10-Year Regional Transmission Plan

2020 Study Report
TEPPC 2010 Study Program

September 2011

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Executive Summary
The 2010 TEPPC Study Program includes three distinct study horizons: 1) a long-term 20-year horizon focused on a 2029 outlook; 2) a medium term 10-year horizon building on the 2019 studies from the 2009 Study Program; and 3) a new medium term 10-year horizon looking out to the year 2020. Study work completed as part of the 2010 Study Program was spread over a period from December 2009 through April 2011.

Reports were created for each individual study horizon as the study results became available. Reports for the 2029 and 2019 study horizons were also prepared.

This report presents the results and analysis for the 2020 horizon studies. The study cases completed were selected from the study requests submitted by stakeholders to TEPPC during the 2010 study request open season. The following are themes of the 2020 study cases.

- State electricity efficiency programs
- Utility demand response programs
- Potential Federal carbon reduction targets
- Increased load sensitivity
- Aggressive build-outs of wind in Montana and Wyoming

Qualifications and disclaimer regarding study scope
The TEPPC studies, results, presentations, and reports should not be interpreted as an endorsement or sanctioning of any projects. The data and modeling assumptions used in the TEPPC studies were developed using a collaborative stakeholder process. The results are presented in a standardized format to facilitate certain comparisons, and key observations are provided for informational purposes only.

The TEPPC studies are completed using a production cost model with the intent to evaluate changes in transmission utilization and generation dispatch. There are limitations in the production cost model's ability to emulate actual operations, which are important to understand to avoid drawing mistaken conclusions from the studies. The limitations of the production cost model, as utilized by TEPPC, include the inability to capture the effects of transactions made under long-term contracts, the impacts of scheduling rules on system dispatch, and the inherently conservative nature of actual operating practices. The TEPPC studies compensate for the limitations to some extent by applying hurdle rates that bring interchange solutions closer to reality.

Capital cost estimates prepared for the 2020 studies were developed using the capital cost spreadsheet tool that was created for TEPPC by Energy and Environmental Economics (E3) in late 2009. The input data to the tool was drawn from public sources by E3, who provided WECC staff with recommendations on reasonable values to be used for TEPPC’s evaluations. In March 2011 the renewable resource capital costs used in the tool were reviewed by E3 who recommended to TEPPC that updated solar photovoltaic (PV) capital costs and associated fixed O&M costs be utilized for the 2020 aggressive wind cost estimations to reflect the reduction in costs for utility-scale solar PV since 2009. Transmission cost estimates including substation component costs and $/mile transmission line costs used in the tool were also reviewed and updated by the Technical Advisory Subcommittee (TAS) of TEPPC in early 2011. The resource
and transmission capital costs derived from the tool for the 2020 aggressive wind and associated transmission expansion studies are estimates only and are used for comparative purposes. Because of the uncertainties surrounding a number of the input assumptions used to calculate the capital cost estimates between study cases, a more detailed analysis of the costs associated with any of the TEPPC study cases, including a sensitivity analysis on key cost assumptions, should be performed prior to making any decisions regarding resource procurement or transmission development.

The renewable resource portfolio assumptions used in the TEPPC 2020 studies reflect available information at the time of the case development on renewable energy policies and procurement trends across the Western Interconnection.

Summary list of 2020 study cases

The dataset used for the 2020 studies includes numerous updates to the transmission, generation, and load data assumed in the 2019 dataset originally built in 2009. Several stakeholders worked from June through December of 2010 to pull together data and fine-tune the modeling of the 2020 TEPPC datasets. The resultant base case provided a baseline for the other 2020 study cases where variations in load, energy efficiency (EE) assumptions, deployment of Demand-side Management (DSM) programs, emission reduction targets, and renewable resource options were applied.

The 2020 study cases are listed below along with a short description of the case and a brief summary of the key study results. Whenever the load forecast was changed in a case, the renewable resources were also adjusted to maintain the energy-based renewable portfolio standard (RPS) requirements. Conventional resource assumptions remained constant across all the study cases except the PC8 carbon reduction case.

- **PC0** is the LRS base case in which the load forecasts submitted by the WECC Balancing Authorities (BAs) were used. The PC0 case was not used for any of the study cases in the 2010 Study Program.
- **PC1** is the State-Provincial Steering Committee (SPSC) reference case with loads adjusted consistent with utility and state assumptions on energy efficiency, DSM, and demand response. The PC1 case represents the “TEPPC Expected Future” case for the purposes of the 2020 studies and the WECC 10-Year Regional Transmission Plan.
- **PC2** is a high loads case where the PC1 loads were increased by 10 percent in both peak and energy. It was observed that the higher loads generally lead to lower transmission utilization (as compared to PC1) because low cost resources previously used for export were absorbed in local areas.
- **PC3** is a high DSM, and high EE, case where the DSM was increased and the PC1 loads were decreased to reflect the full economic EE potential throughout the Western Interconnection. The increased EE and DSM (i.e. lower loads) generally lead to increased transmission utilization (as compared to PC1) as surplus low cost resources in some areas were transferred to other areas to displace local, higher cost resources.
- **PC4** is a carbon reduction case built off the PC3 case where a carbon cost adder was applied to the CO2 emissions from generators in the dataset to achieve a target reduction in CO2 emissions. A $30 per ton carbon adder coupled with renewable resources needed to meet state statutory RPS, high EE and high DSM achieved the targeted 17 percent reduction in CO2 emissions from 2005 levels. This led to generally
lower transmission utilization (as compared to PC3) as remote coal generation was displaced by local gas generation. Interestingly, the combination of the RPS resources, high EE and high DSM facilitated 80 percent of the targeted CO2 reduction.

- **PC5** was not completed. This was a high priority case in the 2010 Study Program to evaluate the impacts of breakthrough technologies on transmission congestion. The study request was canceled due to difficulty in gathering the required data.

- **PC6** and **PC7** are aggressive interior wind development cases. In these cases, 25,000 GWh of renewable generation designated to be used to meet California's RPS requirements in the PC1 reference case reflecting current RPS planning and procurement trends was moved from other areas in the Western Interconnection to Montana and Wyoming, respectively. The combination of relocated resources and incremental transmission identify the potential for significant cost savings that vary from case to case. It is important to note that the resource relocations and transmission expansions studied were not rigorously assessed in terms of their ability to deliver the relocated generation from Wyoming and Montana to particular load areas. In addition, resource and transmission cost uncertainties were not fully analyzed, and a number of other important factors used to make actual resource planning and procurement decisions were not fully addressed.¹

- **PC8** is a second carbon reduction case, also built off the PC3 case, where a reduction of CO2 emissions was achieved by retiring existing coal plants and increasing renewable generation in locations that could utilize transmission capacity freed up by the coal retirements. The replacement of 6000 MW of existing coal plants with selected renewables coupled with statutory RPS resources, high EE and high DSM resulted in a reduction of 24 percent in CO2 emissions from 2005 levels. Transmission utilization was relatively unchanged (as compared to PC3) because the incremental renewable resources were located in areas near the coal plants they replaced.

- **PC9** is a study case designed to evaluate the benefits of the Tres Amigas project that connect the three interconnections through a DC terminus. The case is built off of PC1 and includes the addition of the High Plains Express and SunZia potential future transmission projects. Separate price curves were developed to represent the ERCOT and SPP markets, and were used as price signals to determine the interaction between WECC, ERCOT, and SPP. Economic benefits were realized in the study from the ERCOT and SPP generation being used to displace higher-cost WECC generation, as well as from the selling of surplus low-cost WECC generation to the Electric Reliability Council of Texas (ERCOT) and the Southwest Power Pool (SPP) markets. These benefits are highly dependent upon the price curve assumptions used to model the ERCOT and SPP markets.

A detailed list of the input assumptions for the 2020 PC0 LRS base case is provided in the Assumptions Matrix for the 2020 TEPPC Dataset. Further discussion of the 2020 study cases is provided below with detailed study results provided in the body of the report.

¹ A more detailed discussion of the uncertainties surrounding the resource and transmission cost estimates prepared by TEPPC, as well as the important factors considered when making actual resource planning and procurement decisions can be found in the 2019 Study Report.
The Expected Future case
The PC1 SPSC Reference Case represents the consensus “expected future” for the Western Interconnection in 2020 for the purposes of the 2020 Study Cases. The expected future includes assumptions for loads, generation, transmission, and other study related parameters.

Loads
The historical and projected energy load growth for the PC1 Expected Future case is illustrated in Figure 1.

Figure 1: Energy Load – Actual/Projected

![WECC Loads: Past, Present and Future](image)

Generation
There were several generation additions designed to meet the load growth through 2020 and the state RPS targets listed below in Table 1. Other states and provinces with existing and planned renewable generation portfolios include Alberta, British Columbia, Idaho, Mexico (CFE), and Wyoming.

Table 1: Renewable Portfolio Standards for 2020

<table>
<thead>
<tr>
<th></th>
<th>AZ</th>
<th>CA</th>
<th>CO</th>
<th>MT</th>
<th>NV</th>
<th>NM</th>
<th>OR</th>
<th>TX</th>
<th>UT</th>
<th>WA</th>
</tr>
</thead>
<tbody>
<tr>
<td>RPS % IOUs</td>
<td>10.0</td>
<td>33.0</td>
<td>30.0</td>
<td>15.0</td>
<td>22.0</td>
<td>20.0</td>
<td>20.0&lt;sup&gt;2&lt;/sup&gt;</td>
<td>5.0</td>
<td>13.3</td>
<td>15.0</td>
</tr>
<tr>
<td>RPS %</td>
<td>10.0</td>
<td>33.0</td>
<td>10.0</td>
<td>-</td>
<td>-</td>
<td>10.0</td>
<td>6.7</td>
<td>-</td>
<td>13.3</td>
<td>see&lt;sup&gt;3&lt;/sup&gt;</td>
</tr>
</tbody>
</table>

<sup>2</sup> The 20% standard in OR is only for “large” utilities, defined in statute as follows: “an electric utility that makes sales of electricity to retail electricity consumers in an amount that equals three percent or more of all electricity sold to retail electricity consumers.” PGE, Pacific Power and EWEB are "large" utilities; Idaho Power and consumer-owned utilities other than EWEB are "small utilities."
The generation additions included almost 35,000 MW of renewable resources. The resulting renewable energy by type and state/province from the PC1 solution is shown in Figure 2. Of the solar resources assumed in PC1, 50 percent by capacity is PV, and of this 23 percent by capacity is distributed PV.

Figure 2: Renewable Generation in WECC

The breakdown of annual generation for the PC1 case is shown in Figure 3. This represents the actual dispatch from the PROMOD solution.

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3 In Washington state the 15% standard applies to all “large” utilities having more than 25,000 customers, including PUDs and municipalities.
California Once-Through-Cooling (OTC)

Several generating plants in California that currently use of OTC has been directed by the State Water Board to cease operations or retrofit their cooling systems. The assumed implementation schedule will retire over 13,000 MW of generation in California prior to the year 2020. To maintain the reliability and inertia requirements approximately 7,700 MW of new replacement generation was assumed for the 2020 TEPPC dataset. A summary of the OTC assumptions is shown in Figure 4.

Figure 4: California OTC Implementation
Transmission

The transmission network for the PC1 Expected Future case is based on the 2020 HS1 base case provided by the WECC SRWG. Other assumptions regarding future transmission additions were provided by the Subregional Coordination Group’s (SCG) Foundational Transmission Projects List Report. The Foundational Projects were accepted as inputs to the PC1 case because they have a high likelihood of being in service by 2020. The foundational projects presented in Figure 5 were added to the PC1 transmission network if they were not already included.

Figure 5: Foundational Projects

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4 The System Review Work Group (SRWG) is part of the WECC Planning Coordination Committee.
Other Core Study Cases

Table 2 lists some key study elements associated with loads, Demand Response (DR), and installed generating capacity for the core 2020 study cases. Note that the hourly demand response operating in each case is mostly driven by Location Marginal Prices (LMP), which vary from hour to hour subject to the marginal units and generation constraints.

Table 2: Load and Demand Response Comparison

<table>
<thead>
<tr>
<th>Case</th>
<th>Coincident Peak Demand (MW)*</th>
<th>Demand Response at Peak Hour (MW)</th>
<th>Installed Generation Capacity (MW)</th>
<th>Total Annual Energy Load (TWh)</th>
<th>Total Annual Demand Response (MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2019 PC1A</td>
<td>179,366</td>
<td>0</td>
<td>271,681</td>
<td>1,062</td>
<td>917</td>
</tr>
<tr>
<td>2020 PC0</td>
<td>178,667</td>
<td>296</td>
<td>267,263</td>
<td>1,026</td>
<td>11,058</td>
</tr>
<tr>
<td>2020 PC1</td>
<td>169,807</td>
<td>4,859</td>
<td>264,598</td>
<td>986</td>
<td>137,200</td>
</tr>
<tr>
<td>2020 PC2</td>
<td>186,695</td>
<td>5,701</td>
<td>272,012</td>
<td>1,083</td>
<td>305,300</td>
</tr>
<tr>
<td>2020 PC3</td>
<td>155,243</td>
<td>252</td>
<td>261,120</td>
<td>885</td>
<td>398,245</td>
</tr>
<tr>
<td>2020 PC4</td>
<td>155,281</td>
<td>677</td>
<td>261,120</td>
<td>883</td>
<td>523,526</td>
</tr>
<tr>
<td>2020 PC6</td>
<td>169,826</td>
<td>4,627</td>
<td>268,836</td>
<td>988</td>
<td>147,434</td>
</tr>
<tr>
<td>2020 PC7</td>
<td>169,817</td>
<td>4,685</td>
<td>264,598</td>
<td>987</td>
<td>153,047</td>
</tr>
<tr>
<td>2020 PC8</td>
<td>155,217</td>
<td>194</td>
<td>265,009</td>
<td>885</td>
<td>393,507</td>
</tr>
<tr>
<td>2020 PC9</td>
<td>169,807</td>
<td>4,627</td>
<td>na</td>
<td>982</td>
<td>135,319</td>
</tr>
</tbody>
</table>

*The coincident peak demand includes the native demand, pumping load, and DC losses, but excludes the demand response adjustment, which is listed in its own column.

The installed generation capacity is similar to a nameplate rating. For any given hour the available generation to serve load and meet reserves is subject to derates and outages.
Key study results
The study results collected for the study cases focus on path utilization, generation dispatch, variable production cost, and carbon emissions.

Path Utilization Results
The most heavily utilized path in the 2020 studies is the California – Oregon Intertie (COI) Path 66, which is a major tieline between Northern California and Oregon. The chronological path flow and duration plot for COI from the PC1 case are presented in Figure 6 and comparisons to a few other 2020 study cases, as well as to historical 2008 flows are shown in Figure 7.

Figure 6: COI Utilization in PC1

Utilization of the COI appears to be noticeably influenced by the load forecasts assumed in each study case. When the load forecast is high in PC2 the utilization of COI is reduced because there is less surplus energy in the Northwest that can be used to displace higher cost resources in California. Similarly, when the forecast is low in PC3, the utilization is increased as lower cost resources available in the Northwest are used to serve load in California.
The companion path to COI is the Pacific DC Intertie (PDCI) that connects Oregon to Southern California. The version of PROMOD that was used for all of the studies in the 2010 Study Program did not equitably account for losses on DC lines versus AC lines. The DC line loss implementation penalized flows on DC lines and shifted flows to the parallel AC system. The result of the problem is that flows on DC paths such as the PDCI are likely understated, while flows on AC paths such as the COI path are likely overstated to some degree. In the case of COI versus the PDCI this is difficult to evaluate since the two paths have the potential to deliver to two separate but interconnected markets.

When the COI and PDCI paths are combined for reporting purposes we can get an idea of the extent of the flows and what the combined congestion looks like. The plots of the combined path durations are provided in Figure 8.

**Figure 8: Combined COI + PDCI Duration Plots**

The correlation of flows on the COI and PDCI to loads is still applicable. The lower loads in PC3 free up more lower-cost energy in the Northwest and increase the exports to California, where the hydro and coal from the Northwest displace higher cost gas resources. The higher loads case (PC2) has the opposite effect.

The Montana – Northwest path (Path 8) was the 2nd most utilized path in the 2020 studies. The path flow and duration plot for Path 8 from the PC1 case are presented in Figure 9 and comparisons of the path flow to a few other study cases, as well as to historical 2008 flows are shown in Figure 10.

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[5] The issue with the modeling of DC lines in PROMOD is discussed in greater detail in TEPPC’s 2019 Study Report.
Figure 9: Montana-Northwest Utilization in PC1

Figure 10: Montana-Northwest Path Duration Plots

Figure 11 shows the most heavily utilized paths for the PC1 case under the TEPPC congestion metrics. The green bars for U99 show how often the path limits were binding.

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6 A congestion metric of U99 represents the number of hours that the flows on a path are greater than 99% of the path’s rated capacity. The U75 and U90 metrics are the same with percents of 75 and 90, respectively.
Figure 12 is a comparison of the average transfers between sub-regions for the PC1, PC2, and PC3 study cases. Note the effect of the increase in loads (PC1 to PC2) and then the decrease in loads (PC1 to PC3). It appears that the surplus energy in Northern California (CA_N), NWPP, and British Columbia is used locally when the loads are high in PC2. The reduction in the amount of economy energy impacts several of the transfers.
Figure 12: Transfers between Sub-regions - PC1, PC2, PC3

Transfers between Sub-Regions (aMW)

- PC1
- PC2
- PC3

Legend:
- AZNMNV To Ca_S
- Basin To AZNMNV
- Basin To Ca_N
- Basin To Ca_S
- Ca_N To Ca_S
- Canada To NWPP
- NWPP To Basin
- NWPP To Ca_N
- NWPP To Ca_S
- RMPA To AZNMNV
- RMPA To Basin

Average Megawatts:
Summary of Generation Results

Some of the key generation results for the 2020 study cases are provided in Table 3. The annual generation is representative of the net energy for load. Although some variation is apparent due to pumped storage and line losses, the demand and energy loads are the same for PC1, PC6, and PC7. Also, the reduced loads in PC3 were used in PC4 and PC8.

Table 3: Key Generation Result Comparison

<table>
<thead>
<tr>
<th>Study Case</th>
<th>Annual Generation (GWh)</th>
<th>Dump Energy (GWh)</th>
<th>Emergency Energy (GWh)</th>
<th>DSM Savings (GWh)</th>
<th>Unutilized Coal (GWh)</th>
<th>CO$_2$ Emissions (MMetricTons)</th>
</tr>
</thead>
<tbody>
<tr>
<td>PC0 Base</td>
<td>1,026,025</td>
<td>29</td>
<td>0.34</td>
<td>11</td>
<td>9,474</td>
<td>383</td>
</tr>
<tr>
<td>PC1 SPSC</td>
<td>985,796</td>
<td>28</td>
<td>0.39</td>
<td>137</td>
<td>12,474</td>
<td>368</td>
</tr>
<tr>
<td>PC2 High Load</td>
<td>1,082,585</td>
<td>15</td>
<td>15.24</td>
<td>305</td>
<td>6,239</td>
<td>406</td>
</tr>
<tr>
<td>PC3 High DSM</td>
<td>884,946</td>
<td>433</td>
<td>0.26</td>
<td>398</td>
<td>26,464</td>
<td>323</td>
</tr>
<tr>
<td>PC4 Carbon Adder</td>
<td>882,640</td>
<td>83</td>
<td>0.26</td>
<td>524</td>
<td>44,331</td>
<td>310</td>
</tr>
<tr>
<td>PC6 Aggressive MT Wind</td>
<td>988,179</td>
<td>2,712</td>
<td>0.54</td>
<td>147</td>
<td>25,310</td>
<td>364</td>
</tr>
<tr>
<td>PC7 Aggressive WY Wind</td>
<td>986,903</td>
<td>1,311</td>
<td>0.41</td>
<td>153</td>
<td>25,299</td>
<td>361</td>
</tr>
<tr>
<td>PC8 Carbon Reduction</td>
<td>885,193</td>
<td>689</td>
<td>0.26</td>
<td>394</td>
<td>24,846</td>
<td>285</td>
</tr>
<tr>
<td>PC9 Tres Amigas</td>
<td>982,488</td>
<td>21</td>
<td>0.40</td>
<td>135</td>
<td>na</td>
<td>368</td>
</tr>
</tbody>
</table>

The amount of un-utilized coal is highest in PC4 due to the carbon cost adder that applies an additional cost to CO$_2$ emissions. Due to their higher CO$_2$ emissions, coal-fired generation becomes incrementally more expensive when CO$_2$ is financially penalized. The un-utilized coal is high for all of the 2020 cases except for the PC2 High Load case. When base-load generation, such as coal, is not utilized it is often an indication of transmission constraints, generation constraints, or a surplus of generation lower on the dispatch stack.

PC1 SPSC Reference Case Synopsis

The preceding transmission plots and generation summary show that the PC1 SPSC Reference case had some inherent issues with transmission constraints and base-load generation cycling. The COI and Montana-Northwest paths were both constrained and several base-load coal units were operated inefficiently, including excessive cycling associated with the generation build-out and transmission constraints.

One of the primary concerns is the high utilization of the COI path with a U99 of 29.6 percent. The interpretation of this is that the COI path is fully loaded at 4,800 MW for almost 30 percent of the year in the PC1 case. Conversely, in 2008 the highest actual flow was 4,661 MW. The
TAS workgroups are conducting an analysis of the modeling assumptions for the COI path, and the results will be made available later.\textsuperscript{7}

Another concern is the cycling of base-load resources in the dispatch results. Over 12,000 GWh of coal generation was not utilized in the PC1 case due to modeling assumptions that give priority to wind, solar, and geothermal resources, while ignoring other key considerations such as transmission rights. This is common to many of the studies for the 2010 Study Program. Modeling improvements may be needed in the future, but specifics have yet to be developed. A joint project underway between WECC and NREL will provide more guidance on the impacts related to ramping and cycling of thermal units.

**PC2 High Load Case and PC3 High DSM Case Synopses**

For the 2020 study series the PC2 and PC3 cases served as bookends for system load variations with the annual energy load for PC2 9.8 percent higher than PC1 and the load for PC3 10.3 percent lower than PC1 as illustrated in Figure 13.

*Figure 13: Annual Energy Load - PC1, PC2, and PC3*

Plots in the preceding “Path Utilization Section” presented how the load variations impacted the flows on some of the key paths. The generation summary in Table 3 also compared some of the key generation results, which show high correlations between load, dump energy, unutilized coal, and CO\textsubscript{2} emissions.

In the high load case the estimated planning reserve margin dropped as shown in Figure 14, with half of the sub-regions ending below the LRS target levels. The most impacted sub-region was Alberta, which actually experienced a few hours of generation deficits in the PC2 case.

---

\textsuperscript{7} One factor contributing to the heavy utilization of COI may be flows shifting from the Pacific DC Intertie (PDCI) path to COI due to the HVDC modeling issues described in the 2019 Study Report.
Figure 14: Planning Margin Change
PC4 Carbon Cost Adder Synopsis

The purpose of the PC4 case was to find a carbon cost adder that would reduce the CO₂ emissions by 17 percent relative to 2005 actual emissions. This was achieved with a $30 per ton carbon cost adder, largely due to a 6.5 percent reduction in coal generation. The chart in Figure 15 shows where the most significant generation changes took place.

The chart in Figure 16 provides a comparison of the variable production cost for the PC1 (SPSC Reference Case), PC2 (High Load Case), PC3 (High DSM Case), and PC4 (Carbon Reduction Case). Note that in PC4 the cost of the carbon cost adder is stacked with the variable production cost of the thermal generation.

**Figure 15: Generation Change PC3 > PC4**

![Annual Energy Difference: 2020 SPSC High DSM Case vs. 2020 SPSC - $30 Carbon Adder](chart15.png)

**Figure 16: Comparison of Production Cost - PC4**

![Total Variable Production Cost](chart16.png)
PC6 and PC7 Aggressive Wind Case Synopses
In the PC6 and PC7 cases the combination of high dump energy and high levels of un-utilized coal are signals of unsatisfactory solutions, often associated with insufficient transmission capacity. The expansion cases with added transmission represent more realistic scenarios, but the transmission expansion alternatives tested with the aggressive wind cases were not optimally sized in relation to the capacity of wind resources relocated to Montana or Wyoming. As such, it is likely that additional transmission capacity would be needed to fully integrate the wind resources studied in these cases.

The aggressive wind cases and the associated expansion cases involve modifications to the renewable resource and transmission assumptions used in the 2020 PC1 reference case. A breakdown of relative costs, including an estimate for incremental resources and transmission, for the aggressive wind cases is shown in Table 4. The combination of relocated resources and incremental transmission identify the potential for significant cost savings that vary from case to case. It is important to note, however, that the aggressive wind resource relocations and transmission expansions studied were not rigorously assessed in terms of their ability to deliver the relocated generation from Wyoming and Montana to particular load areas. In addition, resource and transmission cost uncertainties were not fully analyzed, and a number of other important factors used to make actual resource planning and procurement decisions were not fully addressed. Rather, the different resource relocation and transmission expansion alternatives were analyzed at a strategic level emphasizing: 1) known renewable resource procurement trends and information as a starting point (as reflected in the 2020 PC1 reference case); 2) high level capital cost estimates for resources and transmission studied incrementally to the base 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 the 2020 aggressive wind studies as described in this report can guide subsequent in-depth assessments of possible resource and transmission options to meet particular RPS or other needs. Such targeted assessments might consider more detailed and situation-specific factors such as:

- the cost, feasibility, and responsibility for operationally integrating the relocated wind generation, as compared to the cost, feasibility, and responsibility for operationally integrating the renewable resources removed from the other locations of the Western Interconnection;
- the ability of the relocated wind generation to meet deliverability, “best fit” or other specific procurement criteria;
- the likelihood of the relocated wind generation displacing use of transmission by existing coal and gas generation as shown in the cases studied;
- how realistic timing of renewable generation and especially transmission development would correspond to energy procurement timelines;

---

8 A more detailed discussion of the uncertainties surrounding the resource and transmission cost estimates prepared by TEPPC, as well as the important factors considered when making actual resource planning and procurement decisions can be found in the 2019 Study Report.
• the challenges of environmental siting and permitting renewable resources in various locations in the Western Interconnection and long transmission lines crossing multiple states and diverse habitats; or

• how total costs would be allocated among specific organizations or rate-payer groups.

To the extent possible, TEPPC will bring such issues more fully into future study cycles.\(^9\)

Based on the capital cost estimates prepared for the aggressive wind cases as shown below in Table 4, all of the aggressive wind cases have a cost benefit compared to the PC1 SPSC reference case. The savings are mostly related to the estimated capital costs of the resources.

### Table 4: Annual Costs for Aggressive Wind ($M) relative to PC1\(^{10}\)

<table>
<thead>
<tr>
<th>Component</th>
<th>PC1</th>
<th>PC6</th>
<th>EC6-1</th>
<th>EC6-2</th>
<th>PC7</th>
<th>EC7-1</th>
<th>EC7-2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Added Transmission Capacity (MW)</td>
<td>0</td>
<td>0</td>
<td>3,000</td>
<td>2,200</td>
<td>0</td>
<td>5,000</td>
<td>3,000</td>
</tr>
<tr>
<td>Relocated Gen $M/yr</td>
<td>0</td>
<td>2,641</td>
<td>2,641</td>
<td>2,641</td>
<td>1,836</td>
<td>1,836</td>
<td>1,836</td>
</tr>
<tr>
<td>Removed CA Gen $M/yr</td>
<td>3,932</td>
<td>-3,932</td>
<td>-3,932</td>
<td>-3,932</td>
<td>-3,932</td>
<td>-3,932</td>
<td>-3,932</td>
</tr>
<tr>
<td>Transmission $M/yr</td>
<td>0</td>
<td>0</td>
<td>569</td>
<td>223</td>
<td>0</td>
<td>1,610</td>
<td>337</td>
</tr>
<tr>
<td>Net Var. Prod. Cost relative to PC1 $M/yr</td>
<td>0</td>
<td>1,025</td>
<td>514</td>
<td>680</td>
<td>530</td>
<td>-27</td>
<td>450</td>
</tr>
<tr>
<td>Total Increase $M/yr</td>
<td>na</td>
<td>-266</td>
<td>-208</td>
<td>-388</td>
<td>-1566</td>
<td>-513</td>
<td>-1309</td>
</tr>
</tbody>
</table>

The only case where the variable production cost did not increase relative to the PC1 case was the EC7-1 case. The generation that contributes to production cost is limited to units that are assigned a priced fuel such as natural gas or coal. An increase in production cost is an indication that access to the lower cost generation has been reduced by transmission constraints. As incremental transmission is added the lower cost generation becomes available and the production cost decreases. The addition of deliverable non-priced generation such as wind and solar also reduces the production cost since these resources tend to displace thermal (gas-fired) resources.

The large increase in variable production cost between PC1 and PC6 is primarily due to the curtailment of 5,290 GWh of the added Montana wind because of transmission constraints out of Montana. The curtailed wind energy represents 21 percent of the 25,000 GWh of renewable energy that was relocated to Montana for the PC6 case that was no longer available to displace higher cost resources. A comparison of the curtailments for all of the aggressive wind cases are shown in Table 5. The variable production cost is also affected by transmission constraints in other parts of the Western Interconnection, such as COI, that change the generation dispatch.

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\(^9\) Consistent with its charter, TEPPC takes no position and makes no estimation regarding the allocation of costs to any specific organization or rate-payer group.

\(^{10}\) Only a single year's production cost was calculated and so no changes in production cost across the assumed lifetime of the resources were captured. As such, the cost comparison implicitly assumes the production cost numbers, and their differences between cases, are constant across the 20-year lifetime of the resources being compared. The relative magnitudes of the resource capital cost differences and the production cost differences suggest that there is relatively little distortion in the conclusions drawn from the cost comparisons by making this assumption.
Table 5: Aggressive Wind Curtailments

<table>
<thead>
<tr>
<th>Component</th>
<th>PC1</th>
<th>PC6</th>
<th>EC6-1</th>
<th>EC6-2</th>
<th>PC7</th>
<th>EC7-1</th>
<th>EC7-2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Added Wind Capacity (MW)</td>
<td>0</td>
<td>8,583</td>
<td>8,583</td>
<td>8,583</td>
<td>6,107</td>
<td>6,107</td>
<td>6,107</td>
</tr>
<tr>
<td>Added Transmission Capacity (MW)</td>
<td>0</td>
<td>0</td>
<td>3,000</td>
<td>2,200</td>
<td>0</td>
<td>5,000</td>
<td>3,000</td>
</tr>
<tr>
<td>Added Wind Energy Curtained (GWh)</td>
<td>0</td>
<td>5,290</td>
<td>522</td>
<td>1,499</td>
<td>153</td>
<td>67</td>
<td>73</td>
</tr>
</tbody>
</table>

The chart in Figure 17 compares the estimated capital costs of the resources and transmission for the Montana and Wyoming aggressive wind expansion cases. As indicated by the capacity bars, the transmission projects are not equivalent.

Figure 17: Capital Costs of Expansion Cases

The transmission expansion cases studied with the Montana and Wyoming aggressive wind resource relocations generally include less new transmission capacity than the capacity of the wind resources relocated to Montana and Wyoming. As such, additional transmission investment may be needed to reliably deliver these resources to load centers and to mitigate the transmission congestion observed in the study cases which resulted in a significant amount of cycling and ramping of base-load resources. This additional transmission investment, which appears supportable by the estimated potential generation capital cost savings, would reduce and, depending on the size of the investment and other uncertainties, could eliminate the cost savings shown in Figure 17.
Observations

- High utilization of the COI path was observed in the 2020 studies.\textsuperscript{11} The COI utilization is likely related to the availability of economy energy in the Northwest and planned imports into California. In regional studies, it is common to assume between 10,000 and 13,000 MW of imports from the Northwest and Southwest into California during peak hours.

- High utilizations of the Montana-Northwest path was observed in the 2020 studies (see Figure 10). This path is heavily utilized by design as it is the major path between the Colstrip generating plant and several joint owners in Washington and Oregon. The external shares are approximately 1,300 MW, leaving only 900 MW of the 2,200 MW path open to support other transfers. Because of this, adding large amounts of wind in Montana without adding additional transmission leads to substantial transmission congestion.

- In the PC2 high load case the WECC annual energy load increased by 111,600 GWh, or an hourly average of 12,705 MW. More than half of the increased energy load was served by combined cycle generation and the aggregate utilization factors of the CC plants increased from 32 to 45 percent. Nearly 15,000 GWh of the increased generation was from renewable resources, most of which was from the adjustments to maintain the RPS targets that are based on energy loads.

- The cycling of base-load coal generation is worse in many of the 2020 studies than it was in the 2019 studies. The 10-day plot in Figure 18 of the generation and load in the AZNMSNV sub-region for PC1 shows significant curtailment of coal-fired generation. The basic conclusion in this case (with no applicable transmission constraints between Arizona and California) 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.

Figure 18: PC1 Generation – AZNMSNV

\textsuperscript{11} One factor contributing to the heavy utilization of COI may be flows shifting from PDCI to COI due to the HVDC modeling issues described in the 2019 Study Report.
• In other areas the cycling is often related to the integration of intermittent resources, such as is shown in Figure 19 for the NWPP. Here the wind and hydro generation are displacing the coal generation for several hours (and occasionally nuclear generation). The generation above the pool demand is being exported to other areas and for some of these hours transmission constraints are limiting the amount of exports. During several of the off-peak hours the wind generation is directly displacing the coal generation, and is occasionally displacing the nuclear generation. Figure 20 shows the same plot in incremental cost or “stack” order.

Figure 19: PC1 Generation – NWPP

Figure 20: PC1 Generation - NWPP Stack Order

• With the renewable energy penetration in WECC approaching 17 percent in the 2020 studies, there needs to be more emphasis on how these resources can be successfully integrated. The wind and solar resources have been modeled as must-take resources in
the TEPPC studies, and many of the integration issues have been given a low priority. Wind speeds in most areas of WECC tend to be consistently higher during times of low power demand, and can vary dramatically over a short period of time. Wind generation is still searching for its “dance partner”\textsuperscript{12} and cutting in on base-load units is not necessarily the right answer for maintaining a reliable power system. Besides its tendency for variability, wind generation is often out of synch with area load shapes. The average wind profiles illustrated in Figure 21 suggest how wind generation can contribute to off-peak surpluses by generating more when the loads are reduced. The wind shapes used in the 2020 dataset are based on the NREL meso-scale wind data for 2006.

Figure 21: Average Hourly Wind for PC1

- TEPPC and other WECC groups are beginning to investigate how energy storage could be used to enhance the integration of variable generation. The concept of storing off-peak generation to use later is not new to WECC. There are four sizable hydroelectric pump storage facilities in WECC that provide this benefit today. The pump storage facilities have successfully taken advantage of surplus off-peak generation to pump water “up the hill” for later use. This has a double benefit of providing additional peaking energy and reducing the cycling of coal and CC units. Additional pump storage plants would help with the integration of wind turbines since in many areas wind is more prevalent at night when additional generation is not needed. Other storage technologies are making progress and will offer additional choices. Documentation of research collected by the California Public Utilities Commission is online at Electric Energy Storage.

\textsuperscript{12} Attributed to a quote from David Hawkins, principal engineer for renewable energy at the California Independent System Operator.
Introduction
This report is the third in a series of study reports detailing results from the TEPPC 2010 Study Program. The previous reports included results for studies in 2029 and 2019 horizons, and are available on the WECC website. The focus of this report is on the 2020 horizon series of studies that considered the effects of various load forecasts, renewable portfolios, EE and DSM assumptions, and methods for achieving carbon reductions.

2020 study cases
The study cases for the 2020 portion of the 2010 Study Program are listed in Table 6 with a general description of each case and a summary of the load, resource, and transmission assumptions used.

Table 6: Study Case Descriptions

<table>
<thead>
<tr>
<th>Case Name</th>
<th>Description</th>
<th>Loads</th>
<th>Resources</th>
<th>Transmission</th>
</tr>
</thead>
<tbody>
<tr>
<td>PC0</td>
<td>LRS base case</td>
<td>LRS forecasts</td>
<td>General update based on LRS submittals, IRP evaluation, and RPS targets</td>
<td>Import of 2020HS1 power flow followed by stakeholder input to align network with SCG list of foundational transmission projects</td>
</tr>
<tr>
<td>PC1</td>
<td>SPSC Reference case</td>
<td>Adjusted to reflect state/provincial energy efficiency programs</td>
<td>Renewable portfolio adjusted to maintain RPS requirements based on modified load forecasts</td>
<td></td>
</tr>
<tr>
<td>PC2</td>
<td>High Loads case (relative to PC1)</td>
<td>Peak demand and energy increased by 10%. DSM recalibrated.</td>
<td>Renewable portfolio adjusted to maintain RPS requirements based on modified load forecasts</td>
<td></td>
</tr>
<tr>
<td>PC3</td>
<td>High DSM case (relative to PC1)</td>
<td>Loads decreased &amp; DSM increased</td>
<td>Renewable portfolio adjusted to maintain RPS requirements based on modified load forecasts</td>
<td></td>
</tr>
<tr>
<td>PC4</td>
<td>Low Carbon case</td>
<td>Same as PC3</td>
<td>Same as PC3</td>
<td></td>
</tr>
<tr>
<td>PC5</td>
<td>Breakthrough technology</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PC6</td>
<td>Aggressive Montana Wind</td>
<td>Same as PC1</td>
<td>Add 25,000 GWh of wind in Montana; remove equivalent renewable energy from other areas</td>
<td></td>
</tr>
<tr>
<td>EC6-1</td>
<td>Transmission sensitivity for PC6</td>
<td></td>
<td>Chinook HVDC</td>
<td></td>
</tr>
<tr>
<td>EC6-2</td>
<td>Transmission sensitivity for PC6</td>
<td></td>
<td>MSTI, and Path 8 upgrade</td>
<td></td>
</tr>
<tr>
<td>Case Name</td>
<td>Description</td>
<td>Loads</td>
<td>Resources</td>
<td>Transmission</td>
</tr>
<tr>
<td>-----------</td>
<td>-----------------------------------------------------------------------------</td>
<td>-----------------------------------</td>
<td>---------------------------------------------------------------------------</td>
<td>-------------------------------------------</td>
</tr>
<tr>
<td>PC7</td>
<td>Aggressive Wyoming Wind</td>
<td>Same as PC1</td>
<td>Add 25,000 GWh of wind in Wyoming; remove equivalent renewable energy from other areas</td>
<td></td>
</tr>
<tr>
<td>EC7-1</td>
<td>Transmission sensitivity for PC7</td>
<td></td>
<td></td>
<td>High Plains Express, SunZia, Gateway West #2</td>
</tr>
<tr>
<td>EC7-2</td>
<td>Transmission sensitivity for PC7</td>
<td></td>
<td></td>
<td>TransWest Express HVDC&lt;sup&gt;13&lt;/sup&gt;</td>
</tr>
<tr>
<td>PC8</td>
<td>Western Grid Group Carbon reduction Modifications to achieve a 30% reduction in CO&lt;sub&gt;2&lt;/sub&gt; emissions relative to 2005 levels</td>
<td>Same as PC3</td>
<td>Additional renewables added to achieve carbon reduction targets</td>
<td></td>
</tr>
<tr>
<td>PC9</td>
<td>Tres Amigas project</td>
<td>Same as PC1</td>
<td>ERCOT and SPP markets modeled using multiple CT units</td>
<td>High Plains Express, SunZia</td>
</tr>
</tbody>
</table>

**Central focus of the 2020 studies**

The key questions associated with the 2020 studies are focused on the impact to the Western Interconnection of variations in the loads, EE and DSM assumptions, carbon adders, and the location of renewable resources within the Western Interconnection.

1. Using a consensus “expected future” baseline scenario, what operational and transmission related concerns can be derived from the study results?
2. What is the impact of increased loads on system utilization?
3. What is the impact on the system of applying different levels of energy efficiency and demand response programs?
4. What is the impact of applying different methodologies to reduce carbon emissions to specific target levels?
5. What happens to the transmission utilization and generation and transmission costs when renewable resources are shifted around the Western Interconnection to insert high penetrations of wind resources in Montana and Wyoming?

**Common assumptions among study cases**

A new TEPPC base case was developed for the 2020 studies with the following data changes applied as compared to the 10-year dataset created by TEPPC in 2009 and modified in 2010.

- New transmission network based on the WECC 2020HS1 power flow case.

<sup>13</sup> Due to limited time and staff resources only a limited number of transmission expansion cases were studied. The TransWest Express (TWE) project was selected for analysis as being a representative HVDC project between Wyoming and southern Nevada. The Zephyr HVDC project has similar endpoints to TWE but a longer route (725 miles vs 900 miles).
• Transmission network modified in PROMOD to reflect the Subregional Coordination Group’s (SCG) list of foundational and potential transmission projects. The resultant network includes all of the foundational projects and none of the potential projects.
• Updated load forecasts were derived from the Loads and Resources Subcommittee (LRS) data submittals and the hourly shapes shifted to 2006.
• Updated fuel prices.
• Generation was updated to reflect changes submitted to LRS and changes reported by TEPPC stakeholders.
• Renewable generation updated to meet the state renewable portfolio standards (RPS).
• Hydro generation updated to 2006 profiles, with the exception of California hydro which continues to use 2003 profiles.
• The once-through-cooling (OTC) requirements for California implemented with retrofits or retirements of the noncompliant units. New thermal units were added to maintain area reliability requirements (voltage support, inertia base, ancillary services).
• Gap thermal and renewable generation added to Alberta to model an expected load/resource balance.
• The Intermountain DC line modeled with a nomogram that linked the line flow to the output of the area generation owned by California entities.
• The SCE Import nomogram implemented.
• DSM modeling updated and split into interruptible and economic demand response programs.

Study assumptions
The study results are determined by the input assumptions and program parameters. The studies were conducted using PROMOD IV, a security constrained production cost model (PCM) that seeks the least-cost solution inside the stated constraints. Some of the overarching study assumptions are:

• Renewable Portfolio Standards (RPS) were given a high priority in the studies with wind and solar resources placed at the bottom of the resource stack. Curtailments are only possible when transmission constraints prevent the delivery of wind and solar output;
• contracts are not modeled for either transmission or generation. This open-ended approach for WECC-wide studies is usually appropriate for measuring potential transmission utilization; and
• the incremental changes to the generation and transmission facilities to represent an expected 2020 bulk electric system in the Western Interconnection were based on input from several sources, but should still be considered as input assumptions.

A map of the sub-regions assumed for the TEPPC studies, and used for reporting purposes, is provided in Figure 22. The areas assigned to each sub-region are also listed. Note that in PROMOD a sub-region is synonymous with a pool.
PROMOD uses the sub-region assignments for some of the basic components of its solution. The preliminary generation dispatch is done at the sub-region level. Thus, the generators assigned to areas in each sub-region are made available to meet the load requirements in the respective sub-region before being considered for economic interchange. Generators are almost exclusively assigned to areas, and sub-regions, based on their geographical location. The only exception is based on the extension of the Los Angeles Department of Water and Power (LADWP) balancing area up the IPP DC line into central Utah, prompting the assignment of generation at the IPP bus to the LDWP area.

The operating reserve assignments are also applied at the sub-region level. This requires that reserves be met by resources within the sub-region.

Loads and Generation
The components of the annual WECC energy load requirement for several of the study cases are presented in Figure 23. The scale makes it difficult to see the smaller components but helps to visualize the size of the native load component relative to the other components. The smaller components are shown in Figure 24 without the native load. The pumping load was broken out separately from the other load in California to avoid diluting the variations in the hourly load shapes and provide reporting capability.
Figure 23: WECC Energy Load Comparison

<table>
<thead>
<tr>
<th></th>
<th>2019 PC1A Base</th>
<th>2020 PC0 Base Case</th>
<th>2020 PC1 SPSC Ref.</th>
<th>2020 PC2 High Load</th>
<th>2020 PC3 High DSM</th>
</tr>
</thead>
<tbody>
<tr>
<td>DC Line Losses</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Emergency Energy</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pump Storage Pumping</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pumping Load</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Native Load</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>DSM</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Annual Energy Load Components (GWh)

Figure 24: Annual Energy Load without Native Load

<table>
<thead>
<tr>
<th></th>
<th>2019 PC1A Base</th>
<th>2020 PC0 Base Case</th>
<th>2020 PC1 SPSC Ref.</th>
<th>2020 PC2 High Load</th>
<th>2020 PC3 High DSM</th>
</tr>
</thead>
<tbody>
<tr>
<td>DC Line Losses</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Emergency Energy</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pump Storage Pumping</td>
<td></td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>Pumping Load</td>
<td></td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>DSM</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Annual Energy Load Components (GWh)

14 AC line losses are included in the Native Load
Figure 25 shows the installed generation capacity by sub-region for the 2019 PC1A Base case, the 2020 PC0 Base case, and the 2020 PC1 SPSC Reference case. The available generation for any given hour is reduced due to unit outages and seasonal de-rates.

**Figure 25: Installed Generating Capacity by Sub-region (existing plus incremental)**

The change in hydro capacity for the AZNMSNV and California sub-regions reflects the reassignment of the Hoover plant from the WALC area to the SCE area. In every sub-region except California there is a slight increase in the amount of renewable capacity in the 2020 cases compared to the 2019 case. The RPS requirement calculated for California in the 2020 cases was less than the RPS requirement calculated for the state in the 2019 case due to a decrease in the load forecast used for California between the 2019 and 2020 cases. The significant decrease in installed capacity in California between 2019 PC1A and the 2020 studies is mostly related to the change in the OTC implementation, which replaced over 90 percent of the retired OTC units in 2019 PC1A but only 60 percent in the 2020 studies. The assumptions for availability by resource type, used to calculate planning reserve margins, are shown in Table 7.

**Table 7: Generation Availability (% of Installed Capacity) at Time of Summer Peak by Resource Type**

<table>
<thead>
<tr>
<th>Generation Type</th>
<th>AZ-NM-NV</th>
<th>Basin</th>
<th>Alberta</th>
<th>BC</th>
<th>CA-North</th>
<th>CA-South</th>
<th>NWPP</th>
<th>RMPA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Biomass RPS</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>Geothermal</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>Small Hydro RPS</td>
<td>35</td>
<td>35</td>
<td>35</td>
<td>35</td>
<td>35</td>
<td>35</td>
<td>35</td>
<td>35</td>
</tr>
<tr>
<td>Solar PV</td>
<td>60</td>
<td>60</td>
<td>60</td>
<td>60</td>
<td>60</td>
<td>60</td>
<td>60</td>
<td>60</td>
</tr>
<tr>
<td>Solar CSP0</td>
<td>90</td>
<td>95</td>
<td>95</td>
<td>95</td>
<td>85</td>
<td>85</td>
<td>95</td>
<td>95</td>
</tr>
<tr>
<td>Solar CSP6</td>
<td>95</td>
<td>95</td>
<td>95</td>
<td>95</td>
<td>95</td>
<td>95</td>
<td>95</td>
<td>95</td>
</tr>
<tr>
<td>Wind</td>
<td>10</td>
<td>10</td>
<td>10</td>
<td>10</td>
<td>10</td>
<td>10</td>
<td>10</td>
<td>10</td>
</tr>
<tr>
<td>Hydro</td>
<td>70</td>
<td>70</td>
<td>90</td>
<td>90</td>
<td>70</td>
<td>95</td>
<td>70</td>
<td>70</td>
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<tr>
<td>Pumped Storage</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
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<td>100</td>
<td>100</td>
<td>100</td>
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<td>Coal</td>
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<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
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<td>100</td>
<td>100</td>
</tr>
<tr>
<td>Nuclear</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>Generation Type</td>
<td>AZ-NM-NV</td>
<td>Basin</td>
<td>Alberta</td>
<td>BC</td>
<td>CA-North</td>
<td>CA-South</td>
<td>NWPP</td>
<td>RMPA</td>
</tr>
<tr>
<td>-----------------------</td>
<td>----------</td>
<td>-------</td>
<td>---------</td>
<td>----</td>
<td>----------</td>
<td>----------</td>
<td>------</td>
<td>------</td>
</tr>
<tr>
<td>Combined Cycle</td>
<td>95</td>
<td>95</td>
<td>100</td>
<td>95</td>
<td>95</td>
<td>95</td>
<td>95</td>
<td>95</td>
</tr>
<tr>
<td>Combustion Turbine</td>
<td>95</td>
<td>95</td>
<td>100</td>
<td>95</td>
<td>95</td>
<td>95</td>
<td>95</td>
<td>95</td>
</tr>
<tr>
<td>Other Steam</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
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<tr>
<td>Other</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>Negative Bus Load</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>Dispatchable DSM</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
</tr>
</tbody>
</table>
**California Once-Through-Cooling (OTC)**

California state policy to comply with Section 316(b) of the Clean Water Act has set targets for the shutdown or repowering of several generation plants. Stakeholders from California provided an implementation plan that was used in the 2020 TEPPC studies. Table 8 provides a summary of the plan that reduces the California thermal resources by a net 5,300 MW.

**Table 8: CA Once-through-cooling (MW)**

<table>
<thead>
<tr>
<th>Type</th>
<th>OTC Retirements</th>
<th>Repower</th>
<th>OTC Additions</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Combined Cycle</td>
<td>0</td>
<td>328</td>
<td>3,669</td>
<td>3,997</td>
</tr>
<tr>
<td>Combustion Turbine</td>
<td>(156)</td>
<td>(188)</td>
<td>3,746</td>
<td>3,402</td>
</tr>
<tr>
<td>Internal Combustion</td>
<td>0</td>
<td>0</td>
<td>163</td>
<td>163</td>
</tr>
<tr>
<td>Steam</td>
<td>(12,862)</td>
<td>0</td>
<td>0</td>
<td>(12,862)</td>
</tr>
<tr>
<td>Total</td>
<td>(13,018)</td>
<td>140</td>
<td>7,578</td>
<td>(5,300)</td>
</tr>
</tbody>
</table>

**Generation retirements**

Information derived from the LRS data submittals, utility IRP postings, and other sources was used to develop generation retirement schedules for the 2020 TEPPC dataset. A summary of the non-OTC retirements is provided in Figure 26. Under the California OTC implementation plan described in the previous section, an additional net 5,300 MW of thermal retirements were modeled.

**Figure 26: Generation Retirements (Non-OTC)**
Transmission Projects

The lists of transmission projects considered for inclusion in the 2020 dataset are provided in map and list form in the graphics below. The projects were divided into two categories – foundational projects and potential projects. Maps of the projects for both categories are provided in Figures 27 and 28.

Only the foundational projects were included in the transmission network for 2020. The foundational projects were accepted as inputs to the PC1 Expected Future case because they have a high likelihood of being in-service by 2020. The merit of these projects was not evaluated as part of the TEPPC 2010 Study Program.

Figure 27: Map of Foundational Projects
Disclaimer and Limitations
The results presented in this report are generally a product of the input assumptions, which were developed using a collaborative stakeholder process and are limited to the scope of the TEPPC study work. Since the primary focus of the TEPPC study results is the utilization of inter-regional transmission paths, many local transmission constraints are ignored. The format of the reporting of the TEPPC study results tends to be comparative and key observations are provided for informational purposes only. To help stakeholders better understand the information provided by the TEPPC study results, a discussion of the congestion results produced by a production cost model is provided below, as is a description of the differences between the production cost model and actual system operations. An explanation of TEPPC’s capital cost estimates prepared for a selection of the 2020 study cases, including the assumptions used to develop the estimates as well as the uncertainties surrounding the estimates is also provided below.

Evaluating Congestion Using Production Cost Simulation Results
One purpose of TEPPC’s Study Program is the evaluation of transmission congestion under alternative futures. It is important to have a clear understanding of what is meant in this report by the term congestion. It is possible to have reliable delivery of energy in a congested system. In this context, system reliability can be characterized as “keeping the lights on” while responding in a predictable fashion to both planned and unplanned outages in generation and
transmission. System congestion, on the other hand is a measure of the economic performance of the transmission system which answers the question, “How well does the transmission system, while operating within the bounds of reliable operation, perform to deliver lowest cost\textsuperscript{15}\textsuperscript{15} energy to consumers?” If there is a low cost resource in the system that is underutilized because there is not enough transmission capacity while operating within reliability standards, then the system is said to be congested, meaning that one or more transmission lines are at their limits. This forces the use of higher cost resources to meet load than would have been used had there not been a transmission system constraint. The load is still being served reliably, albeit at a higher energy cost than without transmission constraints.

The system variable production cost associated with serving load given a set of resource and transmission assumptions must be added to the capital cost of the resource and transmission additions in order to make a comparison among expansion alternatives. TEPPC uses production cost simulation to calculate energy costs differences for different resource portfolios and transmission additions in order to assist in addressing such comparisons. TEPPC also estimates the annualized capital costs for both resource and transmission additions and has done so for the 2020 aggressive wind and associated transmission expansion studies.

The Divergence Between Modeled and Actual Operations

In the evaluation of the TEPPC studies, congestion is measured by the number of hours that a constrained transmission facility operates at 99 percent of its limit or higher (referred to as the U99 metric). Since the simulation does not allow constraints to be exceeded without incurring a cost penalty, the 99 percent level represents effective full utilization of a path. This interpretation seems straightforward; however, in interpreting the results some caution is required. It is important to understand the limitations in the simulation ability to emulate actual operations to avoid drawing mistaken conclusions from the studies.

One of the known difficulties with production cost simulations is the difficulty of capturing the effects of transactions made under long-term contracts. For instance, a take-or-pay agreement for fuel may cause a given plant to run at full capacity when it would be operated at a lower level if it were dispatched based on short term fuel prices. This kind of contract-specific information is generally regarded as confidential by the unit’s operator. By design, the TEPPC database has been developed from publicly available sources so that it can be used by stakeholders for their own studies. Having a public database also allows TEPPC studies to be conducted in a transparent environment. The inaccuracy introduced by using only public data is somewhat minimized in long range studies because over time contracts expire and replacement contracts trend toward the actual fuel costs. However, there is always a set of legacy agreements that alter hourly dispatch decisions (energy returns, peaking commitments, etc.) that a public database will not recognize.

Another difficult issue to address in production cost simulation is the impact of scheduling rules on system dispatch. Outside of the California ISO’s area, energy is scheduled between balancing areas in the Western Interconnection based on contract paths for fixed blocks of energy. It is well understood that contract path schedules do not correspond to actual system

\textsuperscript{15} Or otherwise desirable energy sources judged to be clean and renewable with assumptions internalized within simulations to capture the desirability of resources in the modeling or by the use of adders that allow the minimization of production cost to be used as the objective function for dispatch optimization.
flows. Actual flows are a result of the set of specific, locational injections and withdrawals of energy and the physical properties of the transmission system.\textsuperscript{16} System physics dictate actual flows without regard for facility ownership or scheduling rights represented by contract paths. Yet, with the exception of a centrally dispatched RTO or ISO, scheduling based on flow distribution has not been adopted because of complexities of dealing with transmission ownership rights and with cross compensation among transmission owners.

Under contract path scheduling, parties must obtain rights to submit a schedule, using the Transmission Service Request procedures outlined in open access tariffs. Available Transmission Capacity (ATC), made available in response to a transmission service request, reflects firm commitments. If the holder of a right to transmission service on a particular path does not schedule its use, unscheduled transmission capacity may be sold to others as non-firm service. However, this occurs only on an hourly or daily basis. There are also constraints imposed on scheduling and actual flow levels to avoid reliability problems. For instance, if a path is fully scheduled, no additional power can be scheduled over that path, even if the actual flow turns out to be below the path’s transfer capability limit. This may leave some capacity apparently unused. However, the loop flow (the difference between the scheduled and actual flows) created by these schedules, is flowing on other lines in the system. This scheduling rule is a decentralized approach to keep a scheduling party within its contractual rights and avoiding reliability problems elsewhere in the system. Another mismatch between actual and simulated operation is a result of the timing requirements for the submission of schedules. Schedules are submitted a day-ahead or with changes 30 or more minutes before the next hour. It is impossible to schedule every last MW of transfer capability because scheduling occurs at these discrete time intervals. All of the above factors are real constraints on actual operations that cannot be explicitly modeled in TEPPC study cases.

Finally, system operators are inherently conservative because their prime directive is to keep the lights on. There is a reluctance to operate transmission lines at their maximum capacity hour after hour because of the increased risk such operation entails. Operators must also deal with situations in which otherwise uneconomic generation must be run to support local voltage. Operators also tend to deal with neighboring systems rather than all parties in the Western Interconnection. This tends to produce a local optimum rather than the global optimum dispatch that occurs in a production cost simulation. The limitation in trading partners occurs because of the difficulty of dealing with all possible region-wide generator and transmission usage options in the limited time available for hour-to-hour decision making. These factors and other practical limitations produce what might be called a de facto de-rating of transmission paths in real world operations. The effects of such operational practices are very difficult to estimate and even harder to simulate, so simulation results tend to overstate the transmission system’s ability to economically move energy and understate the need for transmission expansion.

Because of all these factors, finding congestion in a production cost simulation study provides an indicator of the possibility of savings that can be achieved by transmission expansion, but that information alone is not sufficient to justify investment. In fact, new transmission investment

\textsuperscript{16} The primary physical property of an AC network is the impedance of its elements. Impedance is a measure of the opposition to flow on an AC transmission line. The relative impedance of the lines determines flow distribution. The relationship is inversely proportional, so lines with higher impedance carry less power than lines with lower impedance.
is rarely justified based on the results of a congestion analysis alone. Still, when transmission is added in a congestion study, the simulation can be repeated and the results used to estimate the incremental production cost savings associated with the transmission expansion. While the absolute operating results of a single simulation may not precisely match actual system operating costs, the incremental energy cost differences calculated between pairs of cases are more reliable because they represent the cost difference between two operating conditions that are the result of applying a single change, such as the addition of a transmission line, while all other assumed infrastructure and operating rules are kept constant.

**TEPPC’s Capital Cost Analysis**

In 2009 the Western Electric Industry Leaders (WEIL) funded the development of a capital cost estimating tool\(^\text{17}\) 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, who provided WECC staff with recommendations on reasonable values to be used for TEPPC’s evaluations.

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\(^{17}\) TEPPC’s capital cost estimating tool is available for review and use by TEPPC stakeholders at the following location:

http://www.wecc.biz/committees/BOD/TEPPC/Shared%20Documents/Forms/AllItems.aspx?RootFolder=%2fcommittees%2fBOD%2fTEPPC%2fShared%20Documents%2fIE3%20Capital%20Cost%20Tool&FolderCTID=&View=%7b3FECCB9E%2d172C%2dC1%2d9880%2dA1CF02C537B7%7d
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. As a result of this decrease, E3 recommended that TEPPC update its capital cost estimates and associated fixed O&M costs for solar PV technologies. Table 9 provides the original and revised capital and fixed O&M cost assumed by TEPPC for solar PV resources.

### Table 9: Solar PV Cost Changes

<table>
<thead>
<tr>
<th></th>
<th>Fixed-Tilt</th>
<th></th>
<th>Tracking</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Original</td>
<td>Revised</td>
<td>Original</td>
<td>Revised</td>
</tr>
<tr>
<td>Capital Cost ($/kW-AC)</td>
<td>$4,500</td>
<td>$4,000</td>
<td>$5,700</td>
<td>$4,700</td>
</tr>
<tr>
<td>Fixed O&amp;M ($/kW-yr-AC)</td>
<td>$50</td>
<td>$36</td>
<td>$65</td>
<td>$50</td>
</tr>
</tbody>
</table>

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. The levelized fixed costs used to develop the resource capital cost estimates associated with the 2020 aggressive wind cases assumed a 20-year amortization (i.e., cost recovery) period and were calculated using E3’s suggested financing assumptions, regional multipliers, and the updated solar PV capital costs. Generic resource capacity factors were replaced in the cost tool with the case-specific resource capacity factors used in the production cost model.\(^{18}\) The case-specific resource levelized fixed costs are outlined in the Study Case Assumptions and Results section of this report.

In addition to calculating the capital cost of the renewable resources studied in the two aggressive wind study cases, the capacity value of the aggressive wind portfolio was compared to the capacity value of the resources removed from other locations within the Western Interconnection and contributing to California’s RPS requirements 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 10 below summarizes the on-peak capacity value assumptions applied to the renewable resources studied in the 2020 aggressive wind cases.

\(^{18}\) The resource capacity factor is used within the levelized cost calculation to determine the amount of production tax incentive that should be applied against the capital and fixed costs. To be consistent, the impact of production tax credits on the 2020 resource cost estimates were calculated using the capacity factors of the resources modeled in the study cases rather than the generic capacity factors provided within the cost estimating tool.
Table 10: Percentage of Installed Capacity of Renewable Resources Available to Serve Load at Time of Peak Generation

<table>
<thead>
<tr>
<th>Generation Type</th>
<th>AZ-NM-NV</th>
<th>Basin</th>
<th>Canada</th>
<th>California</th>
<th>NWPP</th>
<th>RMPA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Biomass</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
</tr>
<tr>
<td>Geothermal</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
</tr>
<tr>
<td>Small Hydro</td>
<td>35%</td>
<td>35%</td>
<td>35%</td>
<td>35%</td>
<td>35%</td>
<td>35%</td>
</tr>
<tr>
<td>Solar PV</td>
<td>60%</td>
<td>60%</td>
<td>60%</td>
<td>60%</td>
<td>60%</td>
<td>60%</td>
</tr>
<tr>
<td>Solar CSP – No storage</td>
<td>90%</td>
<td>95%</td>
<td>95%</td>
<td>85%</td>
<td>95%</td>
<td>95%</td>
</tr>
<tr>
<td>Solar CSP – 6 hours storage</td>
<td>95%</td>
<td>95%</td>
<td>95%</td>
<td>95%</td>
<td>95%</td>
<td>95%</td>
</tr>
<tr>
<td>Wind</td>
<td>10%</td>
<td>10%</td>
<td>10%</td>
<td>10%</td>
<td>10%</td>
<td>10%</td>
</tr>
</tbody>
</table>

No additional resources were added to the production cost simulation of the aggressive wind cases outside of the renewables needed to offset the 25,000 GWh of energy removed from resources being used to meet California’s RPS requirement in the 2020 PC1 case. However, to equalize the capacity value of the aggressive wind resources and California’s RPS resources that were removed, the capital cost of combustion turbines (CTs) needed to replace the on-peak capacity value of California’s RPS resources net of the capacity value provided by the relocated resources was added to each aggressive wind capital cost estimate. 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 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 2020 transmission expansion projects were also drawn from the E3 cost tool, and are estimates based on line mileage by jurisdiction for a range of voltage options and include the cost of both right-of-way and 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 (i.e., cost recovery) period.

The cost tool originally developed by E3 provides an estimate for substation and termination costs which 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, the Technical Advisory Subcommittee (TAS) of TEPPC asked the Studies Work Group (SWG) to review and update the substation cost estimates so that a distinction could be made between projects involving new versus existing substations. In December 2010 the SWG developed revised substation cost estimates that break out costs for site preparation, transformation, line terminations, and compensation independently. Table 11 below outlines the substation component costs developed by the SWG and used to estimate the capital cost of the 2020 aggressive wind transmission expansion projects.
Table 11: TEPPC Substation Component Cost Estimates

<table>
<thead>
<tr>
<th>Component</th>
<th>500 kV</th>
<th>345 kV</th>
<th>230 kV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Single Line Termination</td>
<td>$4,000,000</td>
<td>$2,600,000</td>
<td>$1,500,000</td>
</tr>
<tr>
<td>Double Line Termination</td>
<td>$6,500,000</td>
<td>$4,000,000</td>
<td>$2,000,000</td>
</tr>
<tr>
<td>Series Capacitors</td>
<td>$25,000,000</td>
<td>$25,000,000</td>
<td></td>
</tr>
<tr>
<td>Shunt Reactors</td>
<td>$6,000,000</td>
<td>$6,000,000</td>
<td></td>
</tr>
<tr>
<td>Three Phase Transformer Bank</td>
<td>$25,000,000</td>
<td>$18,000,000</td>
<td>$7,000,000</td>
</tr>
<tr>
<td>Site Preparation</td>
<td>$11,350,000</td>
<td>$9,650,000</td>
<td>$8,500,000</td>
</tr>
</tbody>
</table>

Transmission line and right-of-way (ROW) costs originally recommended by E3 and incorporated into the cost tool were based on the Western Renewable Energy Zone (WREZ) Transmission Model. These costs were benchmarked against E3’s Green House Gas Calculator and RPS Calculator, which gave similar costs at the time the tool was being developed. After reviewing the results of TEPPC’s capital cost estimates for the 2020 aggressive wind transmission expansion studies, and comparing these estimates against project developer cost estimates for the same or similar projects, TAS requested the WECC staff review the transmission line cost assumptions used in the E3 cost tool. In response to this request, WECC staff 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. These estimates generally represented project developers’ prospective estimates of what the projects will cost. 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.

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 still in early stages of development. Two HVDC project cost estimates reviewed by the staff, however, were collected from documents filed with the Alberta Utilities Commission (AUC) and reflect cost estimates based upon 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.

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19 The costs listed for line terminations, series and shunt compensation and transformation are the installed cost and 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.

20 HVDC termination costs, estimated to be $250 million per convertor station, were subtracted from the project cost estimates collected in order to estimate a $/mile line cost for the DC projects. Similarly, reported substation costs for the AC projects, or an estimate of $50 million per 500-kV substation, were subtracted from the project cost estimates in order to estimate a $/mile line cost for the AC projects.

WECC staff 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. TAS agreed to update the transmission line costs in TEPPC’s cost tool using the average HVDC transmission line cost estimated from the project costs collected by the staff. The AC transmission line costs in TEPPC’s cost tool were also updated, and were updated using the same multipliers used to derive the WREZ transmission line costs.\textsuperscript{22} The original and revised transmission line costs used to estimate the capital cost of the 2020 aggressive wind transmission expansion projects are shown in Table 11 below.

Table 12: TEPPC Transmission Line Cost Estimates

<table>
<thead>
<tr>
<th>Technology</th>
<th>WREZ Multiplier</th>
<th>Original Line Cost ($M/\text{mi}, \text{no ROW})</th>
<th>Revised Line Cost ($M/\text{mi}, \text{no ROW})</th>
</tr>
</thead>
<tbody>
<tr>
<td>HVDC</td>
<td>0.8*500-kV SC</td>
<td>$1.44</td>
<td>$2.20</td>
</tr>
<tr>
<td>500-kV single-circuit (SC)</td>
<td>1</td>
<td>$1.80</td>
<td>$2.75</td>
</tr>
<tr>
<td>500-kV double-circuit</td>
<td>1.6*500-kV SC</td>
<td>$2.88</td>
<td>$4.40</td>
</tr>
<tr>
<td>345-kV single-circuit</td>
<td>0.7*500-kV SC</td>
<td>$1.26</td>
<td>$1.93</td>
</tr>
<tr>
<td>345-kV double-circuit</td>
<td>1.6*345-kV SC</td>
<td>$2.02</td>
<td>$3.08</td>
</tr>
<tr>
<td>230-kV single-circuit</td>
<td>0.5*500-kV SC</td>
<td>$0.90</td>
<td>$1.38</td>
</tr>
<tr>
<td>230-kV double-circuit</td>
<td>1.6*230-kV SC</td>
<td>$1.44</td>
<td>$2.20</td>
</tr>
</tbody>
</table>

WECC staff used the E3 cost estimating tool in conjunction with updated solar PV costs, and updated transmission line and substation component costs to calculate an annualized fixed cost for the incremental wind and transmission investment modeled in the two 2020 aggressive wind and transmission expansion study cases. These estimates can be compared across the aggressive wind scenarios, and to the 2020 PC1 case to determine net savings in resource and transmission capital costs.

There are a number of uncertainties surrounding the input assumptions used to calculate the capital cost estimates between study cases, including the assumed continuation of federal tax incentives, the assumed capacity factor of the aggressive wind resources, and the estimated cost of the transmission expansion projects. A more detailed analysis of the costs associated with any of the TEPPC study cases, including a sensitivity analysis on key cost assumptions, should be performed prior to making any decisions regarding resource procurement or transmission development.

\textsuperscript{22} 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.
Study Case Assumptions and Results
The specific assumptions and results associated with the individual 2020 study cases are presented by case in the following sections.

2020 PC0 – LRS Base case
The PC0 case is the TEPPC base or common case with load forecasts provided under the Loads and Resources annual data submittal. After applying the state renewable portfolio standards and updating the generation data to reflect the incremental renewable projects, the renewable share of total WECC generation was 16.8 percent. The annual generation breakdown is shown in Figure 29.

Figure 29: PC0 Annual Generation

The most utilized paths in PC0 are listed in Table 13 sorted by their U90 value (the percent of hours that the flow is above 90 percent of the path limit). The table shows that the COI path is the most heavily utilized. A few of the listed paths have high utilizations due to modeling assumptions and resource placement. For example, the SDGE-CFE path is highly utilized because insufficient resources were added in CFE. The INYO-Control and IID-SCE paths are highly utilized due to the addition of renewable generation in west central Nevada, east central California, and southeast California.
Table 13: Most Utilized Paths PC0

<table>
<thead>
<tr>
<th>Name</th>
<th>U75</th>
<th>U90</th>
<th>U99</th>
<th>Pos Flow Limit (MW)</th>
<th>Neg Flow Limit (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>COI</td>
<td>63.38</td>
<td>50.59</td>
<td>25.34</td>
<td>4,800</td>
<td>-3,675</td>
</tr>
<tr>
<td>COB</td>
<td>62.58</td>
<td>50.52</td>
<td>31.92</td>
<td>4,800</td>
<td>-4,800</td>
</tr>
<tr>
<td>INYO-Control 115-kV TIE</td>
<td>60.31</td>
<td>40.76</td>
<td>16.59</td>
<td>56</td>
<td>-56</td>
</tr>
<tr>
<td>SDG&amp;G – Mexico (CFE)</td>
<td>37.73</td>
<td>30.94</td>
<td>27.32</td>
<td>408</td>
<td>-800</td>
</tr>
<tr>
<td>Montana-Northwest</td>
<td>47.30</td>
<td>21.98</td>
<td>10.00</td>
<td>2,200</td>
<td>-1,350</td>
</tr>
<tr>
<td>Intermountain – Gonder 230 kV</td>
<td>45.12</td>
<td>24.36</td>
<td>13.30</td>
<td>200</td>
<td>-9,999</td>
</tr>
<tr>
<td>IPP DC Line</td>
<td>44.41</td>
<td>20.51</td>
<td>12.52</td>
<td>2,400</td>
<td>-1,400</td>
</tr>
<tr>
<td>West of Crossover</td>
<td>71.32</td>
<td>14.09</td>
<td>0.00</td>
<td>2,598</td>
<td>-9,999</td>
</tr>
<tr>
<td>TOT2C</td>
<td>24.65</td>
<td>13.41</td>
<td>8.24</td>
<td>300</td>
<td>-300</td>
</tr>
<tr>
<td>Pacific DC Intertie</td>
<td>13.54</td>
<td>9.34</td>
<td>6.59</td>
<td>3,100</td>
<td>-2,780</td>
</tr>
<tr>
<td>Alberta – British Columbia</td>
<td>13.17</td>
<td>5.58</td>
<td>3.19</td>
<td>700</td>
<td>-720</td>
</tr>
<tr>
<td>West of Colstrip</td>
<td>13.54</td>
<td>9.34</td>
<td>6.59</td>
<td>3,100</td>
<td>-2,780</td>
</tr>
</tbody>
</table>

The PC0 case was not used in any of the 2020 studies. The dataset was made available for other stakeholders to use and does provide a starting point with load forecasts based on the LRS data submittals.

2020 PC1 – SPSC Reference case

Central Question: What impact will future load growth and generation needs (as defined by input assumptions) have on transmission congestion in the Western Interconnection?

Input Assumptions:
The input assumptions are based on data provided by the SPSC with significant contributions from Lawrence Berkeley National Laboratory (LBNL). The primary change relative to the PC0 case involved updates to the 2020 BA load forecasts to incorporate expected savings from current/ongoing energy efficiency programs and policies not embedded in the BA forecasts. In many cases, adjustments solely reflected the impact of new federal standards; ratepayer-funded programs were already fully captured in the LRS data. The resulting percent changes applied to the load forecasts by balancing authority in both energy and peak demand are shown in Figures 30 and 31.

---

23 The distribution of flows between COI and PDCI may be influenced by the HVDC modeling issues described in the 2019 Study Report.
Figure 30: Energy Adjustments for PC1

Figure 31: Peak Adjustments for PC1
The relative growth in state and provincial energy loads from the 2009 actual to the 2020 PC1 forecast is illustrated in Figure 32.

Figure 32: State Energy Loads - PC1

2020 PC1 Load Forecast by State in Annual Energy

Legend
- 2009 Actual Load (GWh)
- 2009 - 2020 Incremental Load Forecast (GWh)
- % State percent of total WECC 2020 load

WECC 2020 PC1 Load (Total): 981,460 GWh

Note: Mexico (CFE) = 1.6%
Texas (El Paso) = 0.8%
The generation retirements and additions by state/province and type are summarized in Table 14.

Table 14: Generation Additions and Retirements (2010 – 2020) – PC1

<table>
<thead>
<tr>
<th>Retirements (MW)</th>
<th>AB</th>
<th>AZ</th>
<th>BC</th>
<th>CA</th>
<th>CO</th>
<th>ID</th>
<th>MX</th>
<th>NV</th>
<th>NM</th>
<th>OR</th>
<th>TX</th>
<th>UT</th>
<th>WA</th>
<th>WY</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>586</td>
<td>0</td>
<td>226</td>
<td>0</td>
<td>0</td>
<td>330</td>
<td></td>
<td></td>
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<td></td>
<td>1,142</td>
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<td>CC</td>
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<td>47</td>
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<td>0</td>
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<td></td>
<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>47</td>
</tr>
<tr>
<td>CT - nonOTC</td>
<td>118</td>
<td>337</td>
<td>0</td>
<td>39</td>
<td>0</td>
<td></td>
<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>494</td>
</tr>
<tr>
<td>CT - OTC</td>
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<td>156</td>
<td>0</td>
<td>0</td>
<td>0</td>
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<td></td>
<td></td>
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<td>12,862</td>
</tr>
<tr>
<td>Total</td>
<td>704</td>
<td>13,402</td>
<td>341</td>
<td>39</td>
<td>668</td>
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<td>15,154</td>
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</table>

<table>
<thead>
<tr>
<th>Additions (MW)</th>
<th>AB</th>
<th>AZ</th>
<th>BC</th>
<th>CA</th>
<th>CO</th>
<th>ID</th>
<th>MX</th>
<th>NV</th>
<th>NM</th>
<th>OR</th>
<th>TX</th>
<th>UT</th>
<th>WA</th>
<th>WY</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Biomass</td>
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<td>11</td>
<td>377</td>
<td>336</td>
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<td>26</td>
<td>68</td>
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<tr>
<td>Coal</td>
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<td>1,685</td>
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<td>2,518</td>
<td>4,329</td>
<td>200</td>
<td>300</td>
<td>381</td>
<td>120</td>
<td>524</td>
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<td>9,803</td>
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<td>CT</td>
<td>2,215</td>
<td>560</td>
<td>3,746</td>
<td>180</td>
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<td>524</td>
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<td>7,325</td>
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<td>1,289</td>
<td>27</td>
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<td>220</td>
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<td>Hydro</td>
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<td></td>
<td></td>
<td>100</td>
</tr>
<tr>
<td>IC</td>
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<td></td>
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<td></td>
<td></td>
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<td></td>
<td></td>
<td>163</td>
</tr>
<tr>
<td>Pumped Storage</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td>40</td>
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<td>Small Hydro</td>
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<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>294</td>
</tr>
<tr>
<td>Solar</td>
<td>2,116</td>
<td>9,007</td>
<td>1,034</td>
<td></td>
<td></td>
<td></td>
<td>773</td>
<td>390</td>
<td>20</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>13,339</td>
</tr>
<tr>
<td>Wind</td>
<td>2,475</td>
<td>179</td>
<td>958</td>
<td>4,725</td>
<td>2,064</td>
<td>260</td>
<td>455</td>
<td>150</td>
<td>494</td>
<td>2,431</td>
<td></td>
<td>100</td>
<td>2,800</td>
<td>675</td>
<td>18,075</td>
</tr>
<tr>
<td>Total</td>
<td>7,793</td>
<td>2,866</td>
<td>1,425</td>
<td>23,634</td>
<td>4,217</td>
<td>746</td>
<td>1,272</td>
<td>588</td>
<td>1,818</td>
<td>967</td>
<td>2,788</td>
<td>288</td>
<td>1,398</td>
<td>3,036</td>
<td>53,995</td>
</tr>
<tr>
<td>Net Change</td>
<td>7,089</td>
<td>2,866</td>
<td>1,425</td>
<td>10,232</td>
<td>3,876</td>
<td>746</td>
<td>1,233</td>
<td>588</td>
<td>1,150</td>
<td>967</td>
<td>2,788</td>
<td>288</td>
<td>1,398</td>
<td>3,036</td>
<td>38,841</td>
</tr>
</tbody>
</table>

24 Of the solar generation additions, 52 percent by capacity is PV.
The renewable resources were also adjusted in PC1 to adhere to the RPS target levels for each state. The renewable energy by state and province are shown in Figure 33. The inset table is a breakdown of the renewable resource capacity by type.

**Figure 33: Renewable Resources by Area**
Key Results (PC1)
The most utilized paths in PC1 are listed in Table 15 sorted by their U90 value. The COI path continued to be the most heavily utilized path. The U75, U90, and U99 values for the most heavily utilized paths are plotted in Figure 34.

Table 15: Most Utilized Paths PC1

<table>
<thead>
<tr>
<th>Name</th>
<th>U75</th>
<th>U90</th>
<th>U99</th>
<th>Pos Flow Limit (MW)</th>
<th>Neg Flow Limit (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>COI</td>
<td>65.18</td>
<td>51.81</td>
<td>29.58</td>
<td>4,800</td>
<td>-3,675</td>
</tr>
<tr>
<td>COB</td>
<td>63.98</td>
<td>51.25</td>
<td>31.47</td>
<td>4,800</td>
<td>-4,800</td>
</tr>
<tr>
<td>INYO-Control 115-kv TIE</td>
<td>60.26</td>
<td>40.52</td>
<td>16.56</td>
<td>56</td>
<td>-56</td>
</tr>
<tr>
<td>SDG&amp;G – Mexico (CFE)</td>
<td>45.28</td>
<td>37.43</td>
<td>33.39</td>
<td>408</td>
<td>-800</td>
</tr>
<tr>
<td>Montana-Northwest</td>
<td>52.19</td>
<td>24.95</td>
<td>10.85</td>
<td>2,200</td>
<td>-1,350</td>
</tr>
<tr>
<td>Intermountain – Gonder 230 kV</td>
<td>44.02</td>
<td>23.95</td>
<td>13.98</td>
<td>200</td>
<td>-9,999</td>
</tr>
<tr>
<td>IPP DC Line</td>
<td>44.91</td>
<td>20.80</td>
<td>13.32</td>
<td>2,400</td>
<td>-1,400</td>
</tr>
<tr>
<td>IID – SCE</td>
<td>71.51</td>
<td>18.42</td>
<td>4.01</td>
<td>600</td>
<td>-99,999</td>
</tr>
<tr>
<td>TOT2C</td>
<td>23.13</td>
<td>12.88</td>
<td>8.09</td>
<td>300</td>
<td>-300</td>
</tr>
<tr>
<td>Pacific DC Intertie</td>
<td>14.40</td>
<td>10.10</td>
<td>6.94</td>
<td>3,100</td>
<td>-2,780</td>
</tr>
<tr>
<td>West of Crossover</td>
<td>70.00</td>
<td>9.47</td>
<td>0.00</td>
<td>2,598</td>
<td>-9,999</td>
</tr>
<tr>
<td>Alberta – British Columbia</td>
<td>7.38</td>
<td>3.61</td>
<td>2.57</td>
<td>700</td>
<td>-720</td>
</tr>
<tr>
<td>West of Colstrip</td>
<td>57.32</td>
<td>0.00</td>
<td>0.00</td>
<td>2,598</td>
<td>-9,999</td>
</tr>
</tbody>
</table>

Figure 34: Heavily Utilized Paths - PC1

![Figure 34: Heavily Utilized Paths - Sorted by U90](image)

Again, the high path utilization for a few of the paths is related to the placement of renewable resources near buses that feed into the paths. The INYO-CONTROL 115-kV TIE and IID-SCE
paths are examples of this situation, and it is anticipated that the local utilities will either add facilities to integrate the resources or site them elsewhere. A set of duration plots for the COI path is provided in Figure 35. Note that the COI path is one of the paths that may be impacted by the way losses on DC lines are calculated in PROMOD. The conclusion is that some of the flows that could use the PDCI are shifted by the least-cost solution to the COI path due to the DC loss calculation.

**Figure 35: COI Path Duration Plots**

![COI Path Duration Plots](image)

**Figure 36: COI + PDCI Duration Plots – PC1**

![COI + PDCI Path Duration Plots](image)

Figure 37 shows a comparison of the energy transfers between sub-regions for PC0 compared to PC1. The most significant difference is observed in transfers between AZNMMNV and CA_S.
A comparison of the generation results for PC0 and PC1 is shown in Table 16. The decreased loads required 40,229 GWh less generation than in PC0 and produced 15 Million metric tons less CO₂.
Table 16: Generation Comparison PC0 > PC1

<table>
<thead>
<tr>
<th>Category</th>
<th>2020 TEPPC PC0 Base Case</th>
<th>2020 SPSC Reference Case</th>
<th>Difference</th>
<th>Diff %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional Hydro</td>
<td>246,813,430</td>
<td>246,812,313</td>
<td>(1,117)</td>
<td>0.000</td>
</tr>
<tr>
<td>Pumped Storage</td>
<td>2,533,056</td>
<td>2,616,848</td>
<td>83,792</td>
<td>3.308</td>
</tr>
<tr>
<td>Steam – Coal</td>
<td>290,755,640</td>
<td>287,756,234</td>
<td>(2,999,406)</td>
<td>-1.032</td>
</tr>
<tr>
<td>Steam – Other</td>
<td>3,583,717</td>
<td>76,417,356</td>
<td>(458,445)</td>
<td>-12.792</td>
</tr>
<tr>
<td>Nuclear</td>
<td>76,513,723</td>
<td>76,417,356</td>
<td>(96,366)</td>
<td>-0.126</td>
</tr>
<tr>
<td>Combined Cycle</td>
<td>189,141,411</td>
<td>161,069,942</td>
<td>(28,071,468)</td>
<td>-14.842</td>
</tr>
<tr>
<td>Combustion Turbine</td>
<td>13,376,444</td>
<td>12,306,838</td>
<td>(1,069,606)</td>
<td>-7.996</td>
</tr>
<tr>
<td>Cogeneration</td>
<td>26,067,551</td>
<td>26,084,042</td>
<td>16,492</td>
<td>0.063</td>
</tr>
<tr>
<td>IC</td>
<td>298,940</td>
<td>225,484</td>
<td>(73,456)</td>
<td>-24.572</td>
</tr>
<tr>
<td>Negative Bus Load</td>
<td>4,640,148</td>
<td>4,640,148</td>
<td>0</td>
<td>0.000</td>
</tr>
<tr>
<td>Biomass RPS</td>
<td>15,723,744</td>
<td>14,900,622</td>
<td>(823,122)</td>
<td>-5.235</td>
</tr>
<tr>
<td>Geothermal</td>
<td>35,738,065</td>
<td>35,741,481</td>
<td>3,416</td>
<td>0.010</td>
</tr>
<tr>
<td>Small Hydro RPS</td>
<td>7,755,782</td>
<td>7,755,782</td>
<td>0</td>
<td>0.000</td>
</tr>
<tr>
<td>Solar</td>
<td>31,580,224</td>
<td>29,672,103</td>
<td>(1,908,352)</td>
<td>-6.042</td>
</tr>
<tr>
<td>Wind</td>
<td>81,503,286</td>
<td>76,671,934</td>
<td>(4,831,352)</td>
<td>-5.928</td>
</tr>
<tr>
<td>Total</td>
<td>1,026,025,159</td>
<td>985,796,398</td>
<td>(40,228,761)</td>
<td>-3.921</td>
</tr>
<tr>
<td>Renewable Total</td>
<td>172,301,102</td>
<td>164,741,922</td>
<td>(7,599,180)</td>
<td>-4.387</td>
</tr>
<tr>
<td>Renewable Percent (%)</td>
<td>16.8</td>
<td>16.7</td>
<td>(0)</td>
<td>-0.485</td>
</tr>
</tbody>
</table>

Other Results (see TEPPC Glossary for definitions)

<table>
<thead>
<tr>
<th></th>
<th>Value1</th>
<th>Value2</th>
<th>Difference</th>
<th>Diff %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dump Energy</td>
<td>28,780</td>
<td>27,907</td>
<td>(874)</td>
<td>-3.035</td>
</tr>
<tr>
<td>Emergency Energy</td>
<td>338</td>
<td>390</td>
<td>53</td>
<td>15.573</td>
</tr>
<tr>
<td>CO₂ Emissions (MMetric Tons)</td>
<td>383</td>
<td>368</td>
<td>(15)</td>
<td>-3.981</td>
</tr>
<tr>
<td>CO₂ Adder ($/metric ton)</td>
<td>0.000</td>
<td>0.000</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Variable Production Cost (thermal units excl DSM)

<table>
<thead>
<tr>
<th></th>
<th>Value1</th>
<th>Value2</th>
<th>Difference</th>
<th>Diff %</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO2 Adder (Total M$)</td>
<td>0</td>
<td>0</td>
<td>(0)</td>
<td>0.000</td>
</tr>
<tr>
<td>Other Variable Costs (M$)</td>
<td>19,934</td>
<td>18,189</td>
<td>(1,745)</td>
<td>-8.753</td>
</tr>
<tr>
<td>Total Var. Prod. Cost (M$)</td>
<td>19,934</td>
<td>18,189</td>
<td>(1,745)</td>
<td>-8.753</td>
</tr>
</tbody>
</table>
2020 PC2 – High Loads case
Central Question: How will transmission utilization results change if future load growth is greater than currently forecast?

Input Assumptions:
The peak and energy load forecasts for PC1 were increased by 10 percent to model a high load condition. The renewable resources were adjusted to maintain the state RPS targets and the DSM was recalibrated to account for the increased LMPs.

The coincident WECC peak demand increased by 16,888 MW from 169,807 MW to 186,695 MW.

Key Results (PC2)
With the peak and energy loads in each area increased universally, there is less surplus generation available to support economic transfers and in most cases the utilization of the major transmission paths is reduced. The chart in Figure 38 shows how the generation compensated for the increase in loads.

Figure 38: Change in Generation - PC1 > PC2

Higher loads led to a reduction in the amount of low cost generation available for export/import. This is reflected in the duration plots shown in Figure 39 that compare the combined COI and PDCI flows for several cases.
A snapshot of the overall WECC generation dispatch for the PC2 case is shown in Figure 40. In the simulation the WECC peak occurred on July 27th. The majority of the “Other” category in the plot is DSM, which is modeled as a resource in the study. Note how most of the load following is done by the CC, hydro, and CT units.
The annual generation results relative to the change in generation dispatch are shown in Table 17, including the changes by generation type and results for emissions and production cost. The higher loads caused the emissions and production cost to increase as more thermal generation was required.

The effects of adding more renewable resources to maintain the percentage shares of RPS are also evident.

Table 17: Annual Changes PC1 > PC2

<table>
<thead>
<tr>
<th>Category</th>
<th>2020 SPSC Reference Case</th>
<th>2020 SPSC High Load Case</th>
<th>Difference</th>
<th>Diff %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional Hydro</td>
<td>246,812,313</td>
<td>246,793,060</td>
<td>(19,253)</td>
<td>-0.008</td>
</tr>
<tr>
<td>Pumped Storage</td>
<td>2,618,848</td>
<td>2,778,887</td>
<td>160,039</td>
<td>6.192</td>
</tr>
<tr>
<td>Steam – Coal</td>
<td>287,756,234</td>
<td>293,990,651</td>
<td>6,234,418</td>
<td>2.167</td>
</tr>
<tr>
<td>Steam – Other</td>
<td>76,417,356</td>
<td>4,355,619</td>
<td>1,230,347</td>
<td>39.368</td>
</tr>
<tr>
<td>Nuclear</td>
<td>76,417,356</td>
<td>76,744,882</td>
<td>327,526</td>
<td>0.429</td>
</tr>
<tr>
<td>Combined Cycle</td>
<td>161,069,942</td>
<td>225,354,139</td>
<td>64,284,197</td>
<td>39.911</td>
</tr>
<tr>
<td>Combustion Turbine</td>
<td>12,306,838</td>
<td>19,694,940</td>
<td>7,388,102</td>
<td>60.032</td>
</tr>
<tr>
<td>Cogeneration</td>
<td>26,084,042</td>
<td>28,131,073</td>
<td>2,047,030</td>
<td>7.848</td>
</tr>
<tr>
<td>IC</td>
<td>225,484</td>
<td>375,725</td>
<td>150,242</td>
<td>66.631</td>
</tr>
<tr>
<td>Negative Bus Load</td>
<td>4,640,148</td>
<td>4,640,148</td>
<td>0</td>
<td>0.000</td>
</tr>
<tr>
<td>Biomass RPS</td>
<td>14,900,622</td>
<td>16,811,987</td>
<td>1,911,365</td>
<td>12.827</td>
</tr>
<tr>
<td>Geothermal</td>
<td>35,741,481</td>
<td>35,736,765</td>
<td>(4,715)</td>
<td>-0.013</td>
</tr>
<tr>
<td>Small Hydro RPS</td>
<td>7,755,782</td>
<td>7,871,262</td>
<td>115,480</td>
<td>1.489</td>
</tr>
<tr>
<td>Solar</td>
<td>29,671,934</td>
<td>36,109,106</td>
<td>6,437,003</td>
<td>21.694</td>
</tr>
<tr>
<td>Wind</td>
<td>76,671,934</td>
<td>83,196,534</td>
<td>6,524,600</td>
<td>8.510</td>
</tr>
<tr>
<td>Total</td>
<td>985,796,398</td>
<td>1,082,584,778</td>
<td>96,788,380</td>
<td>9.818</td>
</tr>
<tr>
<td>Renewable Total</td>
<td>164,741,922</td>
<td>179,725,654</td>
<td>14,983,732</td>
<td>9.095</td>
</tr>
<tr>
<td>Renewable Percent (%)</td>
<td>16.7</td>
<td>16.6</td>
<td>(0)</td>
<td>-0.658</td>
</tr>
</tbody>
</table>

Other Results (see TEPPC Glossary for definitions)

<p>| | | | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Dump Energy</td>
<td>27,907</td>
<td>14,705</td>
<td>(13,202)</td>
<td>-47.307</td>
</tr>
<tr>
<td>Emergency Energy</td>
<td>390</td>
<td>15,237</td>
<td>14,847</td>
<td>3,804.772</td>
</tr>
<tr>
<td>CO₂ Emissions (MMetric Tons)</td>
<td>368</td>
<td>406</td>
<td>38</td>
<td>10.377</td>
</tr>
<tr>
<td>CO₂ Adder ($/metric ton)</td>
<td>0.000</td>
<td>0.000</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Variable Production Cost (thermal units excl DSM)

<p>| | | | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂ Adder (Total M$)</td>
<td>0</td>
<td>0</td>
<td>(0)</td>
<td>0.000</td>
</tr>
<tr>
<td>Other Variable Costs (M$)</td>
<td>18,189</td>
<td>22,729</td>
<td>4,540</td>
<td>24,960</td>
</tr>
<tr>
<td>Total Var. Prod. Cost (M$)</td>
<td>18,189</td>
<td>22,729</td>
<td>4,540</td>
<td>24,960</td>
</tr>
</tbody>
</table>

Figure 41 compares the change in load to the change in generation for each sub-region. Increased transfers are reflected for the sub-regions where the changes in load and generation are not equivalent. A few of the areas compensated for the increased loads by reducing exports.
Figure 41: Load/Gen changes PC1 > PC2

Change in Load Compared to Change in Generation - Reference Case vs. High Load Case

- Change in Load
- Change in Generation

GWh

- Alberta
- British Columbia
- NWPP
- BASIN
- RMPP
- CA_North
- CA_South
- AZNMNV
Figure 42 reports how the transmission utilization changed between PC1 and PC2. The column titled “Change in U90 Relative to Ref Case” provides the percentage increase in U90 for the listed path as compared to the U90 value reported for that path in the 2020 PC1 reference case.

**Figure 42: Transmission Utilization Changes PC1 > PC2**

<table>
<thead>
<tr>
<th>Path</th>
<th>U90</th>
<th>Change in U90 Relative to Ref Case</th>
</tr>
</thead>
<tbody>
<tr>
<td>WEST OF CROSSOVER</td>
<td>21%</td>
<td>11%</td>
</tr>
<tr>
<td>ID - SCE</td>
<td>28%</td>
<td>9%</td>
</tr>
<tr>
<td>NORTH OF SAN ONOFRE</td>
<td>9%</td>
<td>6%</td>
</tr>
<tr>
<td>TOT 2C</td>
<td>18%</td>
<td>5%</td>
</tr>
<tr>
<td>MIDWAY - LOS BANOS</td>
<td>6%</td>
<td>5%</td>
</tr>
</tbody>
</table>

**Greatest Decreases in U90**

<table>
<thead>
<tr>
<th>Path</th>
<th>U90</th>
<th>Change in U90 Relative to Ref Case</th>
</tr>
</thead>
<tbody>
<tr>
<td>NORTHWEST - CANADA</td>
<td>1%</td>
<td>-5%</td>
</tr>
<tr>
<td>IPP DC LINE</td>
<td>14%</td>
<td>-6%</td>
</tr>
<tr>
<td>PACIFIC DC INTERTIE</td>
<td>4%</td>
<td>-7%</td>
</tr>
<tr>
<td>INTERMOUNTAIN - GONDER 230 KV</td>
<td>8%</td>
<td>-16%</td>
</tr>
<tr>
<td>COI</td>
<td>36%</td>
<td>-16%</td>
</tr>
</tbody>
</table>
2020 PC3 – High DSM case

Central Question: How will transmission utilization results change if EE programs reach their full economic potential25 and more aggressive DSM programs are in place in the 10-year timeframe?

Input Assumptions

The peak and energy load forecasts were further reduced from the PC1 SPSC reference case to model implementation of the full economic potential of energy efficiency programs and additional DSM programs in the Western Interconnection. This resulted in a decrease of 8.6 percent in the coincident WECC peak demand. Figure 43 shows the relative scale of the incremental savings from PC0 to PC1 and finally to PC3.

The expanded efficiency estimates or targets are highest in Alberta, Arizona, British Columbia, Colorado, Idaho, Nevada, Oregon, and Washington. The implementation brings the WECC total energy savings to 20 percent, including the embedded savings in the LRS forecasts.

Figure 43: Energy Savings

The reduced forecasts also yield lower growth rates. Figure 44 shows the difference in the Compound Annual Growth Rate (CAGR) for the efficiency and DSM adjusted forecasts compared to the original LRS forecast.

---

25 The total cost-effective potential without taking account of limitations from current market barriers or program implementation difficulties.
Information about DSM plans was collected from several sources and then incorporated into the PC3 high DSM case. The goal was to determine the expected amount of DSM by program type.\(^{26}\) This included interruptible load, direct load/peak control, and capacity load resources. Interruptible targets for the reliability and economic components of DSM were developed and modeled in the input data. During the process the various groups have introduced some terminology confusion. For example there is a recognized overlap of demand-side management and demand response, and these terms are used interchangeably in this report. Table 18 below lists the types of DSM and also the nomenclature that is used in this report.

**Table 18: DSM Program List**

<table>
<thead>
<tr>
<th>DSM Program Type</th>
<th>Interruptible For Reliability</th>
<th>Interruptible For Economics</th>
</tr>
</thead>
<tbody>
<tr>
<td>Contractual DSM Load</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Direct Control Load Management (DCLM)</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Critical Peak-Pricing with Control</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Load as a Capacity Resource</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Labels used in this report</td>
<td>Reliability DR</td>
<td>Economic DR</td>
</tr>
</tbody>
</table>

\(^{26}\) See the WECC Data Collection Manual for the detailed definitions.
Key Results (PC3)
The change in demand response is presented in Figure 45. By far the state with the largest changes of both types of demand response is California.

Figure 45: Change in Demand Response PC1 > PC3
The changes related to the generation dispatch are shown in Table 19. Note the 10 percent reduction in the amount of generation needed to meet the load requirements. The majority of the increased dump energy is caused by hydro generation that is stranded in British Columbia.

Table 19: Annual Changes PC1 > PC3

<table>
<thead>
<tr>
<th>Category</th>
<th>2020 SPSC Reference Case</th>
<th>2020 SPSC High DSM Case</th>
<th>Difference</th>
<th>Diff %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional Hydro</td>
<td>246,812,313</td>
<td>246,779,117</td>
<td>(33,197)</td>
<td>-0.013</td>
</tr>
<tr>
<td>Pumped Storage</td>
<td>2,616,848</td>
<td>2,932,576</td>
<td>315,729</td>
<td>12.065</td>
</tr>
<tr>
<td>Steam – Coal</td>
<td>287,756,234</td>
<td>273,766,131</td>
<td>(13,990,103)</td>
<td>-4.862</td>
</tr>
<tr>
<td>Steam – Other</td>
<td>76,417,356</td>
<td>2,616,045</td>
<td>(509,226)</td>
<td>-16.294</td>
</tr>
<tr>
<td>Nuclear</td>
<td>76,417,356</td>
<td>75,204,407</td>
<td>(1,212,949)</td>
<td>-1.587</td>
</tr>
<tr>
<td>Combined Cycle</td>
<td>161,069,942</td>
<td>95,660,270</td>
<td>(65,409,673)</td>
<td>-40.609</td>
</tr>
<tr>
<td>Combustion Turbine</td>
<td>12,306,838</td>
<td>7,868,278</td>
<td>(4,438,559)</td>
<td>-36.066</td>
</tr>
<tr>
<td>Cogeneration</td>
<td>26,084,042</td>
<td>22,510,857</td>
<td>(3,573,185)</td>
<td>-13.699</td>
</tr>
<tr>
<td>IC</td>
<td>225,484</td>
<td>155,271</td>
<td>(70,213)</td>
<td>-31.139</td>
</tr>
<tr>
<td>Negative Bus Load</td>
<td>4,640,148</td>
<td>4,640,148</td>
<td>0</td>
<td>0.000</td>
</tr>
<tr>
<td>Biomass RPS</td>
<td>14,900,622</td>
<td>12,216,378</td>
<td>(2,684,243)</td>
<td>-18.014</td>
</tr>
<tr>
<td>Geothermal</td>
<td>35,741,481</td>
<td>34,702,778</td>
<td>(1,038,703)</td>
<td>-2.906</td>
</tr>
<tr>
<td>Small Hydro RPS</td>
<td>7,755,782</td>
<td>7,755,792</td>
<td>0</td>
<td>0.000</td>
</tr>
<tr>
<td>Solar</td>
<td>29,672,103</td>
<td>26,436,282</td>
<td>(3,235,822)</td>
<td>-10.905</td>
</tr>
<tr>
<td>Wind</td>
<td>76,671,934</td>
<td>71,701,608</td>
<td>(4,970,326)</td>
<td>-6.483</td>
</tr>
<tr>
<td>Total</td>
<td>985,796,398</td>
<td>884,945,939</td>
<td>(100,850,460)</td>
<td>-10.230</td>
</tr>
</tbody>
</table>

| Renewable Total        | 164,741,922               | 152,812,838             | (11,929,084) | -7.241 |
| Renewable Percent (%)  | 16.7                      | 17.3                    | 0           | 3.330  |

Other Results (see TEPPC Glossary for definitions)

| Dump Energy            | 27,907                    | 432,750                 | 404,843     | 1,450.690 |
| Emergency Energy       | 390                       | 257                     | (133)       | -34.055   |
| CO₂ Emissions (MMetric Tons) | 368                   | 323                     | (45)        | -12.108   |
| CO₂ Adder ($/metric ton) | 0.000                   | 0.000           | 0.000       | 0.000     |

Variable Production Cost (thermal units excl DSM)

| CO₂ Adder (Total M$)     | 0                          | 0                        | (0)         | 0.000    |
| Other Variable Costs (M$) | 18,189                    | 13,617                   | (4,572)     | -25.137  |
| Total Var. Prod. Cost (M$) | 18,189                    | 13,617                   | (4,572)     | -25.137  |
The table shows the result of decreasing the renewable resources in response to the lower load forecasts. The lower load forecast also contributed to an increase in the amount of unutilized coal-fired generation (26,464 GWh) in PC3. Note also the 25 percent reduction in variable production cost.

Figure 46 compares the change in load to the change in generation for each sub-region and Figure 47 compares the amount of demand response.

The reduction in loads freed up more low cost generation that is then available to displace higher cost generation in other areas, resulting in increased utilization of the transmission system as seen in Figure 48. The column in Figure 48 titled “Change in U90 Relative to Ref
Case" provides the percentage increase in U90 for the listed path as compared to the U90 value reported for that path in the 2020 PC1 reference case.

**Figure 48: Change in Transmission Utilization**

<table>
<thead>
<tr>
<th>Path</th>
<th>U90</th>
<th>Change in U90 Relative to Ref Case</th>
</tr>
</thead>
<tbody>
<tr>
<td>NORTHWEST - CANADA</td>
<td>31%</td>
<td>25%</td>
</tr>
<tr>
<td>IDAHO - SIERRA</td>
<td>74%</td>
<td>22%</td>
</tr>
<tr>
<td>IPP DC LINE</td>
<td>21%</td>
<td>19%</td>
</tr>
<tr>
<td>PACIFIC DC INTERTIE</td>
<td>38%</td>
<td>17%</td>
</tr>
<tr>
<td>TOT 2B2</td>
<td>23%</td>
<td>13%</td>
</tr>
<tr>
<td>INTERMOUNTAIN - GONDER 230 KV</td>
<td>36%</td>
<td>12%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Path</th>
<th>U90</th>
<th>Change in U90 Relative to Ref Case</th>
</tr>
</thead>
<tbody>
<tr>
<td>MIDPOINT - SUMMER LAKE</td>
<td>4%</td>
<td>-3%</td>
</tr>
<tr>
<td>WEST OF BROADVIEW</td>
<td>2%</td>
<td>-3%</td>
</tr>
<tr>
<td>MONTANA - NORTHWEST</td>
<td>21%</td>
<td>-4%</td>
</tr>
<tr>
<td>WEST OF CROSSOVER</td>
<td>5%</td>
<td>-4%</td>
</tr>
<tr>
<td>IID - SCE</td>
<td>10%</td>
<td>-9%</td>
</tr>
</tbody>
</table>
2020 PC4 – Carbon Reduction case

Central Question: What level of carbon adder is required to reduce CO₂ emissions by 17 percent relative to 2005 levels?

Input Assumptions:
The only change from the PC3 assumptions was the application of a carbon cost adder to the CO₂ emissions. The carbon cost adder provides an impetus to shift generation from coal to gas.

The target level of CO₂ is 311.25 MMetricTons, which is 17 percent below the 2005 WECC level of 375 MMetricTons. Using an iterative approach, the value for the appropriate carbon adder was found to be $30/Ton ($33.07/Metric Ton), as shown in Figure 49. The carbon cost adder cases are all based off of the High DSM case. The emissions from the reference case are not part of the progression of carbon adders and are only included for comparison purposes.

Figure 49: Carbon Adder comparisons
Key Results (PC4)
The expectation of a shift from coal generation to gas generation was realized, and is shown in Figure 50 and Table 20.

Figure 50: Change by Area and Type
Table 20: Annual Changes PC3 > PC4

<table>
<thead>
<tr>
<th>Category</th>
<th>2020 SPSC High DSM Case</th>
<th>2020 SPSC -$30 Carbon Adder</th>
<th>Difference</th>
<th>Diff %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional Hydro</td>
<td>246,779,117</td>
<td>246,771,924</td>
<td>(7,193)</td>
<td>-0.003</td>
</tr>
<tr>
<td>Pumped Storage</td>
<td>2,932,576</td>
<td>1,954,218</td>
<td>(978,359)</td>
<td>-33.362</td>
</tr>
<tr>
<td>Steam – Coal</td>
<td>273,766,131</td>
<td>255,898,689</td>
<td>(17,867,442)</td>
<td>-6.527</td>
</tr>
<tr>
<td>Steam – Other</td>
<td>2,616,045</td>
<td>2,479,121</td>
<td>(136,924)</td>
<td>-5.234</td>
</tr>
<tr>
<td>Nuclear</td>
<td>75,204,407</td>
<td>76,817,694</td>
<td>1,613,557</td>
<td>2.146</td>
</tr>
<tr>
<td>Combined Cycle</td>
<td>95,660,270</td>
<td>109,451,902</td>
<td>13,791,633</td>
<td>14.417</td>
</tr>
<tr>
<td>Combustion Turbine</td>
<td>7,868,278</td>
<td>8,214,089</td>
<td>345,811</td>
<td>4.395</td>
</tr>
<tr>
<td>Cogeneration</td>
<td>22,510,857</td>
<td>22,718,466</td>
<td>207,609</td>
<td>0.922</td>
</tr>
<tr>
<td>IC</td>
<td>155,271</td>
<td>139,671</td>
<td>(15,599)</td>
<td>-10.047</td>
</tr>
<tr>
<td>Negative Bus Load</td>
<td>4,640,148</td>
<td>4,640,148</td>
<td>0</td>
<td>0.000</td>
</tr>
<tr>
<td>Biomass RPS</td>
<td>12,216,378</td>
<td>12,923,135</td>
<td>706,757</td>
<td>5.785</td>
</tr>
<tr>
<td>Geothermal</td>
<td>34,702,778</td>
<td>34,736,619</td>
<td>33,841</td>
<td>0.098</td>
</tr>
<tr>
<td>Small Hydro RPS</td>
<td>7,755,792</td>
<td>7,755,792</td>
<td>0</td>
<td>0.000</td>
</tr>
<tr>
<td>Solar</td>
<td>26,436,282</td>
<td>26,436,282</td>
<td>0</td>
<td>0.000</td>
</tr>
<tr>
<td>Wind</td>
<td>71,701,608</td>
<td>71,701,608</td>
<td>0</td>
<td>0.000</td>
</tr>
<tr>
<td>Total</td>
<td>884,945,939</td>
<td>882,639,629</td>
<td>(2,306,309)</td>
<td>-0.261</td>
</tr>
<tr>
<td>Renewable Total</td>
<td>152,812,838</td>
<td>153,553,436</td>
<td>740,598</td>
<td>0.485</td>
</tr>
<tr>
<td>Renewable Percent (%)</td>
<td>17.3</td>
<td>17.4</td>
<td>(0)</td>
<td>0.747</td>
</tr>
</tbody>
</table>

Other Results (see TEPPC Glossary for definitions)

<table>
<thead>
<tr>
<th></th>
<th>2020 SPSC High DSM Case</th>
<th>2020 SPSC -$30 Carbon Adder</th>
<th>Difference</th>
<th>Diff %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dump Energy</td>
<td>432,750</td>
<td>82,731</td>
<td>(350,018)</td>
<td>-80.882</td>
</tr>
<tr>
<td>Emergency Energy</td>
<td>257</td>
<td>257</td>
<td>0</td>
<td>0.000</td>
</tr>
<tr>
<td>CO₂ Emissions (MMetric Tons)</td>
<td>323</td>
<td>310</td>
<td>(13)</td>
<td>-4.023</td>
</tr>
<tr>
<td>CO₂ Adder ($/metric ton)</td>
<td>0.000</td>
<td>33.069</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Variable Production Cost (thermal units excl DSM)

<table>
<thead>
<tr>
<th></th>
<th>2020 SPSC High DSM Case</th>
<th>2020 SPSC -$30 Carbon Adder</th>
<th>Difference</th>
<th>Diff %</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO2 Adder (Total M$)</td>
<td>0</td>
<td>10,257</td>
<td>10,257</td>
<td>0.000</td>
</tr>
<tr>
<td>Other Variable Costs (M$)</td>
<td>13,617</td>
<td>13,994</td>
<td>378</td>
<td>2.773</td>
</tr>
<tr>
<td>Total Var. Prod. Cost (M$)</td>
<td>13,617</td>
<td>24,251</td>
<td>10,634</td>
<td>78.097</td>
</tr>
</tbody>
</table>

Most of the 78 percent increase in production cost was due to the carbon cost adder, which shifted generation from coal to gas. Although the CO₂ emissions rate of gas is approximately half of the rate for coal, gas-fired generation still emits CO₂.

Figure 51 provides a comparison of the variable production costs for a few of the study cases.
The change in path utilization from PC3 to PC4 is presented in Figure 52. The column in Figure 52 titled “Change in U90 Relative to High DSM Case” provides the percentage increase in U90 for the listed path as compared to the U90 value reported for that path in the High DSM case. The decreases are more significant than the increases, reflective of the shift from coal generation to gas generation.

Figure 52: Change in Path utilization PC3 > PC4

The reduced dispatch of coal generation is also reflected in the utilization of some of the transmission paths, such as the Montana – Northwest path shown in Figure 53 and the combined COI and PDCI paths shown in Figure 54.
The change in the annual energy transfers between sub-regions from PC3 to PC4 is shown in Figure 55. The costs associated with the emissions penalty for coal-fired generation resulted in decreased transfers from a few of the sub-regions such as AZNMNV, Basin, and NWPP.
Figure 55: Annual Energy Transfers PC3 and PC4

Transfers between Sub-Regions (aMW)

Average Megawatts

AZNMNV To Ca_S
Basin To AZNMNV
Basin To Ca_N
Basin To Ca_S
Ca_N To Ca_S
Canada To NWPP
NWPP To Basin
NWPP To Ca_N
NWPP To Ca_S
RMPA To AZNMNV
RMPA To Basin

PC3
PC4
2020 PC6 – Aggressive Montana Wind case

Central Question: What is the effect on system utilization and generation and transmission costs of moving an equivalent 25,000 GWh of renewable resources from other areas of the Western Interconnection into Montana?

Input Assumptions:
Renewable generation equivalent to 25,000 GWh that was designated to serve California RPS requirements in the PC1 reference case reflecting current RPS planning and procurement trends was removed from several areas (Figure 56) and replaced by wind generation in Montana (Figure 57). The resources removed from California were the lowest ranked resources (based on cost and environmental factors) used to model the 33 percent RPS requirement in the PC1 reference case. The Western Renewable Energy Zone (WREZ) Peer Analysis Tool was used to identify the best locations for the incremental wind.

Figure 56: Resources removed for PC6 and PC7 aggressive wind studies

<table>
<thead>
<tr>
<th>States from Which Resources Will be Removed</th>
</tr>
</thead>
<tbody>
<tr>
<td>WREZ Zone</td>
</tr>
<tr>
<td>--------------</td>
</tr>
<tr>
<td>MT_NW</td>
</tr>
<tr>
<td>MT_Ct</td>
</tr>
<tr>
<td>MT_NW</td>
</tr>
<tr>
<td>MT_NE</td>
</tr>
<tr>
<td>Total</td>
</tr>
</tbody>
</table>
A total of 8,583 MW of additional wind generation was added in Montana for the PC6 aggressive Montana wind case. The implied capacity factor is 33 percent.27

Key Results (PC6)
The solution for PC6 without any added transmission is largely unacceptable. With nearly 2,800 GWh of dump energy and extreme displacement of coal and hydro (unused coal = 25,310 GWh), the usefulness of the results are questionable. There were several hours where the incremental wind was curtailed due to transmission shortages. Out of the 25,000 GWh of added wind energy, only 19,710 GWh was utilized. See the expansion cases for results that can be used to draw conclusions about aggressive wind development in Montana.

Stakeholders familiar with the northwest sub-region and Montana, in particular, have advised TEPPC that additional wind generation in Montana cannot be integrated without additional transmission capacity. The existing transmission lines between Montana and other load centers are currently under contract to deliver the output from existing facilities, including the Colstrip generating plant. Also, without generation that provides similar characteristics, the line rating would have to be decreased. Hence, the PROMOD solution is unrealistic and potentially impossible.

A snapshot of the PC6 PROMOD simulation results for the NWMT area is shown in Figure 58. For many hours there is sufficient wind to serve the area load and fill all of the paths out of the area. The wind is modeled as a must-take resource and other resources have to follow the load and wind.

Figure 58: NWMT generation - PC6

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27 The capacity factor for the aggressive wind resources is based on the wind generation profiles used to model the resources in the production cost simulation. These generation profiles are based on NREL meso-scale wind sites selected to represent the aggressive wind resources.
In Figure 58, the wind is somewhat irregular and, at 2:00 pm on February 26th, a lull in wind generation required the NWMT subregion to purchase energy, prompting the start-up of a coal unit. Another coal unit is started on February 28th. Both of the dispatched coal units have constraints that require them to remain on for 168 hours and not be operated below their minimum capacity level. When there was sufficient wind energy to serve the area load and fill the available transmission capacity, the constrained coal and hydro have no place to go (are not used to serve load) and become dump energy. There are periods where the only type of generation serving the Montana load and filling the transmission lines is wind. The operators in and around Montana would not allow this condition and would have to curtail the wind. **In order to integrate the 25,000 GWh of additional wind energy it would be necessary to add transmission capacity to help move the surplus energy and maintain local reliability.** The Colstrip to Broadview duration plots in Figure 59 show how much the Colstrip units were impacted by the high penetration of wind expansion in Montana.

**Figure 59: Colstrip to Broadview Utilization PC6**
Expansion Cases (EC6-1 and EC6-2)
For the EC6-1 case it was assumed that a transmission project similar to the Chinook DC transmission project was added to act as a transfer path for the wind. A nomogram was employed to force the transfer of the incremental wind down the Chinook DC line.

In the EC6-2 case the MSTI and Path 8 (Montana-Northwest path) upgrade projects were modeled together. All of the expansion projects are shown in the map in Figure 60.

- EC6-1 includes the Chinook DC project with expansion capacities as follows.
  - Montana to Idaho (3,000 MW)
  - Idaho to Southern Nevada (3,000 MW)
- EC6-2 includes the Path 8 upgrade and MSTI project with expansion capacities as follows.
  - Montana to Northern Idaho (+700 MW)
  - Montana to Southern Idaho (1,500 MW)

Figure 60: Map of expansion projects for PC6

A few of the key study results for the aggressive Montana wind cases are shown in Table 21. Although the expansion cases improved the delivery options, neither one added enough transmission capacity to resolve all of the congestion problems. This isn't surprising since only 3,000 MW of transmission capacity was added in contrast to the 8,600 MW of wind additions. Many of the existing paths out of Montana were already heavily utilized before the wind generation was added.
Table 21: Key Results for Montana expansion

<table>
<thead>
<tr>
<th>Case</th>
<th>WECC Renewable %</th>
<th>Variable Production Cost ($M)</th>
<th>CO2 Emissions (MMetricTons)</th>
<th>Dump Energy (GWh)</th>
<th>Un-used Coal (GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>PC0</td>
<td>16.8</td>
<td>19,934</td>
<td>383</td>
<td>29</td>
<td>9,474</td>
</tr>
<tr>
<td>PC1</td>
<td>16.7</td>
<td>18,189</td>
<td>368</td>
<td>28</td>
<td>12,474</td>
</tr>
<tr>
<td>PC6</td>
<td>16.2</td>
<td>19,214</td>
<td>364</td>
<td>2,712</td>
<td>25,310</td>
</tr>
<tr>
<td>EC6-1</td>
<td>16.6</td>
<td>18,703</td>
<td>365</td>
<td>1,924</td>
<td>19,728</td>
</tr>
<tr>
<td>EC6-2</td>
<td>16.5</td>
<td>18,868</td>
<td>364</td>
<td>2,427</td>
<td>21,998</td>
</tr>
</tbody>
</table>

The utilization of the Montana – Northwest path for both expansion cases is compared in Figure 61 to the PC1 and PC6 cases. The plot for PC6 also shows a blip at the left where the transmission constraints were exceeded for a few hours. The EC6-2 expansion included an upgrade to the Montana-Northwest path rating (from 2,200 MW to 2,900 MW) and this is reflected in the increased utilization.

Figure 61: Montana-Northwest Path Duration Plots
Figure 62 shows how the generation dispatch for NWMT changed after the Chinook project was added (compare to Figure 58). The additional transmission capacity enabled the delivery of more coal, hydro, and wind energy to other areas. The added capacity also reduced the amount of dump energy.

Figure 62: NWMT Generation - EC6-1
A summary comparison of the annual generation results for PC6 and EC6-1 is provided in Table 22. The tabular results show several dispatch related values, including which types of generation increased or decreased. The Chinook project provided a path to export surplus coal and wind energy that was stranded in PC6. The coal and wind was mostly used to displace more expensive CC generation and the end result is a $511 million reduction in production cost.

Table 22: Annual Change PC6 > EC6-1

<table>
<thead>
<tr>
<th>Category</th>
<th>2020 Aggressive MT Wind</th>
<th>2020 Aggressive MT Wind with Chinook</th>
<th>Difference</th>
<th>Diff %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional Hydro</td>
<td>246,807,876</td>
<td>246,830,119</td>
<td>22,243</td>
<td>0.009</td>
</tr>
<tr>
<td>Pumped Storage</td>
<td>2,297,916</td>
<td>2,479,876</td>
<td>181,960</td>
<td>7.918</td>
</tr>
<tr>
<td>Steam – Coal</td>
<td>274,919,523</td>
<td>280,501,538</td>
<td>5,582,015</td>
<td>2.030</td>
</tr>
<tr>
<td>Steam – Other</td>
<td>3,394,953</td>
<td>3,431,825</td>
<td>36,872</td>
<td>1.086</td>
</tr>
<tr>
<td>Nuclear</td>
<td>75,530,993</td>
<td>75,794,493</td>
<td>263,499</td>
<td>0.349</td>
</tr>
<tr>
<td>Combined Cycle</td>
<td>180,181,074</td>
<td>168,682,327</td>
<td>(11,498,747)</td>
<td>-6.382</td>
</tr>
<tr>
<td>Combustion Turbine</td>
<td>13,759,473</td>
<td>14,225,914</td>
<td>466,441</td>
<td>3.390</td>
</tr>
<tr>
<td>Cogeneration</td>
<td>26,816,624</td>
<td>26,910,742</td>
<td>94,117</td>
<td>0.351</td>
</tr>
<tr>
<td>IC</td>
<td>267,012</td>
<td>235,842</td>
<td>(31,170)</td>
<td>-11.674</td>
</tr>
<tr>
<td>Negative Bus Load</td>
<td>4,591,682</td>
<td>4,640,148</td>
<td>48,466</td>
<td>1.056</td>
</tr>
<tr>
<td>Biomass RPS</td>
<td>14,374,764</td>
<td>13,949,518</td>
<td>(425,246)</td>
<td>-2.958</td>
</tr>
<tr>
<td>Geothermal</td>
<td>30,412,471</td>
<td>30,396,482</td>
<td>(15,989)</td>
<td>-0.053</td>
</tr>
<tr>
<td>Small Hydro RPS</td>
<td>7,263,784</td>
<td>7,263,784</td>
<td>0</td>
<td>0.000</td>
</tr>
<tr>
<td>Solar</td>
<td>20,091,058</td>
<td>20,091,058</td>
<td>0</td>
<td>0.000</td>
</tr>
<tr>
<td>Wind</td>
<td>87,469,548</td>
<td>92,778,778</td>
<td>5,309,229</td>
<td>6.070</td>
</tr>
<tr>
<td>Total</td>
<td>988,178,751</td>
<td>988,212,442</td>
<td>33,691</td>
<td>0.003</td>
</tr>
</tbody>
</table>

| Renewable Total           | 159,611,624              | 164,479,619                          | 4,867,995  | 3.050  |
| Renewable Percent (%)     | 16.2                     | 16.6                                 | (0)        | 3.046  |

Other Results (see TEPPC Glossary for definitions)

| Dump Energy               | 2,711,563                | 1,924,156                            | (787,408)  | -29.039|
| Emergency Energy          | 535                      | 1,862                                | 1,327      | 284.204|
| CO₂ Emissions (MMetric Tons) | 364                    | 365                                | 1          | 0.218  |
| CO₂ Adder ($/metric ton)  | 0.000                    | 0.000                               | (0)        | 0.000  |

Variable Production Cost (thermal units excl DSM)

| CO₂ Adder (Total M$)      | 0                        | 0                                   | 0          | 0.000  |
| Other Variable Costs (M$) | 19,214                   | 18,703                              | (511)      | -2.660 |
| Total Var. Prod. Cost (M$) | 19,214                  | 18,703                             | (511)      | -2.660 |
The transfers between sub-regions are compared in Figure 63. The NWPP to Basin transfers show a reversal for the EC6-1 case. This is likely related to the intermediate converter station on the Chinook DC line. A portion of the energy flowing down the Chinook line is jumping off at Borah and delivering energy to the NWPP via the AC system. This is consistent with the pool level dispatch that gave preference for the surplus resources in Montana to the areas in the NWPP subregion.

Figure 63: Regional Transfers Aggressive Montana Wind

In the EC6-2 case the MSTI path is used to transfer economy energy from Montana to Idaho (NWPP to Basin). The upgrade to the Montana to Northwest path (Path 8) is used to deliver economy energy to the coastal NWPP states.

A summary comparison of the estimated capital costs for the Montana wind cases is provided in Table 23 and Figure 64. As noted in the Executive Summary, the transmission expansions studied with the aggressive Montana wind relocations were not rigorously assessed in terms of their ability to deliver the relocated generation from Montana to particular load areas. In addition, resource and transmission cost uncertainties associated with these cases were not fully analyzed, and a number of other important factors used to make actual resource planning and procurement decisions were not fully addressed.\(^{28}\)

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\(^{28}\) A more detailed discussion of the uncertainties surrounding the resource and transmission cost estimates prepared by TEPPC, as well as the important factors considered when making actual resource planning and procurement decisions can be found in the 2019 Study Report.
Table 23: Estimated Capital Costs of Montana Expansion ($M/yr)

<table>
<thead>
<tr>
<th>2020 Aggressive MT Wind and Transmission Expansion</th>
<th>Change(^1) in Resource Capital Cost</th>
<th>Transmission Capital Cost</th>
<th>Change(^1) in Production Cost</th>
<th>Annual Net Change(^1)</th>
</tr>
</thead>
<tbody>
<tr>
<td>25,000 GWh Relocation to MT</td>
<td>-1,291</td>
<td>0</td>
<td>1,025</td>
<td>-266</td>
</tr>
<tr>
<td>plus Chinook Project, 3,000 MW</td>
<td>-1,291</td>
<td>569</td>
<td>514</td>
<td>-208</td>
</tr>
<tr>
<td>plus MSTI &amp; MT-NW Path 8 Upgrades, 2,200 MW</td>
<td>-1,291</td>
<td>223</td>
<td>680</td>
<td>-388</td>
</tr>
</tbody>
</table>

\(^1\)Change is relative to the 2020 PC1 Reference Case; Values are presented in $M/year

Figure 64: Estimated Capital Cost Savings of Montana Expansion

The transmission expansion cases studied with the Montana aggressive wind resource relocation generally include less new transmission capacity than the capacity of the wind resources relocated to Montana. As such, additional transmission investment may be needed to reliably deliver these resources to load centers and to mitigate the transmission congestion observed in the study cases which resulted in a significant amount of cycling and ramping of base-load resources. This additional transmission investment, which appears supportable by the estimated potential generation capital cost savings, would reduce and, depending on the size of the investment and other uncertainties, could eliminate the cost savings shown in Table 23 and Figure 64.
2020 PC7 – Aggressive Wyoming Wind case

Central Question: What is the effect on system utilization and generation and transmission costs of moving an equivalent 25,000 GWh of renewable resources from other areas of the Western Interconnection into Wyoming?

Input Assumptions:
Renewable generation equivalent to 25,000 GWh that was designated to serve California RPS requirements in the PC1 reference case reflecting current RPS planning and procurement trends was removed from several areas and replaced by wind generation in Wyoming. The same generation was removed as was reported for PC6. Figure 65 shows the location of the incremental wind resources. Just as for PC6, the resources removed from California were the lowest ranked resources (based on cost and environmental factors) used to model the 33 percent RPS requirement in the PC1 reference case. The WREZ Peer Analysis Tool was used to identify the best locations for the incremental wind.

Figure 65: Location of Wyoming resource additions

<table>
<thead>
<tr>
<th>WREZ Zone</th>
<th>GWh of Wind</th>
<th>% of Wind</th>
</tr>
</thead>
<tbody>
<tr>
<td>WY_EC</td>
<td>7,891</td>
<td>32%</td>
</tr>
<tr>
<td>WY_NO</td>
<td>863</td>
<td>3%</td>
</tr>
<tr>
<td>WY_EA</td>
<td>13,816</td>
<td>55%</td>
</tr>
<tr>
<td>WY_SO</td>
<td>2,430</td>
<td>10%</td>
</tr>
<tr>
<td>Total</td>
<td>25,000</td>
<td>100%</td>
</tr>
</tbody>
</table>

A total of 6,107 MW of additional wind generation was added in Wyoming for the PC7 aggressive Wyoming wind case. The implied capacity factor is 47 percent.\(^{29}\)

Key Results (PC7)
The solution for PC7 without any added transmission is better than PC6, but still may be unacceptable. With over 1,300 GWh of dump energy and extreme displacement of coal (unused coal was 25,299 GWh), the usefulness of the results is questionable. See the expansion cases for results that can be used to draw conclusions about aggressive wind development in Wyoming.

An example of the PC7 PROMOD simulation results for the Wyoming area is shown in Figure 66.

\(^{29}\) The capacity factor for the aggressive wind resources is based on the wind generation profiles used to model the resources in the production cost simulation. These generation profiles are based on NREL meso-scale wind sites selected to represent the aggressive wind resources.
When the wind dies down PROMOD starts a coal unit to help meet the load and later as the wind picks up again the coal is backed down to minimum. There isn’t room to take both the minimum coal and the wind, so the coal is dumped (because all wind is modeled as must-take and the coal has to stay on to avoid damage from stops and starts). Due to the large penetration of wind this sequence occurs quite frequently.

Figure 67 shows which paths were the most heavily utilized in PC7, and Figure 68 shows how they changed relative to the PC1 reference case. The column in Figure 68 titled “Change in U90 Relative to Ref Case” provides the percentage increase in U90 for the listed path as compared to the U90 value reported for that path in the 2020 PC1 reference case.
The 25,000 GWh of additional generation changed the utilization of several WECC paths as evidenced by all of the red arrows in Figure 68.

Expansion Cases (EC7-1 and EC7-2)
Two expansion cases with added transmission lines were run against the PC7 aggressive Wyoming wind case. The projects are listed below and a rough map of the expansion transmission is provided in Figure 69.

- **EC7-1** includes the High Plains Express, SunZia, and Gateway West #2 projects. The expansion capacities are:
  - Wyoming to Idaho (1,500 MW)
  - Wyoming to Colorado (3,500 MW)
  - Colorado to New Mexico (3,700 MW)
  - New Mexico to Arizona (6,000 MW)
- **EC7-2** includes the TransWest Express HVDC project.  
  - Wyoming to Southern Nevada (3,000 MW)

---

30 Due to limited time and staff resources only a limited number of transmission expansion cases were studied. The TransWest Express (TWE) project was selected for analysis as being a representative HVDC project between Wyoming and southern Nevada. The Zephyr HVDC project, which has similar endpoints to TWE but a longer route (725 miles vs 900 miles), would be expected to produce similar, but somewhat lower, cost savings.
Because the EC7-1 transmission has both HPX and GW#2 out of Wyoming, the capacity leaving the state is the sum of the two projects, or 1,500 MW plus 3,500 MW for a total of 5,000 MW. The TransWest express project has a capacity of 3,000 MW. Both are depicted in Figure 70.

Figure 70: Expansion Capacity
The duration plots in Figure 71 compare the utilization of the TOT3 path (Path 36) for both expansion cases. TOT3 had the highest U90 utilization in the PC7 case. The expansion projects for EC7-1 provide more mitigation than those in EC7-2.

Figure 71: TOT3 Comparison - WY Expansion
The utilization of the expansion projects is presented in Figure 72. Keep in mind that the incremental capacities and termination points of each project relative to the incremental wind resources are not the same. For example, the High Plains Express project interconnects on the Eastern side of Wyoming, and is geographically closer to the majority of the incremental wind resources studied in the aggressive Wyoming wind case. The TransWest Express project, on the other hand, interconnects on the Western side of Wyoming and only a limited amount of lower voltage transmission capacity interconnects the Eastern and Western sides of the state. As such, local transmission congestion issues prevented a higher utilization of the TransWest Express project as compared to the High Plains Express project.

Figure 72: Wyoming transmission expansion plots

Also shown in Figure 72 is a duration plot of wind resources included in a nomogram applied to the TransWest HVDC project. This nomogram forced the output of specific wind projects located in Wyoming onto the DC line. This was necessary because of the problem with PROMOD’s DC line loss algorithm discussed earlier. The difference between the wind included in the DC nomogram and the duration plot of the TransWest Express project are flows on the DC line dispatched by the model purely based on economics.

The expansion projects in EC7-1 provided additional transmission to export the surplus generation out of Wyoming. Figure 73 shows how this changed the generation results compared to the PC7 case.
A summary of some of the key results for the aggressive Wyoming wind case and the expansion cases are presented in Table 24. The results for EC7-2 suggest that more incremental transmission is needed.

**Table 24: Key Results for Wyoming Expansion**

<table>
<thead>
<tr>
<th>Case</th>
<th>WECC Renewable %</th>
<th>Variable Production Cost ($M)</th>
<th>CO2 Emissions (MMetricTons)</th>
<th>Dump Energy (GWh)</th>
<th>Un-used Coal (GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>PC0</td>
<td>16.8</td>
<td>19,934</td>
<td>383</td>
<td>29</td>
<td>9,474</td>
</tr>
<tr>
<td>PC1</td>
<td>16.7</td>
<td>18,189</td>
<td>368</td>
<td>28</td>
<td>12,474</td>
</tr>
<tr>
<td>PC7</td>
<td>16.7</td>
<td>18,719</td>
<td>361</td>
<td>1,311</td>
<td>25,299</td>
</tr>
<tr>
<td>EC7-1</td>
<td>16.7</td>
<td>18,162</td>
<td>366</td>
<td>11</td>
<td>14,072</td>
</tr>
<tr>
<td>EC7-2</td>
<td>16.7</td>
<td>18,639</td>
<td>362</td>
<td>1,315</td>
<td>22,936</td>
</tr>
</tbody>
</table>
Figure 74 shows the changes in path utilization between PC7 and EC7-1. The decreases imply that the HPX is offloading the other east to west paths as expected. This phenomenon is explored in more detail in the plots of COI and WOR in Figures 75 and 76.

**Figure 74: Change in utilization PC7 > EC7-1**

<table>
<thead>
<tr>
<th>Path</th>
<th>U90</th>
<th>Change in U90 Relative to the Agg Wind Case</th>
</tr>
</thead>
<tbody>
<tr>
<td>MIDPOINT - SUMMER LAKE</td>
<td>1.84%</td>
<td>-29.37%</td>
</tr>
<tr>
<td>BRIDGER WEST</td>
<td>0.00%</td>
<td>-29.22%</td>
</tr>
<tr>
<td>IPP DCLINE</td>
<td>7.99%</td>
<td>-22.50%</td>
</tr>
<tr>
<td>INTERMOUNTAIN - GONDER 230KV</td>
<td>1.82%</td>
<td>-18.02%</td>
</tr>
<tr>
<td>BONANZA WEST</td>
<td>21.33%</td>
<td>-16.20%</td>
</tr>
<tr>
<td>SOUTHWEST OF FOUR CORNERS</td>
<td>13.96%</td>
<td>-15.22%</td>
</tr>
</tbody>
</table>

**Figure 75: Wyoming expansion impact to COI**

![COI Path Duration Plots](image-url)
Figure 76: Wyoming expansion impact to WOR

![WEST OF COLORADO RIVER (WOR) Path Duration Plots](image)

Figure 77 provides a comparison of the regional transfers for the aggressive Wyoming wind cases. It is interesting to note that for both expansion cases the economy energy from Wyoming essentially flowed through the AZNMNV subregion.

Figure 77: Regional Transfers - PC7 Series

![Transfers between Sub-Regions (aMW)](image)

A summary comparison of the estimated capital costs for the Wyoming wind cases is provided in Table 25 and Figure 78. As noted in the Executive Summary, the transmission expansions studied with the aggressive Wyoming wind relocations were not rigorously assessed in terms of their ability to deliver the relocated generation from Wyoming to particular load areas. In addition, resource and transmission cost uncertainties associated with these cases were not
fully analyzed, and a number of other important factors used to make actual resource planning and procurement decisions were not fully addressed.31

Table 25: Estimated Capital and Production Costs of Wyoming Expansion ($M/yr)

<table>
<thead>
<tr>
<th>2020 Aggressive WY Wind and Transmission Expansion</th>
<th>Change(^1) in Resource Capital Cost</th>
<th>Transmission Capital Cost</th>
<th>Change(^1) in Production Cost</th>
<th>Annual Net Change(^1)</th>
</tr>
</thead>
<tbody>
<tr>
<td>25,000 GWh Relocation to WY</td>
<td>-2096</td>
<td>0</td>
<td>530</td>
<td>-1556</td>
</tr>
<tr>
<td>plus SunZia and High Plains Express &amp; Gateway West #2, 5000 MW</td>
<td>-2096</td>
<td>1610</td>
<td>-27</td>
<td>-513</td>
</tr>
<tr>
<td>plus TransWest Express, 3000 MW</td>
<td>-2096</td>
<td>337</td>
<td>450</td>
<td>-1309</td>
</tr>
</tbody>
</table>

\(^1\) Change is relative to the 2020 PC1 Reference Case; Values are presented in $M/year

Figure 78: Estimated Capital and Production Cost Savings of Wyoming Expansion

The transmission expansion cases studied with the Wyoming aggressive wind resource relocation generally include less new transmission capacity than the capacity of the wind resources relocated to Wyoming. As such, additional transmission investment may be needed to reliably deliver these resources to load centers and to mitigate the transmission congestion observed in the study cases which resulted in a significant amount of cycling and ramping of base-load resources. This additional transmission investment, which appears supportable by the estimated potential generation capital cost savings, would reduce and, depending on the size of the investment and other uncertainties, could eliminate the cost savings shown in Table 25 and Figure 78.

---

31 A more detailed discussion of the uncertainties surrounding the resource and transmission cost estimates prepared by TEPPC, as well as the important factors considered when making actual resource planning and procurement decisions can be found in the 2019 Study Report.
2020 PC8 – Aggressive Carbon Reduction case

Central Question: How can a combination of coal plant retirements, energy efficiency, and renewable resources be used to reduce CO₂ emissions by 30 percent relative to 2005 levels?

Input Assumptions:
In an attempt to achieve the carbon reduction targets set forth for the 2020 PC8 case, which sets the 2020 CO₂ emissions target at 262.5 million metric tons, the following input assumptions were used for the loads, generation, and transmission:

- Loads - Load forecasts from the 2020 PC3 High DSM case were used as they reflected cumulative energy efficiency savings equal to roughly 20 percent.
- Generation – A total of 6,000 MW of existing coal plant capacity (see list in Table 26) was assumed retired. Additional renewable resources (Table 27) were then added in an attempt to replace the energy lost from the retirements while at the same time maintaining reserve margins\textsuperscript{32}. Locations for the incremental renewables were determined by considering transmission capacity that would be freed-up by the retiring of the coal plants.
- Transmission – No incremental transmission was added to the 2020 PC8 case relative to the 2020 PC1 Reference Case.

\textsuperscript{32} The on-peak capacity of the renewable resources added to the case was equivalent to the capacity of retired coal plants.
Table 26: PC8 Coal Retirements

<table>
<thead>
<tr>
<th>Plant Name</th>
<th>Unit No.</th>
<th>State</th>
<th>Plant Name</th>
<th>Unit No.</th>
<th>State</th>
</tr>
</thead>
<tbody>
<tr>
<td>Apache Station</td>
<td>2</td>
<td>Arizona</td>
<td>Martin Drake</td>
<td>5</td>
<td>Colorado</td>
</tr>
<tr>
<td>Apache Station</td>
<td>3</td>
<td>Arizona</td>
<td>Martin Drake</td>
<td>6</td>
<td>Colorado</td>
</tr>
<tr>
<td>Arapahoe*</td>
<td>3</td>
<td>Colorado</td>
<td>Martin Drake</td>
<td>7</td>
<td>Colorado</td>
</tr>
<tr>
<td>Cameo*</td>
<td>1</td>
<td>Colorado</td>
<td>Naughton</td>
<td>1</td>
<td>Wyoming</td>
</tr>
<tr>
<td>Cameo*</td>
<td>2</td>
<td>Colorado</td>
<td>Naughton</td>
<td>2</td>
<td>Wyoming</td>
</tr>
<tr>
<td>Carbon</td>
<td>1</td>
<td>Utah</td>
<td>Nucla</td>
<td>1</td>
<td>Colorado</td>
</tr>
<tr>
<td>Carbon</td>
<td>2</td>
<td>Utah</td>
<td>Nucla</td>
<td>2</td>
<td>Colorado</td>
</tr>
<tr>
<td>Cholla</td>
<td>1</td>
<td>Arizona</td>
<td>Nucla</td>
<td>3</td>
<td>Colorado</td>
</tr>
<tr>
<td>Cholla</td>
<td>3</td>
<td>Arizona</td>
<td>Nucla</td>
<td>4</td>
<td>Colorado</td>
</tr>
<tr>
<td>Colstrip</td>
<td>1</td>
<td>Montana</td>
<td>Osage</td>
<td>1</td>
<td>Wyoming</td>
</tr>
<tr>
<td>Colstrip</td>
<td>2</td>
<td>Montana</td>
<td>Osage</td>
<td>2</td>
<td>Wyoming</td>
</tr>
<tr>
<td>Corette</td>
<td>1</td>
<td>Montana</td>
<td>Osage</td>
<td>3</td>
<td>Wyoming</td>
</tr>
<tr>
<td>Dave Johnston</td>
<td>1</td>
<td>Wyoming</td>
<td>Reid Gardner*</td>
<td>1</td>
<td>Nevada</td>
</tr>
<tr>
<td>Dave Johnston</td>
<td>2</td>
<td>Wyoming</td>
<td>Reid Gardner*</td>
<td>2</td>
<td>Nevada</td>
</tr>
<tr>
<td>Dave Johnston</td>
<td>3</td>
<td>Wyoming</td>
<td>Reid Gardner*</td>
<td>3</td>
<td>Nevada</td>
</tr>
<tr>
<td>Four Corners</td>
<td>1</td>
<td>New Mexico</td>
<td>San Juan</td>
<td>4</td>
<td>New Mexico</td>
</tr>
<tr>
<td>Four Corners</td>
<td>2</td>
<td>New Mexico</td>
<td>Sunnyside</td>
<td>1</td>
<td>Utah</td>
</tr>
<tr>
<td>Four Corners</td>
<td>3</td>
<td>New Mexico</td>
<td>Valmy</td>
<td>1</td>
<td>Nevada</td>
</tr>
<tr>
<td>Four Corners</td>
<td>4</td>
<td>New Mexico</td>
<td>W N Clark</td>
<td>1</td>
<td>Colorado</td>
</tr>
<tr>
<td>Irvington</td>
<td>4</td>
<td>Arizona</td>
<td>W N Clark</td>
<td>2</td>
<td>Colorado</td>
</tr>
<tr>
<td>KUCC</td>
<td>1</td>
<td>Utah</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>KUCC</td>
<td>2</td>
<td>Utah</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>KUCC</td>
<td>3</td>
<td>Utah</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>KUCC</td>
<td>4</td>
<td>Utah</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*Plant was already set to retired in the 2020 SPSC Reference Case.

Table 27: Renewables added for PC8 (MW)

<table>
<thead>
<tr>
<th>Location</th>
<th>Biomass</th>
<th>Geothermal</th>
<th>Solar CSP 6</th>
<th>Wind</th>
</tr>
</thead>
<tbody>
<tr>
<td>AZ_SO</td>
<td></td>
<td>500</td>
<td></td>
<td></td>
</tr>
<tr>
<td>AZ_WE</td>
<td></td>
<td>1,500</td>
<td></td>
<td></td>
</tr>
<tr>
<td>MT_CT</td>
<td></td>
<td>1,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>NV_EA</td>
<td></td>
<td>300</td>
<td></td>
<td></td>
</tr>
<tr>
<td>NV_NO</td>
<td></td>
<td>800</td>
<td></td>
<td></td>
</tr>
<tr>
<td>NV_SW</td>
<td></td>
<td>1,400</td>
<td></td>
<td></td>
</tr>
<tr>
<td>NV_WE</td>
<td></td>
<td>300</td>
<td>300</td>
<td></td>
</tr>
<tr>
<td>OR_NE</td>
<td>200</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>OR_SO</td>
<td>100</td>
<td>150</td>
<td></td>
<td></td>
</tr>
<tr>
<td>OR_WE</td>
<td></td>
<td>150</td>
<td></td>
<td></td>
</tr>
<tr>
<td>WA_SO</td>
<td>100</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>WY_EC</td>
<td></td>
<td>2,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>WY_SO</td>
<td></td>
<td>1,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>400</td>
<td>1,400</td>
<td>4,000</td>
<td>4,000</td>
</tr>
</tbody>
</table>

The Western Grid Group (WGG), study requester of the PC8 case, provided the list of coal plant retirements that would be modeled in this particular carbon reduction case. To determine the list of retirements, WGG retained Synapse Energy Economics Incorporated to develop a model that
generates a list of possible coal plant retirements based on forward-going economic merit.\textsuperscript{33} The economic merit analysis compared estimated all-in operating costs of coal fired generation in the west, plus the operating and capital cost of environmental upgrades needed to meet Clean Air Act BART and Strict Utility MACT requirements and Clean Water Act Section 316(b) requirements, against the replacement costs of new and existing natural gas combined cycle units. This comparison produced an economic merit order which identified candidates for the coal plant retirements. The coal plants selected for retirement in the PC8 case produced roughly 17 percent of the energy generated from coal in the Western Interconnection in 2008.

Key Results (PC8):
A few of the generation results with the input changes described above are presented in Table 28. The targeted level of carbon reduction was not achieved with the level of coal retirements and renewable resources modeled. A total of 83 million metric tons was reduced as compared to the 2020 PC1 Reference case, but an additional reduction of 22.2 million metric tons is still needed to reach the targeted reduction.

Table 28: PC8 Results

<table>
<thead>
<tr>
<th></th>
<th>CO2 Emissions (MMetric Tons)</th>
<th>Coal Generation Change Relative to PC1</th>
<th>Renewable Generation Contribution to Total Energy</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Target</strong></td>
<td>262.5</td>
<td>-10%</td>
<td>20.0%</td>
</tr>
<tr>
<td><strong>Case results</strong></td>
<td>284.7</td>
<td>-15%</td>
<td>21.7%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(41,016 GWh)</td>
<td>192,410 GWh</td>
</tr>
<tr>
<td><strong>Deviation</strong></td>
<td>-22.2</td>
<td>5%</td>
<td>1.7%</td>
</tr>
</tbody>
</table>

The chart in Figure 79 presents a comparison of how the CO\textsubscript{2} emissions vary between several of the 2020 study cases, as well as the shortfall in the PC8 case.

\textsuperscript{33} Link to Synapse report: http://www.wecc.biz/committees/BOD/TEPPC/TAS/SWG/10March2011/Lists/Minutes/1/WGG_Coal_Plant_Database_Documentation_Final.pdf
Figure 79: CO₂ Emissions

Figure 80 shows the cumulative results of the coal retirements and incremental renewable generation. The goal of adding more renewable resources was to replace the energy lost from the retired coal plants without requiring additional combined cycle generation. In the absence of additional renewables, combined cycle plants would have increased generation in order to serve loads previously served by the coal generation. Since combined cycle plants also emit CO₂, reaching the carbon reduction target in the PC8 case would have been even less likely.

Figure 80: Generation change PC3 > PC8
The standard generation comparison is provided in Table 29 and shows the effect of the coal retirements and incremental renewables.
Table 29: Generation Comparison PC8 vs. PC3

<table>
<thead>
<tr>
<th>Category</th>
<th>2020 SPSC High DSM Case</th>
<th>WGG Carbon Reduction w 17% List of Coal Retirements plus More Renewables</th>
<th>Difference</th>
<th>Diff %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional Hydro</td>
<td>246,779,117</td>
<td>246,763,722</td>
<td>(15,395)</td>
<td>-0.006</td>
</tr>
<tr>
<td>Pumped Storage</td>
<td>2,932,576</td>
<td>2,894,490</td>
<td>(38,086)</td>
<td>-1.299</td>
</tr>
<tr>
<td>Steam – Coal</td>
<td>273,766,131</td>
<td>232,749,894</td>
<td>(41,016,236)</td>
<td>-14.982</td>
</tr>
<tr>
<td>Steam – Other</td>
<td>2,616,045</td>
<td>2,610,360</td>
<td>(5,686)</td>
<td>-0.217</td>
</tr>
<tr>
<td>Nuclear</td>
<td>75,204,407</td>
<td>74,811,150</td>
<td>(393,257)</td>
<td>-0.523</td>
</tr>
<tr>
<td>Combined Cycle</td>
<td>95,660,270</td>
<td>98,495,036</td>
<td>2,834,767</td>
<td>2.963</td>
</tr>
<tr>
<td>Combustion Turbine</td>
<td>7,868,278</td>
<td>7,874,440</td>
<td>6.162</td>
<td>0.078</td>
</tr>
<tr>
<td>Cogeneration</td>
<td>22,510,857</td>
<td>21,780,058</td>
<td>(730,800)</td>
<td>-3.246</td>
</tr>
<tr>
<td>IC</td>
<td>155,271</td>
<td>163,305</td>
<td>8,035</td>
<td>5.175</td>
</tr>
<tr>
<td>Negative Bus Load</td>
<td>4,640,148</td>
<td>4,640,148</td>
<td>0</td>
<td>0.000</td>
</tr>
<tr>
<td>Biomass RPS</td>
<td>12,216,378</td>
<td>13,438,097</td>
<td>1,221,718</td>
<td>10.001</td>
</tr>
<tr>
<td>Geothermal</td>
<td>34,702,778</td>
<td>44,929,867</td>
<td>10,227,089</td>
<td>29.471</td>
</tr>
<tr>
<td>Small Hydro RPS</td>
<td>7,755,792</td>
<td>7,755,792</td>
<td>0</td>
<td>0.000</td>
</tr>
<tr>
<td>Solar</td>
<td>26,436,282</td>
<td>39,809,585</td>
<td>13,373,303</td>
<td>50.587</td>
</tr>
<tr>
<td>Wind</td>
<td>71,701,608</td>
<td>86,476,916</td>
<td>14,775,309</td>
<td>20.607</td>
</tr>
<tr>
<td>Total</td>
<td>884,945,939</td>
<td>885,192,861</td>
<td>246,922</td>
<td>0.028</td>
</tr>
</tbody>
</table>

Renewable Total: 152,812,838
Renewable Percent (%): 17.3

Other Results (see TEPPC Glossary for definitions)

- Dump Energy: 432,750, 689,267, 256,517, 59.276
- Emergency Energy: 257, 257, 0, 0.000
- CO₂ Adder ($/metric ton): 0.000, 0.000

Variable Production Cost (thermal units excl DSM)

- CO₂ Adder (Total M$): 0, 0, 0, 0.000
- Other Variable Costs (M$): 13,617, 13,139, (477), -3.506

A plot of the regional transfers for a sequence of runs which included applying the coal retirements alone, and then adding incremental renewables in addition to applying the coal plant retirements is shown in Figure 81. This shows how the loss of the coal generation impacts the regional transfers, and then how the placement of incremental renewables brings regional transfers nearly back to pre-retirement levels. The goal of adding the incremental renewables was to utilize the freed up transmission capacity resulting from the coal retirements such that the added resources had limited additional impact on the transmission system.
With the additional solar resources in the AZNMNV sub-region it’s easy to see in Figure 82 how the solar generation correlates with the load. The solar shapes also show the effect of clouds and haze that develop during the heat of the day.

Figure 82: Generation snapshot for AZNMNV - PC8

Equivalent plots of the WECC generation for PC3 and PC8 in Figures 83 and 84 illustrate the effect of the generation retirements and incremental renewable resources in PC8. Most noteworthy and obvious is the decrease in coal generation and increase in renewable generation.
Limitations of the Study:
No information was readily available to TEPPC to estimate the capital costs associated with the retiring of coal plants, or adding environmental equipment to coal plants to comply with pending environmental regulations. An estimate of the change in variable production cost associated with retrofitting coal plants to comply with regulations was also not available. Such information should all be included as part of a cost analysis of this study case.

Furthermore, coal plant retirements and renewable energy additions were modeled without an investigation of the impact these changes may have on system reliability. In addition, the impact of the coal retirements and the subsequent addition of renewable resources on path ratings was not considered.

Finally, an extensive analysis was not done to determine the optimal type and location of renewable resource that could replace the coal generation that was retired. Future work could attempt to optimize the mix of renewables selected based on location relative to transmission, resource quality (capacity factor) and characteristics, and capital cost. Optimization could also
be done to reduce any transmission congestion observed as a result of adding the incremental resources.
2020 PC9 – Tres Amigas Grid Connection case
Central Question: How can the development of the Tres Amigas superstation help WECC to achieve its RPS goals and increase efficiency?

Input Assumptions:
A general market model of the two adjacent regional councils which would connect with WECC through Tres Amigas was provided by ZGlobal. Tres Amigas intends to connect the Southwest Power Pool (SPP or SWPP), one of the seven councils of the Eastern Interconnection, with ERCOT and WECC. A few references from the Tres Amigas website are included below.

Tres Amigas, LLC will unite the nation's electric grid. Utilizing the latest advances in power grid technology, Tres Amigas is focused on providing the first common Interconnection of America's three power grids to help the country achieve its renewable energy goals and facilitate the smooth, reliable and efficient transfer of green power from region to region.

Figure 85: Tres Amigas map
Tres Amigas also plans to incorporate energy storage, but this was not modeled in the TEPPC study.

The model for Tres Amigas, provided by Z-Global, was basically a set of energy cost curves to describe the price at which the SPP and ERCOT markets are willing to buy or sell power from/to WECC. The price curves are based on available 2009 price data for SPP and 2008 price data for ERCOT. These price curves were consolidated into two periods, summer (June through September), and Non-summer (October through May) for both SPP and ERCOT. On-peak, off-peak, and Sunday price curves were generated for each of these time periods. The curves are shown below in Tables 30 through 33. Red numbers seen in the tables represent flows from WECC into the other interconnections while the black numbers indicate flows from either ERCOT or SPP into WECC.

Table 30: SPP Summer Price Curve
<table>
<thead>
<tr>
<th>MW Range</th>
<th>PEAK Heat Rate</th>
<th>OFF-PEAK Heat Rate</th>
<th>SUNDAY Heat Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>(3,100)-(2,658)</td>
<td>2.00</td>
<td>1.77</td>
<td>1.85</td>
</tr>
<tr>
<td>(2,657)-(2,215)</td>
<td>2.01</td>
<td>1.82</td>
<td>2.00</td>
</tr>
<tr>
<td>(2,214)-(1,772)</td>
<td>2.99</td>
<td>2.32</td>
<td>2.27</td>
</tr>
<tr>
<td>(1,771)-(1,329)</td>
<td>3.19</td>
<td>2.60</td>
<td>2.66</td>
</tr>
<tr>
<td>(1,328)-(886)</td>
<td>3.42</td>
<td>3.27</td>
<td>3.36</td>
</tr>
<tr>
<td>(885)-(443)</td>
<td>3.71</td>
<td>3.49</td>
<td>3.48</td>
</tr>
<tr>
<td>(442)-0</td>
<td>4.03</td>
<td>3.85</td>
<td>3.80</td>
</tr>
<tr>
<td>0-442</td>
<td>5.3</td>
<td>5.2</td>
<td>3.91</td>
</tr>
<tr>
<td>443-885</td>
<td>7.03</td>
<td>6.7</td>
<td>4.7</td>
</tr>
<tr>
<td>886-1,328</td>
<td>8.5</td>
<td>7.8</td>
<td>6</td>
</tr>
<tr>
<td>1,329-1,771</td>
<td>9.01</td>
<td>8.1</td>
<td>7.3</td>
</tr>
<tr>
<td>1,772-2,214</td>
<td>9.95</td>
<td>8.7</td>
<td>8.3</td>
</tr>
<tr>
<td>2,215-2,657</td>
<td>10.7</td>
<td>9.0</td>
<td>9</td>
</tr>
<tr>
<td>2,658-3,100</td>
<td>11.9</td>
<td>10.3</td>
<td>10</td>
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</table>
Table 31: SPP Non-Summer Price Curve

<table>
<thead>
<tr>
<th>MW Range</th>
<th>PEAK Heat Rate</th>
<th>OFF-PEAK Heat Rate</th>
<th>SUNDAY Heat Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>(3,100)-(2,658)</td>
<td>2.00</td>
<td>1.78</td>
<td>1.75</td>
</tr>
<tr>
<td>(2,657)-(2,215)</td>
<td>2.59</td>
<td>2.07</td>
<td>2.00</td>
</tr>
<tr>
<td>(2,214)-(1,772)</td>
<td>2.80</td>
<td>2.19</td>
<td>2.10</td>
</tr>
<tr>
<td>(1,771)-(1,329)</td>
<td>2.91</td>
<td>2.21</td>
<td>2.12</td>
</tr>
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<td>(1,328)-(886)</td>
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<td>2.59</td>
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<tr>
<td>(885)-(443)</td>
<td>3.06</td>
<td>2.88</td>
<td>2.80</td>
</tr>
<tr>
<td>(442)-0</td>
<td>3.11</td>
<td>2.88</td>
<td>2.89</td>
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<td>3.7</td>
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<td>443-885</td>
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<td>4.7</td>
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<td>886-1,328</td>
<td>7.85</td>
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<td>5.8</td>
</tr>
<tr>
<td>1,329-1,771</td>
<td>8.85</td>
<td>7.9</td>
<td>6.5</td>
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<td>1,772-2,214</td>
<td>9.9</td>
<td>8.7</td>
<td>7.3</td>
</tr>
<tr>
<td>2,215-2,657</td>
<td>10.9</td>
<td>9.0</td>
<td>8</td>
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<tr>
<td>2,658-3,100</td>
<td>11</td>
<td>9.8</td>
<td>8.5</td>
</tr>
</tbody>
</table>
### Table 32: ERCOT Summer Price Curve

<table>
<thead>
<tr>
<th>MW Range</th>
<th>PEAK Heat Rate</th>
<th>OFF-PEAK Heat Rate</th>
<th>SUNDAY Heat Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>(2,000)-(1,716)</td>
<td>1.84</td>
<td>1.69</td>
<td>1.80</td>
</tr>
<tr>
<td>(1,715)-(1,430)</td>
<td>2.62</td>
<td>2.18</td>
<td>2.31</td>
</tr>
<tr>
<td>(1,429)-(1,144)</td>
<td>3.57</td>
<td>2.81</td>
<td>2.31</td>
</tr>
<tr>
<td>(1,143)-(858)</td>
<td>3.82</td>
<td>2.99</td>
<td>2.69</td>
</tr>
<tr>
<td>(857)-(572)</td>
<td>3.90</td>
<td>3.40</td>
<td>3.51</td>
</tr>
<tr>
<td>(571)-(286)</td>
<td>3.9</td>
<td>3.52</td>
<td>3.73</td>
</tr>
<tr>
<td>(285)-0</td>
<td>3.96</td>
<td>3.60</td>
<td>3.77</td>
</tr>
<tr>
<td>0-285</td>
<td>5.2</td>
<td>3.7</td>
<td>3.95</td>
</tr>
<tr>
<td>286-571</td>
<td>6.29</td>
<td>5.2</td>
<td>4.1</td>
</tr>
<tr>
<td>572-857</td>
<td>8.3</td>
<td>6.7</td>
<td>5.16</td>
</tr>
<tr>
<td>858-1,143</td>
<td>9.3</td>
<td>7.8</td>
<td>5.5</td>
</tr>
<tr>
<td>1,144-1,429</td>
<td>10.1</td>
<td>8.8</td>
<td>6.3</td>
</tr>
<tr>
<td>1,430-1,715</td>
<td>11.2</td>
<td>9.4</td>
<td>7.3</td>
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<tr>
<td>1,716-2,000</td>
<td>11.5</td>
<td>10.0</td>
<td>8.6</td>
</tr>
</tbody>
</table>
Table 33: ERCOT Non-Summer Price Curve

<table>
<thead>
<tr>
<th>Maximum MW</th>
<th>MW Band</th>
</tr>
</thead>
<tbody>
<tr>
<td>ERCOT</td>
<td>2,000</td>
</tr>
</tbody>
</table>

**NON-SUMMER (OCT-DEC, JAN-MAY)**

<table>
<thead>
<tr>
<th>MW Range</th>
<th>PEAK Heat Rate</th>
<th>OFF-PEAK Heat Rate</th>
<th>SUNDAY Heat Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>(2,000)-(1,716)</td>
<td>1.59</td>
<td>1.35</td>
<td>1.64</td>
</tr>
<tr>
<td>(1,715)-(1,430)</td>
<td>2.15</td>
<td>1.62</td>
<td>1.8</td>
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<tr>
<td>(1,429)-(1,144)</td>
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<td>1.81</td>
<td>2.07</td>
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<td>2.08</td>
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<tr>
<td>(857)-(572)</td>
<td>3.00</td>
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<td>2.39</td>
</tr>
<tr>
<td>(571)-(286)</td>
<td>3.22</td>
<td>2.84</td>
<td>2.51</td>
</tr>
<tr>
<td>(285)-0</td>
<td>3.36</td>
<td>3.12</td>
<td>3.03</td>
</tr>
<tr>
<td>0-285</td>
<td>5.62</td>
<td>3.6</td>
<td>3.25</td>
</tr>
<tr>
<td>286-571</td>
<td>6</td>
<td>4.7</td>
<td>3.47</td>
</tr>
<tr>
<td>572-857</td>
<td>6.25</td>
<td>5.6</td>
<td>4.9</td>
</tr>
<tr>
<td>858-1,143</td>
<td>8.5</td>
<td>6.7</td>
<td>6.1</td>
</tr>
<tr>
<td>1,144-1,429</td>
<td>9.6</td>
<td>7.3</td>
<td>6.9</td>
</tr>
<tr>
<td>1,430-1,715</td>
<td>9.9</td>
<td>8.2</td>
<td>7.4</td>
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<tr>
<td>1,716-2,000</td>
<td>10.7</td>
<td>8.4</td>
<td>8.3</td>
</tr>
</tbody>
</table>

The implementation of the Tres Amigas model in PROMOD was accomplished by modeling a load and multiple generators at each market that utilize the curves described above and that are dispatched based on a WECC price signal. The WECC price signal is based on the hourly price derived from three key buses in the Western Interconnection, namely 14005_WESTWING, 15021_PALOVERDE, and 30060_MIDWAY. The High Plains Express project was also added to the model to interconnect Tres Amigas to the greater system and to provide a path between Wyoming and New Mexico. The transmission interconnection of Tres Amigas is shown below in Figure 87.
Key Results (PC9):
It is difficult to evaluate how well the modeling of Tres Amigas worked without a measure of the expectations or historical data for comparisons. The Modeling Work Group (MWG) implemented a few modifications to improve the results, but there may still be room for improvement.
Nonetheless, results from the study show an economic benefit was realized from ERCOT and SPP generation displacing more expensive WECC generation when the WECC marginal price was higher than that of ERCOT and SPP. Similarly, economic benefit was realized from WECC selling surplus generation to the ERCOT and SPP markets when the WECC marginal price was lower than that of ERCOT and SPP. These benefits are highly dependent upon the price curve assumptions, but by comparing the variable production costs between PC1 and PC9, a net economic benefit of approximately $400 million per year was observed.
Figure 88 shows the simulated hourly imports into WECC from ERCOT and SPP through the Tres Amigas hub. The transfers were primarily into WECC and were more dominant during the spring when more units were out for maintenance. One of the adjustments made by the MWG was to limit the off-peak flows under the assumption that all three regions would be in a similar surplus condition.
A 10-day snapshot of the Tres Amigas market is shown in Figure 89. The energy above the demand line (demand for both ERCOT and SWPP) represents flows into WECC and the gaps below the demand represent exports from WECC. The Sunday cycles (July 12\textsuperscript{th} and July 19\textsuperscript{th}) may need further analysis and possibly some refinement.
The same plot for a period in February (Figure 90) shows daily, short-lived exports to WECC but the pattern is not consistent with market transfers.

**Figure 90: Tres Amigas Market - February**

Comparisons of the path utilization for the combined COI+PDCI path and the West of Colorado River path are shown in Figures 91 and 92.

**Figure 91: COI+PDCI Path Duration Plots**
Figure 92: West of Colorado River Path Duration Plots
General Observations Based on the 2020 Study Case Results

- One of the concerns raised by the study results is the increasing amount of surplus generation during light load hours. The modeling assumptions may be creating an unrealistic generation dispatch that cycles base-load thermal generation at levels that may not be sustainable. The generator owners and operators may not be willing to assume the increased risk and the generation participants may be subject to take or pay requirements.

- The majority of the foundational transmission projects (see Figure 5) are designed to upgrade local systems, upgrade intraregional networks, or provide paths to deliver renewable energy to load centers. Several areas that have been identified for renewable development are not addressed by the foundational list, but may be captured in the potential project list. A limited number of the Potential Projects were incorporated into the Aggressive Montana wind and Aggressive Wyoming wind expansion cases as part of the TEPPC 2020 Studies. In the TEPPC 2019 Studies all of the Potential Projects were incorporated into one or more of the study cases.

- The projected increase in energy load between 2009 and 2020 is 120,786 GWh. The estimated coincident peak demand increased by 22,903 MW from 146,904 MW in 2009 to 169,807 MW in the 2020 PC1 case. The amount of assumed net incremental generation over the same period is 38,841 MW, of which 34,880 MW is renewable generation.

- The assumptions for meeting the planning reserve margins (PRM) in each of the subregions were based on the generation assumptions, RPS requirements, and interchange estimates. Table 30 shows the reserve assumptions for the PC1 case.

Table 34: Planning Reserve Margins - PC1

<table>
<thead>
<tr>
<th>Overall Summary</th>
<th>AZNMNV</th>
<th>Basin</th>
<th>Alberta</th>
<th>BC</th>
<th>CA-North</th>
<th>CA-South</th>
<th>NWPP</th>
<th>RMPA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Planning Reserve %</td>
<td>13.5</td>
<td>12.6</td>
<td>14.1</td>
<td>14.1</td>
<td>17.0</td>
<td>17.0</td>
<td>17.2</td>
<td>12.5</td>
</tr>
<tr>
<td>Peak Load</td>
<td>31,316</td>
<td>15,972</td>
<td>15,049</td>
<td>11,393</td>
<td>26,475</td>
<td>39,086</td>
<td>27,083</td>
<td>13,661</td>
</tr>
<tr>
<td>Gen Requirement (Peak Load + Reserves)</td>
<td>35,544</td>
<td>17,984</td>
<td>17,171</td>
<td>12,999</td>
<td>30,976</td>
<td>45,672</td>
<td>31,741</td>
<td>15,369</td>
</tr>
<tr>
<td>Gen Capacity Available at time of Peak in Dataset</td>
<td>43,763</td>
<td>19,294</td>
<td>16,545</td>
<td>16,125</td>
<td>29,764</td>
<td>39,350</td>
<td>38,974</td>
<td>16,963</td>
</tr>
<tr>
<td>Initial Gap</td>
<td>-8,219</td>
<td>-1,310</td>
<td>626</td>
<td>-3,125</td>
<td>1,213</td>
<td>6,322</td>
<td>-7,233</td>
<td>-1,594</td>
</tr>
<tr>
<td>Gap Adjustment (Net Exports)</td>
<td>5,661</td>
<td>975</td>
<td>0</td>
<td>0</td>
<td>-4,000</td>
<td>-9,215</td>
<td>6,579</td>
<td>0</td>
</tr>
<tr>
<td>Adjusted Gap</td>
<td>-2,558</td>
<td>-335</td>
<td>626</td>
<td>-3,126</td>
<td>-2,787</td>
<td>-2,893</td>
<td>-664</td>
<td>-1,594</td>
</tr>
<tr>
<td>Resulting PRM (%)</td>
<td>22</td>
<td>15</td>
<td>10</td>
<td>42</td>
<td>28</td>
<td>24</td>
<td>20</td>
<td>24</td>
</tr>
</tbody>
</table>

The row named “Gap Adjustment (Net Exports)” represents the assumed transfers between sub-regions. The assumptions can be compared to the import/export assumptions in the study results. For example, the chart in Figure 93 shows a snapshot of the interchange results of the PC1 case for Southern California, which had an assumed peak import of 9,215 MW. Although there are a few spikes approaching 11,000, the range appears to be reasonable.
• The full flexibility of combined cycle (CC) plants is not captured in the way they are modeled in the TEPPC datasets. Combined cycle plants consist of one or more gas turbines combined with a steam turbine, usually with separate generators. Due to modeling limitations in PROMOD, the CC plants in the TEPPC datasets are modeled as a single unit, rather than as separate units. The operating dependencies and heat rate configurations are complex, largely dependent on whether a plant has an exhaust damper to bypass the steam generator. Ventyx, the developer of PROMOD, has been reluctant to expand the modeling capabilities for CC plants based on their past design as base-load resources and their nonlinear heat-rates. Although some of the current plants can operate in multiple configurations, there are significant efficiency and maintenance impacts, and WECC doesn’t have sufficient information to model this. There is an expectation for more design options for CC plants in the future, including those that offer a wider operating range and increased durability.

• The 2020 TEPPC studies do not attempt to evaluate the intricacies of integrating large amounts of renewable resources within the hourly operating time frame. The variability of wind requires back-up capacity that can respond quickly. This is often quantified as a wind integration factor (the ratio of regulation per megawatt of wind capacity necessary to meet reliability requirements). For a system with 100 MW of installed wind capacity and an assumed wind integration factor of 20 percent, an additional 20 MW of regulation would be needed. This is not explicitly modeled in the studies.

• TEPPC is actively seeking a methodology to assess the cost of cycling base-load generation. Work to quantify the cost is ongoing throughout the industry and at least one
vendor has enhanced their dispatch algorithm to consider a cycling or ramping cost in its generator dispatch. The plot in Figure 94 that shows a one week snapshot of the Springerville coal plant generation illustrates the problem. The operation of the plant is not consistent with current practices.

Figure 94: Springerville Cycling example - PC1

The plot in Figure 95 shows a 10-day snapshot of the generation in the AZNMSNV sub-region. A cost penalty for excessive cycling would be a good improvement and could smooth out the base-load resources.

A comparison of the capacity factors for a sampling of coal plants is presented in Figure 96. Note that the intention of PC4 was to shift production from coal to gas as a way to reduce CO₂ emissions. In most of the other cases any reductions were due to displacement issues and transmission congestion.
• A WECC-wide system dispatch with a production cost model has some limitations related to the input assumptions and the optimistic solution. There is a considerable amount of data, and attempts to model the Western Interconnection in future years are difficult. The data and other modeling parameters are tested and validated in the following ways.
  
    ○ Path utilizations are compared to historical
o Generator operation is compared to expected behavior and historical dispatch patterns.
o Stakeholder feedback helps to tune input parameters
## Glossary

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>AESO</td>
<td>Alberta Electric System Operator</td>
</tr>
<tr>
<td>ATC</td>
<td>Available Transmission Capacity</td>
</tr>
<tr>
<td>AWEA</td>
<td>American Wind Energy Association</td>
</tr>
<tr>
<td>CAISO</td>
<td>California Independent System Operator</td>
</tr>
<tr>
<td>CCGP</td>
<td>Colorado Coordinated Planning Group, a subregional transmission planning area within WestConnect</td>
</tr>
<tr>
<td>CDEAC</td>
<td>Clean and Diversified Energy Advisory Committee</td>
</tr>
<tr>
<td>Dump Energy</td>
<td>PROMOD output: Excess generation output that does not serve any load, primarily caused by constraints that limit operational changes or prevent delivery to load.</td>
</tr>
<tr>
<td>ColumbiaGrid</td>
<td>A subregional transmission planning group within the Western Interconnection</td>
</tr>
<tr>
<td>Congestion Cost</td>
<td>Congestion costs arise when, in order to respect transmission constraints, some higher-cost generation is dispatched in favor of lower-cost generation that would otherwise be used (in the absence of the constraint). The cost of transmission congestion, assuming that demand is fixed and must be met, is the net cost of the replacement power that must be supplied by the higher-cost resources.</td>
</tr>
<tr>
<td>CSP</td>
<td>Concentrating solar power facilities</td>
</tr>
<tr>
<td>DOE</td>
<td>United States Department of Energy</td>
</tr>
<tr>
<td>DWG</td>
<td>Data Work Group of the Technical Advisory Subcommittee</td>
</tr>
<tr>
<td>EIA</td>
<td>Energy Information Agency</td>
</tr>
<tr>
<td>Emergency Energy</td>
<td>PROMOD output: Represents fictitious high-cost generation that is dispatched to satisfy load requirements when a load cannot be served by local generation and imports.</td>
</tr>
<tr>
<td>EPACT</td>
<td>Energy Policy Act of 2005</td>
</tr>
<tr>
<td>FERC</td>
<td>Federal Energy Regulatory Commission</td>
</tr>
<tr>
<td>HWG</td>
<td>Historical Analysis Work Group of the Technical Advisory Subcommittee</td>
</tr>
<tr>
<td>Heat Rate</td>
<td>The measure of the thermal efficiency of a generator’s ability to convert fuel to electrical energy. The heat rate is equal to the heat value of the fuel measured in BTU required to produce a kilowatt-hour of electrical energy.</td>
</tr>
<tr>
<td>HTC</td>
<td>Hydro-Thermal Co-optimization (see definition)</td>
</tr>
<tr>
<td>Hydro-Thermal Co-optimization (HTC)</td>
<td>A hydro modeling option developed by Ventyx for their PROMOD IV product to allow a designated portion of specified hydro resources to respond to price signals during the dispatch solution</td>
</tr>
<tr>
<td>LMP</td>
<td>Locational Marginal Price (see definition)</td>
</tr>
<tr>
<td>Locational Marginal Price</td>
<td>The cost to serve the next MW at a given bus.</td>
</tr>
<tr>
<td>NTTG</td>
<td>Northern Tier Transmission Group, a subregional transmission planning group within the Western Interconnection</td>
</tr>
<tr>
<td>NREL</td>
<td>National Renewable Energy Laboratory</td>
</tr>
<tr>
<td>Acronym</td>
<td>Description</td>
</tr>
<tr>
<td>-----------</td>
<td>-----------------------------------------------------------------------------</td>
</tr>
<tr>
<td>NWPPCC</td>
<td>Northwest Power and Conservation Council</td>
</tr>
<tr>
<td>OASIS</td>
<td>Open Access Same-time Information System</td>
</tr>
<tr>
<td>OATI</td>
<td>Open Access Technology International, Inc</td>
</tr>
<tr>
<td>PCC</td>
<td>Planning Coordination Committee of WECC</td>
</tr>
<tr>
<td>OTC</td>
<td>Operational Transfer Capacity, or Once Through Cooling</td>
</tr>
<tr>
<td>PCM</td>
<td>Production Cost Model</td>
</tr>
<tr>
<td>PLF</td>
<td>Proportional Load Following</td>
</tr>
<tr>
<td>Proportional Load Following</td>
<td>A hydro modeling methodology in which a portion of designated hydro plants follows load</td>
</tr>
<tr>
<td>Portable Data Format</td>
<td>A database structure using Microsoft Access to make the TEPPC datasets transportable between multiple production cost simulation programs, and available to all stakeholders</td>
</tr>
<tr>
<td>PV</td>
<td>Photo-voltaic solar electricity</td>
</tr>
<tr>
<td>RPS</td>
<td>Renewable Portfolio Standard</td>
</tr>
<tr>
<td>Saturated Capacity Index</td>
<td>A transmission congestion index for comparing congestion levels</td>
</tr>
<tr>
<td>SCI</td>
<td>Saturated Capacity Index</td>
</tr>
<tr>
<td>Shadow Price</td>
<td>Cost savings associated with increasing the flow capability (rating) on a constrained transmission facility (such as a line, transformer, etc.) by one MW</td>
</tr>
<tr>
<td>Sierra Planning Area</td>
<td>A subregional transmission planning area within WestConnect</td>
</tr>
<tr>
<td>SSG-WI</td>
<td>Seams Steering Group – Western Interconnection</td>
</tr>
<tr>
<td>Stranded Generation</td>
<td>Generation that would be used to serve load, but is undeliverable due to transmission constraints.</td>
</tr>
<tr>
<td>SWAT</td>
<td>Southwest Area Transmission, a subregional transmission planning area within WestConnect</td>
</tr>
<tr>
<td>SWG</td>
<td>Studies Work Group</td>
</tr>
<tr>
<td>TAS</td>
<td>Technical Advisory Subcommittee of TEPPC</td>
</tr>
<tr>
<td>TEPPC</td>
<td>Transmission Expansion Planning Policy Committee</td>
</tr>
</tbody>
</table>