Sixth Biennial Transmission Assessment 2010-2019

Arizona Corporation Commission
Docket No. E-00000D-09-0020

This document is formatted for back-to-back printing. If it is printed single-sided there will be some pages with no text other than the header and footer.

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 Sixth Biennial Transmission Assessment ("BTA") is based upon ten-year plans filed with the Commission by parties in January 2010 and certain filings during 2009. 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 Sixth Biennial Transmission Assessment process.
- In preparing this report, KEMA has exercised due and customary care but has not, save as specifically stated, independently verified information provided by others. No other warranty, express or implied, is made in relation to the conduct of KEMA or any specific content of this report. Therefore, KEMA assumes no liability for any loss resulting from errors, omissions or misrepresentations made by others.
- Any recommendations, opinions or findings stated in this report are based on circumstances and facts as they existed at the time the assessment was performed. Any changes in such circumstances and facts upon which this report is based may adversely affect any recommendations, opinions or findings contained herein. No part of this report may be modified or deleted to change the content or context without the express written permission of the Arizona Corporation Commission and KEMA.

Contents

1. Overview 1
   1.1 Assessment Authority 1
   1.2 Sixth Biennial Assessment – Purpose and Framework 1
   1.3 Assessment Process 4
      1.3.1 Workshop I: Industry Presentations 4
      1.3.2 Review of Industry Filings in 6th BTA 4
      1.3.3 Preparation of Draft Report, Workshop 2 and Industry Comment 6
2. Ten-Year Plans 7
   2.1 Summary of Arizona Plan 8
   2.2 Plan Changes from Fifth BTA 11
   2.3 Interstate, Merchant and Generation Transmission Projects 15
      2.3.1 Navajo Transmission Project 15
      2.3.2 Palo Verde to Devers No. 2 500 kV Transmission Line 16
      2.3.3 Harcuvar Transmission Project 17
      2.3.4 SunZia Southwest Transmission Project 18
      2.3.5 High Plains Express Initiative 19
      2.3.6 TransWest Express Transmission Project 19
      2.3.7 San Luis Rio Colorado Plant and North Branch Transmission Project 20
      2.3.8 Southline Project 20
      2.3.9 Santa Fe Clean Line Project 21
      2.3.10 Bowie Power Station 21
      2.3.11 Hualapai Valley Solar 22
      2.3.12 Sonoran Solar Energy 22
      2.3.13 Abengoa Solar 23
      2.3.14 Mesquite Solar Project 23
      2.3.15 Starwood Solar I 23
      2.3.16 Arlington Valley Solar Energy 24
      2.3.17 Agua Caliente Solar Energy 24
   2.4 Other Significant Transmission Projects 24
      2.4.1 Welton-Mohawk Supply Project 24
      2.4.2 Southwest Public Power Resources Project 25
      2.4.3 WECC Transfer Path Changes Affecting Arizona 26
3. Transmission Affecting Renewable Development 28

3.1 Background 28
3.1.1 The Arizona Renewable Resource and Transmission Identification Subcommittee 29
3.1.2 The RTTF Finance Subcommittee 30
3.1.3 ARRTIS Findings 31
3.2 Utility RTP Filings 34
3.2.1 Arizona Public Service 34
3.2.2 SRP 37
3.2.3 Tucson Electric Power Company and UNSE 39
3.2.4 SWTC 40
3.3 Related ACC Staff Observations and Conclusions 41
3.3.1 Effectiveness of RTP Projects Selected by the Utilities 41
3.3.2 Impact of RTP Projects on the Arizona Transmission System 42
3.3.3 Impact of RTP Projects on Development of Renewable Resources 42
3.3.4 Staff Comments on Questions raised by the RTTF Financing Subcommittee44
3.3.5 Impact of RTP Implementation on REST Requirements 45
4. Other Commission Ordered Studies 48
4.1 History and Purpose 48
4.2 Local Area Transmission Load Serving Capability Assessment 48
4.2.1 Cochise County Import Assessment 49
4.2.2 Santa Cruz County Import Assessment 52
4.2.3 Mohave County Import Assessment 53
4.2.4 Pinal County Import Assessment 53
4.2.5 Import Assessments Requiring RMR Studies 54
4.2.5.1 Phoenix Metropolitan Area RMR Assessment 55
4.2.5.2 Tucson Area RMR Assessment 56
4.2.5.3 Yuma RMR Conditions and Import Assessment 57
4.2.5.4 Santa Cruz County RMR Assessment 59
4.2.5.5 Mohave County RMR Assessment 60
4.3 Ten Year Snapshot Study 61
4.4 Extreme Contingency Study Work 63
5. National and Regional Transmission Issues 64
5.1 NERC Mandatory Reliability Standards 64
5.2 FERC Siting Authority/National Interest Electric Transmission Corridor 65
5.3 Regional Transmission Planning – WestConnect 66
5.3.1 SWAT Subregional Planning Group 67
5.3.2 Colorado River Transmission Planning Group 69
5.3.3 Central Arizona Transmission Study – High Voltage 70
5.3.4 Central Arizona Transmission Study – Extra High Voltage 70

5.3.5 Short Circuit Working Group 71
5.3.6 Southeast Arizona Transmission Study 71
5.3.7 Eldorado Valley Study Group 72
5.4 Western Area Power Administration Transmission Infrastructure Program 73
5.5 WGA/DOE Western Transmission and Renewable Energy Initiatives 74
5.5.1 Western Renewable Energy Zone Identification Process 74
5.5.2 Westwide/WGA Transmission Planning Initiatives 74
5.5.3 NREL/DOE Western Wind and Solar Integration Study 75
5.6 WECC TEPPC Interconnection Wide Grid Planning Efforts 77
5.7 DOE PEIS for Federal Energy Corridors in Western States 78
5.8 FERC 890 Planning Principles 79
6. Conclusions 82
6.1 Adequacy of System to Reliably Serve Local Load 83
6.2 Efficacy of Commission Ordered Studies 85
6.3 Adequacy of System to Reliably Support the Wholesale Market 87
6.4 Adequacy of Transmission Projects Affecting Renewable Development 89
6.5 Suitability of Transmission Planning Processes Utilized 90
7. Recommendations 94

Tables

Table 1 - Matrix of Utility Filings in 6th BTA 5
Table 2 - List of Parties Filing Ten-Year Plans in 6th BTA 7
Table 3 - Summary of New Projects by Voltage Class 10
Table 4 - Significant EHV Project Changes since Fifth BTA 11
Table 5 - Summary of Project Schedule Changes since 5th BTA 12
Table 6 - Project Name Changes or Aliases 14
Table 7: RTP Projects and Queued Renewable Resources 43
Table 8: REST requirements 2008-2025 46
Table 9 - RMR Study Metrics 55
Table 10 - SWAT Subcommittees Contributing to 6th BTA 68

Figures

Figure 1: Change in Arizona Demand Forecast 9
Figure 2: Transmission Corridors for Renewable Generation Identified by ARRTIS 33
Figure 3: APS' identified RTP Projects 35
Figure 4: APS, SWTC, SRP and TEP Identified RTP Projects 38

Exhibits

Exhibit 1 – Arizona Transmission System Map
Exhibit 2 – Phoenix Metro Transmission System Map
Exhibit 3 – Southeastern Transmission System Map
Exhibit 4 – Yuma Transmission System Map
Exhibit 5 – Pinal County Transmission System Map
Exhibit 6 – WECC Paths Affecting Arizona
Exhibit 7 – Arizona Planned Project Lookup Table
Exhibit 8 – Arizona Demand Forecast Data (5th BTA vs. 6th BTA)
Exhibit 9 – SunZia Southwest Transmission Project
Exhibit 10 – High Plains Express (HPX) Map
Exhibit 11 – WECC Bubble Diagram
Exhibit 12 – TransWest Express Project
Exhibit 13 – ED5-PV Project
Exhibit 14 – Bowie Power Project
Exhibit 15 – Sonoran Solar Energy Project
Exhibit 16 – Abengoa Solar Project
Exhibit 17 – Mesquite Solar Project
Exhibit 18 – Plan Changes Between Fifth and Sixth BTA
Exhibit 19 – Generation Interconnection Queue(s)
Exhibit 20 – Listing of Projects by In-Service Date
Exhibit 21 – Listing of Projects by Voltage Class
Exhibit 22 – Arizona Public Service Project Summary
Exhibit 23 – Salt River Project Summary
Exhibit 24 – Santa Cruz Water and Power District Project Summary
Exhibit 25 – Southwest Transmission Cooperative Project Summary
Exhibit 26 – Tucson Electric Power Project Summary
Exhibit 27 – UNSE Project Summary
Exhibit 28 – NEITC Corridor Map
Exhibit 29 – Southline Transmission Project
Exhibit 30 – Santa Fe Clean Line Project
Exhibit 31 – Eldorado Valley Study Group
Exhibit 32 – Cochise County Transmission Plan
Exhibit 33 – SMRT Project and Study Area
Exhibit 34 – SWTC Renewable Transmission Projects
Exhibit 35 – Starwood Solar I Project

Appendices

Appendix A - Guiding Principles for Determination of System Adequacy and Reliability
Appendix B – History of Commission Ordered Studies
Appendix C   RMR Conditions and Study Methodology
Appendix D - Questions Posed to Industry and Stakeholders – Workshop 2
Appendix E - 2010 BTA Workshop I and II List of Attendees
Appendix F – Listing of Terminology and Acronyms
Appendix G – WestConnect Annual Adequacy Study
Appendix H – WestConnect Biennial Long Range Study
Appendix I – Sources of Information Referenced

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 Utilities Division of the Commission ("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 Sixth 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-09-0020. The filings included technical studies previously ordered by the Commission: Reliability Must Run ("RMR") studies, N-1-1 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 development in Arizona.[3] All entities which made presentations at the first workshop were asked to file the presentations in the docket. Staff and KEMA reviewed these presentations and the transcript of the first and second workshops. Preliminary and final drafts of this Sixth 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

[1] Arizona Revised Statute §40-360.02

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

[3] Including Renewable Transmission Projects filed pursuant to Docket E-01345A-10-0033 and/or presented by utilities during the 6th BTA at Workshop 1.

on Arizona electric transmission system adequacy, reliability, markets and renewable integration (e.g., aggregate ability to meet the existing and planned 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 2010-2019 timeframe in a reliable manner?
- Efficacy of Commission ordered studies - Do the study reports filed in response to Commission ordered RMR, N-1-1 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, adequately address the overall needs for renewable resource development and integration into the Arizona and regional electric power system?
- 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 numerous conclusions during the 6th BTA, including the following key items:

1) As a result of current economic conditions, the statewide demand forecast for the 2010-2019 ten year planning period has shifted by about 4 years since the 5th BTA (i.e., it will take four years longer to reach the 2008 demand forecast levels).

2) A total of 33 transmission projects have been delayed since the 5th BTA, with an average delay of roughly 4 years. In addition, 18 other transmission projects were cancelled. The combination of cancelled and delayed projects represents less than half of the projects filed in the 5th BTA in 2008. These delays and cancellations are consistent with the reduction in statewide demand forecast since the 5th BTA and do not appear to threaten the adequacy of the system or its ability to reliably serve load.

3) Information on transmission reconductor projects, bulk power transformer replacements planned for the purpose of capacity upgrade, and reactive power compensation additions at 115 kV and above, if included in future ten-year plan filings, would assist the Commission in meeting its obligation "to biennially make a determination of the adequacy and reliability of existing and planned transmission facilities in the state of Arizona".

4) All Commission required studies related to adequacy and reliability have been filed. The following conclusions apply to the efficacy of the filed documents relative to the intent of the Commission ordered actions:

   a) The Phoenix, Tucson and Yuma area RMR studies for 2013 and 2019 were thorough and well documented. These RMR studies also indicate that local RMR generation will not be dispatched out of merit order[4] for a significant number of hours or yield RMR costs sufficient to warrant advancing transmission improvements. The Mohave County 2013 and 2018, and Santa Cruz County 2013 and 2019 RMR studies were also well documented. The Mohave County study showed no RMR requirement. However, Santa Cruz County RMR analysis for 2010 showed an RMR requirement of 24 MW. No Santa Cruz RMR requirement was found in 2013 or 2019.

   b) The Commission's concern in the 5th BTA regarding the need for broader stakeholder involvement in the Yuma Area and Mohave County RMR studies has been satisfactorily addressed through the RMR studies for 2013 and 2019 filed in

[4] In a merit order dispatch the most economic mix of dispatchable generating units is selected to run each hour. However, RMR units may be run out of merit order in order to satisfy reliability needs on the grid.

the 6th BTA. Affected utilities and stakeholders participated in the Yuma Area and Mohave County RMR study.

c) The “Ten Year Snapshot Study” (previously referred to as the “N-1-1 Study”) was performed by the Central Arizona Transmission System – Extra High Voltage (“CATS-EHV”) study group and represents a composite assessment of the statewide Arizona transmission system and the performance of the ten-year expansion plan under normal, single-contingency and certain overlapping contingencies. The Extreme Contingency Study was performed by Arizona Public Service Company (“APS”) and examines more severe contingency scenarios such as corridor outages. These studies demonstrate the ten-year plan is robust and should provide adequate and reliable service to Arizona.

d) The proposed definition of “continuity of service” described in the Cochise County Study Group’s (“CCSG”) 2009 technical study report, as filed by Southwest Transmission Cooperative, Inc. (“SWTC”) in January 2010, is appropriate for planning of the Cochise County system. The transmission plan identified in the CCSG 2009 report represents a reasonable set of transmission expansion projects to achieve the “continuity of service” objective in Cochise County. However, based on feedback received from CCSG participants during the 6th BTA workshops, possible changes in the Cochise County load forecast may allow delaying certain components of the plan of service in the 2013-18 time frame, discussed in the CCSG report, without jeopardizing Cochise County’s continuity of service.

e) The Southeast Area Transmission Study Group (“SATS”) report and the SWTC ten-year plan have both identified overload issues on the Apache-Butterfield 230 kV line beginning in 2012. An upgrade of the line is being deferred to 2016. Therefore, interim mitigation measures will be needed in 2012-2015 in order to maintain system reliability. Furthermore, the study has identified numerous 230 kV and 115 kV bus voltage deviations that may be unacceptable, and states that further analysis is needed to address these issues. This analysis will be completed in 2011.

f) Santa Cruz County remains exposed to extended customer outages during a contingency of the radial transmission line serving the county. Additional transmission line improvements outlined in the UNS Electric, Inc. (“UNSE”) ten-year plan for Santa Cruz County will mitigate this exposure, but are contingent upon resolution of a long-standing federal permitting matter.

g) The Central Arizona Transmission System - High Voltage (“CATS-HV”) study of the planned 2019 Pinal County system assumed Southwest Public Power Resource’s (“SPPR”) “Three-Terminal” transmission plan (Pinal Central to ED5, ED5 to Test Track and ED5 to Marana 230 kV lines). However, at 6th BTA Workshop 1 it was announced that SPPR has deferred plans for two of these line additions indefinitely. The impact of these deferrals on the results of the CATS-HV study of 2019 is unknown and cannot be determined from the filed studies.

5) Arizona utilities have been extensively engaged in and providing leadership to, Southwest Area Transmission (“SWAT”) and WestConnect subregional planning processes. These utilities and other stakeholders have also participated and contributed valuable input during the 6th BTA process.

6) FERC has implemented mandatory reliability standards and audits over the past two to three years, including transmission planning standards, as discussed in the body of this report. It is still unclear to Staff how this should be recognized and integrated into the BTA process. Staff and KEMA have attempted to explore this question through data requests and stakeholder workshop discussion. Developing consensus on how to address these standards in the BTA process will take additional time and effort.

7) Technical studies filed in the 6th BTA indicate a generally robust study process for assessing transmission system performance (steady-state and transient) for the 2010-2019 planning period.

8) Regional and subregional planning studies have effectively addressed the interconnected EHV transmission that is critical to a functional interstate wholesale

market. Studies indicate the existing and planned Arizona EHV system is adequate to support a robust wholesale market.

9) Developing Arizona's vast renewable resource potential requires a coordinated and multi-faceted strategy involving stakeholders representing utility, government, economic, developer, environmental, and other interests. Decisions by the Commission and the actions taken by the Arizona utilities and regional stakeholders are important steps towards the state's goal of becoming a national and world leader in renewable energy development.

10) The 2009 utility filings in response to the 5th BTA order for the utilities to identify their top three Renewable Transmission Projects ("RTPs") are responsive to the Commission's order. An inclusive stakeholder process was developed and executed to identify the projects. In addition, the utilities are considering the impact of proposed utility-scale renewable projects as part of their normal planning processes.

11) Most of the transmission corridors identified in the utilities' initial RTP proposals to serve potential renewable generation are compatible with projects in the utilities' previously filed transmission plans. Furthermore, most of the RTPs identified by the utilities are actually advancements of projects already included in previous transmission plans. Such project advancement represents a relatively small incremental investment for a potentially significant renewable benefit.

12) Because the selected RTP projects are ones that have been identified in earlier transmission plans they should contribute to reinforcing the transmission system beyond the specific needs of renewable generation projects. We would expect them to be effective in enabling delivery of renewable resources developed close to either the Phoenix-Tucson regions or the Palo Verde hub. As projects are developed farther from these areas, completely new transmission plans will likely need to be identified and developed.

13) Even if the proposed RTPs filed by Arizona utilities in 2009 are approved and built, they will only provide for integration of a portion of the projected in-state renewable resource potential.

Recommendations

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

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), and

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

   c) Collaborative planning processes in Arizona and throughout the western region that facilitate competitive wholesale markets, and are consistent with FERC Order 890 and the expected order on Transmission Planning and Cost Allocation.

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

3) Staff recommends that the Commission order 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 order SWTC to determine if an engineering "re-rating" of the Apache-Butterfield 230 kV line as proposed in the 6th BTA filings would be an acceptable measure until the line is upgraded in 2016, and to file the results of this assessment by January 31, 2011.

5) Staff recommends that the Commission order APS, SWTC and Tucson Electric Power Company ("TEP") to conduct additional analysis of potential 230 kV and 138

kV voltage deviations in Southeastern Arizona as noted in the 2009 SATS report, file an update based on the 2010 SATS by February 28, 2011, and finalize mitigation plans if needed for this voltage concern in ten-year plan filing(s) for the 7th BTA by January 31, 2012.[5]

6) Staff recommends that the Commission accept the definition of "continuity of service" following a transmission line outage as proposed in the Cochise County Study Group's 2009 technical study report filed by SWTC in January 2010, and that the Commission accept the recommended transmission plan of service presented in Section 4.2.1 of this BTA report in order to achieve this "continuity of service" objective in Cochise County.

    a) Staff further recommends that the Commission establish target dates for SWTC, APS, TEP and Sulphur Springs Valley Electric Cooperative ("SSVEC") to achieve certain milestones and file progress reports with the Commission (as delineated in Section 7, Item 6 of this report) in order to ensure timely progress on the plan of service consistent with the intent of Commission Order 70635 in this regard.

7) Staff recommends that the Commission order UNSE to update its assessment of long term alternatives for Santa Cruz County continuity of service, as part of UNSE's 2012-2021 ten-year planning studies, and file a report on the updated assessment in the 7th BTA in 2012. Furthermore, if any approvals or permits from federal agencies related to the Gateway Transmission Project are still pending at that time, Staff recommends that the Commission require the 7th BTA filings to include a clear action plan and proposed schedule to obtain such approvals.

8) Staff recommends that Commission regulated utilities be required to continue to perform RMR studies in accordance with the methodology set forth in Appendix C to this Sixth BTA, and shall file such studies with ten-year plans for inclusion in future BTA reports.

[5] TEP plans to file updated SATS 2010 study results with Docket Control by January 1, 2011.

9) Staff recommends that the Commission order 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 BTA plan filings starting in January 2011.

10) Staff recommends that the Commission accept the results of the following Commission ordered studies provided as part of the 6th 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) "N-1-1" (Ten-Year Snapshot) study results documenting the performance of Arizona's statewide transmission system in 2019 for a comprehensive set of N-1 contingencies, each tested with the absence of one of nine different major planned transmission projects (N-1-1).

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

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.[6] 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").[7] 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.[8] 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".[9]

1.2 Sixth 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 Sixth Biennial Transmission Assessment ("BTA") evaluates the ten-year transmission plans filed with the Commission in Docket No. E-00000D-09-0020. 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.

[6] Arizona Revised Statute § 40-360.02.A
[7] Arizona Revised Statute § 40-360.02.B
[8] Arizona Revised Statute § 40-360.02.C.7
[9] 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 sixth BTA.[10] These include Reliability Must Run ("RMR"), N-1-1 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.[11]

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 continues to use a set of guiding principles in determining the adequacy and reliability of both transmission and generation systems.[12] 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)[13], and FERC orders.

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

1) Do the combined Arizona transmission system plans meet the load-serving requirements of the state during the 2010-2019 timeframe in a reliable manner?

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

[11] History of Commission Ordered Studies, Appendix B

[12] 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

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

2) Do the required Reliability Must Run, N-1-1, and Extreme Contingency studies comply with, and sufficiently meet, the intended goals of the Commission's orders?

3) 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) 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?

5) 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 NERC, WECC, 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, distributed and posted to the Commission's website 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 of the report was prepared and posted on the website 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 a two-day public Workshop on June 3-4, 2010 in Phoenix, Arizona. A complete listing of the Workshop I attendees and presenters is in Appendix E. Transmission Providers and Subregional Planning Groups presented information regarding their respective transmission expansion plans and related planning activities. Merchant transmission and generation developers reported on their respective development plans. The Workshop provided an informal setting to promote effective discussion of each presentation.[14] Each presentation was followed by an open period of discussion including questions and comments from the audience. Staff and KEMA concluded the session with general comments and discussion of the schedule for completing the 6th BTA.

1.3.2 Review of Industry Filings in 6th BTA

In preparation for Workshop 1, Staff and KEMA reviewed all of the filings that had been made to date by parties in the 6th BTA. Table 1 shows a matrix of the various categories of ten-year planning information filed by utilities during the 6th BTA. A complete list of entities that made ten-year plan filings in this BTA is shown in Table 2.

[14] 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 6th BTA

Utility	Ten-Year Plan	2010-2019 Utility Technical Study Report	RMR Study Report	Planning Criteria & Ratings	Joint Study Report(s)
APS	X	X	X	X	Extreme Contingency Study[15]
Electric Districts ("ED") 3&4	X				
SRP	X	X	*(Participated in APS Phoenix RMR Study)*	X	10 Year Snapshot Study[16] & CATS-HV Study[17]
SSEVC	X[18]				
SWTC	X	X		X	Cochise County Report[19]
TEP	X	X	X	X	SATS[20]
UNSE	X	X	X	X	Santa Cruz 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 2010-2019 ten-year plans. Although individual technical studies were not filed in this BTA by WAPA and some smaller utilities, Staff concludes that by-in-large their plans were modeled and analyzed as part of the joint studies that were filed.

15 Filed on behalf of CATS-EHV study group.

16 Ten-Year Snapshot Study (2019 system) filed on behalf of SRP, APS, WAPA, ED 3 & 4, et al.

17 Filed on behalf of all study participants including SRP, APS, ED 2-5, SWTC, TEP, WAPA, et al.

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, WAPA, SSVEC, et al.

20 Southeast Arizona Transmission System Study Report filed on behalf of SWTC, TEP/UNSE, WAPA, APS, et al.

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 territories." The 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. Some parties questioned during the workshops if filing of stability analysis for transmission plans beyond five years is of value due to the many uncertainties regarding loads, types of resources, and generator characteristics that must be assumed for stability modeling. In Staff's opinion, stability analysis during the initial five years of the plan should generally suffice for the BTA process, but stability analysis for the 6-10 year period is also informative for Staff's preliminary assessment of the longer term transmission plan if it's provided.

As indicated in Table 1, technical studies are augmented by other relevant information. APS, TEP, SWTC and UNSE included their internal transmission planning criteria and system ratings in the 6th BTA filings as required by Arizona Corporation Commission ("ACC") Decision No. 63876 (July 25, 2001). APS provided their planning criteria as part of their internal "Transmission Planning Process and Guidelines" included in their 6th BTA filing. SRP also provided their criteria and ratings. Such documents provide useful reference material for use by Staff.

1.3.3 Preparation of Draft Report, Workshop 2 and Industry Comment

Staff and KEMA provided an initial draft of the 2010 BTA report for industry review and comment in July 2010. The first draft report was based on the docketed ten-year plans and information gathered at Workshop I.[21] The first draft report was placed on the Commission's website and distributed via industry distribution lists to expedite the review process. Industry comments were docketed for other parties' review, comment and response. Oral comments on the draft report were received at Workshop 2 on August 4, 2010. A revised draft report reflecting this input was issued to stakeholders for review and comment on August 16, 2010. This round of comments was also reflected in the final report.

[21] Transcripts of Workshop I held June 3-4, 2010 are available on the ACC Docket Control site.

2. Ten-Year Plans

Table 2 provides a list of entities that filed ten-year transmission plans with the Commission in January 2010. The ten-year plans for proposed power plants and their associated transmission lines must be filed annually once an initial filing is made in advance of an application for a Certificate of Environmental Compatibility ("CEC") at the Commission. The 6th BTA assessment examines the aggregate ten-year plan.

Table 2 - List of Parties Filing Ten-Year Plans in 6th BTA

Abengoa Solar Inc.	Sempra Energy
Ajo Improvement Company[22]	Sonoran Solar Energy, LLC
Arizona Public Service Company	Southern California Edison
Bowie Power Station, LLC	Southwest Transmission Cooperative
Central Arizona Project[23]	Southwestern Power Group
El Paso Electric Company	Starwood Solar I, LLC
Electric Districts No. 3 and 4	Sulphur Springs Valley Electric Cooperative
Gila Bend Power Partners[24]	SunZia Southwest Transmission Project
Hualapai Valley Solar LLC	Tucson Electric Power
Public Service Co. of New Mexico	UNS Electric, Inc. ("UNSE")
Salt River Project	Welton-Mohawk Irrigation & Drainage District ("WMIID")

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. In addition, utilities who are signatories to the WECC Reliability Agreement are also obligated to comply with certain technical performance standards. Furthermore, the utilities observe guidelines

[22] Ajo's filing simply reported no change in the status of its load serving projects since the 5th BTA

[23] Contains a filing by the Central Arizona Water Conservation District regarding the Harcuvar project

[24] The sponsor's January 2010 filing states the project is on hold due to current market conditions

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.

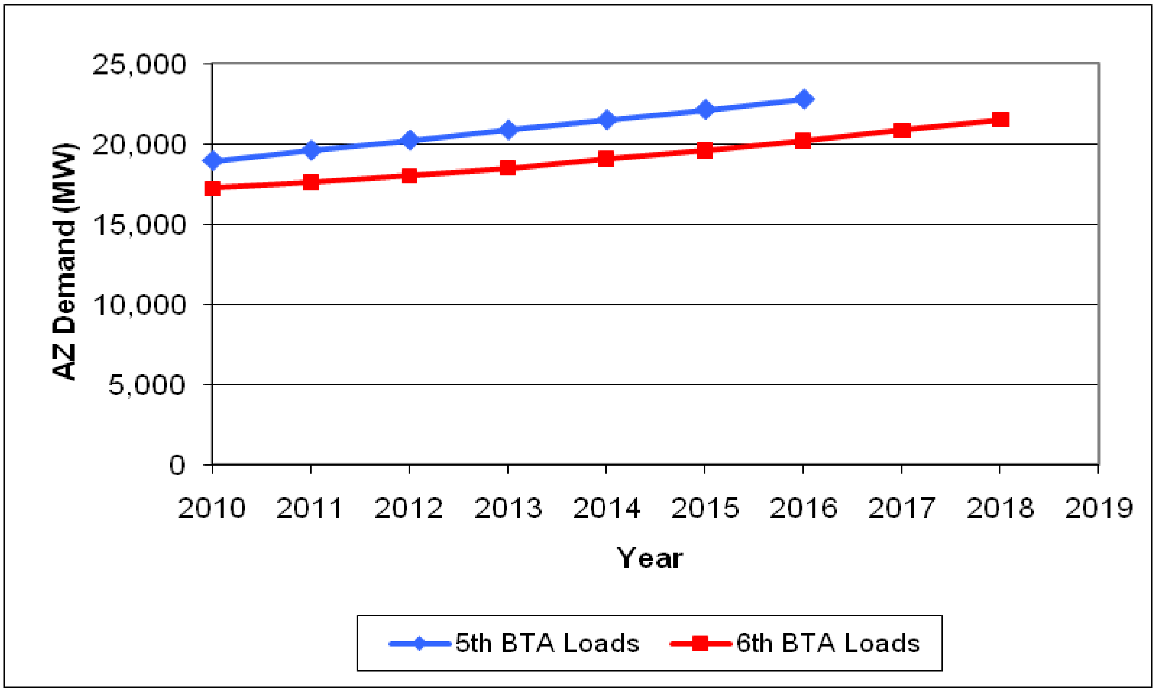
During Workshop I the following parties gave presentations regarding projects for which no ten-year plan was filed in the 6th BTA: High Plains Express Initiative, TransWest Express Transmission Line, Navajo Transmission Project, Southline Transmission Project, and Santa Fe Transmission Project. While such projects are described in this report, they were not considered as planned system elements for the purpose of Staff's assessment of adequacy and reliability in the 6th BTA.

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 projects 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 is reliability of supply to customers (e.g., "reliability-driven" projects). In the 6th BTA, a number of additional transmission proposals for integration of renewable resources have also been filed by the utilities, and those are addressed in Section 3 of Staff's report. In the current section Staff focuses on the 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 5th BTA as a result of current economic conditions.

Figure 1: Change in Arizona Demand Forecast



As shown in Figure 1, the statewide demand forecast has shifted by about four (4) years since the 5th BTA (for detailed forecast data see Exhibit 8). All other factors being equal, this suggests that many planned reliability-driven transmission projects in Arizona could be delayed about four years from the in-service dates shown in the 5th BTA ten-year plans. However, this isn't universally true since the percent change in local area forecasts can vary significantly from the statewide percentages. In addition, there may be reliability drivers for certain projects other than the demand forecast. Nevertheless, the four-year shift shown in Figure 1 is useful in assessing the filed changes in the current ten-year plan.

A complete list of the individual projects filed as part of the 6th BTA ten-year plan(s) is shown in Exhibit 7. The list of project changes only since the 5th BTA is shown in Exhibit 18. Exhibits 20 and 21 sort the full list of projects in the 6th BTA by in-service date and voltage class, respectively.

Table 3 depicts the number of new transmission projects filed in the 6th BTA and the associated mileage by voltage class. Projects with a to-be-determined ("TBD") in-service date or that are beyond the Ten-Year Plan timeframe have been grouped together as a single category.

Phased projects with differing in-service dates for the respective phases were tabulated as separate projects.

Table 3 - Summary of New Projects by Voltage Class

Voltage Class	Number of Projects (2010 to 2019)	Number of Projects (Post 2019 and TBD)	Approximate Mileage[25]
500 kV	1	3	135
345 kV	0	3	27
230 kV	2	5	167
138 kV	3	0	28
115 kV	5	1	109
Total	11	12	466

The projects filed in the 6th 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). In many cases, the filings also include planned additions of bulk power substations. However, several other significant classes of transmission system capital expansion utilized for the purpose of increasing capacity are (i) reconductoring of existing transmission lines, (ii) bulk power substation transformer bank replacements and (iii) certain reactive power compensation facility additions. Other than certain series capacitor installation/upgrade plans that were included, the ten-year plans filed in the current and prior BTAs overlook these three important categories of transmission system capacity upgrades. 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."[26] (*Emphasis Added*) Therefore, Staff concludes 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.

---

[25] The final mileage of many projects is still to be determined (TBD), so estimates were used for Table 3.

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

2.2 Plan Changes from Fifth 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 5th BTA is provided in Exhibit 18. For ease of reference a list of changes that have occurred at only 345 kV and above are provided in Table 4.

Table 4 - Significant EHV Project Changes since Fifth BTA

In-Service Date	Project	Voltage Class	Description of Change
2012	345/69 kV Interconnection at Western's Flagstaff 345kV bus	345 kV	Delayed from 2010
2013	Mazatzal Loop-in of Cholla-Pinnacle Peak 345 kV line	345 kV	Delayed from 2011
2013	Moenkopi-Eldorado 500 kV Series Capacitor Upgrade Project	500 kV	Delayed from 2012
2014	Delany-Sun Valley 500 kV line	500 kV	Delayed from 2010
2014	Palo Verde Hub-North Gila 500 kV #2 line	500 kV	Delayed from 2012
2014	Pinal Central-Tortolita 500 kV line	500 kV	Delayed from 2011
2014	Pinal West-Pinal Central – Randolph - Abel-Browning 500 kV line	500 kV	Delayed from 2011
2016	Sun Valley-Morgan 500 kV line	500 kV	Delayed from 2012
2012	Delany – Palo Verde 500kV line	500 kV	New Project
2015	Vail – Irvington 345 kV line	345 kV	New Project
2020	Pinal Central – Abel #2 500kV line	500 kV	New Project
TBD	Abel – RS20 500kV	500 kV	New Project
TBD	Interconnection of Greenlee-Winchester 345kV line with future Willow Substation	345 kV	New Project
TBD	Irvington – South 345 kV line	345 kV	New Project
TBD	RS20 – Coronado 500kV	500 kV	New Project
TBD	Winchester to Vail Double-Circuit 345 kV Line	345 kV	New Project
TBD	Palo Verde – Devers #2 500 kV Line	500 kV	CEC Denied – Case #130

Table 5 shows the number of projects delayed (or advanced) since the 5th BTA by voltage level.

Table 5 - Summary of Project Schedule Changes since 5th BTA[27]

Voltage Class	Advanced 1 Year or more	Delayed 1 Year	Delayed 2 Years	Delayed 3 Years	Delayed 4 Years	Delayed 5 Years or more
500 kV	0	1	1	2	2	0
345 kV	0	0	2	0	0	1
230 kV	0	0	2	2	1	5
138 kV	2	4	3	2	0	2
115 kV	2	2	0	0	0	1
Total	4	7	8	6	3	9

There were a total of 129 transmission projects listed in the previous ten-year plan.[28] Table 5 indicates that of this previous total, 37 projects have had a change in planned in-service date since the 5th BTA, including 33 that were delayed. Eighteen additional projects were cancelled. This means the balance of the projects from the 5th BTA have either been placed in-service since or are still planned for the same in-service date as before. The average delay for projects that have changed in-service dates is roughly four years. In Staff's opinion, these statistics on changes to the planned ten-year transmission projects are reasonable given the reduced demand forecast shown in Figure 1. In spite of the economy and demand forecast, many transmission projects have no change in schedule and four projects have actually been advanced. This may reflect the fact that load growth in local areas often varies significantly from system-wide averages.

Some projects or proposed substations have undergone a name change in recent filings as shown in Table 6.

[27] Excludes change of Devers – Palo Verde #2 500kV line to TBD status.

[28] Fifth Biennial Transmission Assessment 2008-2017, Docket No. E-00000D-07-0376, page 15.

Table 6 - Project Name Changes or Aliases

Current Name	Formerly Known As
Delany	Harquahala Junction
Sun Valley	TS5
Pinal Central	Pinal South
Dinosaur	RS19
Trilby Wash	TS1
Sugarloaf	Second Knoll
Abel	Southeast Valley ("SEV")
Mineral Park	Mercator Mill
Scatter Wash	TS6
Morgan	TS9
Sun City	Catalina
Medina	SS NO 22

2.3 Interstate, Merchant and Generation Transmission Projects

Interstate transmission is essential to enabling a 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 are discussed in this section of the BTA.

2.3.1 Navajo Transmission Project

The Navajo Transmission Project ("NTP") is a 500 kV transmission line project proposed by the Dine Power Authority (an enterprise of the Navajo Nation), with an approximate total length of 478 miles.[29] The line will extend from a new substation located near the Four Corners Power Plant in northwestern New Mexico to the Marketplace Substation, south of Boulder City, Nevada. A new Desert Rock power plant will interconnect to the line in New Mexico near Four Corners. The NTP will be constructed in three segments which traverse Arizona.

- Segment 1 – About 180 miles of 500 kV single circuit transmission from Desert Rock Generating Facility in northwestern New Mexico crossing Navajo lands to the proposed Red Mesa West Substation near Navajo Generating Station in northern Arizona.
- Segment 2 – 62 mile 500 kV single circuit transmission line from a new Red Mesa West substation to the existing Moenkopi Substation. This segment generally parallels an existing Glen Canyon to Flagstaff 345 kV transmission line corridor.
- Segment 3 – About a 218 mile 500 kV single circuit transmission line from the existing Moenkopi Substation to Marketplace Substation in Nevada. Segment 3 generally parallels an existing Moenkopi to El Dorado 500 kV transmission line.

No ten-year plan was filed for this project in the 6th BTA. However, a project update was provided by Dine's Steve Begay at the BTA Workshop I on June 3, 2010. NTP is evaluating a

[29] CEC Case#103, Docket No. L-00000U-00-0103, approved under Decision #63197.

number of options for the design of the Desert Rock power plant including coal plus solar, or some other combination of resources including a blend of solar and natural gas fired generation. Regarding the 500 kV transmission segments, NTP believes that Segment 3 is currently the most needed due to existing congestion constraints in the system. An overview map showing the general routing of each segment is included as Exhibit 1. Project schedule is yet to be determined, and therefore it has been excluded in the 2010-2019 planning studies filed in the 6th BTA.

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

The Palo Verde to Devers No. 2 ("PVD2") 500 kV Project[30] is a SCE sponsored interstate transmission project. The overall scope of the project extends approximately 270 miles from the proposed Delany Substation[31] in Arizona to SCE's Devers Substation near Palm Springs, then continuing on to SCE's Valley Substation near Romoland, California. On June 6, 2007, the Arizona Corporation Commission denied SCE's application for a CEC for the portion of the PVD2 transmission line located in Arizona.[32] SCE's ten-year plan filing in the 6th BTA states that in November 2009, SCE received an order from the California PUC allowing SCE to proceed with construction of the California portion of PVD2. Based on the latest project configuration, the California portion extends eastward from Valley Substation via Devers to a newly proposed substation site referred to as Midpoint or the Colorado River 500 kV Switchyard in the vicinity of Blythe, California. Based on this reconfiguration, SCE must seek further California PUC authorization before reinitiating the CEC approval process with the ACC. An overview map showing the general routing of the PVD2 transmission line[33] is included as Exhibit 1. Specific routing for the Arizona portion of PVD2 would be determined through the CEC process. This Arizona portion of the reconfigured project consists of a single transmission line segment as follows:

> Colorado River 500 kV Substation - Delany Substation: A new 500 kV transmission line between Arizona and California. This segment is approximately

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

[31] Delany Substation was previously known as Harquahala Junction.

[32] ACC Decision No. 69638.

[33] Designated by project number "A16" in 6th BTA Staff Report exhibits.

104 miles long. The proposed transmission line routing parallels the existing Palo Verde to Devers 500 kV transmission line.

On May 16, 2008, SCE filed a pre-filing application with FERC under Section 50.6 - Transmission Line Siting process. This filing triggered a project-wide National Environmental Policy Act ("NEPA") review, preparation of a preliminary draft Environmental Impact Study ("EIS"), and a public notice process along the entire right-of-way. The Arizona Corporation Commission has responded to this FERC filing.[34] A project update posted by SCE in May 2009[35] stated that a recent update of the economic analysis for the project no longer demonstrates sufficient benefits to California customers to build the Arizona portion of the line. SCE gives the following reasons for this change in economics:

- The increase in California's mandated 2020 RPS target to 33%, together with the development of both renewable and conventional generation in the vicinity of the California River 500 kV Switchyard, which will decrease the need for imports from Arizona.
- A decrease in the expected differential in fuel prices between Arizona and California.
- Reduced load growth in California as a result of changed economic conditions.

Therefore, SCE has stated it will cease its pre-filing activities at the FERC and put its plans for re-filing with the ACC on hold.

2.3.3 Harcuvar Transmission Project

The Harcuvar Transmission Project ("HTP") is a proposed 230 kV transmission project located approximately 60 miles west of the Palo Verde Hub and is sponsored by various entities including renewable and thermal energy developers, merchant transmission providers, and load serving entities in Arizona. The Central Arizona Water Conservation District ("CAWCD"), as one

[34] http://elibrary.ferc.gov/idmws/nvcommon/NVViewer.asp?Doc=11687511:0 and http://elibrary.ferc.gov/idmws/nvcommon/NVViewer.asp?Doc=11709962:0

[35] http://www.sce.com/NR/rdonlyres/0A5F8FEB-5357-4C11-BD93-07387DE4B2C1/0/090515_DPV2ProjectUpdate_May2009.pdf

of the project sponsors, filed ten-year plans with the Commission in January 2009 and 2010.[36] The project consists of two principal components:

- Approximately a 90 mile 230 kV loop in La Paz County, Arizona.
- Joint ownership, together with SCE, of the Arizona segment of the PVD2 500 kV line.

In its latest BTA filing HTP notes that on May 15, 2009, SCE notified the ACC by letter that their latest economic "analysis does not support re-filing with the ACC, at this time, for authorization of the Arizona portion of [PVD2]." The BTA filing goes on to state that because the PVD2 line is "critical to the success of the HTP", the HTP must either await the renewal of SCE's filing with the ACC for PDV2, "or some other project offering equivalent value and functionality." Therefore, CAWCD is pursuing other options to enhance transmission capacity to its major pumping loads in La Paz and Mohave counties.

2.3.4 SunZia Southwest Transmission Project

The project is sponsored by Southwestern Power Group. 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 primary alternative would construct two 500 kV AC lines, but an option is also under study to build one of the lines as an HVDC (direct current) line. An overview map showing the general routing is included as Exhibit 9.[37] 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 2014.

The SunZia ten-year plan filed in January 2010 was not accompanied by power flow or stability studies. However, SunZia reports that a full set of technical studies will be prepared when the project's design is sufficiently finalized. It is involved in the regional and subregional planning process thru the following forums and activities:

[36] The filing is identified in the ACC E-Docket by "Central Arizona Project" as the filing party.

[37] Recently introduced southern route options (e.g., the "Tucson route") are not shown in Exhibit 9.

- The WECC path rating process (e.g., through Phase 3) is expected to be complete by the end of 2010 (based on the two 500 kV AC line option).
- Subregional Planning — Regular project updates are provided to SWAT and its subcommittees.
- Open Season — Six parties have now signed the participation agreement (SRP, TEP, Tri-State G&T, Shell WindEnergy, Southwestern Power Group and Energy Capital Partners).

2.3.5 High Plains Express Initiative

The project is sponsored by NextEra Energy. An update on the project was presented by Jerry Vaninetti of NextEra Energy at Workshop 1. High Plains Express ("HPX") is a multi-state, 500kV transmission initiative that extends from Wyoming to Arizona. The project's vision is to significantly strengthen the eastern portion of the WECC grid, especially along a north to south backbone. NextEra has not filed a ten-year plan for the project. Therefore, this project was not considered for the adequacy analysis nor included in the ten-year plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points is included as Exhibit 10.

According to NextEra, HPX could eventually incorporate many of the transmission projects already under development within its overall project footprint in eastern and southern WECC.

2.3.6 TransWest Express Transmission Project

The project is currently owned by Anschutz Corporation. A ten-year plan filing was not made for this project in the 6th BTA, but consultant Gary Mirich of Energy Strategies gave an update on the project at Workshop 1 (no slides were presented). The project is currently conceptualized as a 600 kV bi-polar transmission line from southeastern Wyoming to the El Dorado Valley region (south of Las Vegas, NV) with a rating of approximately 3,000 MW. The targeted in-service date is 2015. Mr. Mirich described the project as renewable line that may be supplemented by gas-fired generation. He stated that the project is currently in Phase II of the WECC Path Rating Process. An overview map showing the general routing of the line, as published in the 5th BTA, is included as Exhibit 12.

2.3.7 San Luis Rio Colorado Plant and North Branch Transmission Project

The project is sponsored by Generadora del Desierto S.A. de C.V. (GDD) and Western Area Power Administration (WAPA). On August 21, 2008, the DOE published, in the Federal Register, notice of its decision to issue a Presidential Permit to construct, operate, maintain and connect a new double circuit 230 kV transmission line across the U.S.-Mexico border from Yuma County, North Gila Substation to San Luis Rio Colorado, Sonora, Mexico.[38]

The North Branch Transmission Project consists of two 230 kV transmission lines which will connect to a new 230 kV substation to be built next to WAPA's Gila 161 kV substation. The new double circuit 230 kV lines will continue north to the APS North Gila 500 kV station. WAPA will own the new transmission on the US side. GDD will own the short transmission on the Mexico side. According to Jim Charters of Western States Energy Solutions, project participation agreements are being developed between WAPA, North Branch and APS. No update on the project was filed in the 6th BTA.

2.3.8 Southline Project

The project is sponsored by Black Forest Partners. No filing was made in the 6th BTA, but Bill Kipp of Black Forest gave a slide presentation on this merchant transmission line at Workshop 1. He stated that the goal of the project is to accelerate the use of renewable energy. This project was not considered for the adequacy analysis nor included in the ten-year plan statistics compiled for this BTA. Southline is contemplated to be a combination of new and rebuilt EHV transmission elements, with 230 kV, 345 kV and 500kV segments, for renewable deliveries from southeastern New Mexico to the Palo Verde Hub area, passing through southeastern Arizona in route. In southern New Mexico, they plan to follow the route of an abandoned railroad track in order to minimize environmental impacts. From southeast Arizona to Palo Verde, they may participate in announced utility projects or procure contractual delivery arrangements in lieu of new physical line construction. Beyond Palo Verde, they believe the Southline could potentially fit well with other projects that are exploring options west of Palo Verde. Black Forest is

[38] Federal Register / Vol. 73, No. 163/ Thursday, August 21, 2008/Notices, page 49447. http://edocket.access.gpo.gov/2008/pdf/E8-19392.pdf

currently completing joint technical studies with TEP, SWTC, Western and other parties – which they plan to file with the Commission in the near future. Most of the east to west capacity is envisioned for renewable delivery, while much of the west to east capacity is envisioned for load serving purposes. A simplified one-line diagram of the project is shown in Exhibit 29.

2.3.9 Santa Fe Clean Line Project

The project is sponsored by Clean Line Energy Partners LLC ("Clean Line"). Keith Sparks of Clean Line gave a presentation on the project at Workshop 1, but no filing has been received to date. Therefore, the project was not considered for the adequacy analysis nor included in the ten-year plan statistics compiled for this BTA. Clean Line, an independent developer of high voltage transmission, provided supplemental information after the workshops, which are included below. The Santa Fe Clean Line transmission project ("Santa Fe") which will consist of one ±500 kV or ±600 kV High Voltage Direct Current ("HVDC") overhead transmission line capable of transmitting up to 3,500 MW of power from renewable projects in eastern New Mexico to Southern California, Southern Nevada, Arizona, and other areas in the Southwest.

Santa Fe is meeting with local and state authorities in Arizona, and other states to begin informal outreach efforts. Santa Fe has conducted an initial corridor feasibility study and is in the first phases of refining the corridors to identify preferred and alternative routes. A map of the "study area" is provided as Exhibit 30. Santa Fe will conduct an environmental impact statement pursuant to NEPA, and work closely with state and federal agencies.

Before the Project was acquired by Clean Line in May 2010, the previous developer (Integration Transmission Services) spent over 24 months developing the concept for the line, including various meetings with the ACC staff. Building on this work, the Santa Fe has completed a Memorandum of Understanding with Dine Power Authority, regularly engaged in SATS and WECC planning stakeholder meetings, submitted an application for Western's Transmission Infrastructure Program, and opened discussions with Western as a potential project partner.

2.3.10 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's filing in the 6th BTA notes that the Commission has extended the CEC for the project through December 31, 2010 in Decision No. 69339. SWPG has applied for an additional extension through December 31, 2020. The physical alignment of the line and Willow Substation were amended through Decision No. 70588 in November 2008. Exhibit 14 depicts the amended alignment.

PDS consulting gave a presentation on the project at Workshop 1. SWPG continues to be active in SWAT subcommittees, including SATS. A Final Facilities Study Report is expected from TEP in the third quarter 2010. The estimated operation date for the gen-tie is late 2013.

2.3.11 Hualapai Valley Solar

Mohave Sun Power LLC is sponsoring this project. Ten-year plans in 2009 and 2010 describe a conceptual 345 kV or 500 kV gen-tie from a solar power project to be built in northwestern Arizona to interconnect with an existing EHV transmission facility. No route has been determined. The line may connect into either the Mead Phoenix Project 500 kV transmission line, the Mead-Peacock-Liberty 345 kV transmission line, or the Moenkopi-Eldorado 500 kV transmission line. The proposed in-service date is the fourth quarter of 2013. Since a defined transmission plan of service hasn't been identified to date, the project wasn't modeled in any technical studies filed in the 6th BTA docket. However, power flow and stability analysis were filed as part of the power plant filings at the Commission in August 2009.[39]

2.3.12 Sonoran Solar Energy

Sonoran Solar Energy plans to build a 500 kV gen-tie to interconnect its proposed 375 MW solar generation project with SRP's Jojoba Substation. The 3 mile long line will be located in Maricopa County, Arizona and will be in service by summer 2013 to support plant start-up and testing. A map of the gen-tie route is shown in Exhibit 15. Sonoran states that technical study reports for this interconnection plan were included as part of the 90-day filing notice in November 2009.

[39] ACC Docket No. E-00000M-08-0170 and Docket No. L-00000NN-09-0541-00151.

2.3.13 Abengoa Solar

Abengoa Solar plans to build a 230 kV overhead gen-tie (approximately 20 mile) to interconnect its proposed 280 MW Solana solar generation project near Gila Bend, Arizona with APS' Gila River Substation.[40] A route map is shown in Exhibit 16. The project will use concentrated solar power ("CSP") technology with storage capability. Technical planning studies were filed with the project's 90-day notice in July 2008. The project and gen-tie received a CEC in December 2008.[41] APS will procure the output under a 30-year purchase agreement. Abengoa states that an interconnection facilities study was completed by APS in August 2009 and concludes that an additional loop-in of the line through Gila Bend Substation en route to Gila River Substation, as contemplated at the time of the CEC application, is not needed.[42] The facilities study was included in Abengoa's BTA filing.

2.3.14 Mesquite Solar Project

Sempra Energy filed a ten-year plan for its 230 kV gen-tie from their Mesquite Solar photovoltaic project to Hassayampa Substation, which includes expansion of switchyard facilities at the existing Mesquite Generating Station adjacent to Hassayampa Substation. The project one-line diagram is shown in Exhibit 17. Sempra advised Staff that the expected date for initial solar production at the plant has slipped to October 2011, with additional stages coming on-line shortly thereafter.

2.3.15 Starwood Solar I

Starwood Energy filed a ten-year plan for the Starwood Solar I project in June 2009. The plan describes a 500 kV gen-tie to connect the generating project to APS' planned Delany Substation. Starwood refers to APS as the surrogate for meeting the ACC's requirement for filing of transmission planning criteria and system ratings. Construction of the gen-tie to Delany Substation is expected to start in 2010 and be completed in 2013. A subsequent extension to Harquahala Substation is also mentioned in Starwood's ten-year plan, but the timing of this

---

[40] Also known as Panda Substation.

[41] ACC Docket No. L-00000GG-08-0407-00139, Decision No. 70638 and Docket No. L-00000GG-08-0407-00140, Decision No. 70639.

[42] The facilities study also specifies certain APS 69kV network upgrades that need to be completed.

segment is uncertain and dependent on an ongoing APS cluster interconnection study and commercial negotiations with the Harquahala Power Plant. No technical studies were filed. Starwood states that technical studies supporting its transmission plan will be filed upon study completion. Exhibit 35 provides more plan details.

2.3.16 Arlington Valley Solar Energy

AVSE LLC filed a Ten-Year Plan in January 2009, describing two 115 kV or 230 kV gen-tie lines from the project site to Hassayampa Substation, plus 500-1000 feet of 500 kV line on the high side of the step up transformer bank at Hassayampa. The gen-ties will be 3-7 miles in length and will originate at Arlington Valley Solar 1 and 2 Generating Plant switchyards, respectively. Aggregate generating plant capacity is approximately 250 MW. The estimated in-service date is 4th quarter 2012. No BTA update was filed in 2010.

2.3.17 Agua Caliente Solar Energy

The project developer, NextLight Renewable Power LLC, filed a ten-year plan in January 2009. The filing described a loop in of the existing Hassayampa – North Gila 500 kV line into a new 500 kV switchyard (Hoodoo Wash) to be built in the vicinity of the Agua Caliente Solar Project site approximately 10 miles north of Dateland, Arizona in Yuma County. The 280 MW concentrating solar power plant will be located about 2 miles north of the existing 500 kV line. The gen-tie voltage is not specified. A 90-day Plan filing was made in November 2008. The anticipated in-service date is mid-2012. No BTA filing was made in 2010.

2.4 Other Significant Transmission Projects

2.4.1 Welton-Mohawk Supply Project

WMIDD is planning to participate as a minority owner in the Hassayampa to North Gila No. 2 500 kV line project, to construct a new 500/230 kV receiving station that will intersect with the new 500 kV line in the vicinity of North Gila Substation (or connect at North Gila Sub), and to construct a 230 kV transmission project from the new receiving station about 35 miles to its existing WAPA Ligurta Substation, which serves as the delivery point to WMIDD. WMIDD is participating in subregional planning forums, including SWAT, to assure that its project plans are properly vetted and coordinated within the region. The project is needed to serve new load growth in WMIDD's service area.

2.4.2 Southwest Public Power Resources Project

Southwest Public Power Resources ("SPPR") is sponsoring a project to add transmission in Pinal County. No filing was made in the 6th BTA, but Dennis Delaney of K.R. Saline & Associates ("K.R. Saline") gave a presentation on the project at Workshop 1.

SPPR previously proposed the Three Terminal Plan ("TTP") transmission project during the 5th BTA in order to interconnect SPPR's Sawtooth Generation Project No. 1 located in Pinal County and deliver power to SPPR participants. However, Mr. Delaney advised that plans for the Sawtooth 620 MW combined cycle gas-fired plant have been cancelled and the transmission plan has been revised. The TTP project originally consisted of the following three new 230 kV transmission elements:

- Santa Rosa/Test Track to ED5 (Circuit 1)
- ED5 to Pinal Central (Circuit 2)
- ED5 to Marana (Circuit 3)

In place of the Sawtooth Generation Project, SPPR now plans to pursue a PPA for firm power at Palo Verde for delivery over the Southeast Valley Project ("SEV") to its load area. Based on this new approach, SPPR expects to change its ten-year plan as follows:

- Interconnect TTP Circuit 1 through new 500/230 kV transformation at Test Track
- Install a 230/115 kV transformer at ED5
- Delay TTP Circuits 2 and 3 (e.g., beyond ten-year plan)
- Utilize the extension of the Southeast Valley ("SEV") project from Pinal West to Test Track and Pinal Central

SPPR is negotiating with Western for a bi-directional transmission path between Palo Verde and Pinal County, as indicated in Exhibit 13. This would allow SPPR to integrate new renewable resources that are expected to connect to its local system, and deliver them to SEV busses and/or the Palo Verde hub (when the path is not being used for delivery of its PPA capacity from Palo Verde hub). At least 300MW of renewables are currently queued in the local system.

2.4.3 WECC Transfer Path Changes Affecting Arizona

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. The following path rating increases have been completed or in-progress since the 5th BTA:

- The rating of the East of the River ("EOR") Path or Path 49 increased by 1,245 MW due to upgrades to both the Navajo-Crystal and the Perkins-Mead 500 kV lines. The resulting east to west direction path rating changed to 9,300 MW.
- The Coronado to Silver King 500 kV path upgrade was completed in 2010 changing the original path rating from 1,100 MW to 1,494 MW in the East to West direction.
- The rating of Path 51 ("Navajo South Transmission System") was increased in 2009 from 2,264 MW to 2,800 MW[43] due to upgrades of the four series capacitors within the path. The rating is defined in the north to south direction, and the increase will take effect in late 2010 or early 2011.

No other WECC path rating changes in Arizona are currently approved for the 2010-2019 periods, but it is likely that some increases will occur in this period due to major interstate transmission projects described in this report. Future WECC path rating studies will determine the timing and amount of these increases.

[43] The Path 51 rating was inadvertently reported as 3,200 MW in the 5th BTA Staff Report.

3. Transmission Affecting Renewable Development

Developing Arizona's vast renewable resource potential requires a coordinated and multi-faceted strategy involving stakeholders representing many sectors and interests including utility, government, economic, developer, environmental, and others. Decisions by the Commission and the actions taken by the Arizona utilities and regional stakeholders are important factors that will affect how and when this potential is developed.

3.1 Background

The Commission's 5th BTA Decision directed Commission-regulated utilities to develop viable plans to identify future transmission projects and to propose funding mechanisms to construct the top three transmission projects in their respective service territories. In addition, the Commission directed the jurisdictional utilities to conduct a joint workshop or series of planning meetings to develop ways in which new transmission projects could be identified, approved for construction, and financed in a manner that supports renewable energy growth.

The Commission's 5th BTA (2008) Decision directed Commission-regulated utilities to:

- "[B]y April 30, 2009, conduct joint workshops or planning meetings to develop ways in which new transmission projects can be identified, approved for construction, and financed in a manner that will support the growth of renewables in Arizona."[44]
- "[T]ake the results of the Arizona Renewable Transmission Task Force and the SWAT Renewable Transmission Task Force Plans developed for the Fifth Biennial Transmission Assessment and identify the top three potential renewable transmission projects in their respective service territories."[45]
- "[E]ither alone or in cooperation with other interested utilities," "develop plans to identify future renewable transmission projects and develop plans and propose funding mechanisms to construct the top three renewable transmission projects. These plans

44. Arizona Corporation Commission, Order 70635, Docket E-00000D-07-0376; page 8.
45. Ibid.

and mechanisms" are to be "filed with the Commission no later than October 31, 2009 and shall be discussed in" the 6th BTA.[46]

SRP also participated in this process, including SWAT RTTF subcommittees, and voluntarily filed its top three RTPs with the Commission.

3.1.1 The Arizona Renewable Resource and Transmission Identification Subcommittee

In response to a prior Commission directive in the 4th BTA, the SWAT Sub-Regional Planning Group formed a Renewable Transmission Task Force ("RTTF") to consider transmission needs for developing renewable resources. In response to the directive of the 5th BTA, 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 to aid the utilities' response to the BTA Decision. The primary tasks of ARRTIS were to:

- Identify potential constraint areas for Arizona renewable resource development;
- Assist the RTTF by providing information to assess transmission options; and
- Inform and assist the regulated utilities in their response to the BTA Order.

The ARRTIS convened approximately a five-month process to gather, review and map renewable resource data and environmentally sensitive areas for the state of Arizona and to provide input and support to the RTTF renewable transmission planning efforts. The process identified areas within the state where solar and wind resources were technically ideal for utility-scale generation development, defined and located environmentally sensitive areas and those that would be excluded by statute or law from consideration for generation facilities.

ARRTIS created a four-tier system to characterize the environmental sensitivity of land areas within the state: low; moderate; high; and excluded. The ARRTIS took a position that (1) Exclusion Areas would be the only areas in the state that should be considered precluded for

46. Ibid, page 9.

utility-scale generation, and (2) no assumption of any specific renewable generation project's viability should be made based on its location.

The analysis found that approximately half of Arizona's land area could be appropriate for utility-scale generation. The further application of ARRTIS-defined sensitivity criteria allowed the RTTF to more strategically define the state's potential transmission network to support renewables. The RTTF used the information provided by the ARRTIS to identify transmission options that would link the resource areas to the existing transmission system and/or to load pockets within the state or to export markets.

3.1.2 The RTTF Finance Subcommittee

The RTTF also established a Finance Subcommittee to develop a methodology for identifying, planning, and facilitating renewable transmission projects ("RTP") development in Arizona, including methods for providing utilities with a means to effectively finance and construct RTPs.

The RTTF assigned the Finance Subcommittee the tasks of investigating and recommending financing methodologies for RTPs in Arizona. The findings and recommendations of the Subcommittee were to be submitted to the RTTF and the jurisdictional utilities subject to the fifth BTA Decision. In coordination with the RTTF subcommittee, and the ARRTIS, the Finance Subcommittee also supported the utilities responsible for the Workshops as directed by the ACC. This information was intended for the utilities' consideration as part of their response to an ACC decision requiring the utilities to identify and develop plans for the top three renewable transmission projects, submit a report by 31 October 2009, and have this report discussed in the Commission's next BTA.[47]

As part of this process the Renewable Transmission Action Plan ("RTAP") was proposed that could be used as part of the BTA process. The RTAP was conceived as a procedure for the Commission to review and approve a utility's identified RTAP within or in parallel with the BTA process.[48]

47. ACC Decision No. 70635, issued on December 11, 2008.

48. APS is the only utility that filed an RTAP with the Commission, pursuant to a separate proceeding (Docket No. E-01345A-10-0033).

In addition, a memorandum of proposed findings was proposed related to renewable transmission projects.[49] The intent was that the utilities consider using the memorandum as part of their response to the 5th BTA Decision. The ACC could then choose to include the proposed findings from the memorandum in future orders. The participants in the RTTF process generally agreed to accept the memorandum and RTAP as the recommended method for identifying action plans and financing for the RTPs in Arizona. Utility responses that were filed in October 2009 defined the first set of RTPs.

The memorandum recommended that:

- Each jurisdictional utility will file[50] an RTAP, concurrent with the filing of its ten-year plan;
- Jurisdictional utilities' RTAPs may include RTPs with ownership participation involving non-jurisdictional parties (i.e., merchants, independents, etc.); and
- The RTAP should:
    - Identify the RTPs that provide access to areas within Arizona that have renewable energy resources or facilities that enable renewable resources to be delivered to load centers;
    - Describe how each RTP is expected to advance renewable resource deployment;
    - Present the development approach and schedule for the proposed RTPs;
    - Estimate the expected costs of the RTPs, including the range of bill impacts for retail customers for each project;
    - Discuss cost recovery, including any special regulatory treatment that will be sought; and
    - Report the status of RTPs identified in the previous RTAP.

3.1.3 ARRTIS Findings

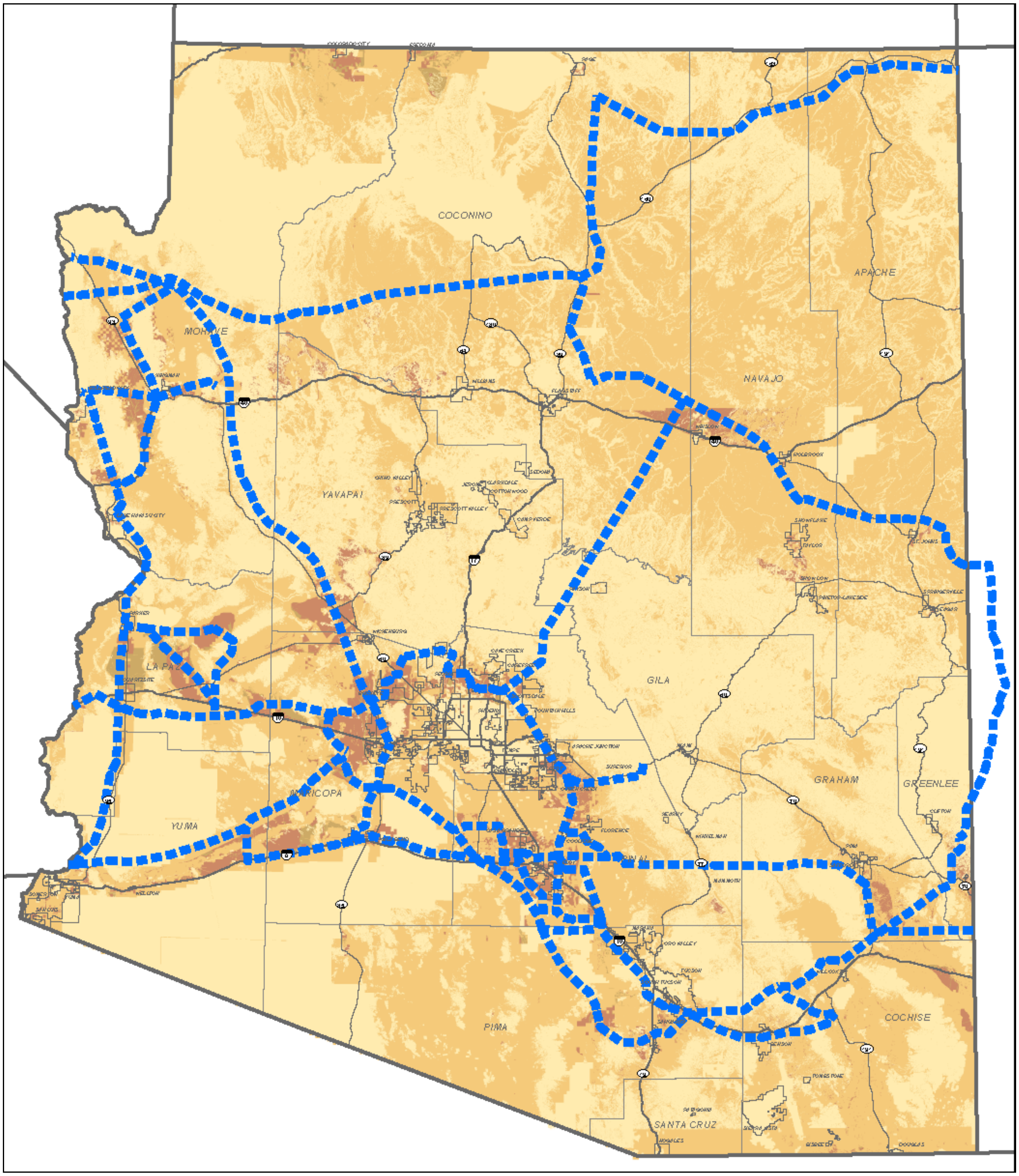
Five maps were developed as part of the ARRTIS process:

49. See *Final Report on the Activities of the Finance Subcommittee*, Renewable Energy Transmission Task Force, Southwest Area Transmission Planning Group, October 5, 2009, page 12.
50. The Subcommittee did not make any specific recommendations regarding the procedural mechanisms for filing the RTPs and RTAPs.

- Arizona Solar Resources
- Arizona Wind Resources
- Environmental Exclusion and Resource Sensitivity Areas (Solar)
- Environmental Exclusion and Resource Sensitivity Areas (Wind)
- Non-Exclusion Solar Resource Areas Identified by ARRTIS

These maps were used by RTTF to identify transmission corridors suitable for delivering renewable generation. These corridors are options the utilities considered in responding to the 5th BTA Order. The map of these corridors is shown in Figure 2.

Figure 2: Transmission Corridors for Renewable Generation Identified by ARRTIS



3.2 Utility RTP Filings

Each of the jurisdictional utilities filed responses by 31 October 2009. It is interesting to note that many of the corridors identified by ARRTIS as shown in Figure 2 are compatible with projects in the utilities' previous transmission plans.

3.2.1 Arizona Public Service

In determining its top RTPs APS considered the input from the two workshops, the ARRTIS' work, the Finance Subcommittee's work, and the RTTF's work. They assessed the comparative economic value of viable renewable resource and transmission line combinations. In addition to the economic analysis, APS conducted a qualitative analysis that included:

- Potential to support multiple renewable energy markets,
- Likelihood of attracting participants to the project,
- Expected permitting sensitivity (resource and transmission),
- Interconnection queue robustness,
- Expected near-term utilization,
- Potential to bring benefits beyond renewable integration.

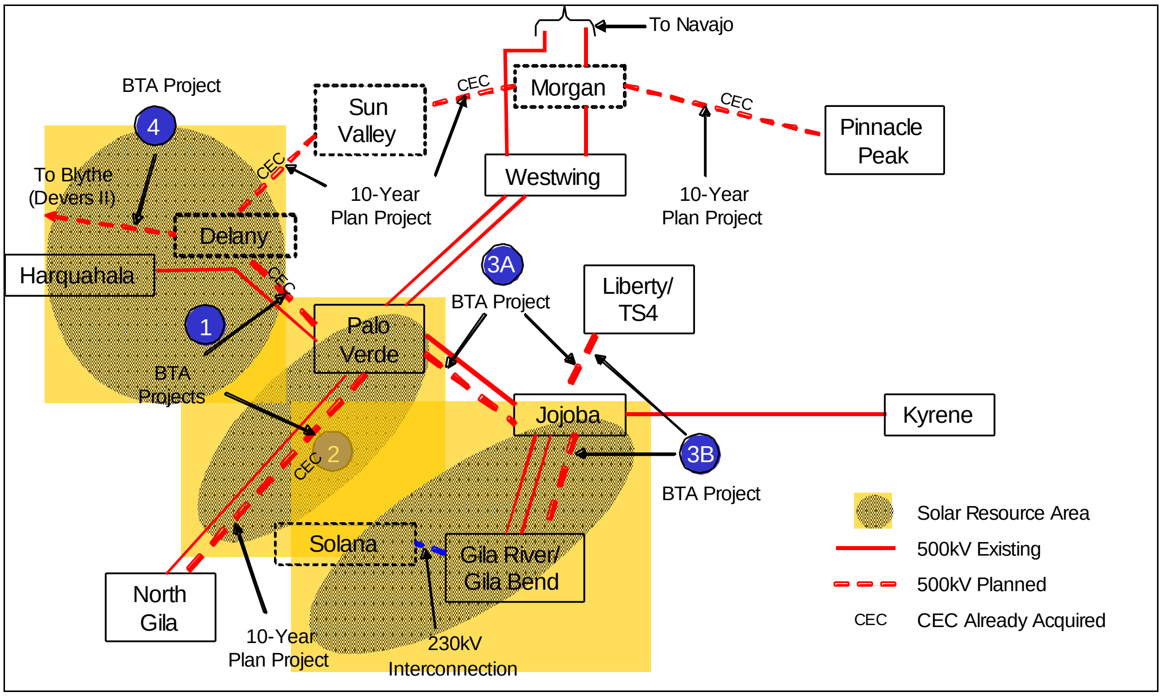
Based upon its analysis, APS identified the RTPs that it believes were best suited to support the growth of renewable resources in Arizona while considering the costs and benefits to APS customers.

APS identified four RTP projects:

1. Delany to Palo Verde 500 kV;
2. Palo Verde to North Gila 500 kV #2;
3. a) Palo Verde to Liberty 500 kV,
   b) Gila Bend to Liberty 500 kV;
4. Delany to Blythe (e.g., SCE's proposed Colorado River 500 kV Substation)

A fourth project was included because APS believes it would significantly support development of renewable resources in Arizona for exports to California and to deliver solar resources to Arizona utilities at the Delany switchyard. These four projects are shown in Figure 3.

Figure 3: APS' identified RTP Projects



3.2.1.1 Delany to Palo Verde 500 kV

This project is a 500 kV transmission line from the Palo Verde hub to a new Delany switchyard, about 18 miles west of the Palo Verde hub. The new switchyard would be located along a 500kV loop that will eventually run from Palo Verde around the west and then north side of the Valley to the Pinnacle Peak substation.

The Delany area has excellent solar conditions, and there are interconnection requests for several thousand MW of renewable generation in the Delany area—a clear indicator that there is a robust interest in renewable resource development. This project also provides access to the Palo Verde hub allowing exports of renewable energy.

3.2.1.2 Palo Verde to North Gila 500 kV #2

This project is a potential 500 kV transmission line from the Palo Verde hub area to the North Gila Substation, located outside of Yuma. It is approximately 114 miles in length and would parallel an existing jointly owned 500 kV line. This project also provides access to the Palo Verde hub allowing exports of renewable energy.

The area has excellent solar conditions and there are interconnection requests to the area adjacent to this line indicating a robust interest in this renewable resource area. This line would also provide additional transmission to the Yuma load pocket, increasing load-serving capability in Yuma, and providing additional resource flexibility to serve both the Valley and Yuma load pockets.

Due to the magnitude of project costs, this project is conceived as a participant transmission project. SRP, the Imperial Irrigation District, and the Welton-Mohawk Irrigation and Drainage District are the other current participants, each holding a 20% share of the project. In addition, the Western Area Power Administration has expressed an interest in participating in the project. WAPA involvement would provide the potential for federal government funding for WAPA transmission expansions that foster renewable energy.

3.2.1.3 Palo Verde to Liberty and Gila Bend to Liberty 500 kV

This two-part conceptual transmission project includes a 500 kV transmission line from the Palo Verde hub to a new substation near the existing Liberty substation in the West Valley and a 500kV transmission line from the Gila Bend/Gila River area to a new substation near the existing Liberty substation.

The area around the Palo Verde hub and the Gila Bend area have excellent solar conditions, which could result in the development of significant solar generation facilities. APS believes that developing these projects would mitigate inconsistency between the periods required to construct transmission lines and renewable resource facilities—where transmission infrastructure takes longer to build than renewable resource facilities.

3.2.1.4 Delany to Blythe

This project was originally proposed by Southern California Edison. APS supports development of this transmission line because it could influence additional solar resource development in Arizona given the potential for additional export capability to California.

3.2.1.5 APS Cost Analysis

APS worked with the other utilities and interested stakeholders to develop plans to identify the best three RTPs. APS used the methodology developed by the Finance Subcommittee for identifying RTPs. APS selected the RTPs considering the costs and benefits to APS customers. APS established a plan to develop the project, proposed funding mechanisms, provided background explaining the value of the project in supporting renewable energy development in Arizona, and described potential rate impacts to APS's customers for the projects selected.

APS used the National Renewable Energy Laboratory's Western Wind Resource Dataset to estimate annual capacity factors of the four potential wind sites. Likewise, the Department of Energy's Solar Advisory Model was used to model concentrating solar power and solar photovoltaic plants at the twelve potential solar sites. Transmission costs were estimated using the capital costs for 500 kV transmission lines used in the Western Governors Association Western Renewable Energy Zone process, model, and report.

3.2.2 SRP

In selecting its top three RTP projects, SRP considered these factors:

- Closeness to renewable resources
- Permitting issues
- Ability to provide access to renewable resources and to serve multiple purposes
- Access to multiple resources, resource dense areas or energy hubs
- Relative cost and schedule
- Proximity to SRP's service territory
- Integration into local transmission & generation system
- Ability to align partnerships
- Likelihood of meeting permitting requirements
- Enhancing system reliability

The three projects identified by SRP, as shown in Figure 4, were:

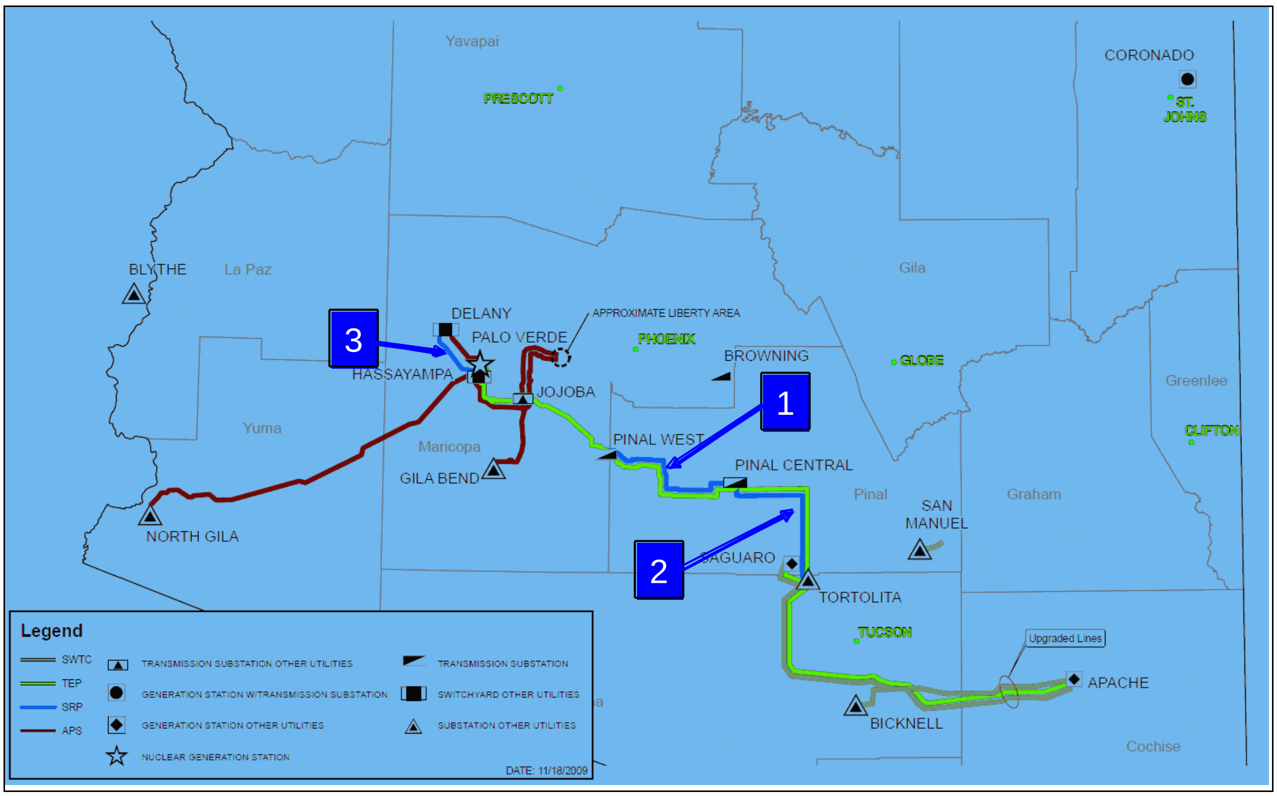
1) Pinal West – Pinal Central 500 kV

2) Pinal Central – Tortolita 500 kV

3) Delany – Palo Verde 500 kV

It should be noted that SRP's RTP #3 is the same as APS's RTP #1 (i.e., a joint participation project).

Figure 4: APS, SWTC, SRP and TEP Identified RTP Projects



3.2.2.1 Pinal West – Pinal Central 500 kV

This project is a 50-mile line that is an integral piece of the Hassayampa to Pinal West to Pinal Central to Browning project. Today there are 11 interconnection requests to that line—all solar—for 3,500 MW. The line adds a critical link from the SRP Southeast Valley to Palo Verde.

It also provides another parallel path from the Palo Verde area into the Valley, and gives access for Pinal County resources to Palo Verde.

3.2.2.2 Pinal Central to Tortolita 500 kV

SRP advised at Workshop 1 that there are about 500 MW of renewable transmission projects in the queue between Pinal Central and Tortolita. In addition to providing a means to integrate these projects, the addition of Pinal Central to Tortolita would help to support delivery of new renewable resources from western Arizona to load centers further east such as Pinal County and Tucson. The project is being proposed jointly with TEP.

3.2.2.3 Delany to Palo Verde

This project is a short transmission project—18 miles. There are seven requests for interconnection totaling 3,300 MW—all solar--in the area. It is part of the Palo Verde-TS-5 APS project. The proposed Delany Substation site is located in the very rich solar resource area of Harquahala Valley. As previously noted, this is a jointly-owned project with APS.

3.2.3 Tucson Electric Power Company and UNSE

TEP and UNSE jointly filed their RTP project report in the Docket in 2009. Three projects were selected:

1) Palo Verde to Pinal West to Pinal Central 500 kV
2) Pinal Central to Tortolita 500 kV
3) Western Apache to Tortolita 115 kV to 230 kV Line Upgrade

All of these projects will help to support delivery of renewable resources from western Arizona to load centers in southeastern Arizona, including Tucson. The Pinal West to Pinal Central and Pinal Central to Tortolita projects were also proposed by SRP, as discussed above (they are joint ownership projects). Only the third project is unique to TEP and is discussed in more detail below.

3.2.3.1 Western Apache to Tortolita 115 kV to 230 kV Upgrade

The third project is an upgrade of the existing 115 kV system that has been in service for many years. The project is shown in green in the bottom right of Figure 4, above. Originally it was to deliver power to preference customers from hydro units delivered over the 115 kV lines. Over the years the rest of the system and local load has grown up around these facilities.

TEP observes that efforts to move renewable resources across the existing 115 kV system will experience congestion due to single-contingency criteria. The upgrade of the selected line to 230 kV will remove those legacy limitations and facilitate renewable development. This third project would also interconnect with the radial lines reaching down into southeast Arizona and provide opportunities for renewables to connect to the system and be delivered throughout the state.

3.2.4 SWTC

SWTC selected its top three RTPs by recognizing that the upgrades that will support renewable resource development in southeastern Arizona are the same as those needed to meet NERC reliability standards and to support continued growth in the area. SWTC will contact developers as they announce intentions to build renewable resource projects in Southeast Arizona.

SWTC has worked with other utilities since the Order was issued in developing its top three RTPs. The selected projects are:

1) San Manuel Interconnect Project—involves interconnecting the SWTC Apache to Hayden 115 kV line into the APS San Manuel Substation;

2) Apache to Bicknell 230 kV Line Upgrades (see Figure 4) —involves upgrading the existing 795 ACSR conductor of this 230 kV line to a higher-ampacity rated conductor, to meet NERC Reliability Standards and support continued growth in the area; and

3) Western Saguaro to Apache 115 kV Line Upgrade—would provide additional transmission transfer capability of up to 1,000 MW that could be used for renewable generation in the area and could increase Western's customer's access to potential renewable areas identified by the RTTF.

A more detailed drawing showing these three projects is provided in Exhibit 34. The EHV 345 kV system (shown in green in Exhibit 34) is owned by TEP. SWTC's system is shown in yellow (230 kV) and purple (115 kV). The 230 kV facilities are a back-bone system extending from Greenlee to Bicknell. The 115 kV facilities extend from Bicknell to Marana Tap. SWTC also owns a 115 kV system extending from Apache to the SRP Hayden Substation. Both TEP and SWTC are part owners of the Southeast Valley 500 kV line (shown in red) which extends from the Palo Verde Hassayampa Switchyard to Pinal West and are also part owners of the portion proposed for extension from Pinal West to Pinal Central in 2013. Various facilities owned by APS and SRP are also shown.

There is only one renewable resource project that is currently in the active generator queue listing located near San Manuel, Arizona. Other projects have been in previous queue listings, but have been withdrawn for various reasons.

3.3 Related ACC Staff Observations and Conclusions

The proposed RTPs described above represent the first utility filings in response to the 5th BTA request for an analysis of the impact of renewables on transmission plans. On the whole the filings are responsive to the Commission's request. An inclusive stakeholder process was also developed and executed to identify the initial set of transmission RTPs. Most of the proposed RTPs are not entirely new proposals, but actually represent advancement of projects that have already been in planning for reasons other than renewable integration.

3.3.1 Effectiveness of RTP Projects Selected by the Utilities

As already noted many of the projects identified by the utilities are found in previous transmission plans of the utilities to meet various needs, including reliability, market access and renewable resource procurement plans. Since the majority of conceptual transmission corridors identified in the ARRTIS report were generally along existing and planned corridors, this initial set of RTPs should not be a surprise. They appear to be a reasonable set of initial renewable development projects that will facilitate renewable resource development in the southern half of the state, close to either the Phoenix or Tucson load regions or the resource rich Palo Verde hub region.

We conclude that the projects selected should be effective in enabling development and delivery of renewable resources to the load centers of the Arizona utilities or the Palo Verde hub.

3.3.2 Impact of RTP Projects on the Arizona Transmission System

Because many of the selected RTPs have been identified in earlier transmission plans, they should contribute to reinforcing the transmission system for general use in addition to facilitating the integration of renewable generation.

3.3.3 Impact of RTP Projects on Development of Renewable Resources

The identified projects should be effective in enabling delivery of renewable resources developed close to either the Phoenix-Tucson regions or the Palo Verde hub. As projects are developed farther from these areas, transmission facilities that were not proposed in earlier 10-year plans will likely need to be developed.

The RTP projects and the queued renewable generation in the areas the RTPs serve are shown in Table 7.

Table 7: RTP Projects and Queued Renewable Resources

RTP	RTP sponsor(s)	Estimated transfer capability (MW)[51]	Queued renewables in area served by RTP as of May 2010 (MW)
Delany – Palo Verde	APS, SRP	1,000	3,300[52]
Palo Verde – Pinal West 500kV	TEP	1,000	n/a[53]
Pinal West – Pinal Central 500kV	SRP, TEP	1,000	3,500
North Gila – Hassayampa 500kV #2	APS, SRP	1,000	4,468[54]
Pinal Central – Tortolita 500kV	SRP, TEP	1,000	500
Delany – Blythe 500kV	APS, SRP	1,000	n/a[55]
Hassayampa – Jojoba – Palo Verde – Liberty area 500kV	APS	1,000	500
Gila Bend – Liberty area 500kV*	APS	1,000	890
Western Apache – Tortolita 230kV Saguaro – Apache 115kV Upgrade	TEP, SWTC	500	297
San Manuel Interconnect	SWTC	To be determined	0
Apache – Bicknell 230kV Upgrade	SWTC	To be determined	0
Total(s)		**9,500**	**13,455**

[51] Actual value to be determined through future path rating studies.

[52] The 3,300 MW figure reflects the amount of renewable generation in the queue at the time of the 6th BTA Workshop 1, but SRP advises that the amount in the queue has since dropped to 1,500MW. APS concurs that 1500 MW is queued at Delany in its response to Data Request 1 in Docket E-01345A-10-0033.

[53] No queue of renewables along this section, but still useful for deliveries of Delany-PV area MW to Arizona load centers further east (e.g., already accounted for in table and left out to avoid double counting - not intended to prejudice the choice between this RTP and other RTPs.)

[54] Value quoted by APS in response to Data Request 1 in Docket E-01345A-10-0033.

[55] Same queue as Delany-PV.

3.3.4 Staff Comments on Questions raised by the RTTF Financing Subcommittee

1. ***Is the BTA the best forum for determining cost-recovery status of rate-based assets since there is no filing in a BTA?***

   The BTA and RTAP processes should not be used for cost-recovery or rate-base decisions by the Commission. The goal should be to identify transmission projects for Arizona, describe their justifications, to present a ranking or priority to the projects, and to inform the Commission of changes in the transmission plans from year-to-year.

   The RTAP and renewable needs analyses should also be largely for informational purposes. The Commission is seeking a better understanding as to how expanded renewable generation development would affect transmission plans. The economic analysis is also intended to establish a technical, procedural, and economic means for the utilities to identify, prioritize and incorporate changes to transmission plans that should be made due to potential renewable generation expansion.

2. ***Should RTPs be submitted annually (i.e. included in the 10-year plans) or biennially (i.e. as part of the BTA and 10-year plans)?***

   In the long run the RTAP should be developed and submitted biennially with the BTA. However, if the pace of renewable generation development warrants, then annual filings may be required.

3. ***How are legitimate RTPs that arise unannounced to be afforded RTAP treatment by the Commission?***

   The RTAP process should identify the top three RTPs, but as was done this year, additional projects can also be identified for informational purposes. The Commission would then have an expectation as to what transmission projects might be needed to support other renewable projects. In any case, the Commission would be open to applications for "unexpected" renewable resource developments that might require an *ad hoc* RTAP.

4. ***Do the Commission and Staff require further guidelines to assist with differentiation of a candidate RTP and transmission project proposed in the ordinary course of business?***

   The emphasis here should be on identifying projects that need priority handling/processing outside the ordinary course of business and that can be justified specifically to support renewable generation projects.

5. ***Do the Commission and Staff have the tools to make allocation decisions that might be required under '4.' above?***

   We believe the Commission and Staff have the capability, but will monitor their needs as the overall RTP/RTAP process evolves in the future.

3.3.5 Impact of RTP Implementation on REST Requirements

The Renewable Energy Standard and Tariff R14-2-1801 ("REST") became effective August 14, 2007, following approval by the Commission. Among other things, the REST rules require jurisdictional utilities to generate or purchase at least 15% of their total annual retail energy requirements from eligible renewable energy resources by 2025, with smaller amounts required in earlier years. For calendar year 2009, the Commission established a requirement of 2.0 percent of a utility's 2009 total retail kWh sales, with 15 percent of that requirement to be satisfied through energy received from distributed energy ("DE") resources. The REST requirements for the 2008-2025 periods are shown in Table 8.

Table 8: REST requirements 2008-2025

Year	REST goals	Year	REST goals
2008	1.75% (10% DE)	2017	7.00% (30% DE)
2009	2.00% (15% DE)	2018	8.00% (30% DE)
2010	2.50% (20% DE)	2019	9.00% (30% DE)
2011	3.00% (25% DE)	2020	10.00% (30% DE)
2012	3.50% (30% DE)	2021	11.00% (30% DE)
2013	4.00% (30% DE)	2022	12.00% (30% DE)
2014	4.50% (30% DE)	2023	13.00% (30% DE)
2015	5.00% (30% DE)	2024	14.00% (30% DE)
2016	6.00% (30% DE)	2025	15.00% (30% DE)

In general, the utilities have met or exceeded the overall REST goals—total renewable energy of 2.00% from renewables. The goal for DE to have been 15% of the total has generally not been met, though each of the utilities reports a surge in new DE added in 2009.

The REST requirements are likely to affect the transmission plans of Arizona utilities in two general ways—first, utility-scale renewable generation will likely require at least some transmission improvements that are different from those that would otherwise be needed; and, second, the DE component will, in effect, reduce the load on the distribution and transmission systems.

- The information in the utility REST reports can be used to make a comparison of the scale of the REST goals with the delivery capability of the transmission projects proposed in the Arizona utilities' 2009 RTAP filings. The 15% energy requirement by 2025 could require total renewable generating capacity equal to 24-41% of the system peak load. This assumes an annual capacity factor for all renewable sources to be 25-35% and a system load factor of 55%. So 10,000 MW peak load would be 48,180,000 MWh/year. A 15% renewable requirement would be 7,226,000 MWh annually or an average of 825 MW. If total renewable generation had an annual capacity factor or 20% (the low end of a reasonable range) then 4,125 MW of renewables would be needed to supply the 7,226,000 MWh of annual energy. If renewables have an annual capacity factor of 35% (the high end of a reasonable range) then only 2,357 MW of renewables would be required.

- The utility-scale renewable generation requirement could range from 17% to 29% (i.e., 70% of the total installed renewable capacity) of the system peak load. This is a significant amount of utility-scale generation and would require transmission reinforcement of some consequence. The amount of renewable generation today is still relatively low and so has not had a significant impact on transmission plans.

4. Other Commission Ordered Studies

4.1 History and Purpose

In addition to the assessment of transmission needs for renewable resource integration discussed in Section 3 above, 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.
- N-1-1 and Extreme Contingency studies have been required to ascertain the transmission system's robustness to withstand more severe emergency scenarios since the Third BTA.

Such studies have a twofold purpose. First, the ordered studies are intended to improve the thoroughness and accuracy of the conclusions and recommendations resulting from the BTA. Second, the ordered studies are intended to better inform the Commission about areas of the transmission system that potentially need improvement, and identify if additional Commission focus on such areas is prudent. These three categories of results in the 6th BTA are discussed in more detail below.

4.2 Local Area Transmission Load Serving Capability Assessment

In the First 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 Second BTA added a fourth area located in Southeastern Arizona (Santa Cruz County). Subsequent BTAs added Mohave County. Updated RMR studies were filed for these five areas in the 6^{th} BTA. Prior BTAs have also looked at import constraints in Pinal County, which have been analyzed through the SWAT CATS-HV 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 is addressed in this BTA report.

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.[56] 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").[57] In addition, the Commission coined the term "continuity of service" in Decision No. 70635, which is discussed further in this 6th BTA report.

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

4.2.1 Cochise County Import Assessment

The Cochise County load serving entities are APS, TEP, and Sulphur Springs Valley Electric Cooperative ("SSVEC"). The Cochise County load, from Ft. Huachuca to Douglas, is served via four radial transmission lines (115 kV, 138 kV and 230 kV). The loss of any one of these lines would require dropping of some customers until manual restoration procedures can be performed. Utilities serving Cochise County have historically had a "restoration of service"[58] paradigm in their planning and operating procedures for transmission outages. This has been of concern to Staff since the first BTA over a decade ago. The critical nature of Fort Huachuca's mission and the accompanying load growth in southern Cochise County[59] are strong

---

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

[57] Appendix C, RMR Conditions and Study Methodology

[58] As defined in Appendix F of the Fifth 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 restore 18 MW of load for loss of Vail-Ft. Huachuca 138kV.

[59] At the time of the CCSG report Cochise County load was forecast to grow by 13% from 2013 to 2018, but the impact of current economic conditions on this forecast is unknown.

justifications for transition to a “continuity of service”[60] planning and operating paradigm for transmission outages.

The 5th BTA Staff Report in 2008 noted that APS, SSVEC and TEP each have an obligation to assure that adequate transmission import capability is available to meet the load requirements of all distribution customers within their service areas.[61] Following the 5th BTA, the Commission determined that perpetuating a “restoration of service” paradigm for single contingency transmission outages in Cochise County is not in the public’s interest. Therefore, the Commission ordered that APS, SSVEC and TEP perform studies in order to develop a transmission plan of service that assures “continuity of service” for single contingency transmission outages in Cochise County within five to ten years (e.g. 2013-2018).[62]

In response to the Commission’s order, the Cochise County Study Group (“CCSG”) of SATS conducted a new technical planning study in 2009. A map of the study area is shown in Exhibit 32. The report from this study was included in SWTC’s 6th BTA filing dated January 2010. The summary report on that study filed by SWTC elaborates the following interpretation of “continuity of service” that has been promulgated by the Commission:

> “The CCSG agreed that a definition for continuity of service is that loss of any single transmission facility will not result in loss of load that requires subsequent System Operator intervention, either directly or through Energy Management System (action), to restore service. Specifying without Operator intervention reduces outage time to be within the timeframe that automated schemes typically operate (e.g. seconds to minutes). Implementing existing manual operational procedures could help restore at least partial power to the affected areas but this does not meet the continuity of service principle as defined by the ACC. The CCSG clarification offers significant improvement over historically experienced “restoration of service” by limiting potential interruptions to seconds or minutes versus historical outages lasting hours or days.”

The CCSG 2009 study group primarily consisted of transmission planning staff from SSVEC, SWTC, TEP, Western, APS and Fort Huachuca. The study was performed using WECC

[60] Pursuant to Arizona Administrative Code R14-2-208(D) (1), “Each utility shall make reasonable efforts to reestablish service within the shortest possible time when service interruptions occur.”

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

[62] Reference 5th Biennial Transmission Assessment (E-00000D-07-0376) (Section 5.1.3, pages 65-67); and Decision No. 70635 (5.d, page 3)

approved 2013 and 2018 system models and was completed in November 2009. The summary report filed by SWTC states:

> "After a thorough technical analysis of the different potential transmission and/or generation alternatives proposed for resolving the continuity of service issue in the Cochise County, it became apparent that a combination of two or more initial alternatives would be needed to fully resolve the issue. The recommended transmission plan was tested and found to be technically capable of meeting the NERC Reliability Standards and the WECC System Performance Criteria as well as complying with the ACC Order 70635 to provide for continuity of service in Cochise County in both 2013 (or by a 308MW load level) and 2018 (or by a 348MW load level). The recommended transmission plan is detailed below:
>
> - New Palominas - Hereford 69 kV line
> - Proposed 50 MVA, 115/69 kV transformer at Boothill
> - Loop Webb - Tombstone 69 kV line through Boothill
> - Proposed Fort Huachuca 138 kV - Buffalo Soldier 69 kV tie (needed in 2018)
> - Operate the following normally open circuits as normally closed circuits:
>   - Charleston - Bella Vista 69 kV line
>   - Keating Junction - Hawes 69 kV line
>   - Mc Neal - San Pedro 69 kV line
>
> - Install shunt capacitors at the following substations
>   - 13.2 MVAR at Webb 69 kV substation
>   - 8 MVAR at Ramsey 69 kV substation
>   - 8 MVAR at Hawes 69 kV substation
>   - 8 MVAR at Pueblo 69 kV substation
>   - 6 MVAR at Webb 69 kV substation (needed in 2018)"

Although capital cost estimates are not provided for this list of projects in the CCSG report, in Staff's opinion based on generic costs, this set of capital expansion projects should turn out to be a reasonable level of expenditure to achieve the "continuity of service" paradigm in Cochise County. CCSG states that it intends to develop detailed cost estimates for these projects in 2010 and to open negotiations for the related contractual arrangements including "cost responsibility, wheeling arrangements, EPC (engineering, procurement, and construction), Operations and Maintenance (O&M), Load Serving agreement, etc." so that these can be completed in time to construct the facilities when needed. The CCSG report does not provide an implementation schedule for the plan of service. Based on feedback received from CCSG participants during the 6th BTA, pending changes in the Cochise County load forecast may allow delaying certain components of the plan of service without jeopardizing Cochise County's continuity of service.

4.2.2 Santa Cruz County Import Assessment

Santa Cruz County, similar to Cochise County, is served by a radial transmission line. UNSE is the load serving entity in Santa Cruz County. The customer service and system impacts and risks associated with the loss of the single transmission line serving Santa Cruz County are well chronicled in prior BTA assessments and siting proceedings of the Gateway 345 kV transmission project.[63] The Gateway Transmission Project was proposed as a solution and a Certificate of Environmental Compatibility was approved by the Commission. A NEPA environmental impact study has been concluded for the project but Federal Records of Decision and a Presidential Permit for the new 345 kV Gateway Transmission Project are still pending with federal agencies.

UNSE 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 UNSE in February, 2010.

The UNSE ten-year plan includes the Gateway Project and associated 138 kV line from Gateway to Valencia. UNSE received a CEC in 2009 (Case No. 144, Decision No. 71282) to rebuild and convert the existing 115 kV line between Western's Nogales switchyard and the UNSE Valencia substation to 138 kV. Part of this project includes transferring the point of interconnection of UNSE from Western's Nogales switchyard to a future interconnection in TEP's Vail Substation. However, this project alone will not achieve the continuity of service objective for Santa Cruz County until the 345 kV Gateway Project is completed. At present, Santa Cruz County remains exposed to service outages for all of its UNSE customers following the loss of the single transmission line serving the county. The most recent reported outage occurred on July 16, 2008 and resulted in 63,455 customer hours of service interruption.[64] The ten-year plan also includes a Gateway – Sonoita 138 kV line, which will improve local reliability but is still contingent upon permitting and completion of the Gateway Project.

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

[64] Records of Arizona Corporation Commission, Outages Forms, Reported by Rick Molina with UNS Electric on July 17, 2008

Also note the discussion of Santa Cruz County RMR requirements in section 4.2.5 below.

4.2.3 Mohave County Import Assessment

As directed in the fifth Biennial Transmission Assessment, UNSE is working with the CRT to address issues in Mohave County. UNSE and Mohave Electric Cooperative ("MEC") are the load serving entities in Mohave County. UNSE still shows the Griffith – North Havasu 230 kV line in its ten-year plan and has an approved Certificate of Environmental Compatibility (CEC) (Case #88). The N. Havasu – Franconia section is built and operating temporarily at 69 kV, but the Franconia – Griffith section is not needed until 2016 or beyond, according to UNSE's 6th BTA filing. UNSE is considering a request for extension of the CEC to 2016 or beyond, pending further review of the results of the Mohave County RMR study. Other UNSE transmission projects in Mohave County are postponed indefinitely due to the economic downtown.

See section 4.2.5 below for discussion of the Mohave County RMR study.

4.2.4 Pinal County Import Assessment

The load serving entities providing electric service in Pinal County are APS, SRP, Electrical District Nos. 2, 3, 4, and 5, and the San Carlos Irrigation District ("SCIP"). These entities, other utilities and stakeholders participated in the Central Arizona Transmission System – High Voltage ("CATS-HV") Study for the area, which was filed in the 6th BTA by SWAT in September 2009. The CATS-HV Study provides a comprehensive analysis of all projects in the ten-year plan period for Pinal County, as well as the underlying 69 kV system, by analyzing the planned 2019 system.

The CATS-HV Study of 2019 addressed base case (NERC Category A) and N-1 (NERC Category B) conditions. It did not address other more severe overlapping contingency events, as was done in prior CATS-HV studies, because the ten-year plan has not changed significantly in the area for this BTA. The study performed power flow analysis, but did not address stability analysis. No overloads were identified within Pinal County in the study. Some 69 kV undervoltages were found for loss of the Coolidge – Valley Farms 115 kV line, but can be corrected by routine shunt capacitor additions during the planning cycle.

It should be noted that the study for 2019 assumed SPPR's "Three-Terminal" transmission plan (Pinal Central to ED5, ED5 to Test Track and ED5 to Marana 230 kV lines). As previously discussed in section 2, SPPR has now deferred plans for two of these line additions indefinitely. The impact of these project deferrals on the results of the CATS-HV study of 2019 is unknown.

4.2.5 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 SIL of the local transmission system. The Commission has adopted a definition of RMR Conditions and Study Methodology to be utilized for RMR study requirements.[65] It 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
- RMR energy - The amount of energy served from RMR generation
- RMR peak demand - The maximum RMR amount of capacity that the RMR generators would be required to produce
- RMR costs - The costs of out-of-merit-order[66] dispatch from RMR generation

A summary of the RMR study results filed in the 6th BTA is provided in Table 9.

[65] Appendix C, RMR Conditions and Study Methodology

[66] Out-of-merit order generation is more expensive than generation in the economic dispatch order

Table 9 - RMR Study Metrics

Area	Year	Peak Load (MW)	SIL (MW)	Import (MW) @ Peak	RMR Gen MW @ Peak	RMR Hours Per Yr	Annual RMR GWh	Annual Cost ($000)
Phoenix	2013	12,129	11,296	11,232	897	45	15	0
	2019	14,621	11,693	12,459	2,162	497	317	0
Tucson	2013	2,592	1,948	2,162	430	697	42	$624
	2019	2,883	2,442	2,853	30	252	15	$261
Yuma	2013	446	312	285	161	950	43	0
	2019	562	473	477	85	171	4	0
Mohave County[67]	2013	826	816[68]	816	10	n/a	n/a	0
	2018	935	889[69]	895	40	n/a	n/a	0
Santa Cruz County[70]	2010	93.5	51	n/a	24	n/a	n/a	n/a
	2013	100	127	100	0	0	0	0
	2018	117	127	117	0	0	0	0

4.2.5.1 Phoenix Metropolitan Area RMR Assessment

The interconnected transmission system serving the metropolitan Phoenix area is owned and operated by APS, SRP and WAPA. 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 exists for the Phoenix area because the peak load for the area exceeds the SIL of the existing and planned transmission system serving the area.

The Phoenix area 2010-2019 RMR study performed detailed RMR analysis for 2013 and 2019. The study concludes that RMR requirements for the Phoenix metropolitan area are not significant and advancement of transmission projects to increase import capability is presently

[67] Mohave County RMR generation values quoted are less than the hydro plant output required at summer peak for water release requirements according to USBR

[68] Assumes Black Mesa 230kV bus is not connected to Parker Davis System

[69] Assumes Black Mesa 230kV bus is connected to Parker Davis System via Parker-N.Havasu 230kV

[70] Area peak load includes a 5% demand margin for voltage security analysis

not cost justified. The required metrics are shown in Table 9. Other key RMR study findings for the Phoenix metropolitan area are as follows:

1) Planned Phoenix area transmission and local generation can reliably serve Phoenix area peak load in 2013 and 2019. In addition, the projected local generation reserve margin exceeds the required reserve margin by 2,265 MW in 2013 and 1,000 MW in 2019.[71] This translates into a Loss of Load Probability of much less than one day in ten years.

2) Local generation is not expected to be dispatched out of economic dispatch order in 2013 and 2019.

3) There are no emission impacts due to RMR generation energy production in 2013 and 2019 because the local units are not dispatched out of economic dispatch order.

4) Phoenix area RMR conditions pose no impact to local generation capacity factor and total yearly natural gas consumption by the Phoenix area generators because the local units are already scheduled in economic dispatch order irrespective of the SIL being exceeded.

The Phoenix area RMR study is thorough and well documented. The study comports to the Commission's RMR study methodology and actually performs production cost simulations using industry accepted study tools and publicly available data. No flaws in assumptions or modeling are evident in the report.

4.2.5.2 Tucson Area RMR Assessment

The Tucson area is interconnected to the EHV transmission system via three substations: Tortolita 500/138 kV, South 345/138 kV and Vail 345/138 kV. These three stations interconnect and supply energy to the local TEP service area. 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.

[71] The RMR area reserve requirement is based on a Loss of Load Probability (LOLP) criteria of one day in ten years (i.e., some unserved load is permitted 1 day in each 10 years).

As shown in Table 9, the Tucson area peak load forecast for 2013 and 2019 both exceed the reported SIL for the respective years. Therefore, an RMR condition will exist. TEP filed an amended Tucson area RMR Study report in February 2010 that contains the information necessary for Staff to complete its assessment of RMR needs. Staff has reviewed the amended report and finds the RMR study to be complete and a thorough representation of RMR conditions that exist in the Tucson area.

In the absence of RMR generation, the Tucson area is subject to voltage collapse and cascading overloads during transmission contingencies. TEP developed an estimate of the capital expenditures necessary to mitigate these reliability issues absent RMR generation. They concluded that $156.5 - $197.6 million in upgrades would be required in 2013, and $1.5 - $3.4 million would be required in 2019. Given the magnitude of the RMR costs as shown in Table 9 for 2013 and 2019, TEP concludes that the incremental capital expenditures are not justified. Staff concurs with this conclusion.

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.

In addition, the study makes the following conclusions regarding operation of the Tucson area under 2010 peak load conditions, which were studied per Commission order in the 5th BTA.

- The TEP system can survive N-2 contingencies of parallel lines in the Springerville to Vail corridor at 2010 peak load levels.
- The TEP system can survive loss of all transformers at any given EHV substation 2010 peak load levels.

4.2.5.3 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 WAPA 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 WAPA, WMIID, IID and parties in the area seeking to connect under Large Generator Interconnection Agreement(s) ("LGIA") Yuma, Mohave County and Santa Cruz County."

For the 2010 RMR study effort, APS formed an open forum under the guidance of the Colorado River Transmission (CRT) sub-regional study group of SWAT and held several meetings to discuss the need to incorporate the plans of all entities in Yuma County. As a result of this stakeholder process WAPA, IID, WMIDD have all agreed that the cut plane for the Yuma RMR study should remain as previously defined.

The APS Yuma area 2010 RMR study concludes that RMR conditions do exist for the Yuma area and that there is some limited amount of RMR costs in 2011. The planned APS transmission improvements in the area are sufficient to mitigate RMR cost that would otherwise be associated with 2016 RMR conditions. APS reported that advancement of planned transmission projects to increase import capability in earlier years is not warranted. The following other key RMR study findings were reported for the APS Yuma area:

1) Planned Yuma area transmission and local generation can reliably serve area peak load in 2013 and 2019. In addition, the projected local generation reserve margin exceeds the required reserve margin by 152 MW in 2013 and 228 MW in 2019. This translates into a Loss of Load Probability of much less than one day in ten years.

2) The Yuma area load is expected to exceed the available transmission import capability for 950 hours in 2013 and 171 hours in 2019. The import constraint could cause APS Yuma generation to be dispatched out of economic dispatch order for 22 hours in 2013 and zero hours in 2019.

3) The estimated annual economic cost of Yuma area generation required to run out of economic dispatch order is negligible for 2013 and 2019.

4) Removing the transmission constraint would reduce total Yuma area air emissions by a minimal amount for 2013 and 2019.

5) Removing the transmission constraint could reduce total yearly natural gas consumption by 0.006 BCF for 2013 and has no impact on 2019.

The APS Yuma area RMR study is thorough and well documented. The study comports to the Commission's RMR study methodology and actually performs 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 5th BTA.

4.2.5.4 Santa Cruz County RMR Assessment

UNSE filed the 2010 RMR study of the Mohave County Study System on March 8, 2010. The existing Santa Cruz UNSE system was explicitly modeled within the 2010, 2013 and 2019 Arizona coordinated heavy summer cases prepared by the Southeast Arizona Transmission Study ("SATS") group. The cases were revised to include detailed representations of TEP's 138 kV system and UNSE 115 kV transmission radial line in Santa Cruz County. The 115 kV to 138 kV conversion is detailed in the 2013 and 2019 cases. Actual power factor data, representing UNS Electric's power factor improvement program, was used to model substation reactive demand in the 2010 study (unity power factor loads were assumed in the 2008 study).

For N-1 contingencies the SIL was calculated to be 51 MW in the 2010 case, prior to upgrade of the Nogales-Valencia line from 115 kV to 138 kV. Since the forecast load exceeds import capability there is an RMR requirement of 24 MW in 2010. The report[72] provides estimates of RMR emissions and RMR costs ($550,000 in 2010).

In 2013 and 2019 the SIL increases to 127 MW due to the line conversion to 138 kV and the improved voltage regulation afforded by the stiffer source served directly from TEP's Extra High

[72] UNSE's updated report on Santa Cruz County RMR analysis, dated Aug. 13, 2010.

Voltage (“EHV”) system via a new 345/138 kV transformer, Vail T3, which is assumed to be in-service by 2013. There is no RMR requirement in 2013 or 2019.

4.2.5.5 Mohave County RMR Assessment

UNSE filed the 2010 RMR study of the Mohave County Study System on March 8, 2010.[73] The study was performed for 2013 and 2018 under the oversight of the Colorado River Transmission (“CRT”) Study Group. The scope of this study required an assessment of the portion of the WAPA 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.

In the 2008 RMR study, SIL calculations were based on the assumption that certain hydro units were operated in a base load condition. However, in the 2010 study, the SIL was calculated with no generation on line per ACC RMR study guidelines. Another key difference from the 2008 study is the change in the study interface shown in Exhibit 33. The 2008 cut plane passed through the Mead to White Hills, Round Valley to Peacock, and Peacock to Liberty transmission lines. The CRT agreed that the 2010 cut plane more accurately defines the transmission ties that supply the Study System. Thermal overloads outside of the study area were ignored because they were physically removed from the study area cut plane, and it is assumed the respective load serving entities (“LSE’) will address such limitations in the supply plans for their own service areas.

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 2013 and 2018 planning horizon. Hydroelectric generation within the study system must be run regardless to meet minimum river flow requirements. No additional generation is needed to assure system reliability.

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

4.3 Ten Year Snapshot Study

The CATS EHV workgroup filed a report in September 2009 documenting results of its 2009 “Ten Year Snapshot Study” which looked at the 2019 system. The study is done every other year, and was previously referred to as the “N-1-1 Study”. The CATS EHV workgroup included representatives from the following transmission owners: APS, SRP, SWTC, TEP, WAPA and Electrical District 3. The report was compiled by SRP on behalf of the workgroup. It was approved by SWAT in August 2009.

Whereas some of the Arizona transmission owners have filed technical study reports for their respective areas of the system as part of the 6th BTA, the CATS-EHV Ten Year Snapshot Study represents the only comprehensive assessment of 2019 Arizona transmission plans (i.e., the end of the ten-year plan). Furthermore, unlike prior Ten Year Snapshots that focused on the Central Arizona system, for the first time the Ten Year Snapshot Study done in 2009 includes all transmission and generation projects statewide. This makes the report uniquely valuable for assessing the overall adequacy of Arizona transmission plans in 2019.

The Ten Year Snap Shot Study consists of conducting N-0 and N-1 power flow analyses that determine the adequacy of the ten-year plan. In addition, fifteen base case project deferral scenarios (nine APS projects, four SRP projects, one TEP project and the Palo Verde-Devers #2 500 kV line) 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 2009 Ten Year Snapshot Study reached the following major conclusions:

1) The 2019 transmission plan is robust.

2) There were no overloaded transmission system elements in the 2019 base case (e.g., the plan complies with the NERC TPL-001 reliability standard).

3) There were few overloads or voltage issues due to outages (in most cases operating solutions are available to resolve these; in some cases the utilities are still considering mitigation measures).

4) Even with delay or cancellation of any individual transmission project in the 2019 plan, loading levels and voltage deviations were acceptable for contingencies.

5) Delay of multiple projects in the planned 2019 system could have significant impacts on performance.

Additional Staff/KEMA observations regarding the study are as follows:

1) The 2019 base case (model) used for the study was based on the complete list of projects that were planned to be in service at the time of base case development, which took place from January-April 2009. In other words, there may be some differences between the 2009 Snapshot case and the current 2010-2019 plans covered by the maps and exhibits in the 6th BTA. This means that the projects modeled in the 2009 Snapshot Study are a "hybrid" of the 5th BTA and 6th BTA project plans. The impact of this on performance of the 2019 system is unknown, but in SRP's opinion the model is very close to the 6th BTA plan for 2019.

2) The 2009 Snapshot Study assumed a statewide peak demand forecast of 25,340 MW for 2019. This is a 689 MW (2.65%) reduction from the Arizona demand level assumed in the previous 2018 CATS EHV base case, and reflects the impact of the current economic recession. This 2.65% demand reduction is actually much smaller than the demand reduction reported by the Arizona utilities in response to data request(s) during the 6th BTA. Comparing the 2017 forecast from the 5th BTA vs. the 2018 forecast from the 6th BTA shows a drop in demand of 6-7%. This change is a much greater than the 2.65% drop modeled in the 2009 Snapshot Study, which tends to make the Snapshot Study a more "rigorous" test of 2019 system performance. This also helps offset the impact of any projects in the 2009 Snapshot Study model subsequently postponed or deleted in the 6th BTA plans filed in January 2010.

3) The 2009 Ten Year Snapshot Study includes a comprehensive set of "steady-state" analysis, but does not include any "dynamic" stability analysis. Both types of analysis are required by NERC reliability standards.

4.4 Extreme Contingency Study Work

The Commission directed that parties continue to address and document extreme contingency outage studies for Arizona's major generation hubs and major transmission stations, and identify associated risks and consequences, and possible mitigating infrastructure improvements as necessary. The 6th BTA Extreme Contingency Study was conducted by the SWAT Sub-Regional Transmission Planning Group and was filed by APS on May 27, 2010. The study examined steady-state performance (i.e., power flows and voltages) throughout the Arizona and sub-regional system for selected extreme contingencies in the 2011 and 2016 heavy summer system models which reflected the filed ten-year project plans. 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 as specified in the NERC standards.

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:

- Cholla-Saguaro and Coronado-Silver King 500 kV lines
- Navajo Westwing 500 kV lines
- 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

The details of these study results were provided to the Commission in the report filed by APS, which was provided under a Protective Agreement (due to Critical Electric Infrastructure concerns). Therefore, detailed study results could be made available for presentation to the Commission in closed session, but only a general summary is included in the public BTA report.

In both the 2011 and 2016 extreme contingency analysis, all customer loads can be served (or restored), but some of the contingencies would require generation re-dispatch or a limited amount of local system reconfiguration to alleviate overloads.

5. National and Regional Transmission Issues

5.1 NERC Mandatory Reliability Standards

On July 26, 2006, the NERC was designated as the nation's ERO for the purpose of establishing and overseeing a system of mandatory and enforceable electric system reliability standards. These mandatory reliability standards apply to users, owners and operators of the bulk power system designated by NERC through its compliance registry procedures.

In the spring of 2007, FERC approved NERC's blueprint for the contractual relationship between NERC and eight regional reliability entities. This agreement includes a Compliance Monitoring and Enforcement Program to be used by NERC and regional entities to monitor, assess and enforce compliance with FERC approved mandatory reliability standards. The WECC was authorized as one of the eight regional entities, and a delegation agreement with the WECC was approved by FERC in June 2007. That same month, FERC approved eight proposed regional Reliability Standards for the WECC,[74] in addition to the 83 mandatory NERC reliability Standards.

Over the last three years, NERC has conducted numerous on-site audits and overseen compliance with its mandatory standards. Compliance and violation statistics are compiled monthly and posted on the NERC website (www.nerc.com). According to NERC, "These statistics provide…information regarding new violations that were identified during the current month, as well as updates to previous violations that are making their way through the compliance process." A review of these statistics shows that as of May 2010,[75]

- Total active violations (i.e. all violations that have not been closed or dismissed) at both NERC and the Regional Entities totaled almost 2,300.
- Many of these violations are related to NERC standards on critical infrastructure protection (in particular, Standards CIP-002 through CIP-009).

---

[74] http://www.ferc.gov/EventCalendar/Files/20070608171203-RR07-11-000.pdf

[75] http://www.nerc.com/files/Compliance%20Violations%20Statistics%20-%20May%202010.pdf (Compliance Trending – May 2010)

NERC also identifies the "Top 10 Most Violated Standards" for a rolling 12 month period for NERC as a whole and for each of the 8 regional entities. For WECC, it is interesting to note that:

- All of NERC's top 5 violations are included in WECC's top 6 violations, though not in the same order.
- The top 6 WECC violations include those standards related to:
  - Transmission and Generation Protection Systems (PRC-005)
  - System Restoration Plans (EOP-005)
  - Sabotage Reporting (CIP-001)
  - Normal Operations Planning (TOP-002)
  - Personnel & Training (CIP-004)
  - Systems Security Management (CIP-007)

None of the Top 10 Most Violated Standards for WECC (or NERC as a whole) is related to Transmission Planning (TPL).

5.2 FERC Siting Authority/National Interest Electric Transmission Corridor

As amended by the Energy Policy Act of 2005 ("EPAct 2005"), the Federal Power Act ("FPA"), provides for federal "backstop" siting of certain proposed electric transmission facilities that would be located within a National Interest Electric Transmission Corridor ("NIETC") established by the Department of Energy.[76] On October 2, 2007, DOE issued its National Electric Transmission Congestion Report and order formally designating the Mid-Atlantic and Southwest National Corridors.[77] The Southwest NIETC includes seven counties in Southern California and three counties in western Arizona. These NIETC designations became effective October 5, 2007, and will remain in effect until 2019 unless DOE rescinds, renews, or extends them.

[76] http://www.ferc.gov/industries/electric/indus-act/siting.asp

[77] Federal Register / Vol. 72, No. 193 / Friday, October 5, 2007 / Notices

On April 26, 2010, DOE released its 2009 *National Electric Transmission Congestion Study*, which reexamines transmission congestion in both the Eastern and Western Interconnections. This report notes both progress made and continuing concerns in and around key load centers.[78] Specifically, with regard to the Southwestern region of WECC, the report finds[79]:

- "…(T)he Southern California region remains challenged…Although many promising generation and transmission projects are now in the planning or regulatory approval stages…(s)low development of new generation and transmission facilities could compromise near-term grid reliability in Southern California, despite growing demand response and smart grid capabilities. For these reasons, the Department concludes that Southern California remains congested, and that it should retain its status as a Critical Congestion Area."
- "Based on the progress in addressing congestion issues, the Department no longer identifies the Phoenix-Tucson area as a Congestion Area of Concern." In supporting this statement, the DOE report specifically cites the Department's agreement with the ACC's Fifth Biennial Transmission Assessment that states, "The existing and planned transmission systems serving the Phoenix, Santa Cruz County, Tucson and Yuma areas are adequate and should reliably meet the local energy needs of the respective areas through 2017."

5.3 Regional Transmission Planning – WestConnect

WestConnect is composed of electric utility companies[80] 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. A WestConnect Steering Committee is charged with the task of overseeing development and implementation of a variety of initiatives for the above stated purpose on

---

[78] http://www.oe.energy.gov/1371.htm

[79] U.S. Department of Energy, *National Electric Transmission Congestion Study*, December 2009, pp xii-xiii, and page 96.

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

behalf of the WestConnect members.[81] A WestConnect Regional Planning Management Committee reports directly to the Steering Committee. Annually, WestConnect prepares a ten-year integrated regional transmission plan that is derived from the study efforts of its subregional planning groups.

Charles Reinhold of WestConnect presented an overview of their activities and an update on regional transmission planning processes at the 6th BTA Workshop 1 on June 3-4, 2010. A major objective of WestConnect is to address seams issues in appropriate forums through the WECC region. It also has an active work group on large generator interconnection processes.

The process for developing WestConnect's 2010-2019 transmission plan was approved by the Regional Planning Management Committee on April 26, 2010. The plan is expected to reflect about $15 billion in capital infrastructure expansion. Complete maps of the plan will be available on WestConnect's website. This includes 6,255 miles of "planned" lines above 100 kV of which 1,573 miles are in Arizona. It also includes another 4,145 miles of "conceptual" lines of which 830 miles are in Arizona.

5.3.1 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 any other subregional transmission planning ("STP") groups that 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, IID, El Paso Electric, Nevada Power, 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 regional planning group includes seven main subcommittees which are overseen by the SWAT

[81] 2007 WestConnect Planning Report, page 3

Oversight Committee. Separate web pages are provided for each of these subcommittees and the SWAT Oversight Committee on the WestConnect website.[82] 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 6th BTA. The respective subcommittees, and chair-persons, are listed in Table 10

Table 10 - SWAT Subcommittees Contributing to 6th BTA

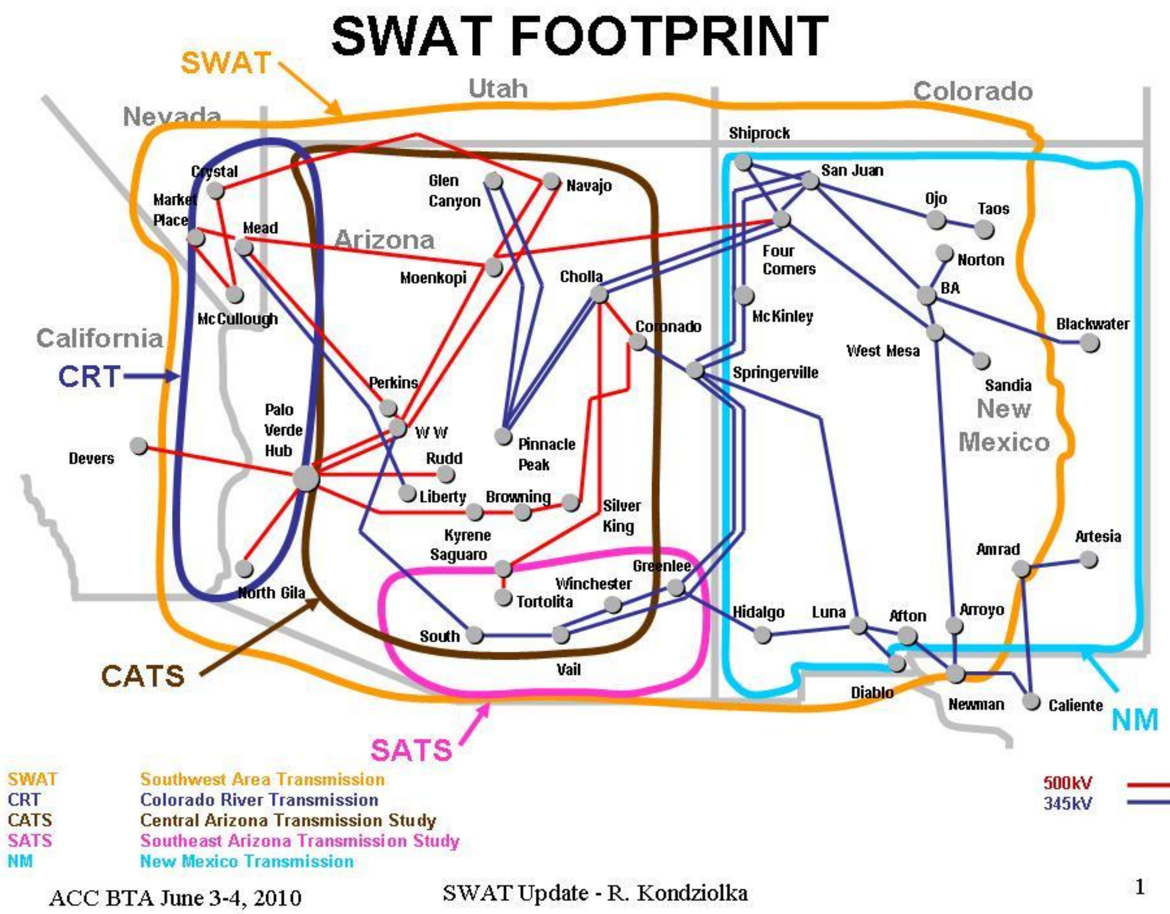
Oversight Committee – Robert Kondziolka CRT Subcommittee – Josh Johnston CATS Subcommittee – Joe Herrera* CATS-EHV Subcommittee – LeeAnn Torkelson & CATS-HV Subcommittee – Joe Herrera* (Note – CATS EHV & CATS HV have now consolidated as the CATS Subcommittee) SATS Subcommittee – Gary Trent NM Subcommittee – Tom Duane Short Circuit Working Group – Kevin Salsbury Renewable Energy Transmission Task Force – Peter Krzykos Arizona Renewable Resources & Transmission Identification Subcommittee (ARRTIS)** - Amanda Ormond* and Greg Bernosky Finance Subcommittee** - Tom Wray* Common Corridor Structure Separation Task Force** – Brian Keel Transmission Corridor Planning Committee – Greg Bernosky Eldorado Valley Area Study Group – Chuck Russell * Non Transmission Provider ** Task Force Work Completed – No Longer Active

In particular in this BTA, the Commission wishes to acknowledge the efforts of Mr. Robert Kondziolka, SWAT Steering Committee Chair who has announced his resignation of the chairmanship due to a new job assignment at SRP. His leadership in SWAT and many contributions to the BTA process over the years are greatly appreciated by the Commission.

The geographic area(s) covered by SWAT and various subcommittees are shown in Figure 5.

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

Figure 5: SWAT Footprint



The Commission acknowledges the 2009 reports of the ARRTIS and Finance subcommittees, as well as the Common Corridor Structure Separation Task Force, which have recently disbanded.

5.3.2 Colorado River Transmission Planning Group

The Colorado River Transmission subcommittee ("CRT") was formed to study the area within the geographic region straddling the Colorado River from southern Nevada to Yuma, Arizona. This study group includes the participation of: Arizona Power Authority, WAPA, Nevada Power Company, SCE, IID, California ISO, Los Angeles Department of Water and Power, APS, SRP, SWTC, TEP, CAP, and other interested Stakeholders. The CRT study group has been actively engaged in technical studies of the Harcuvar Project and its interconnection with the Palo Verde to Devers No. 2 500 kV project, as well as the 2010 RMR studies of the Yuma Area and Mohave County.

5.3.3 Central Arizona Transmission Study – High Voltage

Prior to merging with CATS-EHV, the CATS HV study area consisted of the high voltage transmission system in Pinal County. The CATS HV 2009 study report focused on generation development scenarios and transmission corridor development in Pinal County using a 2018 power flow base case.

5.3.4 Central Arizona Transmission Study – Extra High Voltage

The Central Arizona Transmission Study Extra High Voltage ("CATS EHV") study group has the most longevity as a coordinated transmission planning forum in Arizona. Arizona transmission providers that participate in the CATS EHV study group are APS, SRP, SWTC, TEP and WAPA. Over the past few years this SWAT study group has shouldered a large portion of the burden of performing the Commission ordered transmission studies for the BTA process.

The following studies were conducted by CATS EHV to establish the adequacy of the ten-year plans and were presented at the 6th BTA Workshop I.[83]

- Tenth Year Snap Shot Study (2019) – considers N-0, N-1 contingencies and N-1-1 analysis of the ten-year planned projects (e.g., NERC Category A and B scenarios).
- 2014 and 2018 RMR for the Metropolitan Phoenix Area filed with the APS Ten-Year Plan.
- A Common Corridor and Extreme Contingencies study report were filed by SWAT as a confidential document (NERC Category D).

Details of these study results are provided elsewhere in this Staff report.

[83] http://www.azcc.gov/Divisions/Utilities/Electric/Biennial/2008%20BTA/SRP%20ACC_BTA_Workshop-Directed%20Work.ppt

5.3.5 Short Circuit Working Group

The SWAT Short Circuit Working Group ("SCWG") was formed for the purpose of developing a coordinated short circuit study model of the SWAT subregional area transmission system. This study tool is needed to enable a consolidated and coordinated short circuit model that yields consistent and accurate short circuit results. The tools and model developed by the SCWG are needed by transmission planning groups and by transmission providers performing system impact studies for proposed interconnections. SCWG is currently expanding its model into California as needed for various studies.

5.3.6 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 11 lists the transmission providers who are participants in the study process.

Table 11 - 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

Numerous local load serving entities and other stakeholders have been participating in the SATS study process. These entities include Fort Huachuca Military Reservation, Sulphur Springs Valley Electric Cooperative, Trico Electric Cooperative, and UNSE. Graham County Electric Cooperative and Duncan Valley Electric Cooperative did not attend the SATS meetings, but they were represented by SWTC and their respective loads were included in the study.

SATS vision is a 20 year transmission plan covering the SATS study area, which is effected through an agreement between participants to conduct the study as a "single system" (i.e., non-parochial) approach. The 2009 SATS study was filed in the 6th BTA in March 2010 and compliments the Long Range Plan conceived for central Arizona by the original CATS study group. The study also impacts broader regional plans and the SATS 2009 final report is posted on the WestConnect website.

The 2009 SATS Study analyzed southeast Arizona transmission plans for 2010-2014 and 2019 based on NERC Category A-D scenarios. The report concludes that with the planned projects and the additional mitigation measures proposed for each year, the transmission system within the SATS footprint meets the NERC Reliability Standards and WECC System Performance Criteria. However, the report notes that up to ten 115, 138, and 230 kV buses have voltage deviations greater than 5% for a single contingency and up to six 115 and 230 kV buses had voltage deviations greater than 10% for Category C contingencies. The report says this voltage concern will continue to be evaluated, but does not give a timetable for resolving this concern. In addition, the report notes overloads of the SWTC Apache – Butterfield 230 kV line occurred for various contingencies in different study years and mentions the following mitigation options:

- Upgrade line capacity in 2016[84]
- Implement an interim “re-rating” of the line until actual upgrade, or
- Cross-tripping of the Winchester or Bicknell 345/230 kV transformers

In Staff’s opinion the tripping of a 345/230 kV facility to mitigate a 230 kV line overload could further weaken the interconnected grid, and should only be used as a last resort.

5.3.7 Eldorado Valley Study Group

An informational presentation on this new SWAT study group was given by Chuck Russell of SRP at 6th BTA Workshop 1, but no filing has been made in the BTA. This SWAT work group is still in its formative stages and is open to all stakeholders. It is not associated with any particular merchant or utility transmission project, and will look collectively at system impacts of the various transmission projects proposing to terminate at one or more of the EHV substations in the Eldorado Valley (e.g., Marketplace, Eldorado or Mead). The study scope is still being developed. Among other deliverables, it is expected that the scope will include short circuit

[84] SWTC’s Ten-Year Plan filed in January 2010 states they are also considering construction of a new Winchester-Vail 345kV line as an alternative to upgrading the Apache-Butterfield 230kV line

impacts. A preliminary diagram of transmission projects connecting into the Eldorado Valley is shown in Exhibit 31.

5.4 Western Area Power Administration Transmission Infrastructure Program

Western did not submit a filing in the 6th BTA, but gave a presentation on their Transmission Infrastructure Program ("TIP") at Workshop 1. The program derives from Western's responsibility to implement Section 402 of the American Recovery and Reinvestment Act, which grants Western borrowing authority of $3.25 billion for transmission projects that meet certain key project criteria including:

- Have at least one terminus in the area served by Western
- Be in the public interest
- Have a reasonable expectation of repayment of the loan (payments must be made solely from revenues accrued by the project)
- Use a public process to set rates for the facility
- Independently provides for generation ancillary services

Western is accepting proposals for projects that meet the above criteria, including projects intended to deliver (or facilitate delivery of) renewable resources. Over 200 project proposals have been received to date, including several major proposals that directly impact Arizona such as:

- TransWest Express
- SunZia
- Sonoran-Mohave Renewable Transmission ("SMRT") Project (see Exhibit 33)

Western is seeking projects with broad-based participation.

5.5 WGA/DOE Western Transmission and Renewable Energy Initiatives

5.5.1 Western Renewable Energy Zone Identification Process

The Western Governor's Association ("WGA") and DOE issued a joint Phase 1 report on renewable energy opportunities in the western region in June of 2009.[85] The report indentified Qualified Resource Areas, but not Western Renewable Energy Zones ("WREZ"). The report includes a map of renewable resource concentrations or "Hubs" that may be most cost-effective for integration through development of suitable regional transmission infrastructure. WREZ working groups are currently in the process of identifying Western Renewable Energy Zones based on the information from the Phase 1 report as well as environmental considerations that may limit development of some of the raw renewable resources identified at the Hubs. The report also states that a new modeling tool has been developed to assist in the Phase 2 process which:

> "…will allow load-serving entities, regional planners, renewable energy developers, state and provincial regulators and other interested parties to estimate the relative economic attractiveness of delivering power from specific Western Renewable Energy Zones to existing load centers across the Western Interconnection. The model assists users in identifying robust renewable resource portfolios and the transmission required to deliver the renewable energy. More specifically, the model allows users to examine different renewable resource development scenarios by allowing them to test the relative economic attractiveness of different renewable resource choices under user-customized assumptions."

The model will continue to be refined during Phase 2 of the WREZ initiative. The Phase 1 report is available on the WGA website.

5.5.2 Westwide/WGA Transmission Planning Initiatives

Amanda Ormond of Western Energy Group gave a presentation at the 6th BTA Workshop 1 on the status of Westwide transmission planning initiatives. Major funding allocations totaling some $16 million were announced in 2010 by the DOE for this activity in the west. A portion of

[85] The report is available at
http://www.westgov.org/index.php?option=com_content&view=article&id=55&Itemid=41

these funds are allocated to the WECC for interconnection wide transmission planning processes. WECC formed a Scenario Planning Steering Group ("SPSG") to provide strategic guidance to the TEPPC on scenarios, tools and modeling assumptions. DOE allocated $12 million to the WGA to expand the 2009 WREZ study on resource assessments and transmission planning, including integration of renewable generation. WGA has formed a State Provincial Steering Committee ("SPSC") to develop recommendations and guidance on how these funds should be utilized and has also assigned WGA representatives to the WECC SPSG.

The WECC SPSG has formulated the following set of goals for its portion of the DOE funding:

- Transmission planning: Develop sound interconnection-wide transmission plans that inform investment decisions and government policy decisions.
- Integration of variable generation: Promote technological and institutional improvements that minimize the cost of integrating variable renewable generation while maintaining system reliability.
- Efficient use of the grid: Evaluate and promote reforms to increase use of the existing transmission system ….to move renewable power.
- Better Integration of utility level resource and transmission plans.

The SPSC has submitted an initial scenario study request to the WECC TEPPC.

5.5.3 NREL/DOE Western Wind and Solar Integration Study

The National Renewable Energy Laboratory ("NREL") is the nation's primary laboratory for renewable energy and energy efficiency research and development. NREL's mission and strategy are focused on advancing the U.S. Department of Energy's and our nation's energy goals. The laboratory's scientists and researchers support critical market objectives to accelerate research from scientific innovations to market-viable alternative energy solutions.[86]

The focus of the Western Wind and Solar Integration Study (WWSIS), which was funded by the DOE, was to investigate the operational impact of up to 35% energy penetration of wind, photovoltaic (PV), and concentrating solar power (CSP) generation on the power system

[86] NREL Overview at: http://www.nrel.gov/overview/

operated by the WestConnect group of utilities in Arizona, Colorado, Nevada, New Mexico, and Wyoming (excluding the WestConnect member systems in California). The study concludes that:

> "…it is operationally feasible for WestConnect to accommodate 30% wind and 5% solar energy penetration, assuming the following changes to current practice could be made over time:

- Substantially increase balancing area cooperation or consolidation, real or virtual;
- Increase the use of sub-hourly scheduling for generation and interchanges;
- Increase utilization of transmission;
- Enable coordinated commitment and economic dispatch of generation over wider regions;
- Incorporate state-of-the-art wind and solar forecasts in unit commitment and grid operations;
- Increase the flexibility of dispatchable generation where appropriate (e.g., reduce minimum generation levels, increase ramp rates, reduce start/stop costs or minimum down time);
- Commit additional operating reserves as appropriate;
- Build transmission as appropriate to accommodate renewable energy expansion;
- Target new or existing demand response programs (load participation) to accommodate increased variability and uncertainty;
    - Require wind plants to provide down reserves."[87]

APS, TEP, SRP, WAPA and Tri-State G&T had representatives on the technical review committee. In filed BTA comments with the Commission, SRP noted that there are also a number of important limitations acknowledged by the study as follows:[88]

- WWSIS is an operations study, not a transmission planning study.
- WWSIS is not a cost-benefit analysis, even though wind and solar capital costs were incorporated in scenario development.

---

[87] See executive summary of report at: http://www.nrel.gov/docs/fy10osti/47781.pdf
[88] Ibid., p 6.

- WWSIS is not a reliability study, although analysis of the capacity value of wind and solar was conducted to assess their contributions to resource adequacy.
- WWSIS does not address dynamic stability issues.
- WWSIS does not attempt to optimize the balance between wind and solar resources.

5.6 WECC TEPPC Interconnection Wide Grid Planning Efforts

SRP's Robert Kondziolka gave an update on the WECC TEPPC efforts at the 6th BTA Workshop 1. He reiterated that TEPPC's analyses and studies focus on studies with Interconnection-wide implications including reliability, cost, and emissions. TEPPC's role does **not** include

- Detailed project-specific studies
- Advocating projects
- Identifying potential "winners" and "losers"
- Siting and cost allocation

One of TEPPC's key roles is to provide governance over the RTEP (Regional Transmission Expansion Project) process, which implements region-wide transmission planning activities pursuant to WECC's $14.5 million funding grant under DOE-FOA000068. This represents an extraordinary opportunity to expand the capability of planning processes in the West, provides for broader input from a wider range of stakeholders into planning processes, expands WECC's ability to study a broader range of scenarios, and to ascertain the impacts of policy and technology drivers. Mr. Kondziolka emphasized that this does not result in a change in TEPPC governance. Although TEPPC has an expanded range of responsibilities, WECC will not take on any role related to transmission siting or cost allocation issues.

RTEP's desired outcomes are:

- Increased coordination among entities in the Western Interconnection
- Increased awareness of how energy policy decisions impact reliability and cost
- Ability to answer key policy questions at State, Provincial and Federal levels
- Additional information for use by decision makers in siting and cost allocation proceedings

A flow chart of the TEPPC scenario planning process is shown in Exhibit 36.

5.7 DOE PEIS for Federal Energy Corridors in Western States

Section 368 of EPAct 2005 addresses energy right of way corridors on federal lands. Section 368 requires the Departments of Commerce, Defense, Energy and Interior to consult with each other and within 2 years:

1. Designate, under their respective authorities, corridors for energy facilities on Federal land in eleven contiguous Western States.

2. Perform any environmental reviews that may be required to complete the designation of such corridors.

3. Incorporate the designated corridors into the relevant agency land use and resource management plans or equivalent plans.

In November 2008, the Final West-wide Energy Corridor PEIS[89] was issued. It describes a Proposed Action Alternative that designates "131 Section 368 energy corridors, totaling approximately 6,112 miles in length….(These) corridors would occur in all 11 western states and would be designated for pipeline and transmission line (multimodal) use, with a width of 3,500 feet, unless specified otherwise because of environmental or management constraints or local designations." According to the PEIS, "The vast majority of the proposed corridors in each state fall on lands managed by BLM…" The numbers and lengths of corridors were designated for states in southwestern WECC:

- In Arizona, 16 corridors totaling 650 miles;
- In New Mexico, 4 corridors totaling 293 miles;
- In Nevada, 34 corridors totaling 1,622 miles; and
- In California, 20 corridors, totaling 823 miles.

[89] US Department of Energy, Programmatic Environmental Impact Statement, *Designation of Energy Corridors on Federal Land in the 11 Western States* (DOE/EIS-0386), November 2008.

Subsequently, in January 2009, Records of Decision ("ROD") were issued by both the Bureau of Land Management ("BLM")[90] and the USDA Forest Service ("FS")[91]. The only modification made by BLM was the exclusion of a segment of corridor 81-272 in the Mimbres planning area in New Mexico. However, BLM did offer numerous clarifications to the Final PEIS, including three in the State of Arizona. These are cited on page 9 of the ROD.

According to the Forest Services ROD, "Designation of the Section 368 energy corridors…requires the FS to amend specific land plans…Only those plans where Section 368 corridors are located are amended by this ROD." The ROD lists the specific forest or grassland land use plans affected for each of the 11 states. In Arizona, these include the Land Management Plans ("LMP") for: Apache-Sitgreaves National Forest ("NF"), Coronado NF, Kaibab NF, Prescott NF, and Tonto NF.

5.8 FERC 890 Planning Principles

On June 17, 2010, FERC issued a Notice of Proposed Rulemaking ("NOPR") addressing changes to its transmission planning and cost allocation policies[92]. This action was taken to remedy a preliminary finding that deficiencies continue to exist in the rules previously established in FERC Order 890. Interested parties were given through September 29, 2010 to file comments on the NOPR.

FERC's NOPR calls for reforms in three specific areas, including:

- **Participation in Regional Planning Processes**. Each transmission provider must participate in a regional transmission planning process that produces a regional transmission plan. The regional planning process should result in a plan that identifies

---

[90] *Approved Resource Management Plan Amendments/Record of Decision for Designation of Energy Corridors on Bureau of Land Management-Administered Lands in the 11 Western States*, January 2009, page 9.

[91] Record of Decision: *USDA Forest Service, Designation of Section 368 Energy Corridors on National Forest System Land in 10 Western States*, January 4, 2009, pages 28-29.

[92] Notice of Proposed Rulemaking, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 131 FERC ¶61, 253 (2010) (NOPR).

the facilities that cost-effectively meet the needs of transmission providers, their customers, and other stakeholders.

- **Public Policy Driven Projects**. In addition to evaluating proposed transmission enhancements based on considerations of reliability and overall cost reduction, transmission providers would be required to consider projects proposed to facilitate compliance with public policy requirements established by state or federal laws or regulations, such as renewable portfolio standards.
- **Non-incumbent Transmission Developers' Participation in the Transmission Development Process**. Provisions that establish a Federal right of first refusal for an incumbent transmission provider with respect to facilities that are included in a regional transmission plan would be eliminated. Non-incumbent transmission developers should have full opportunity to participate in the regional planning process.

6. Conclusions

The quality of industry reports and Commission ordered BTA study results available for the BTA process have progressively improved over the past ten 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 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 2010-2019 timeframe in a reliable manner?
- Efficacy of Commission ordered studies - Do the study reports filed in response to Commission ordered RMR, N-1-1 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, adequately support the overall needs for renewable resource development and integration into the Arizona and regional electric power system?
- 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 NERC, WECC and FERC?

These five issues are discussed in Sections 6.1 through 6.5, respectively.

6.1 Adequacy of System to Reliably Serve Local Load

Based on the ten-year plans, technical studies, criteria, and assumptions filed in the 6th BTA and/or obtained through subsequent data requests, Staff and KEMA reach the following conclusions:

1) As a result of current economic conditions, the statewide demand forecast for the 2010-2019 ten-year planning period has shifted by about four years since the 5th BTA (i.e., it will take four years longer to reach the 2008 demand forecast levels).

2) A total of 33 transmission projects have been delayed since the 5th BTA, with an average delay of roughly four years. In addition, 18 other transmission projects were cancelled. The combination of cancelled and delayed projects represents slightly more than one-third of the projects filed in the 5th BTA. These delays and cancellations are consistent with the reduction in statewide demand forecast since the 5th BTA and do not appear to threaten the adequacy of the system or its ability to reliably serve load. This conclusion is validated by the results of the studies filed in the 6th BTA.

3) Information on transmission reconductor projects, bulk power transformer capacity upgrades and reactive power compensation projects planned for the purpose of capacity upgrade at 115 kV and above, if included in future ten-year plan filings, would assist the Commission in meeting its obligation "to biennially make a determination of the adequacy and reliability of existing and planned transmission facilities in the state of Arizona".

4) The SATS report and the SWTC Ten-Year Plan have both identified overload issues on the Apache-Butterfield 230 kV line beginning in 2012. Although an upgrade of the line is planned for 2016, no clear resolution of this overload is provided for earlier years. Mitigation prior to 2016 is based on tripping of an upstream 345 kV EHV facility or possible implementation of an interim "uprate" (e.g., an engineering analysis to rerate the existing facility without any physical upgrading). An "uprate" of the line, if supported by thorough engineering analysis, would be preferable to tripping of EHV facilities as an interim mitigation. Furthermore, the study has

identified numerous 230 kV and 115 kV bus voltage deviations that may be unacceptable, and states that further analysis is needed to address this issue. Staff agrees and views this as a potential deficiency in the 2009 SATS report.

5) UNSE's long-standing effort to permit and construct a second line to Santa Cruz County remains stalled due to i) lack of a National Environmental Protection Act ("NEPA") Record of Decision from federal agencies and ii) delay in issuance of a Presidential Permit. UNSE has included an upgrade of the Nogales – Valencia 115kV line to 138 kV in its current ten-year plan, which will clearly help to support adequacy of supply to Santa Cruz County. However, Santa Cruz County remains exposed to extended outages for all of its UNSE customers following the loss of the radial transmission line serving the county. Additional transmission line improvements outlined in the UNSE Ten-Year Plan for Santa Cruz County are contingent upon resolving the pending federal permitting matter.

On a broader note, Staff and KEMA have some concern that certain additional information may be needed in future BTA filings in order to ensure that the Commission has adequate information "to biennially make a determination of the adequacy and reliability of existing and planned transmission facilities in the state of Arizona."[93] Specifically, we note the absence of information regarding planned transmission reconductor projects and bulk power transformer additions (including replacements) in existing substations. Ten-year transmission plans filed in the current (and prior) BTAs focus on projects that require a CEC (e.g., new transmission lines, transmission reconfigurations including taps and loop-ins, and upgrades of the design voltage of existing transmission lines such as 115 kV to 138 kV), but ignores certain other categories of transmission system upgrades that enhance reliability. Therefore, Staff and KEMA conclude that the filed plans in future BTAs should be augmented by additional information on planned projects at 115 kV and above related to transmission capacity upgrades including reconductor projects, substation transformer replacements and reactive compensation installations/upgrades.

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

6.2 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 study of N-1-1 contingencies (i.e., the “Ten Year Snapshot Study”) performed by the CATS-EHV study group. APS filed the Extreme Contingency Study performed in conjunction with the SWAT Sub-Regional Transmission Planning Group. TEP filed the Southeast Arizona Transmission Study (“SATS” study) performed under SWAT. And, SWTC filed the Cochise County Study Group 2009 technical study performed under the oversight of SATS.

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

1) The Phoenix area, Tucson area and Yuma area RMR studies of 2013 and 2019 were thorough and well documented. These studies comport with the Commission’s RMR study methodology and production cost simulations were performed using industry accepted study tools and publicly available data. No flaws in assumptions or modeling are evident in these three reports. The studies show that each RMR area will have sufficient maximum load serving capability to reliably serve the respective area’s load during the next ten year period. The RMR studies also indicate local RMR generation will not be dispatched out of merit order for significant hours or yield RMR costs sufficient to warrant advancing transmission improvements. The Mohave County 2013 and 2018, and Santa Cruz County 2013 and 2019 RMR studies were also well documented. The Mohave County study showed no RMR requirement. However, Santa Cruz County RMR analysis for 2010 showed an RMR requirement of 24 MW. No Santa Cruz RMR requirement was found in 2013 or 2019.

2) The Commission’s concern expressed in the 5th BTA in regard to the need for additional stakeholder involvement in the Yuma area RMR study has been satisfactorily addressed in the RMR study of 2013 and 2019. WAPA, WMIID, IID and other stakeholders participated in the APS RMR study of the Yuma area and have concurred with the cut plane definition, study plan and results.

3) The Commission's concern expressed in the 5th BTA about the need for a coordinated RMR cut plane definition and joint study of Mohave County, including WAPA participation, has been satisfactorily addressed in the RMR study of 2013 and 2018.

4) A "Ten Year Snapshot Study" (previously referred to as the "N-1-1 Study") and an Extreme Contingency Study were performed by the CATS – EHV study group and APS, respectively. The filed studies were well documented and comport with the study scope previously directed by the Commission.[94] The studies comport with the study effort outlined by Commission Staff. These studies both represent a composite assessment of the Arizona system reflecting all filed projects in the ten-year plan, and the performance of the overall system under normal, single-contingency and selected more severe contingency scenarios. Staff and KEMA conclude that these studies demonstrate the ten-year plan is generally robust and should provide adequate and reliable service to Arizona as evidenced by the following observations from these studies:

    a) No thermal overloads or significant voltage problems occur in the 2019 base case.

    b) Eleven transmission facilities experience thermal overloads in the N-1 analysis of 2019. The report notes that these will be mitigated through transmission line reconductors or upratings, transformer replacements, and reconfigurations. Staff concludes these mitigation measures are reasonable, but additional data on such upgrades should be provided in future BTAs.

    c) Excessive voltage deviations are noted in about two dozen N-1 scenarios, but the report states these will be addressed through routine measures such as corrections to system modeling, operational measures and selected substation shunt capacitor additions. Staff concludes this approach is reasonable for addressing the voltage violations.

[94] The Extreme Contingency Study is filed with the Commission under confidentiality

d) Although dynamic stability analysis was not included in the scope of these two studies, stability studies filed by the individual utilities in their ten-year plan filings demonstrate acceptable performance and/or reasonable mitigation measures that can be implemented.

5) Two EHV line overloads and five HV line overloads for N-1-1 conditions were unresolved by the Ten Year Snapshot study. Most of these overloads occur for the N-1-1 scenario that modeled deferral of the Morgan– Pinnacle Peak 500 kV line planned for completion in 2010. Given the advanced stage of construction on this project, Staff concludes that such delay is unlikely.

6) The CATS-HV study of the planned 2019 Pinal County system assumed SPPR's "Three-Terminal" transmission plan (Pinal Central to ED5, ED5 to Test Track and ED5 to Marana 230 kV lines). As previously discussed in Section 2.5.2, SPPR has now deferred plans for two of these line additions indefinitely. It is unclear when this deferral decision was made relative to the development of the CATS-HV study base cases and the impact of these project deferrals on the results of the CATS-HV study of 2019 is unknown and cannot be determined from the filed studies.

7) Staff concludes the proposed definition of "continuity of service" described in the Cochise County Study Group's (CCSG) 2009 technical study report, as filed by SWTC in January 2010, is appropriate for planning of the supply system to Cochise County and that the transmission system plan of expansion identified in the CCSG 2009 report represents a reasonable set of capital expansion projects to achieve the "continuity of service" paradigm in Cochise County. However, it is currently unclear if this plan of service will be implemented by the 2013-2018 timeframe as originally envisioned at the time of Commission Order 70635.

6.3 Adequacy of System to Reliably Support the Wholesale Market

Studies and information filed in the 6th BTA indicate the existing and planned Arizona EHV system is adequate to support a robust wholesale market in the 2010-2019 timeframe. Two key factors that contribute to a robust market are the availability of sufficient generation (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.

Regarding resource availability, the 2019 Ten-Year Snapshot Study base case shows approximately 33,000 MW of in-state generation capacity, some 11,000 MW more than required to serve Arizona's statewide demand forecast of roughly 22,000 MW. Even after accounting for generation reserve requirements, much of this excess will be available for sale on the wholesale market and for export out of Arizona. In addition, this excess generation augments the local resources of Arizona's utilities in the event of major forced power plant outages or other resource emergencies.

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 2019 Arizona system will still perform with minimal problems. 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.

Exhibit 11 provides a summary of transmission delivery capability currently available across Arizona's borders. As shown, the bi-directional transfer capability between Arizona and neighboring states in aggregate is over 12,000 MW. This represents over 50% of Arizona's projected 2019 statewide demand and more than 35% of Arizona's projected 2019 generating capacity. In addition, the exhibit shows a bi-directional transfer capability of approximately 8,000 MW between the Palo Verde Hub and Arizona load centers. This represents a significant transmission capacity available for wholesale transactions and other uses within Arizona from this extremely important energy trading hub, in addition to the export capability available over westbound transmission paths from Palo Verde Hub to California and Nevada. Furthermore, the delivery capabilities shown in Exhibit 11 do not include expected increases from the proposed EHV transmission projects shown in the current ten-year plan.

6.4 Adequacy of Transmission Projects Affecting Renewable Development

Staff and KEMA reached the following conclusions in this regard:

1) Developing Arizona's vast renewable resource potential requires a coordinated and multi-faceted strategy involving stakeholders representing utility, government, economic, developer, environmental, and other interests. Decisions by the Commission and the actions taken by the Arizona utilities and regional stakeholders are important factors that will affect how and when this potential is developed.

2) The 2009 utility filings in response to the 5th BTA request for the utilities to each identify their top three transmission projects are responsive to Commission request. An inclusive stakeholder process was developed and executed to identify the projects.

3) Most of the transmission corridors identified in the utilities' initial transmission proposals to serve potential renewable generation are compatible with projects in the utilities' previous transmission plans. Therefore, the transmission lines identified by the utilities are actually advancements of projects already found in previous transmission plans. Such project advancement represents a relatively small incremental investment for a potentially significant renewable benefit.

4) Since most of the proposed renewable transmission projects have been identified in earlier transmission plans, they should contribute to reinforcing the transmission for general use beyond the specific needs of renewable generation project. Furthermore, we would expect them to be effective in enabling delivery of renewable resources developed close to either the Phoenix-Tucson regions or the Palo Verde hub. As projects are developed farther from these areas, completely new transmission plans will likely need to be identified and developed.

5) Even if the proposed RTPs filed by Arizona utilities in 2009 are approved and built, they will only provide for integration of a portion of the projected in-state renewable resource potential.

6) The impact of utility-scale renewable generation is being incorporated into the utilities' transmission plans as part of their normal planning process. Each utility's ten-year (i.e., BTA) plans, RTP filings and RTAP reports should keep the Commission informed as the situation evolves.

6.5 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/KEMA also makes the following observations and conclusions as regards the suitability of study processes and technical reports in the 6th BTA:

1) Technical studies filed in the 6th BTA indicate a generally robust study process for assessing transmission system performance (steady-state and transient)[95] for the 2010-2019 planning period. This included stability study results[96] from APS, SRP, TEP and SWTC.

2) 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 6th BTA and may be well suited for other local areas in Arizona.

[95] 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.

[96] Some of the filings showed poor "damping" of oscillations on Apache GT Unit 1 for various contingencies in 2009 cases, which SWTC speculated was due to erroneous modeling data from the GT manufacturer. At Workshop 2, SWTC provided Staff with stability case results for the 2010 SATS Heavy Summer Case showing damped response of Apache GT Unit 1.

3) While Arizona's transmission providers have effectively addressed a broad range of study requirements in this BTA, Staff recognizes that these may differ from the studies required for the utilities to comply with mandatory reliability standards implemented by FERC over the past two years (as discussed in section 5.1). Even so, this information may apply to some extent in the BTA process. In an effort to explore these impacts, Staff issued the following data request during the 6th BTA:

    - Has a NERC/WECC reliability standards audit been conducted that assessed your utility's compliance with the NERC Transmission Planning Standards (i.e., TPL-001 through TPL-004)? If so, advise when the most recent set of audit findings were issued and provide a summary of such findings as regards TPL-001 through TPL-004.
    - If your most recent NERC/WECC audit reached a finding of non-compliance with any part(s) of TPL-001 through TPL-004, have such findings been accepted by the utility? If the findings have been accepted, describe your mitigation plan(s) to correct such non-compliance, as well as the status and timetable for completing such mitigation. If the finding(s) are in dispute, describe the nature and status of the dispute.

APS, TEP/UNSE and SWTC all responded they are currently compliant with all applicable NERC transmission planning reliability standards based on the results of their latest audit by NERC/WECC. SRP also voluntarily responded that their audit results were compliant. All of the utilities were audited on TPL-001 through TPL-003, and some were audited on TPL-004 as well. In addition, Staff and KEMA observed that technical studies filed in the 6th BTA covered a range of NERC planning standards/contingency categories, as shown below in Table 12.

Table 12 - NERC Planning Standards/Contingency Categories Covered by 6th BTA

Study	Category A (TPL-001)	Category B (TPL-002)	Category C (TPL-003)	Category D (TPL-004)
SWAT Ten-Year Snapshot Study	X	X		
SWAT Extreme Contingency Study				X
SATS Study	X	X	X	X
APS Internal Study	X	X		
SRP Internal Study	X	X		
TEP Internal Study	X	X	X	X
SWTC Internal Study	X	X	X	X

Developing consensus on how to address the results of NERC/WECC reliability audits in the BTA process will take additional time and effort, but as a minimum it would be informative for utility filings in future BTAs to include confirmed findings regarding TPL-001 through TPL-004 compliance from NERC/WECC reliability audits that have been finalized and filed with FERC, as well as a description of any associated mitigation plan(s) filed with the FERC since the most recent BTA.

7. Recommendations

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

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 regarding transmission system planning reliability standards, and

   c) Collaborative planning processes in Arizona and throughout the western region that facilitate competitive wholesale markets, and are consistent with FERC Order 890 and the expected order on Transmission Planning and Cost Allocation.

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

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

4) Staff recommends that the Commission order SWTC to determine if an engineering "re-rating" of the Apache-Butterfield 230 kV line as proposed in the 6th BTA filings would be an acceptable measure until the line is upgraded in 2016, and to file the results of this assessment by January 31, 2011.

5) Staff recommends that the Commission order APS, SWTC and TEP to conduct additional analysis of potential 230 kV and 138 kV voltage deviations in Southeastern Arizona as noted in the 2009 SATS report, file an update based on the 2010 SATS study by February 28, 2011, and finalize mitigation plans if needed for this voltage concern in ten-year plan filing(s) for the 7th BTA by January 31, 2012.

6) Staff recommends that the Commission accept the definition of "continuity of service" following a transmission line outage as proposed in the Cochise County Study Group's 2009 technical study report filed by SWTC in January 2010, and that the Commission accept the recommended transmission plan of service as shown in Section 4.2.1 of this 6th BTA report in order to achieve this "continuity of service" objective in Cochise County. Staff further recommends that the Commission establish target dates for SWTC, APS, TEP and SSVEC as follows:

   a) June 30, 2011, to identify the components of the plan in a facility study that provide the most benefit to customer reliability and can be implemented in the shortest timeframe, and to file a progress report with the Commission that includes planned in-service dates for all relevant elements of the plan reflecting these priorities.

   b) September 30, 2011, to submit a progress report including in-service dates for the components of the plan of service identified in the June 30, 2011, facility study. This schedule shall reflect the most recent load forecast.

   c) December 31, 2011, to substantially complete contractual negotiations with affected parties over cost responsibility, wheeling arrangements, Engineering, Procurement and Construction ("EPC"), operations and maintenance, etc. (described as a pending items in the CCSG 2009 report), and to file a draft memorandum of understanding among affected parties addressing these items with the Commission.

   d) June 30, 2012, to file a progress report with the Commission including an executed memorandum of understanding between the parties that includes planned in-service dates for all remaining elements of the plan in the 2013-2018 timeframe. If applicable, in-service dates beyond 2013-2018 may be proposed for later stages of the plan if justified by documented changes in the load forecast[97].

e) December 31, 2012, to receive all required approvals and permits needed to complete remaining components of the plan, and file a progress report on plan implementation with the Commission. If any related approvals or permits from appropriate regulatory agencies are still pending at that time, the progress report shall identify a clear action plan and proposed schedule to obtain such approvals.

7) Staff recommends that the Commission order UNSE to update its assessment of long term alternatives for Santa Cruz County continuity of service, as part of UNSE's 2012-2021 ten-year planning studies, and file a report on the updated assessment in the 7th BTA in 2012. Furthermore, if any approvals or permits from federal agencies related to the Gateway Transmission Project are still pending at that time, Staff recommends that the Commission require the 7th BTA filings to include a clear action plan and proposed schedule to obtain such approvals.

8) Staff recommends that Commission regulated utilities be required to continue to perform RMR studies in accordance with the methodology set forth in Appendix C to this Sixth BTA, and shall file such studies with ten-year plans for inclusion in future BTA reports.

9) Staff recommends that the Commission order 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 BTA plan filings starting in January 2011.

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

[97] Load forecast updates may include the impacts of demand side management, demand response, energy efficiency improvements, distributed generation and other applicable factors.

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

b) "N-1-1" (Ten-Year Snapshot) study results documenting the performance of Arizona's statewide transmission system in 2019 for a comprehensive set of N-1 contingencies, each tested with the absence of one of nine different major planned transmission projects.

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