Seventh Biennial Transmission Assessment (2012-2021) Staff Report

Docket No. E-00000D-11-0017.

October 30, 2012

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Foreword

- This report has been prepared on behalf of the Arizona Corporation Commission ("ACC" or "Commission"). It was prepared in accordance with a contract between KEMA, Inc. ("KEMA") and the Arizona Corporation Commission. It is considered a public document. Use of the report by other parties shall be at their own risk. Neither KEMA nor the Arizona Corporation Commission accepts any duty of care to such third parties.
- Arizona's Seventh Biennial Transmission Assessment ("BTA") is based upon ten-year plans filed with the Commission by parties in January 2012 and certain filings during 2011. It also incorporates information received through data requests, and comments provided by participants and attendees in the BTA workshops and report review process. The ACC Staff and KEMA are appreciative of the contributions, cooperation and support of industry participants throughout Arizona's Seventh Biennial Transmission Assessment process.
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Executive Summary

The Arizona Corporation Commission ("ACC" or "Commission") biennially reviews ten-year plans filed by parties intending to construct transmission facilities at 115 kV or above, and issues a written decision regarding the adequacy of the existing and planned transmission facilities to reliably meet the present and future needs of the state.[1] Staff of the Commission's Utilities Division ("Staff"), with the assistance of the consulting firm of KEMA, Inc. ("KEMA"), reviewed and analyzed the ten-year plans and related filings, issued data requests, conducted workshops for stakeholder input, and drafted this Seventh Biennial Transmission Assessment ("BTA") report. Neither Staff nor KEMA performed any technical studies during this process, but relied upon studies prepared and filed by other parties. Staff and KEMA used an open, transparent and collaborative process to obtain utility and stakeholder input, including two public workshops.[2]

Staff and KEMA reviewed all ten-year plans and filings submitted to Docket No. E-00000D-11-0017.[3] The filings included technical studies previously ordered by the Commission: Reliability Must Run ("RMR") studies, Ten Year Snapshot study, Extreme Contingency study, and reliability of transmission supply to certain local load pockets. Staff and KEMA also reviewed the impacts of transmission projects proposed by utilities to accommodate renewable energy export from Arizona. A copy of all presentations made at the workshops was subsequently posted on the Commission website. Preliminary and final drafts of this Seventh BTA report were prepared by KEMA and reviewed by Staff and were made available for industry and stakeholder comments. The collaborative local, sub regional, and regional transmission planning processes used by Arizona utilities and other stakeholders have yielded a significant number of relevant technical studies and other filings that were reviewed for this BTA.

This assessment is not intended to establish Commission policy. It also is not intended to assess individual transmission providers' plans except in the context of their aggregate impact on Arizona electric transmission system adequacy and reliability, as required by Arizona

[1] Arizona Revised Statute §40-360.02.

[2] Some information submitted by utilities was provided subject to confidentiality restrictions.

[3] Seventh BTA filings that were inadvertently filed under Docket No. E-00000D-09-0020 (the Sixth BTA) were also reviewed.

Revised Statute 40-360.02G (i.e., the aggregate ability to meet the present and future energy needs of the state). This BTA is not final unless and until approved by a written decision of the Commission.

Staff's assessment has addressed five fundamental issues during the course of this BTA:

- *Adequacy of the system to reliably serve local load* - Does the combination of the filed ten-year transmission plans meet the load serving needs of the state during the 2012-2021 timeframe in a reliable manner?
- *Efficacy of Commission ordered studies* - Do the study reports filed in response to Commission ordered RMR, Ten Year Snapshot and Extreme Contingency studies comply with, and sufficiently meet, the intended goals of the Commission's orders?
- *Adequacy of system to reliably support the wholesale market* - Do the transmission planning efforts effectively address concerns raised in previous BTAs about the adequacy of the state's transmission system to reliably support the competitive wholesale market in Arizona?
- *Adequacy of renewable transmission plans* - Do transmission providers' ten-year transmission expansion plans, including their renewable transmission project proposals, effectively address concerns raised in previous BTAs regarding adequately addressing the overall needs for renewable resource development and integration into the Arizona and regional electric power system (including export of such resources from Arizona to neighboring markets)?
- *Suitability of transmission planning processes utilized* - Do the plans and planning activities comport with transmission planning principles and good utility practices accepted by the power industry and the reliability planning standards established by the North American Electricity Reliability Corporation ("NERC"), Western Electricity Coordinating Council ("WECC"), and Federal Energy Regulatory Commission ("FERC")?

General Conclusions

Staff and KEMA reached the following key conclusions for the Seventh BTA:

1) As a result of current economic conditions, the statewide demand forecast for the 2012-2021 ten year planning period has shifted by about six years since the Sixth BTA (e.g., it will take about six years longer to reach the previous 2012 demand forecast level).

2) A total of 37 transmission projects have been delayed since the Sixth BTA, with an average delay of five to six years. In addition, six extra-high voltage ("EHV") transmission projects were cancelled. These delays and cancellations are consistent with the reduction in statewide demand forecast since the Sixth BTA and do not appear to threaten the adequacy of the system or its ability to reliably serve load. On the other hand, eight new transmission projects totaling 90 line miles at 115 kV and 230 kV are proposed as part of the utilities' ten-year plans filed in the Seventh BTA. No new lines are proposed in this BTA at either 345 kV or 500 kV.

3) A total of 23 parties (utilities and developers) made ten-year plan filings in the Seventh BTA. Some of these filings were made on behalf of several parties. All Commission required studies related to adequacy and reliability have been filed. The following conclusions apply to the efficacy and findings of the filed documents relative to the intent of the Commission ordered actions:

    a) The RMR studies for Phoenix, Tucson, Yuma, Santa Cruz County and Mohave County were all thorough and well documented. They project zero RMR costs in all areas except Tucson. However, RMR costs for Tucson are too small to justify any capital upgrades to the grid at this time. On whole, there appears to be minimal benefit to performing RMR analysis in BTAs for the next few years. This observation is consistent with RMR study results from recent BTAs.

    b) The "Ten Year Snapshot Study" (previously referred to as the "n-1-1 Study") was performed by SRP and coordinated through the Central Arizona Transmission System ("CATS") study group and represents a composite assessment of the 2021 statewide Arizona transmission system performance under normal (n-0), single-contingency (n-1) and certain overlapping (n-1-1) contingencies. The Extreme Contingency Study was performed by Arizona Public Service Company ("APS") and Tucson Electric Power ("TEP") and coordinated through CATS. The study examined more severe contingency scenarios such as complete transmission corridor outages or major transmission element outages at EHV substations. These studies demonstrate the ten-year plan is robust and should provide adequate and reliable service to Arizona.

c) The proposed transmission expansion plan identified in filings by the Cochise County Study Group ("CCSG") Participants was predicated upon a "continuity of service" definition that does not appear to be economically justified. Based on updated reliability information provided by the CCSG, Staff observes that the transmission system in Cochise County already meets NERC reliability standards and currently has a level of reliability that is comparable to other largely rural areas. Therefore, Staff concludes that the Commission should consider suspending implementation of the new continuity of service definition and retain the existing "restoration of service" planning paradigm for now.

d) Unisource Electric Inc.'s ("UNS Electric") previous plan to construct a new 345 kV or 138 kV line to the Santa Cruz County load pocket in order to reduce customer outage exposure does not appear to be economically justified at this time. UNS Electric will be filing an application with the Commission to remove the requirement to construct this second transmission line. Given the decrease in demand forecast for the area and other improvements being done by UNS Electric to the local transmission system and generating facilities, Staff concurs with this change in the ten-year plan.

e) The Southeast Arizona Transmission Study Group ("SATS") report filed by TEP confirms that potential 230 kV and 115 kV bus voltage deviations noted in the SATS area during the Sixth BTA have been mitigated by transmission plans filed in the Seventh BTA. As directed in the Sixth BTA decision, SWTC also filed a re-rating study for the Apache-Butterfield 230 kV line in the Seventh BTA which confirmed that this is a suitable approach to mitigating area loading limits noted in the Sixth BTA.

4) Arizona utilities have been extensively engaged in, and providing leadership to, Southwest Area Transmission ("SWAT") and WestConnect subregional planning processes and FERC Order 1000 ("Order 1000") compliance efforts. These utilities and other stakeholders have also participated and contributed valuable input during the Seventh BTA process.

5) Results of NERC reliability standards audits over the past two years as provided by the jurisdictional utilities in the Seventh BTA proceeding did not indicate any reliability standards concerns for the Arizona system.

6) Technical studies filed in the Seventh BTA indicate a generally robust study process for assessing transmission system performance (steady-state and transient) for the 2012-2021 planning period.

7) The 2011 filing by Arizona utilities in response to Commission Decision No. 72031 directing the utilities to jointly conduct or procure a study to identify the barriers to and solutions for enhancing Arizona's ability to export renewable energy is responsive to the Commission's order. Staff also observes that during the course of the export study, utilities engaged Arizona stakeholders in a successful process of seeking their input and ideas.

8) Developing Arizona's vast renewable resource potential and export opportunities requires a coordinated and multi-faceted strategy involving stakeholders representing utility, government, economic, developer, environmental, and other interests. In particular, seams issues[4] between Arizona and California pose challenges to major growth in renewable exports. In this regard Staff and KEMA note that Order 1000 encourages improved regional planning and cost sharing

[4] In this context seams issues include differences in the electric energy market models, scheduling and congestion management protocols, planning, licensing, ownership and operational control of transmission facilities that cross state boundaries, etc.

processes and we conclude that it would be beneficial for the Commission to monitor progress on seams issues that occurs as a result of Order 1000 implementation efforts in the WestConnect region.

9) Staff and KEMA find the 2011 renewable export study approach was reasonable and used a suitable approach and assumptions. Generally, the Renewable Transmission Projects ("RTP") improved exports to California by less than 500 MW. However, the potential need for transmission improvements west of the Colorado River was not thoroughly examined in the study. We believe that studying additional system operating scenarios (e.g., spring, summer, fall) and more detailed examination of transmission limits west of the Colorado River, would likely find smaller incremental export benefits than the values shown in the 2011 study report.

10) Differences between the findings of the 2011 Arizona study "Enhancing Arizona's Ability to Export Renewable Energy" and the California Transmission Planning Group's 2011 study on transmission expansion needs for renewable integration demonstrate that improved coordination is needed between transmission planning studies in the WestConnect/SWAT region and California in order to adequately assess the seams issues.

Recommendations

Based upon observations and conclusions discussed above, Staff submits the following recommendations for Commission consideration:

1) Staff recommends that the Commission continue to support the use of the:

   a) "Guiding Principles for ACC Staff Determination of Electric System Adequacy and Reliability" (See Appendix A);

   b) NERC reliability standards, WECC system performance criteria, and FERC enforcement policies relative to compliance with transmission planning reliability standards; and

   c) Collaborative transmission planning processes such as those that currently exist in Arizona and which help to facilitate competitive wholesale markets and broad stakeholder participation in grid expansion plans.

2) Staff recommends that the Commission continue to support the policy that generation interconnections should be granted a Certificate of Environmental Compatibility ("CEC") only when they meet regional and national reliability standards and the applicable Commission requirements.[5]

3) Staff recommends that the Commission continue to require the jurisdictional utilities to report relevant findings in future BTAs regarding compliance with transmission planning standards (TPL-001 through TPL-004) from NERC/WECC reliability audits that have been finalized and filed with FERC.

4) Staff recommends that the Commission suspend efforts to upgrade reliability to a *continuity of service* definition for Cochise County and Santa Cruz County due to the high cost of capital upgrades and of new transmission construction that would be needed to achieve such a level of reliability and the low customer density in these service areas, and suspend its directive from the Sixth BTA for filing two more CCSG

[5] See Appendix A – Guiding Principles for Determination of System Adequacy and Reliability.

progress reports in 2012. In addition, Staff recommends that the CCSG participants and UNS Electric continue to monitor the reliability in Cochise and Santa Cruz Counties, respectively, and propose any modifications that they deem to be appropriate in future ten-year plans. Staff also recommends that the Commission continue to collect applicable outage data from the respective utilities in order to monitor any changes in Cochise County and Santa Cruz County system reliability in future BTA proceedings.

5) Staff recommends that the Commission continue to require the jurisdictional utilities to include planned transmission reconductor projects, transformer capacity upgrade projects and reactive power compensation facility additions at 115 kV and above in future 10-year plan filings.

6) Staff recommends that the Commission accept the results of the following Commission ordered studies provided as part of the Seventh BTA filings:

   a) "Extreme Contingency" outage study for Arizona's major transmission corridors and substations, and the associated risks and consequences of such overlapping contingencies.

   b) Ten-Year Snapshot study results documenting the performance of Arizona's statewide transmission system in 2021 for a comprehensive set of n-1 contingencies, each tested with the absence of different major planned transmission projects.

   c) RMR studies for Phoenix, Tucson, Yuma, Mohave County and Santa Cruz County.

   d) The report, *Enhancing Arizona's Ability to Export Renewable Energy*, that addressed the Commission's study requirement as directed in the Sixth BTA.

7) Staff recommends the Commission suspend the requirement for performing RMR studies in every BTA and implement criteria for restarting such studies based on a biennial review of factors such as:

- An increase of more than 2.5% in an RMR pocket load forecast since the previous BTA (e.g., relative to the load forecast for an RMR pocket for the final RMR study year for which RMR studies were last filed)[6].
- Planned retirement (or an expected long-term outage during the summer months of June, July or August) of a transmission or substation facility required to serve an RMR load pocket, unless a facility being retired will be replaced with a comparable facility before the next summer season.
- Planned retirement (or an expected long-term outage during the summer months of June, July or August) of a generating unit in an RMR load pocket that has been utilized in the past for RMR purposes, unless a generator being retired will be replaced with a comparable unit before the next summer season.
- A significant customer outage in an RMR load pocket during summer months, defined as a sustained outage of more than one hour that exceeds the greater of 100 MW or 10% of the peak demand in an RMR pocket.

8) Staff recommends that the Commission issue an order that directs Arizona utilities to advise each interconnection applicant of the need to contact the Commission for appropriate ACC filing requirements at the time the applicant files for interconnection.

[6] For example, the final RMR study year filed in the Seventh BTA is 2021 and future BTA load forecasts for 2021 would be compared to the Seventh BTA forecast amount for this year to determine the percent increase. Using the data for the Phoenix RMR area, the peak demand forecast for 2021 is currently 14,209 MW so the need for restarting RMR analysis would be considered if and when a revised 2021 forecast exceeds 14,209 x 1.025 = 14,564 MW.

1 Overview

1.1 Assessment Authority

Arizona statutes require every entity considering construction of any transmission line equal to or greater than 115 kV within Arizona during the next ten year period to file a ten-year plan with the Arizona Corporation Commission ("ACC" or "Commission") on or before January 31 of each year.[7] Every entity considering construction of a new power plant of 100 Megawatts ("MW") or greater within Arizona is required to file a plan with the Commission at least 90 days before filing an application for a Certificate of Environmental Compatibility ("CEC").[8] All such plans filed with the Commission must include power flow and stability analysis reports showing the effect of the planned facilities on the current and future Arizona electric transmission system.[9] The Commission is required to biennially examine the plans and "issue a written decision regarding the adequacy of the existing and planned transmission facilities in Arizona to meet the present and future energy needs of the state in a reliable manner".[10]

1.2 Seventh Biennial Assessment – Purpose and Framework

The purpose of this report is to inform the Commission of currently planned transmission facilities and offer an assessment of the adequacy of the existing and planned Arizona electrical transmission system. This Seventh Biennial Transmission Assessment ("Seventh BTA") evaluates the ten-year transmission plans filed with the Commission in Docket No. E-00000D-11-0017. This report fulfills the statutory obligation to review these transmission plans and assess whether the Arizona transmission system is and will remain adequate throughout the ten-year timeframe.

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[7] Arizona Revised Statute § 40-360.02.A.

[8] Arizona Revised Statute § 40-360.02.B.

[9] Arizona Revised Statute § 40-360.02.C.7.

[10] Arizona Revised Statute § 40-360.02.G.

The Commission ordered that supplemental study work also be performed by the industry as a portion of this Seventh BTA.[11] These include RMR, Ten Year Snapshot and extreme contingency studies, as required in prior BTAs. The Commission also required an assessment of transmission capacity available or required for renewable energy development in Arizona, as well as the determination of the top three transmission projects for renewables by each Arizona utility. This report examines the transmission plans filed by the industry to address these topics as well as other Commission ordered studies.[12]

In the Arizona BTA process, entities conduct their own technical studies or engage in joint studies, participate in collaborative and open regional planning processes, and present the study results in their ten-year plan reports and at public workshops. Commission Staff ("Staff") participates in a number of these collaborative processes and relies on the technical reports and documents filed with the Commission and other publicly available industry reports, rather than performing independent technical study work. Staff continue to use a set of guiding principles in determining the adequacy and reliability of both transmission and generation systems.[13] Staff's guiding principles are based upon best engineering/planning practices established in Arizona coupled with the use of WECC planning principles, and are also intended to be consistent with applicable North American Electricity Reliability Corporation ("NERC") reliability standards (e.g., TPL-001 through TPL-004)[14], and FERC orders.

Staff retained KEMA, Inc. ("KEMA") to assist them with this Seventh BTA. Staff and KEMA critically reviewed and analyzed the filed transmission planning reports and ten-year plans and addressed the following five fundamental issues:

1) *Adequacy of the system to reliably serve local load* - Does the combination of the filed ten-year transmission system plans meet the load-serving requirements of the state during the 2012-2021 timeframe in a reliable manner?

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[11] Decision No. 70635, Docket No. E-00000D-07-0376.

[12] History of Commission Ordered Studies, Appendix B.

[13] Guiding Principles for ACC Staff Determination of Electric System Adequacy and Reliability: Appendix A - Arizona's Best Engineering Practices, Jerry D. Smith, ACC, pre-filed comments for the Gila Bend Power Plant Hearing, Docket No. E-00000V-00-0106, November 9, 2000.

[14] NERC Reliability Standards, Transmission Planning (TPL) at http://www.nerc.com/page.php?cid=2|20.

2) *Efficacy of Commission ordered studies* - Do the study reports filed in response to Commission ordered Reliability Must Run, Ten Year Snapshot and Extreme Contingency studies comply with, and sufficiently meet, the intended goals of the Commission's orders?

3) *Adequacy of system to reliably support the wholesale market* - Were steps taken in the most recent transmission planning studies to effectively address concerns raised in previous BTAs about the adequacy of the state's transmission system to reliably support the competitive wholesale market in Arizona?

4) *Adequacy of renewable transmission plans* - Do transmission providers' ten-year expansion plans, including their renewable transmission project proposals, adequately support the overall needs for renewable resource development and integration into the Arizona and regional electric power system (including export of such resources from Arizona to neighboring markets)?

5) *Suitability of transmission planning processes utilized* - Do the plans and planning activities utilized comport with transmission planning principles and good utility practices accepted by the power industry and the reliability planning standards established by the WECC, NERC and FERC?

1.3 Assessment Process

A three-stage approach was used to prepare this BTA report. The first stage consisted of a workshop which offered participants the opportunity to make presentations supplementing their ten-year plan filings. During the second stage, Staff and KEMA prepared and distributed the first draft report for public comment. The next stage of the process consisted of a second workshop for Staff and KEMA to present their draft findings and facilitate discussion of the draft of the report. A revised, final draft report was prepared and distributed following the second workshop. A summary of each stage of the BTA process is described in the following sections.

1.3.1 Workshop I: Industry Presentations

KEMA assisted Staff in arranging and facilitating a public stakeholder workshop on July 10, 2012 in Phoenix, Arizona. A complete listing of the Workshop I attendees and presenters is in Appendix E. Utilities and Subregional Planning Groups presented information regarding their respective transmission expansion plans and related planning activities. Several merchant transmission and generation developers reported on their respective development plans. The workshop provided an informal setting to promote effective discussion of each presentation.[15] Each presentation was followed by an open period of discussion including questions and comments from the audience. KEMA concluded the session with general comments and discussion of the schedule for completing the Seventh BTA.

1.3.2 Review of Industry Filings in Seventh BTA

In preparation for Workshop I, Staff and KEMA reviewed all of the filings that had been made to date by parties in the Seventh BTA.

Table 1 shows a matrix of the various categories of ten-year planning information filed by utilities during the Seventh BTA. A complete list of entities that made ten-year plan filings in this BTA is shown in Table 2.

[15] The Workshop I agenda and presentation materials are located at http://www.cc.state.az.us/divisions/utilities/electric/Biennial.asp.

Table 1 - Matrix of Utility Filings in Seventh BTA

Utility	Ten-Year Plan	2012-2021 Utility Technical Study Report	RMR Study Report	Planning Criteria & Ratings	Filings of Joint Study Report(s)
APS	X	X	*(Phoenix & Yuma Areas)*	X	Extreme Contingency Study[16]
SRP	X	X	*(Participated in APS's Phoenix area study)*	X	10 Year Snapshot Study[17]
SSEVC	X[18]				
SWTC	X	X		X	Cochise County Report[19]
TEP	X	X	*(Tucson Area)*	X	SATS[20]
UNS Electric	X	X	*(Santa Cruz County and Mohave County)*	X	Santa Cruz County Report and Mohave County Report

The combination of individual studies and joint studies listed in Table 1 provides the main basis upon which Staff has assessed adequacy of the 2012-2021 ten-year plan(s). Although individual technical studies were not filed in this BTA by Western Area Power Administration ("Western") and some smaller utilities, Staff concludes that, by and large, their transmission plans were modeled and analyzed as part of the joint studies that were filed.

Arizona Revised Statute § 40-360.02 (C) (7) requires that: "The plans for any new facilities shall include a power flow and stability analysis report showing the effect on the current Arizona electric transmission system. Transmission owners shall provide the technical reports, analysis or basis for projects that are included for serving customer load growth in their service

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[16] Performed by APS and TEP and coordinated through CATS study group.

[17] Ten-Year Snapshot Study (2021 system) filed on behalf of the study participants including SRP, APS, WESTERN, SWTC, ED 3 and SunZia.

[18] SSVEC's filing is limited to comments on the Cochise County Report.

[19] Filed on behalf of all study participants including SWTC, APS, TEP, WESTERN, SSVEC, et al.

[20] Southeast Arizona Transmission System 2010 Study Report filed on behalf of SWTC, TEP/UNS Electric, WESTERN, APS, et al filed in January 2011.

territories." Staff anticipates that technical analysis of this type, including both power flow and stability, will be included in the technical reports filed by utilities in the BTA. While power flow analysis is expected for the full 10-year period, stability analysis for the initial five years of the plan should generally suffice for the BTA process.

As indicated in Table 1 technical studies are augmented by other relevant information, including the internal transmission planning criteria and system ratings of the utilities as required by Commission Decision No. 63876 (July 25, 2001). Such documents provide useful reference material for use by Staff.

1.3.3 Preparation of Draft Report, Workshop II and Industry Comment

Staff and KEMA provided an initial draft of the 2012 BTA Staff report for utility and stakeholder review and comment in advance of Workshop II. The draft report was based on the docketed ten-year plans and information gathered at Workshop I. A second stakeholder workshop in the Seventh BTA was held on August 16, 2012, and was again facilitated by KEMA. At Workshop II the SWAT provided additional reports on important subregional study group activities and Western provided an update for the TransWest Express Project. Informative presentations were also provided by WECC's Transmission Planning Director Brad Nickell, as well as the Western Interstate Energy Board, the Regulatory Assistance Project and the California Transmission Planning Group. Copies of all workshop presentations were subsequently posted on the Commission web site.[21] The draft Staff report was presented by KEMA and stakeholder questions and oral feedback were received at Workshop II. Staff and KEMA invited stakeholders to also submit written comments on the draft report and to consider docketing these comments which allows for other parties' review, comment and response.   Staff and KEMA advised that a revised draft Staff report reflecting these inputs would subsequently be

[21] See http://www.azcc.gov/Divisions/Utilities/Electric/BTA-Index.ASP.

issued to stakeholders for review and comment, and this next round of comments was reflected in the final report.

2 Summary of Ten-Year Plans

Table 2 provides a list of entities that filed ten-year transmission plans with the Commission during 2011- 2012. The Seventh BTA assessment examines the aggregate ten-year plan.

Table 2 - Parties that Filed Ten-Year Plans in Seventh BTA

Ajo Improvement Company*	Public Service Company of New Mexico
Arizona Public Service Company	Salt River Project
Boquillas Wind, LLC	Sempra Generation
Bowie Power Station, LLC	SolarReserve, LLC
BP Wind Energy North America	Southern California Edison
Clean Line Energy Partners	Southwest Transmission Cooperative
El Paso Electric Company	Sulphur Springs Valley Electric Cooperative
EnviroMission*	SunZia Southwest Transmission Project
Foresight Flying M¸ LLC	Tucson Electric Power
Gila Bend Power Partners, LLC*	UNS Electric, Inc. (“UNSE”)
Hualapai Valley Solar, LLC	Welton-Mohawk Irrigation & Drainage District (“WMIID”)
Perrin Ranch Wind, LLC	

***Filed in Docket No. E-00000D-09-0020.

Utilities in the United States are required by FERC to plan, design and operate their bulk transmission systems in accordance with the NERC Reliability Standards. Furthermore, the utilities observe guidelines established at the state level, and their own internal planning criteria, guidelines, and methods. These planning practices are utilized to ensure that the WECC interconnection and individual member systems are planned for reliable service to customers under various system conditions and that plans are coordinated through a consistent set of standards, criteria, and guidelines. In Decision No. 72031, the Commission directed the jurisdictional utilities to “report relevant findings in future BTAs regarding compliance with transmission planning standards…from NERC/WECC reliability audits that have been finalized and filed with FERC.” Table 3 summarizes the related information filed in the Seventh BTA.

Table 3 - NERC/WECC Reliability Compliance Audit Status[22]

Utility	Reliability Audit Finalized and Filed with FERC Since Sixth BTA	Comments Related to Transmission Planning Standards
APS	No	Next audit is scheduled in 2013
TEP/UNS Electric	Yes	Received a report of "no findings"
SWTC	No	Next audit is scheduled in 2012

Based on the results of NERC/WECC reliability standards audits over the past two years, as provided by the jurisdictional utilities in the Seventh BTA proceeding, there were no planning standards compliance concerns identified in Arizona's bulk electric system.

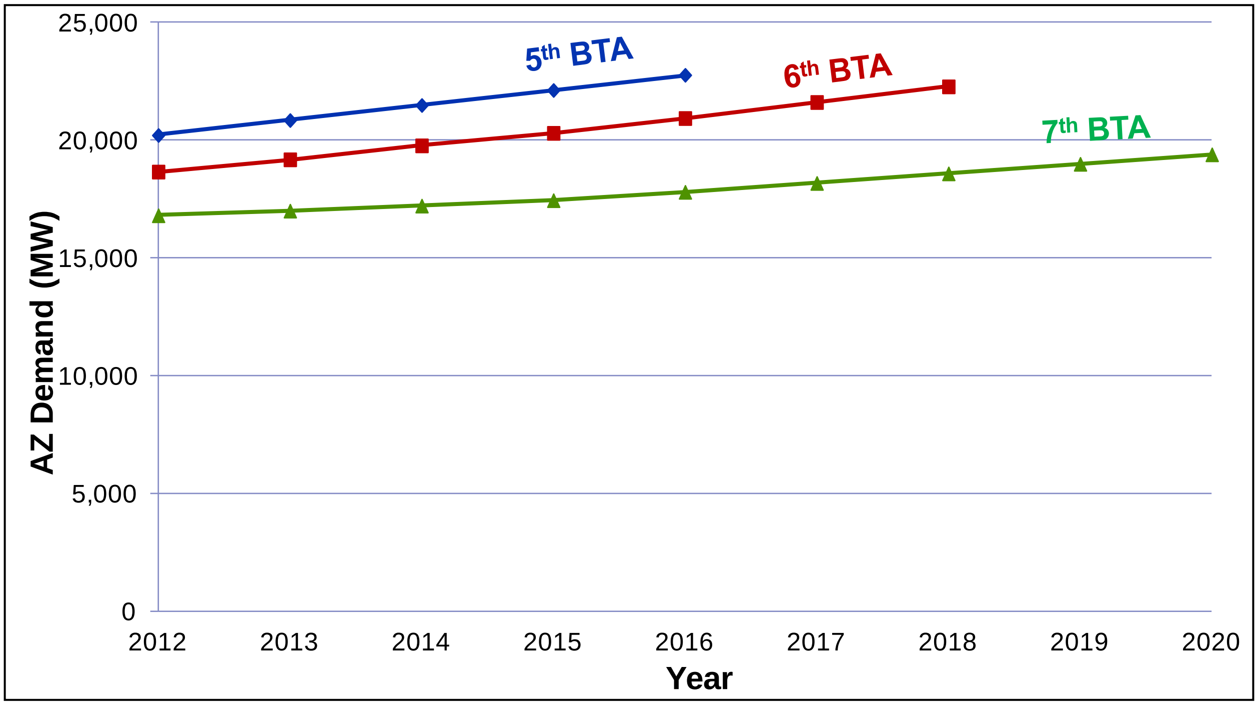
2.1 Summary of Arizona Plan

The BTA examines the aggregation of all of the docketed projects as a coordinated transmission system expansion plan for Arizona from a system perspective, without regard to sponsorship or ownership. Projects that have not been filed are not included in this adequacy analysis for the BTA, but may still be depicted along with all other projects in the maps provided in Exhibits 1-6.

The principal driver for transmission plans filed by the utilities in the Seventh BTA is load growth and reliability of supply to customers (e.g., "reliability-driven" projects). The need for and timing of reliability projects is driven primarily by the demand forecast. Figure 1 shows the change in the statewide demand forecast since the Fifth and Sixth BTAs as a result of current economic conditions.

[22] While SRP is not a jurisdictional utility, it provided information in its Ten Year Plan filing that no applicable audit results have occurred since the Sixth BTA.

Figure 1: Change in Arizona Demand Forecast



As shown in Figure 1, the statewide demand forecast has shifted by about six years since the Sixth BTA (for detailed forecast data see Exhibit 8). This is two years longer than the shift that was observed between the Fifth BTA and Sixth BTA, and is indicative of the continuing impact of the national economic recession on electrical demand. All other factors being equal, this suggests that many planned reliability-driven transmission projects in Arizona could be delayed about six years from the in-service dates shown in the Sixth BTA ten-year plans.

In Decision No. 72031, the Commission directed jurisdictional utilities to "include the effects of distributed renewable generation and energy efficiency programs on future transmission expansion needs in future ten-year plan filings." The filed ten-year plans of APS, SRP, TEP/UNS Electric and SWTC in the Seventh BTA state that these factors were taken into account in developing the demand forecasts used in studies performed for the current ten-year plan(s). At Workshop I, Staff and KEMA pointed out the decrease in the individual utility load forecasts from 2010 to 2012 and asked utilities if this is due to the effects of distributed generation ("DG") and energy efficiency ("EE"). The utilities responded that DG and EE were taken into account in developing both sets of demand forecasts, and that the main factor behind the drop in the forecast from 2010 to 2012 is the impact of the continuing economic recession.

A complete list of the individual projects identified by utilities in their Seventh BTA ten-year plan(s) is shown in Exhibit 7. Projects with identifiers that begin with the letter "A" or "B" were filed in previous 10-year plans. Projects with identifiers beginning with "C" are newly filed projects in the Seventh BTA. Exhibits 11 and 12 sort the full list of projects in the Seventh BTA by in-service date and voltage class, respectively. Lists of projects by individual utility are shown in Exhibits 13 through 17.

The Commission's Guiding Principles for Determination of System Adequacy and Reliability state that the ACC is obligated "to biennially make a determination of the adequacy and reliability of existing and planned transmission facilities in the state of Arizona."[23] In Decision No. 72031, the Commission determined that plans to reconductor existing transmission lines, upgrade bulk power transformer capacity, and expand reactive power compensation to support transmission capacity upgrades should also be filed in the BTA so that the Commission can perform a more comprehensive assessment of transmission adequacy and reliability in the ten-year plan. The projects filed in the Seventh BTA include planned transmission lines at 115 kV and higher, including major reconfigurations (e.g., loop-ins) and upgrades from a lower design voltage to a higher design voltage (e.g., 115 kV to 138 kV), reconductoring of existing transmission lines, bulk power substation transformer bank replacements, and reactive power compensation facility additions at 115 kV and above.

Under the FERC's regulations, generation developers seeking to interconnect to a transmission provider's system must file an interconnection application.[24] The rules and procedures for such applications are defined in the respective utility's Open Access Transmission Tariff ("OATT"). As part of the BTA process, Arizona utilities provide an updated summary of their generation interconnection queue(s) as found in Exhibit 10. In parallel with the FERC's interconnection process, any party contemplating construction of transmission in Arizona (including generator tie

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[23] From paragraph 2 of the Guiding Principles (see Appendix A to this report).

[24] Generators over 20 MW are interconnected pursuant to a Large Generator Interconnection Agreement; generators 20 MW or less are interconnected pursuant to a Small Generator Interconnection Agreement.

lines) are subject to Arizona Revised Statute § 40-360.02.A which requires the filing of a ten year plan with the Commission. Table 4 provides a high level comparison of generation capacity reflected in the utilities' 2012 generator interconnection queues vs. the ten-year plan filings by generation developers per ARS § 40-360.02.A.

Table 4 - Summary of Filed Generator Interconnection Projects

Utility	Approximate Capacity (MW) of Generators	
	***In Utility Queues*[25]**	***Filed 10-Year Plans in Seventh BTA***
APS	8,329	540
SRP	4,424	833[26]
TEP/UNS Electric	1,400	500
Western[27]	n/a	1,200
Total	14,153	3,073

As shown in Table 4, less than 25 percent of the generator capacity in the current utility interconnection queues (at or above 115 kV) are reported in filed transmission plans in the Seventh BTA. The cause of this large gap in generator ten-year plan filings vs. interconnection queues is unclear but may be due to a number of factors such as developers' lack of knowledge of the Commission's BTA filing requirements, competitive concerns on the part of developers, the possibility of multiple interconnection requests in utility queues as a result of a given developer considering different interconnection options, etc.

Another factor may be renewable developers who incorrectly believe they are exempt from the BTA filing requirements. While large scale wind and photovoltaic generating projects are exempt from the Commission's power plant Certificate of Environmental Compatibility ("CEC")

[25] Only includes projects seeking to interconnect at 115 kV or above.
[26] Excludes Hualapi Valley Solar project (340 MW) as SRP advises the application has been withdrawn.
[27] Western does not file in the BTA, but generator developers seeking to interconnect with Western's system in Arizona are subject to the applicable filing requirements of ARS § 40-360.02.A.

filing requirements, any transmission (gen-tie) lines of 115 kV or greater for such plants are subject to the Commission's filing requirements as shown in Table 5.

Table 5 - Commission's Gen-tie and Power Plant Filing Requirements

Type of Project	**Plant Size (MW)**	**Transmission/Gen-tie Filing Requirements** *(115 kV and above)*[28]		**New Power Plants**
		Ten Year Plan[29]	***CEC***	***90-Day Plan Filing Requirement***
Thermal electric, nuclear, hydro, solar thermal, geothermal	≥100	Subject to ARS § 40-360.02.A	Both plant and gen-tie are subject to respective CEC filing requirements	Plant developers must file a plan with the ACC 90 days prior to filing a CEC application
Photovoltaic, wind	All sizes	Subject to ARS § 40-360.02.A	Only gen-ties are subject to CEC filing requirements	Does not apply

Even though some new generator projects build on existing generating plant sites and may interconnect directly into existing transmission stations without constructing any new transmission, it's unlikely that this factor alone would account for the large gap noted in Table 4. In order to ensure that power plant and transmission line developers are alerted to the various filing requirements and comply with those filing requirements, Staff concludes that it would be beneficial for the Commission to direct Arizona utilities to advise each interconnection applicant

[28] Generating projects that interconnect below 115 kV, or connect directly into a utility's system without constructing transmission, are exempt from these filing requirements.

[29] Arizona Revised Statute § 40-360.02.A requires that: "Every person contemplating construction of any transmission line within the state during any ten year period shall file a ten year plan with the commission on or before January 31 of each year."

of the need to contact the Commission for appropriate ACC filing requirements at the time the applicant files for interconnection.

2.2 Plan Changes since the Sixth BTA

Transmission plans inevitably evolve over time and are often in a state of flux. Significant changes can occur as a result of regulatory actions, state and federal policy developments, siting and permitting challenges, shifts in load forecasts, identification of new generating plants, third-party interconnection and delivery requests, and changes in the economic or financial climate faced by a project sponsor. A combined list of changes for all voltage levels 115 kV and above that have been filed since the Sixth BTA is provided in Exhibit 9. For ease of reference a list of changes that have occurred at only Extra High Voltage ("EHV") levels of 345 kV and above are provided in Table 6.

Table 6 - Significant EHV Project Changes since Sixth BTA

In-Service Date	Project	Voltage Class (kV)	Description of Change
2010	White Hills substation	345/69	Removed from UNS Electric 10-year plan
2010	Morgan-Pinnacle Peak 500 KV line	500	Completed
2012	McKinley 345kV Reactor Addition	345	New Project - 2012
2012	Youngs Canyon 345/69 kV Interconnection: at Western's Flagstaff 345kV bus	345	Changed project Name
2012	Vail 345/138kV Transformer #3	345/138	Reporting new transformers was not previously required.
2013	Series Capacitor Replacement at Vail 345kV Substation on the Springerville – Vail 345kV Line	345	New Project - 2013
2013	Delaney – Palo Verde 500kV line	500	Changed In-Service date from 2012 to 2013
2014	Pinal Central-Tortolita 500 kV line	500	Changed project Status from "Not Yet Filed" to "Filed April 2012" to "Approved July 2012"
2014	Pinal West-Pinal Central – Randolph - Abel-Browning 500 kV line	500	Removed SWTC from Participants List

In-Service Date	Project	Voltage Class (kV)	Description of Change
2015	Mazatzal Loop-in of Cholla-Pinnacle Peak 345 kV line	345	Changed In-Service date from 2013 to 2015
2015	Series Capacitor Replacement at Vail 345kV Substation on the Winchester – Vail 345kV Line	345	New Project - 2015
2015	Bicknell 345/230 kV Transformer Replacement	345/230	New Project - 2015
2015	Greenlee 2nd 345/230 kV Transformer	345/230	New Project - 2015
2015	Delaney-Sun Valley 500 kV line	500	Changed In-Service date from 2014 to 2015
2015	Palo Verde Hub-North Gila 500 kV #2 line	500	Removed SRP from Participants List
2016	Interconnection of Greenlee-Winchester 345kV line with future Willow Substation	345	Changed In-Service date from TBD to 2016
2016	SunZia Project	500	Changed In-Service date from 2013 to 2016
2017	Series Capacitor Replacement at Greenlee 345kV Substation on the Springerville – Greenlee 345kV Line	345	New Project - 2017
TBD	Future Gateway-Comision Federale de Electricidad 345 kV line	345	Removed from TEP 10-year plan
TBD	Interconnection line -South-future Gateway 345 kV line	345	Removed from TEP, UNS Electric 10-year plan
TBD	Springerville-Greenlee 345 kV line - 2nd circuit	345	Changed project Status from "Not Yet Filed" to "Approved"
TBD	Tortolita North Loop 345 kV line	345	Removed from TEP 10-year plan
TBD	Winchester-Vail 345 kV line #2 and #3	345	Removed from TEP 10-year plan
TBD	Gateway 345/115 kV or 345/138 kV substations	345/138	Removed from UNS Electric 10-year plan
TBD	RS26-Fountain Hill substation	345/230/ 115	Changed In-Service date from 2014 to TBD
TBD	Northeast Arizona to Phoenix 500kV	500	Changed project Name
TBD	Pinal Central – Abel #2 500kV line	500	Changed In-Service date from 2020 to TBD

Table 6 shows that 6 EHV projects were cancelled since the Sixth BTA. Table 7 shows the number of transmission projects delayed (or advanced) since the Sixth BTA by voltage level.

Table 7 - Summary of Transmission Lines In-Service Date since Sixth BTA

Voltage Class (kV)	Delayed 1 Year	Delayed 2 Years	Delayed 3 Years	Delayed 4 Years	Delayed 5 Years or more	Delay TBD	In-Service Date from TBD to Set Date
500	2	0	1	0	0	1	0
345	0	1	0	0	0	1	1
230	3	0	2	0	1	0	1
138	1	9	2	4	1	0	0
115	0	1	1	1	0	5	0
Total	6	11	6	5	2	7	2

Table 7 indicates that 37 projects from the Sixth BTA ten-year plan have had a delay in planned in-service dates in the Seventh BTA. In Staff's opinion, these statistics on changes to the planned ten-year transmission plan since the Sixth BTA are consistent with the reduced demand forecast shown in Figure 1.

Some projects or proposed substations have undergone a name change in recent filings as shown in Table 8.

Table 8 - Project Name Changes or Aliases

Current Name	Formerly Known As
Abel	RS22 / Southeast Valley ("SEV")
Ball	RS17
Browning	RS18
Delaney	Delany
Dinosaur	RS19
Morgan	TS9
Pfister	RS-24
Schrader	RS16

3 Plan for Enhancing Arizona Renewable Exports

The Commission's decision in the Sixth BTA (2010)[30] addressed the ability of the Arizona transmission system to export renewable energy to neighboring states by directing the jurisdictional utilities to jointly conduct or procure a study to identify the barriers to and solutions for enhancing Arizona's ability to export renewable energy. The study was to identify specific transmission corridors that should be built to accomplish this objective. The utilities were also to conduct stakeholder workshops in conjunction with the study.

The study and results were filed as required at the Commission by November 1, 2011, and included as part of the 2012 BTA proceeding.[31] This section of the Seventh BTA report summarizes Staff and KEMA's findings in this regard.

In a separate filing APS provided an update of its Renewable Transmission Action Plan ("RTAP") in compliance with Commission Decision No. 72057.[32] In this latest filing APS did not propose any new renewable transmission projects ("RTP") beyond those filed in the Sixth BTA, but stated that "As the development of large renewable energy projects evolves, APS will explore new renewable transmission opportunities."

3.1 Utilities Engage Consultant for Study

The Arizona utilities engaged PDS Consulting, LLC ("PDS") to prepare their report, *Enhancing Arizona's Ability to Export Renewable Energy*, to address the Commission's study requirement as directed in the Sixth BTA. The utilities included APS, SRP, SWTC, TEP, and UNS Electric.

The report is presented in five sections:

1) Summaries of the Commission Order and the participating Arizona Utilities;
2) Overview and summary of State and regional renewable energy requirements and assessments, and prior evaluations of Arizona's renewable energy resources and related transmission projects;

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[30] Commission Decision No. 72031, 10 December 2010.

[31] *Enhancing Arizona's Ability to Export Renewable Energy, A Report to Address the Arizona Corporation Commission's Sixth Biennial Transmission Assessment, Commission Decision 72031*, PDS Consulting, PLC, October 2011 (http://images.edocket.azcc.gov/docketpdf/0000130865.pdf).

[32] See Docket No. E-00000D-11-0017, APS Ten-Year Transmission System Plan, Attachment C, filed 31 January 2012.

3) Evaluating the existing transmission system and the incremental impact of renewable RTP, and identifying transmission corridors that enhance export capability;
4) Describing stakeholder input, including identifying barriers to and solutions for enhancing Arizona's ability to export renewable energy; and
5) Current status of the export market environment.

3.2 Study Approach

The renewable energy standards and renewable portfolio standards of Arizona and the adjacent states were reviewed to identify the potential export markets. The existing and potential renewable capabilities of each state were also reviewed to determine how much renewable generation might be developed within each state.

Various other regional studies and reports were also reviewed to identify regions within each state that would likely see renewable generation developed. These included:

- Western Renewable Energy Zone ("WREZ"), Phase 1 Report, for the Western Governors' Association ("WGA") and DOE;
- Arizona Renewable Energy Assessment by Black and Veatch;
- Arizona Renewable Resource and Transmission Identification Subcommittee ("ARRTIS") work;
- Renewable Transmission Task Force ("RTTF") work; and
- Arizona Utilities' Renewable Transmission Projects ("RTP"s).

The focus of the review was Arizona and the adjacent states—New Mexico, Colorado, Utah, Nevada and California. The renewable generation requirements for each state were compared with the renewable generation potential. The most likely states for Arizona renewable energy exports were those states where the requirements were much larger than the potential.

Transmission studies made by the Arizona utilities and various regional bodies were reviewed to identify transmission facilities needed for renewable generation. This information was used to build a map of potential transmission projects that would facilitate renewable generation deliverability.

The most likely geographic locations for renewable generation within Arizona were identified. The approach evaluated renewable generation from Arizona renewable generation injection zones for delivery to the likely states.

A power flow computer model was used to evaluate Arizona - and the surrounding WECC – transmission system under n-0 and n-1 conditions to determine the benefit of various transmission projects on renewable generation export capability. Various combinations of generation injection and adjacent-state delivery points were evaluated.

The study had a number of important assumptions including:

- Only one load-level and condition was studied—SWAT 2014 Heavy Summer Base case;
- California was identified as the only likely state with a potentially significant need for additional renewable generation exports from Arizona;
- Therefore, the analysis only evaluated the impact on flows on the East-of-the Colorado River ("EOR") transmission facilities (e.g., WECC Path 49);
- Facilities needed west of Path 49 (outside of Arizona) were not studied;
- The assessment did not address contractual arrangements;
- Only utility-proposed Renewable Transmission Projects were evaluated;
- The RTP projects were analyzed together as a whole (not individually); and
- Renewable generation injections were analyzed at individual buses only (not simultaneously).

As part of the process, the Arizona utilities began the stakeholder involvement process with a small focus group of stakeholders representing renewable energy and transmission developers. This group helped develop a preliminary list of barriers to and potential solutions for enhancing Arizona's ability to export renewable energy. This laid the foundation for discussion and further evaluation by a larger stakeholder group in a workshop process.

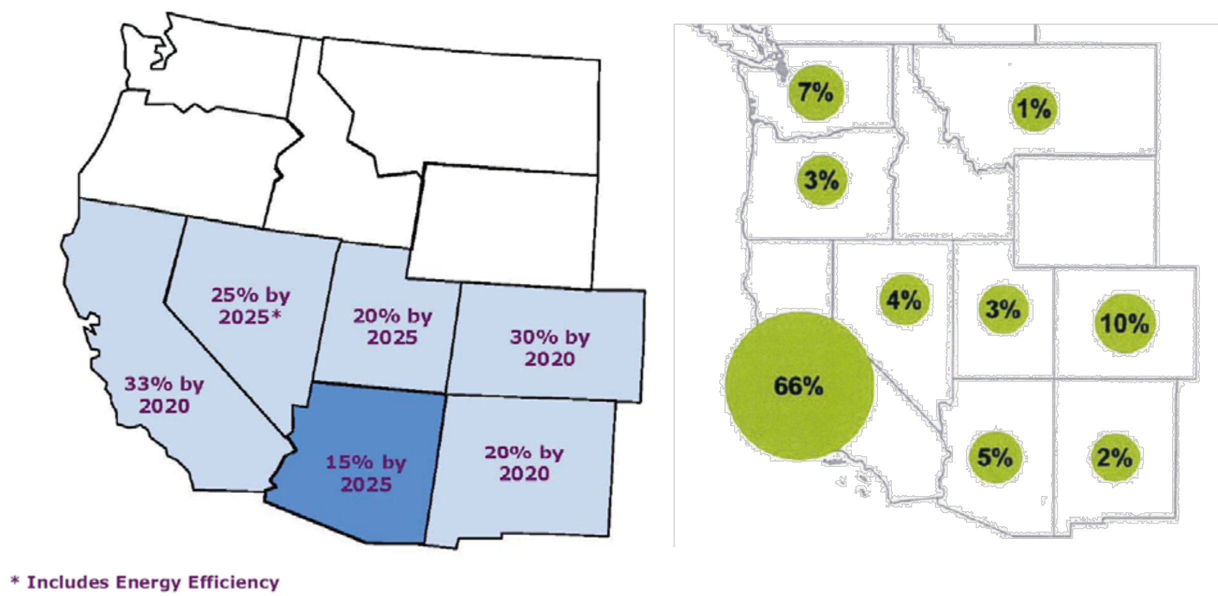
The utilities then formed a technical group to direct the consultant, PDS, in preparing a preliminary technical analysis that was used as the foundation of this report. The utilities hosted a Stakeholder Workshop on October 5, 2011, which was attended by individuals representing organizations, including renewable energy developers, transmission developers, state agencies, including the Commission, and industry consultants. The workshop solicited input from stakeholders regarding barriers and solutions for enhancing Arizona's ability to export renewable energy, including the potential development of transmission corridors.

This study approached a very large subject with a wide range of renewable energy sources and destinations, with a wide range of possible transmission options; and all to be completed in less than a year from the Commission's Order. KEMA and Staff believe this approach and the assumptions used for the study are acceptable.

3.3 Critical Variables Identified

The renewable standards adopted by Arizona and adjacent states are shown in Figure 2. California has the highest requirement—33%—of these states (left figure). California also has the largest electric load, by far, of these states. The combined effect is that California has 66% of the total renewable energy requirements in the WECC (right figure). The study found that California was the obvious target for renewable energy deliveries.

Figure 2: Arizona and adjacent state renewable standards—percent by state and percent of total WECC load



Sources: Percent by state—*Enhancing Arizona's Ability to Export Renewable Energy*, Barriers and solutions workshop, PDS Consulting, PLC, 5 October 2011.

Percent of total WECC load—*Enhancing Arizona's Ability to Export Renewable Energy,* A Report to Address the Arizona Corporation Commission Sixth Biennial Transmission Assessment Commission Decision No. 72031, PDS Consulting, PLC, October 2011, page 37.

Arizona and the adjacent states in the Southwest have renewable energy standard requirements or goals. Their combined effect is to substantially increase the demand for renewable energy in the region. Each state has slightly different requirements or goals:

- **Arizona**—requires Commission-regulated utilities to obtain 15% of their energy from renewable resources by 2025. In addition, distributed generation should be at least 30% of the renewable portfolio (4.5% of total energy in 2025). In addition, the utilities are mandated to meet 22% energy efficiency standard by 2020. Similarly, SRP has established a goal of meeting 20% of its expected retail energy requirements with sustainable resources (including energy efficiency) by 2020.

- **California**—requires all retail electric providers to procure 33% of their retail energy sales from renewable sources by 2020. In addition, utilities must obtain at least 75% of their requirements from in-state generation or connecting directly into California balancing authorities by January 1, 2017.[33] The specifics of implementing these requirements are subject to an ongoing proceeding.

  Estimates are that California will need about 50,000 GWh of renewable energy annually to meet these requirements. For comparison purposes, the total Arizona statewide retail electric consumption from all generation sources on an annual basis is about 70,000 GWh.[34]

- **Colorado**—requires investor-owned utilities to obtain 30% of retail sales from renewable resources by 2020. In-state renewables will count as 1.25 times external resources.

- **Nevada**— requires renewables to supply 20% of sales by 2015 and 25% by 2025.

- **New Mexico**— requires regulated electric utilities to have renewables meet 15% of their electricity needs by 2015 and 20% by 2020. Rural electric cooperatives must utilize renewable energy for 5% of their electricity needs by 2015, increasing to 10% by 2020.

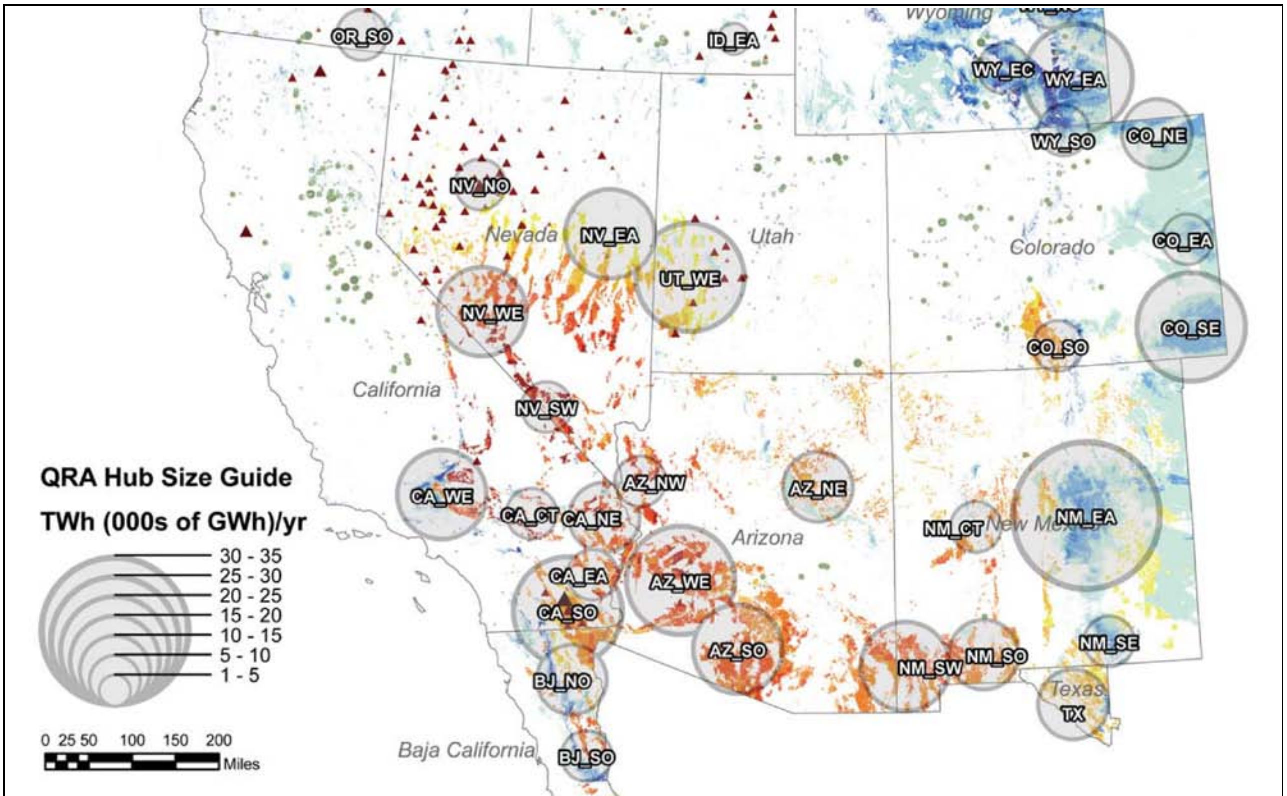
- **Utah**—has a 'goal' for 20% renewable energy by 2025, but utilities are only required to pursue renewable energy when it is cost effective to do so.

The Arizona renewable export study used the zones identified in the WREZ study shown in Figure 3 to identify renewable energy zones.

[33] California rules may also allow "dynamic scheduling" for out-of-state resources to some extent (this method continuously adjusts delivery schedules into the receiving balancing authority in order to match the output of a variable generation resource allowing such remote generation to be treated as if it were part of a balancing authority's own resources.)

[34] U. S. Energy Information Administration data for 2011.

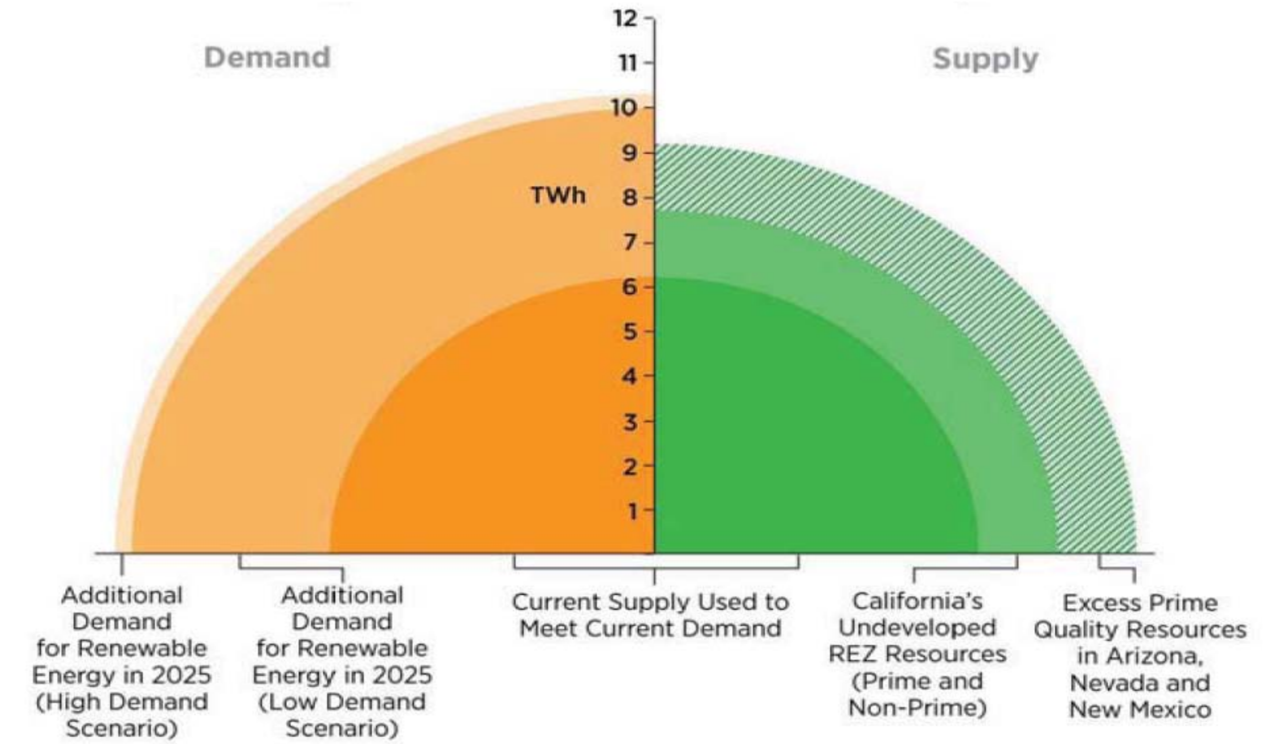
Figure 3: WREZ identified zones



Source: WREZ Initiative Hub Map, from *Western Renewable Energy Zones*, June 2009, a joint initiative of the Western Governors' Association and the U. S. Department of Energy

The report compares the state-by-state balance between renewable generation potential and requirements. Arizona and the adjacent states all had significantly more potential than requirements with the notable exception of California. California's renewable energy requirements are more than the state's potential as can be seen in Figure 4. These comparisons were what led to selecting California as the only target for renewable Arizona exports. The study adopted a renewable generation scenario with 20% delivered to Arizona and 80% to California.

Figure 4: California's in-state renewable energy supply and demand



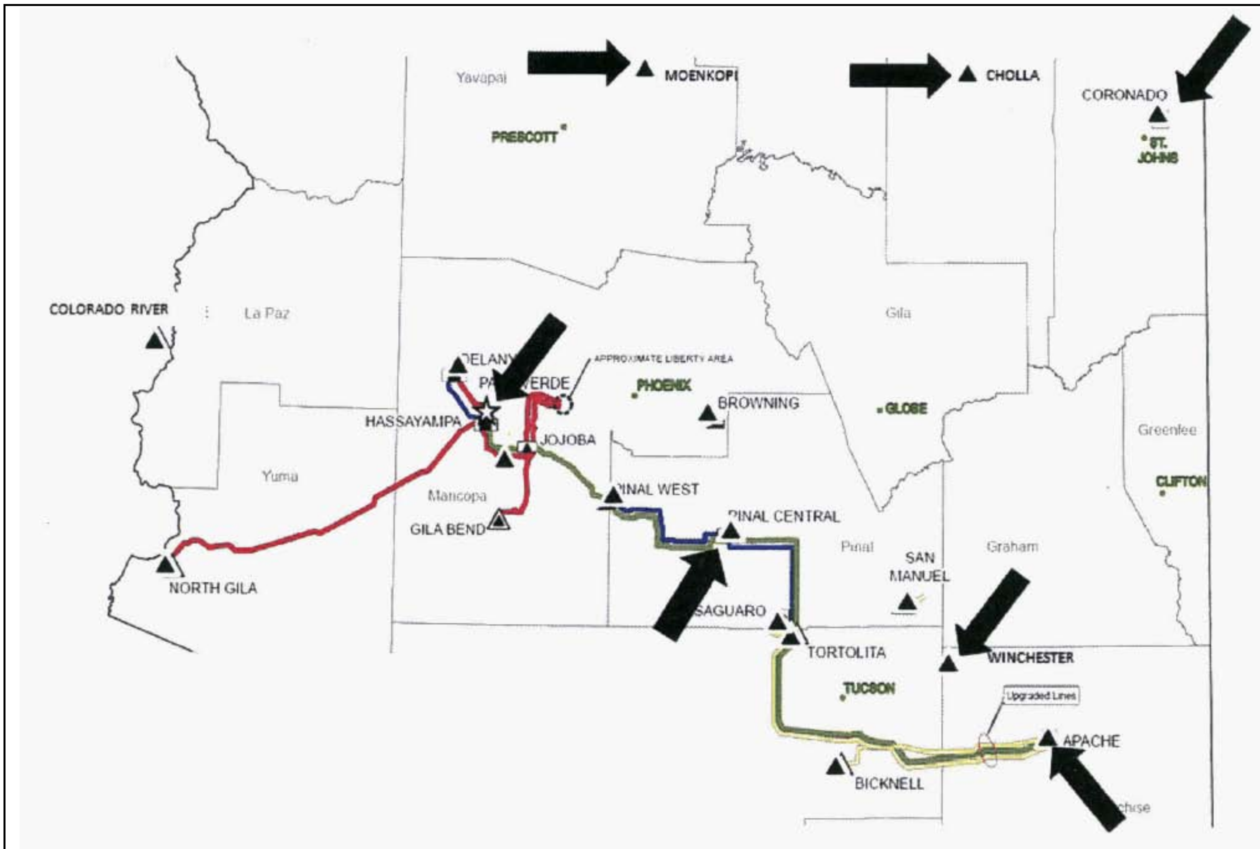
Source: *Enhancing Arizona's Ability to Export Renewable Energy*, page 8.

The RTTF established the Arizona Renewable Resource and Transmission Identification Subcommittee ("ARRTIS") to identify those areas in Arizona with the best potential for renewable generation project development based on resource availability and environmental sensitivities. The following busses, based on ARRTIS activities, were selected to represent renewable generation injection points:

1) Palo Verde 500kV
2) Pinal Central 500kV
3) Moenkopi 500kV
4) Cholla 500KV
5) Coronado 500kV
6) Winchester 345kV
7) Apache 230kV

These seven injection points are shown in Figure 5.

Figure 5: Seven buses selected to represent renewable generation injection points



Source: Enhancing Arizona's Ability to Export Renewable Energy, A Report to Address the Arizona Corporation Commission Sixth Biennial Transmission Assessment, Commission Decision No. 72031, PDS Consulting, PLC, October 2011, page 16.

3.4 Identified Transmission Obstacles to Exports

The *Enhancing Arizona's Ability to Export Renewable Energy* report listed four types of barriers to renewable exports:[35]

[35] *Enhancing Arizona's Ability to Export Renewable Energy*, pages 29-34.

1) Economic concerns include—insufficient demand for Arizona renewables, cost recovery and allocation, permitting risk, and customer interconnection and delivery cost;
2) Physical limitations include—technical limitations, contract obligations and agreements, and system reliability;
3) Permitting corridors or rights-of-way include—duplicative permitting process, creating new transmission corridors, permitting risks, and public opposition; and
4) Regulatory structure includes—California's ruling regarding importing out-of-state renewable generation, seams issues, changing regulatory landscape, applicability of Arizona's CEC process, and lack of organized markets.

Of the various obstacles above, KEMA and Staff believe that the following will be the most problematic:

- **California issues**—seem to be the most critical obstacles to Arizona renewable generation exports.
  - California is the only reasonable renewable generation export target. There are very limited opportunities for Arizona renewable exports to the other adjacent states since these states have more renewable generation potential than in-state requirements.
  - Even if California opens its renewable portfolio standards ("RPS") to significant amounts of imported renewable power, there will be significant technical transmission limitations for power delivery to California west of Path 49, either directly from Arizona or via southern Nevada. These limitations will need to be mitigated in order for significant amounts of additional renewable resources to be exported from Arizona to California.
  - The paths into California consisting of the EOR and West of Colorado River ("WOR") systems and the associated scheduling limitations limit the actual available transmission capacity to export from Arizona.
  - There are significant issues related to the coordination of policies and markets between states, specifically between Arizona and California.
  - Since solar and wind generation are variable and intermittent, providing some kind of interregional balancing market (or other arrangement) will likely be important to successful integration of the levels of renewables proposed in state standards and goals. The proposed westwide energy imbalance market ("EIM") if implemented may be helpful for integrating renewable resources,

but may not be sufficient to support export of additional large scale generation built in Arizona.

- **Cost recovery and allocation**—as is often true, cost issues are obstacles here.
  - The Arizona transmission owners will want assured cost recovery if they proceed with RTPs. The Commission and Arizona customers will be interested in how these costs will be allocated among them. Will the RTP costs become part of the general revenue requirements of the utilities or will they be allocated, at least in part, to the renewable generation developed for export?
  - Arizona Utilities' current rate mechanisms are based on the resource need for Arizona ratepayers, and do not allow for transmission specifically for exporting.
  - A methodology for allocating costs of new facilities to customers that specifically benefit from those new facilities may require multiple jurisdictions for approval (e.g., California and Arizona, and/or FERC and State)

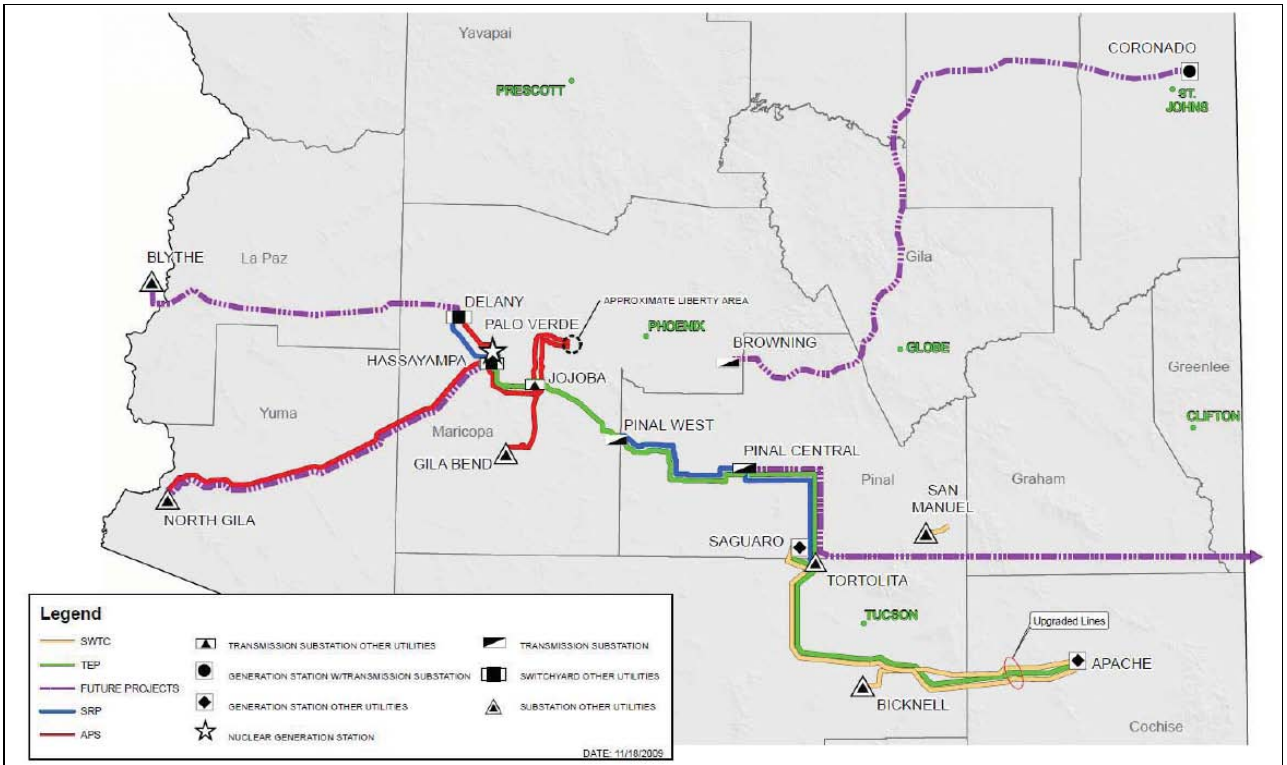
- **Internal Arizona transmission issues**—that must be addressed to see that RTPs are built.
  - Minimal transmission and sub-transmission assets exist in the renewable energy zones for some renewable resources to economically interconnect and deliver to potential markets.
  - Transmission lines have various and complex contractual obligations that may limit firm long-term transmission commitments for renewable energy delivery for exports. Long-term transmission commitments are needed for financing utility scale renewable energy projects.
  - The mix of private, state, federal, and tribal lands throughout Arizona often results in the need for several levels of regulatory approval that often are a duplication of effort.
  - Permitting additional corridors ahead of 'need' to prepare for renewable exports from renewable energy zones or additional interconnections to market facilities is difficult.
  - Negative public perception of transmission facilities continues to add risk and uncertainty of permitting transmission lines.
  - A consistent and cohesive state-wide policy vision is needed to guide renewable energy development for Arizona and the region from the state to county level.

– Transmission permitting requires a substantial amount of time and monetary investment that must be borne by the developer throughout the process.
– Recovery of permitting costs (and other development costs) could be allowed in the event the project does not move forward.

3.5 Identified Transmission Solutions for Technical Obstacles to Exports

The study evaluated the benefit of the RTPs identified in earlier work. These facilities will serve multiple purposes in addition to facilitating renewable generation exports including reliability within Arizona, and increasing internal transmission capability to serve Arizona load. The RTPs considered are shown in Figure 6.

Figure 6: Arizona renewable transmission projects



Source: *Enhancing Arizona's Ability to Export Renewable Energy*, page 12.

The increased EOR (Path 49) export capability due to the RTPs from each renewable generation injection bus is shown in Table 9. The large increase for Pinal Central is somewhat misleading, and it highlights how the RTPs have multiple benefits. The RTPs include two

500 kV lines that increase deliverability to Pinal West which then allows increased deliverability to California. Especially obvious from Table 9 is that the RTPs provide virtually no benefit for exporting renewable resources from Coronado or Cholla.

Table 9 - Impact of RTPs on Arizona export capability

Injection bus	East of Colorado River flow (MW)		
	Without RTPs	With RTPs	Increase
Pinal Central 500 kV	5,940	7,473	1,533
Palo Verde 500 kV	6,911	7,437	526*
Winchester 345 kV	5,324	5,589	265
Moenkopi 500 kV	6,747	6,926	179
Apache 230 kV	5,275	5,447	172
Coronado 500 kV	5,982	5,984	2
Cholla 500 kV	5,569	5,569	0
*Sensitivity cases that added the Delaney-Colorado River 500 kV and North Gila-Imperial Valley #2 500 kV lines showed significantly higher increases in EOR flow.			

The study report identified solutions that were primarily procedural or regulatory changes including:

- Develop a common vision for renewable generation and associated transmission for the state of Arizona;
- Help maintain a competitive edge by reducing the time it takes to get new renewable generation to market, which would give Arizona a distinct advantage over California-based renewables;
- Streamline permitting—for projects with a demonstrated need and in an established corridor;
- Improve existing system efficiency by applying new technologies;
- Improve interstate coordination on seams issues, especially with California;
- Revise ARS 40-360 to provide more flexibility in defining "need";
- Continue to create incentives for transmission development; and
- Develop more physical connections with California to increase export capability.

The internal Arizona issues and related solutions seem manageable, if cost recovery and allocation can be settled and the RTP facilities can be built. The more substantive problems are external to Arizona, and will be challenging to overcome without some type of regional imperative.

3.6 Responsiveness of Study to Commission Order

Staff and KEMA find the study was reasonable and used a suitable approach and assumptions. Generally the RTPs improved exports to California by less than 500 MW. However, the potential need for WOR transmission improvements was not thoroughly examined in the study. KEMA and Staff believe that studying additional system operating scenarios (e.g., spring, summer, and fall) and more detailed examination of WOR transmission limits would likely find smaller incremental export benefits than the values shown in Table 9.

The specific transmission corridors identified were largely presented in the RTP process presented by the utilities in the Sixth BTA. These facilities fall along existing transmission corridors between Apache in Southeastern Arizona and Palo Verde. Additional corridor possibilities could run along Interstates 8 and 10.

KEMA and Staff believe that during the course of the export study, utilities engaged Arizona stakeholders in a successful process of seeking their input and ideas. [36] This stakeholder process resulted in a list of numerous potential barriers along with potential solutions to development of renewable resources and related transmission in Arizona for export.

[36] Staff and KEMA noted that Attachment D – Stakeholder List, from the 2011 PDS report lists very few *out-of-state* stakeholders.

4 Interstate, Merchant and Generation Transmission Projects

Interstate transmission is essential to enabling the state's utilities access to the wholesale market for purchases and sales. Interstate and market-driven transmission projects facilitate a more robust and viable wholesale market, complement the state's electric infrastructure, and allow for additional power import/export. Various generation market access projects, merchant generation interconnections, and merchant transmission projects were filed for use in the Seventh BTA and/or were presented as updates at one of the two workshops. Staff's summary of the information filed and/or presented is given below.

4.1 Palo Verde to Devers No. 2 500 kV Transmission Line

The Palo Verde to Devers No. 2 ("DPV2") 500 kV Project[37] is a SCE sponsored interstate transmission project. The original scope of the project extended approximately 270 miles from the proposed Delaney Substation[38] in Arizona, then westward across the Colorado River near Blythe, California and continuing on to SCE's Valley Substation near Romoland, California.

In June 2007, the Commission denied SCE's original application for a CEC for the portion of the DPV2 transmission line located in Arizona.[39] However, the California PUC has approved construction of the California portion of the project.[40]

SCE's ten-year plan filing in the Seventh BTA[41] states that it continues to evaluate whether it will proceed with the Arizona portion of the project and it might seek to construct this section during the ten-year plan period. However, SCE also notes that as of the filing date it had 6,621 MW of generator interconnection applications in its queue in the vicinity of Blythe, California. This generation alone is well in excess of the planned capacity of DPV2.

[37] ACC Docket No. L-00000A-0295-00130.

[38] Delaney Substation was previously known as Harquahala Junction.

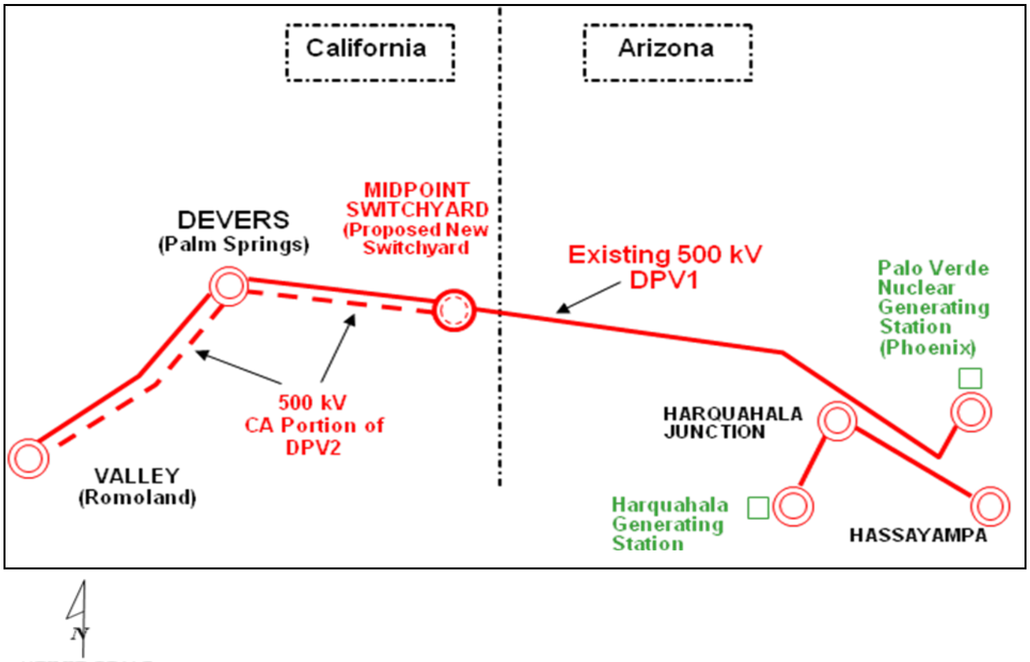
[39] ACC Decision No. 69638.

[40] The CPUC ordered SCE to seek its approval before resuming pursuit of Arizona portion of the project.

[41] Filed January 31, 2011.

A simplified one-line diagram of the DPV2 project prepared by SCE is shown in Figure 7 (Staff notes that the figure is missing an existing 500 kV connection between the Palo Verde and Hassayampa, and that the Devers-Valley section is no longer part of the DPV2 scope).

Figure 7 - Simplified One Line Diagram of Current DPV2 Plan



Source – *SCE's Fifth BTA workshop presentation (May 22-23, 2008).*

4.2 SunZia Southwest Transmission Project

The project is sponsored by Southwestern Power Group, Salt River Project, Tucson Electric Power, Tri-State Generation and Transmission Association, and Shell Wind Energy. Southwestern Power Group is the project manager on behalf of all the sponsors. SunZia proposes to permit and construct up to two interstate merchant EHV transmission lines from a new substation in Lincoln County, New Mexico, to Pinal Central Substation in Arizona. The project is intended to transport renewable generation from wind, solar, and geothermal resources to markets in the Arizona and the western region. The current project proposal is to construct up to two 500 kV AC lines. An overview map showing the general routing is included as Exhibit 19. The total estimated corridor length is 471 miles, of which approximately 176 miles are located in Arizona. The project would be constructed in phases, with the initial phase placed in service in 2016.

SunZia filed a ten-year plan in January 2012 and sponsored a presentation at Workshop I, held on July 10, 2012. Progress and milestone dates were reported in the filing and/or workshop as follows:

- Project completed the WECC path rating process and was granted Phase 3 status in March, 2011.
- WECC approved an accepted path rating at 3,000 MWs for two 500kV AC lines.
- BLM initiated an Environmental Impact Statement ("EIS") in May 2009 followed by a year-long scoping period.
- BLM achieved agreement with US Department of Defense Energy Siting Clearinghouse on routes acceptable to military missions in New Mexico.
- One of seven pilot projects supported by the Federal Rapid Response Team for Transmission ("RRTT"), announced October, 2011.
- Commenced anchor tenant discussions in January, 2012.
- Draft EIS issued by BLM in May, 2012 for a 90-day public review period (NEPA process).
- Project plans to file a CEC application in mid-2013.

4.3 Centennial West Clean Line Project

The project (formerly known as the Santa Fe Clean Line Project) is sponsored by Clean Line Energy Partners LLC ("Clean Line"). Clean Line filed a ten-year plan in the Seventh BTA and gave a presentation on the project at Workshop I. The transmission project will consist of a ±600 kV High Voltage Direct Current ("HVDC") line about 900 miles long. It is being designed to transmit up to 3,500 MW of power from renewable projects in eastern New Mexico to Southern California, terminating near San Bernardino.

The project anticipates filing a CEC application once the National Environmental Policy Act ("NEPA") process results in a draft EIS. A map of the corridor alternatives and proposed substations is shown in Exhibit 20. The projected in-service date is 2018.

4.4 Bowie Power Station

The Bowie Power Station, owned by Southwestern Power Group ("SWPG"), is a natural gas fired 1,000 MW electric generation facility planned for southeastern Arizona near the community of Bowie in Cochise County. The Bowie Power Station will connect with TEP's Greenlee-Winchester-Vail 345 kV line at Willow Substation via two 345 kV transmission lines approximately 15 miles in length.

SWPG filed in the Seventh BTA and sponsored a presentation at Workshop I. In Decision No. 71951 dated 11/1/2010, the Commission granted Bowie a second extension on the duration of the CEC through 12/31/2020. The project status and target dates were presented at Workshop I, but have been updated since then as follows:

- Interconnection Request with TEP completed
- Initial System Impact Study ("SIS") completed
- The Final SIS Re-Study Report was issued by TEP on 7/2/2012
- Facilities Study to be updated by 9/15/2012
- Large Generator Interconnection Agreement ("LGIA") to be executed by 8/31/2012
- File LGIA with the FERC and Commission by 11/15/2012

4.5 Boquillas Wind, LLC

Boquillas Wind LLC is a wholly owned subsidiary of Edison Mission Energy. They are developing a wind generation project approximately 85 miles west of Flagstaff, Arizona. In their BTA filing in January 2012 they propose building an eleven mile 230 kV gen-tie to interconnect with APS's Round Valley-Seligman 230 kV line. The expected in-service date is fourth quarter 2013 and the planned capacity is up to 260 MW. Both a System Impact Study and an Interconnection Facility Study have been performed by APS and were filed by Boquillas in the docket in 2011.

4.6 BP Wind Energy North America Project

BP Wind proposes a 500 MW wind generation project in Mohave County approximately 40 miles north of Kingman, Arizona. They envision building a gen-tie to interconnect either with the Mead Phoenix Project (500 kV) operated by SRP or the Mead-Peacock-Liberty 345 kV line operated by Western (both lines are on a common corridor). A 2013 or 2014 commercial operation date is anticipated.

4.7 Hualapai Valley Solar

Hualapai Valley Solar LLC filed their latest ten-year plan in January 2011. The project is located in northwestern Arizona and at the time of the last filing had a planned in-service date in the first quarter of 2014. Several gen-tie options were under study at the time of the filing with a proposed interconnection into SRP's Mead Phoenix Project. SRP advises that the interconnection application has since been withdrawn.

4.8 Abengoa Solar

Abengoa Solar Inc. is currently constructing the 280 MW Solana Solar Generating Station near Gila Bend, Arizona using concentrating solar power ("CSP") technology. The project is being built by Arizona Solar One, LLC – a wholly owned subsidiary. It will connect to APS's Panda Substation via a double-circuit 230 kV, 20 mile long gen-tie line. CEC's have been granted for both the power plant and the gen-tie in Decision Nos. 70638 and 72680, respectively. Arizona Solar One and APS have executed a Large Generator Interconnection Agreement and a 30-year power purchase contract for the plant. The gen-tie is planned to go in service by June 2013. A copy of the Interconnection Facilities Study was included in Abengoa's January 2012 BTA filing.

4.9 Foresight Flying M, LLC

Foresight Flying M, LLC plans to build a 500 MW Grapevine Canyon Wind Project and an interconnection with Western's Flagstaff-Pinnacle Peak No. 1 and 2 345 kV transmission lines approximately 22 miles southeast of Flagstaff, Arizona. The gen-tie could be up to 15 miles in length (alternative alignments were still under review at the time of the January 2012 BTA filing). It is anticipated that the overall wind project will be built in two or more major phases. The projected in-service date is late 2013 or early 2014. A copy of the SIS was included in the project's 2011 BTA filing.

4.10 Gila Bend Power Partners, LLC

Gila Bend Power Partners ("GBPP") is planning to build an 833 MW combined cycle generating plant, along with a 500 kV gen-tie and the new Watermelon Substation, in order to interconnect the project with the APS Gila River-Jojoba 500 kV double-circuit line. A copy of the System Impact Study was included with Gila Bend's January 2012 filing in the BTA. The project has been approved by the Commission through February 7, 2018 in CEC case numbers 106, 109 and 119.

It should be noted that the Gila River-Jojoba 500 kV line is being constructed as part of a separate project – namely the Gila River Panda (2,080 MW) Generation Project. GBPP proposes a loop-in of this double-circuit line into a new Watermelon Substation. The System Impact Study for GBPP assumed a combined output of 2,913 MW from the two generating projects (GBPP and Panda). The combined one-line diagram for these projects is shown in Exhibit 23.

4.11 SolarReserve, LLC

SolarReserve, LLC plans to construct a 150 MW concentrating solar project in Maricopa County near Gila Bend, Arizona. A 230 kV gen-tie is proposed to the Panda Gila River Substation. Commercial operation is expected in early 2015. A copy of the System Impact Study was included with SolarReserve's 2011 BTA filing. It was performed as a "cluster study" by APS and included other generating projects in the same area of the system.

4.12 Southline Transmission Project

No filing was made in the Seventh BTA, but Black Forest Partners, LP, manager of the Southline Transmission Project, gave a presentation on this merchant transmission line at Workshop I. A simplified diagram of the project siting map is shown in Exhibit 21.

The Southline Transmission Project is sponsored by Southline Transmission, L.L.C. and managed by Black Forest Partners, LP. The project consists of two proposed segments between Southern New Mexico and Southern Arizona: 1) a new 240 mile 345kV double circuit line between the existing Afton substation outside Las Cruces, NM and the existing Apache substation outside Wilcox, Arizona and 2) an upgrade of approximately 120 miles of existing

115kV lines to double circuit 230kV between Apache and the existing Saguaro/Tortolita stations northwest of Tucson.

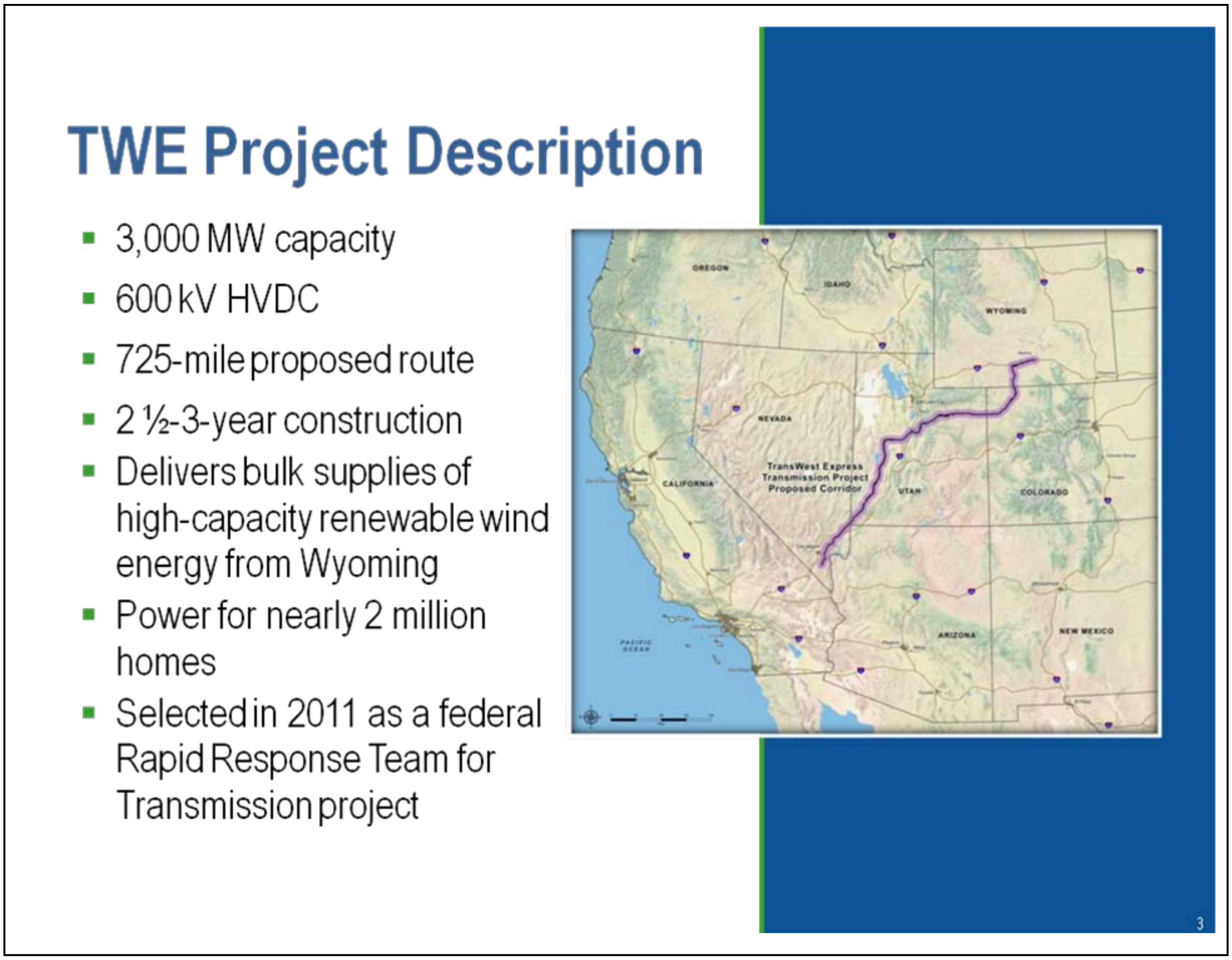
Black Forest reported that:

- The project is currently in Phase 2 of the WECC path rating process.
- BLM and Western are serving as the Joint Lead Agencies for the preparation of an EIS under the NEPA process.
- Southline has executed an Advanced Funding Agreement with Western pursuant to Western's Transmission Infrastructure Program under which Southline will cover Western's development period costs.
- Western is evaluating to what extent it will participate in the project.

4.13 TransWest Express ("TWE")

Western gave a presentation on the project's status at Workshop II. In 2011 the TWE Project was selected as one of the five western US projects by the federal Rapid Response Team for Transmission. A summary of the project and route map is shown in Figure 8.

Figure 8: TransWest Express Project Description



Western and TransWest entered into a development agreement in September 2011. The project is currently in Phase 2 of the WECC Path Rating Process which should be completed by mid-2013. Western and the BLM are serving as a joint lead agency for the EIS. A draft EIS is scheduled for release in early 2013. The final EIS and Record of Decision are scheduled for 2014. Western will make a decision on its participation as an owner in the TWE Project after environmental analysis is complete.

4.14 EnviroMission

EnviroMission plans to build a 200 MW solar project in La Paz County, Arizona and interconnect into Western's Bouse Substation or a nearby 161kV line. Capacity and energy from the project will be exported to the Southern California Public Power Authority with the point of delivery at either Marketplace or Mead Substation in southern Nevada. The target operating date is 2015.

5 Other Commission Ordered Studies

5.1 History and Purpose

Utility distribution companies have the obligation to assure that adequate import capability is available to meet the load requirements of all distribution customers within their service areas.[42] In addition to assessing the ability of the statewide system to meet this fundamental requirement through the BTA process, over the years the Commission has ordered that certain other supplemental study work be performed by Arizona utilities to broaden and facilitate biennial assessments. Study work previously ordered by the Commission falls into three categories:

- The transmission load serving capability of specified local load pockets has been a study requirement since the First BTA.
- Reliability must run ("RMR") studies have been required for selected constrained transmission import areas with local generation since the Second BTA.
- Ten Year Snapshot and Extreme Contingency studies have been required to ascertain the transmission system's robustness to withstand more severe emergency scenarios since the Third BTA.

These three categories of results in the Seventh BTA are discussed in more detail below.

5.2 Local Area Transmission Load Serving Capability Assessment

In the 1st BTA, Staff identified three load pockets in Arizona that should be monitored for transmission import constraints and reliability must-run ("RMR") generation requirements: Phoenix, Tucson and Yuma. The 2nd BTA added a fourth area located in Southeastern Arizona (Santa Cruz County). Subsequent BTAs added Mohave County.

The past few BTA studies have shown decreasing RMR costs in most of the areas as transmission system upgrades and local generation have been added. Updated RMR studies were filed for these five areas in the Seventh BTA. Prior BTAs have also looked at import

[42] Arizona Administrative Code R14-2—1609.B.

constraints in Pinal County, which have been analyzed through the SWAT CATS Study. This study looks at import constraints, but not RMR requirements, per se.

In addition, although the Commission did not order an RMR study for Cochise County, it directed in Decision No. 70635 that studies be filed for both Cochise County and Santa Cruz County addressing "continuity of service" issues. The transmission import capability for each of these local areas was addressed in recent BTA reports and is updated in the Seventh BTA.

In the following subsections, non-RMR import and continuity of service assessments are discussed first, followed by specific RMR studies done for this BTA.

5.2.1 Cochise County Import Assessment

The Cochise County load serving entities are APS, TEP, and Sulphur Springs Valley Electric Cooperative ("SSVEC"). The southern Cochise County load pocket, from Fort Huachuca on the west end to San Pedro on the east end, is served via four radial transmission lines from the north at 115 kV, 138 kV and 230 kV. The peak load in the area is roughly 175 MW. The loss of any of these 115 kV and 230 kV lines could require dropping some customers until manual restoration procedures can be performed.[43] This is consistent with NERC reliability standards which permit loss of load for single contingency (n-1) transmission outages in areas served from radial transmission systems – like southern Cochise County.

Like many other rural areas of Arizona, the utilities serving Cochise County have historically followed a "restoration of service"[44] approach in their transmission system planning. However, this came under scrutiny by the Commission as a result of extended customer service outages that occurred in Cochise County during the period October 9-11, 2007. As a result, during the Fifth BTA the Commission proposed replacing the restoration of service paradigm with a "continuity of service" paradigm intended to automatically restore customer loads within seconds

[43] Loss of the 138kV line serving the Fort will result in automatic transfer of the load to an existing TEP 46kV line. Depending on the load at the time of the transfer, some load at the Fort might need to be curtailed to maintain voltage.

[44] As defined in Appendix F of the 5th BTA, the restoration of service paradigm relies on manual, operator initiated actions to restore load following most N-1 transmission contingencies. However, TEP does have an automatic scheme in place to maintain service to load for loss of Vail-Ft. Huachuca 138kV.

or minutes of any n-1 transmission outage. The Commission ordered the respective utilities to identify a system expansion plan that could accomplish this objective. Due to the high costs of achieving this goal through installing either new local generating facilities or new high voltage transmission lines into the area, the utilities focused on 69 kV subtransmission expansion options.

During the Sixth BTA, the Cochise County Study Group ("CCSG") consisting of TEP, APS, SWTC and SSVEC completed technical planning studies that identified a staged grid expansion plan that could achieve the continuity of service definition. In the Sixth BTA decision the Commission approved this plan in concept and directed the respective utilities to file a series of progress reports during 2011 and 2012 to document their progress in developing cost sharing arrangements and a memorandum of understanding for construction of the facilities. The CCSG completed the three required filings during 2011. These filings, which included some refinements to the area expansion plan, confirmed that the capital cost of the full plan would exceed $100 million (see Exhibit 22). Filings by CCSG Participants in December 2011 advised that a memorandum of understanding had been drafted, but a significant difference of opinion existed among the parties in regard to capital cost allocation. This led to a filing by the utilities in March 2012 which asked the Commission for an extension of the filing deadlines for the remaining progress reports in order to allow time to review the cost effectiveness of the expansion plan and/or to identify other possible alternatives that might be more cost effective. The Commission responded to this request in Decision No. 73132 on May 1, 2012. This decision granted the CCSG Participant's Request for Extension for remaining filings and deferred the resolution of this matter to the Seventh BTA.

In accordance with this decision, Staff and KEMA reviewed the CCSG's filed progress reports and estimated costs of the proposed expansion plan. In addition, Staff and KEMA met with the CCSG Participants in July 2012 to review the facts and obtain additional data from the CCSG Participants related to reliability of the Cochise County transmission system in recent years. CCSG Participants also provided a list of improvements that have been made to the county's grid since 2007 as summarized in Table 10. All of these improvements are in addition to those proposed as part of the continuity of service expansion plan.

Table 10 - Recent Cochise County Upgrades/Improvements

Utility	Description	Status
SWTC	Improve coordination of protective relays throughout system, and correct flawed relay settings on the substation facilities that caused extended outages in 2007	Complete
SWTC & APS	Apache Substation 115/69 kV transformer upgrade	Complete
SSVEC	Upgrade the Tombstone Junction 69 kV switching station	Complete
APS	Build new Palominas Substation and Don Luis-Palominas 69 kV line with provisions for future emergency tie installation between Palominas and SSVEC Hereford Substation	Complete
APS	Modify remote startup controls for Fairview gas turbine plant	Complete
APS	Replace McNeal 69 kV circuit breaker (normally-open tie point to SSVEC)	Complete
SSVEC	Upgrade key 69 kV tie point switches to full remote control operation	In-progress
SSVEC	Significant installation of fiber optics to improve SCADA and protection	In-progress
SSVEC	Build new Hereford Substation and Ramsey-Hereford 69 kV line with provisions for future emergency tie installation between Ramsey and APS Palominas Sub	In-progress
SSVEC & TEP	Numerous Cochise County 138 kV, 69 kV & 46 kV pole replacements	Complete
TEP	Extensive pole testing and fire guard treatment of 138 kV poles	Complete

Other key inputs were presented by CCSG Participants to Staff and KEMA as follows:

- SSVEC has now determined that converting certain 69 kV tie points in its Cochise County subtransmission system from normally-open operation to normally-closed operation, as assumed in the continuity of service expansion plan filed in September 2011, would require additional capital investments in order to upgrade its 69 kV system due to the resulting loop flows. This could significantly increase the total cost of the plan and SSVEC's rate impacts.
- TEP points out a distinction between its facilities that serve Fort Huachuca and the facilities that are owned and operated by the other CCSG participants. Expansion plans that involve Fort Huachuca do not depend on normally-closed operation of the proposed ties to the TEP system in Cochise County. Therefore, normally-open operation of the proposed Kartchner to Buffalo Soldier 69kV line and 69/13.8kV substation project would

not negate any benefits to the rest of CCSG as the tie would be funded and used solely by the Fort.[45]

- TEP's current arrangement for loss of the 138 kV line to Fort Huachuca (a 25 MW peak load) is automatic transfer of load to TEP's existing 46 kV line to Fort Huachuca. Upon tripping of the 138 kV line and transfer of the load to the 46 kV line, TEP operators will call upon Fort Huachuca operating personnel to reduce load to the extent it is needed to alleviate voltage issues. The 46 kV circuit can supply approximately 16-18 MW.
- TEP is concerned that any future projects in Cochise County serving Fort Huachuca, such as the Fort Huachuca to Buffalo Soldiers 69 kV tie, can only be done to the extent that they do not violate Two County bond rules (i.e., that would result in supply via TEP to load outside of Pima and Cochise counties).

Based on our assessment of CCSG's 2011 progress report filings and other information obtained from CCSG, Staff and KEMA arrived at the following observations:

- Extended Cochise County customer outages that occurred in October 2007 were due to the combination of a planned construction-related transmission outage and improper substation relay settings. This has been corrected and no longer poses a concern. Related relay coordination and testing requirements are also covered by NERC reliability standards that have been implemented since 2007.
- CCSG Participant's have made a significant effort since the 2007 outage events to improve the reliability, maintenance and operability of the transmission and subtransmission system serving Cochise County.
- The current ten-year plan for the Cochise County transmission system (absent the continuity of service expansion projects) can reliably serve the peak load forecast and does not result in cascading outages for any single contingency (n-1) transmission outage. This is consistent with NERC reliability standards.
- Transmission system reliability in Cochise County appears to be comparable to other largely rural areas of Arizona, even without building the grid expansion plan identified by CCSG to upgrade to a continuity of service definition.

[45] TEP has been advised that Fort Huachuca has requested Federal funding to construct a second backup path to the Fort (e.g., Kartchner-Buffalo Soldier 69 kV line and 69/13.8kV substation project) that could pick up the remaining 7 MW of load under n-1 contingencies. CCSG's September 2011 filing states that Congressional approval is required for this funding.

- There are four existing radial transmission sources into the southern Cochise County load pocket of interest in this assessment. The maximum Cochise County loss of load exposure for a single contingency (n-1) transmission outage during peak load conditions in 2012 is 63 MW (SSVEC), of which over 44 MW can be quickly restored through operator actions. This would leave only 19 MW (approximately 10% of the total southern Cochise County peak load) without service until the transmission source can be re-energized.
- Cochise County's transmission outage statistics for 2008-2011 were within the range of typical values for a rural system. During this four year period an average of 2.25 transmission outages occurred per year (excluding momentary outages under 5 minutes). On average, after utilities completed initial load transfers, less than 15 MW of customer load remained out of service during these outage events.
- The past four years of in-depth technical assessment by the CCSG participants has greatly improved the mutual understanding of system operating and planning issues which directly benefits Cochise County reliability. This four year assessment process has also revealed that the capital cost of an expansion plan capable of achieving the continuity of service definition is not a cost effective approach for southern Cochise County.

Based on these findings, Staff concludes that:

- Neither transmission expansion, subtransmission expansion nor local generation expansion offer a cost effective means of upgrading to a continuity of service definition in Cochise County.
- Use of the current restoration of service standard is appropriate for a largely rural area such as Cochise County and efforts to implement a continuity of service standard should be suspended.
- The Commission should review applicable outage data from the utilities in future BTA proceedings in order to monitor any changes in Cochise County reliability.

5.2.2 Santa Cruz County Import Assessment

Santa Cruz County, similar to Cochise County, is served by a radial transmission system. UNS Electric is the load serving entity in Santa Cruz County. The Gateway 345 kV transmission project – previously envisioned as a bulk power transmission tie between Arizona and Mexico – for several years appeared to provide a feasible option for a second transmission source into

Santa Cruz County.[46] The ten-year plan previously included a 138 kV line from Gateway to Valencia. However, UNS Electric's Seventh BTA filing advises that this project has been dropped. At Workshop I, TEP confirmed that it no longer has plans to build a major tie to Mexico or a second 138 kV line into Santa Cruz County.

UNS Electric analyzed transmission needs in Santa Cruz County in 2009 to develop transmission plans that address the recommendations in the 2008 Biennial Transmission Assessment related to continuity of service. A Santa Cruz County Continuity of Service Summary Report and Reference Filing was made by UNS Electric in February, 2010.

UNS Electric's current ten-year plan is capable of serving up to 159 MW of load through a combination of the radial transmission delivery capability and local generation (including four combustion turbines at Valencia Substation in Nogales with a total capacity of 61 MW). However, Santa Cruz County remains exposed to at least short-term service outages for all local customers following the loss of the single transmission line serving the county. Like Cochise County, the supply to Santa Cruz County currently relies on restoration of service paradigm. Procedures for timely restoration are in place for virtually all outage conditions. Unlike Cochise County, a major feature of the Santa Cruz restoration plan is the availability of the four existing gas turbine generators at Valencia along with an emergency tie between TEP and Santa Cruz County. Use of black start generation capabilities at Valencia along with closing of distribution level backup ties allows restoration of all or most of the Santa Cruz County load during an n-1 outage of the single transmission source (depending on demand levels at the time of the outage). The current ten-year plan also calls for conversion of the radial 115 kV line to 138 kV operation, which will increase the area load serving capability to 159 MW under normal conditions. However, it should be noted that with the reduction in county load forecast since the Sixth BTA, it's unlikely demand will reach 100 MW during the next ten-years.

UNS Electric has also implemented improvements in communication systems, outage management procedures, switching capabilities, transformers and other operational and maintenance improvements during recent years for Santa Cruz County. Local capital improvements include addition of remote starting capability for the Valencia Generating

[46] ACC Docket No. L-00000-01-0111.

Substation which supports restoration during transmission outages, as well as upgrade of UNS Electric's transmission tie facilities with Western (Nogales Tap).

Based on these improvements and cancellation of the Gateway EHV line, UNS Electric concludes that construction of a second transmission source into Santa Cruz County is not cost effective for a largely rural area. In view of the above findings Staff concludes that the Commission should support continued use of a suitable restoration of service paradigm for largely rural areas such as Santa Cruz County. However, Staff also concludes the Commission should collect applicable outage data from UNS Electric in future BTA proceedings in order to monitor any changes in Santa Cruz County reliability.

Discussion of Santa Cruz County RMR analysis is included in Section 5.2.5.4 below.

5.2.3 Mohave County Import Assessment

See Section 5.2.5.5 for a discussion of the Mohave County RMR study.

5.2.4 Pinal County Import Assessment

This analysis was previously performed by the CATS-HV Subcommittee, but has since been subsumed into CATS Ten Year Snapshot Study (see Section 5.3).

5.2.5 Import Assessments Requiring RMR Studies

Five of Arizona's seven load pockets contain local generation with potential RMR conditions. An RMR condition exists when the local load served by a utility distribution company ("UDC"), or group of UDCs, exceeds the simultaneous import limit of the local transmission system. The Commission has adopted the use of two terms as indicators of the load serving capability of local load pockets in RMR studies: Simultaneous Import Limit ("SIL") and Maximum Load Serving Capability ("MLSC").[47] It also requires that two representative years be studied for each RMR area in the BTA, and that the RMR studies identify the following four RMR metrics by area:

- RMR hours - The number of hours during which the local load is above the SIL

[47] Appendix C, RMR Conditions and Study Methodology.

- RMR energy - The amount of energy served from RMR generation
- RMR at peak demand - The maximum amount of capacity that the RMR generators would be required to produce to meet the peak demand
- RMR costs - The costs of out-of-merit-order[48] dispatch from RMR generation

A high-level summary of RMR study results in the Seventh BTA is provided in Table 11.

Table 11 - Summary of RMR Study Results

Area	Year	Study Area Load (MW)	RMR Gen MW @ Peak	Annual Cost ($000)
Phoenix	2014	11,885	396	0
	2021	14,209	2,275	0
Tucson	2014	2,533	294	$187
	2021	2,880	338	$1,188
Yuma	2014	440	122	0
	2021	510	31	0
Mohave County[49]	2014	890	0	0
	2021	975	0	0
Santa Cruz County[50]	2014	78.4	16	$544
	2021	83.8	0	0

[48] Out-of-merit order dispatch is generation that is run, for reliability needs, outside the economic dispatch order. It is typically more expensive than generation run in the economic dispatch order.
[49] The required level of local generation dispatch is less than the normal hydro plant run-of-river MW output levels per USBR's summer peak water release requirements, so no RMR is required.
[50] Area peak load included a 5% demand margin for post-transient voltage stability analysis.[51] For example, the final RMR study year filed in the Seventh BTA is 2021 and future BTA load forecasts for 2021 would be compared to the Seventh BTA forecast amount for this year to determine the percent increase.
Using the data for the Phoenix RMR area, the peak demand forecast for 2021 is currently 14,209 MW so the need for restarting RMR analysis would be considered if and when a revised 2021 forecast exceeds 14,209 x 1.025 = 14,564 MW.

It is evident from Table 11 that RMR costs in Arizona are becoming negligible. This is good news. In fact in the Phoenix, Yuma and Mohave County areas the projected RMR costs are actually zero because the required generators are already expected to be dispatched for other reasons such as voltage regulation. RMR costs in Santa Cruz County are also expected to drop to zero within the next few years. The only remaining area with actual RMR dispatch costs is Tucson. While Tucson RMR costs are projected to increase to slightly over $1 million per year by 2021, TEP's BTA filing concludes that this is a fraction of the dollar value of capital upgrades that would be required to eliminate these costs, so that no capital upgrades are justified on this basis. Staff concurs.

Moreover, Staff recognizes that the process of developing RMR cost projections for the above areas of the Arizona system in and of itself to be a time consuming process that adds to the utilities' overhead (labor) costs. Given the diminishing value of this analysis to the BTA process, Staff concludes that it would be appropriate to suspend RMR analysis for one or more future BTA proceedings and to establish a set of conditions that would trigger an end to this suspension. Examples of such triggering events would include:

- An increase of more than 2.5% in an RMR pocket load forecast since the previous BTA (i.e., relative to the load forecast for an RMR pocket for the final RMR study year for which RMR studies were last filed).[51]
- Planned retirement (or an expected long-term outage during the summer months of June, July or August) of a key transmission or substation facilities supplying an RMR load pocket, unless a facility being retired will be replaced with a comparable facility before the next summer season.
- Planned retirement (or an expected long term outage during the summer months of June, July or August) of a generating unit in an RMR load pocket that has been utilized in the past for RMR purposes, unless a generator being retired will be replaced with a comparable unit before the next summer season.
- A significant customer outage in an RMR load pocket defined as a sustained outage of more than one hour exceeding the greater of 100 MW or 10% of the peak demand in the pocket)

[51] For example, the final RMR study year filed in the Seventh BTA is 2021 and future BTA load forecasts for 2021 would be compared to the Seventh BTA forecast amount for this year to determine the percent increase.

Using the data for the Phoenix RMR area, the peak demand forecast for 2021 is currently 14,209 MW so the need for restarting RMR analysis would be considered if and when a revised 2021 forecast exceeds 14,209 x 1.025 = 14,564 MW.

5.2.5.1 Phoenix Metropolitan Area RMR Assessment

The interconnected transmission system serving the metropolitan Phoenix area is owned and operated by APS, SRP and Western. Approximately 99% of the Phoenix area electric energy requirements during the course of the year are served by imports of remote resources into the area over the transmission system. However, an RMR condition can exist for the Phoenix area during the few hours that the peak load for the area exceeds the SIL of the existing and planned transmission system serving the area.

The Phoenix area 2012-2021 RMR study performed detailed RMR analysis for 2014 and 2021.

The Phoenix area RMR study is thorough and well documented. The study comports to the Commission's RMR study methodology and included production cost simulations using industry accepted study tools and publicly available data. The study concludes that RMR costs for the Phoenix metropolitan area in the study years are expected to be zero dollars. This is because the units that would be run to meet the RMR need are already expected to be running in a merit order dispatch during the few hours when RMR capacity is needed.

5.2.5.2 Tucson Area RMR Assessment

An RMR condition exists for the Tucson area because the local TEP load exceeds the SIL of the existing and planned local TEP transmission system.

The Tucson area RMR study is thorough and well documented. The study comports to the Commission's RMR study methodology and the results of production cost simulations. Assumptions and modeling evident in the report are accurate and appropriate for the TEP system.

TEP's Seventh BTA RMR filing reports projected RMR costs of $186,774 in 2014 and $1,188,526 in 2021. It also estimates that the capital costs of improvements needed to eliminate these RMR costs in the same two years would be $12.5 million and $132 million, respectively. The filing concludes that such upgrades are not cost effective. Staff supports this conclusion.

5.2.5.3 Yuma RMR Conditions and Import Assessment

The Yuma area is served by an internal APS 69 kV sub transmission network containing the entire APS load in the transmission import limited area. There are external ties to Western at Gila Substation and the Imperial Irrigation District ("IID") at Yucca Substation. There is also a 500 kV bulk power interface at North Gila with 500 kV lines running east to the Palo Verde Hub and west to Imperial Valley in California.

As part of the ACC Fifth BTA, Per Decision No. 70635, under Section 5.2 Efficacy of Commission Ordered Studies, item IC states: "There needs to be a system perspective of the RMR conditions for the entire Yuma County area in the future rather than limiting the RMR analysis solely to the APS 69 kV system. This is particularly true given that the SIL and MLSC import limits to the APS system are restricted by the overloads on other transmission providers' systems. This is underscored by the fact that major system changes are being proposed for that area by other interconnected entities such as Western, WMIID, IID and parties in the area seeking to connect under Large Generator Interconnection Agreement(s) ("LGIA")."

The Yuma area Seventh BTA RMR study was performed by APS and coordinated with SWAT's Colorado River Transmission ("CRT") Subcommittee. It is thorough and well documented. The study comports to the Commission's RMR study methodology and included production cost simulations using industry accepted study tools and publicly available data. Assumptions and modeling evident in the report are accurate and appropriate for the APS system, and reflect stakeholder concurrence on modeling and cut plane definition as ordered by the Commission in the Fifth BTA. The study concludes that RMR costs for the Yuma area in the study years are expected to be zero dollars. This is because the units that would be run to meet the RMR need are already expected to be running in a merit order dispatch during the few hours when RMR capacity is needed.

5.2.5.4 Santa Cruz County RMR Assessment

UNS Electric filed the latest RMR study of the Santa Cruz County System for the 2014 and 2021 systems. The 115 kV to 138 kV conversion is assumed in the 2021 case. In 2014, UNS Electric found an RMR generating cost of $544,525. This cost will be eliminated after the conversion of the line to 138 kV. The Santa Cruz County RMR study is thorough and well documented.

5.2.5.5 Mohave County RMR Assessment

UNS Electric filed the Seventh BTA RMR study of the Mohave County Study System in January 2012.[52] The Mohave County RMR study is thorough and well documented. The Seventh BTA study was performed for 2014 and 2021 under the oversight of the Colorado River Transmission ("CRT") Subcommittee. The scope of this study required an assessment of the portion of the Western's Desert Southwest Region ("DSW") transmission network within Mohave County, Arizona. DSW owns and operates all of the transmission network facilities within the Mohave County Study System.

Power flow simulations show the Study System is reliable and capable of serving all load within the specified cut plane. The SIL analysis indicates that a relatively small amount of generation may be required in the 2014 and 2021 planning horizon. However, even larger amounts of hydroelectric generation (317MW) within the study system must be run to meet the USBR's minimum river flow requirements even during summer peak conditions. Therefore, the expected level of run of river generation exceeds any RMR generation dispatch that is needed to assure system reliability.

5.3 Ten-Year Snapshot Study

SRP filed the report for this study of the Arizona statewide 2021 system which was coordinated through the CATS subcommittee. The study is done every other year, and was previously referred to as the "n-1-1 Study". The CATS subcommittee included representatives from the following transmission owners: APS, SRP, SWTC, TEP, Western and Electrical District #3. It was approved by CATS in January 2012.

Whereas some of the Arizona transmission owners have filed technical study reports for their respective areas of the system as part of the Seventh BTA, the CATS Ten-Year Snapshot Study represents the only comprehensive assessment of 2021 Arizona transmission plans (i.e., the

[52] Filed on behalf of various parties including Western, APS, Mohave Electric Coop, IID, TEP, et al.

end of the ten-year plan). Furthermore, the Ten Year Snapshot Study done in 2011 includes all transmission and generation projects statewide. This makes the report uniquely valuable for assessing the overall adequacy of Arizona transmission plans in 2021.

The 2021 case modeled a statewide load of 22,825 MW which is 2,515 MW (9.9%) lower than the statewide load modeled in the previous (i.e., 2019) Ten-Year Snapshot Study. This represents a load level less than the Sixth BTA load forecast but greater than the Seventh BTA load forecast. This is consistent with the timing of when the study base case assumptions were developed (early 2011). The 2021 base case (model) used for the study was based on the complete list of projects that were planned to be in service by 2021 at the time of base case development, which took place from January-April 2011. APS advised at Workshop II that this list accurately reflects the filed Seventh BTA ten-year plans.

The Ten-Year Snapshot Study consists of conducting n-0 and n-1 power flow analyses that determine the adequacy of the ten-year plan. In addition, the study ran sensitivity analyses for individual proposed projects removed from the base case. However, in this regard, it should be noted that removal of an individual project in some cases involved the removal of multiple transmission lines and/or bulk power transformers. In all a total of fourteen base case project deferral scenarios (seven APS projects, four SRP projects, one TEP project and 2 scenarios involving the SunZia project) were analyzed under both n-0 and n-1 conditions to assess the impact of such deferrals on system performance. All Arizona transmission system facilities with design voltages of 115 kV or greater were monitored for compliance with thermal (loading) and voltage criteria for all contingencies tested. The 2011 Ten Year Snapshot Study reached the following major conclusions:

1) Arizona's 2021 transmission plan is robust and supports the statewide load forecast.

2) There were no overloaded transmission system elements or voltage violations in the 2021 n-0 base case.

3) Single contingency n-1 outage analysis showed some overloads and voltage deviations that will need further investigation by the utilities in future studies.

4) Delay of either the Pinal West-Duke-Pinal Central 500 kV line ("South East Valley Project") or the Pinal Central-Tortolita 500 kV Project beyond 2021 could have significant negative impact on system performance.

5) Delaying any one of the other projects beyond 2021 does not show a significant impact on system performance, but this finding should not be interpreted as meaning that the projects are unneeded. In fact, each contributes to overall system performance.

APS's presentation on the 2021 study results during Workshop I states that sensitivity analyses for n-1-1 thermal violations and voltage violations without the South East Valley (SEV) Project in place show that these violations were caused by including the SunZia Project in the model for this scenario. Since SunZia has yet to file an interconnection application, the Ten-Year Snapshot Study report infers that completion of a subsequent system impact study should determine suitable mitigation measures for these violations which will be included in future ten-year plan filings.

5.4 Extreme Contingency Study Work

The Commission directed that parties in Decision No. 67457 address and document extreme contingency outage studies for Arizona's major generation hubs and major transmission stations, identify associated risks and consequences, and identify possible mitigating infrastructure improvements, if necessary. The Seventh BTA Extreme Contingency Study was conducted by APS and TEP, and was coordinated through the CATS subcommittee. The study examined steady-state performance (i.e., power flows and voltages) throughout Arizona for selected extreme contingencies in the supply to the Phoenix and Tucson load areas. The Phoenix area analysis was done using 2013 and 2021 heavy summer system models which reflected the filed ten-year project plans. Similarly, the Tucson area analysis was done using 2014 and 2021 heavy summer models. This analysis generally corresponds to NERC Category C and D events (e.g., NERC Reliability Standards TPL-003 and TPL-004), but did not include an assessment of transient stability performance.

The EHV common corridor and transformer outages analyzed were chosen based upon exposure to forest fires and other extreme common-mode contingency scenarios, and included the following multiple facility contingencies:

- Supply to Phoenix area
    - Cholla-Saguaro and Coronado-Silver King 500 kV lines
    - Navajo Westwing 500 kV lines (the "Navajo South" system)
    - Four Corners-Cholla-Pinnacle Peak 345 kV lines
    - Glen Canyon-Flagstaff-Pinnacle Peak 345 kV lines
    - Loss of all EHV transformer banks at Browning Substation
- Supply to Tucson area
    - Springerville 345 kV common corridor
    - Tortolita 500/138 kV Substation
    - Vail 345/138 kV Substation

In both the Phoenix and Tucson extreme contingency analyses, all customer loads can be served (or restored) and local resource reserve requirements can be met, but some of the contingencies would require operators to take certain mitigation measures. APS also reported at Workshop I that extreme contingency (multiple element) outage events for Arizona's other major generation hubs and transmission stations were not run in the extreme contingency study because those events are already addressed by other filed studies.

APS filed the detailed 2012 study results with the Commission under a Protective Agreement. Therefore, this Staff report – a public document – only includes information about the study from the APS presentation given at Workshop I.

Staff found the 2012 study satisfies the requirements of Commission Decision No. 67457.

6 National and Regional Transmission Issues

6.1 FERC Order 1000

The Federal Energy Regulatory Commission ("FERC") issued Order No. 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities* on July 21, 2011. Order 1000 revises FERC's electric transmission planning and cost allocation requirements for public utility transmission providers. The order builds on Order No. 890 with respect to transmission planning processes and cost allocation methods.

Arizona's largest transmission owners—APS, SRP, SWTC, TEP and Western participate in WestConnect's transmission planning process.[53] FERC recently suggested that WestConnect is a reasonable candidate to be defined as a transmission planning region per Order 1000, and it is expected that the respective FERC-jurisdictional utilities will request FERC approval of their Order 1000 compliance filings to designate WestConnect as their transmission planning region. The WestConnect Transmission Owners have initiated a stakeholder process to guide the appropriate filings with Order 1000. Compliance filings are due for Regional transmission planning and cost allocation processes were due October 11, 2012 and for inter-regional transmission planning and cost allocation processes are due by April 11, 2013.

6.1.1 Role of WestConnect

Transmission providers are establishing a WestConnect Order 1000 compliant regional transmission planning process. WestConnect has formed six teams to address key issues required by Order 1000:

1. Governance—to determine governance, membership, voting
2. Planning—to expand WestConnect Planning Process to be Order 1000 compliant
3. Cost Allocation—to determine cost allocation methodology including calculation of benefits
4. Compliance—to prepare OATT language for compliance filings
5. Communications—to develop and implement stakeholder communication strategy
6. Legal and Negotiation – to develop the Planning and Participation Agreement

[53] Pursuant to the 2007 WestConnect Regional Planning Project Agreement.

Subregional transmission planning, within the WestConnect foot print, is being performed by Southwest Area Transmission Planning Group ("SWAT"), the Colorado Coordinated Planning Group ("CCPG"), and the Sierra Subregional Planning Group ("SSPG"). Annually a ten-year integrated regional transmission plan is derived from their efforts that coordinate all transmission plans across the WestConnect planning area.

6.1.2 Relationship to the BTA process

KEMA and Staff believe that Arizona has been in the forefront of regional planning efforts through the BTA process. Order 1000 addresses three main areas: planning, cost allocation, and non-incumbent developers. The BTA process addresses many of these issues:

1) In regard to planning, Order 1000 requires:

    a) Transmission providers must participate in a regional transmission planning process—which is what the BTA process does, albeit with a focus on the intra-state impacts of transmission planned to be constructed within Arizona during the BTA planning horizon. Order 1000 expands this focus across larger regions such as WestConnect.

    b) Local and regional transmission planning processes must consider transmission needs driven by public policy requirements (such as renewable portfolio requirements) established by state or federal laws or regulations. This issue has been addressed in both the Sixth and Seventh BTA.

    c) Transmission providers in each pair of neighboring transmission planning regions must coordinate to determine if there are more efficient or cost-effective solutions to their mutual transmission needs. Since the BTA process is an Arizona process, it has only addressed the system within the state.

2) In regard to cost allocation, Order 1000 requires:

    a) Public utility transmission providers must participate in a regional transmission planning process in which certain transmission projects may be chosen for cost allocation. It should be noted that Arizona utilities have historically found creative ways to share costs among projects that benefit multiple utilities.

    b) Transmission providers in neighboring transmission planning regions must have a common interregional cost allocation method for new interregional transmission facilities. Since the BTA process is an Arizona process, it has addressed the system within the state.

c) Participant-funding of new transmission facilities is permitted. The BTA process has also addressed this issue.

3) In regard to non-incumbent developers, Order 1000 requires:

a) Transmission providers must remove from FERC approved tariffs and agreements a federal right of first refusal for a transmission facility selected in a regional transmission plan. Staff and KEMA observe that this issue is outside the BTA process.

6.2 Regional Transmission Planning – WestConnect

WestConnect is composed of electric utility companies[54] providing transmission services throughout the southwestern United States. Its members work collaboratively to assess stakeholder and market needs and to develop cost-effective enhancements to the western wholesale electricity market. WestConnect is committed to coordinating its work with other regional industry efforts to achieve as much consistency as possible in the western Interconnection.

6.2.1 SWAT Subregional Planning Group

WestConnect subregional transmission planning is performed by the Southwest Area Transmission Subregional Planning Group ("SWAT"), the Colorado Coordinated Planning Group ("CCPG"), and the Sierra Subregional Planning Group ("SSPG") which comprise the WestConnect planning area. The goal of SWAT is to promote subregional planning in the Desert Southwest including Arizona. SWAT is comprised of transmission regulators/governmental entities, transmission users, transmission owners, transmission operators and environmental entities. APS, SRP, SWTC, TEP, Western, Tri-State Transmission and Generation Association, Imperial Irrigation District, El Paso Electric, NV Energy, and Public Service Company of New Mexico are all transmission providers and SWAT participants.

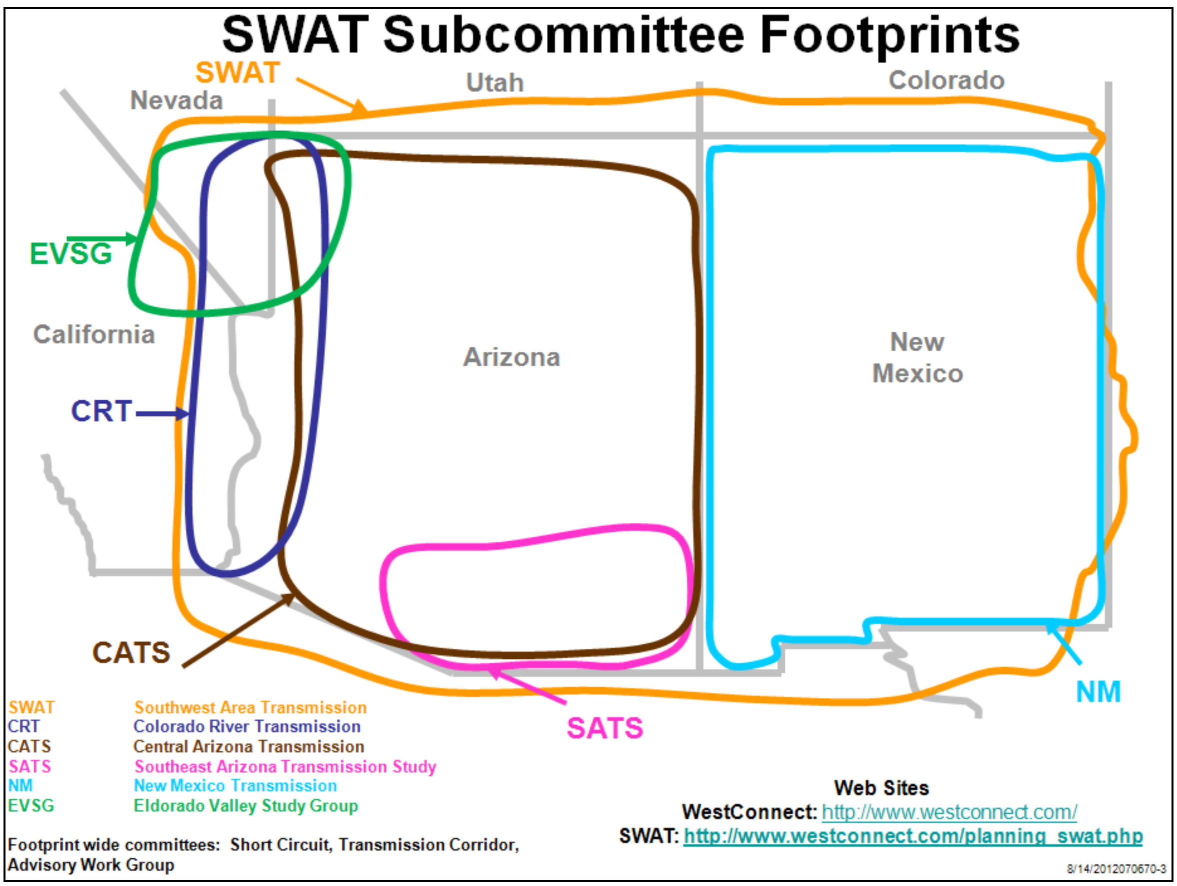
SWAT subcommittees and study groups have been performing studies in response to Commission ordered study requirements for the BTA for a number of years. The SWAT

[54] The membership of WestConnect is available at: http://www.westconnect.com/about_steeringcomm.php.

regional planning group includes seven main subcommittees which are overseen by the SWAT Oversight Committee. Separate web pages are provided for each of these subcommittees and the SWAT Oversight Committee on the WestConnect website.[55] SWAT subcommittees' meeting notices, notes, presentations, and reports are posted on their respective web pages. As noted throughout this report, SWAT subcommittees contributed in substantive ways to the Seventh BTA.

The geographic area(s) covered by SWAT and various subcommittees are shown in Figure 9.

Figure 9: SWAT Footprint(s)



[55] SWAT website: http://westconnect.com/planning_swat.php.

Following the Sixth BTA, the CATS EHV and CATSHV subcommittees were combined into a single subcommittee ("CATS"). As shown in Figure 9, the CATS study area is basically defined as the state of Arizona. SWAT filings in the Seventh BTA have actually been prepared by the CATS and SATS subcommittees. Analysis of Pinal County expansion, which was reported in the Sixth BTA, has since been absorbed into other CATS' studies and the individual utility ten-year planning studies.

Other current subcommittee and work group activities as provided by SWAT at Workshop #2 are summarized briefly below.

6.2.2 Colorado River Transmission Subcommittee

The focus of the CRT for the Seventh BTA was the Yuma and Mohave RMR studies. The results of these Commission-ordered studies are included in Section 5.2.5 of this BTA report.

6.2.3 Southeast Arizona Transmission Study

The SWAT Southeast Arizona Transmission Study ("SATS") Subcommittee was formed to study the Southeastern Arizona region. The SATS study area encompasses the southeastern portion of Pinal County, southern Graham County, most of Pima and all of Cochise Counties and Santa Cruz County. Table 12 lists the transmission providers who are participants in the study process.

Table 12 - SATS Participating Transmission Providers

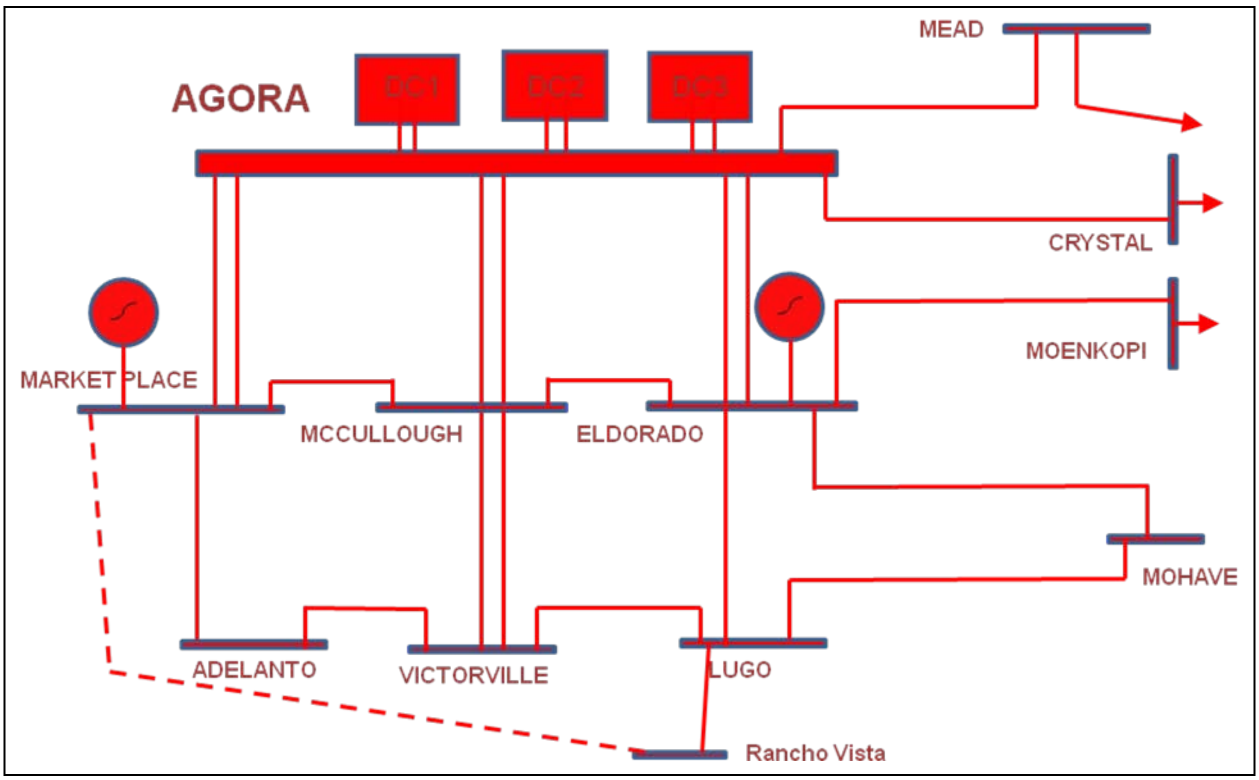
Arizona Public Service Company	Southwest Transmission Cooperative
Central Arizona Project	Tucson Electric Power
El Paso Electric Company	Western Area Power Administration
Public Service Company of New Mexico	US Bureau of Reclamation
UNS Electric	

6.2.4 Eldorado Valley Study Group ("EVSG")

The study group was formed in May 2010 in order to coordinate the development of all projects coming into and leaving the Eldorado Valley which is located in the southernmost tip of Nevada. This is a major hub of transmission expansion activity in the desert southwest. This hub is of significant interest to the State of Arizona due to its strong ties to the Arizona transmission system and its location along the export path from Arizona to California. A long list of transmission projects currently propose interconnecting at this hub – including projects from Arizona - as shown in Exhibit 24.

During the past two years EVSG performed a high level feasibility study that looked at conceptual expansion models for this hub. The base case configuration for this conceptual analysis assumed a new Agora Switchyard as shown in Figure 10. The study did not model specific HVDC projects, but assumed three new HVDC transmission projects from the north terminating at this bus (e.g., DC1, DC2, and DC3).[56]

Figure 10: EVSG Agora Concept



From this base case, incremental 500 kV AC transmission expansion was modeled from the Eldorado Valley area into southern California to assess the range of potential benefits to

[56] Details of the HVDC projects assumed are not required for this type of analysis since they are simply modeled as an equivalent generator at the receiving-end bus (e.g., Agora).

westbound transfer capability. The study concluded that the addition of one new 500 kV AC line into the Los Angeles load basin could provide as much as 2,681 MW of incremental westbound transfer capability.

6.2.5 Short Circuit Working Group

The working group finalized a combined short circuit database to enable improved modeling of seams between participating entities. Accurate modeling of short circuit impacts is critical to assessment of both transmission and generation expansion plans.

6.3 Western Area Power Administration Transmission Infrastructure Program

Western gave an update on their Transmission Infrastructure Program ("TIP") at Seventh BTA Workshop I. The program derives from Western's responsibility to implement Section 402 of the American Recovery and Reinvestment Act ("ARRA"), which grants borrowing authority of $3.25 billion for transmission projects and directs Western to identify, prioritize and participate in the study, facilitation, financing, planning, operating, maintaining, and construction of new or upgraded transmission facilities.

Projects under consideration for TIP funding must:

- Facilitate the delivery to market of power generated by renewable resources constructed or reasonably expected to be constructed.
- Have at least one terminus located within Western's service territory.

Western's Administrator must certify prior to borrowing funds from the US Treasury that a project satisfies these factors:

- Public interest nexus
- No adverse impact to system reliability or operations, or other statutory obligations.
- Reasonable expectation that the project will generate enough transmission service revenue to repay the principal investment; all operating costs, including overhead; and the accrued interest by the end of the project's service life.

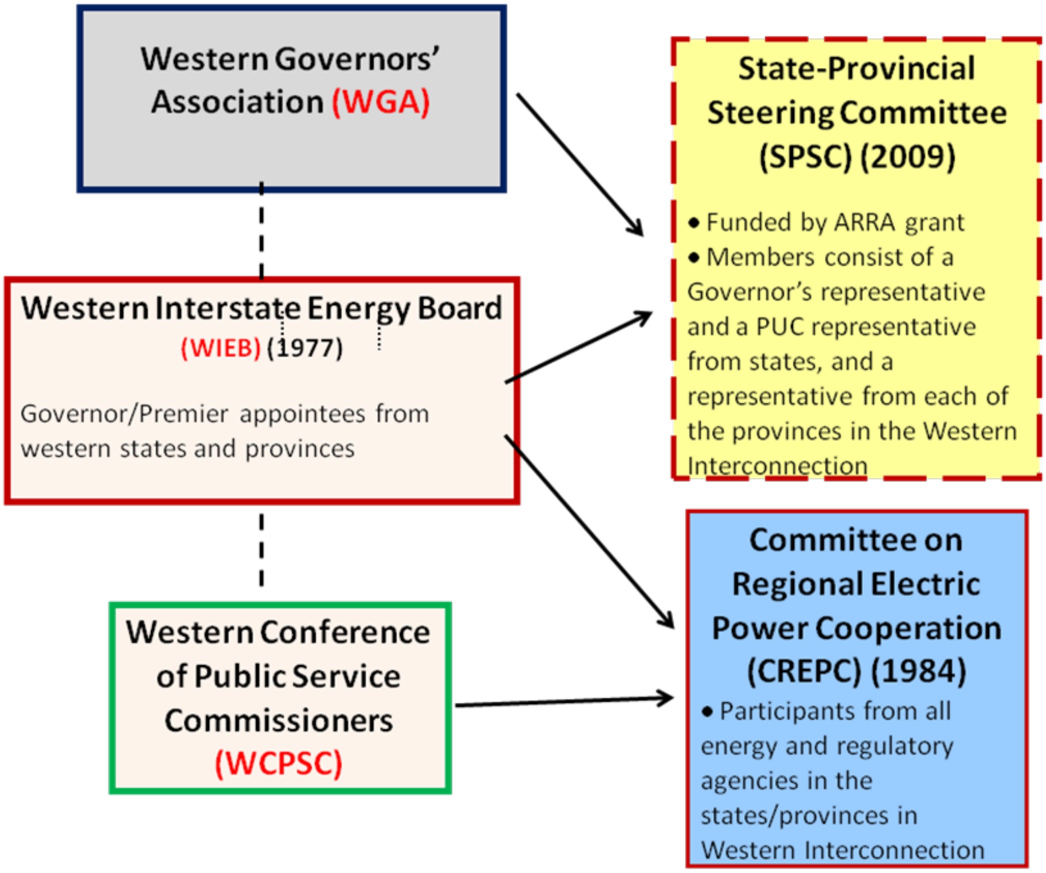
Three TIP project models exist:

- Financier model
    - Long-term construction financing
    - Western owns capacity
    - Example Project – Montana Alberta Tie Limited
- Public-Private Partnership model
    - Partnership with Merchant Transmission Developer
    - Western uses borrowing authority to finance ownership in Project
    - Example Project - TransWest Express Transmission Project ("TWE")
- Western internal transmission projects
    - Partnership with W Regional office to add or upgrade needed transmission identified typically through 10-year planning process.
    - Example Project - Electrical District 5-Palo Verde Hub Project

6.4 WGA/CREPC/SPSC Initiatives

Thomas Carr, Western Interstate Energy Board, and Lisa Schwartz, Regulatory Assistance Project, gave a presentation on WGA/CREPC/SPSC initiatives at Workshop II. A diagram showing the relationship between these western states organizations is shown in Figure 11.

Figure 11: Relationship between Western States Organizations



SPSC activities that are currently funded by an ARRA grant include:

- **Topic A** - Transmission planning (delegated to WECC)
  - Input on transmission expansion studies
  - Input on development of 10 and 20 year interconnection-wide transmission plans
  - Analyze policies to improve efficiency of the transmission system
- **Topic B -** Analyze region-wide actions to minimize the cost of integrating large amounts of renewable energy
- **Topic C -** Participate in WECC-organized forum for utility and state/provincial resource planners
- **Topic D -** Demonstrate process for participation in decisions/consensus for participating in development of a plan under Topic A

Commissioners from 12 state commissions are currently exploring questions related to formation of an Energy Imbalance Market ("EIM") in the West. They recently issued a stakeholder inquiry targeting information in key topic areas and completed the following steps:

- Developed a detailed straw man market design
- Received cost estimates for forming an EIM market operator (estimates provided by both Southwest Power Pool and California ISO)
- Refined benefits analysis from National Renewable Energy Laboratory

CREPC/SPSC is also attempting to address regional concerns over resource planning uncertainties related to renewable energy portfolio requirements throughout the western states through establishing a resource planning forum.[57] The topics currently being addressed in this forum include:

- Lawrence Berkeley National Laboratory findings on review of western utility integrated resource plans
- Integration of variable generation
- Distribution/transmission sector interface
- Risk analysis in resource planning
- Natural gas/electric interface

Lisa Schwartz described the "Regulatory Assistance Project" ("RAP") and their current effort to explore coordinated resource procurement by utilities in western renewable resource zones ("WREZ") of common/multi-state interest and to help create a critical mass of transmission needs (≥500 kV AC) in support of such procurement. The RAP has conducted interviews with 25 Western US and Canadian utilities and commissions and developed a report with recommendations on coordinated, joint transmission development, and broader perspectives on planning and development.[58]

Given that 2/3 of the RPS requirements in the west are in California, the RAP is also developing a white paper describing California's transmission planning practices and underlying renewable procurement processes. One point of particular interest is interpretation of California's 33%

[57] Information is available at WIEB's webpage - http://www.westgov.org/wieb/.

[58] The report is available at http://www.westgov.org/component/joomdoc/doc_download/1555-wrez-3-full-report-2012.

RPS rules related to treatment of out-of-state renewable resources. A wide range of interpretations exist as to which out of state resource "buckets" are eligible under the RPS rules. However, based on the interviews that RAP has conducted they opined that at the present time the California utilities are overwhelmingly interested in "Bucket 1" resources and clearly stated a preference for:

- Energy plus renewable energy credits delivered to a California balancing area without substitution, or
- Out of state renewables scheduled into a California balancing authority via dynamic scheduling

The RAP has drafted a paper on this topic that is posted on the WEIB website.[59]

6.5 WECC Regional Transmission Expansion Planning

Brad Nickell, WECC's Director of Transmission Planning, provided an overview of the current RTEP process and activities at Workshop #2.

WECC has been integrating a Global Information System based planning tool for long-term capital expansion that is intended to optimize new generation and transmission plans. It incorporates reliability, policy, environmental and cost considerations. One feature of the tool is the ability to select proposed transmission corridors considering environmental, cultural, historical and archaeological factors. In the future, the tool will be expanded to also consider the impact of water resources on the planning process.

Mr. Nickell also discussed WECC's current 2013 transmission expansion planning cycle which is being used to develop a portfolio of 10-20 year expansion plans. About two-thirds of the analytical work on the plan has been completed to date. Draft study results will be ready for stakeholder review by the first quarter of 2013. The planned timeline calls for completion of the final report and approval by WECC's board in September 2013. This planning process being utilized includes both 10 year scenarios which are based on near-term decisions and scenarios gathered through a WECC stakeholder request process and 20 year scenarios reflecting potential energy futures. The 20 year scenarios are being developed by the Scenario Planning

[59] http://www.westgov.org/wieb/.

Steering Group which reports to the Transmission Expansion Planning Policy Committee ("TEPPC"). This process is represented by the decision tree shown in Figure 12.

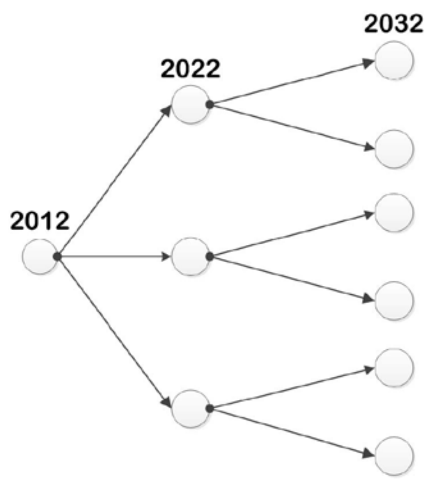
Figure 12: WECC Transmission Expansion Planning

2013 Transmission Plans

Connecting the Dots

How might Western Interconnection need to change to accommodate changes in the supply and demand for electric energy?

- 10-year – understanding impacts of near-term decisions (bottoms-up)
- 20-year – understanding drivers of potential energy futures (top-down)
- The Plans tell the story of how they are connected



Understanding the impacts of decisions, not determining what should be done

WECC

The overarching goals for this 10-20 year planning process are to create credible data and models for use in other planning processes by the WECC and its stakeholders, provide a correlation between possible energy futures and transmission plans in the west that account for costs and environmental impacts, and collect information that can be used by others in decision-making processes relating to energy planning.

In regard to FERC's Order 1000, Mr. Nickell advised that WECC is currently gathering stakeholder input and working with subregional planning groups in order to understand their potential needs related to compliance. WECC's focus in this process is on the regional-interregional coordination aspect.

Finally, the WECC has an important role in establishing major path ratings in the region. Exhibit 6 provides a map of the WECC rated transmission paths in Arizona. Ratings of these transmission paths are increased in two ways - either a new line is constructed and integrated into an existing path, or one or more existing lines in a path are upgraded to achieve an increased path rating. Such path rating changes must go through an exhaustive WECC path rating process, which includes technical studies and peer review, in order to implement such path rating increases.

6.6 California Transmission Planning for Renewables

The California Transmission Planning Group ("CTPG") accepted an invitation from the Commission to present a summary of their 2011 statewide transmission expansion planning study for renewable integration at Workshop II. A complete copy of this presentation is posted on the Seventh BTA webpage.[60]

CTPG is an ad hoc transmission planning group that represents both publically-owned and investor-owned utilities in California. In 2011 the group conducted a study to evaluate the transmission expansion requirements for a range of potential renewable portfolio scenarios that were predicated on the CA 33% RPS target in 2020. These scenarios included both in-state and out-of-state renewables. Two of the nine scenarios evaluated in the study represented renewable imports from the desert southwest as follows:

[60] See file name "CTPG_for_ACC_BTA_Presentation_08-16-2012" at: http://www.azcc.gov/Divisions/Utilities/Electric/BTA-Index.ASP.

Table 13 - CTPG 2020 West-of-River Renewable Import Scenarios

Scenario No.	Incremental WOR Renewable Import Schedule	Portion Scheduled from S. Nevada	Portion Scheduled from Arizona	Conditions Modeled
8	3,663 MW	50%	50%	Late Sept 9 AM PST
9	3,663 MW	37%	63%	Late Sept 9 AM PST

The base cases for these scenarios also modeled the expected 2020 delivery schedule levels on the EOR and WOR paths for conventional resources, including shares of the Palo Verde Nuclear Generating Project typically delivered to California participants, as found in the initial WECC 2020 autumn base case. With these assumptions, including the incremental 3,663 MW renewable delivery schedule from Arizona and southern Nevada, the resulting WOR base case flow level in Scenarios 8 and 9 was 8,759 MW (e.g., roughly 75% of the path rating).

Based on the 2011 study using these assumptions, the CTPG concluded that transmission upgrades and/or mitigations would be required by 2020 in the WOR corridor area as shown in Table 14.

Table 14 - CTPG's Proposed WOR Corridor Mitigation Plan Components

2nd Ivanpah (S.Cal)-Eldorado (S.Nev) 230 kV and Special Protection System for generation tripping
Special Protection System for trip of Imperial Valley (SDG&E) – La Rosita (ROA) 230 kV for local outage
Reconductor of Highline-Midway 230 kV (IID) or establish Special Protection System to trip Midway generation

A map of the proposed CTPG system improvements is shown in Exhibit 18.

Staff and KEMA observe that there are no new EHV lines included in the list of CTPG upgrades/mitigations identified in Table 14. This lack of planned EHV expansion in southern California appears to differ from the findings of the 2011 Arizona study "Enhancing Arizona's Ability to Export Renewable Energy" which (as noted previously in Section 3.4) concluded that "Even if California opens its RPS to significant amounts of imported renewable power, there will be significant technical transmission limitations for power delivery to California west of Path 49, either directly from Arizona or via southern Nevada." This difference in conclusions between the California and Arizona studies may be due in part to differences in the study years modeled as well as the location and quantity of renewable exports. [61] Staff and KEMA observe that improved coordination is needed between transmission planning studies in the WestConnect/SWAT region and California in order to adequately assess this seams issue.

6.7 Seams Issues

Seams issues include differences in the electric energy market models, scheduling and congestion management protocols, planning, licensing, ownership and operational control of transmission facilities that cross state boundaries, etc. Several of these issues are of particular relevance to the current and future BTA's.

As discussed in Section 6.1, Order 1000 bears directly on seams issues through encouraging regional planning and cost sharing. Even so the western states face some unique challenges in this regard. Half the load in the West is in California and western Washington, but generation is distributed across the region, creating numerous transmission bottlenecks throughout the region. There are also 37 independent balancing authority areas within the WECC interconnection with diverse characteristics. Due to such differences it can be expected that multiple transmission planning regions will form within WECC during the Order 1000 compliance and implementation process. This will leave significant inter-regional seams issues to be resolved.

Historically, the states have tended to address electric transmission needs on a state-by-state basis. The Western Governors' Association, Western Interstate Energy Board and WECC are working with diverse stakeholders through the Regional Transmission Expansion Project ("RTEP") to analyze west-wide transmission requirements under a broad range of alternative energy futures. The joint effort will develop long-term, interconnection-wide transmission expansion plans.

[61] This apparent inconsistency may be related in part to the fact that the CTPG study was based on autumn, shoulder peak load conditions vs. the AZ study assumption of heavy summer load conditions.

There are also other factors to consider. As the western states become more closely interconnected, a problem in one state may become more likely to impact the adjacent states. California is the heavy weight in the west—it is about a third of the load and has a very high RPS target of 33% of energy requirements. High levels of variable wind and solar generation could impact operations across the entire region. In addition to technical considerations, there are various institutional limitations as well – particularly those related to market differences. The California Independent System Operator ("CAISO") was the first (and still the only) entity to establish a locational marginal price ("LMP") electricity market in the western United States. Other balancing authority areas in the west have continued to use the bilateral market concept, which creates a seams issue. Lastly, there are also unexpected 'extraordinary' situations such as the current long-term outage of the San Onofre Nuclear plant in California that can affect operations, planning and reliability in the larger region – including Arizona.

While some of these seams issues fall outside the scope of Order 1000, Staff and KEMA note that the Order's focus on improved regional planning and cost sharing processes will address key seams issues related to system expansion. Therefore, we conclude that it would be beneficial for the Commission to monitor progress on seams issues that occurs as a result of Order 1000 implementation efforts in the WestConnect region.

7 Conclusions

The quality of industry reports and Commission ordered BTA study results available for the BTA process have progressively improved over the past twelve years. The body of reference documents and presentations available for this BTA are among the best filed with the Commission to date. The industry's commitment to and focus on supplying transmission plans and associated information addressing issues and concerns of importance to the Commission are appreciated. A wide range of public policy concerns regarding reliable service to Arizona customers has been addressed during the more than a decade that the BTA process has been active.

The conclusions of this BTA are organized to address five key issues:

- *Adequacy of the system to reliably serve local load* - Does the combination of the filed ten-year transmission plans meet the load serving needs of the state during the 2012-2021 timeframe in a reliable manner?
- *Efficacy of Commission ordered studies* - Do the study reports filed in response to Commission ordered RMR, Ten Year Snapshot and Extreme Contingency studies comply with, and sufficiently meet, the intended goals of the Commission's orders?
- *Adequacy of system to reliably support the wholesale market* - Do the transmission planning efforts effectively address concerns raised in previous BTAs about the adequacy of the state's transmission system to reliably support the competitive wholesale market in Arizona?
- *Adequacy of renewable transmission plans* - Do transmission providers' ten-year transmission expansion plans, including their renewable transmission project proposals, effectively address concerns raised in previous BTAs regarding adequately addressing the overall needs for renewable resource development and integration into the Arizona and regional electric power system (including export of such resources from Arizona to neighboring markets)?
- *Suitability of transmission planning processes utilized* - Do the plans and planning activities comport with transmission planning principles and good utility practices accepted by the power industry and the reliability planning standards established by the NERC, WECC and FERC?

These five issues are discussed in Sections 7.1 through 7.5, respectively.

7.1 Adequacy of System to Reliably Serve Local Load

Based on the ten-year plans, technical studies, criteria, and assumptions filed in the Seventh BTA and/or obtained through subsequent data requests and stakeholder workshops, Staff and KEMA reach the following conclusions:

1) As a result of current economic conditions, the statewide demand forecast for the 2012-2021 ten year planning period has shifted by about six years since the Sixth BTA (e.g., it will take about six years longer to reach the previous 2012 demand forecast level). A total of 37 transmission projects have been delayed since the Sixth BTA, with an average delay of five to sixyears. In addition, six EHV transmission projects were cancelled. These delays and cancellations are consistent with the reduction in statewide demand forecast since the Sixth BTA and do not appear to threaten the adequacy of the system or its ability to reliably serve load. On the other hand, eight new transmission projects totaling 90 line miles at 115 kV and 230 kV are proposed as part of the utilities' ten-year plans filed in the Seventh BTA. No new lines are proposed in this BTA at either 345 kV or 500 kV.

2) A total of 23 parties (utilities and developers) made ten-year plan filings in the Seventh BTA. Some of these filings actually represent multiple additional parties. All Commission required studies related to adequacy and reliability have been filed.

3) Technical studies filed in the Seventh BTA indicate a generally robust study process for assessing transmission system performance (steady-state and transient) for the 2012-2021 planning period.

7.2 Efficacy of Commission Ordered Studies

All Commission required studies related to adequacy and reliability have been filed. APS, SWTC and TEP filed RMR studies. SRP filed the Ten -Year Snapshot Study which was coordinated through the CATS subcommittee. APS filed the Extreme Contingency Study which was performed in conjunction with TEP and coordinated through CATS. TEP filed the Southeast Arizona Transmission Study performed under SWAT. And, SWTC filed compliance filings in 2011 on behalf of the Cochise County Study Group as directed by the Commission's Decision No. 72031 in the Sixth BTA.

The following conclusions apply to the efficacy of the filed documents relative to the intent of the Commission ordered action:

1) The RMR studies for Phoenix, Tucson, Yuma, Santa Cruz County and Mohave County were all thorough and well documented. They project zero RMR costs in all areas except Tucson. However, RMR costs for Tucson are too small to justify any capital upgrades to the grid at this time. On whole, there appears to be minimal benefit to performing RMR analysis in BTAs for the next few years.

2) The Ten Year Snapshot Study represents a composite assessment of the 2021 statewide Arizona transmission system performance under normal (n-0), single-contingency (n-1) and certain overlapping (n-1-1) contingencies. The Extreme Contingency Study examines more severe contingency scenarios such as complete transmission corridor outages and outages of major transmission elements at substations. These studies demonstrate the ten-year plan is robust and should provide adequate and reliable service to Arizona customers.

3) The proposed transmission expansion plan identified in filings by the Cochise County Study Group participants was predicated upon a "continuity of service" definition that does not appear to be economically justified. Based on updated reliability information provided to the CCSG, Staff and KEMA observe that the transmission system in Cochise County already meets NERC reliability standards and currently has a level of reliability that is comparable to other largely rural areas. Therefore, Staff concludes that the Commission should suspend implementation of the new continuity of service definition and retain the existing "restoration of service" planning paradigm for now.

4) UNS Electric's previous plan to construct a new 345 kV or 138 kV line to the Santa Cruz County load pocket in order to reduce customer outage exposure does not

appear to be economically justified at this time. UNS Electric will be filing an application with the Commission to remove the requirement to construct this second transmission line. Given the decrease in demand forecast for the area and improvements that UNS Electric has made to its local transmission system and generating facilities, Staff concurs with this change in the ten-year plan.

5) The Southeast Arizona Transmission Study Group report and the SWTC ten-year plan filings, including a rerating study for the Apache-Butterfield 230 kV line[62], confirm that this is a suitable approach for mitigating area loading limits noted in the Sixth BTA. Also, potential bus voltage deviations noted in the SATS area during the Sixth BTA have been mitigated by revised transmission plans filed in the Seventh BTA.

7.3 Adequacy of System to Reliably Support the Wholesale Market

Most of the transmission system technical studies filed in the Seventh BTA reflect summer peak demand conditions. This is a common assumption for system expansion planning studies. In addition to representing the single peak demand level, the generation dispatch and interchange schedules modeled in these studies reflect just one possible set of wholesale transactions. In actual operation, wholesale market transactions occur hour to hour under a wide range of conditions including peak, off-peak and shoulder-peak load periods throughout the year. Therefore, a thorough analysis of the adequacy of the system to support wholesale transactions would need to include a similar range of system conditions and transaction scenarios (intrastate and interstate transactions). However, such studies are not filed in the BTA.

Even so, it can still be inferred from peak load studies and information filed in the Seventh BTA that the existing and planned Arizona EHV system should be adequate to support a robust wholesale market in the 2012-2021 timeframe. Two key factors that contribute to a robust

[62] Filed in January 2011 by SWTC in Docket No. E-00000D-09-0020. SWTC advised Staff in September 2012 that structure improvements needed to uprate the line from 365 MVA to 401 MVA, as contemplated in that filing, have since been completed.

market are the availability of sufficient generation reserves (above and beyond local and statewide demand) and the availability of sufficient transmission capability for transferring power to meet the needs of the wholesale market both within Arizona and across state borders. Even after accounting for generation reserve requirements, in-state generation will be available at peak system load for sale on the wholesale market and for export out of Arizona.[63] In addition, this generation augments the local resources of Arizona's utilities in the event of major forced power plant outages or other resource emergencies. While there is no guarantee that generation reserves will be available for wholesale transactions under all load conditions, the significant drop in the statewide load forecast since the Sixth BTA and the expected growth in renewable resources would suggest that additional generation reserves should be available for such transactions.

Regarding delivery capability, the Ten-Year Snapshot study looks at n-1-1 conditions and demonstrates that even after removing any one of the major planned EHV transmission projects in the current ten-year plan, the 2021 Arizona system will still perform with minimal performance issues (assuming suitable mitigation plans are identified through the pending SunZia interconnection study). From this result, it can be inferred that sufficient statewide transmission capacity will exist on a day-to-day basis to handle both native load requirements and wholesale power transactions without a significant risk of congestion on Arizona's EHV delivery paths. Furthermore, following completion of the Ten-Year Snapshot study for the current BTA, the WECC approved a Performance Category Upgrade of the Hassayampa to Jojoba and Hassayampa to Pinal West; and Jojoba to Kyrene 500 kV transmission corridors. According to SRP comments at Workshop I, this will increase the 2014 Palo Verde East path rating by 1,525 MW. Although this upgrade was not modeled in the Seventh BTA studies, this additional delivery capability will help to support greater wholesale market transactions.

Even though the Ten-Year Snapshot study considers the impacts if major planned projects are not built, it must again be noted that system performance in these study scenarios is performed under peak system demand condition with all other transmission facilities assumed to be in service. In reality, during most days of the year any number of transmission and generation

[63] The Ten-Year Snapshot study projects that Arizona will have an installed capacity reserve margin of at least 26.9% in 2021, which is generally considered adequate according to industry guidelines.

facilities are scheduled (planned) to be out of service for maintenance, repair or construction activities. Such planned outages can have a significant impact on the ability of the system to support wholesale transactions. Such planned outages are not modeled in the expansion planning studies filed in the BTA, but they are modeled in both seasonal and daily operating studies typically performed by various Arizona utilities and the WECC Reliability Coordinator. These operational studies allow the operators to determine the level of wholesale transactions that can reliably be scheduled in any given hour as well as the amount ancillary services required to support such transactions. Operational assessments of this type are outside the scope of the BTA, but are critical to determining the day to day level of intrastate and interstate wholesale transactions including export of renewables from Arizona to neighboring states.

7.4 Adequacy of Transmission for Exporting Renewables from Arizona

Staff and KEMA reached the following conclusions in this regard:

1) Developing Arizona's vast renewable resource potential and export opportunities requires a coordinated and multi-faceted strategy involving stakeholders representing utility, government, economic, developer, environmental, and other interests. In particular, seams issues between Arizona and California pose challenges to major growth in renewable exports. In this regard Staff and KEMA note that Order 1000 encourages improved regional planning and cost sharing processes and we conclude that it would be beneficial for the Commission to monitor progress on seams issues that occurs as a result of Order 1000 implementation efforts in the WestConnect region.

2) The 2011 filing by Arizona utilities in response to Commission Decision No. 72031 directing the utilities to jointly conduct or procure a study to identify the barriers to and solutions for enhancing Arizona's ability to export renewable energy is responsive to the Commission's order. Staff also observes that during the course of the export study, utilities engaged stakeholders in a successful process of seeking their input and ideas.

3) The technical assessment included in the 2011 renewable export study approach was reasonable, if somewhat simplified. The approach used in the study did not evaluate a range of variables that would likely result in smaller increases due to more-restrictive transmission limits. We believe that a more-rigorous study would likely find smaller incremental export benefits from the identified transmission facilities than the values found in the 2011 utility study.

4) Differences between the findings of the 2011 Arizona study "Enhancing Arizona's Ability to Export Renewable Energy" and the California Transmission Planning Group's 2011 study on transmission expansion needs for renewable integration demonstrate that improved coordination is needed between transmission planning studies in the WestConnect/SWAT region and California in order to adequately assess the seams issues.

7.5 Suitability of Transmission Planning Processes Utilized

The State of Arizona is fortunate that its transmission providers are engaged in and providing leadership to the SWAT and WestConnect subregional planning processes. These planning forums utilize an open, transparent, and collaborative approach to transmission planning. Stakeholder participation has been broad-based and inclusive of other interested parties that desire to engage in the planning process.

Staff and KEMA also make the following observations and conclusions in regard to the suitability of study processes and technical reports in the Seventh BTA:

1) Arizona utilities have been extensively engaged in, and providing leadership to, Southwest Area Transmission and WestConnect subregional planning processes and Order 1000 compliance efforts. These utilities and other stakeholders have also participated and contributed valuable input during the Seventh BTA process.

2) Technical studies filed in the 7[7h] BTA indicate a generally robust study process for assessing transmission system performance (steady-state and transient)[64] for the 2012-2021 planning period. This included stability study results from APS, SRP, TEP and SWTC.

3) SATS is the first SWAT Subcommittee to study and coordinate local HV and EHV transmission system plans in a common forum. This approach to subregional planning has produced useful study results in the Sixth and Seventh BTAs and may be well suited for other local areas in Arizona.

4) While Arizona's transmission providers have effectively addressed a broad range of study requirements in this BTA, Staff recognizes that these differ in some respects from the studies required for the utilities to comply with mandatory reliability standards implemented by FERC over the past several years. Even so, utility reporting of relevant developments from the NERC reliability audit process is beneficial in the BTA process. Results of NERC reliability standards audits over the past two years as provided by the jurisdictional utilities in the Seventh BTA proceeding does not indicate any reliability standards concerns for the Arizona system.

[64] For the purpose of this report, Staff uses the terms "dynamic stability" and "transient stability" interchangeably in reference to time domain studies that model fault events or other disturbances.

8 Recommendations

Based upon the observations and findings discussed in the conclusions, Staff submits the following recommendations for Commission consideration:

1) Staff recommends that the Commission continue to support the use of the:

    a) "Guiding Principles for ACC Staff Determination of Electric System Adequacy and Reliability" (See Appendix A);

    b) NERC reliability standards, WECC system performance criteria, and FERC enforcement policies relative to compliance with transmission planning reliability standards; and

    c) Collaborative transmission planning processes such as those that currently exist in Arizona and which help to facilitate competitive wholesale markets and broad stakeholder participation in grid expansion plans.

2) Staff recommends that the Commission continue to support the policy that generation interconnections should be granted a Certificate of Environmental Compatibility only when they meet regional and national reliability standards and the applicable Commission requirements.[65]

3) Staff recommends that the Commission continue to require the jurisdictional utilities to report relevant findings in future BTAs regarding compliance with transmission planning standards (TPL-001 through TPL-004) from NERC/WECC reliability audits that have been finalized and filed with FERC.

4) Staff recommends that the Commission suspend efforts to upgrade reliability to a continuity of service definition for Cochise County and Santa Cruz County due to the high cost of capital upgrades and of new transmission construction that would be needed to achieve such a level of reliability and the low customer density in these service areas, and suspend its directive from the Sixth BTA for filing two more CCSG

[65] See Appendix A – Guiding Principles for Determination of System Adequacy and Reliability.

progress reports in 2012. In addition, Staff recommends that the CCSG participants and UNS Electric continue to monitor the reliability in Cochise and Santa Cruz Counties, respectively, and propose any modifications that they deem to be appropriate in future ten-year plans. Staff also recommends that the Commission continue to collect applicable outage data from the respective utilities in order to monitor any changes in Cochise County and Santa Cruz County system reliability in future BTA proceedings.

5) Staff recommends that the Commission continue to require the jurisdictional utilities to include planned transmission reconductor projects, transformer capacity upgrade projects and reactive power compensation facility additions at 115 kV and above in future 10-year plan filings.

6) Staff recommends that the Commission accept the results of the following Commission ordered studies provided as part of the Seventh BTA filings:
    a) "Extreme Contingency" outage study for Arizona's major transmission corridors and substations, and the associated risks and consequences of such overlapping contingencies.

    b) Ten-Year Snapshot study results documenting the performance of Arizona's statewide transmission system in 2021 for a comprehensive set of n-1 contingencies, each tested with the absence of different major planned transmission projects.

    c) RMR studies for Phoenix, Tucson, Yuma, Mohave County and Santa Cruz County.

    d) The report, *Enhancing Arizona's Ability to Export Renewable Energy*, that addressed the Commission's study requirement as directed in the Sixth BTA.

7) Staff recommends the Commission suspend the requirement for performing RMR studies in every BTA and implement criteria for restarting such studies based on a biennial review of factors such as:

- An increase of more than 2.5% in an RMR pocket load forecast since the previous BTA (i.e., relative to the load forecast for an RMR pocket for the final RMR study year for which RMR studies were last filed)[66].
- Planned retirement (or an expected outage during the summer months of June, July or August) of a transmission or substation facility required to serve an RMR load pocket, unless a facility being retired will be replaced with a comparable facility before the next summer season.
- Planned retirement (or an expected outage during the summer months of June, July or August) of a generating unit in an RMR load pocket that has been utilized in the past for RMR purposes, unless a generator being retired will be replaced with a comparable unit before the next summer season.
- A significant customer outage in an RMR load pocket during summer months defined as a sustained outage of more than one hour that exceeds the greater of 100 MW or 10% of the peak demand in an RMR pocket.

8) Staff recommends that the Commission issue an order that directs Arizona utilities to advise each interconnection applicant of the need to contact the Commission for appropriate ACC filing requirements at the time the applicant files for interconnection.

[66] For example, the final RMR study year filed in the Seventh BTA is 2021 and future BTA load forecasts for 2021 would be compared to the Seventh BTA forecast amount for this year to determine the percent increase. Using the data for the Phoenix RMR area, the peak demand forecast for 2021 is currently 14,209 MW so the need for restarting RMR analysis would be considered if and when a revised 2021 forecast exceeds 14,209 x 1.025 = 14,564 MW.

9 List of Acronyms Used In Report

AC	Alternating Current	**EIM**	Energy Imbalance Market
ACC	Arizona Corporation Commission	**EIS**	Environmental Impact Statement
ANPP	Arizona Nuclear Power Plant	**EOR**	East of (Colorado) River
APS	Arizona Public Service	**EPS**	Environmental Portfolio Standards
ARRA	American Recovery and Reinvestment Act	**ERO**	Electric Reliability Organization
ARRTIS	Arizona Renewable Resource and Transmission Identification Subcommittee	**EVSG**	Eldorado Valley Study Group
ATC	Available Transfer Capability	**FERC**	Federal Energy Regulatory Commission
AZ	Arizona	**FOR**	Forced Outage Rate
AZNM	AZ-NM EHV Subcommittee	**FPA**	Federal Power Act
BA	Balancing Authority	**GT**	Gas Turbine
BLM	Bureau of Land Management	**GBPP**	Gila Bend Power Partners
BTA	Biennial Transmission Assessment	**HV**	High Voltage
CA	California	**HVDC**	High Voltage Direct Current
CATS	Central Arizona Transmission System	**I/S**	In-Service
CAWCD	Central AZ Water Conservation District	**IID**	Imperial Irrigation District
CC	Combined Cycle	**IPP**	Independent Power Producer
CC&N	Certificate of Convenience & Necessity	**ISO**	Independent System Operator
CCSG	Cochise County Study Group	**KEMA**	KEMA, Inc
CDEAC	Clean and Diversified Energy Advisory Committee	**kV**	Kilovolt
CEC	Certificate of Environmental Compatibility	**kWh**	Kilowatt-Hour
CO	Colorado	**LGIA**	Large Generator Interconnection Agreement
CREPC	Commission on Regional Electric Power	**LLC**	Limited Liability Corporation
CRT	Colorado River Transmission Subcommittee	**LMP**	Land Management Plan Locational Marginal Price
CSP	Concentrating Solar Power	**MISO**	Midwest Independent System Operator
CTPG	California Transmission Planning Group	**MLSC**	Maximum Load Serving Capability
DOE	Department of Energy	**MOU**	Memorandum of Understanding
DPA	Dine Power Authority	**MVA**	Megavolt-Ampere
DPV2	Palo Verde-Devers No. 2 500kV	**MVAR**	Megavolt-Ampere Reactive
DSW	Desert Southwest Region	**MW**	Megawatt
ED	Electric District	**n-0**	No Contingency
EHV	Extra High Voltage	**n-1**	Single Contingency

n-1-1	Overlapping Contingency
n-2	Double Contingency
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NF	National Forest
NG	Natural Gas
NM	New Mexico
NOI	Notice of Inquiry
NOPR	Notice of Proposed Rulemaking
NREL	National Renewable Energy Laboratory
NV	Nevada
OASIS	Open Access Same Time Information System
OATT	Open Access Transmission Tariff
PDS	PDS Consulting, LLC
PEIS	Programmatic Environmental Impact Statement
PJM	Pennsylvania-New Jersey-Maryland (ISO)
PNM	Public Service of New Mexico
PV	Palo Verde and/or Photovoltaic
RAP	Regulatory Assistance Project
RMR	Reliability Must Run
ROD	Record of Decision
RPS	Renewable Portfolio Standard
RRTT	Rapid Response Team for Transmission
RTAP	Renewable Transmission Action Plan
RTEP	Regional Transmission Expansion Project
RTTF	Renewable Transmission Task Force
RTO	Regional Transmission Organization
RTP	Renewable Transmission Project
SATS	Southeastern Arizona Transmission Study
SCE	Southern California Edison
SCED	Security Constrained Economic Dispatch
SDG&E	San Diego Gas and Electric
SEV	South East Valley
SIL	Simultaneous Import Limit
SIS	System Impact Study
SPS	Special Protection System
SPSC	State-Provincial Steering Committee
SRP	Salt River Project
SSPG	Sierra Subregional Planning Group
SSVEC	Sulphur Springs Valley Electric Cooperative
ST	Steam Turbine
Staff	Utilities Division Staff
SWAT	Southwest Area Transmission Study Group
SWPG	Southwest Power Group
SWTC	Southwest Transmission Cooperative
TEP	Tucson Electric Power
TEPPC	Transmission Expansion Planning Policy Committee
TIP	Transmission Infrastructure Program
TNMP	Texas-New Mexico Power Company
TTC	Total Transfer Capability
TWE	TransWest Express
UDC	Utility Distribution Company
UNS Electric	UniSource Electric, Inc.
Western	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WGA	Western Governors' Association
WIEB	Western Interstate Energy Board
WOR	West of (Colorado) River
WREZs	Western Renewable Energy Zones
WWMID	Welton-Mohawk Irrigation & Drainage District