewable resources needed to produce 12,000 GWh of energy is a function of the annual capacity factor of the resources selected in each case. It varied from 2,586 MW needed for the PC10 Northern Nevada resource relocation case to 5,299 MW of capacity needed for the Coastal Northwest case. This variation is due to the technology mix as well as the regional difference between the resources removed from California and the resources selected for each relocation case. The details of each relocation case are found in

10 For all states except California, WECC's high DSM study assumed FERC's "Expanded Business as Usual" scenario; for California, WECC's high DSM study assumed FERC's "Achievable Participation" scenario.

11 The renewable resource rankings were provided by the CPUC and utilized three factors: Commercial interest (projects having contracts or being short-listed) was most important, environmental score, and estimated resource value. This information was used to select renewable resources to meet California RPS requirements in the 10-year planning studies.

their respective sections in the 2019 Study Report (2019 PC7 - PC14). In addition, 25,000 GWh of 'aggressive wind' relocation was studied for Montana and Wyoming. Results from these studies are detailed in the 2020 Study Report under 2020 PC6 and 2020 PC7, respectively.

Figure 8: WECC Incremental RPS Energy by State[12]



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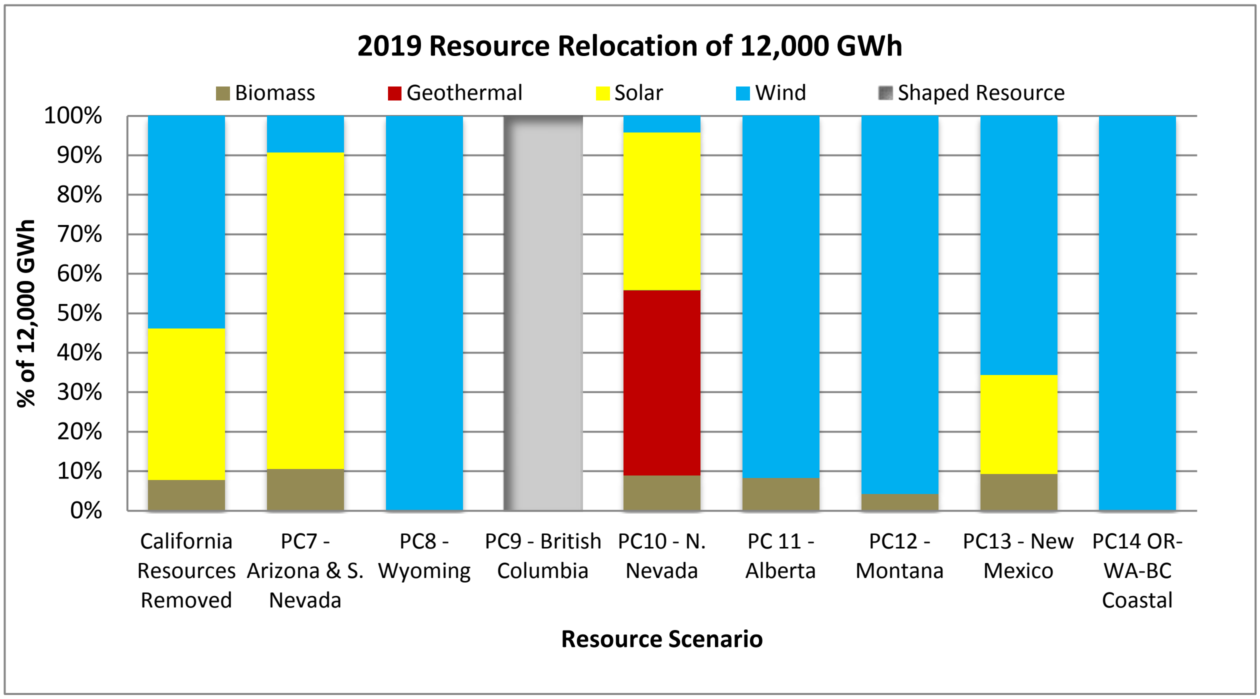
12 British Columbia has a clean and renewable generation standard of 93 percent, all of which is to be met by renewable resources located within the province.

Figure 9: 2019 Renewable Resource Relocation Portfolios



Overall, the resource relocation cases showed that there are cost-efficient remote resource options as compared to a portfolio of lowest-ranking California resources in the Expected Future case. Figure 10 demonstrates the estimated resource capital cost savings calculated between the resource portfolio assumed in the 2019 Expected Future and the portfolio assumed in the eight resource relocation cases. The estimated savings reported for these cases are a function of the installed capacity of resources needed to produce 12,000 GWh of energy in each case, and the estimated levelized fixed cost for the particular resource type in the location studied.

The estimated resource capital cost savings are lowest in the relocation cases that included significant solar and/or geothermal additions. The savings are the greatest in the cases that included significant high capacity factor wind resources. There are two key drivers for the occasionally very-large cost differentials. First, the capacity factors for different renewable generation types are vastly different. As an example, a capacity factor of solar PV is in the range of 20 percent. The capacity factor for many high-quality wind areas is in the 40 percent range. Therefore, half the installed capacity is required to yield the same amount of energy. Second, the capital cost of solar (equivalent megawatt capacity) is nearly double that of wind. Taken together, there is a 4X capital cost spread between wind and solar. The capital cost assumptions and calculation methodology are detailed below in Section 5.1.8.

The capital costs of the different technologies are evolving quickly and it is anticipated that the cost of solar will continue to decrease while the efficiencies increase.

Figure 10: Resource Capital Cost Comparison

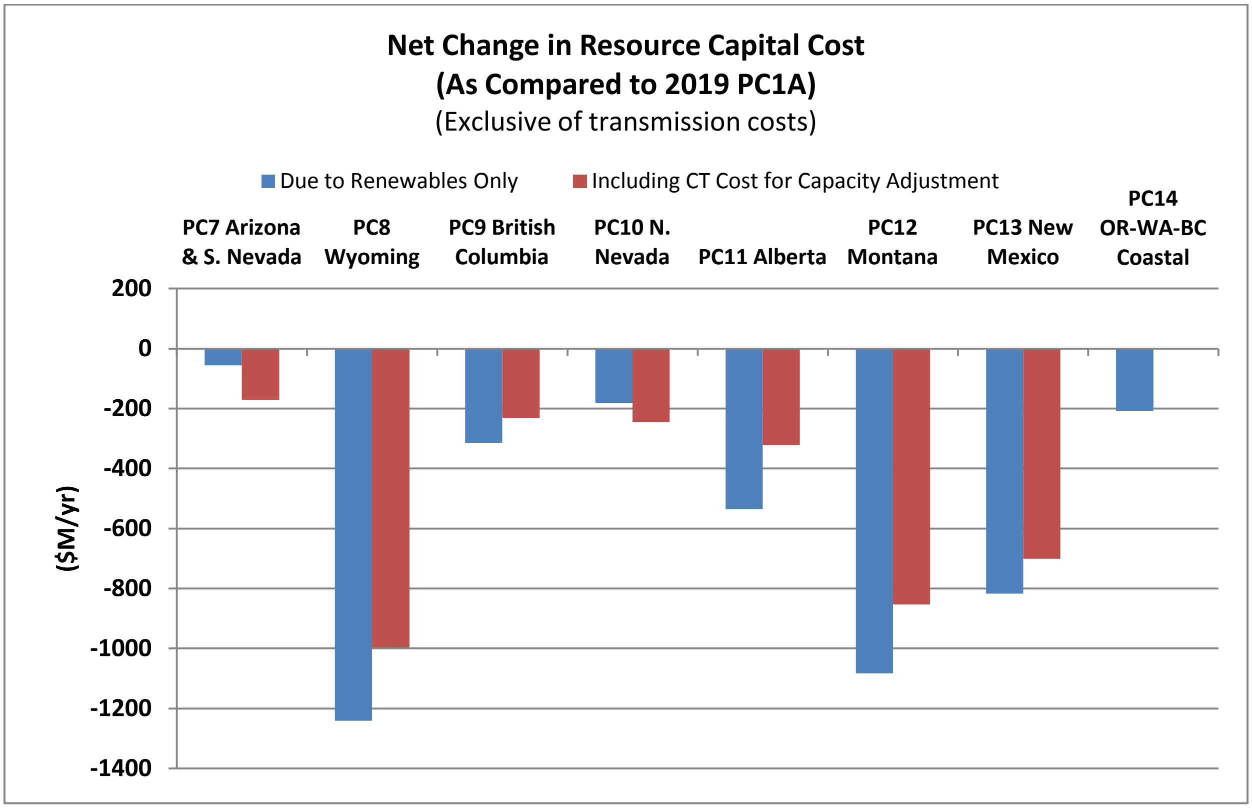
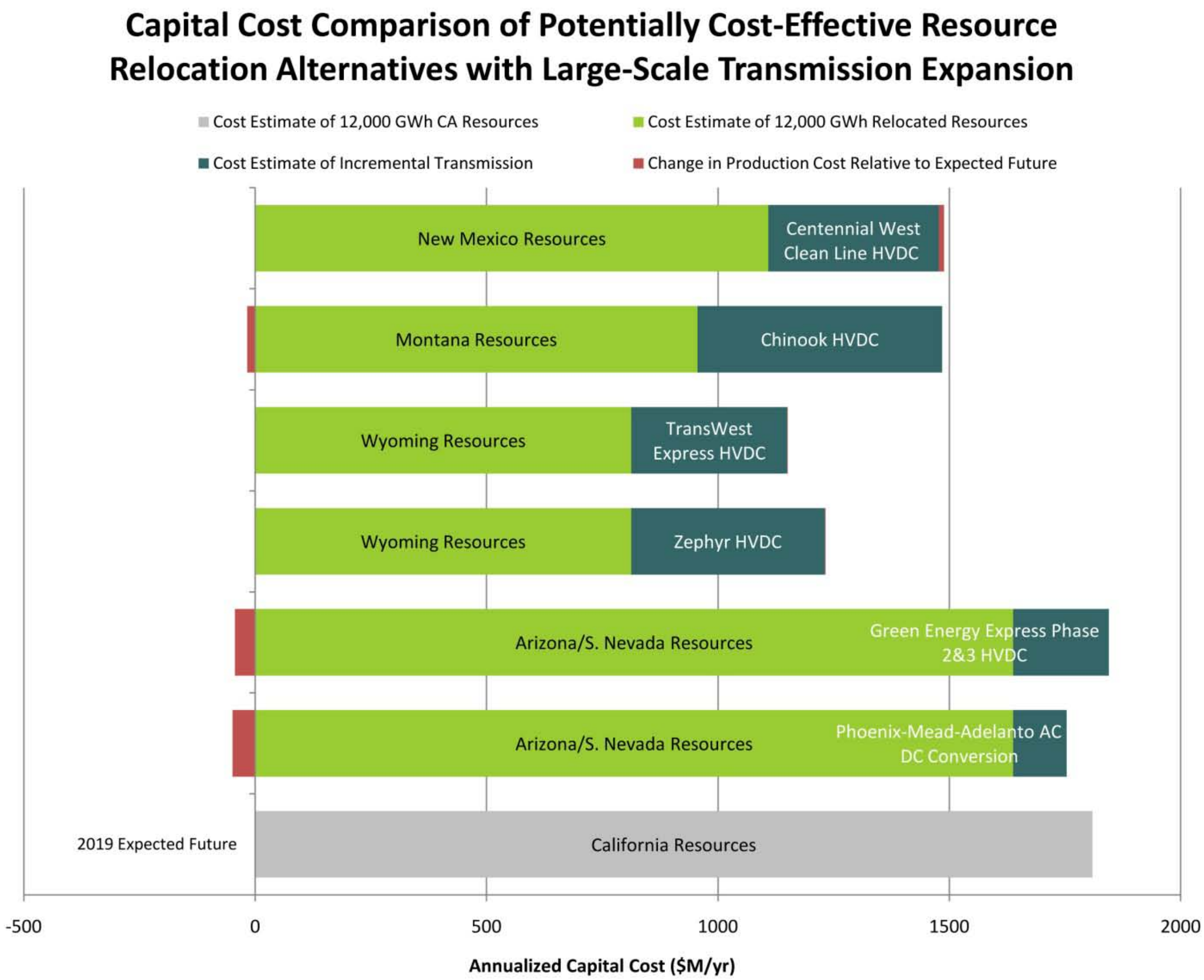


Figure 10 shows the effect on the resource capital cost savings of the capacity cost adjustments made to maintain an equivalent on-peak capacity value between the relocation cases and the resource portfolio removed from California. The estimated cost differential for building 12,000 GWh of renewable generation in the eight relocation cases, rather than in California, more than offsets the cost of building the additional conventional generating capacity necessary to achieve the same level of dependable generating capacity assumed in 2019 PC1A. The nature of the relocation studies did not address combinations of relocations of the 12,000 GWh to multiple areas, which may have provided additional insights about geographical diversity related to renewable expansion.

It was assumed that transmission expansion would accompany the level of resource development evaluated in the resource relocation cases. Transmission expansion alternatives were evaluated together with the resource relocation alternatives, some of which are shown in Figure 11. The transmission alternatives studied were not rigorously assessed in terms of their ability to deliver the relocated generation from particular resource areas to particular load areas. Additionally, there was no technical study to measure the reliability aspects of increased renewable penetration in the areas selected for the relocated resources. However, it was found that the incremental costs for transmission expansion alternatives could be paid for using the resource capital cost savings illustrated in Figure 10. Generation, transmission utilization, and capital cost comparisons of the resource relocation and transmission expansion scenarios are detailed in the [2019 Study Report](#).

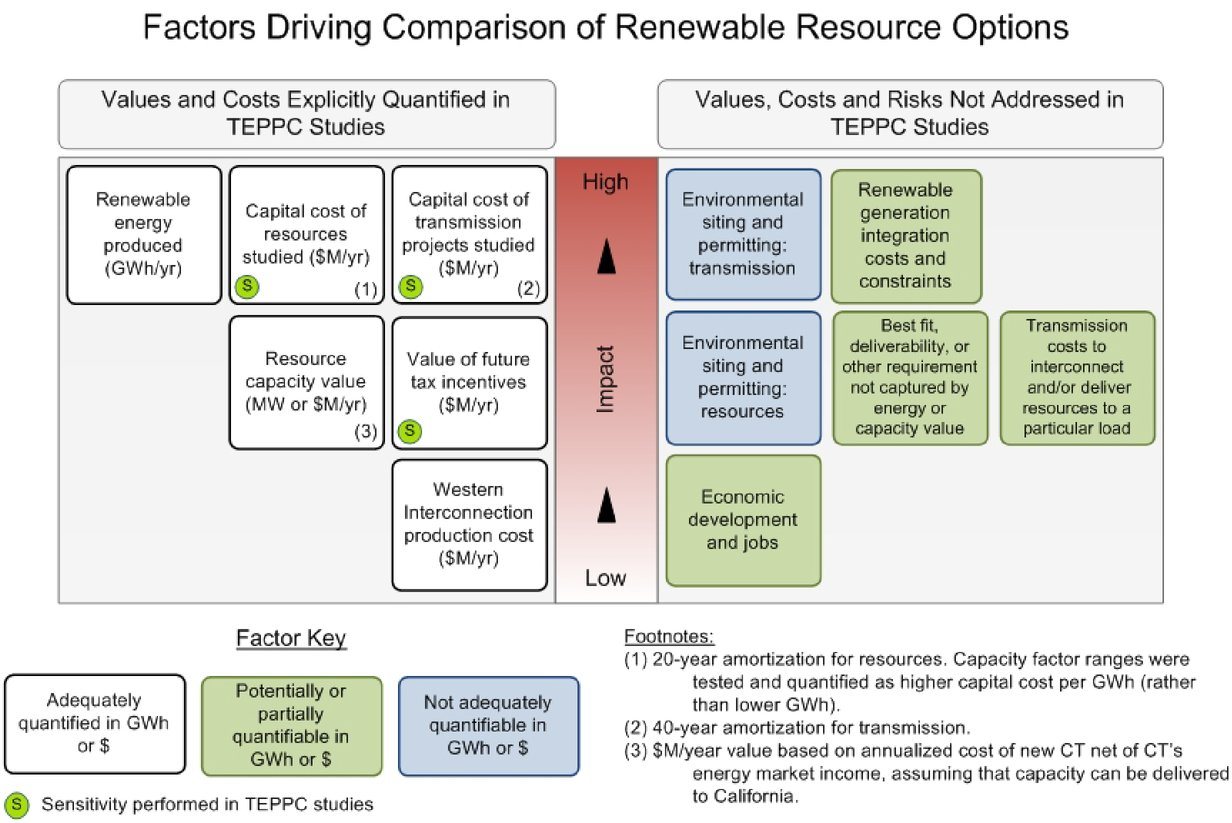
Figure 11: Capital Cost Comparison of Potentially Cost-Effective Resource Relocation Alternatives with Large-Scale Transmission Expansion[13]



[13] The capital costs are assumed to be net of applicable tax incentives and tax credits. This is an abridged graphic from the 2019 Study Report.

For the renewable resource relocation study cases, the analysis performed considered a finite set of values and costs. Figure 12 illustrates those values and costs that may play into a resource decision and which were considered in this analysis. As with any business or regulatory decision, it is the impacts to the entity making the decision that are considered.

Figure 12: Factors Driving Renewable Resource and Transmission Development



3.4 Analyses of Other Study Requests

In addition to an Expected Future and various alternative futures, WECC analyzed other cases to fulfill TEPPC study requests. The additional cases were aimed at understanding an aggressive carbon policy target and the interaction between the proposed Tres Amigas Superstation and the Western Interconnection. The results of these cases are detailed in the 2020 Study Report in 2020 PC8 and 2020 PC9, respectively.

4 Observations and Recommendations

Plan observations and recommendations are based on stakeholder-requested studies performed as part of the RTEP process. The results from many of the studies have been described above. Note: all study cases informed the Plan observations but did not necessarily result in a recommendation.

4.1 Cost-effective remote renewable resources

A number of long-distance transmission alternatives, coupled with alternative remote renewable resources, appear cost-effective as compared to local renewable generation assumed in the

Expected Future case. Results from some of the resource relocation plus transmission expansion alternatives (see 2019 Study Report) evaluated as part of the 10-year planning studies suggest significant total cost savings may result under the alternative resource futures as compared with generation assumed in the Expected Future. Other studies performed as part of the 10-year planning studies suggest that additional transmission may also be required if remote resources are selected in lieu of local generation for pending retirements (e.g., once-though cooling).

WECC suggests that decision-makers keep an open mind regarding transmission infrastructure investment and resource procurement options. Accessing some of the most potentially productive renewable resources by developing viable transmission projects in the Western Interconnection may provide lower-cost, environmentally-preferred options for LSEs and consumers. Local, state, and provincial jurisdictions should consider these opportunities for their compatibility with relevant energy policies, and commercial and business paradigms. They should be flexible enough to comply with such policies so as not forego significant economic benefits that may accrue to their ratepayers.

The different resource relocation and transmission expansion alternatives that were studied, and that support this recommendation, were analyzed at a strategic level emphasizing:

1. known renewable resource procurement trends and information as a starting point;
2. high-level capital cost estimates for resources and transmission studied incrementally to the Expected Future case; and
3. simulation of west-wide generation dispatch and transmission utilization as constrained by a given load, resource, and transmission configuration.

Information provided by these studies can guide subsequent in-depth assessments of various resource and transmission options to meet particular RPS needs or other obligations. They should include a more detailed analysis of the costs and uncertainties associated with any resource and/or transmission alternative considered.

Table 2 outlines the resource and transmission alternatives that appear cost-effective as compared to a portion of the renewable generation assumed in the 2019 Expected Future. The table provides a comparison between the capital costs for 12,000 GWh of the lowest-ranking resources assumed in the 2019 PC1A and the capital costs for 12,000 GWh of high-quality (capacity factor) resources plus incremental long-distance transmission alternatives. These transmission alternatives add enough incremental capacity to transport the relocated resources back to or near the load centers the resources assumed in the 2019 Expected Future originally served. All the transmission alternatives presented in the table below that appear cost-effective, together with their associated resource alternative, are HVDC projects. Additional transmission alternatives investigated with each resource relocation alternative also appeared cost-effective, but did not add enough incremental capacity to transport the full nameplate capacity of the relocated resources. These transmission and associated resource relocation alternatives are discussed in further detail in the 2019 Study Report. Large potential cost savings were also observed as part of the aggressive wind study cases investigated on the 2020 Expected Future. These cases involved relocating 25,000 GWh of renewable generation, designated to be used to meet California's RPS requirements, from various locations around the Interconnection to Montana and Wyoming, respectively. The transmission alternatives studied with the 25,000 GWh resource relocations were not optimized. Despite this, the results are still informative and can be found in the 2020 Study Report.

Table 2: Cost Comparison of Potentially Cost-Effective Resource Relocation Alternatives with Transmission Expansion

Case		***Cost Estimates* ($M/yr)**[14]			
Resource Relocation	**Transmission Expansion**	**12,000 GWh of Resources**	**Incremental Transmission**	**Change in Production Cost Relative to Expected Future**	**Net Change in Cost**
Expected Future		1,810	-	-	-
Arizona/ Southern Nevada	**Phoenix-Mead-Adelanto AC to DC Conversion**	1,638	116	(49)	(105)
Arizona/ Southern Nevada	**Green Energy Express Phase 2&3 HVDC**	1,638	207	(44)	(9)
New Mexico	**Centennial West Clean Line HVDC**	1,109	369	11	(321)
Montana	**Chinook HVDC**	956	529	(17)	(342)
Wyoming	**Zephyr HVDC**	813	418	2	(577)
Wyoming	**TransWest Express HVDC**	813	337	1	(659)

As mentioned previously, the resource capital cost estimates calculated in each resource relocation case are a function of the installed capacity of resources needed to produce 12,000 GWh of energy, which itself is a function of the capacity factor assumed for the resources. The capacity factors of the wind and solar resources modeled in the resource relocation cases were determined using NREL-based wind and solar hourly generation profiles created for the PCM studies.

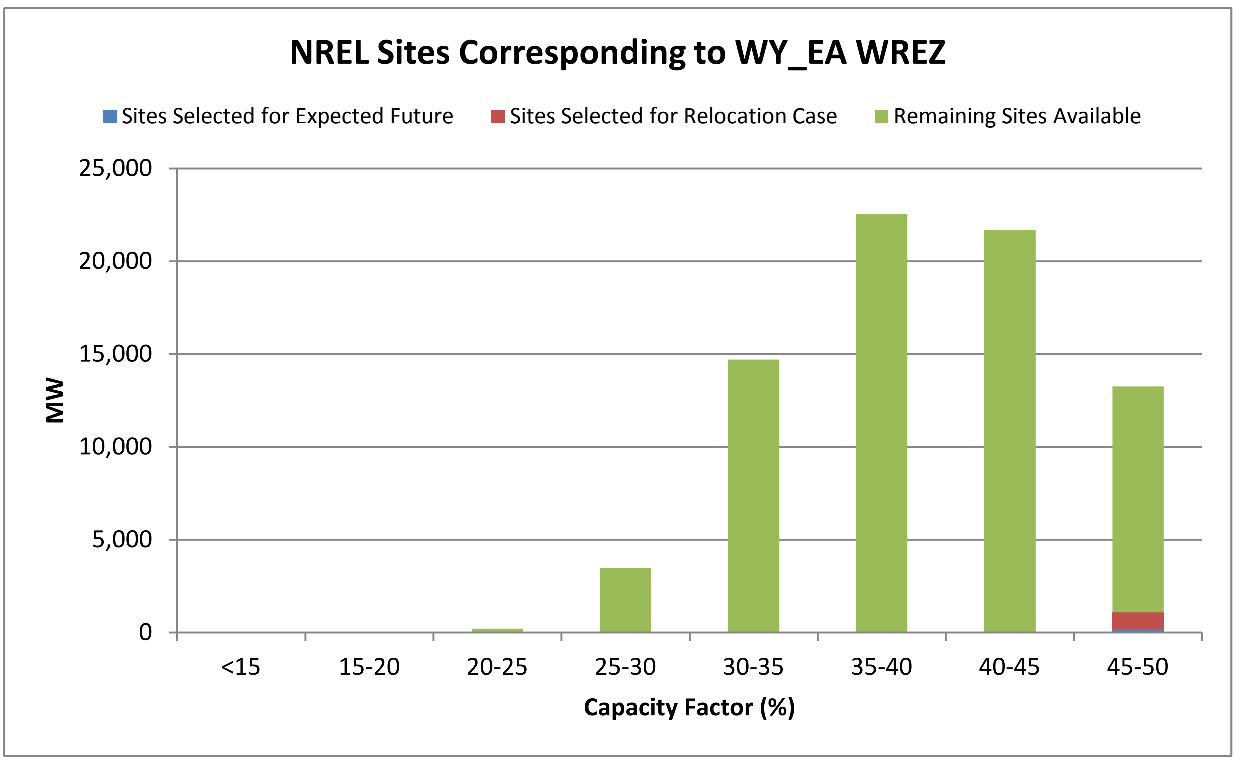
The hourly generation profiles used for the wind and solar resources were created from meso-scale wind and solar datasets developed by NREL that cover the entire U.S. portion of the Western Interconnection. Each of the 30,000 sites in the wind dataset represents 30 MW of installed capacity in a 2km by 2km square based on 100 meter hub heights and with a time resolution of one hour. For the resource relocation cases, detailed in the 2019 Study Report, aggregate wind generation profiles were created for each relocated wind resource by selecting enough of the NREL sites to obtain the target amount of energy being studied. Site selection was done by selecting the highest capacity factor (e.g., best resource quality) NREL sites in the geographic location corresponding to the geographic location selected for the relocated

[14] Capital cost estimates for the resources reflect a 20-year amortization period. A 40-year amortization period was assumed for the transmission capital costs, and a single year's estimated production cost was used.

resource. The geographic locations selected for the relocated wind and solar resources correspond to WREZ hubs.

Figure 13 is a histogram of the NREL sites, by capacity factor, corresponding to the WY_EA (Wyoming East) WREZ. This WREZ hub was selected as the location for a part of the 12,000 GWh relocated in the Wyoming resource relocation case. Approximately 2,500 NREL sites correspond to the WY_EA WREZ resource area, which equates to roughly 75,000 MW of capacity. For the Wyoming resource relocation case 880 MW were located within the WY_EA WREZ, which required the selection of 29 NREL sites to create the hourly generation profile used in the PCM. As described above, these sites were selected from the highest capacity factor sites from among the approximately 2,500 sites available in the NREL data corresponding to the WY_EA WREZ. After the selection of sites needed for the relocated resources, 406 sites, which equate to over 12,000 MW of resources, remained with a capacity factor between 45 and 50 percent. Similar results were observed for the other relocated resources evaluated, which suggest that there are significant high-quality resources available with the capacity factors assumed in the resource relocation cases evaluated.

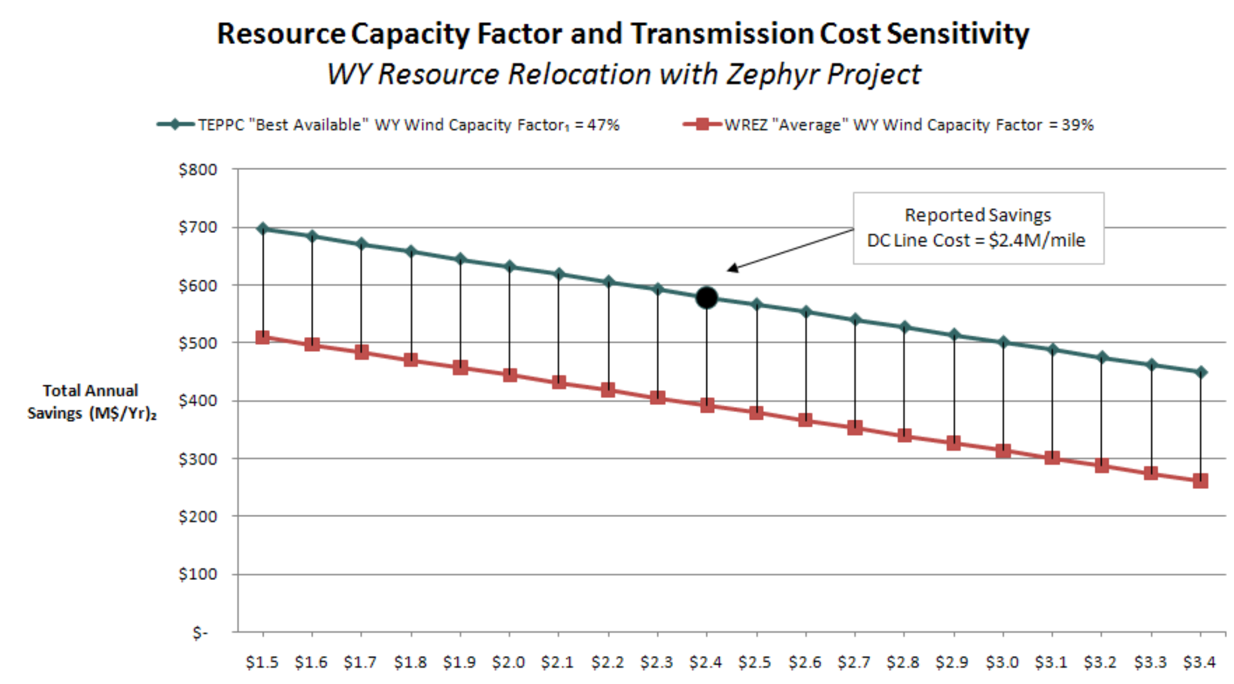
Figure 13: NREL Meso-Scale Wind Profiles Selected for Wyoming Resource Relocation Study



WECC recommends that policy decision-makers consider the cost-based findings detailed in the Plan when crafting policy that may restrict procurement choices. The capital cost calculation methodology used to produce the cost estimates presented for the resource and transmission alternatives evaluated is described in greater detail in Section 5.1.8, but in general reflect point (median) estimates of resource and transmission costs. Actual costs for resource and/or transmission alternatives must be viewed as covering a significant range of uncertainty, and this cost risk will factor prominently into investment decisions.

A sensitivity analysis was performed on two critical input assumptions used to produce the capital cost analysis presented in this section and recognized to be associated with a large degree of uncertainty. These assumptions include the assumed capacity factor of the wind resources studied in the relocation cases, and the estimated cost of the transmission expansion projects that provided enough incremental capacity to transport the full nameplate capacity of the relocated resources. Graphs illustrating results from the cost sensitivities performed on the resource capacity factor and transmission capital cost assumptions are shown below in Figures 14 - 17. These graphs demonstrate how sensitive the reported cost savings for these cases are to key input assumptions. A detailed description of the uncertainties surrounding the capital cost estimates calculated, as well as the complete sensitivity analysis performed on the cost estimates, is provided in the 2019 Study Report.

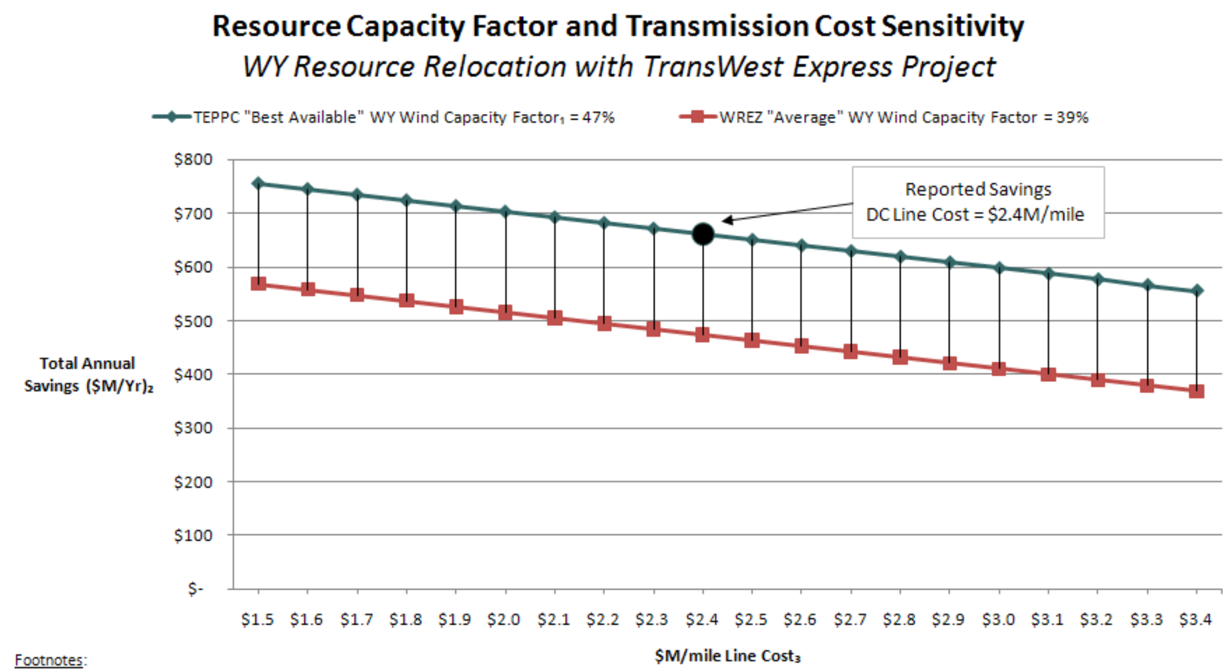
Figure 14: Resource Capacity Factor and Transmission Cost Sensitivity – Wyoming Resource Relocation with Zephyr HVDC



Footnotes:

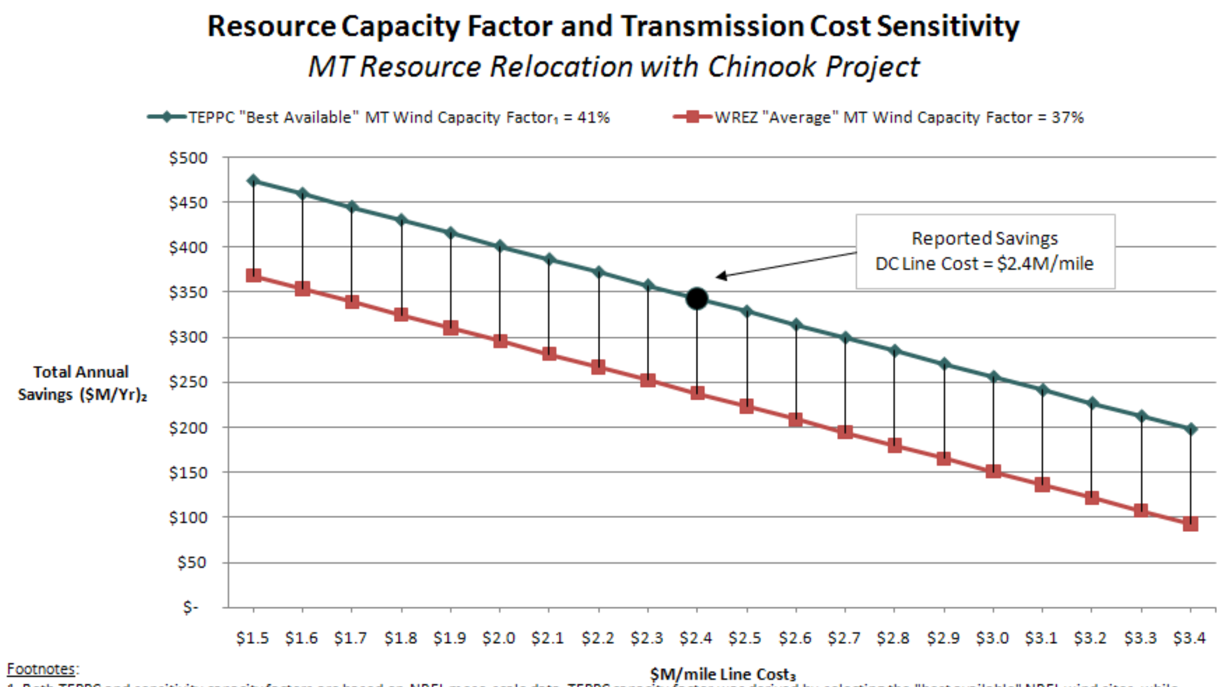
1. Both TEPPC and sensitivity capacity factors are based on NREL meso-scale data. TEPPC capacity factor was derived by selecting the "best available" NREL wind sites, while the "Average" (sensitivity) reflects the average capacity factor all NREL wind sites in the WREZ locations selected for specific relocated resources.
2. Total annual savings (relative to 2019 Expected Future) = resource capital cost savings - transmission project capital cost + decrease in production cost
3. Inclusive of right-of-way costs. Sensitivity range is based on $/mile trasmission line costs of publicly available project cost information taken from projects in varying stages of development.

Figure 15: Resource Capacity Factor and Transmission Cost Sensitivity – Wyoming Resource Relocation with TransWest Express HVDC



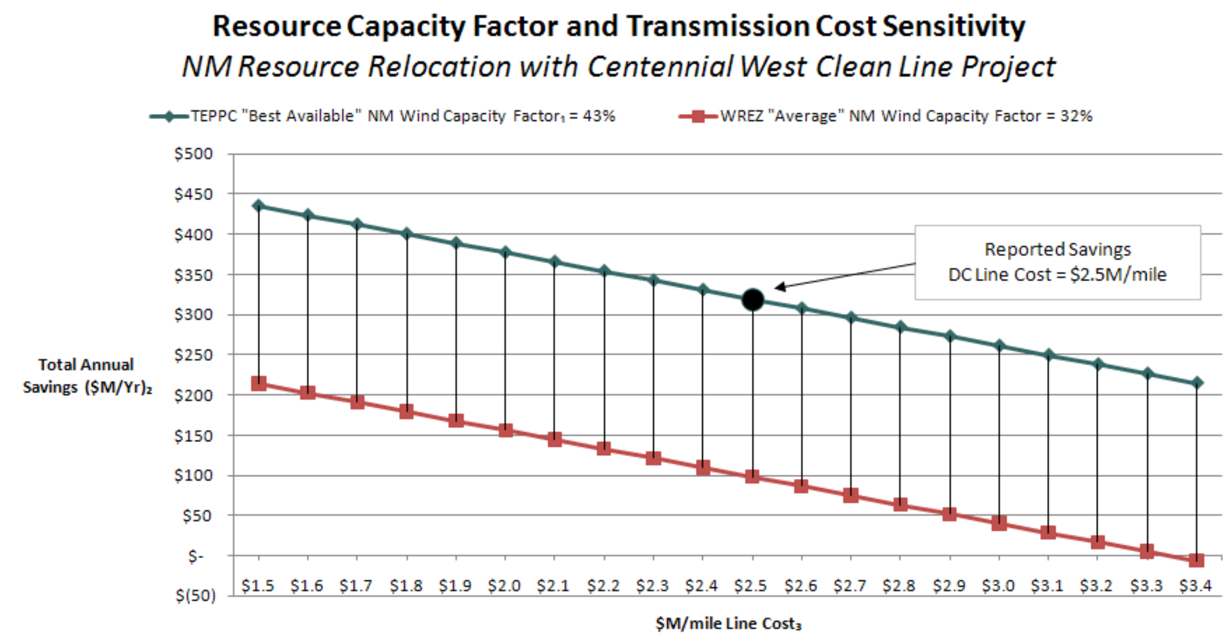
Footnotes:
1. Both TEPPC and sensitivity capacity factors are based on NREL meso-scale data. TEPPC capacity factor was derived by selecting the "best available" NREL wind sites, while the "Average" (sensitivity) reflects the average capacity factor all NREL wind sites in the WREZ locations selected for specific relocated resources.
2. Total annual savings (relative to 2019 Expected Future) = resource capital cost savings - transmission project capital cost + decrease in production cost
3. Inclusive of right-of-way costs. Sensitivity range is based on $/mile trasmission line costs of publicly available project cost information taken from projects in varying stages of development.

Figure 16: Resource Capacity Factor and Transmission Cost Sensitivity – Montana Resource Relocation with Chinook HVDC



Footnotes:
1. Both TEPPC and sensitivity capacity factors are based on NREL meso-scale data. TEPPC capacity factor was derived by selecting the "best available" NREL wind sites, while the "Average" (sensitivity) reflects the average capacity factor all NREL wind sites in the WREZ locations selected for specific relocated resources.
2. Total annual savings (relative to 2019 Expected Future) = resource capital cost savings - transmission project capital cost + decrease in production cost
3. Inclusive of right-of-way costs. Sensitivity range is based on $/mile trasmission line costs of publicly available project cost information taken from projects in varying stages of development.

Figure 17: Resource Capacity Factor and Transmission Cost Sensitivity – New Mexico Resource Relocation with Centennial West Clean Line HVDC



Footnotes:

1. Both TEPPC and sensitivity capacity factors are based on NREL meso-scale data. TEPPC capacity factor was derived by selecting the "best available" NREL wind sites, while the "Average" (sensitivity) reflects the average capacity factor all NREL wind sites in the WREZ locations selected for specific relocated resources.
2. Total annual savings (relative to 2019 Expected Future) = resource capital cost savings - transmission project capital cost + decrease in production cost
3. Inclusive of right-of-way costs. Sensitivity range is based on $/mile trasmission line costs of publicly available project cost information taken from projects in varying stages of development.

4.2 Montana to Northwest – Path 8

Recommendation

In the 10-year planning studies, the utilization of and congestion on the Montana to Northwest transmission Path (Path 8) remains consistently high and increases notably under a variety of conditions. This behavior is observed because the transmission system used to export resources from Montana was designed specifically to carry existing high capacity factor generation. WECC recommends decision-makers consider transmission upgrades or other mitigating measures that relieve congestion on Path 8 as renewable, or other types of generation, are expanded in Montana. WECC cannot make specific recommendations to mitigate the congestion. This may be future work for WECC or others.

Much of the analysis performed in the 10-year planning studies assumes 588 MW of new resources (455 MW of wind) will be installed in Montana by 2020, which contributes significantly to transmission congestion for Montana exports. If these resources are not constructed, it is expected that Path 8 utilization levels will not differ greatly from what is observed today.

While individual solutions to mitigate potential congestion on Path 8 were not evaluated, the solutions proposed appear to relieve congestion on Path 8.

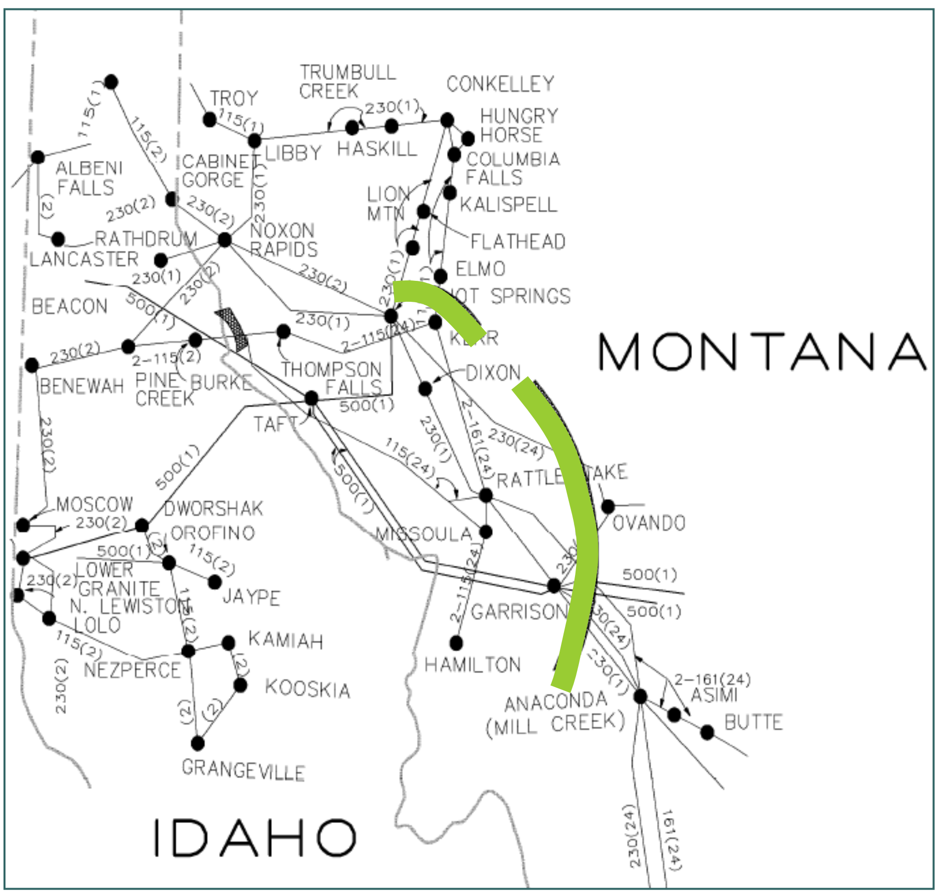
Description

Path 8, the largest of three Montana export paths, consists of the lines running between western Montana and the Pacific Northwest states. It is the only major WECC Path available to export resources out of the state. The lines included as part of Path 8 are the metered tie lines between NorthWestern Energy (NWMT) and Bonneville Power Administration, plus the tie lines between NWMT and Avista Corp. Key path characteristics as defined by the WECC 2011 Path Rating Catalog can be found in Table 3. Figure 18 shows the physical cut plane that forms the Montana to Northwest Path.[15]

Table 3: Path 8 Characteristics

Path Characteristics	
Rating E to W	2,200 MW
Rating W to E	1,350 MW
Max Voltage	500 kV

Figure 18: Path 8 Cutplanes



Summary of Findings

Path 8 and other Montana export paths may substantially increase in the 10-year timeframe as new generation is added and existing generation remains online (i.e., not retired). This finding is supported by historical information,[16] congestion analyses, project development information, and renewable resource potential. If this scenario unfolds, plausible options to relieve the induced congestion and enable the delivery of additional resources include:

- expanding transmission out of Montana to deliver resources directly to load centers; or
- adding new lines or upgrading existing lines out of Montana that access less constrained paths.

Of the three export paths used to transfer resources out of Montana, Path 8 is the most congested according to the metrics[17] evaluated as part of the 10-year planning studies. Historical data shows that Path 8 has been, and remains, heavily utilized. This is consistent with its original design to move large quantities of base-load generation out of Montana to the Pacific Northwest. This information demonstrates that today's level of utilization on Path 8 is high when compared to other WECC Paths. Furthermore, the 10-year planning studies showed that export path utilization out of Montana will increase in almost all load and resource scenarios considered. Over the 10-year timeframe, some resource development scenarios revealed congestion on Montana export paths that is severe and could restrict the ability to export additional generation resources out of the state. Additional factors suggest there may be an economic benefit in building transmission to access renewable resources in the state with the additional benefit of relieving congestion along the Montana export paths.

Supporting Analyses

Results from historical and future congestion analyses support the selection of Path 8 as an area of concern. The analyses suggest high levels of congestion along the paths may restrict new potential resources located within Montana from accessing external load centers. The study results that form these observations are highly dependent on the assumption that additional renewable generation will be developed in Montana. At a minimum, the supporting analyses reinforce the need to monitor and perform additional studies on the Montana export paths.

Historical Path Utilization

The TEPPC Transmission Path Utilization Reports quantify the historical utilization of major transmission paths in the Western Interconnection and provide insight to where transmission congestion occurred during the historic study year. The last three path utilization studies (conducted in 2007-2009) provided relevant congestion information for Path 8.

The 2009 TEPPC Transmission Path Utilization Study analyzed 2009 and 2008 flow, schedule, and available transmission capacity data for Path 8 and Path 18 (Montana-Idaho). The study identified Path 8 as the fifth most heavily utilized path in the Western Interconnection, relative to its capacity. Path 8 received this ranking based on flow, schedule, and block-hour schedule

16 Path 8 capacity was constructed to transport Colstrip generation.
17 The transmission utilization and congestion metrics are described in Section 5.1.6.

metrics. In the same study year, Path 18 was the 16th and 17th most heavily utilized path based on directional and net schedule metrics, respectively.

The 2008 TEPPC Transmission Path Utilization Study analyzed 2007 flow and schedule data for Path 8 and Path 18. Overall, Path 8 was listed as one of the top 10 most heavily used in the Western Interconnection in 2007. This ranking was based on Path 8 being one of the six most heavily utilized paths according to actual flow and maximum directional schedule metrics. Path 18 ranked as the sixth and eighth most congested path according to max and net schedule metrics, respectively. According to flow metrics, Path 18 ranked as the 17th most heavily utilized path.

The 2007 TEPPC Transmission Path Utilization Study looked back at path flow data from 1999 through 2005. It was found that Path 8 operated at 75 percent of its limit for 25 to 50 percent of the year in the highest load year. Path 8 actual flow data and schedule are presented as duration charts in Figure 19 and Figure 20.

Figure 19: Path 8 Historical Flow Duration Chart

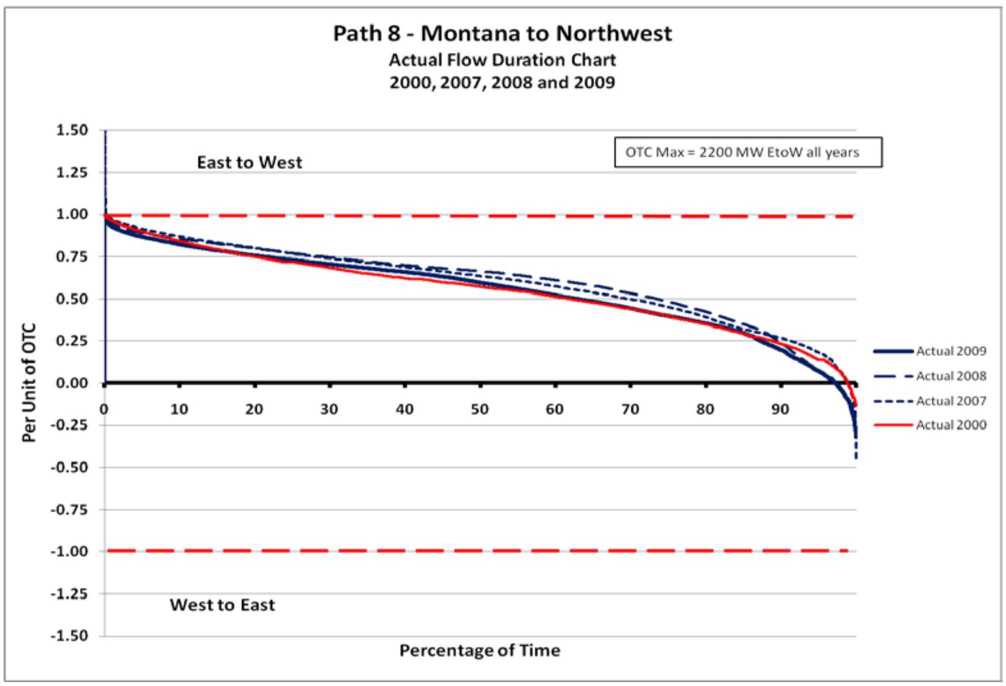
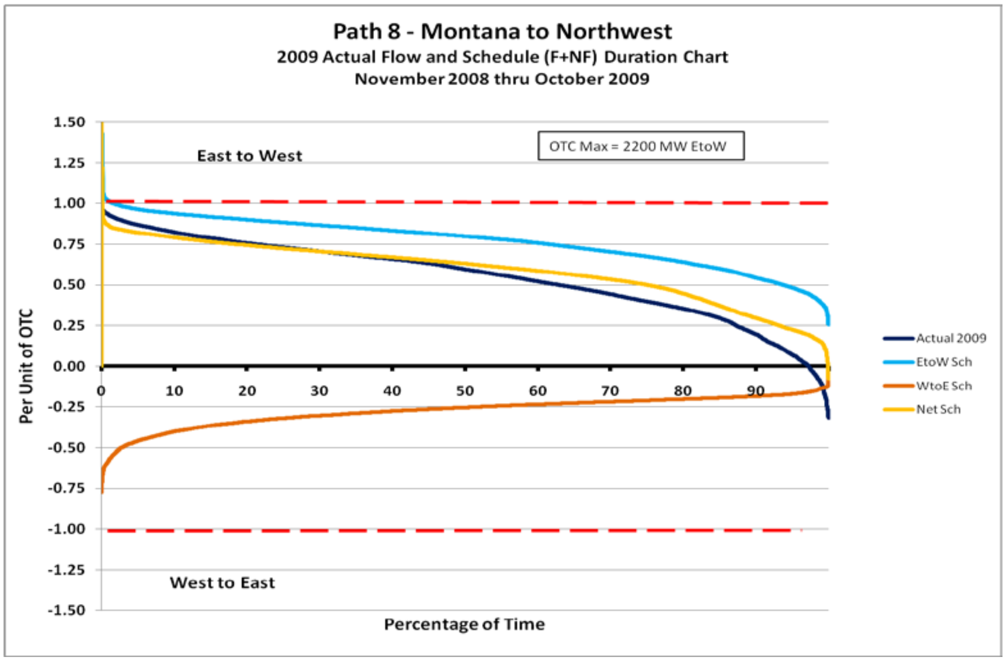


Figure 20: Path 8 Historical Schedule Data Duration Chart



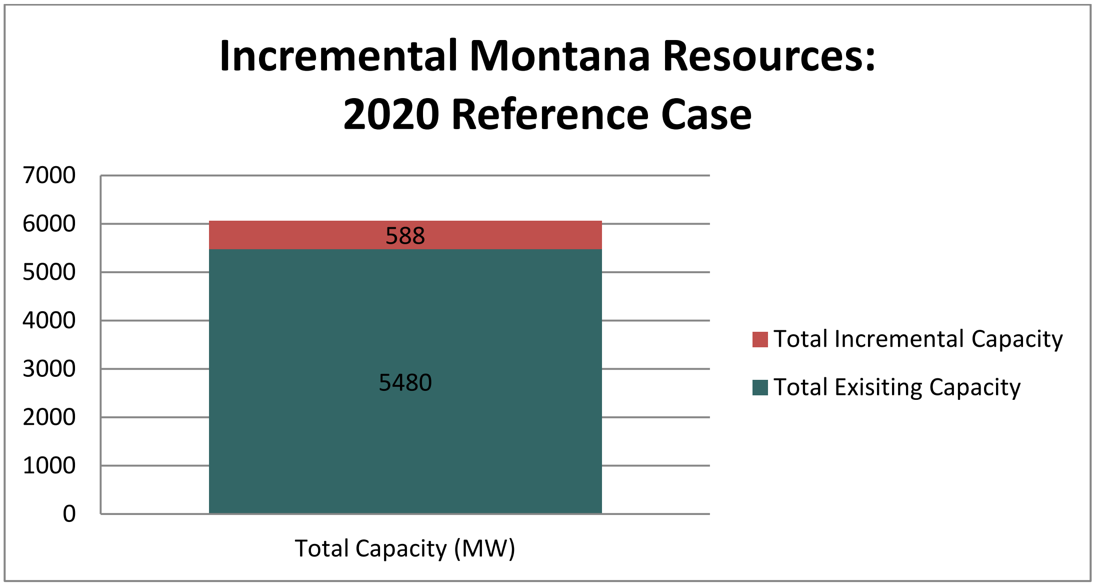
Regional Operating Characteristics

In current operation, much of the energy exported from Montana originates from the Colstrip Power Plant located east of Billings, Montana. The four units deliver a combined generating capacity of 2,100 MW to the system. Currently, these are operated as a base-load resource and historically not subject to frequent ramping. Montana is also home to considerable hydroelectric resources from which energy can be transferred to load centers inside and outside Montana over its export paths. These existing hydro resources represent nearly 2,500 MW of generation capacity. However some hydro resources such as Libby, Hungry Horse, and Noxon in the northwest corner of Montana do not impact Path 8 capability.

Based on the amount of renewable energy modeled in the 10-year planning studies, variable generation could have significant impacts on the manner in which the existing coal and hydro resources are dispatched and operated. The studies suggest this impact would be intensified, perhaps to unacceptable reliability impact levels, if the congestion issues along the Montana export paths are not addressed. It is important to note that, in the PCM, wind and other renewables are modeled as 'must-take' resources. This grants renewable generation transmission priority and causes conventional resources like coal (in this case Colstrip specifically) to back down when transmission constraints are encountered. This type of operation is not consistent with present-day scheduling and operational standards and is an indication that without sufficient transmission, new generation would not be able to operate. Figure 21 shows the total present-day existing generation capacity in Montana,[18] as well as the capacity of the incremental resources added in the 2020 Expected Future case.

[18] Note that not all sources impact Montana's export paths because of their location with respect to the export paths.

Figure 21: Montana Existing and Incremental Resource Capacity



Of the 588 MW of capacity added to Montana in the 2020 Expected Future case, 455 MW was wind-powered – a fraction of the state's renewable potential. This amount of variable generation introduced a considerable amount of congestion on the Montana export paths, especially Path 8. This is not surprising since the study did not add new transmission to accommodate the new resources.

Congestion Analysis

Three metrics — utilization, risk, and value — are used to help quantify the amount of conditional congestion along a path in TEPPC study cases. The Recurrent Count and Total Recurrent Congestion Score indicate high utilization and congestion across a range of study cases (i.e., chronically congested). These metrics help identify areas of congestion within the Western Interconnection regardless of any future scenario. The following congestion analyses investigate conditional and chronic congestion along Path 8 using these metrics.

Conditional Congestion

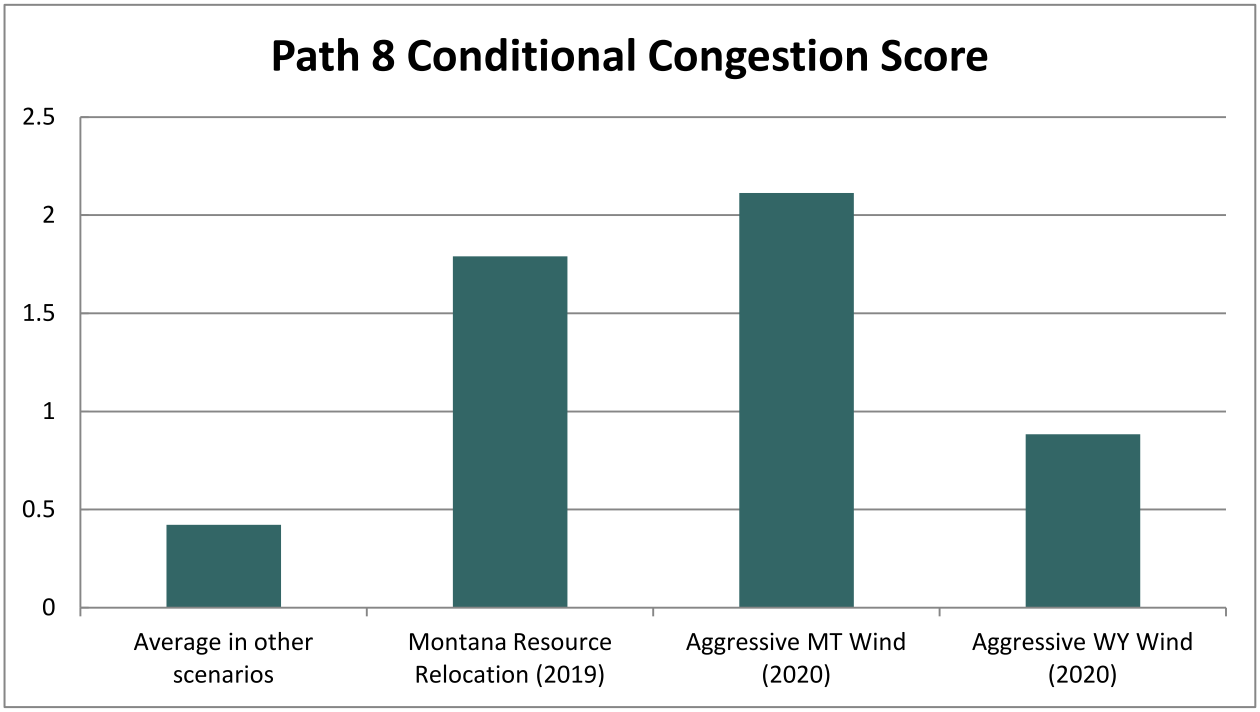
Congestion that is contingent on a specific future (e.g., resource location, load level) is termed conditional congestion. In order to identify the scenarios where congestion is most severe, the analysis reviews conditional congestion scores for each path for all study cases analyzed in the 2010 TEPPC Study Program. The scenarios for which congestion along the Montana export paths is most contingent are summarized in Table 4.

Table 4: Montana Export Path Conditional Congestion

Montana Export Path	Conditional Congestion Scenarios
Path 8: Montana to Northwest	Montana Resource Relocation (2019 PC12) Aggressive Montana Wind (2020 PC6) Aggressive Wyoming Wind (2020 PC7)
Path 18: Montana – Idaho	Montana Resource Relocation (2019 PC12) Aggressive Montana Wind (2020 PC6)
Path 80: Montana Southeast	Aggressive Montana Wind (2020 PC7)

The conditional congestion scores calculated for Path 8 in the identified study cases were from 50 to 80 percent higher than the average score in all other cases for which Path 8 met the definition of being "highly utilized." These relatively high levels of congestion on Path 8 are contingent on three scenarios. The increase in congestion for these scenarios is shown in Figure 22.

Figure 22: Montana to Northwest Conditional Congestion Score



In both the 2019 and the 2020 Montana resource relocation study cases, Path 8 operated above 90 percent of its limit for at least 40 percent of the year. This extreme level of utilization is reflected in the high conditional congestion score. The drastic increase in congestion along Path 8 in these specific Montana and Wyoming resource scenarios is due to the system's inability to integrate the amount of renewable resources modeled while continuing to operate base-load coal units in a traditional manner without additional transmission.

There is also valuable insight to be gained by finding those scenarios for which the utilization of Path 8 is the lowest. The Path was highly utilized in every case except the 2020 Carbon Reduction case. This was the result of a $30 per ton carbon adder that decreased the output of the Colstrip generators. The Path was highly utilized in all other cases, but experienced lower levels of congestion (compared to its overall average) in the following scenarios:

- British Columbia Resource Relocation (2019)
- Northern Nevada Resource Relocation (2019)
- Northwest Coastal Resource Relocation (2019)

Recurrent Count

This metric identifies those paths that are highly utilized across a range of plausible futures. A utilization screening was applied to the 15 study cases used to inform the Plan, and the Montana to Northwest Path passed this screening in 14 cases. Relative to the other paths, Path 8 had the second highest Recurrent Count. In terms of frequency, this Path is one of the most heavily utilized paths regardless of the resource future. Path 18 passed the utilization screening in two scenarios, and Path 80 was highly utilized in one scenario.

Total Recurrent Congestion Score

The Total Recurrent Congestion Score applies the principles of the Recurrent Count, but focuses on congestion rather than utilization by summing the Conditional Congestion Score across all study cases for which the path passed the utilization screening. This gives a measure for the magnitude of the path's congestion, regardless of the future scenario. A high Total Recurrent Congestion Score might indicate a chronically congested path. Path 8 had the 2nd highest Total Recurrent Congestion Score. Alternatively, Paths 18 and 80 had much lower Total Recurrent Congestion Scores, which point toward these paths being conditionally congested, not recurrently congested.

Expansion Cases

There are numerous ways to relieve a highly utilized path that becomes congested when new generation is added, one of which is transmission expansion. Congestion relief is just one of many reasons to build transmission; however, not all highly utilized paths are congested[19].

Due to the significant amount of congestion identified along the Montana export paths, valuable insight can be gained by modeling transmission expansion in the 2020 Expected Future case. However, since Path 8 is the only chronically congested Montana export path, the impact of transmission expansion modeled on the Expected Future case will only be evident there. Other Montana export paths (i.e., Path 18 and Path 80) are conditionally congested in specific scenarios, none of which are the Expected Future case. Therefore, the analysis looked exclusively at the impact of transmission expansion on Path 8, not Path 18 or Path 80.

Based on known projects and stakeholder input, the following projects were modeled to provide information on their ability to relieve congestion on Path 8 identified in the 2020 Expected Future case.

- Chinook – 500-kV DC, 3,000 MW transmission line originating near Harlowton, Montana, traversing Idaho and terminating in the Eldorado Valley, south of Las Vegas, Nevada.[20]
- Mountain State Transmission Intertie (MSTI) – 500-kV AC, 1,500 MW transmission line, delivering electricity from Townsend, Montana to Midpoint, Idaho. The intent of the MSTI project addresses the need for new electric transmission service, delivering power from generation to customers.
- Path 8 Upgrade – A series compensation project that would increase the Path 8 rating from 2,200 MW to 2,900 MW.

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19 The utilization and congestion metrics are explained in Section 5.1.6.

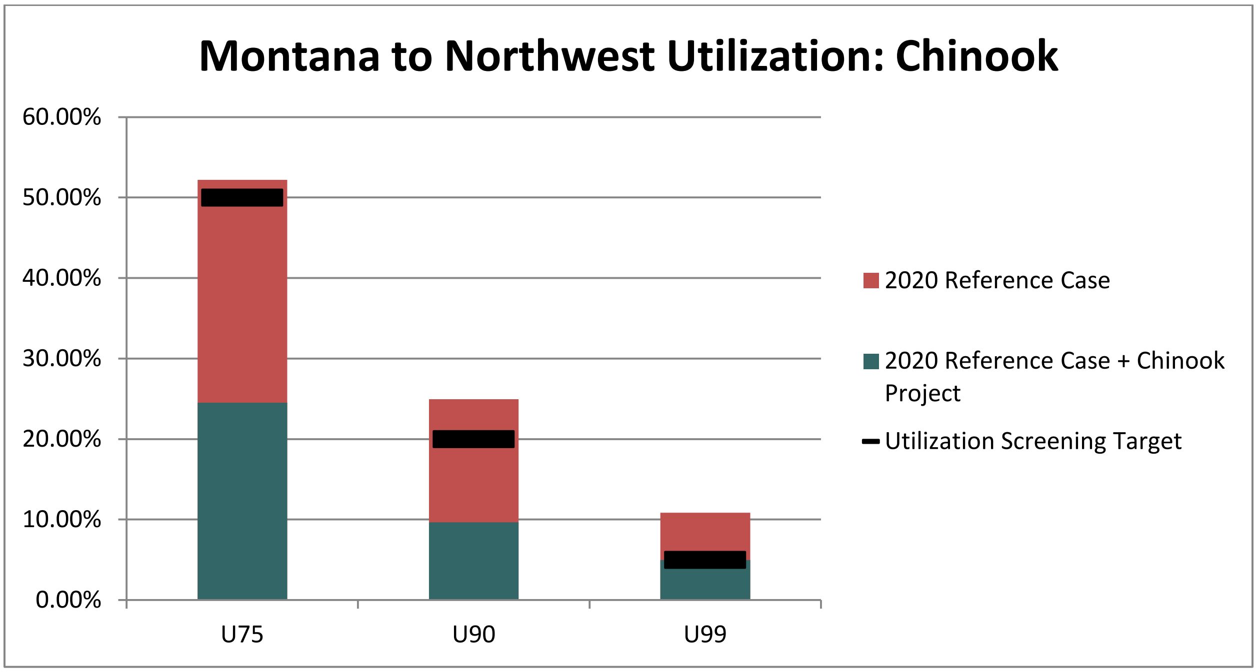
20 This project was modeled in the 2020 Expected Future case with an intermediate converter station at Borah, Idaho.

By comparing the amount of congestion remaining after the addition of the Chinook, MSTI, and Path 8 Upgrades, it is easier to understand the type of impact these projects might have on Path 8 in the 2020 Expected Future case.

Chinook

In the 2020 Expected Future case, Path 8 passed the utilization screening based on all three of the utilization metrics, U75, U90, and U99.[21] After the implementation of the Chinook project, Montana-Northwest no longer passed any of the screenings, meaning that by definition the path was no longer highly utilized. This decrease in utilization along Path 8 can be seen in Figure 23.

Figure 23: Montana to Northwest Utilization (Chinook)



In addition to reducing the congestion along Path 8, the Chinook project also reduced the WECC-wide average U99 from 5.74 to 5.64 percent. The average U75 decreased from 15.08 to 13.63 percent, as well. Overall, the Chinook project was effective at reducing congestion along Path 8 and lowering WECC-wide transmission utilization. If the PCM more accurately modeled high-voltage DC (HVDC) lines, it is expected that Path 8 utilization would be further reduced, along with the Pacific-Tie Paths and possibly Path 15 (Midway-Los Banos).

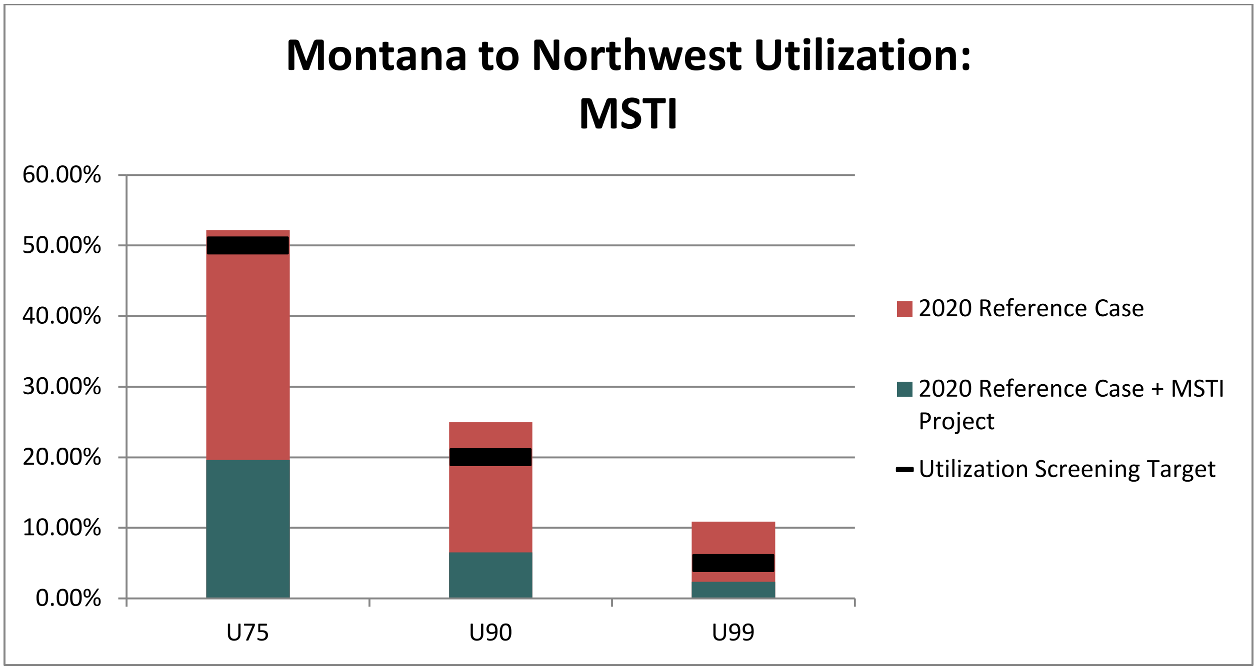
21 Utilization metrics (U75, U90, and U99) represent the number of hours when flows are greater than the percentage of the path's rated capacity (i.e., U75 = 75 hours). They are often reported as a percentage of the time frame being considered.

The addition of the Chinook project introduced more congestion and higher utilization along the TOT 2C Path. The U90 levels along TOT 2C increased from 12.88 percent in the 2020 Expected Future case to 21.50 percent in the Chinook scenario.[22]

MSTI

The addition of the MSTI project also resulted in Path 8 no longer being highly utilized. All three utilization metrics decreased, with more than a 30 percent decrease in the U75 metric. The changes in the utilization values are shown below in Figure 24. Path 8 passed all utilization metrics by a wide margin.

Figure 24: Montana to Northwest Utilization (MSTI)



In the MSTI expansion case, the entire WECC-wide U90 average did not show substantial change. With the addition of the MSTI project, the total number of paths that passed the utilization screening did not decrease. However, the MSTI project had a drastic effect on the utilization and congestion along Path 8.

There was a significant change in the utilization of the West of Crossover Path. In the Expected Future case West of Crossover operated at U75 for 70 percent of the year, and at U90 for 9.47 percent of the year. The utilization of this Path increased after the addition of the MSTI project to 74.70 percent and 29.06 percent, respectively. This increase could be due to the region's

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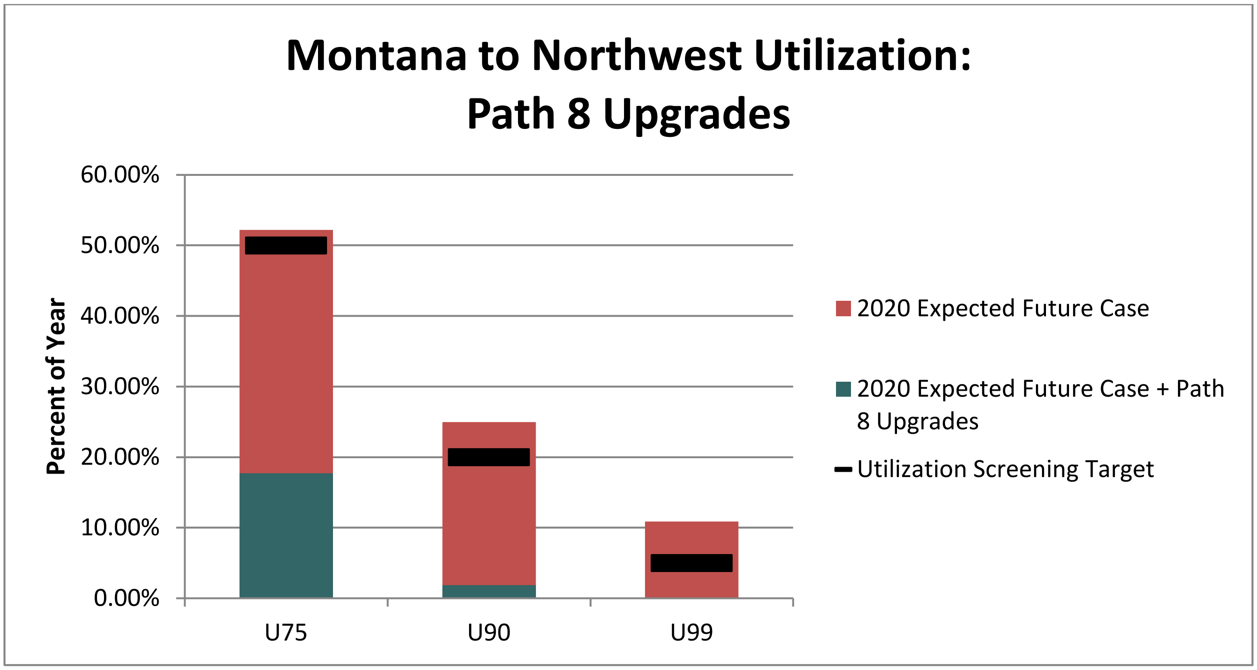
[22] This result was obtained with the Borah intermediate converter in service. The PCM is currently not able to effectively simulate the operation of an intermediate converter. The control parameters of such a convertor station could likely be established to reduce or at least not increase congestion on TOT 2C.

increased export capacity after the addition of the MSTI project. This may have caused an increase in coal generation from the Colstrip generators in the PCM, which would likely not happen in reality since the West of Crossover Path can be controlled using phase shifting transformers.

Path 8 Upgrades

The Path 8 Upgrade project resulted in the greatest decrease in Montana to Northwest utilization metrics. The project effectively increased the east to west limit of the line from 2,200 MW to 2,900 MW. Path 8 did not pass any of the utilization screenings after the implementation of the upgrades. The decrease in each of the utilization metrics is shown in Figure 25.

Figure 25: Montana to Northwest Utilization (Path 8 Upgrades)



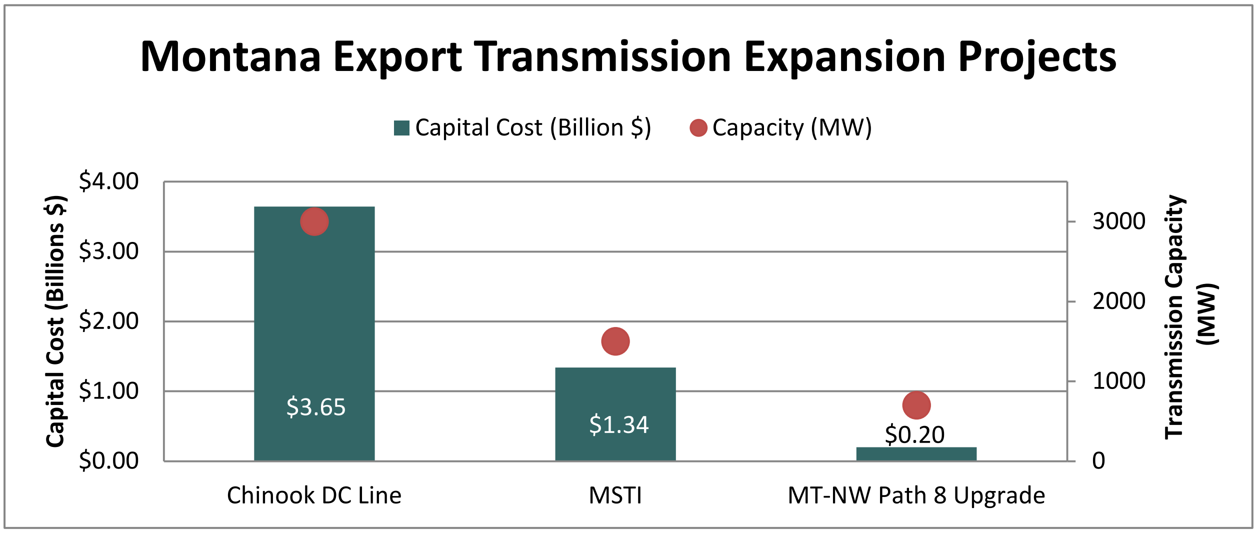
The Path 8 Upgrades had no effect on the WECC-wide average U90 value or the number of paths that passed the utilization screening. For those paths that passed the utilization screening in the Path 8 Upgrade expansion case, there were no significant increases or decreases in utilization.

All three of the expansion cases run off the Expected Future case effectively reduced congestion along Path 8.

Capital Costs

Each of the projects modeled in the expansion cases have a capital cost associated with implementing the incremental transmission. Figure 26 shows the wide range of cost estimates for these projects. Importantly, each project has a different rating, termination point, and stated purpose. No comparison as to the relative value of the projects can be made from these analyses. For clarity, the varying degree of transmission capacity is shown on the chart. A more detailed explanation of capital costs and their uncertainty can be found in Section 5.1.8.

Figure 26: Capital Cost Estimates and Project Capacity[23]



External Impacts & Added Value

Information currently unavailable to WECC may impact the Montana export path recommendation. The following describes some of the unavailable information and its possible impacts on recommendations. Additionally, a description of how completing the recommendation for the Montana export paths may assist in the completion of other planning recommendations that are included in this report is also provided below.

Limitations

The congestion analysis referenced above was completed using the PCM. The PCM operates in an ideal world and performs an economic dispatch of the Western Interconnection that is unrealistic. Interpreting results from the PCM into meaningful metrics that compare to real life operation is often difficult. For example, the PCM routinely dispatches lines well above 90 percent of their operating limits. This relatively high level of flow is rarely allowed in actual operations. To the extent possible, the congestion metrics used in these supporting analyses consider these types of operating realities.

Moreover, no specific contractual agreements (other than the IPP DC line incorporation into the Los Angeles Department of Water and Power's (LADWP) Balancing Area) were modeled in the PCM, which impacts generation dispatch. Had these contracts been modeled, flows along Path 8 could increase or decrease in the model, thereby potentially affecting the recommendation.

Resource assumptions affect the generation dispatch performed by the PCM and the subsequent transmission flows observed across the system as a result of the economic dispatch. Renewable resources are the least-cost resources available to the PCM and are therefore dispatched first, and, as such, assumptions regarding the location of renewable resources can have a notable impact on transmission results. The resource assumptions used to develop the cases analyzed by TEPPC were based on known renewable resource

[23] The cost estimate for the Chinook project does not include the estimated $250M cost for a converter station at Borah.

procurement trends at the time the case was developed. Recent policy changes in California related to renewable energy development within the state are not incorporated into this Plan.

Supporting Other Recommendations

The Cost-effective remote renewable resources recommendation has parallel conclusions to the Montana to Northwest recommendation. The congestion relief recommendation for the Montana export paths supports other recommendations in the Plan, such as those based around energy policy. Resources will likely be built if there is more export capacity out of Montana. In addition, more resource development in Montana will help to further justify the need to reduce congestion out of Montana in order to get those new resources to load areas.

4.3 Pacific-Tie Paths – Paths 65 and 66

Recommendation

The utilization of and congestion on the Pacific-Tie Paths, Pacific DC Intertie (Path 65) and California-Oregon Intertie (Path 66), remain consistently high and increases under a variety of conditions analyzed in the 10-year planning studies. WECC recommends consideration by decision-makers for transmission upgrades or other mitigating measures that relieve congestion on Paths 65 and 66. WECC cannot make specific recommendations to mitigate the congestion. This may be future work for WECC or others.

Much of the analysis performed in the 10-year planning studies assumes almost 8,800 MW of wind generation will be installed in Oregon and Washington by 2020, which contributes significantly to transmission congestion along the Pacific-Tie Paths. If these resources do not materialize, congestion along these paths will be less prevalent. While individual solutions to mitigate potential congestion on the Pacific-Tie Paths were not evaluated, the solutions proposed appear to relieve congestion on Paths 65 and 66.

Description

Path 65 is a +/- 500-kV DC multi-terminal system stretching from the Celilo station (Big Eddy area) in northern Oregon to the Sylmar station in southern California. The system is divided into northern and southern systems, with the demarcation point at the Nevada-Oregon state border. Transfer limits for the path are based on sending end-measured power. Key path characteristics as defined by the WECC 2011 Path Rating Catalog can be found in Table 5. Figure 27 shows the physical cut plane that forms the PDCI Path.[24]

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[24] WECC 2011 Path Rating Catalog: Link Access to the Path Rating Catalog is limited.

Table 5: Path 65 Characteristics

Path Characteristics	
Rating N to S	3,100 MW
Rating S to N	3,100 MW
Max Voltage	500-kV DC

Figure 27: PDCI Cutplane

Path 66 is an AC intertie composed of three 500-kV lines between Oregon and northern California. Key path characteristics as defined by the WECC 2011 Path Rating Catalog can be found in Table 6. Figure 28 shows the physical cut plane that forms the California-Oregon Intertie (COI) Path.[25] In a recent report published May 2011 titled COI Utilization Report, the Transmission Utilization Group composed of owners of the COI, determined that entities that need firm delivery will require new transmission capacity.

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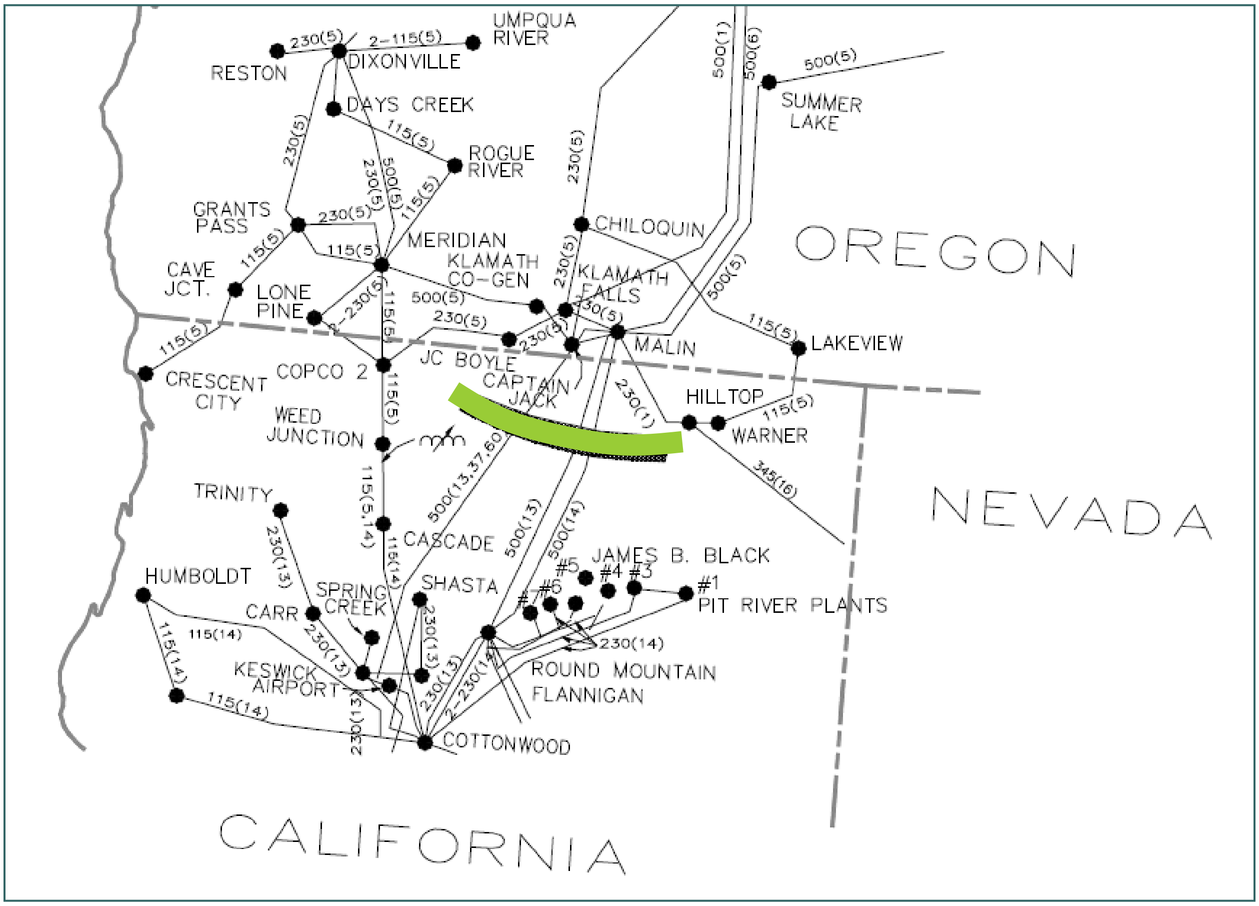
[25] WECC 2011 Path Rating Catalog: Link. Access to the Path Rating Catalog is limited.

Table 6: Path 66 Characteristics

Path Characteristics	
Rating N to S	4,800 MW
Rating S to N	3,675 MW
Max Voltage	500-kV AC

Figure 28: California-Oregon Intertie Cutplane



Summary of Findings

Historical data, congestion analysis, project development information, and the potential opportunity to import renewables from the northwest into California support the finding that transmission congestion along Paths 65 and 66 may become more severe in the 10-year timeframe to 2020. Plausible options to reduce the congestion and enable the delivery of additional resources include:

- expanding transmission out of the Northwest delivering resources directly to load centers; or
- adding new lines or upgrading existing lines out of the Northwest that access less constrained paths; or
- creating a portfolio of complementary resources to shift path loading.

Historical data show the COI and PDCI as congested paths in 2007. This information can be used to conclude that today's levels of congestion on Paths 65 and 66 are extreme compared to other WECC Paths. The 10-year planning studies show that utilization of these paths will likely increase. Specifically, scenarios could develop over the 10-year timeframe that result in severe congestion on the COI and PDCI that would greatly restrict resource delivery out of the Northwest. Additional factors suggest there may be an economic benefit to building transmission that would have the additional benefit of relieving congestion along Paths 65 and 66.

Supporting Analyses

Results from historical and future congestion analyses support the selection of Paths 65 and 66 as areas of concern. The analyses also suggest that high levels of congestion along these paths may restrict potential resources located in the northwest from accessing load centers in California. At a minimum, the supporting analyses reinforce the need for additional studies on the COI and PDCI.

Historical Path Utilization

The WECC Transmission Path Utilization Studies quantify the historical utilization of major transmission paths in the Western Interconnection and provide insight to where transmission congestion occurred during the historic study year. The past three path utilization studies (conducted in 2007-2009) provided relevant congestion information for the COI and PDCI.

Flow and schedule data from 2009 and 2008 were analyzed for Paths 65 and 66 in the 2009 TEPPC Transmission Path Utilization Study. Neither Path 65 nor Path 66 was listed as one of the top 10 most heavily utilized paths in the Western Interconnection for this study year. Path 66 flow was above 75 percent of the path's operating limit for nine percent of the study year, and above 90 percent of the OTC for one percent of the year. Flow on Path 65 was above 75 percent of the path's operating limit for 10 percent of the study year, and above 90 percent of the operating limit for three percent of the year. There were 582 MWs of capacity available 95 percent of the time on Path 66, and 537 MWs of capacity available 95 percent of the study year on Path 65.

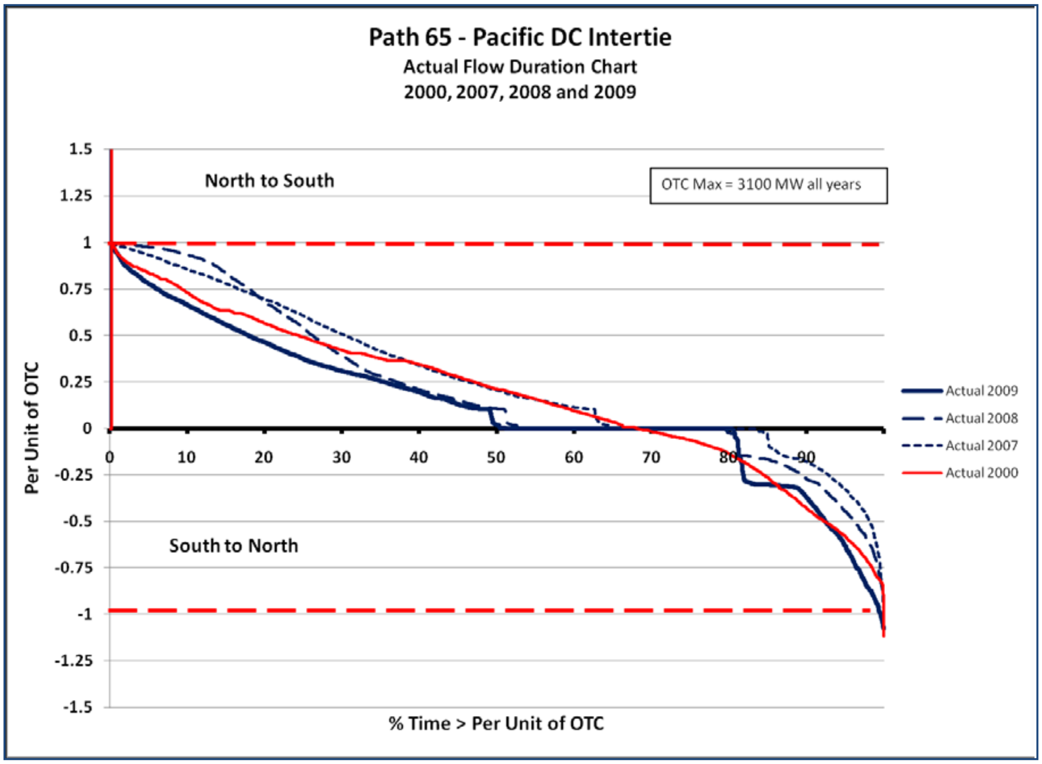
The 2007 flow and schedule data were analyzed for Paths 65 and 66 in the 2008 TEPPC Transmission Path Utilization Study. Based on actual flow metrics, the COI made the final list as one of the most heavily used paths in the Western Interconnection. The PDCI was not one of the final most heavily utilized paths, but it did rank highly according to flow and net schedule metrics. Flow for Path 66 was at least 90 percent of the path limit for three percent of the year, with a flow for Path 65 of at least 90 percent of the path limit for seven percent of the year.

The 2007 TEPPC Transmission Path Utilization Study took a retrospective look at path flow data from 1999 to 2005. Over this time period, both the COI and PDCI experienced a maximum summer U75 greater than 30 percent.

In addition to WECC's historical congestion analysis, the need for further investigation into new capacity is further supported by a recent report authored by the owners of the lines that comprise Path 66.[26]

Duration plots are presented for historical data on the following pages. Figure 29 shows Path 65 historic flow and Figure 30 shows Path 65 historic schedule data. This information for Path 66 is shown in Figures 31 and 32.

Figure 29: Path 65 Historic Actual Flow



26 Transmission Utilization Group, COI Utilization Report, 5/4/2011, https://www.columbiagrid.org/download.cfm?DVID=2189

Figure 30: Path 65 Historic Schedule Data

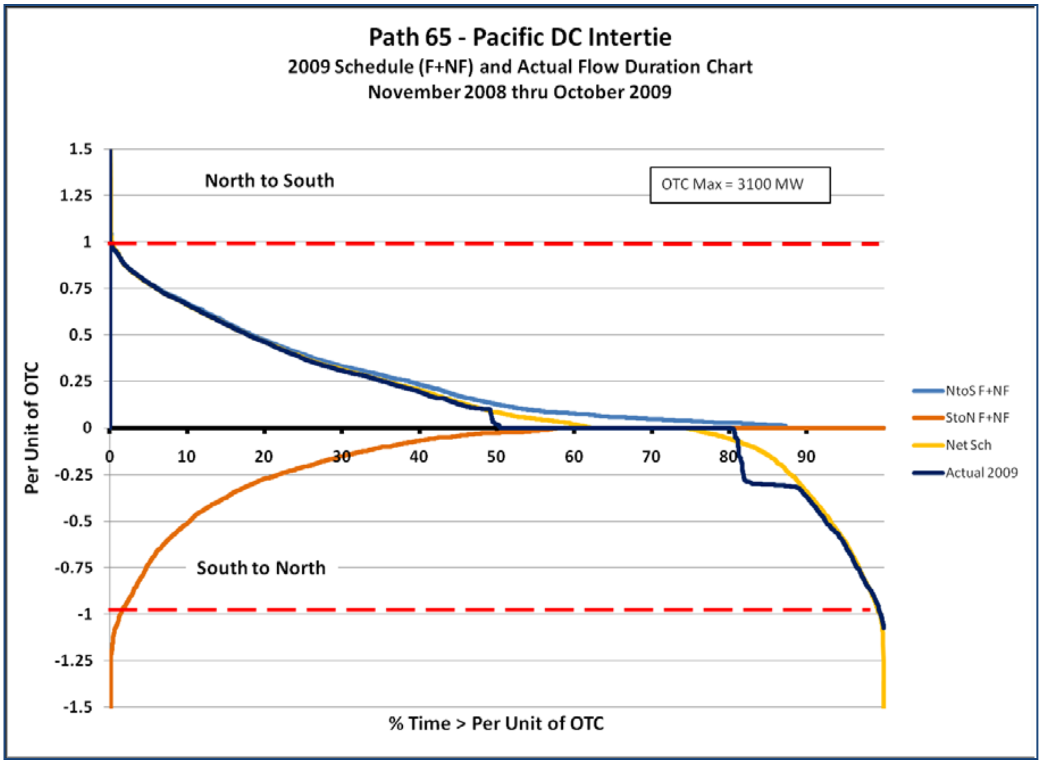


Figure 31: Path 66 Historic Actual Flow

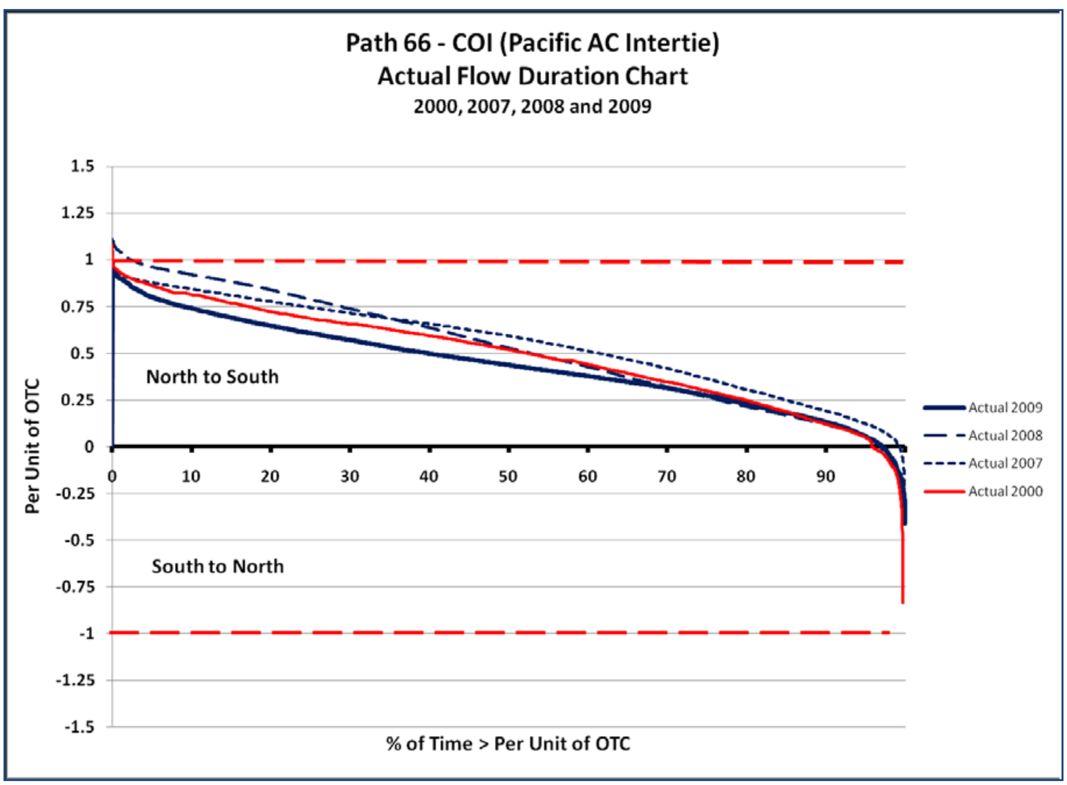
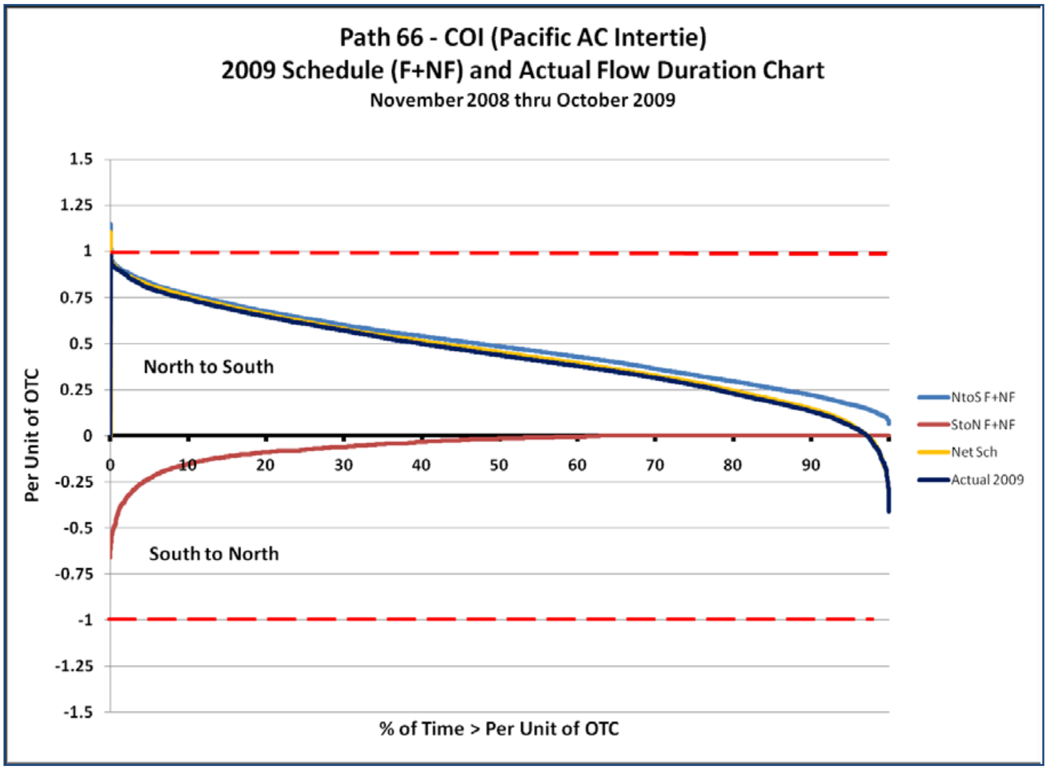


Figure 32: Path 66 Historic Schedule Data



Regional Operating Characteristics

The Northwest's main source of power is hydro generation. From 2010 to 2020, the Expected Future case predicts that Oregon and Washington will install a combined 5,200 MW of wind. The drastic increase in variable resources in the Northwest, without transmission expansion, is likely the cause for increased congestion along the Pacific-Tie Paths. In the 2020 Expected Future case, 61 percent of TEPPC Northwest Power Pool (NWPP)[27] generation was from hydro resources. In this study case, the NWPP had surplus generation of over 24,000 GWh. California had a generation shortage in the study case and imported 71,327 GWh of energy. Paths 65 and 66 transfers serve as the primary connection between available hydro generation in the Northwest and California load centers. The comparison of generation and loads in the NWPP and California in Figure 33 shows California's preference for hydro generation over local, and more expensive, gas generation. This is a driving force behind the high utilization of the Pacific-Tie Paths in the 2020 study cases.

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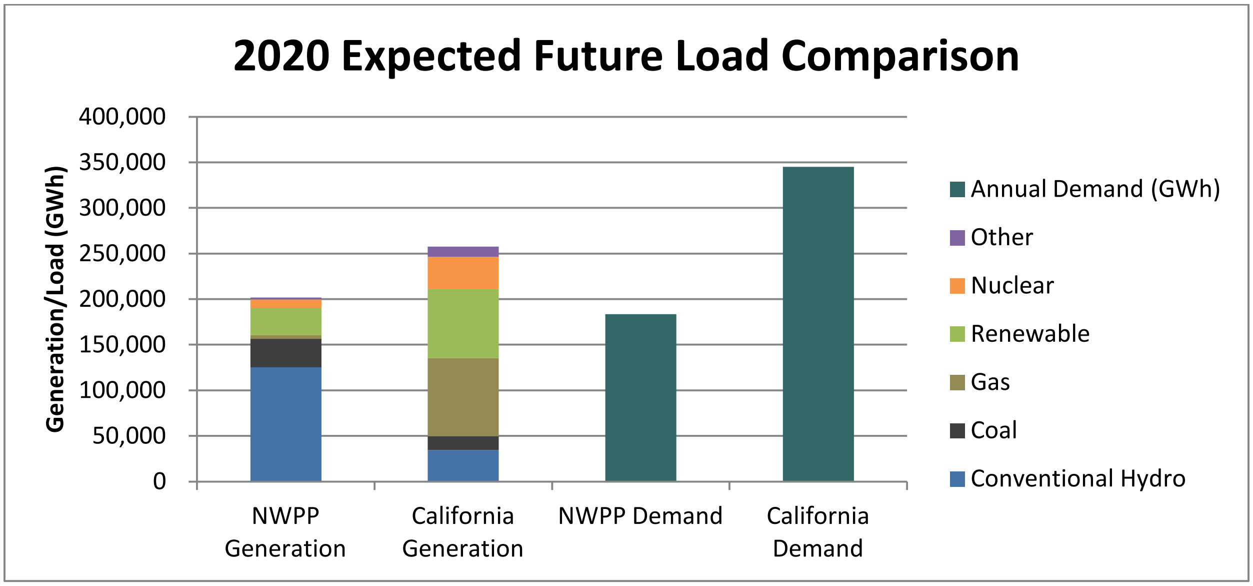
[27] The TEPPC Northwest Power Pool is a TEPPC-defined region (pool) in the PCM. It is not the same footprint as the Northwest Power Pool Reserve Sharing Group footprint.

Figure 33: NWPP/California Loads and Select Resources in 2020



The Northwest hydro resources are transferred directly to the southern California load center along Path 65. As a consequence, Path 65 generally flows north to south. Path 66, an AC intertie, transports energy into northern California where it is distributed to load centers throughout the state via the AC system. In actual operation, the paths are highly interdependent in terms of their simultaneous operating constraints.

Congestion Analysis

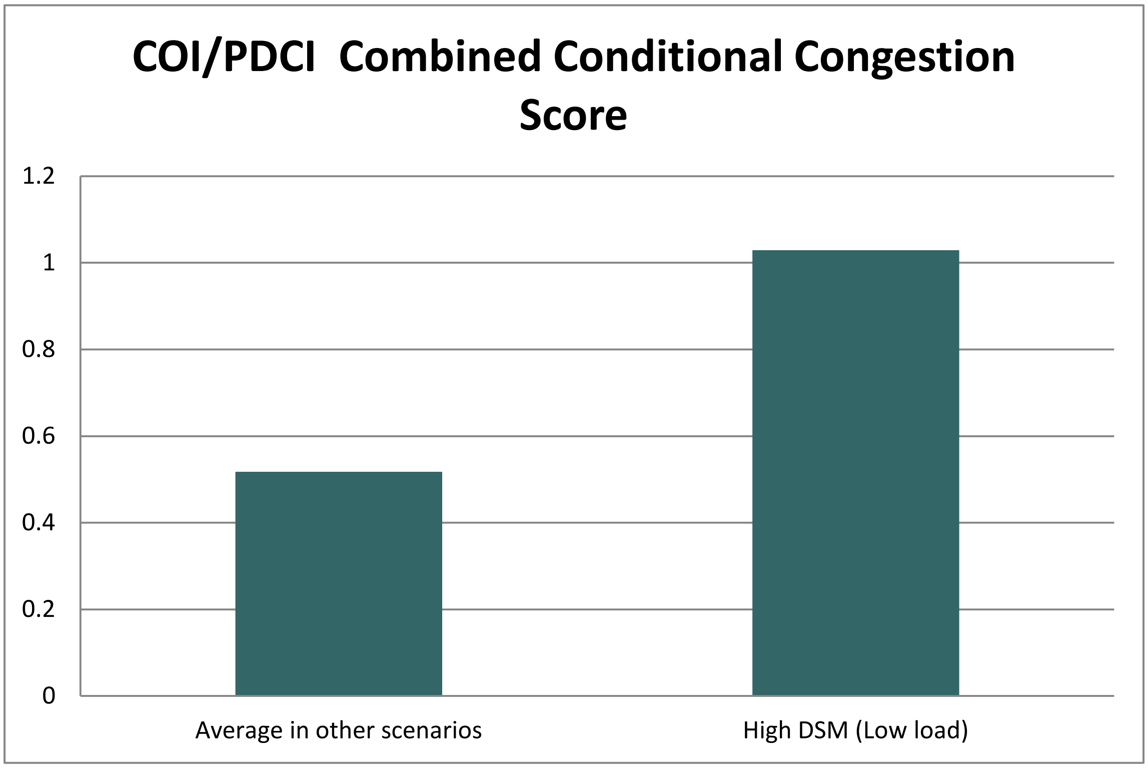
PCM results from the 2010 TEPPC Study Program were used in the congestion analysis. Due to DC line modeling issues, the PCM tends to use AC lines (i.e., the COI) before utilizing DC lines (i.e., the PDCI). Because of this, congestion metrics for the COI and PDCI were combined by summing the flows of the two paths and calculating the congestion metrics using their combined limit. By combining the two paths, a more accurate understanding of congestion due to energy flows from the Pacific-Tie Paths is achieved.

Conditional Congestion

Congestion that is contingent on a specific future (e.g., resource location, load level) is termed conditional congestion. In order to identify the scenarios in which congestion along the COI and PDCI is most severe, the analysis selected the highest conditional congestion score across all study cases analyzed in the 2010 TEPPC Study Program. Extremely high levels of congestion along the combined path representing Paths 65 and 66 were observed in the High DSM case (2020 PC3).

The conditional congestion scores calculated for the combined Pacific-Tie Path in the High DSM scenario was 90 percent higher than the average conditional congestion score in all other cases for which the combined path passed the utilization screening. The relative increase in congestion is shown in Figure 34.

Figure 34: COI/PDCI Combined Conditional Congestion Score



The combined path was highly utilized in five total cases, but experienced relatively low levels of congestion (compared to its overall average) in the Aggressive Montana Wind case (2020 PC6) and the Aggressive Wyoming Wind case (2020 PC7). The Aggressive Montana Wind case that features a high penetration of wind into Montana caused some congestion along the combined COI/PDCI Path, although the severity of the congestion is less than other cases for which the combined Path was highly utilized. Due to the geographic location of wind resources in Montana and Wyoming, external transmission constraints existed (Path 8) that prevented much of the 25,000 GWh of relocated resources from flowing on the Pacific-Tie Paths. These transmission constraints also caused a redispatch of the system, featuring an increase in California combined cycle generation. These factors combined to produce only a small spike in Pacific-Tie Path utilization despite the quantity of relocated resources. Results were similar for the Aggressive Wyoming Wind case.

Recurrent Count

This metric identifies those paths that are highly utilized across a range of plausible futures. A utilization screening was applied to all 15 of the study cases used in the 10-year planning studies, and the combined COI/PDCI Path passed the screening in five of 15 cases.

Relative to other paths, the combined Pacific-Tie Paths had an average Recurrent Count. In terms of frequency, the combined Path was one of the top 15 most utilized paths in the Western Interconnection in the 10-year planning studies. However, when the path flows were not combined, the COI had a Recurrent Count of 15 and PDCI had a Recurrent Count of four. The COI was the most heavily utilized path according to this metric. The disparity between the COI and PDCI in the Recurrent Count indicates the over utilization of the COI in the PCM.

Total Recurrent Congestion Score

The Total Recurrent Congestion Score applies the principles of the Recurrent Count, but focuses on congestion rather than utilization by summing the Conditional Congestion Score across all study cases. This gives a measure of the magnitude of the congestion present, regardless of the future scenario. The combined Paths 65 and 66 had the second highest Total Recurrent Congestion Score (with the COI singular path removed from the top seed and ignoring 115-kV paths).

Expansion Cases

There are numerous ways to relieve a congested path, one of which is transmission expansion. Congestion relief is just one of many reasons to build transmission; however, not all congestion is necessarily unfavorable.

Due to the significant amount of congestion identified along Paths 65 and 66, valuable insight can be gained by modeling transmission expansion in the 2020 Reference Case. The following projects were modeled in order to provide information on the effect they had on relieving congestion identified on the combined COI/PDCI Path.

- Chinook – 500-kV DC, 3,000-MW transmission line originating near Harlowton, Montana, traversing Idaho and terminating in the Eldorado Valley, south of Las Vegas, Nevada.[28]
- Canada - Pacific Northwest - Northern California – 500-kV AC and DC combination that will transport up to 3,000 MW of power from resources in British Columbia and the Pacific Northwest to northern California.
- TransWest Express – 600-kV DC, 3,000-MW transmission line starting in Wyoming, traversing Utah and terminating in the Eldorado Valley, south of Las Vegas, Nevada.[29]

By comparing the amount of congestion along the combined COI/PDCI Path in the 2020 Expected Future case to the congestion remaining after the addition of the Chinook, the Canada-Pacific Northwest-Northern California Project, or the TransWest Express, it is easier to understand the type of impact these projects could have on Paths 65 and 66.[30]

Chinook

In the 2020 Expected Future, the combined COI/PDCI Path passed the utilization screening based on the U99 metric. The Path was at U99 for 6.65 percent of the year in the Expected Future case. The implementation of the Chinook project greatly decreased flow on the COI/PDCI Path. The U99 metric dropped to 1.80 percent of the year. Utilization at the 90 percent level decreased from 13.98 percent of the year to 5.07 percent. The decrease in all utilization metrics is shown in Figure 35.

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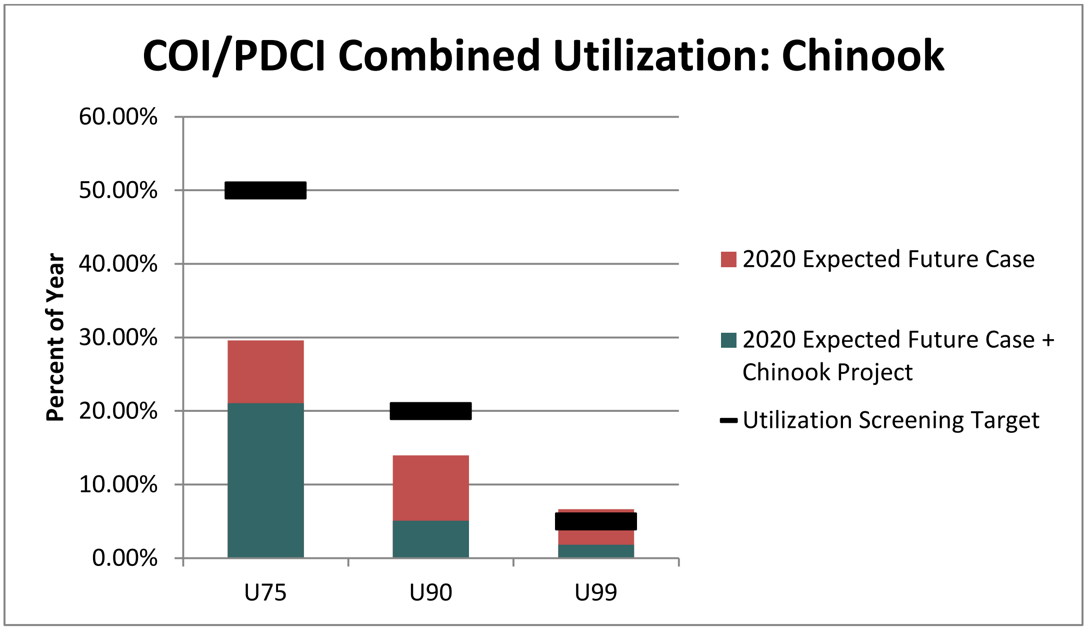
[28] This project was modeled in the 2020 Expected Future case with an intermediate converter station at Borah, Idaho.

[29] The TransWest Express project was used as a proxy for any HVDC project running from Wyoming to the El Dorado Valley. TEPPC is aware of at least one other project (Zephyr) that serves the same purpose.

[30] The PROMOD dispatch logic was used to model the DC lines. As a result, COI/PDCI was likely over utilized, and the incremental DC lines were underutilized due to modeling issues.

Figure 35: COI/PDCI Utilization (Chinook)



In addition to reducing the congestion along the combined paths, the Chinook project also reduced the WECC-wide average U99 from 2.87 percent to 2.57 percent. The average U75 decreased from 15.08 percent to 13.82 percent, as well. In addition to reducing congestion on Paths 65 and 66, the Chinook project was effective at reducing congestion along Path 8 and lowered WECC-wide utilization values.

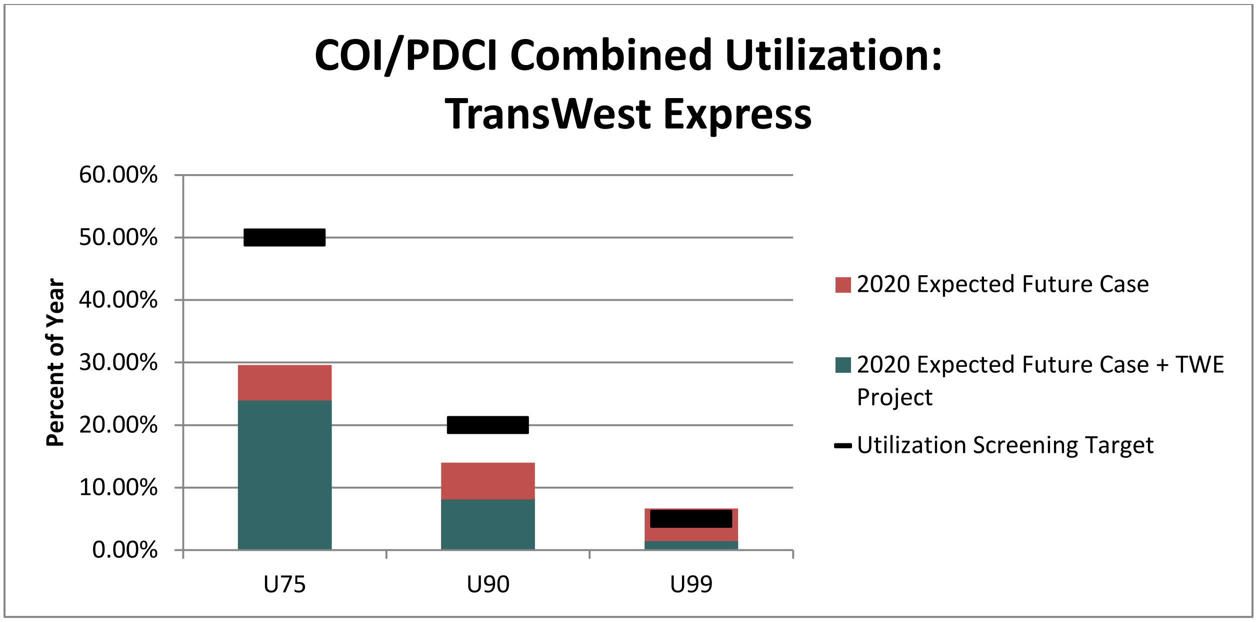
However, the Chinook project did introduce more congestion and higher utilization along the TOT 2C Path. The U90 levels along TOT 2C increased from 12.88 percent in the 2020 Expected Future case to 21.79 percent in the Chinook expansion case.[31]

TransWest Express

The addition of the TransWest Express Project substantially reduced congestion and utilization along the COI/PDCI combined Path. All three utilization metrics decreased significant amounts relative to the Expected Future case. The original U99 metric that caused COI/PDCI to pass the utilization screening in the 2020 Expected Future case decreased more than five percent after the addition of the TransWest Express project. With a U99 value of 1.46 percent after the addition of the TransWest Express Project, the COI/PDCI Path was no longer highly utilized (by definition). The decreases in all three utilization metrics can be seen in Figure 36.

[31] This result was obtained with the Borah intermediate converter in service. The PCM is currently not able to effectively simulate the operation of an intermediate converter. The control parameters of such a convertor station could likely be established to reduce, or at least not exacerbate, congestion on TOT 2C.

Figure 36: COI/PDCI Utilization (TransWest Express)

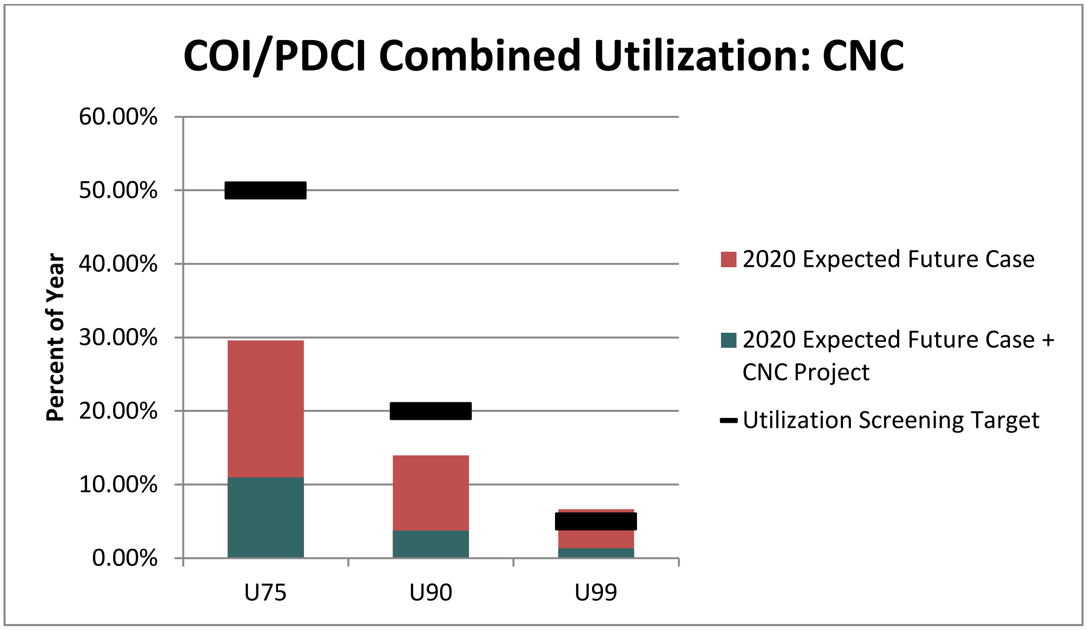


The implementation of the TransWest Express (TWE) project had a positive impact on the utilization of the Western Interconnection as a whole. In the 2020 Expected Future case, 11 paths passed the utilization screening. After the implementation of the TransWest Express Project this number dropped to eight. The average utilization for WECC paths dropped to 5.03 percent from the 5.74 percent observed in the Expected Future.

Canada–Pacific Northwest–Northern California

The Canada-Pacific Northwest-Northern California (CNC) Project resulted in the greatest decrease in the COI/PDCI Path utilization. By adding 3,000 MW of capacity (the CNC Project) directly parallel to the COI and PDCI, the U99 level for the combined paths dropped below the screening level. The U90 for the paths decreased from 13.98 percent of the year down to 3.71 percent after the addition of the CNC Project. The large drops in the utilization metrics are shown in Figure 37.

Figure 37: COI/PDCI Utilization (CNC)

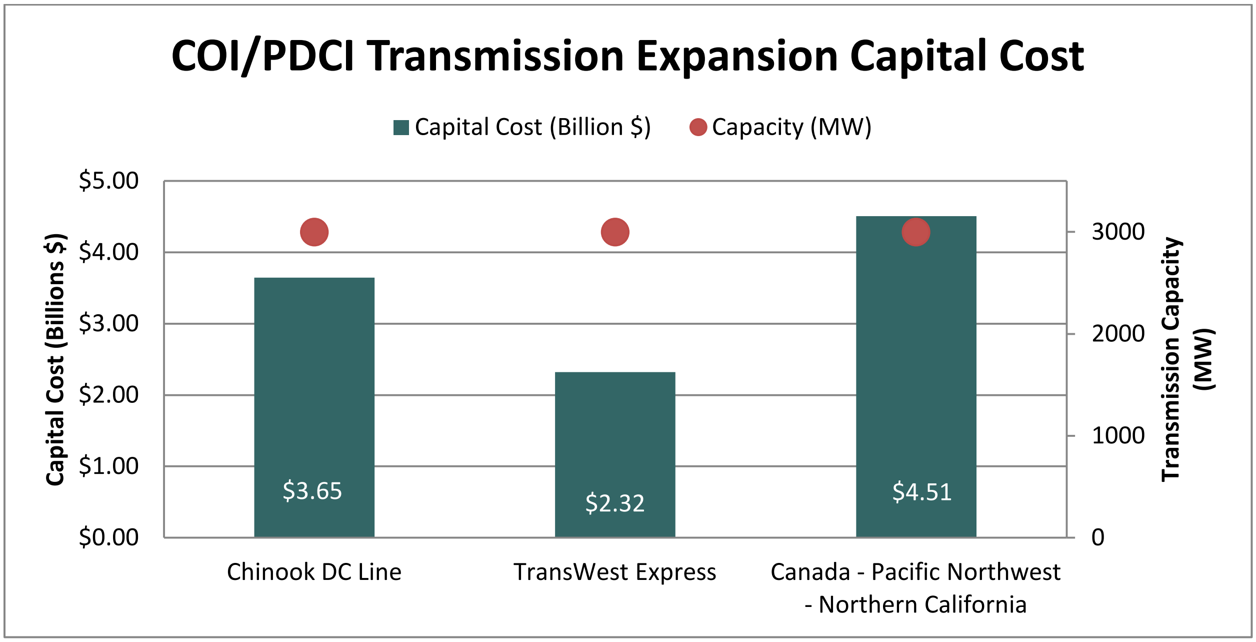


The CNC Project also had an effect on the WECC-wide average U90. In the Expected Future case, the WECC average U90 was 5.74 percent. After the addition of the CNC Project, that value dropped to 5.31 percent. When considering all WECC Paths, this decrease is substantial. It appears that that the CNC Project effectively reduces congestion along the COI/PDCI Paths and reduces path utilization WECC-wide.

Capital Costs

Each of the projects modeled in the expansion cases has a capital cost associated with implementing the incremental transmission. Figure 38 shows the estimated capital cost for the expansion cases that were evaluated for COI/PDCI Path congestion relief purposes.

Figure 38: COI/PDCI Transmission Expansion Capital Cost Estimates[32]



Project Development

There is project development currently underway along or directly parallel to the COI/PDCI Path. Six of these projects are listed below.

- CNC
- Chinook
- TWE
- Triton HVDC Sea Cable Project
- West Coast Cable
- Zephyr

These projects were either on the SCG Foundational Transmission Projects List or in the WECC Transmission Project Information Portal.

External Impacts & Added Value

Information currently unavailable to WECC may have an impact on Paths 65 and 66 recommendations. The following describe some of this information and its potential impact on recommendations. A description for how completing the recommendation for the COI/PDCI Path may assist in the completion of other planning recommendations included in this report is also provided.

Limitations

The congestion analysis referenced above was completed using the PCM. The PCM operates in an ideal world and performs an economic dispatch of the Western Interconnection that is unachievable in practice. Interpreting results from the PCM into meaningful metrics that

[32] The cost estimate for the Chinook project does not include the estimated $250M cost for a converter station at Borah.

compare to actual operation is often difficult. For example, PCMs routinely dispatch lines well above 90 percent of their operating limits, a practice not normally seen in actual operations. To the extent possible, the congestion metrics used in this supporting analysis consider these types of operating realities.

Moreover, no specific contractual agreements (other than the IPP DC line incorporation into LADWP's Balancing Area) were modeled in the PCM, which impacts generation dispatch. Had these contracts been modeled, flows along the COI/PDCI could increase or decrease in the model, thereby potentially affecting the recommendation.

Resource assumptions affect the generation dispatch performed by the PCM and the subsequent transmission flows observed across the system as a result of the economic dispatch. Renewable resources are the least-cost resources available to the PCM and are therefore dispatched first. As such, assumptions regarding the location of renewable resources can have a notable impact on transmission results. The resource assumptions used to develop the cases analyzed by TEPPC were based on known renewable resource procurement trends at the time the case was developed. Recent policy changes in California related to renewable energy development within the state are not incorporated into this Plan.

Supporting Other Recommendations

The resource-focused recommendation has parallel goals to the Path 65/66 recommendation. More resources will likely be built in the Northwest if there is less congestion along the COI/PDCI Path. In the same manner, more resource development in the northwest will help to further justify the need to reduce congestion along the COI/PDCI Path in order to get those new resources to load areas.

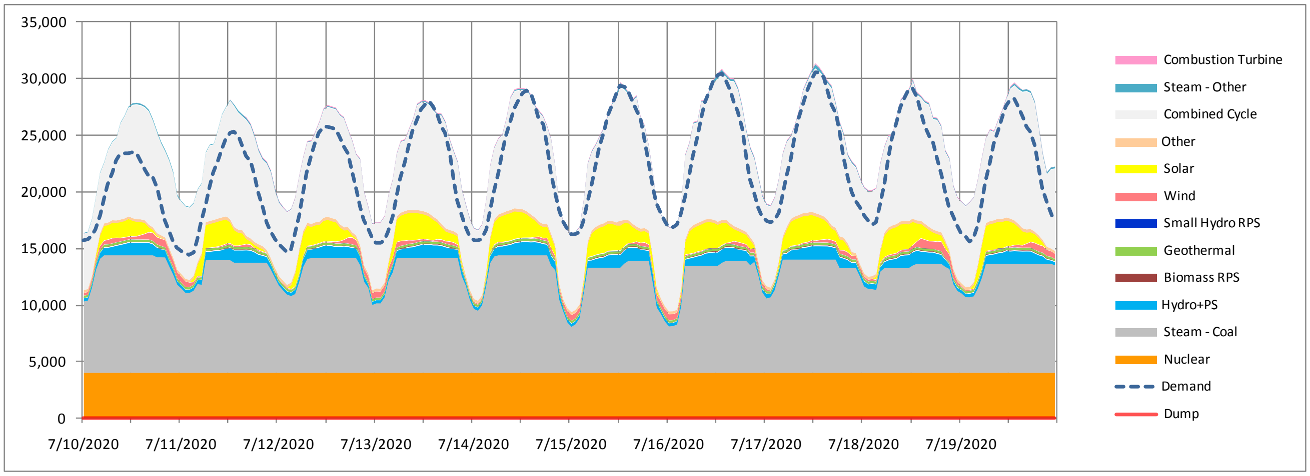
4.4 Operational impacts of variable generation

All of the cases analyzed in the 10-year planning studies included high levels of variable generation (wind and solar resources). This caused significant and unprecedented levels of conventional generation ramping and cycling. WECC recommends that future transmission and resource planning studies at all levels include a comprehensive review of integration issues, including the impact of variable generation on the operation of base-load resources.

In the Expected Future case, there was significant cycling of base-load generation. Although the production cost model was able to dispatch the generation around the variable resources to meet the load requirements in each hour, significant changes in the dispatch compared with historical operations were observed. The 10-day plot is shown in Figure 39 of the generation and load in the Arizona-New Mexico-southern Nevada (AZNMSNV) subregion in the 2020 Expected Future. This shows significant curtailment of typically base-loaded, coal-fired generation due to a decreased need to export resources from the subregion into southern California. This is a result of large amount of variable generation in California and minimum operating requirements for gas-fired resources.

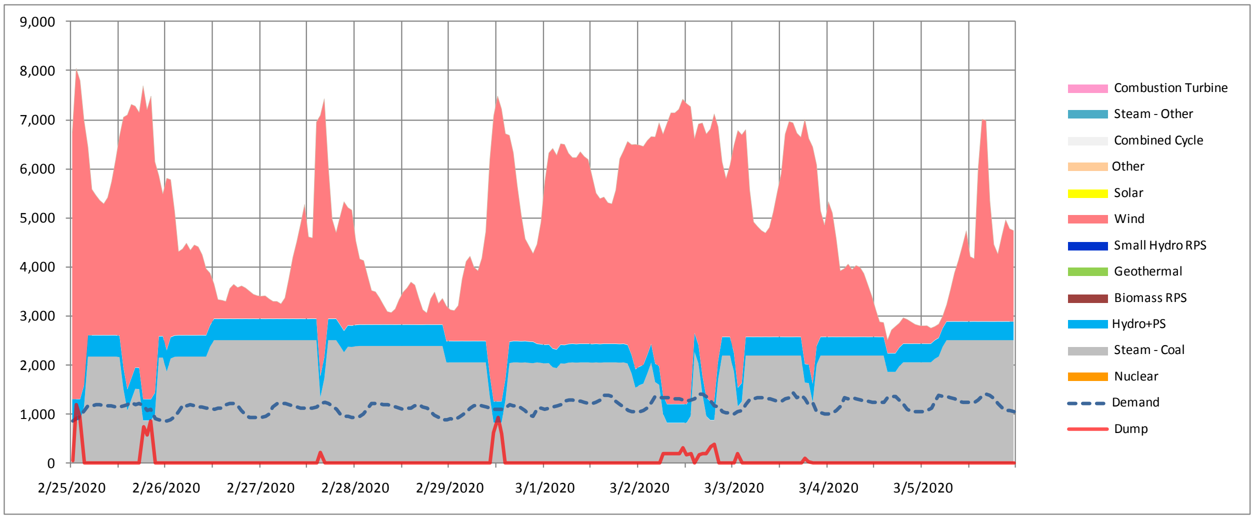
The basic conclusion in this case (with no apparent transmission constraints limiting the output of AZNMSNV base-load units) is that, for the Western Interconnection overall, there is insufficient load during the off-peak hours to absorb the generation in the generation stack above the minimum capacity requirement that results in the need to back-down or shut off of base-load resources during low-load hours.

Figure 39: PC1 Generation – AZNMSNV



As variable generation levels are increased, the amount of cycling of dispatchable units increased. In one extreme case, the Aggressive Montana Wind Case, where 25,000 GWh (8,583 MW) of wind generation was added in Montana along with 3,000 MW of incremental transmission capacity, cycling was so extreme that it exceeded what many would believe is achievable in real operations. As shown in Figure 40, the amount of 'dump energy,' or energy that was unable to be dispatched was significant. Dump energy is a good indicator of transmission constraints that impact generation operating constraints. It represents an amount of economic energy that is not able to be utilized and must instead be replaced by more expensive resources. It is important to the Aggressive Wind case, described in the above example, that there was no known transmission projects with sufficient proposed capacity to export the amount of generation relocated to Montana. The lack of sufficient transmission capacity out of Montana clearly contributed to the amount of cycling observed in the case, but the case still provides an example of the impact variable generation can have on the operation of conventional resources when there is insufficient means to manage the variability being put onto the system.

Figure 40: NW Montana Dispatch in the Aggressive Montana Wind Case with the Addition of Chinook



As a first step to help address variable generation integration issues in the TEPPC process, the State-Provincial Steering Committee (SPSC) submitted a request to TEPPC for its 2011 Study Program. The request called for the development of a screening tool to evaluate the technical feasibility and cost of integrating variable generation assumed in cases with a high penetration of variable generation.

4.5 Planning cooperation

Planning in the Western Interconnection is conducted at the local, state, provincial, subregional, and regional levels to inform infrastructure decisions, regulatory approvals, and public policy. Planning processes produce the IRPs (transmission plans) that describe a future(s) and provide a roadmap for what decisions may be needed to ensure reliability, meet public policy directives, and minimize cost and environmental impact under that future.

The electric power industry responds to state and provincial public policy directives. Federal reliability standards, tariff requirements, business practices, and environmental regulations guide infrastructure choices. State and provincial regulators review plans and address the ratemaking aspects of power purchases and investments made in response to plans.

LSEs and state and provincial regulators have the greatest influence over the execution of any plan. Successful plans and planning processes need to generate both quantitative and qualitative information that *enables* the key plan users, LSEs and state and provincial governments and regulators, to better understand their strategic options and support their decision-making processes.

WECC's goal is that policy- and decision-makers can look to the Interconnection-wide transmission Plan for highly-useful information. To do so will require WECC to better understand the needs of the states and provinces. TEPPC will need to formulate its study plans, as much as possible, with the objective of meeting those needs.

Regional transmisison planning cooperation achievements

The Western Interconnection has a rich history of successful planning cooperation, notably the Seams Steering Group-Western Interconnection (SSG-WI) organized by the industry in 2000-2001 at the request of Western Governors, the Governors' sponsored Clean and Diversified Energy Initiative (CDEI), and the WREZ initiative.

With the lapse of SSG-WI, WECC formed TEPPC in 2006, which led the west in developing comprehensive regional transmission reports in 2007-09. RTEP built on these efforts with numerous improvements to planning cooperation and plan execution.

- States and provinces, utilities, SPGs, Non-Governmental Organizations, tribes, and other stakeholders are working together under a common framework to identify and address transmission planning questions.
- SPGs have a forum (i.e., the SCG) to identify planning seams issues and develop a common list of transmission assumptions for use in regional transmission planning.
- RTEP funding allows for acceleration of efforts to improve data, models, and study design.
- WECC has developed high-quality core staff to execute studies.
- A process for developing common EE and DSM assumptions and models for use in regional transmission planning has been created.
- A forum for including environmental and cultural considerations in regional transmission planning has been created.

Opportunities to improve regional transmission planning cooperation

Even with the improvements outlined above, the need to increase coordination and improve planning analyses remains.

Based on stakeholder input garnered as part of the process used to create the Plan, WECC recommends the following:

1. Reconcile the various datasets, methodologies, and results between the Plan and SPG plans, utility IRPs, and other efforts to develop consistency regarding 1) reliability assessments of elements in the Plan, 2) operational impacts of variable generation in the Plan, and 3) selection and documentation of load, generation, and transmission assumptions in the Plan.
2. Incorporate integrated resource planning methodologies into future RTEP planning cycles. To further cooperation, develop a common understanding of state and regulatory mandates regarding development of IRPs, implementation of Renewable Portfolio Standards (RPS) requirements, LSE procurement objectives, and variable generation resource integration.
3. Develop a common understanding of what state/provincial policy- and decision-makers need to see in study execution, results, and interpretation to support the mandates stated in item 2 (above).
4. Subregional Planning Group planning processes should consider Plan information and results to identify the subregional impacts of the Plan and potential transmission expansions within subregions.
5. Assuming progress in # 1-3 above, LSEs, energy agencies, and Public Utility Commissions should consider Plan information and results in their respective processes. Where the benefits of a transmission solution identified in the Plan extend beyond one state or province, regulators and policy-makers should work in collaboration to evaluate

the solution in the context of the IRP processes for multiple utilities. One vehicle to do this is with the relevant Subregional Planning Group(s).

WECC has a pivotal role in assuring the recommendations listed above are successfully executed. Specific directives for WECC in the next RTEP planning cycle are listed in Section 4.9.

4.6 Environmental and cultural considerations in planning processes

As part of the RTEP process, the SPSG Environmental Data Task Force (EDTF) conducted a case study and interviews on environmental data that can be included in transmission planning processes. The result of this work, described in Section 5.1.8 and detailed in the Environmental Recommendations for Transmission Planning, produced the following recommendations.

- Use the catalog of preferred Geographic Information System data to plan for and compare potential transmission alternatives as described in Table D-1 of the Environmental Recommendations for Transmission report. As it becomes available and as appropriate, incorporate information from the state wildlife agency Decision Support Systems and other state or provincial data.
- Use the recommended classification of land areas (described below) along with stakeholder guidance, for transmission planning, the Long-Term Planning Tool (LTPT), and to compare potential transmission alternatives.
- Work with the EDTF and the WGA to explore existing data on economic values of environmental and cultural resources, goods, and services at a level appropriate for WECC's long-term planning process.
- Amend the TEPPC Planning Protocol to include a comparison of future transmission alternatives based on criteria derived from the environmental and cultural data sets.
- Conduct regular outreach to evaluate and improve the integration of environmental and cultural information into regional transmission planning.

4.7 Water resources impact on the future generation mix

As part of the U.S. DOE transmission planning grants, the WGA was awarded funding to examine how water supply considerations may intersect with current and future electricity generation and transmission in the Western Interconnection. The DOE is funding a consortium[33] of national laboratories, universities, and industry groups — led by Sandia National Laboratory — to provide technical assistance to the energy-water assessment. These preliminary results demonstrated the relationship between electric generation and water use, sometimes described as the energy-water nexus, in the Western Interconnection. The outcome of the case study described in Section 5.1.8 and detailed in the WGA report, resulted in the following recommendations for subsequent RTEP cycles.

[33] The consortium includes Sandia National Laboratory, Argonne National Laboratory, the Electric Power Research Institute, the National Renewable Energy Laboratory, the Idaho National Laboratory, the Pacific Northwest National Laboratory, and the University of Texas. Specific personnel can be found in the Appendix on Energy-Water within the WGA Water Report.

- WECC will work with the WGA to refine and improve the analysis of water withdrawal for electricity generation in transmission planning studies. Specifically, WECC will integrate WGA-provided water supply information into the WECC LTPT to evaluate impacts and options for electric generation.
- The WGA and the national laboratories will work closely with RTEP stakeholders regarding the progress of the analysis of the energy-water nexus. The tools and analysis described in Section 5.1.8 will be available to WECC stakeholders. The WGA and the national laboratories welcome input to their current and future analytic efforts.
- The WGA and the national laboratories will execute an assessment of historic drought impacts and how they may increase risk to power plants due to lack of water availability.

4.8 Gaps in Regional Transmission Planning Processes

Great strides have been made recently as part of the RTEP process, outlined in Section 4.5 above, but gaps still exist. In support of the recommendations listed in Section 4.5, WECC plans to make the following enhancements in the next RTEP planning cycle.

1. Define a common set of key questions to be answered by the next set of regional transmission plans through outreach involving discussions and other forums with utilities, policy-makers, utility-regulators, permitting agencies and other key stakeholders.
2. Develop a list of questions regarding proposed transmission projects to better understand the project purpose and other parameters at different stages of transmission project development, and post the information to WECC Transmission Project Information Portal.
3. Expand WECC's analytic capabilities and activities to assure the future regional transmission plans include the following.

    a. Information to enable the comparison of the costs and benefits of transmission expansion with other alternatives (e.g., DSM, distributed generation, and other non-traditional options). Expand Interconnection-wide the economic analysis of resource relocation cases and transmission expansion.
    b. The impact of contracts and operational practices, environmental limits on hydro options, challenges to continued operation of existing power plants.
    c. The identification of long-term Available Transmission Capacity (ATC) on WECC Paths.
    d. Testing potential transmission expansion solutions against a broad-range of possible generation and load futures with major public policy implications (e.g., testing the transmission assumptions against a plausible range of generation and load combinations).
    e. Further refining capital and variable cost assumptions and calculation methodologies to include a robust sensitivity analysis that identifies what assumptions most affect the study results.
    f. Further evaluate the potential impact of enacted and proposed energy policies.
    g. Further evaluate the reliability ramifications of transmission and generation elements included in future transmission plans.
    h. Incorporate generation cycling costs into production cost models.
    i. Define an objective and consistent set of criteria for identifying transmission projects assumed constructed. The criteria should include items such as: 1) under construction, 2) permitted, or 3) other criteria that provide a high level of confidence the project will be constructed within the planning time horizon.

j. An expansion of the economic analysis of resource relocation cases to include options Interconnection-wide.
k. Quantify cost and risk metrics and evaluate solutions against these metrics.
l. Make modeling improvements to better simulate DC line performance.

4. Encourage greater stakeholder participation in defining load, generation, and transmission assumptions used to construct planning studies;
5. Identify and evaluate the challenges of integrating the variable generation assumed in the Plan and identify possible options to address these challenges.

4.9 Other Observations

Carbon Reduction

Electric sector carbon reduction policies and their impact on generation, transmission utilization, and rate-payers are on the minds of decision-makers across the Western Interconnection. The RTEP studies looked at two carbon reduction cases, 17 percent and 30 percent reductions from 2005 levels.

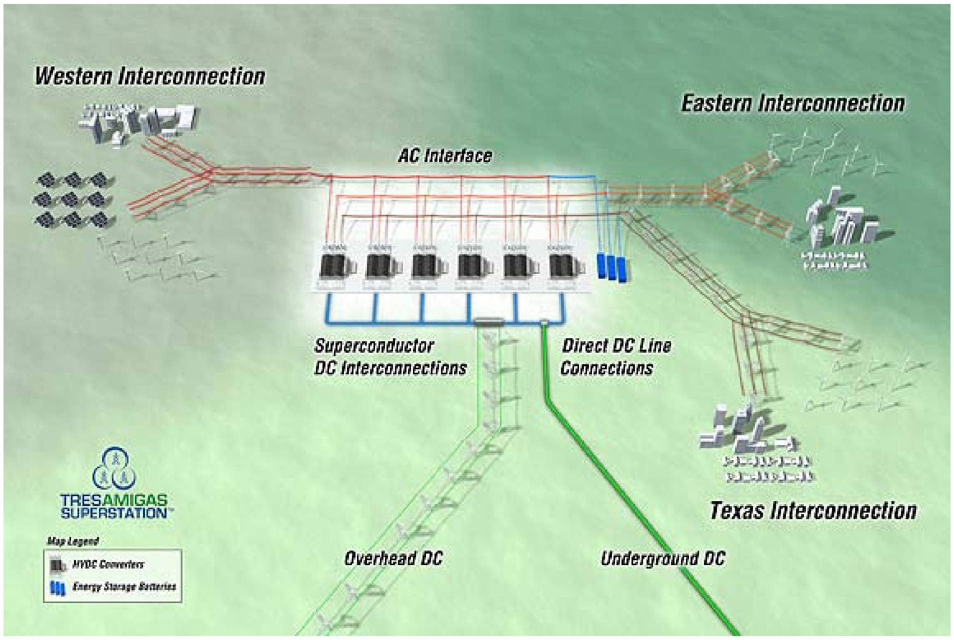
The 2020 PC4 (SPSC Carbon Reduction) case built on the 2020 PC3 (high EE/DSM) case assumptions by applying a carbon-cost adder to the carbon dioxide (CO_2) emissions, but did not retire any generation. The carbon-cost adder provided an impetus to shift generation from coal to gas. Using an iterative approach, a carbon adder of $30/Ton ($33.07/Metric Ton) achieved the PC4 case goal of a 17 percent reduction in carbon emissions in comparison to the Expected Future case. Importantly, the majority of the carbon reductions were from the increased EE, not the carbon-cost adder.

The 2020 PC8 (Western Grid Group Carbon Reduction) case sought to reduce carbon emissions by 30 percent relative to 2005 levels using a combination of EE, 6,000 MW of coal plant retirements, and additional renewable resources. Coal retirements were replaced by an equivalent capacity value of renewable resources, but this resource exchange did not displace enough CO_2 emissions to achieve a 30 percent reduction in CO_2 from 2005 levels. More coal retirements, plus additional renewable resources, would be needed to achieve this reduction. Although the target was not reached, it did provide useful information regarding what it is that drives carbon reduction. Like the PC4 case above, reduction in energy usage drove emissions down in these cases more than any other single action.

Tres Amigas Superstation

The Tres Amigas Superstation, shown in Figure 41, is a three-way DC converter connecting the Western and Eastern Interconnections and ERCOT. Tres Amigas has and continues to update its economic data to WECC, showing possible significant economic advantage to the WECC grid when interconnected to the other grids. Studies were performed for the purpose of understanding the station's impact on transmission flows and power transfers into and out of the Western Interconnection. No specific conclusions could be drawn from the analysis except that further work is needed regarding the initial connection design and other future scenarios. Further work will need to include a reliability assessment based on various transmission scenarios that could evolve from this project.

Figure 41: Tres Amigas Superstation



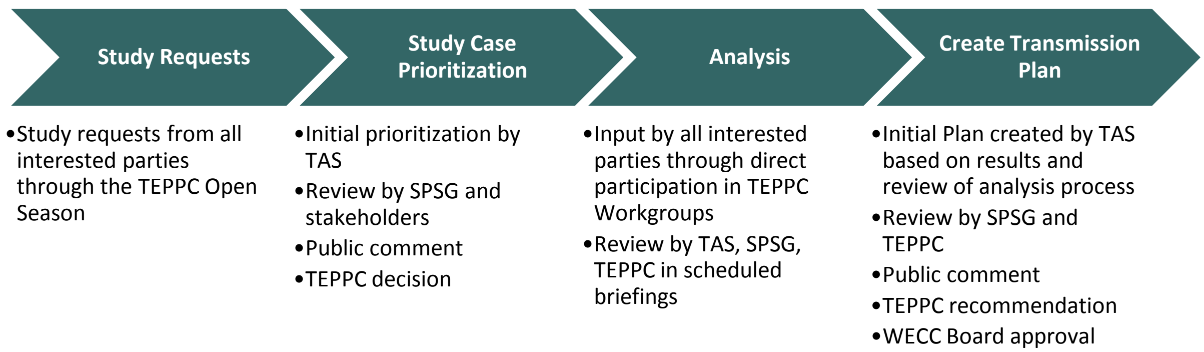
5 Development of the Plan

The WECC 10-Year Regional Transmission Plan is informational, with the objective to provide information to stakeholders for their decision-making processes regarding where and when to build new transmission or take other related actions to help ensure the Western Interconnection is reliable, low-cost, efficient, and environmentally sound. In support of this objective, WECC's analyses are aimed toward:

- understanding transmission system needs over a broad-range of potential futures;
- recognizing the potential economic benefits of transmission expansion, and;
- identifying transmission additions that, if foregone or delayed, will result in diminished opportunities to realize infrastructure benefits over a likely range of futures.

5.1 Process for Developing the Plan

Each organization listed in Section 6 has different responsibilities in addition to their combined responsibility to assure robust stakeholder input into the Plan. The diagram below describes the processes and roles of the individual organizations in helping to create the Plan.



The objective of the RTEP process is to provide information to stakeholders for their decision-making processes regarding where and when to build new transmission or take other related actions to help ensure the Western Interconnection is reliable, low-cost, efficient, and environmentally sound.

The process seeks to:

- understand the Expected Future network and alternative future networks;
- identify transmission congestion issues and relationships;
- evaluate possible solutions; and
- create a set of recommendations that address load growth, generation additions, high-level reliability considerations, and energy and environmental regulations and policies.

Accomplishing this objective requires a sequence of complex analytical steps. While TEPPC has undertaken these steps for three planning cycles, 2011 was the first year that the study results have been integrated into a 10-year plan.

These nine steps constitute the analytic approach:

1. acquire system data, modeling tools, and abilities;
2. determine the Plan's overarching objective;
3. develop Plan assumptions;
4. characterize issues and key questions;
5. conduct analysis;
6. organize results, determine relationships, and identify problems;
7. determine potential solutions to identified problems;
8. evaluate proposed solutions for possible reliability implications, cost impacts, environmental and water attributes, and policy achievement; and
9. develop recommendations.

The following subsections describe the stakeholder and analytic processes used to prepare the Plan.

5.1.1 Acquire system data, modeling tools, and abilities

The beginning of the RTEP process occurred well before any annual cycle or preparation of the Plan. Acquiring system data and modeling tools is the first step and an ongoing process.

System data is acquired from Balancing Authorities (BA) annually, through formal data request processes. The most important data acquisition in transmission expansion analyses occurs through WECC's loads and resources information filing by the BAs. This comprehensive process allows the annual compilation of data that describes the existing system; loads, generation, and operating characteristics. It also provides BA forecasts for system loads, resources, and capacity that are projected annually through a 10-year horizon.

Models are acquired as needed and updated periodically.[34] The PCM used by WECC is Ventyx's PROMOD IV. In addition, WECC uses spreadsheet-based tools for evaluating capital costs, ensuring renewable energy requirements are meet, verifying a load/resource balance is achieved, etc.

5.1.2 Determine the Plan's overarching objective

The objective of the Plan is to provide information and guidance for decision-makers to determine where and when to build new transmission or take other related actions. The methods used to reach this objective are embodied in the execution of the 2010 TEPPC Study Program.

As described in the TEPPC RTEP Protocol (Protocol), the TEPPC expansion planning studies and process are consistent with the requirements of FERC Order 890. This includes the planning principles (excluding cost allocation) and the requirement for an annual study request cycle. All requests received from any stakeholder in the study request window (open from November 1st through January 31st each cycle) provide the starting point for developing the next TEPPC Study Program.

[34] There are a number of submodels used that characterize hydroelectric output and dispatched demand-side resources. Data and model improvements are constant activities within planning cycles.

5.1.3 Develop Plan assumptions

As part of every TEPPC Study Program, WECC and stakeholders develop and update the assumptions and parameters of the data sets that describe both the existing and future network. These assumptions form the 'expected network' for the 10-year studies. They include loads, existing and incremental generation facilities, generation characteristics, and existing and incremental transmission facilities.

Highlights of major assumptions and information sources used to conduct the 2010 TEPPC Study Program include the following.

Loads: Loads in the TEPPC dataset reflect the load forecasts of the BAs, as submitted to the WECC Loads and Resources Subcommittee (LRS). EE and DSM assumptions are also provided by the BAs. In addition, the SPSC provided adjustments to the LRS load forecasts to the extent they did not fully account for existing state, provincial, or federal energy efficiency policies; ratepayer-funded EE programs; and existing demand response programs and plans.

Generation: This includes existing system generators, projects under construction, and renewable resource additions that are required to meet statutory RPS and additional thermal generation needed to achieve a reasonable load/resource balance for subregions of the Western Interconnection. The generation additions were selected from resources proposed in utility IRP, proposed generation in BA submittals to the LRS, and where WREZ resource screening results indicated a need.

Generation Characteristics: Assumed operational characteristics (e.g., capacity factors, generation profiles, heat rates, ramp rates, maintenance schedules) for various generation types (e.g., gas, coal, wind, solar, geothermal) are provided by WECC BAs, other organizations (such as NREL for wind and solar characteristics), and other publicly available information sources.

Hydro generation is a significant resource in the Western Interconnection. In the PCM, hydro generation is modeled using a variety of methods that attempt to capture the unique operating characteristics of the resource. In 2011, a mixture of fixed historical time series, proportional load following algorithms, and a hydro-thermal co-optimization technique were used to model hydro generation in the 10-year planning studies. Hydro dispatchability constraints due to environmental or other operational factors (e.g., irrigation water deliveries, flood control, environmental release) were captured in the model using minimum and maximum operating levels and monthly energy limits.

Existing Transmission System Network: The existing transmission network, including the associated electrical characteristics and operational limitations, came from the WECC Technical Studies Subcommittee (TSS).[35] The TSS manages a central database of technical information about the Western Interconnection transmission system and performed reliability studies.

Incremental Transmission Facilities: For the 2010 Study Program, incremental regional transmission additions, those assumed to be built and in operation by 2020, were provided to

[35] The TSS is a subcommittee of the WECC Planning Coordination Committee (PCC).

TEPPC by its SCG. These project additions were identified in the SCG Foundational Transmission Projects List Report as projects that meet a set of criteria adopted by the SCG. Though these projects did not result from TEPPC analysis, they reflect major projects that are advanced the farthest through the SPG's respective planning processes, and are those most likely to be built by 2020. These projects are included as input assumptions in the Expected Future case. Information regarding the existing transmission system network, along with local[36] future transmission additions, was provided by the TSS through the incorporation of its 2020 HS1 base case.

5.1.4 Characterize issues and key questions

Beyond the network assumptions, the objective of individual study cases in the TEPPC Study Program is to explore an issue of interest (e.g., generation resource location, public policy) or answer a key question. In order to explore an issue, additional specification of study case assumptions was performed. For example: the 2019 resource relocation cases required removing 12,000 GWh of renewable generation from California and replacing it with an equivalent amount of generation in eight separate subareas of the Western Interconnection. Other cases, run as part of the 2010 TEPPC Study Program, specified an adjusted forecast for expected EE and DSM that was not already in the BA-submitted load forecast. Additional examples of characterizing study cases can be found in the SPSC's High DSM and Carbon Reduction cases. The assumptions associated with the characterizations generally come from the requesting party, which coordinates closely with TEPPC's TAS work groups (Data, Modeling, and Studies), the SPSC Scenarios Work Group, and others.

5.1.5 Conduct analysis

After individual study cases were characterized, they were evaluated in a PCM that simulates the hourly operation of the entire Western Interconnection for the study year. By simulating operations for the whole year, information was obtained on how different model assumptions and inputs might impact system dispatch, transmission congestion, asset utilization, and the ability to serve system loads.

TEPPC's analytic study process to evaluate critical network needs and potential solutions included PCM simulations. As part of the 2010 TEPPC Study Program, the primary source of analytic information used to inform the Plan, more than 100 separate simulations, were analyzed by WECC.

The results of the simulations provide information on transmission system congestion and utilization, generation utilization, fuel usage, emissions, unserved load, and production costs. The cases analyzed were intended to;

- analyze potential transmission capacity additions through 2020;
- help define central tendencies that address energy policy concerns and constraints; and
- address uncertainties identified in the 10-year horizon.

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[36] Local additions are comprised of network upgrades near load centers and lines that are not significant from a regional perspective.

Reviewed as a package, the results provide useful information to compare the changes from one study case to another.

For example, the suite of study cases in the 2019 Study Report, known as the resource relocation study cases, reflect specific stakeholder study requests to remove significant quantities of future resources out of California, and to relocate them into different areas of the Western Interconnection. One objective of these studies was to see how much congestion occurs with resources in one location compared to another and to see if there was commonality in congested transmission paths across multiple cases. These cases test various uncertain and plausible resource futures as well as the associated incremental generation and transmission costs, and transmission system utilization, if the generation were to be developed over the 10-year period.

A second major area of transmission use analysis is undertaken annually, separate from and in parallel to the PCM simulations. This consists of highly detailed studies of past congestion that occurred on key Western Interconnection transmission paths. For the 2010 TEPPC Study Program, real-time data for actual transfers, schedules, and reported available transmission capacity were assessed for 25 paths that represent the major transmission system interconnections between the BAs and the major resource and load areas of the Western Interconnection. Individual line data used for the existing system congestion analysis is aggregated to the appropriate WECC Path. Congestion was evaluated and reported using a variety of path utilization metrics, described in Section 5.1.6. The analysis identified the most congested paths during various seasons by flow directions and years. This analysis enabled TEPPC to compare and contrast historical and simulated future congestion.

5.1.6 Organize results, determine relationships, and identify problems

The results of the Expected Future case, study cases, and historical congestion were evaluated to identify patterns. These patterns were compared to existing knowledge and observations of how the Western Interconnection operates to determine why study case results might show variations in operation and congestion. The most significant of the future congestion results emerged over the course of reviewing many cases and could be compared to path congestion results from the historical analyses. Paths that were historically highly utilized, as well as paths that were consistently congested across a range of study cases, rose to the top as the paths highlighted in the Plan.

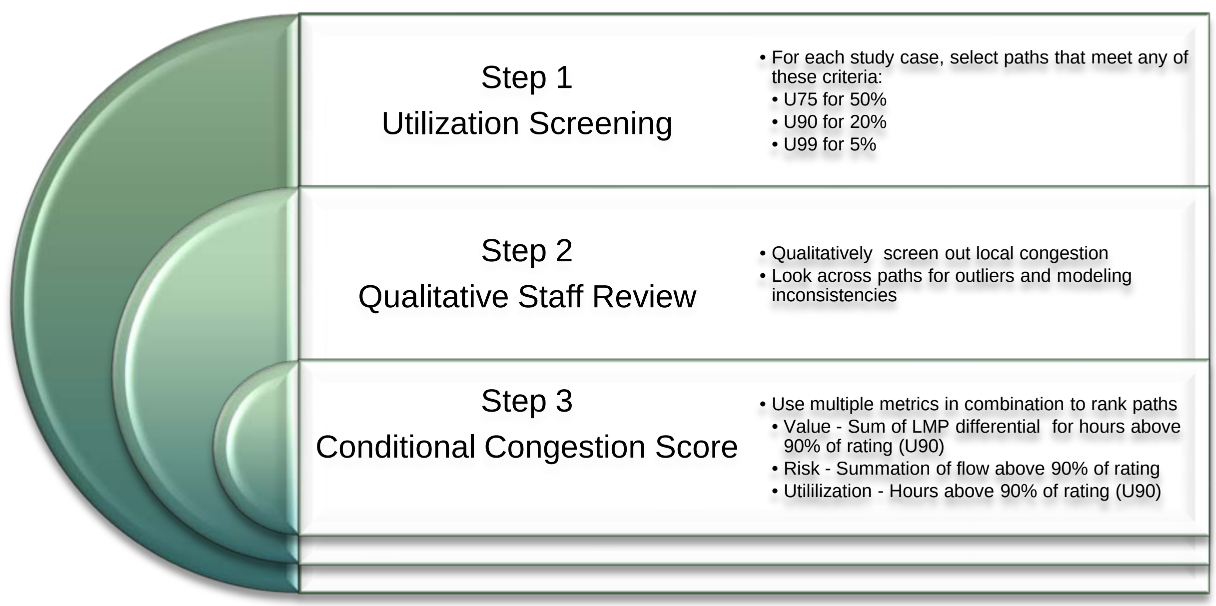
Congestion might be the result of either physical or contractual limitations. Physical congestion is caused by limits on actual energy flows on lines or paths. Contractual congestion is driven by transmission rights and the availability of transmission capacity in the market. The production cost simulations did not contain proprietary information regarding commercial reservations and potential contracts and as such, only identified physical congestion. Results from the PCM simulations provided an estimate of general patterns for future physical transmission congestion and utilization, and differences in transmission utilization observed between sets of study cases. The historical analysis provided some information regarding contractual congestion.

These differing types of congestion might have high, medium, low, or no priority for finding mitigation solutions. The process for synthesizing results occurred as part of the development of the Plan.

While hourly production cost modeling may produce useful information about hourly congestion, by itself this information is usually not sufficient to drive new investment and business decisions. Given the decentralized market structure and transmission ownership in the Western Interconnection, new major transmission investment is likely to be driven by a utility's desire to access renewable and other generation resources with a high-degree of delivery assurance. Relying on 'as available' hourly transmission capacity, derived from hourly production cost modeling, is unlikely to provide a sufficient assurance of delivery to support large investments in new generation resources. Consideration of total generation and transmission capital and operating costs does provide useful information to inform transmission investment decisions.

Information on future path utilization and congestion[37] emanating from the TEPPC study case results is featured in the Future Congestion Analysis section of the path discussions. Each of the 2010 TEPPC study cases used to inform the WECC 10-Year Regional Transmission Plan was evaluated in a three-step process. This approach brought quantitative value, risk, and utilization indicators together with qualitative WECC and stakeholder review to indicate highly utilized or congested paths for each study case. This allowed for a breakdown from the path perspective where the method revealed study cases that caused a specific path to be highly utilized or congested. This information was displayed on the Congestion Dashboard for 40 of the 65 WECC paths. The other 25 paths did not meet the utilization screening for any of the study cases. Figure 42 outlines this process, followed by a detailed explanation of each step in the process.

Figure 42: Congestion Analysis Process



[37] In previous discussions, there has been significant dialogue regarding the terms "utilization" and "congestion," and their use. Utilization is a term that describes the extent to which the transmission line (path) is used. Congestion is a word to describe at what time a transmission line may be over utilized. For purposes of this communication, high utilization is defined as the times when path flows are above 75 percent of the path rating (U75). Congestion occurs when the path flows are above 90 percent of the path rating (U90).

Step 1 – Utilization Screening

The utilization screening is intended to capture any highly utilized or potentially congested paths in the TEPPC study cases. Any path with a U75[38] for 50 percent of the year, U90[39] for 20 percent of the year, or U99[40] for five percent of the year is analyzed further. A path is defined as being ‘highly utilized’ if it meets any one of these screening criteria.

Step 2 – Qualitative WECC Review

WECC and stakeholders qualitatively reviewed and screened out paths that showed congestion based on how the modeling was performed (e.g., localized congestion due to how new generation was added to the model that would not occur in reality). Paths that were screened out were not analyzed further but were tracked throughout the process and presented for stakeholder review. The only paths that screened out in this step were the SDG&E-CFE (Path 45) and Intermountain-to-Mona (Path 28) 345-kV Paths.

Step 3 – Conditional Congestion Score

The remaining paths were scored using three normalized metrics that quantify value, risk, and utilization. The sum of the normalized metrics makes up the Conditional Congestion Score. If a path passed the Utilization Screening for a particular case, it was given a Conditional Congestion Score.

1. The Value metric is the sum of the hourly locational marginal price (LMP)[41] difference across the path for hours above U90. This metric is an indicator of the relative value of the transmission congestion across the path, shown on the Value View of the dashboard.
2. The Risk metric is a summation of the flow along a path for all hours above U90 and is an indicator of how often the path is heavily loaded and how much energy could be at risk during these periods of heavy loading. This metric is shown on the Risk View of the dashboard.
3. The Utilization metric is simply U90 and provides a way to compare the utilization of paths regardless of size. This metric is shown on the Utilization View of the dashboard.

The Congestion Dashboard uses this results synthesizing methodology to present congestion information that can be viewed either from the perspective of the study case or the individual path.

5.1.7 Determine potential solutions to identified problems

The information and results of the previous steps provide the framework for identifying possible network needs. Project-based transmission expansion alternatives to address the needs identified were selected using a list of proposed transmission projects known to WECC. Transmission expansion projects that were added to the Expected Future were analyzed to determine the impact of individual projects on possible network needs. The results of these analyses are presented with the individual case results in the WECC Path Reports. This

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[38] U75 is the number of hours when flows are greater than 75 percent of the path’s rated capacity.
[39] U90 is the number of hours when flows are greater than 90 percent of the path’s rated capacity.
[40] U99 is the number of hours when flows are at the path’s rated capacity.
[41] The PCM calculates an LMP at each point (bus) within the system. The LMP represents the cost of serving the next megawatt of load at that particular point in the system.

analysis provides insight into how a particular transmission project might impact possible network needs. The analysis did not attempt to identify an optimal transmission expansion solution for the Western Interconnection.

5.1.8 Evaluate proposed solutions for possible reliability implications, cost impacts, environmental and water attributes, and policy achievement

There are additional considerations and evaluations that must be performed in addition to analyzing congestion and potential solutions. The Expected Future network, study cases, and potential transmission capacity additions and projects need to be evaluated in regard to:

- capital and operating costs;
- reliability implications;
- environmental attributes; and
- public policy directives.

This section describes the process and activities undertaken to fulfill this need.

Capital Costs

In 2009, the Western Electric Industry Leaders (WEIL) funded the development of a capital cost estimating tool[42] by Energy and Environmental Economics (E3). This tool calculates an annual levelized fixed cost for a given resource or transmission addition. The input data to the tool was drawn from public sources by E3, whose staff provided WECC with recommendations on reasonable values to be used for TEPPC's economic evaluations of study cases.

Resource Capital Cost Estimates

In March 2011, E3 reviewed the capital costs assumed for the renewable resources in TEPPC's estimating tool and determined that costs of utility-scale solar PV had decreased dramatically since the tool was originally developed. The capital cost estimates and associated fixed Operating and Maintenance (O&M) costs for solar PV technologies were adjusted to reflect this change. Table 7 shows the capital and fixed O&M costs assumed by TEPPC for renewable resources.

Table 7: Renewable Generation Capital Cost Assumptions[43]

Cost	Solar PV		Solar Thermal		Wind	Geothermal	Biomass	Small Hydro
($/kW-AC)	Fixed-Tilt	Tracking	No Storage	With Storage				
Capital Cost	$4,000	$4,700	$5,350	$7,500	$2,350	$5,500	$4,250	$3,300
Fixed O&M	$36	$50	$65	$65	$50	$180	$155	$25

42 TEPPC's capital cost estimating tool is available for review and use by TEPPC stakeholders on the TEPPC Web page.

43 Cost estimates provided in this table and used in the capital cost spreadsheet tool developed for TEPPC were gathered by E3 from publicly available data sources. The data sources used to collect this information are outlined at the location provided in footnote 42.

TEPPC's capital cost tool allows the user to select a resource type from a data set that covers the full range of renewable and conventional resource options. Regional multipliers were also developed by E3 to reflect regional differences in costs of land, labor, and materials. Resource capital cost estimates calculated for the resource relocation cases studied by TEPPC assume a 20-year amortization (cost recovery) period. The estimates were calculated using the updated solar PV capital costs, E3's suggested financing assumptions, regional multipliers, and the assumed continuation of U.S. Federal tax incentives. Table 8 provides a summary of the tax incentive assumptions that are incorporated into TEPPC's resource capital cost estimates. These assumptions were applied only to resources located within the U.S.

Table 8: Tax Assumptions used in TEPPC's Capital Cost Analysis

Resource Type	Investment Tax Credit (ITC)	Capital Cost Available for ITC	Production Tax Credit ($/MWh)	Production Tax Credit Duration (years)
Biomass			$21.00	10
Geothermal			$21.00	10
Solar Thermal	30%	95%		
Solar PV	30%	95%		
Wind			$21.00	10

The capacity value of the relocated resource portfolio was compared to the capacity value of the resources removed from the Expected Future case. This was done to determine the amount of additional on-peak capacity needed to equalize the capacity value of the new resource mix with the old resource mix. Table 9 summarizes the on-peak capacity value assumptions applied to the renewable resources studied in TEPPC's resource relocation cases. These assumptions were developed by the TAS Studies Work Group (SWG) for the purposes of calculating the load and resource balance in the TEPPC study cases.

Table 9: Percentage of Installed Capacity of Renewable Resources Available to Serve Load at Time of Peak

Generation Type	AZ-NM-SNV	Basin	Canada	California	NWPP	RMPA
Biomass	100%	100%	100%	100%	100%	100%
Geothermal	100%	100%	100%	100%	100%	100%
Small Hydro	35%	35%	35%	35%	35%	35%
Solar PV	60%	60%	60%	60%	60%	60%
Solar CSP – No storage	90%	95%	95%	85%	95%	95%
Solar CSP – 6 hours storage	95%	95%	95%	95%	95%	95%
Wind	10%	10%	10%	10%	10%	10%

No additional resources were added to the production cost simulation of the resource relocation cases outside of the renewables needed to offset the energy removed from resources assumed in the Expected Future case. However, the capital cost of combustion turbines (CT) needed to replace the on-peak capacity value of the removed resources was added to each resource relocation capital cost estimate. This was done to equalize the capacity value of the relocated renewables and the renewables removed from a case. A levelized cost of $149.33/kW-year was used for the additional CT capacity. This cost reflects the capital cost per kW of a CT, minus the estimated offsetting energy market net revenues that would be received by the CT as a contribution toward recovering its fixed costs.

Transmission Capital Cost Estimates

The transmission capital cost estimates calculated for the various transmission expansion projects were also drawn from the E3 cost tool. These are estimates based on line mileage by jurisdiction for a range of voltage options and include the cost of right-of-way, transmission line, and substation construction. The annual levelized-fixed-cost calculation emulates the revenue-requirement calculations used in utility rate cases (e.g., recognizing investment, O&M expense, depreciation, cost of capital, capital structure) and assumes a 40-year amortization (cost recovery) period.

The E3 cost tool provides an estimate for substation and termination costs that can be used directly in the spreadsheet tool to calculate the total annualized transmission cost estimate. After reviewing E3's recommended values for these costs, TAS asked the SWG to review and update the substation cost estimates to reveal the distinction between projects involving new versus existing substations. In December 2010, the SWG developed revised substation cost estimates that broke out independent costs for site preparation, transformation, line terminations, and compensation. Table 10 outlines the substation component costs developed by the SWG that were used to estimate the capital cost of the transmission expansion projects evaluated in the TEPPC study cases.

Table 10: TEPPC Substation Component Cost Estimates[44]

	500 kV	345 kV	230 kV
Single Line Termination	$4,000,000	$2,600,000	$1,500,000
Double Line Termination	$6,500,000	$4,000,000	$2,000,000
Series Capacitors	$25,000,000	$25,000,000	
Shunt Reactors	$6,000,000	$6,000,000	
Three Phase Transformer Bank	$25,000,000	$18,000,000	$7,000,000
Site Preparation	$11,350,000	$9,650,000	$8,500,000

Transmission line and right-of-way (ROW) costs, originally recommended by E3 and incorporated into the cost tool, were based on the WREZ Transmission Model. These costs were benchmarked against E3's Green House Gas and RPS Calculators that gave similar costs at the time the tool was being developed. After reviewing the results of TEPPC's capital cost estimates for a number of transmission expansion studies, and comparing these against project developer cost estimates for the same or similar projects, TAS requested that WECC review the

[44] The costs listed for line terminations, series and shunt compensation, and transformation are the installed costs. They include engineering, material procurement, and construction labor for two breakers, switches, bus work, controls, etc. The costs listed for site preparation include a new control building, site preparation and below-grade portion, such as foundations, ground grid, conduit/raceway, etc.

transmission line cost assumptions used in the E3 cost tool. In response to this request, WECC collected publicly available project cost estimates for seven HVDC and seven 500-kV AC transmission projects in varying stages of development in the Western Interconnection. An estimated $/mile line cost was then extracted from the project cost estimates collected and was compared against the $/mile transmission line costs originally used in TEPPC's cost tool.[45]

The average transmission line cost collected for the HVDC projects was $2.4M/mile including ROW, as compared to a cost of $1.7M/mile including an average ROW used in TEPPC's original cost tool. The highest and lowest transmission line costs collected for the HVDC projects were $3.4M/mile and $1.5M/mile including ROW, respectively. Most of the HVDC project costs collected were very high-level cost estimates for projects in early stages of development at the time. Two HVDC project cost estimates reviewed by WECC, however, were collected from documents filed with the Alberta Utilities Commission (AUC) and reflect cost estimates based on installed costs assuming an in-service date of 2014. The HVDC line costs estimated for these projects, the Western Alberta Transmission Line and the Eastern Alberta Transmission line, were $2.9M/mile and $2.5M/mile including ROW, respectively.[46]

WECC had less confidence in the average transmission line costs collected for the 500-kV AC projects due to the difficulty encountered in separating out substation costs and transmission line costs associated with other voltage levels from the total transmission project cost estimates. As a result, TAS agreed to update the transmission line costs in TEPPC's cost tool using the average HVDC transmission line costs estimated from the project costs collected by WECC. The AC transmission line costs in TEPPC's cost tool were also updated using the same multipliers used to derive the WREZ transmission line costs.[47] The revised transmission line costs used to estimate the capital cost of the transmission expansion projects studied by TEPPC are shown in Table 11.

Table 11: TEPPC Transmission Line Cost Estimates

Technology	WREZ Multiplier	Revised Line Cost ($M/mi, no ROW)
HVDC	0.8*500-kV SC	**$2.20**
500-kV single-circuit (SC)	1	**$2.75**
500-kV double-circuit	1.6*500-kV SC	**$4.40**
345-kV single-circuit	0.7*500-kV SC	**$1.93**
345-kV double-circuit	1.6*345-kV SC	**$3.08**

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45 HVDC termination costs, estimated at $250 million per converter station, were subtracted from the project cost estimates collected to estimate a $/mile line cost for the DC projects. Reported substation costs for the AC projects, or an estimate of $50 million per 500-kV substation, were subtracted from the project cost estimates to estimate a $/mile line cost for the AC projects.

46 AUC filing for the Western Alberta Transmission Line. AUC filing for the Eastern Alberta Transmission Line. These projects include a full metallic return path rather than the less-costly ground electrodes typically utilized on long-distance HVDC projects.

47 In the WREZ process, the 500-kV single-circuit transmission line cost was the base cost from which all other line costs were calculated. TEPPC's revised line costs use the new HVDC line cost to calculate all other line costs.

230-kV single-circuit	0.5*500-kV SC	**$1.38**
230-kV double-circuit	1.6*230-kV SC	**$2.20**

WECC used the E3 cost estimating tool, in conjunction with updated solar PV costs, to update transmission line and substation component costs and calculate an annualized fixed cost for incremental resource and/or transmission investments. This process was modeled in each resource relocation and transmission expansion study case considered as part of the Plan.[48] These estimates were added to the operating costs for each given case and compared to the Expected Future to determine net savings in resource and transmission capital costs.

The capital costs provided in the E3 tool and used in the 10-year planning studies reflect a generic characterization of costs for generation technologies deployed under a wide-range of conditions and for large prospective transmission projects that would have to undergo extensive siting and permitting processes. There is a large degree of uncertainty surrounding the assumptions used to develop the capital cost estimates described in the Plan. TEPPC performed a cost sensitivity analysis on three input assumptions, including the assumed continuation of tax incentives, the assumed capacity factor of wind resources studied in the relocation cases and the estimated cost of the transmission expansion projects studied with the resource relocations. Despite these efforts, a more detailed analysis of the costs associated with any of the study cases described in the Plan, including a sensitivity analysis on key cost assumptions, should be performed prior to making any decisions regarding resource procurement or transmission development. A discussion of the resource capacity factor and transmission cost sensitivity analysis performed for the resource relocation cases is described in greater detail in Section 4. Results from the sensitivity analysis performed on the assumed continuation of tax incentives can be found in the 2019 Study Report.

Reliability Screening

Individual transmission providers (TP) and transmission operators are required, by NERC standards, to perform planning reliability studies that meet standards. SPGs also perform reliability studies for their respective footprints and, in some cases, these studies either replace or augment individual TP reliability analyses. A comprehensive review of the reliability implications of each new major transmission project is completed prior to construction and operation through the WECC Path Rating Process.

An important requirement under WECC's agreement with the DOE is that its Interconnection-wide plans would be evaluated for their reliability implications. This analysis is not designed to supplant or augment reliability analyses performed by other organizations or by WECC as part of other processes, which in combination assure future additions to the Western Interconnection are designed to meet reliability requirements. Rather, the reliability screening is designed to

[48] The capital cost estimates for the transmission expansion projects include only those incremental facilities added to the assumed transmission network topology, based on developer-submitted General Electric Positive Sequence Load Flow (PSLF) raw data files, needed to model the project in the studies.

identify where elements of the Plan, analyzed as a package, may have reliability criterion violations or might need additional investigation.

WECC, with the assistance of the SCG and Quanta Technology, conducted a high-level reliability screening of the Expected Future case to better understand areas where further analysis should be conducted. Importantly, this is the first-time WECC has attempted to perform any type of reliability analysis of PCM cases. The primary objective of screening during this study cycle was to gain an understanding of how best to perform reliability screenings in future planning cycles. A report detailing the lessons learned and next steps will be provided in a separate report. The following is a synopsis of the reliability screening process.

A power flow analysis was conducted on the Expected Future case for 10 specific hours shown in Table 12. The SCG provided WECC with a list of hours of interest and provided guidance on selecting transmission contingencies (N-1 outages). SCG members also provided technical assistance to WECC during the analysis.

Table 12: Hours Selected for Reliability Screening

Case #	Date	Hour of Day	Reason for Selection	WECC Load (MW)
1	02/07/2020	6	Highest TOT2A flow	97,200
2	03/15/2020	12	Greatest delta between AZ-NM-NV load and largest renewables online (4321MW delta)	100,160
3	06/22/2020	1	Peak TOT3 flow	91,530
4	06/27/2020	16	High North of John Day, COI and PDCI flows	133,850
5	07/27/2020	17	WECC Peak Hour	159,400
6	09/8/2020	22	Highest EOR flow (6557MW)	119,550
7	10/4/2020	3	Light NW load and high wind	102,875
8	10/18/2020	4	Lowest AZ-NM-NV load (10869MW)	82,000
9	10/30/2020	19	High wind and NW Path flows	112,960
10	12/23/2020	10	Highest WOR flow (9232MW)	122,980

The process in creating a power flow case from a PCM case is shown in Figure 43. The power flow case that was used as a starting point was the Northern Tier Transmission Group[49] (NTTG) Summer Peak of the PROMOD TEPPC (2020 PC0) base case dataset,[50] which created the

49 NTTG has recently (as of 2011) gone through a Reliability Analysis for their footprint. A special thanks for his collaboration to Ronald Schellberg representing Idaho Power Co. in NTTG.

50 The only material difference between the 2020 PC0 dataset and the Expected Future case (2020 PC1) is that the total load in the latter is less due to additional Energy Efficiency assumed.

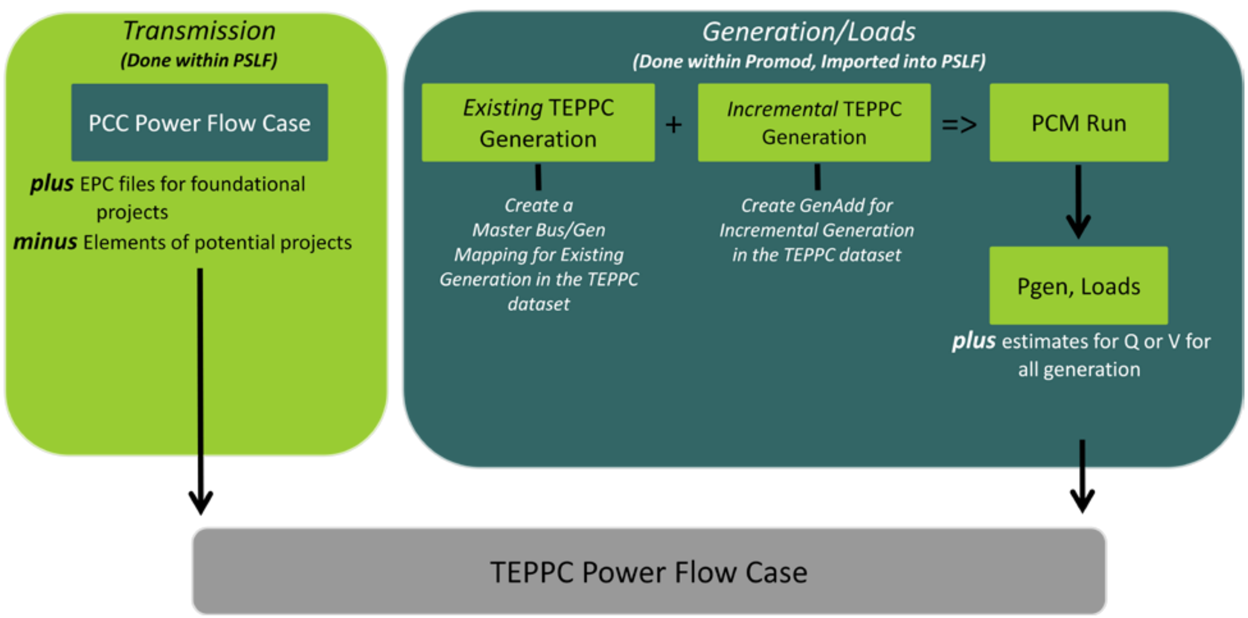
"transmission" components and reconciled the "generation" components (i.e., the transmission and generation from the PCM) in the power flow case.

Next, for each of the 10 hours, the generation and loads were extracted from the PCM case output and imported into the power flow case (i.e., the PSLF software) and combined with voltage and reactive data. This resulted in 10 separate power flow cases.

The 10 cases were first tested without any outage (N-0) to see if there were any thermal or voltage violations. To the extent possible, any violation that appeared to be model-related was resolved by changing operating parameters. This "tuning," done in the normal course of power flow analysis, proved to be difficult and time-consuming.

After each of the 10 cases was tested without outages, a first-order (N-1) reliability screening was performed. The list of N-1 contingency events included all WECC facilities 230 kV or higher, as well as any facility included in the WECC 2011 Path Rating Catalog. The list of N-1 contingency events totaled 3,032 single line outages, 369 transformer outages, and 66 generator[51] outages. The facilities included in the contingency events were monitored and reported for thermal and voltage violations using criteria reviewed by WECC and the SCG. A key limitation to the reliability screening is that automated Remedial Action Schemes (RAS) were not included. RAS is a key component to maintaining system reliability during events and, when not included, impacts the screening results on many WECC paths.

Figure 43: PCM to Powerflow Conversion



Lessons Learned

The inherent discrepancies between the PCM (i.e., PROMOD) and a power flow model (e.g., different aggregation of system generators and loads, data needed in one model but not the other, seasonal operating assumptions) made the process of case conversion, obtaining a

[51] Generators with a minimum base at 500 MVA

power flow solution, and running steady state contingency analysis difficult. Automating this process in future planning cycles will be a challenge.

The use of a single-starting power flow case is problematic. Voltage and reactive schedules, along with seasonally-switched devices significantly impact the results. Therefore, in future planning cycles, as series of starting cases will have to be created and then matched on an individual PCM case. This should yield better results, despite the significant increase in the effort required.

To understand the model and system nuances that drive the reliability screening results requires a level of technical review which is considerable and demanding personnel with intimate knowledge of each subregion of the Western Interconnection. Future efforts will require close review by individual SPGs and the SCG.

Environmental Analysis

As part of the RTEP process, the SPSG formed the EDTF in June 2010 to "develop recommendations on the type, quality, and sources of data on land, wildlife, cultural, historical, archaeological, and water resources (in coordination with work conducted via the State-Provincial Steering Committee), exploring ways to transform that data into study cases and into the models." Throughout this report, these resources are referred to as environmental and cultural information or data.

SPSG's technical support contractor, ICF International (ICF), interviewed a diverse cross-section of stakeholders involved in transmission planning and compiled a catalog of geospatial data sets to help achieve EDTF's goals. The findings and observations from their work, as well as information from other stakeholder-driven studies and input from EDTF members, form the basis for EDTF's recommendations for incorporating environmental and cultural factors into future transmission planning cycles.

The Environmental Recommendations for Transmission Report describes in full the five recommendations that follow. These recommendations were approved by the SPSG on May 24, 2011.

Environmental and Cultural Data Sets

The EDTF produced and recommends using the preferred catalog of Geographic Information System environmental and cultural data sets (or subsequent iterations) in Table D-1 of the Environmental Recommendations for Transmission report to plan for and compare potential transmission alternatives in future transmission planning cycles. These data layers were identified by a number of means: by EDTF members, from similar studies, and by subject matter experts. They represent currently available data that the EDTF found appropriate to date for use in consideration of environmental and cultural resources during regional transmission planning. To ensure preferred data sets remain current, the EDTF recommends that the TEPPC Planning Protocol has a process added to review and validate data sets for update and inclusion by appropriate stakeholders; either the EDTF or its successor. As they become available and as appropriate, state wildlife agency Decision Support Systems data — and other state and provincial data (such as data layers for state forests, parks, and wildlife management areas) — may be incorporated into the preferred data list.

Land Classification System

The EDTF has developed and recommends use of a classification of land areas or area types that describe four tiers of suitability for transmission development, based on their environmental and cultural sensitivities and constraints. The following are the four suitability categories.

1. Least risk of environmental or cultural resource sensitivities and constraints (e.g., designated energy corridors).
2. Low-to-moderate risk of environmental or cultural resource sensitivities and constraints (e.g., other public lands).
3. High risk of environmental or cultural resource sensitivities and constraints (e.g., national monuments).
4. Areas presently precluded by law or regulation (e.g., wilderness areas).

The EDTF recommends applying this land classification system (or future iterations) and the environmental and cultural data sets to plan for and compare potential transmission alternatives. The EDTF will work with WECC and its technical contractors to integrate this approach into their LTPTs and the transmission planning process (e.g., 10- and 20-year plans).

Economic Valuation

In 2011, the EDTF will work with technical contractors to explore existing data on the economic value of environmental and cultural resources, goods, and services at a level appropriate for WECC's long-term planning process.

Additional Guidance and Process

The EDTF recommends an amendment for consideration by TEPPC to the TEPPC Planning Protocol to include a comparison of future transmission alternatives based on criteria derived from the environmental and cultural data sets. The EDTF recommends that this proposed amendment also describe a process for maintaining and updating the environmental and cultural data sets.

Additional recommendations include:

1. reporting results of comparing transmission alternatives (i.e., future transmission lines and transmission options stemming from the transmission planning process) based on these environmental and cultural criteria;
2. providing workarounds for selected data gaps; and
3. describing an integrated and complementary approach for considering these data sets with respect to generation evaluation and transmission planning.

Future Stakeholder Involvement

The EDTF recommends working with WECC to:

- conduct regular outreach (e.g., share lessons learned, leverage complementary efforts, and incorporate feedback from previous planning cycles);
- include and exceed current RTEP stakeholders;
- evaluate and improve the integration of environmental and cultural information into regional transmission planning.

Energy-Water Analysis

As part of the RTEP process, the WGA and the Western States Water Council are working with WECC, the DOE, the national laboratories, and other stakeholders to evaluate water resource issues associated with the siting, transmission, and mix of energy supplies in the Western Interconnection. The goal is to understand the interconnections between energy and water, to assess potential trade-offs associated with water use for electricity generation, and to develop strategies to promote generation and transmission plans that are compatible with available water supplies.

This analysis can inform transmission planning decisions across the Western Interconnection in several ways:

1) identify regions and electric generation at risk due to potential water scarcity;
2) evaluate power plant and electric system vulnerabilities due to drought;
3) identify and deploy technological or management options for planners and plant managers to account for water availability when siting and designing electric generation; and
4) prepare governors, industry, and regulators to understand the long-term challenges and potential trade-offs associated with electricity and water supply decisions.

To understand how best to incorporate water impacts into future RTEP cycles, the case study that follows was performed.

Energy-Water Analysis Case Study

To understand how water considerations can be used in future RTEP processes, the WGA and the laboratory consortium have analyzed a number of 10-year planning studies. The focus of the water analysis is a comparison of water consumption due to electricity generation and its impact on the water supply in the Western U.S.

The primary tool for the energy-water analysis is the Energy-Power-Water Simulation Tool developed by Sandia National Laboratory. The lab team conducted the following steps to assess water supply risks due to power plant generation.

1. 2010 TEPPC Study Program Results: WECC provided the laboratory team with four separate PCM output files associated with the study cases from the 2020 studies:

    - PC0 (TEPPC Base case);
    - PC1 (Expected Future case, a.k.a. SPSC Reference Case);
    - PC2 (SPSC High-Load case); and
    - PC3 (SPSC High-DSM case).

    The data include plant-specific information including plant name, bus designator, and location by state, type of plant, status (e.g., existing, under construction, planned, future) and annual/monthly power production in megawatt-hours. Plants in Alberta, British Columbia, and Mexico were not included in this analysis.

2. Water Use Calculations by Plant: The labs developed an assessment of thermoelectric water withdrawal and consumption factors for over 40 different combinations of plant type and cooling technology.[52] These factors were linked to specific power plants in the PCM output files and were used to calculate water consumption by plant based on plant-specific electricity production rates. For existing plants that may use older and less efficient technologies, the laboratories used the eGRID database and United States Geological Survey's (USGS) county level water use statistics. These statistics were adjusted by projected generation under the TEPPC study cases to calculate water use. The labs distinguished between freshwater and saline water use by plant using data from the USGS and accounted for this important distinction in their analysis.
3. Assessment of Water Availability in the West: In order to understand the implications of water demands for electricity, the laboratories developed an assessment of water availability across the U.S. portion of the Western Interconnection.

   For water supply, the laboratories used the USGS National Hydrographic Dataset, which includes stream flow data from 23,000 stream gauges across the West. For water demand, the laboratories used statistics published by the USGS on consumptive use of water. Because this data was last published in 1995, the laboratories projected water demands based on population and gross domestic product.

   This assessment allowed comparison of supply and demand on a per-watershed basis and provided a high-level assessment of water availability at a regional scale across the Western United States.
4. Areas and/or Electricity Generation at Risk: The laboratories overlaid water consumption by electric generation under the WECC scenarios with water availability by hydrologic unit (watershed) to identify potential areas at risk due to water supply constraints.

Preliminary Results of the Energy-Water Analysis

The preliminary results and conclusions of the energy-water analysis conducted by the WGA and the national laboratories focused on water consumption associated with electricity generation and its impact on water supply in the West. The WGA and the national laboratories plan to refine this analysis over time, particularly with respect to plant-specific cooling technologies and water consumption, and the regional characterization of water supply availability and demand across the West. However, these preliminary results highlight critical issues that should be considered in transmission planning.

Several conclusions emerged based on the preliminary analysis conducted by the WGA and the national laboratories:

1. thermoelectric generation will drive a significant increase in water consumption by 2020;
2. water demands for thermoelectric use are relatively small in relation to water demands for agriculture or municipal and industrial use;

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[52] Macknick, Jordan, *Water Withdrawal and Consumption and Parasitic Energy Factors*, National Renewable Energy Lab, December 2010.

3. thermoelectric water demands are a significant driver of *new* demands and their spatial and temporal distribution can be critical; and
4. study cases do perform differently with respect to water withdrawal and consumption.

Thermoelectric generation will drive a significant increase in electric sector water consumption by 2020

In the Expected Future case, electricity production increased 14 percent, while water withdrawals increased by less than five percent between 2009 and 2020. But water consumption by power plants increased over 20 percent during this same period, from 38 million gallons per day (mgd) to 46 mgd. Water consumption is more concerning than withdrawal to many Western water managers since water that is consumed is actually removed from the hydrologic system and is unavailable for use by downstream water demands.

This increase in water consumption is due to two primary factors: 1) an increase in thermoelectric generation from 2010-2020; and 2) an increase in water consumption intensity, or water consumed per unit of electricity generated. Water withdrawal intensity actually declines across the study case. This is largely a result of a decrease in the use of Once-Through-Cooling technologies, which have high water withdrawal intensity. However, water consumption intensity increases by almost 10 percent across the 10-year study period as closed-loop cooling technologies tend to evaporate more water as consumptive loss.

Increased demands for electric generation are relatively small in relation to agriculture or municipal and industrial use

Agriculture is the primary consumptive user of water in the Western United States, constituting approximately 95 percent in 2010. Municipal is the next highest consumptive user at only 3 percent of the total. Thermoelectric generation follows in a cluster of uses, each of which constitutes less than 1 percent of the total, including industry, mining, and livestock.

New thermoelectric demands are a significant driver of new water demands, and their spatial and temporal distribution can be critical

Municipal demands are the most significant new demand over the 10-year study period, constituting an increase in withdrawal of over 500 mgd and an increase in consumption of over 200 mgd. However, thermoelectric generation accounts for the second-largest new consumptive demand at approximately 50 mgd, comprising approximately 10 percent of the new water demand for the study period. Agricultural water use has been relatively flat for the last 40 years and was not projected to increase over the study period.

In addition to being a significant contribution to new consumptive water demand, water consumption from the thermoelectric sector (both current and proposed) is concentrated in the American Southwest (Figure 44). The American Southwest, including the Colorado River Basin, is the most water-stressed region in the United States. This is the place where competition for water will be the most acute over the coming decades. In addition, much of the new electricity generation occurs near population centers, often the same places facing new municipal and industrial demands.

Figure 45 depicts the ratio of water supply to water consumption, by basin, across the Western Interconnection. The lower the ratio, the closer the basin is to a full allocation of available water supply. The higher the ratio, the more water is available to meet future demands. Figure 46 shows the amount of new water consumption by basin across those basins with a supply to consumption ratio of two or less (i.e., with the greatest level of potential water stress). In short, significant new thermoelectric water withdrawals are projected in basins that may be most prone to water stress.

Figure 44: Current (left) and Projected (right) Thermoelectric Water Consumption

Thermoelectric Consumption 2010 New Thermoelectric Consumption 2020

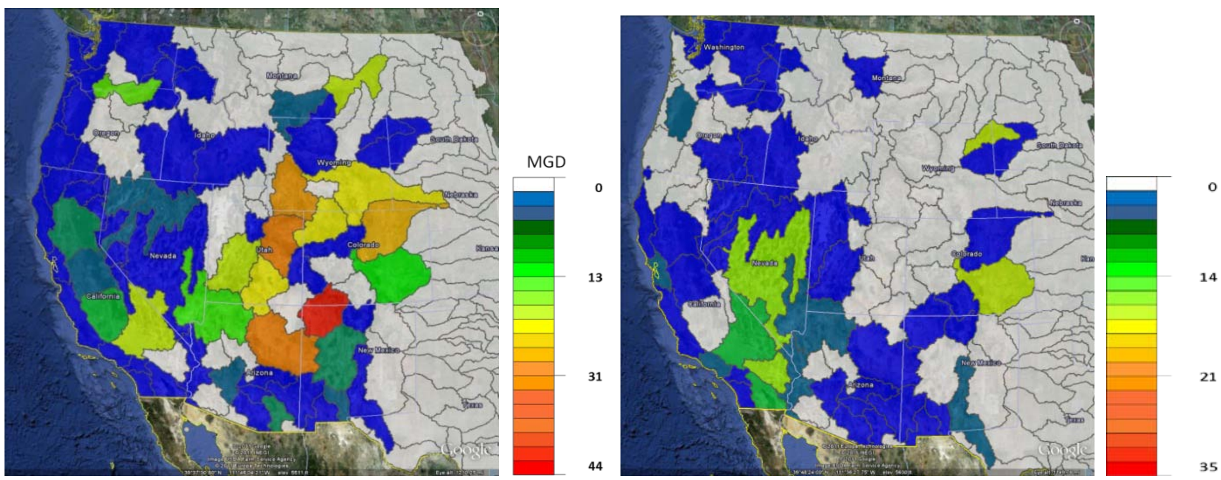


Figure 45: ***Ratio of Water Supply to Consumption in Western Basins***

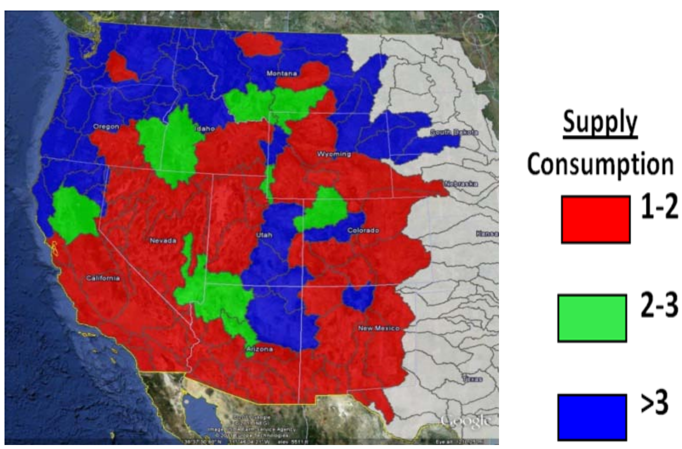
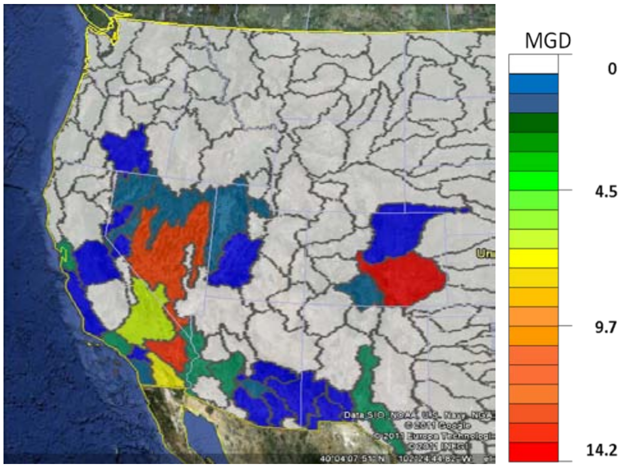


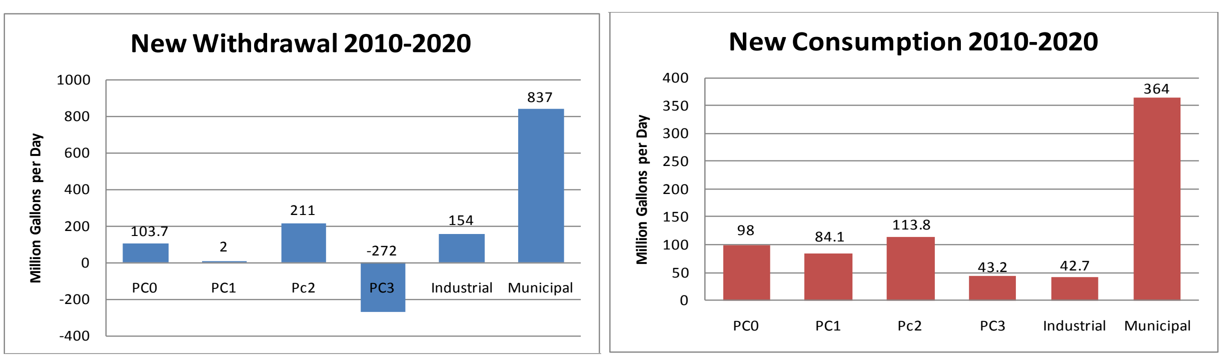
Figure 46: New Power Plant Consumption in Basins with a Low Ratio of Supply to Consumption



The study cases do perform differently with respect to water withdrawal and consumption

The results presented above regarding thermoelectric generation and water use are for the Expected Future case. While the TEPPC study cases do perform similarly in many ways with respect to water use, some differences do emerge among scenarios. For example, new water withdrawals for thermoelectric generation range from -272 mgd (PC3 – High-DSM case) to +211 mgd (PC2 – High-Load case), and new water consumption for thermoelectric generation ranges from 43 mgd (PC3) to 113.8 mgd (PC2) (Figure 47). These differences are the result of different overall generation levels and different technological and operational mixes among the four TEPPC study cases. In large part, these differences are due to changes in operations at *existing* power plants as the mix and operation of new plants are relatively similar across study cases. Distinctions between study cases should be considered closely and may indicate potential technological or operational remedies to address acute water stress related to thermoelectric generation.

Figure 47: ***Comparison of TEPPC study cases for new water withdrawal and consumption***



The result of this work led to a set of recommendations that are described in Section 4.7.

Public Policy Analysis

Information about how the Expected Future network, study cases, potential transmission capacity additions, and projects will meet known public policy directives (e.g., accessing renewable energy zones, RPS compliance, and carbon reduction) is reported on in the individual study cases.

5.1.9 Develop Recommendations

Identifying, screening, and organizing results of the analyses conducted under the TEPPC Study Program resulted in a collaborative set of observations and actionable recommendations, which include:

1. transmission capacity additions;
2. suggestions for addressing unanswered questions;
3. identification of follow-up studies;
4. suggestions for improving the planning process for the second 10-Year Plan and the first 20-Year Plan; and
5. opportunities for collaboration.

6 Organizations Involved in Developing the Plan

6.1 WECC

The Western Electricity Coordinating Council (WECC) is the Regional Entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection. It is comprised of a diverse set of electric industry stakeholders from across the West, including in the U.S., all or parts of 14 Western states; in Canada, Alberta and British Columbia; and in Mexico, Northern Baja California. WECC is governed by an independent and balanced stakeholder Board of Directors (WECC Board), consisting of 32 directors with representation from seven membership classes. WECC has seven, non-affiliated board members with a variety of skills and backgrounds.

Among its functions, WECC serves as a regional planning and policy facilitator for the Western Interconnection. WECC operates in a public, stakeholder-driven process through its committee structure to address issues of transmission planning, resource adequacy, variable generation integration, and the operational and commercial aspects of these issues.

The WECC Board has the responsibility for approving the 10-Year Regional Transmission Plan.

6.1.1 Transmission Expansion Planning Policy Committee (TEPPC)

TEPPC — a WECC Board committee — conducts and facilitates economic transmission planning in the Western Interconnection. TEPPC activities include fulfilling transmission owner/operator and SPG planning requirements under FERC Order 890.[53] TEPPC has a balanced membership comprised of individuals from WECC-member organizations and stakeholders.

TEPPC has four main functions.

[53] Transmission owners and/or operators meet their Order 890 planning requirements with respect to their SPGs and TEPPC through their Attachment Ks to their Open Access Transmission Tariffs. SPGs interact with TEPPC according to their charters.

1. Oversee and maintain a public data base for production cost and related analysis.
2. Develop and implement Interconnection-wide expansion planning processes in coordination with the Planning Coordination Committee (PCC), other WECC committees, Subregional Planning Groups (SPGs), and other stakeholders.
3. Guide and improve the economic analysis and modeling of the Western Interconnection and conduct transmission studies.
4. Prepare Interconnection-wide transmission plans consistent with applicable NERC and WECC Reliability Standards.

TEPPC has 19 members selected for their expertise, geographic diversity, and stakeholder representation. It has a Technical Advisory Subcommittee (TAS) and workgroups. These units work in concert to perform analysis and help stakeholders engage in planning processes. Its primary workgroups are the Studies Workgroup (SWG), Modeling Workgroup (MWG), Data Workgroup (DWG), and Historical Workgroup (HWG). Each workgroup is tasked with performing specific duties in the TEPPC Study Program. Workgroup decisions are made by consensus, with approval from TAS and review from TEPPC.

TEPPC's role is to ensure the creation of the WECC 10-Year Regional Transmission Plan and to recommend that Plan to the WECC Board of Directors for approval.

6.1.2 Scenario Planning Steering Group (SPSG)

The SPSG is a multi-constituency steering group that provides strategic guidance and direct participation on TEPPC activities. The purpose of the SPSG is to provide strategic guidance to TEPPC on:

- the scenarios to be modeled in transmission planning studies;
- the modeling tools to be used; and
- key assumptions to be used in creating and reviewing the scenarios.

The SPSG's membership includes TEPPC members to ensure communication between the groups. The SPSG members participate regularly in TEPPC activities, and it is the responsibility of the SPSG to assure that input from nontraditional stakeholders, specifically Non-Governmental Organizations, is incorporated into the Western Interconnection's planning processes and deliverables.

The SPSG participated in analyzing study results, developing transmission plan criteria, and reviewing and commenting on the processes for creating TEPPC reports and transmission plans. The SPSG's Environmental Data Task Force (EDTF) took the lead in performing a case study of environmental factors for transmission planning. This led to the development of the environmental recommendations contained in the Plan.

6.2 State-Provincial Steering Committee (SPSC)

The SPSC consists of appointees from each state and province in the Western Interconnection, and it comprises one-third of the SPSG membership. The Western States Water Council and the Western Governors' Wildlife Council are ex-officio members of the SPSC. The purpose of the SPSC is to provide input to Western Interconnection transmission planning and analysis through the following three tasks.

1. Providing input into regional transmission planning.
2. Improving the efficient use of the existing grid.
3. Enabling the integration of large amounts of variable generation.

The SPSC took the lead in setting a number of the targets used in the Plan. In addition, the SPSC's Demand-Side Management Task Force led the development of EE and DSM and assumptions in the 2020 cases.

6.3 Western Interstate Energy Board (WIEB)

The WIEB is an organization of 12 western states and three western Canadian provinces. The purpose of WIEB is to provide the instruments and framework for cooperative state efforts to "enhance the economy of the West and contribute to the well-being of the region's people."[54] WIEB seeks to achieve this through cooperative efforts among member states/provinces, and with the federal government. WIEB serves as the energy arm of the Western Governors' Association (WGA).

Much of the WIEB's work is conducted through committees. Its Committee on Regional Electric Power Cooperation (CREPC) consists of the public utility commissions, energy agencies, and facility siting agencies in the Western Region's states and Canadian provinces. WIEB staff and CREPC members participate in TEPPC activities. CREPC and the SPSC are closely linked through common staff and entity membership.

As it relates to the Plan, WIEB's role and contributions were realized through the SPSC.

6.4 Western Governors' Association (WGA)

The Western Governors' Association is an independent, nonpartisan organization of governors representing 19 Western states and three U.S.-flag Pacific islands. Through their Association, governors identify and address key policy and governance issues related to natural resources, the environment, human services, economic development, international relations, and public management.

The WGA has two primary roles in the Plan in addition to participating in the broader planning activities. First, the WGA provided staff support for the SPSC and its ongoing activities. Second, the WGA provided comparative information on water withdrawal and consumption, by generation type, for the various study cases. This information was provided by the Western States Water Council and Sandia National Laboratory. The results of this activity are reported in the Plan.

In addition to ongoing water analysis, the Western Regional Air Partnership will evaluate generation air emissions of ozone precursors and the Western Governors' Wildlife Council will provide environmental data and analysis from the WGA Wildlife Decision Support System.

54 WIEB website.

6.5 Subregional Planning Groups (SPG)

The nine TEPPC-recognized SPGs have been organized to address common issues within a particular portion of the Western Interconnection. Their memberships are diverse, comprised of the major Load-Serving Entities (LSE), Transmission Owners, and Transmission Operators in their respective areas. Some SPGs include state entities and smaller LSEs, such as municipal utilities and rural electric cooperatives. Under their respective charters, SPGs may assess and prepare transmission plans for the electrical infrastructure within their individual boundaries. The SPGs provide a forum for input from large and small owners, operators, LSEs, customers, and other stakeholders — some of whose interests do not extend to the entire Western Interconnection. Each SPG gathers information to help identify the aggregate needs of internal and external consumers to aid the WECC RTEP process.

The SPG Coordination Group (SCG) coordinates SPG activities of mutual interest and with regard to TEPPC. In response to a request of TEPPC, the SCG prepared the SCG Foundational Transmission Projects List based on criteria developed by the SCG. The list identified projects having a high probability of being constructed by 2020. These projects provide an assumed minimum transmission system starting point for TEPPC's future congestion studies, and are included as inputs into the WECC 10-Year Regional Transmission Plan. Other projects listed as 'potential' were be used by TEPPC as possible capacity addition solutions.

Individually, the SPGs have many roles in the creation of the Plan. The SPGs provide much of the current and future transmission assumptions through their planning activities. These roles include evaluating the development status of projects and describing why transmission additions are being proposed. In addition, the SPGs perform reliability studies on the portion of the network they serve. These reliability studies help inform the more general reliability evaluations that will be performed as part of creating the Plan.

6.6 States and Provinces

State and provincial agencies and utility commissions participate in TEPPC activities. This is accomplished through their direct participation in the TEPPC and its subgroups; and through participation in multijurisdictional organizations such as the WIEB, CREPC, and SPSC.

6.7 Federal Agencies

The U.S. Department of Energy (DOE), Department of the Interior (DOI), and Department of Agriculture (DOAg) participate in TEPPC activities through ex-officio positions on the SPSG. In addition, the DOE partially funds TEPPC activities through its grant to WECC. The Plan will be filed with the DOE to meet, in-part, the terms of the Grant.