Eighth Biennial Transmission Assessment 2014-2023

Staff Report

Docket No. E-00000D-13-0002

Decision No. 74785

October 29, 2014

Prepared by Arizona Corporation Commission Staff

And

K. R. Saline & Associates, PLC

K. R. Saline & Associates, PLC.
160 North Pasadena, Suite #101
Mesa, Arizona 85201

Foreword

This report has been prepared on behalf of the Arizona Corporation Commission ("ACC" or "Commission"). It was prepared in accordance with a contract agreement between K.R. Saline and Associates, PLC ("KRSA") and the Commission. It is considered a public document. Use of the report by other parties shall be at their own risk. Neither KRSA nor the Commission accepts any duty of care to such third parties.

Arizona's Eighth Biennial Transmission Assessment ("BTA" or "Eighth BTA") is based upon ten year plans filed with the Commission by parties in January 2014. It also incorporates information and comments provided by participants and attendees in the BTA workshops and report review process. The ACC Staff and KRSA are appreciative of the contributions, cooperation, and support of industry participants throughout Arizona's Eighth BTA process.

In preparing this report, KRSA 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 KRSA or any specific content of this report. Therefore, KRSA 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 ACC and KRSA.

Cover Photo

Photo is of the recently energized Pinal West – Duke 500 kV transmission line looking west at the Maricopa Road crossing in Maricopa, Arizona on April 24, 2014.

Executive Summary

The Arizona Corporation Commission ("ACC" or "Commission") biennially reviews ten year plans filed by parties intending to construct transmission lines, and issues a written decision regarding the adequacy of the existing and planned transmission facilities to reliably meet the present and future needs of Arizona.[1] Staff of the Commission's Utilities Division ("Staff"), with the aid of the consulting firm K.R. Saline & Associates, PLC ("KRSA"), scrutinized the ten year plans and related filings, held open and transparent workshops on May 15, 2014 ("Workshop I") and August 28, 2014 ("Workshop II") to solicit industry participation, and drafted this Eighth Biennial Transmission Assessment ("BTA" or "Eighth BTA"). The development of this Eighth BTA relied solely upon study work provided by third parties through their Commission filings. Staff and KRSA did examine and question study work; however, Staff and KRSA stopped short of independently verifying the study results.

Staff and KRSA reviewed each ten year plan filing submitted to the Commission.[2] The filings included utility transmission plans with supporting technical study work, merchant developer transmission projects, generator interconnection tie-lines, and Commission-ordered technical studies including the Ten Year Snapshot and Extreme Contingency study. Staff and KRSA examined the Workshop I presentations and reviewed the recordings.[3] The presentations provided at Workshop I were valuable and the information useful for Staff and KRSA in performing this Eighth BTA. Two drafts of this Eighth BTA were prepared by Staff and KRSA and made available for industry and stakeholder comments.

This Eighth BTA assesses the adequacy of Arizona's transmission system to reliably meet the existing and planned energy needs of the state by addressing four fundamental public policy questions during the course of this BTA:[4]

---

[1] Arizona Revised Statute §40-360.02
[2] Docket No. E-00000D-13-0002
[3] Video of May 15, 2014 Workshop I are available at the ACC Public Meeting Archive - http://media-07.granicus.com:443/OnDemand/azcc/azcc_0e21c628-a065-40a0-9053-ded5de4b5197.mp4
[4] This BTA does not establish Commission policy and is not final unless and until approved by a written decision of the Commission.

1. Adequacy of the existing and planned transmission system to reliably serve local load - Does the existing and planned transmission system meet the load serving needs of the state during the 2014-2023 timeframe in a reliable manner?

2. Efficacy of the Commission-ordered studies - Do the Simultaneous Import Limit ("SIL"), Maximum Load Serving Capability ("MLSC"), Reliability Must Run[5] ("RMR"), Ten Year Snapshot, and Extreme Contingency studies filed as part of the Eighth BTA comply with, and sufficiently meet, the intended goals of the Commission's orders?
3. Adequacy of the system to reliably support the wholesale market - Did 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?
4. Suitability of the transmission planning processes utilized - Did 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 North American Electricity Reliability Corporation ("NERC") and Western Electricity Coordinating Council ("WECC")?

General Conclusions

The information provided by the utilities and other transmission developers for the Eighth BTA was comprehensive and responsive to the statutory and Commission-ordered requirements. The information provided was used to develop the conclusions of the Eighth BTA and organized to answer the four key policy questions:

Adequacy of the Existing and Planned Transmission System to Reliably Serve Local Load

The adequacy of the transmission system to reliably serve load is central to the BTA. Based upon the technical study work examined by Staff and KRSA, the existing and proposed transmission

[5] RMR Studies were not required for the Eight BTA based upon criteria set by the Commission in the 7th BTA

system meets the load serving requirements of Arizona in a reliable manner for the 2014-2023 timeframe.

1. The aggregate of the filed ten year plans ("Arizona Plan") is a comprehensive summary of filed ten year transmission expansion plans from a holistic perspective. The Arizona Plan includes eighteen filing entities and consists of sixty transmission projects of approximately 907 miles in length. An additional twenty six projects are beyond the ten year horizon or have in-service dates that are yet to be determined and account for an additional 766 miles of new transmission.
2. The 2014 level of summer preparedness of the utilities in Arizona has been assessed and is sufficient. The current electric utility system in Arizona is judged to be adequate to reliably meet the energy needs of the state in 2014.
3. The statewide demand forecast has shifted downward by approximately one year since the Seventh BTA. Over the past three BTAs load forecasts have changed substantially along with the associated transmission projects. In order to provide the Commission with additional information on the impact on load forecasts on transmission projects, Staff concludes that for reliability or load growth driven transmission projects a system load level range at which a transmission project is needed should be reported along with the projected in-service year beginning with ten year transmission plans filed in January 2016.
4. The SIL and MLSC, measures of the transmission system ability to serve load reliably in load pockets, are adequate to meet ten year local load forecasts.
5. Staff and KRSA have carefully examined the utilities' transmission planning actions resulting from the September 8, 2011 outage and conclude the utilities are addressing the concerns raised by the Federal Energy Regulatory Commission ("FERC") and NERC, which should help prevent similar future outages.
6. Each Arizona utility provided information and details on their plans to ensure physical security and resiliency of the Arizona electric system. Staff and KRSA conclude the Arizona utilities are taking actions to address the physical security risks to reasonably ensure the reliable operation of the Arizona transmission system.
7. Staff concludes that while the utilities have included the effect of distributed generation ("DG") and energy efficiency ("EE") standards, the impact of these standards and related uncertainty on

specific transmission needs has not been specifically identified. This is information that would benefit Staff and the Commission and should be provided by the utilities for the Ninth BTA.

8. Utilities, through the Southwest Area Transmission ("SWAT") subregional planning group and its Coal Reduction Assessment Task Force[6] ("CRATF"), have begun to examine the potential impact on bulk electric system stability of actual and proposed coal plant retirements and their associated inertia coupled with increased use of solar photovoltaic and wind generation, which do not currently provide inertia benefits. This is an issue that the Commission and Staff should follow closely and on which the utilities should report their findings to the Commission as directed in the Recommendations section below.

Efficacy of Commission-Ordered Studies

The Commission has ordered the following studies to be performed as part of the BTA: SIL, MLSC, RMR, Ten Year Snapshot, and Extreme Contingency Analysis. The principal purpose of the Commission-ordered studies is to assure the certainty of the conclusions and recommendations within the BTA. Each Commission-ordered study required for the Eighth BTA is filed with the Commission. Staff and KRSA conclude the Commission-ordered studies demonstrate that the Arizona transmission system is reasonably prepared to reliably serve local load in the ten year timeframe.

1. As indicated previously, the SIL and MLSC are adequate to meet ten year local load forecasts.
2. In the Seventh BTA, Staff suspended the RMR studies and implemented requirement criteria for restarting such studies on a biennial review of specific triggering factors. None of the triggering factors occurred for the Eighth BTA which would require RMR study work in any of the RMR areas.
3. The Ten Year Snapshot study indicates Arizona's transmission plan is robust and supports the statewide load forecast through 2023. However, to address any potential low voltage issues, the future the Ten Year Snapshot study should monitor system elements down to and including the 115 kilovolt ("kV") level.

[6] This study was initiated by the SWAT stakeholders to determine if the know and projected retirement of coal generation and the increase in solar photovoltaic and wind generation in the next five years may cause system stability issues.

4. The Extreme Contingency study satisfies the Commission's requirement to address and document extreme contingency outage studies for Arizona's major generation hubs and major transmission stations.

Adequacy of System to Reliably Support Wholesale Market

Regional and sub-regional planning studies have effectively addressed the interconnected extra high voltage ("EHV") transmission that is critical to a functional interstate wholesale market. Based upon the technical study work filed with the Commission and industry presentations, the existing and planned Arizona EHV system is adequate to support a robust wholesale market.

1. Seven major EHV transmission projects are proposed and have been addressed in this BTA. Individually and collectively these projects will improve the opportunity for interstate commerce.
2. Staff and KRSA conclude the Arizona utilities are taking sufficient action with respect to transmission planning impacts related to the integration of renewable generation resources.
3. The Fifth BTA ordered the utilities to provide their top three renewable transmission projects ("RTPs"). The Arizona utility RTPs are progressing with five of the RTPs planned to be in-service by 2016, one RTP being actively pursued for development and three RTPs are being monitored for development as reliability and resource needs arise. Additionally, one RTP is no longer being pursued, but is instead being worked on jointly as part of the Southline Project. Finally, one RTP has moved outside of the ten year plan window because the line was successfully re-rated without new transmission development.
4. FERC Order No. 1000 requires FERC jurisdictional transmission providers and encourages non-jurisdictional transmission providers to work collaboratively with stakeholders on a regional and interregional basis to improve regional transmission planning processes and cost allocation mechanisms in a cost-effective manner. All Arizona FERC jurisdictional transmission providers have made their compliance filings with the FERC to implement Order 1000 through the WestConnect Regional Transmission Planning process and are awaiting a FERC order to move forward with implementation. Staff has been an active stakeholder participant in the development of the recommended WestConnect Order No. 1000 transmission planning processes, and believes the results of the WestConnect regional transmission planning will be supportive, once available, in assessing transmission adequacy for the state in future BTAs.

Suitability of Utilized Planning Processes

Based upon information provided by the utilities, the Arizona utilities utilize significant and well defined transmission planning processes.

1. The results of NERC/WECC reliability standard audits over the past two years, as provided by the utilities in the Eighth BTA proceeding, indicate there were no concerns of Arizona's bulk electric system failing to comply with the applicable planning standards established by NERC/WECC.
2. Technical studies filed in the Eighth BTA indicate a robust study process for assessing transmission system performance for the 2014-2023 planning period.
3. Utilities communicate their transmission plans in robust local, state, subregional and regional, open and transparent transmission planning forums using public processes.

Recommendations

Based upon the conclusions, Staff offers the following recommendations for Commission consideration and action:

1. Staff recommends that the Commission support:
    a. The use of the "Guiding Principles for ACC Staff Determination of Electric System Adequacy and Reliability", as revised in this Eighth BTA.
    b. The use of collaborative transmission planning processes such as those that currently exist in Arizona, which help to facilitate competitive wholesale markets and broad stakeholder participation in grid expansion plans.
    c. The continued suspension of the requirement for performing RMR studies in every BTA and use of criteria for restarting such studies based on a biennial review of factors as outlined in the Seventh BTA.
    d. The policy that Arizona utilities advise each interconnection applicant, at the time the applicant files for interconnection, of the need to contact the Commission for appropriate ACC filing requirements related to the Power Plant and Transmission Line Siting Committee.

e. The continued requirement for Arizona utilities to report relevant findings in future BTAs regarding compliance with transmission planning standards from NERC/WECC reliability audits that have been finalized and filed with FERC.

f. The policy that the Load Serving Entities ("LSE") in Cochise and Santa Cruz Counties continue to monitor the reliability in Cochise and Santa Cruz Counties, respectively, and propose any modifications that they deem to be appropriate in future Ten Year Plans. Staff also recommends that the Commission continue to collect applicable outage data from the respective utilities in order to monitor any changes in Cochise County and Santa Cruz County system reliability in future BTA proceedings.

g. The requirements for Arizona utilities to include planned transmission reconductor projects, transformer capacity upgrade projects, and reactive power compensation facility additions at 115 kV and above in future ten year plan filings.

h. The acceptance of the results of the following Commission-ordered studies provided as part of the Eighth BTA filings:

   i. The SIL and MLSC are adequate to meet ten year local load forecasts.

   ii. The RMR studies were not required because none of the triggering factors occurred for the Eighth BTA that would require RMR study work in any of the RMR areas.

   iii. The Extreme Contingency analysis for Arizona's major transmission corridors and substations, and the associated risks and consequences of such overlapping contingencies.

   iv. Ten Year Snapshot study results documenting the performance of Arizona's statewide transmission system in 2023 for a comprehensive set of single ("n-1") contingencies, each tested with the absence of different major planned transmission projects.

2. Staff recommends that the Commission order the following actions to resolve concerns arising from the Eighth BTA:

   a. Direct Arizona utilities to ensure the Commission-ordered Ten Year Snapshot study monitors transmission elements down to and including the 115 kV level for thermal loading and voltage violations.

b. Direct Arizona utilities to describe the driving factor(s) for each transmission project in the Ten Year Plan. For each load growth or reliability driven transmission project, direct Arizona utilities to report, in addition to each transmission project in-service date, a system load level range at which each transmission project is anticipated to be needed. This requirement should first occur with the ten year plans filed in January 2016.

c. Direct Tucson Electric Power ("TEP") to file the SWAT CRATF[7] study report on behalf of the Arizona utilities within 30 days of completion.

    i. If the CRATF study does not include specific recommendations on maintaining Arizona transmission system reliability, Staff recommends the Commission direct Arizona utilities to jointly produce or procure an informational report to identify minimum transmission requirements to maintain adequate system reliability in a fifth year coal reduction scenario. Specific recommendations should include, but not be limited to, the definition of the Arizona system boundary, fifth year baseline Arizona system inertia, and identification of a range of minimum and recommended Arizona system inertia to maintain Arizona transmission system reliability under various system conditions.

    ii. Staff provides the following guidelines to the Arizona utilities for the Arizona system boundary definition.

        (1) Transmission lines or generation station assets located wholly or partially located in Arizona;

        (2) Transmission lines or generation station assets owned wholly or partially owned by Arizona utilities;

        (3) Generating station assets located outside of Arizona, but connected to a transmission line that meets requirements in 2.c.ii.(1) or 2.c.ii.(2).

d. Direct Arizona utilities with retail load to report, as part of the Ninth BTA, the effects of DG and EE installations and/or programs on future transmission needs. Staff

[7] This study was initiated by the SWAT stakeholders to determine if the known and projected retirement of coal generation and the increase in solar photovoltaic and wind generation in the next five years may cause system stability issues.

recommends the Commission direct utilities to conduct or procure a study to more directly identify the effects of DG and EE installations and/or programs.

i. The technical study should be performed on the fifth year transmission plan by disaggregating the utilities' load forecasts from effects of DG and EE and performing contingency analysis with and without the disaggregate DG and EE. The technical study should at a minimum discuss DG and EE forecasting methodologies and transmission loading impacts. The study should monitor transmission down to and including the 115 kV level.

ii. Alternative methodologies or study approaches will be acceptable on condition that the study results satisfy the minimum requirements as outlined in 2.d.i.

iii. The study should be filed at the Commission in January 2016 in the Ninth BTA docket.

iv. This study is supplemental to the previous Commission Decision No. 72031 requiring Arizona utilities to address the effects of DG and EE on future transmission needs in their ten year plan filings.

[This page intentionally blank for formatting purposes]

Table of Contents

Listing of Figures

Listing of Tables

Listing of Exhibits

Listing of Appendices

1 Overview

1.1 Assessment Authority

Arizona statutes require every entity considering construction of any transmission line equal to or greater than 115 kilovolt ("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 31st of each year.[8] Every entity considering construction of a new power plant of 100 Megawatts ("MW") or greater, as defined in the Arizona Revised Statute § 40-360,[9] within Arizona is required to file a plan with the ACC ninety days before filing an application for a Certificate of Environmental Compatibility ("CEC").[10] 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.[11] 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 this State to meet the present and future energy needs of this state in a reliable manner".[12]

1.2 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 Eighth Biennial Transmission Assessment ("Eighth BTA" or "BTA") evaluates the ten year transmission plans filed with the Commission in January 2014.[13] 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.

[8] Arizona Revised Statute § 40-360.02.A
[9] Per Arizona Revised Statute § 40-360 Definitions a power "plant" means "each separate thermal electric, nuclear or hydroelectric generating unit with a nameplate rating of one hundred megawatts or more for which expenditures or financial commitments for land acquisition, materials, construction or engineering in excess of fifty thousand dollars have not been made prior to August 13, 1971."
[10] Arizona Revised Statute § 40-360.02.B
[11] Arizona Revised Statute § 40-360.02.C.7
[12] Arizona Revised Statute § 40-360.02.G
[13] Docket No. E-00000D-13-0002

In the Arizona BTA process, entities conduct their own technical studies, participate in collaborative and open regional planning processes, and present the study results in their ten year plan reports at public workshops. Staff of the Commission's Utilities Division ("Staff") and KR Saline & Associates, PLC ("KRSA") relied on the technical reports and documents filed with the Commission and other publicly available industry reports rather than performing independent technical study work.

In addition to the ten year filings, the Commission ordered supplemental studies to be performed as a portion of this Eighth BTA.[14] These studies include System Import Limit ("SIL")/Maximum Load Serving Capability ("MLSC"), Reliability Must Run ("RMR"), the Ten Year Snapshot study and Extreme Contingency studies required from prior ACC BTAs.[15] Each Commission-ordered study was filed with the Commission.

Staff continues to use a set of the "Guiding Principles for ACC Staff Determination of Electric System Adequacy and Reliability" ("Guiding Principles") to aid it in determining the adequacy and reliability of both transmission and generation systems. These Guiding Principles were adopted in the First BTA and have been re-adopted in every BTA since. However, as part of this Eighth BTA, Staff undertook a review of the Guiding Principles and is proposing revisions to reflect the current state of the industry within Arizona and nationally. Appendix A provides the proposed updated Guiding Principles along with an explanation of the reasons for the proposed changes. These revised Guiding Principles were used to determine the adequacy and reliability of both transmission and generation systems.

Staff retained KRSA to assist with this Eighth BTA. Together, Staff and KRSA critically reviewed the filed ten year plans and addressed the following four key public policy questions:

1. <u>Adequacy of the existing and planned transmission system to reliably serve local load</u> - Does the existing and planned transmission system meet the load serving needs of the state during the 2014-2023 timeframe in a reliable manner?

[14] Decision No. 69389, Docket No. E-00000D-05-0040
[15] A complete history of Commission-ordered Studies is found in Appendix B.

2. Efficacy of the Commission-ordered studies - Do the SIL, MLSC, RMR [16], Ten Year Snapshot, and Extreme Contingency studies filed as part of the Eighth BTA comply with, and sufficiently meet, the intended goals of the Commission's orders?
3. Adequacy of the system to reliably support the wholesale market - Did 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?
4. Suitability of the transmission planning processes utilized - Did 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 North American Electricity Reliability Corporation ("NERC") and Western Electricity Coordinating Council ("WECC")?

1.3 Assessment Process

A four-step approach was used in the preparation of this Eighth BTA report. The first step was the conduct of the Eighth BTA Workshop I ("Workshop I"), during which each entity was provided an opportunity to present their ten year plan filings and address questions from stakeholders. The second step included the review of industry filings submitted for the Eighth BTA. The third step was the development, distribution, and posting of the first draft report for public comment.[17] Revisions were then made and a second draft of the report was posted for public comment. The final step included conducting the Eighth BTA Workshop II ("Workshop II") during which Staff and KRSA presented the second draft of the report.[18] A summary of each step of the BTA process is described in the following sections.

1.3.1 Workshop I: Industry Presentations

KRSA assisted Staff in conducting a public workshop on May 15, 2014, at the Commission's Hearing Room #1 in Phoenix, Arizona. A complete listing of the Workshop I attendees and

[16] RMR Studies were not required for the Eight BTA based upon criteria set by the Commission in the 7th BTA
[17] The first draft was posted to the Commission's website on July 9, 2014
[18] The Workshop II agenda and full presentation materials are located at http://www.cc.state.az.us/divisions/utilities/electric/biennial.asp

presenters is given in Appendix C. The Eighth BTA Workshop I provided an informal setting for entities that filed ten years plans to share their transmission plans with interested stakeholders and the Commission. Further, Workshop I provided an opportunity to discuss transmission related topics of interest for inclusion in this BTA report. A summary listing of presentations made during Workshop I is provided in Table 1.[19]

Table 1 - Summary of Workshop I Presentations

Commission-ordered Study Work	Presentations
Ten Year Plan Presentations	Arizona Public Service ("APS"), Salt River Project ("SRP"), Southwest Transmission Cooperative ("SWTC"), Tucson Electric Power ("TEP")/UniSource Electric ("UNS Electric" or "UNSE"), Sun Zia, Bowie Power Plant, Longview Energy Exchange
Unfiled Merchant Transmission Projects	Centennial West Clean Line Project, Southline Project, North Gila – Imperial Valley #2 ("NG-IV2") Project
Commission-ordered BTA Requirements	Ten Year Snapshot and Extreme Contingency Studies
National and Regional Transmission Issues	WestConnect and Southwest Area Transmission ("SWAT")
Other Transmission Related Topics of Interest	Coal Reduction Impact Assessment, Western Area Power Administration ("Western") Transmission Infrastructure Program ("TIP"), WECC Transmission Expansion Planning Policy Committee ("TEPPC") Update

Prior to Workshop I, each presenter was provided a set of questions, as outlined in Appendix D, to address within their Workshop I presentation. Each presentation was grouped into its respective panel: Ten Year Plan Presentations, Unfiled Merchant Transmission Projects, Commission-ordered BTA Requirements, and Other Transmission Related Topics of Interest. At the conclusion of each panel's presentations an open period of discussion was held for questions and comments from Staff,

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

KRSA, and audience. Staff and KRSA concluded Workshop I with an overview of the remaining steps in the BTA process and noted the following action items:

- APS agreed to file with the Commission the Science Applications International Corporation ("SAIC") report accessing the transmission system impacts of energy efficiency ("EE") and distributed generation ("DG").
- APS and SRP agreed to confirm there were no transmission delays due to EE or DG. Specifically, APS and SRP would examine if EE or DG affected their lowered load forecasts and thus transmission impacts. APS and SRP will file their findings with the Commission.
- SWAT agreed to file the final Coal Reduction Assessment report with the Commission when completed later this year.

Subsequent to the workshop APS and SRP did file the requested documents from the Workshop I action items.

A portion of Workshop I included presentations regarding projects for which no ten year plan was filed[20]. These projects include the Clean Line, Southline, and NG-IV #2 projects. While these projects are described in this report, they were not considered as elements of the ten year plans for which this BTA makes an adequacy determination.

1.3.2 Review of Industry Filings in Eighth BTA

Staff and KRSA reviewed all of the filings that had been made to date by utilities in the Eighth BTA to ensure required data was filed. When deficiencies were identified, data requests were utilized to obtain required data.

[20] Staff notes that § 40-360.02.A requires that "Every person contemplating construction of any transmission line within the state during any ten year period shall file a ten year plan with the commission on or before January 31 of each year." and further § 40-360.02.E states "Failure of any person to comply with the requirements of subsection A, B or C of this section may, in the commission's discretion in the absence of a showing of good cause, constitute a ground for refusing to consider an application of such person."

Table 2 shows a matrix of the various categories of ten year planning information filed by utilities and received from data requests during the Eighth BTA.[21] [22]

Table 2 - Summary of Utility Data

Utility	Ten Year Plan	2014-2023 Utility Technical Study Report	RMR Study Report	Planning Criteria & Ratings	Filings of Joint Study Report(s)
APS	X	X	Not Required in 8th BTA	X	Extreme Contingency Study
SRP	X	X	Not Required in 8th BTA	X	Ten Year Snapshot
SWTC	X	X	Not Required in 8th BTA	X	
TEP	X	X	Not Required in 8th BTA	X	
UNS Electric	X		Not Required in 8th BTA		

1.3.3 Preparation of Draft Report and Industry Comment

Staff and KRSA provided an initial draft of the Eighth BTA report for industry review and comment on July 9, 2014. The first draft report was developed from data contained in the ten year plan submittals, information gathered at Workshop I, and subsequent replies to data requests from the utilities.[23] The draft report was posted on the Commission's website and public notices sent out through various stakeholder distribution lists as part of the review process. During the three week review period, Staff and KRSA received, reviewed and considered industry comments. The comments were collected, categorized, and posted for stakeholder review. Reflecting and addressing comments received from the industry, a second draft of the report was then prepared by Staff and KRSA. The docketed comments and the second draft of the report was the subject of Workshop II.

1.3.4 Workshop II: Staff/KRSA Presentation of Final Report

The 2014 BTA Workshop II was held at the Commission's Meeting Room #1 on August 28, 2014. The purpose of Workshop II was to present the final draft of the Eighth BTA. Questions, comments, and clarification resulting from this workshop were incorporated in the final report for presentation to the Commission.

---

21 The Extreme Contingency Study performed by APS and TEP and coordinated through SWAT
22 The Ten Year Snapshot was performed by SRP and coordinated and filed through SWAT
23 Video of May 15, 2014 Workshop I are available at the ACC Public Meeting Archive - http://media-07.granicus.com:443/OnDemand/azcc/azcc_0e21c628-a065-40a0-9053-ded5de4b5197.mp4

During Workshop II, Staff and KRSA made a presentation[24] summarizing Workshop I action items and comments received during the review period. With the exception of the filing of the CRATF report, all Workshop I action items are now complete. The material provided in response to the action items has been incorporated and referenced in this report. Each document is available through E-docket and is cited at appropriate locations later in this report.

Comments on the first draft of the Eighth BTA report were received from five entities. The parties commenting on the first draft BTA report are listed in Table 3. Their comments were docketed and are available via the ACC's E-docket system. A majority of the comments concerned the recommendations Staff and KRSA offered in the first draft Eighth BTA. The filed comments provided valuable feedback and resulted in refinements in this Eighth BTA report.

Interstate Renewable Energy Council ("IREC")
APS
TEP/UNS Electric
SWTC
SRP

Table 3 - List of Parties Commenting on First Draft Report

1.4 Terminology and Acronyms

Staff and KRSA have strived to define all industry acronyms and provide clarifying footnotes to industry language used throughout the report. Appendix F includes a listing of additional terminology and acronyms that supplement our clarifying efforts.

1.5 Additional Resources

When additional information was required that was not included in the filing, Staff and KRSA used external resources. The additional information resources used in the BTA assessment are listed in Appendix G.

[24] [insert workshop II presentation link when available]

[This page intentionally blank for formatting purposes]

2 Ten Year Plans

Eighteen entities formally filed ten year plans with the Commission. One federal entity provided a courtesy copy of their ten year plan. Table 4 includes the parties that filed ten year transmission plans and the location of additional information on their filings in the Exhibits section of this report.

Table 4 - List of Parties Filing Ten Year Plans 2014 Tabular Reference Table[25]

Entity	Reference Location
APS	Exhibit 13
SRP	Exhibit 14
Sun Zia	Exhibit 15
SWTC	Exhibit 16
TEP	Exhibit 17
UNS Electric	Exhibit 18
Ajo Improvement Company	Exhibit 19
Bowie Power Station	Exhibit 20
BP Wind Energy	Exhibit 20
EnviroMission	Exhibit 20
Gila Bend Power Partners	Exhibit 20
Buckeye Generation Center	Exhibit 20
Longview Energy Exchange	Exhibit 20
Solar Reserve	Exhibit 20
Sun Streams	Exhibit 20
Tribal Solar	Exhibit 20
Public Service Company of New Mexico ("PNM")	N/A
El Paso Electric ("EPE")	N/A
Western Area Power Administration – Desert Southwest	N/A

In addition to new construction projects, the Commission has previously determined that plans to reconductor existing transmission lines, upgrade bulk power transformer capacity, and expand reactive power compensation to support transmission capacity upgrades should be filed in the BTA allowing the Commission to perform a more comprehensive assessment of transmission adequacy

[25] The Western-Desert Southwest ("DSW") plan was not formally filed but a courtesy copy was provided

and reliability.[26] As directed, the projects filed in the Eighth BTA include planned transmission lines at 115 kV and above, including major reconfigurations and upgrades from a lower design voltage to a higher design voltage, reconductoring of existing transmission lines, bulk power substation transformer bank replacements and additions, and reactive power compensation facility additions at 115 kV and above. The Eighth BTA examines the aggregate of these ten year plans.

2.1 Summary of Arizona Plan

The aggregate of the filed ten year plans ("Arizona Plan") is a comprehensive summary of filed ten year transmission expansion plans from a holistic perspective. The Arizona Plan includes eighteen filing entities and consists of sixty transmission projects of approximately 907 miles in length, as shown in Table 5. An additional twenty six projects are beyond the ten year horizon or have in-service dates that are yet to be determined and account for an additional 766 miles of new transmission.[27]

In-Service Date	Number of Projects	Mileage
2014	7	139
2015	15	187
2016	13	193
2017	7	29
2018	5	264
2019	1	TBD
2020	2	-
2021	7	91
2022	2	-
2023	1	4
Subtotal	**60**	**907**
Post 2023 and TBD	26	766
Total	**86**	**1,673**

Table 5 - Summary of Arizona Plan by In-Service Date

Table 5 depicts the number of new transmission projects and associated mileage for each year of the ten year plan. Projects with an in-service date to-be-determined ("TBD") or beyond the ten year 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. As typical in transmission planning, a majority of the Arizona Plan projects fall

[26] Decision No. 72031

[27] Unfiled projects are excluded from this adequacy analysis for the BTA, but are depicted with all other projects on maps provided as Exhibits 1-6.

into the first five years of the planning horizon as years six through ten are less scrutinized or definitive than the first five years of the plan.

Table 6 depicts the number of Arizona Plan projects by voltage class. Projects with multiple voltages or for which the voltage class has not been resolved are reported at the highest voltage class identified for the project.[28]

Notable is the significant mileage of 230 kV projects in Table 6 which is an indicator of the local utility's need to access the available transmission capacities on planned 345 kV and 500 kV facilities for local load serving purposes.[29] As indicated in Table 6, the Arizona Plan also includes a significant number of 500 kV projects. Most of the 500 kV total transmission miles are attributable to four transmission projects: Hassayampa – North Gila 500 kV #2 line; SunZia; Pinal West – Pinal Central – Abel – Browning 500 kV segment; and Palo Verde – Delaney – Sun Valley – Morgan 500 kV. Collectively, these projects account for 538 of the 801 500 kV miles shown in Table 6 above. The Arizona Plan is listed in tabular form in Exhibit 11 and Exhibit 12 by in-service date and voltage class, respectively.

Voltage Class	Number of Project		Mileage
	2014 - 2023	Post 2023 - TBD	
500 kV	10	4	801
345 kV	5	6	330
230 kV	20	13	405
138 kV	23	2	130
115 kV	2	1	7
Total	**60**	**26**	**1,673**

Table 6 - Summary of Arizona Plan by Voltage Class

The Arizona Plan includes merchant generators and one utility generator filing totaling 6,083 MW and requiring 90.75 miles of generator tie-lines, summarized in Table 7. The Longview Energy Exchange represents a significant portion of the total MWs and generator tie-line mileage.

[28] Projects proposing more than one route (i.e. alternative routes) and/or more than one voltage will be counted once and assume the highest mileage/voltage for the summary tables.
[29] Ibid.

Description	Maximum Output (MW)	Gen-Tie Length (mi)
Sun Streams Solar Project	150	0.25
Bowie Power Station	1,000	15
Crossroads Solar Energy Project	150	12
Fort Mohave Solar Project	310	TBD
Buckeye Generation Center Natural Gas	650	0.5
Longview Energy Exchange Pumped Storage Project	2,000	50
Gila Bend Power Plant	833	6
BP Wind Power Plant	500	6
Ocotillo Modernization Project	290	1
EnviroMission Solar Tower	200	TBD
Total	**6,083**	**90.75**

Table 7 - Summary of Plan Generation and Tie-lines

Maps depicting all facilities including in the Arizona Plan are included in Exhibits 1-5 with the Project Look-up table included as Exhibit 6.

2.2 Plan Changes Since the Seventh BTA

Transmission plans predictably change over time. 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 interconnections and delivery requests, and changes in the economic or financial climate faced by a project sponsor. Some projects get built, some have been delayed, and others have been withdrawn from consideration. Further, the in-service dates of some projects have changed, new projects are added, and the scope of the original project changes or the project name may have changed. A table of name changes is provided below in Table 8.

Table 8 – Project Name Changes or Aliases

Current Name	Formerly Known As
Price Road Corridor	East Valley Industrial Expansion

A list of all changes between the Seventh and Eighth BTAs for transmission projects 115 kV and above is provided in Exhibit 9. Table 9 is a list of changes that have occurred at Extra High Voltage ("EHV") levels of 345 kV and above.

Table 9 – Significant EHV Project Changes Since the Seventh BTA

In-Service Date	Project Description	Voltage Class (kV)	Status
2012	3rd Kyrene 500/230kV Transformer	500	Complete
2015	Jojoba Loop-in of Hassayampa - Pinal West 500kV Line	500	New Project - 2015
2016	Pinal Central - Tortolita 500kV Line	500	Deferred 2014 to 2016
2016	Delaney - Palo Verde 500kV Line	500	Deferred 2013 to 2016 & SRP Withdrawn
2016	Delaney - Sun Valley 500kV Line	500	Deferred 2015 to 2016 & SRP Withdrawn
2018	Sun Zia Transmission Project	500	Deferred 2016 to 2018
2018	Sun Valley - Morgan 500kV Line	500	Deferred 2016 to 2018 & SRP Withdrawn
N/A	Hassayampa - Pinal West 500kV Line #2	500	Deferred Indefinitely
N/A	Northeast Arizona - Phoenix 500kV	500	Deferred Indefinitely
2012	McKinley 345kV Reactor Addition	345	Complete
2012	Vail 345/138kV Transformer T3	345	Complete
2013	Youngs Canyon 345/69kV Substation	345	Complete
2015	Springerville - Vail Series Capacitor Replacement at Vail	345	Deferred 2013 to 2015
2017	Mazatzal 345/69kV Substation	345	Deferred 2015 to 2017
2020	Springerville - Greenlee Series Capacitor Replacement at Greenlee (Phil Young)	345	Deferred 2017 to 2020
Postponed Indefinitely	Greenlee 2nd 345/230kV Transformer	345	Removed
Postponed Indefinitely	Bicknell 345/230kV Transformer Replacement	345	Removed
Postponed Indefinitely	Greenlee Switching Station through Hidalgo - Luna	345	Deferred TBD to Indefinitely
Removed	Pinal Central - Abel - RS20 500 kV Line	500	Cancelled

2.3 Driving Factors Affecting the Ten Year Plan – Load Forecast

In reviewing the filings, the chief determinant for the ten year transmission plans in Arizona was found to be the projected future load growth. Figure 1 shows the change in statewide demand forecasts between previous BTAs and the current Eighth BTA.

Figure 1 - Change in Arizona Demand Forecast

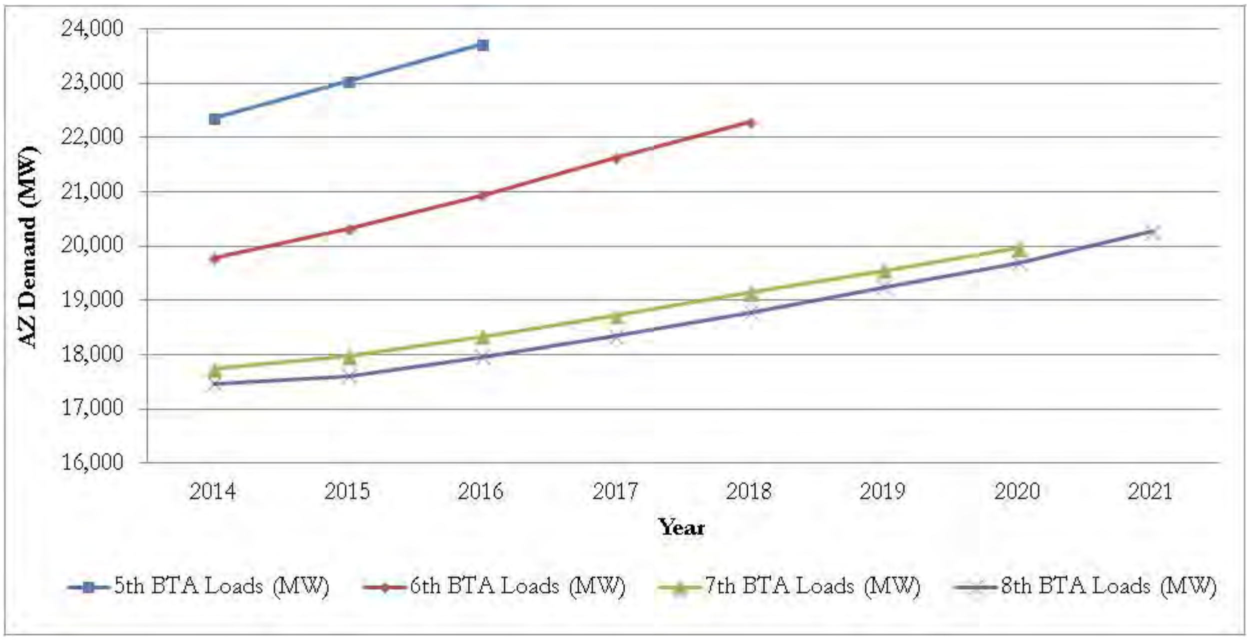


Figure 1 shows the statewide demand forecast has shifted by approximately one year since the Seventh BTA. Although the statewide forecast has slowed by one year, the overall growth rate has remained relatively constant at between 1% and 2% per year. The overall delay of most near-term transmission projects as shown in Exhibit 8 is consistent with this shift in the demand forecast. The detailed forecast data included in Exhibit 8 shows SRP and SWTC Eighth BTA load forecasts are higher than in the Seventh BTA, while TEP and APS load forecasts are lower.[30]

In its Sixth BTA Order the Commission directed Arizona utilities to "include the effects of distributed renewable generation and energy efficiency programs on future transmission expansion needs in future ten year plan filings."[31] The filed ten year plans for APS, SRP, TEP/UNSE and SWTC state that these factors were taken into account in developing the demand forecasts used in studies performed for the current ten year plans.

At Workshop I, Staff and KRSA asked utilities to what extent the decreased demand forecast was due to the effects of DG and/or EE. The utilities responded that DG and EE were taken into

[30] The higher SWTC load forecast is likely explained by the fact that, for the first time in the Eighth BTA, SWTC provided a load forecast that was based on non-coincident peak loads, not coincident peak loads as previously provided.
[31] Decision No. 72031 (December 10, 2010)

account in developing the load forecast for both the previous and current demand forecasts, but that the main factor behind the drop in the forecast from 2012 to 2014 was the impact of the continuing economic recession.

Over the past three BTAs load forecasts have changed substantially along with the associated transmission projects. In order to provide the Commission with additional information on the impact of load forecasts on transmission projects, Staff concludes that for reliability or load growth driven transmission projects a system load level range at which a transmission project is needed should be reported along with the projected in-service year beginning with ten year transmission plans filed on January 31, 2016.

2.4 Driving Factors Affecting the Ten Year Plan – Generator Interconnections

Under FERC regulations, generation developers seeking to interconnect to a transmission provider's system must file an interconnection application.[32] The rules and procedures for such applications are defined in the transmission provider's Open Access Transmission Tariff ("OATT"). As part of the BTA process, Staff and KRSA detailed each utility's generation interconnection queues from the Seventh and Eighth BTA. These are summarized in Table 10 and detailed in Exhibit 10, along with the difference between the two. In parallel with the FERC's interconnection process, any party contemplating construction of transmission in Arizona, including generator tie-lines, must file a ten year plan with the Commission.[33]

Utility	Approximate Capacity (MW) of Generators in Utility Queue		Interconnection Queues from Seventh to Eighth
	Seventh BTA	Eighth BTA	
APS	8,329	4,774	(3,555)
SRP	4,424	1,725	(2,699)
TEP/UNS Electric	1,400	851	(549)
WAPA	4,300	2,660	(1,640)
SWTC	0	0	0
Total	**18,453**	**10,010**	**(8,443)**

Table 10 - Summary of Arizona Generator Interconnection Queues

32 Generators over 20 MW are interconnected pursuant to a Large Generator Interconnection Agreement ("LGIA"); generators 20 MW or less are interconnected pursuant to a Small Generator Interconnection Agreement.
33 ARS § 40-360.02.A

Despite an 8.4 gigawatt ("GW") drop in the Arizona combined interconnection queue since the Seventh BTA, Table 10 shows that over 10 GW of generation capacity is still contemplated for development. Almost half of the interconnection queue generation is in APS' queue. As shown in section 2.2, Arizona's load forecast does not support the need for this much additional generation. Therefore, it is presumed that anticipated exports to California continue to be a driving factor in generation development. A number of proposed and conceptual intrastate and interstate projects are considered in this Eighth BTA between Arizona and California that will increase transfer capacity. However, if the interconnection queues were to fully develop, then the transmission plans filed in the Eighth BTA may not support the level of generation exports and transmission development or reinforcement that would be needed. It should also be noted that a continued withdrawal of projects from the interconnection queues could occur as has been seen over the past two years.

3 Adequacy of the System

State statutes require that the Commission determine the adequacy of existing and planned facilities to meet the present and future energy needs of Arizona in a reliable manner.[34] Adequacy is defined as the ability of the electric systems to supply the aggregate electrical demand and energy requirements at all times, accounting for scheduled and reasonably expected unscheduled outages of system elements. Adequacy is generally considered a planning issue related to the capability and amount of facilities installed. The adequacy of the transmission system in the BTA process is determined through a critical review of the utility ten year plan study work, results of NERC/WECC reliability audits, findings from Commission-ordered BTA study work, review of information presented at the "Summer 2014 Energy Preparedness" meeting[35], and consideration of information provided on physical security of the transmission system.

3.1 Utility Study Work

Individual utilities within the state of Arizona plan and design their bulk transmission systems in accordance with the NERC/WECC Planning Standards, guidelines established at the state level, and their own internal planning criteria, guidelines and methods. These planning practices are utilized to ensure that their respective systems are planned to provide reliable service to customers under various system conditions. These requirements are also intended to ensure that neighboring utilities and neighboring states plan their systems in a coordinated manner by following a consistent set of standards, criteria and guidelines.

In terms of Eighth BTA utility study work filings, "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."[36] The required technical study work should be in compliance with NERC Transmission Planning ("TPL") Standards. Staff and KRSA have received and reviewed the required ten year study work from each

---

34 Arizona Revised Statute § 40-360.02.G
35 Summer 2014 Energy Preparedness April 10, 2014 at the ACC in Phoenix hearing room #1. http://www.azcc.gov/Divisions/Utilities/Electric/SummerPreparedness.asp
36 ARS § 40-36.02.C.7

Arizona utility. Table 11 summarizes the findings from Staff and KRSA's review of the utility provided ten year planning efforts.

Utility	System Configurations Utilized	Category A and B Steady-State and Stability Performed	Category A Issues	Category B Issues	Plans Developed to Resolve Issues
APS	All years heavy summer 2014 - 2023	Yes	No	Yes	Yes
SRP	All years heavy summer 2014 - 2023	Yes	No	No	N/A
SWTC	Heavy summer and light winter for years 2014, 2019, 2023	Yes	No	Yes	Yes
TEP	All years heavy summer 2014 - 2023	Yes	No	Yes	Yes

Table 11 – Summary Table of Utility Study Work

Based on the results, the 2014 technical studies filed in the Eighth BTA indicate a robust study process for assessing transmission system performance, both steady-state and transient,[37] for the 2014-2023 planning period.

3.2 NERC/WECC Reliability Audit

The Commission directed the Arizona utilities to "report relevant findings in future BTAs regarding compliance with transmission planning standards from NERC/WECC reliability audits that have been finalized and filed with FERC."[38] Table 12 summarizes the related information filed in the Eighth BTA.

[37] "Steady State" refers to the time periods before a system disturbance occurs and after the system has fully recovered from a disturbance. "Transient" or "Transient Stability" refers to the time period (0-10 seconds) after a system disturbance occurs, when the system is responding to the disturbance.
[38] Decision No. 72031

Table 12 – WECC Audit Results

Utility	Reliability Audit Finalized and Filed with FERC Since Seventh BTA	Comments Related to Transmission Planning Standards
APS	Yes	Audit performed in November 2013 and received a report of "no findings"
SRP	Yes	Audit performed in August 2013 and received a report of "no findings"
TEP	No	Next audit is scheduled for August 2014
SWTC	No	Next audit is scheduled for January 2015

Based on the results of NERC/WECC reliability standards audits over the past two years, there were no concerns of Arizona's bulk electric system failing to comply with the applicable planning standards established by NERC/WECC.

3.3 Commission-Ordered Studies

Previous BTA processes identified the need for supplemental studies to be performed by Arizona utilities. The purpose of the Commission-ordered studies is to assure the certainty of the conclusions and recommendations within the BTA and to draw attention to potential transmission system concerns which necessitate closer Commission scrutiny.

The Commission-ordered studies falls into three categories: transmission load serving capability, RMR, and the Ten Year Snapshot. Table 13 summarizes the history and purpose of Commission-ordered BTA studies. The subsequent sections discuss the results of Commission-ordered BTA studies.

Commission Ordered Study Work	Purpose	Required Since
Transmission Load Serving Capability	Determine the maximum amount of load which can be served within the transmission constrained import areas	First BTA
Reliability Must Run	Determine constrained transmission import areas with local generation operation requirements	Second BTA
Ten Year Snapshot	Determine transmission system's robustness against delays of major projects	Third BTA
Extreme Contingency	Determine transmission system's stoutness against extreme outage events	Third BTA

Table 13 - Summary of Commission-Ordered BTA Studies[39]

3.3.1 2014 Transmission Load Serving Capability Assessment

Load serving capability is assessed by the ability of the electric system to serve load within a constrained area known as a load pocket. The load pocket constraints generally occur during limited hours of the year. During these limited operating hours each year, there is a requirement for generation located within the load pocket to serve the portion of the load that cannot be served by transmission. This type of generation is often referred to as RMR generation and is required to operate out of merit order. The combination of transmission and generation facilities establishes what is referred to as the load serving capability of an area. The Commission expects utilities to assure that adequate import capability is available to meet the load requirements of all distribution customers within their service areas. The Commission has adopted the use of two terms as indicators of the load serving capability of local load pockets: SIL and MLSC.[40]

In the First BTA, Staff identified three load pockets in Arizona to be monitored for transmission import constraints: Phoenix, Tucson and Yuma. The Second BTA added a fourth and fifth load pocket: Mohave County and Santa Cruz County. Prior BTAs examined import constraints in Pinal

[39] In the Seventh BTA, Staff suspended the requirement for performing RMR studies in every BTA and implemented criteria for restarting such studies on a biennial review of specific system factors.
[40] See Appendix E, RMR Conditions and Study Methodology

County and identified it as a local area that also needed to be monitored. In the Fifth BTA, Cochise County was also identified as needing import assessments to address continuity of service concerns.

3.3.1.1 Cochise County Import Assessment

Although the Commission did not order an RMR study for Cochise County, it directed that studies be filed for Cochise County addressing "continuity of service" issues.[41] However, in the Seventh BTA, Staff recommended suspension of efforts to upgrade reliability to a continuity of service definition for Cochise County due to the high cost of capital upgrades for new transmission required to achieve such a level of reliability and the low customer density in these service areas. This included the suspension of filing of two more Cochise County Study Group ("CCSG") progress reports in 2012.

Further, Staff recommended that the CCSG participants continue to monitor the reliability in Cochise County and propose any modifications that each deemed to be appropriate in future ten year plans. Staff also recommended that the Commission continue to collect applicable outage data from the respective utilities in order to monitor any changes in Cochise County system reliability in future BTA proceedings.

Through a data request Staff and KRSA received Cochise County outage data for APS, TEP and SWTC. Table 14 summarizes transmission outage data only. The outage data indicates relatively few and short duration transmission outages occurred in Cochise County for years 2012-2014.

Year	Number of Outages	Average Outage Time (Minutes)	Average Number of Customer Affected
2012	0	0	0
2013	6	10.85	7,985
2014 (through June 10th)	3	1.13	4,624

Table 14 - Cochise County Outage Data Summary

Staff and KRSA find that Cochise County outage data should continue to be collected and monitored in future BTA. Further, Staff and KRSA find the Cochise County import assessment requirement is satisfied for this Eighth BTA.

[41] Decision No. 70635

3.3.1.2 Santa Cruz Import Assessment

Santa Cruz County, similar to Cochise County, is served by a radial transmission system. UNS Electric is the load serving entity ("LSE") in Santa Cruz County. With the completion of the radial conversion from 115 kV to 138 kV, the area load serving capability increased to 159 MW under normal conditions, through a combination of the radial transmission delivery capability and 61 MW of local combustion turbine generation at Valencia Substation in Nogales. The Eighth BTA load forecast for Santa Cruz is 81 MW in 2021, 3 MW less than the Seventh BTA forecast of 84 MW for 2021.

In addition, the import assessment the Commission directed required studies be filed for Santa Cruz County addressing "continuity of service" issues.[42] However, in the Seventh BTA, Staff recommended suspension of efforts to upgrade reliability to a continuity of service definition for Santa Cruz County due to the high cost of capital upgrades for new transmission required to achieve such a level of reliability, and the low customer density in these service areas.

In addition, Staff recommended that UNS Electric continue to monitor the reliability in Santa Cruz County and propose any modifications that were deemed to be appropriate in future ten year plans. Staff also recommended that the Commission continue to collect applicable outage data from UNS Electric in order to monitor any changes in Santa Cruz County system reliability in future BTA proceedings.

Through a data request Staff and KRSA received Santa Cruz County outage data from UNS Electric. Table 15 summarizes transmission outage data only. The outage data shows that outages occurred in 2013 with an average outage time of 48.5 minutes. Closer examination of the UNS Electric outage data indicates three of the outages occurred during the 115 kV to 138 kV conversion project and the durations were extended due to Valencia generators becoming islanded.

[42] Decision No. 70635

Year	Number of Outages	Average Outage Time (Minutes)	Average Number of Customer Affected
2012	1	0.02	Unknown
2013	8	48.5	16,373
2014 (through June 10th)	2	6.5	19,918

Table 15 - Santa Cruz Outage Data Summary

Staff and KRSA find that Santa Cruz County outage data should continue to be collected and monitored in future BTA. Further, Staff and KRSA find the Santa Cruz County import assessment requirement is satisfied for this Eighth BTA.

3.3.1.3 *Pinal County Import Assessment*

The Pinal County Import Assessment is incorporated into the SWAT Arizona Subcommittee ("SWAT-Arizona" or "SWAT-AZ") Ten Year Snapshot Study discussed in section 3.3.2. Inclusion of Pinal County into the BTA process was prompted by the necessity of transmission providers to implement a remedial action scheme ("RAS") or special protection scheme ("SPS") for single contingencies in previous years when the generation development outpaced the transmission development. The anticipated completion of SRP's Desert Basin to Pinal Central 230 kV will resolve the use of this RAS.

Staff and KRSA conclude this meets the intent of the Pinal County assessment and resolves the concerns within Pinal County. However, Staff and KRSA have determined the Ten Year Snapshot study should include system contingencies and monitoring to the 115 kV level to identify any future system concerns to the Pinal County system.

3.3.1.4 *Import Assessments Requiring RMR Studies*

During some portions of the year, generation units within a load pocket might be required to operate out of merit order[43] to serve a portion of the local load; this is referred to as RMR generation. The power generated from local generation may be more expensive than the power

[43] Merit order is a way of ranking available sources of energy, especially electrical generation, in ascending order of their short-run marginal costs of production, so that those with the lowest marginal costs are the first ones to be brought online to meet demand, and the plants with the highest marginal costs are the last to be brought on line. Dispatching generation in this way minimizes the cost of production of electricity. Sometimes generating units must be started out of merit order, due to transmission congestion, system reliability or other reasons.

from outside resources, and may be environmentally less desirable. During RMR conditions, transmission providers must dispatch RMR generation to relieve the congestion on transmission lines.

The past few BTA studies have shown decreasing RMR costs in most of the areas as transmission system upgrades have been made, local generation has developed, and load growth has stagnated. In the Seventh BTA, Staff suspended the requirement for performing RMR studies in every BTA and implemented criteria for restarting such studies on a biennial review of factors such as: [44]

- An increase of more than 2.5% in an RMR pocket load forecast since the previous BTA.[45]
- Planned retirement or an expected long-term outage during the summer months of June, July, or August of a key transmission or substation facility supplying an RMR load pocket, unless a facility being retired will be replaced with a comparable facility before the next summer season.
- Planned retirement or an expected long term outage during the summer months of June, July, or August of a generating unit in an RMR load pocket that has been utilized in the past for RMR purposes, unless a generator being retired will be replaced with a comparable unit before the next summer season.
- A significant customer outage in an RMR load pocket defined as a sustained outage of more than one hour exceeding the greater of 100 MW or 10% of the peak demand in the pocket.

Each Arizona utility reported that none of the criteria for triggering RMR studies occurred during the Eighth BTA; therefore updated RMR studies were not filed for the five RMR areas.

[44] Decision No. 73625

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

3.3.1.5 Phoenix Metropolitan Area RMR Assessment

The interconnected transmission system serving the metropolitan Phoenix area is owned and operated by APS, SRP and Western. A majority of the Phoenix area ("Phoenix Valley") load is served by transmission imports. Load growth occurring in the north and west segment of the Phoenix Valley is served by APS and the load growth in the east and south is served by SRP. An RMR condition exists for the Phoenix Valley because the peak load for the area exceeds the SIL of the existing and planned transmission system serving the area. However, APS reported that no triggering criteria for restarting the Phoenix Valley RMR studies have occurred since the Seventh BTA, therefore there are no updated results to report for the Eighth BTA.

3.3.1.6 Tucson Area RMR Assessment

The Tucson area is interconnected to the EHV transmission system at Tortolita, South, and Vail. These three stations interconnect and supply energy to the local TEP 138 kV system. 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. TEP reported that no triggering criteria for restarting the Tucson Area RMR studies have occurred since the Seventh BTA.

3.3.1.7 Yuma Area RMR Assessment

The Yuma area is served by an internal APS 69 kV sub-transmission network containing the entire APS load in the transmission import limited area. There are external ties to Western at Gila Substation and the Imperial Irrigation District ("IID") at Yucca Substation. There is also a 500 kV bulk power interface at North Gila with 500 kV lines running east to the Palo Verde Hub and west to Imperial Valley in California. APS reported that no triggering criteria for restarting the Yuma Area RMR studies have occurred since the Seventh BTA.

3.3.1.8 Santa Cruz County RMR Assessment

Santa Cruz County is served by a radial transmission system. UNS Electric is the LSE in Santa Cruz County. UNS Electric reported that no triggering criteria for restarting the Santa Cruz County RMR studies have occurred since the Seventh BTA.

3.3.1.9 Mohave County RMR Assessment

Mohave County is the only Arizona load pocket with local generation that has a peak load that does not exceed its reported SIL rating. UNS Electric is a LSE in Mohave County.[46] UNS Electric reported no triggering criteria for restarting the Mohave County RMR studies have occurred since the Seventh BTA.

3.3.2 Ten Year Snapshot Study

The SWAT-Arizona Subcommittee performed and filed a report documenting results of its Ten Year Snapshot study. This study provides an assessment of the ten year plans proposed by Arizona transmission owners.[47] The Ten Year Snapshot study consists of conducting normal and single contingency ("n-0" and "n-1" respectively) power flow analyses that determine the adequacy of the tenth year of the planning period. The Ten Year Snapshot study also assesses the effect of omitting individually planned transmission projects.[48]

Whereas some of the Arizona transmission owners have filed technical study reports for their respective areas of the system as part of the Eighth BTA, the SWAT-Arizona Ten Year Snapshot study represents the only comprehensive assessment of 2023 Arizona transmission plans. Furthermore, the Ten Year Snapshot study done in 2013 includes all transmission and generation projects statewide, making the report uniquely valuable for assessing the overall adequacy of Arizona transmission plans in 2023.

The 2023 case modeled a statewide load of 23,535 MW which is 710 MW or 3.1% higher than the statewide load modeled in the previous Ten year Snapshot study completed for the year 2021. The 2023 base case model used for the study was based on the complete list of projects that were planned to be in service by 2023 at the time of base case development, which took place from January to April 2013.

In all, a total of nine base case project deferral scenarios, including four APS projects, two SRP projects, one TEP project, one scenario involving the SunZia project, and one scenario involving the

---

[46] Other entities serving load in Mohave County include Aha-Macov, Central Arizona Project, Mohave Electric Cooperative, and the City of Needles

[47] The SWAT-Arizona Subcommittee is partially comprised of the following transmission participants: APS, SRP, SWTC, TEP, UNS Electric and Western.

[48] It should be noted that removal of an individual project in some cases involved the removal of multiple transmission lines and/or bulk power transformers.

Bowie project, were analyzed under both n-0 and n-1 conditions to assess the impact of such deferrals on system performance. All Arizona transmission system facilities with design voltages of 230 kV or greater were monitored for compliance with thermal loading and voltage criteria for all contingencies tested.

The Ten Year Snapshot study reached the following major conclusions:

- Arizona's 2023 transmission plan is robust and supports the statewide load forecast.
- There were no overloaded transmission system elements or voltage violations in the 2023 normal operating base case.
- Single contingency outage analysis on the base case showed a single overloaded element that will need further investigation by the utilities in future studies.
- Delay of the Pinal Central-Tortolita 500 kV or Sun Zia Project beyond 2023 would likely have significant negative impact on system performance.
- Delaying any one of the other projects beyond 2023 shows minimal impact on system performance. Staff and KRSA found the Ten Year Snapshot to be sufficient. However, Staff and KRSA concluded the Ten Year Snapshot needs to study and monitor elements down to and including the 115 kV level.

Staff and KRSA conclude the Ten Year Snapshot study documents the performance of Arizona's statewide transmission system in 2023 for a comprehensive set of n-1 contingencies, each tested with the absence of different major planned transmission projects. However, Staff and KRSA conclude the Ten Year Snapshot should include the monitoring of transmission elements down to and including 115 kV in subsequent study efforts.

3.3.3 Extreme Contingency Study Work

The Commission directed that, as part of the Eighth BTA, 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, if mitigating infrastructure improvements are not planned.[49] Studies have been filed in response to the Commission

[49] Decision No. 67457

requirement. Two extreme contingency studies were performed: one by APS and the other by TEP. Each was coordinated through the SWAT-Arizona subcommittee.

The APS and TEP analyses were performed using 2014 and 2023 summer peak load models which reflected the filed ten year project plans. This analysis generally corresponds to NERC Category C and D events, but did not include an assessment of transient stability performance.[50] EHV transmission line corridors were chosen for study based upon exposure to forest fires and other extreme events. APS performed studies for corridor outages involving five sets of lines/transformers. TEP performed studies for corridor outages involving three sets of lines/transformers.[51]

APS's extreme contingency analyses indicate all load and local Phoenix reserve requirements can be met. The extreme contingency analyses do show that specific outages will require post-contingency operator response including generation re-dispatching and system reconfiguration to alleviate overloads. These APS results are for both the 2014 and 2023 system conditions.

TEP's extreme contingency analysis indicates TEP can withstand each extreme contingency outage. Specifically, TEP's normal operating procedures include the ability to withstand the studied corridor outages by utilizing a Tie Open Load Shed scheme and post-contingency operator response including generation re-dispatching and coordinated mitigation with SWTC. Study results show that TEP can withstand these extreme contingencies under the 2014 and 2023 system conditions.

Staff and KRSA found the Extreme Contingency Analysis studies satisfy the requirements of Commission Decision No. 67457.

3.4 2014 Summer Energy Preparedness

The 2014 Summer Energy Preparedness meeting occurred on April 10, 2014, at the ACC offices. The 2014 Summer Energy Preparedness meeting is an open meeting where electric and natural gas utilities inform the Commission of their level of preparedness to deal with the ensuing summer peak season. The 2014 Summer Energy Preparedness meeting included presentations and comments by the following electric utilities: APS, SRP, TEP/UNS Electric, and Arizona's G&T

[50] NERC Reliability Standards TPL-003 and TPL-004

[51] The details of the extreme contingencies performed by APS and TEP are considered sensitive information and therefore removed from this report.

Cooperatives. APS, SRP, TEP/UNS Electric, and the G&T Cooperatives each indicated preparedness for the 2014 summer peak demand. This preparedness included a declaration of adequate generation and reserves and sufficient transmission capacity to withstand normal outage contingencies. Emergency plans are also in place to respond to extreme outage events, extreme system conditions, and events of natural disaster including storms or fires.

Staff and KRSA were in attendance at the Summer Preparedness open meeting. APS indicated it is well prepared for the up-coming 2014 summer demand. APS stated adequate generation resources are in place to meet customer load and meet reserve requirements, line maintenance efforts are on track, on-going coordination and integration with emergency planners is occurring, and strong customer communication channels are in place.[52]

SRP indicated that SRP transmission, distribution, generation and planned energy purchases are adequate to serve the forecasted year 2014 demand. Additionally, SRP stated contingency plans are in place to handle emergency events and proactive customer communication plans are in place for outage situations.[53]

TEP summarized its presentation noting that sufficient generation and transmission resources are available to meet both TEP's and UNSE's load. TEP stated reliable transmission and distribution systems with capacity to meet peak demand are in place. TEP stated operational testing has been conducted and summer operations plans are in place. TEP stated equipment and plans are available to respond quickly and efficiently to emergencies.[54]

The Arizona G&T Cooperatives indicated the completion of planned upgrades to Apache Generating station, completion of preventive maintenance activities, completion of inspecting 345 kV ground-line wood pole attachments, and focused efforts on line inspection and vegetation management activities. The Arizona G&T Cooperatives have participated in WECC Reliability Coordinator restoration training, reviewed interconnection backup service agreements, updated the joint generation contingency reserve plan for an Apache generating station outage, and participated

[52] APS, *Arizona Public Service Company 2014 Summer Readiness,* given on April 10, 2014, slide 22, http://www.azcc.gov/Divisions/Utilities/Electric/summer%20preparedness/2014%20Summer%20Prep%20-%20APS.pdf
[53] SRP, *SRP Summer Preparedness 2014* Presentation, given on April 10, 2014, slide 21, http://www.azcc.gov/Divisions/Utilities/Electric/summer%20preparedness/2014%20Summer%20Prep%20-%20SRP.pdf
[54] TEP, *2014 Summer Preparedness,* given on April 10, 2014, slide 22, http://www.azcc.gov/Divisions/Utilities/Electric/summer%20preparedness/2014%20Summer%20Prep%20-%20TEP%20UNSE.pdf

in Department of Energy ("DOE") Smart Grid funding programs including replacing the Energy Management System ("EMS").[55]

The 2014 level of summer preparedness of the utilities in Arizona has been assessed and is sufficient. The current electric utility system in Arizona is judged to be adequate to reliably meet the energy needs of the state in 2014.

3.5 Physical Security

FERC directed NERC to submit for approval reliability standards that will require transmission owners and operators to take action or demonstrate that they have taken action to address physical security risks and vulnerabilities related to the reliable operation of the bulk power system. The proposed reliability standards should require owners or operators of the bulk power system to:

1. Identify facilities on the bulk-power system that are critical to reliable system operation, and
2. Validate and implement plans to protect against physical attacks that may compromise the operability or recovery of such facilities.

In response to FERC directive, NERC developed the CIP-014-1 "Physical Security" standard.[56] At their May 13, 2014 meeting, NERC adopted the CIP-014-1 standard. On July 17, 2014, FERC released the Notice of Proposed Rulemaking ("NOPR") seeking comment.

At the request of Staff and KRSA Arizona utilities provided information and details on their plans and efforts to ensure physical security and resiliency in the planning and operation of the Arizona electric system, the details of which are considered confidential. Staff and KRSA conclude the Arizona utilities are taking actions to address the physical security risks to reasonably ensure the reliable operation of the Arizona transmission system.

[55] Arizona's G&T Cooperatives, *Arizona's Cooperatives Summer Preparedness Report to ACC 2014, given on April 10, 2014,sildes 16-17,* http://www.azcc.gov/Divisions/Utilities/Electric/summer%20preparedness/2014%20Summer%20Prep%20-%20G&T.pdf

[56] CIP-014-1 – Physical Security Standard - http://www.nerc.com/pa/Stand/Prjct201404PhsclScrty/CIP-014-1_Physical%20Security_2014_May01_clean.pdf

4 Interstate, Merchant and Generation Transmission Projects

Wholesale market power purchases and sales rely on available interstate transmission. These interstate and merchant transmission projects make possible a competitive and healthy wholesale market while complementing the states' utilities electric infrastructures by providing additional import/export points. Several market access projects and merchant transmission projects are discussed in this BTA. This section of the BTA report highlights the status of eighteen such planned projects that affect Arizona. Exhibit 20 provides tabular listing of the interstate, merchant and generation transmission projects.

4.1 Delaney – Colorado River 500 kV Transmission Line

The Delaney – Colorado River 500 kV transmission line project would provide an additional interstate 500 kV interconnection between Arizona and California.[57] No ten year plan has been filed with the Commission for this project nor was this project specifically discussed at Workshop I. Therefore, this project was not considered for the adequacy assessment nor included in the ten year plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project is included as Exhibit 21.

The Delaney-Colorado River 500 kV line is conceptualized as a 115-140 mile, 500 kV single circuit structure between the APS Delaney 500 kV switchyard located in Arizona and the Southern California Edison ("SCE") Colorado River 500 kV substation.

The Delaney – Colorado River 500 kV line was recently studied as an economic project in the California Independent System Operator ("CAISO") 2013-2014 Transmission Plan. The project demonstrated sufficient benefits when compared to the cost and was recommended for approval by the CAISO Board.[58] At the March 20, 2014 Independent System Operator ("ISO") Board of Governors meeting, the ISO Board of Governors failed to approve the line and CAISO staff was directed to perform further assessments and report the results back to the Board. Subsequently, at

[57] The Arizona portion of the previously planned Palo Verde – Devers #2 Project of which SCE has already built the California portion.

[58] http://www.caiso.com/Documents/Board-Approved2013-2014TransmissionPlan.pdf

the July 16, 2014 ISO Board of Governors approved the Delaney – Colorado River 500 kV transmission line project.[59]

4.2 SunZia Southwest Transmission Project

The SunZia 500 kV transmission line project would provide an interstate 500 kV interconnection between Arizona and New Mexico. A ten year plan was received and this project was presented and discussed at Workshop I. This project was considered for the adequacy assessment and included in the ten year plan statistics compiled for this BTA. Overview maps showing the general routing and interconnection points of this project are included within Exhibits 1, 3, and 5.

The SunZia project is currently planned to consist of approximately 515 miles of two single-circuit 500 kV transmission lines, either two alternating current ("AC") or one AC and one direct current ("DC"), and associated substations beginning at a new substation in central New Mexico and terminating at Pinal Central substation near Coolidge, Arizona. Approximately 200 miles of the proposed route are within Arizona. Depending on the final configuration of the project, it is expected to have a power transfer capacity of between 3,000 and 4,500 MW.

The sponsors of the SunZia Southwest Transmission Project include Salt River Project, Shell Wind Energy, Southwestern Power Group, Tri-State Generation and Transmission Association, and Tucson Electric Power. SunZia is anticipated to deliver primarily renewable energy from sources yet to be determined to markets in Arizona and California. The first phase of commercial operation is expected to commence in 2018.

Milestones achieved since the Seventh BTA include the issuance of a Final EIS for the project in June 2013, with the Record of Decision ("ROD") expected in 2014. SunZia expects to file its CEC application following the BLM's publication in the Federal Register of the Notice of Availability of the ROD. In addition, a Letter of Intent was signed in August 2013 with the project's first anchor tenant, First Wind Energy, LLC, for up to 1,500 MW of capacity.

[59] http://www.caiso.com/Documents/DecisionDelaney-ColoradoRiverTransmissionProject-Motion-July2014.pdf

4.3 Centennial West Clean Line Project

The Centennial West Clean Line Project ("Clean Line") is planned to be a ±600 kV High Voltage Direct Current ("HVDC") transmission line that would provide an interstate interconnection between New Mexico and California with routing and the potential for an interconnection point in Arizona. No ten year plan was filed with the Commission in 2014 for this project. Therefore, this project was not considered for the adequacy assessment nor included in the ten year plan statistics compiled for this BTA. This project was presented and discussed at Workshop I. An overview map showing the general routing and interconnection points of this project is included as Exhibit 22.

The Clean Line project is currently planned to consist of approximately 900 miles of HVDC beginning in northeastern New Mexico and terminating in southern California. Approximately 300 miles of the total project would be in northern Arizona. Clean Line filed an application for right-of-way across Federal lands and a preliminary Plan of Development with the Bureau of Land Management ("BLM") in 2011, and has completed the Project Coordination Review portion of the WECC path rating process. Clean Line last filed a ten year plan in January 2012. The Clean Line Project is sponsored by Clean Line Energy Partners, LLC. The project is expected to deliver 3,500 MW of renewable energy to markets in California and the West. Commercial operation is currently planned to begin in 2020.

4.4 Bowie Power Station

Bowie Power Station is a proposed 1,000 MW natural gas generating station consisting of two combustion turbines and one steam turbine which will be located in Southeastern Arizona and will serve the load requirements of that area. A ten year plan was received and this project was presented and discussed at Workshop I. This project was considered for the adequacy assessment and included in the ten year plan statistics compiled for the Eighth BTA. An overview map showing the general routing and interconnection points of this project are included within Exhibit 1.

The project is owned by Southwestern Power Group II, LLC ("SWPG"). A fifteen mile double-circuit 345 kV transmission line will interconnect the generating facilities to the transmission grid, and will run between Bowie Plant Switchyard and the proposed Willow Switchyard on TEP's Greenlee-Winchester-Vail 345 kV line. CECs for the generating station and transmission facilities were originally granted in March 2002, and were subsequently extended by the Commission through December 2010 and again through December 2020.[60] The proposed alignment of the transmission line was also revised in 2008 to comply with the requirements of the Arizona State Land Department.[61] In September 2013, Bowie submitted a new Class I air quality application to the Arizona Department of Environmental Quality ("ADEQ") and the draft permit is expected soon with the final permit by the end of 2014.

SWPG and TEP entered into an interconnection facilities study agreement on October 12, 2013, and the facilities study was provided by TEP on October 29, 2013. Bowie is working with TEP to complete a large generator interconnection agreement ("LGIA") and continues to participate in regional planning forums. Currently, initial energization of the interconnection facilities is estimated to occur by December 31, 2017, with commercial operation of the initial 500 MW power block occurring by December 31, 2018.

4.5 Mohave County Wind Farm Project

The Mohave County Wind Farm Project, formerly known as the BP Wind Energy North America Project, is comprised of a proposed 500 MW wind energy power plant and associated transmission interconnection tie-line and other facilities, either 345 kV or 500 kV. A ten year plan was received for this project, and the project was considered for the adequacy assessment and included in the ten year plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project are included within Exhibit 1.

The project will be located in Mohave County, Arizona, near the city of Kingman, and will deliver to load-serving entities yet to be determined. The project will interconnect with either the 345 kV Mead-Peacock-Liberty line or the 500 kV Mead-Phoenix line via a gen-tie line approximately 5 miles in length, the final route of which has not yet been determined. A CEC for the transmission line was granted by the Commission in November 2012; commercial operation is expected to begin in 2015 or 2016.

---

[60] Decision No. 71951, dated 11/1/2010, the ACC granted Bowie a second extension on the durations of the CECs through 12/31/2020.

[61] Decision No. 70588, dated 11/6/2008, approved adjustment to Bowie's approximately 15-mile, double-circuit 345 kV generator tie-line on Arizona State Land Department ("ASLD") property. This line interconnects the Willow Substation to TEP's existing Greenlee-Winchester-Vail 345 kV line.

4.6 Gila Bend Power Partners

Gila Bend Power Partners proposes to build a 500 kV transmission line from the planned 833 MW combined cycle Gila Bend Power Project to a new switchyard interconnecting with APS's Gila River Line and the Jojoba Switchyard, and ultimately the Hassayampa Switchyard. A ten year plan was received for this project. This project was considered for the adequacy assessment and included in the ten year plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project are included within Exhibits 1 and 2.

The line would run parallel to the existing Palo Verde to Kyrene 500 kV transmission line. Three CECs have been granted for the project. The project is currently on hold due to unfavorable market conditions. However, Gila Bend Power Partners has filed ten year plans in the Eighth BTA, in both January 2013 and January 2014.

4.7 SolarReserve

SolarReserve, LLC proposes to construct the Crossroads Solar Energy Project, a new 150 MW concentrating solar power plant and transmission line, to be located near the intersection of Interstate 8 and Paloma Road in southwestern Maricopa County, to the Panda – Gila River substation. A ten year plan was received for this project. This project was considered for the adequacy assessment and included in the ten year plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project are included within Exhibit 1.

The new 230 kV gen tie line will be approximately 12 miles in length but its exact route has not yet been determined. However, it is expected to largely follow the Abengoa Solana power project generation tie-line. A CEC for the project was granted in February 2011, and a ten year plan was last filed in January 2014. Current forecasts are for a commercial operation date by the end of 2017.

4.8 Southline Transmission Project

The Southline Transmission Project ("Southline") is a 345 kV line that would provide an interstate 345 kV interconnection between Arizona and New Mexico. No ten year plan has been filed with the Commission for this project, but this project was presented and discussed at Workshop I. Because there was no ten year plan filed, this project was not considered for the adequacy assessment nor included in the ten year plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project is included as Exhibit 23.

Southline Transmission LLC is sponsoring the Southline Project to improve reliability and help facilitate the development and delivery of renewable energy in the region. The Southline Project proposes to build a 360-mile line from Las Cruces, New Mexico to Tucson, Arizona, across federal, state, and private land. Consisting of two segments, the first segment of the project proposes 240 miles of a double-circuit 345-kV line that would link an existing substation at Afton, near Las Cruces, to the existing Apache substation near Wilcox, Arizona. The second segment would upgrade and rebuild 130 miles of existing Western and TEP transmission lines from 115 kV to 230 kV between the Apache substation and the Saguaro substation near Tucson. Overall the project may interconnect with the existing transmission system at up to fourteen substation locations.

On April 11, 2014, the BLM and Western, serving as joint lead agencies, released a Draft Environmental Impact Statement for the project. The ROD is anticipated to be published in Q1 2015. The project is currently in Phase 2 of project planning with in-service anticipated for the end of 2016. When completed, the Southline Project will add 1,000 MW of bidirectional transfer capability to the grid.

4.9 TransWest Express

The TransWest Express Transmission project is a HVDC line planned for the cost-effective delivery of wind energy to Arizona, California, and Nevada. No ten year plan has been filed with the Commission for this project nor was this project specifically discussed at Workshop I. Therefore, this project was not considered for the adequacy assessment nor included in the ten year plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project is included as Exhibit 24.

If developed, the 600 kV HVDC transmission line would include 725 miles of transmission lines. The transmission will originate near Sinclair, WY near the Platte substation and will terminate in Southern Nevada in the Eldorado Valley near the Marketplace substation complex. TransWest Express expects to be rated at 3,000 MW and the transmission line is anticipated to be online in 2017.

The project is jointly being developed between TransWest Express, LLC and Western. The two agencies released a draft Environmental Impact Statement ("EIS") in July 2013. The project is currently conducting requirements of phase 2 of the WECC path rating process.

4.10 EnviroMission

EnviroMission Inc. is sponsoring the development of a 200 MW Solar Tower located in La Paz County, south of Parker, Arizona. A ten year plan was received for this project. This project was considered for the adequacy assessment and included in the ten year plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project are included within Exhibit 1.

The La Paz Solar Tower project would include the development of a single 2,600 foot tall solar electric generation facility and associated gen-tie line. The site selected also has room to potentially accommodate additional solar towers in the future. The project would provide clean renewable energy with dynamic scheduling capabilities and contends to be a base-load resource.

Currently the project has not selected a location for interconnection(s) to the transmission system. A possible interconnection that has been identified includes developing facilities in cooperation with Central Arizona Water and Conservation District ("CAWCD") to jointly serve the Central Arizona Project ("CAP") pumping plants and the project site. These facilities in all likelihood would include a 500 kV interconnection at Salome substation to access the Delaney – Colorado River 500 kV line. The project currently has a targeted in-service date of spring 2017.

4.11 Longview Transmission Project

In January 2014, Longview Energy Exchange, LLC ("Longview") submitted a ten-year transmission plan consisting of three potential transmission corridors that are being considered for interconnecting a 2,000 MW adjustable speed hydro-electric pump storage project by 2021. A ten year plan was presented and discussed at Workshop I. This project was considered for the adequacy assessment and included in the ten-year plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project is included within Exhibit 1.

Longview includes the development of a new 500 kV switchyard at the project site. The 500 kV lines being considered include a 50 mile line from the Longview switchyard and terminating at a new

500 kV switchyard in the vicinity of the existing Peacock Substation to interconnect with the Mead-Perkins 500 kV line, and either a 40 mile line from the Longview switchyard interconnecting at the Navajo transmission system at the Yavapai substation, or a 30 mile line terminating at a new 500 kV switchyard to interconnect with the Moenkopi-Eldorado 500 kV line. Construction is expected to begin in 2018 with an estimated in-service date of 2021.

Feasibility, market assessment and WECC firmed resource studies have been completed for the project. A FERC preliminary permit application was filed,[62] and the FERC Order was issued April 26, 2012. A CEC application with the ACC is pending an environmental study of the routes.

4.12 Buckeye Generation Center

Buckeye Generation Center, formerly known as the Horizon Power Project, is a 650 MW natural-gas peaking facility currently planned for a site within Maricopa County. A ten year plan was received for this project. This project was considered for the adequacy assessment and included in the ten year plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project is included within Exhibits 1 and 2.

The Buckeye Generation Center would include the development of a half mile, 230 kV gen-tie line to connect the project site to a proposed 69/230 kV substation to be constructed, owned and operated by APS. The precise location of the transmission line has not yet been determined. The Buckeye Generation Center is sponsored by Buckeye Generation Center, LLC and is intended to add peaking power to Arizona electric utilities and to the interstate electrical grid. The currently estimated in-service date is 2018.

4.13 Sun Streams

Sun Streams, LLC, a wholly-owned subsidiary of Element Power, is sponsoring the Sun Streams Solar Project substation and gen-tie line to interconnect a proposed 150 MW photovoltaic solar facility. A ten year plan was received for this project. This project was considered for the adequacy assessment and included in the ten year plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project is included within Exhibit 1.

---

[62] Preliminary permit application was filed as project 14341-000

The Sun Streams project includes the development of a 500/34.5 kV step up transformer and 1,600 feet of 500 kV AC single circuit line to be interconnected at 500 kV at the Hassayampa Switchyard. The project is expected to be in-service in the first quarter of 2016. A CEC is pending before the Commission for this tie-line project.

4.14 Tribal Solar

Tribal Solar, LLC, a wholly-owned subsidiary of First Solar, is sponsoring the substation and gen-tie line associated with the proposed Fort Mohave Solar Project. The estimated 310 MW project is planned to include the construction of a 34.5/230 kV substation at the Fort Mohave project site located on the Fort Mohave Indian reservation in Mohave County, Arizona and San Bernardino County, California. A ten year plan was received for this project. This project was considered for the adequacy assessment and included in the ten-year plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project is included within Exhibit 1.

The gen-tie line will be up to twenty five miles in length depending on final project configurations. The gen-tie line and substations will interconnect the proposed Fort Mohave Solar Project with the regional transmission grid at the Mohave Generating Station Substation. Currently, the project's in-service date is uncertain.

4.15 Harcuvar Transmission Project

The Harcuvar Transmission Project ("HTP") is sponsored by the CAWCD. The project is intended to increase system reliability, permit interconnection of potential solar and thermal generation to the grid and provide access to the Palo Verde hub, California ISO and Western's Parker-Davis transmission system. No ten year plan has been filed with the Commission for this project nor was this project specifically discussed at Workshop I. Therefore, this project was not considered for the adequacy assessment nor included in the ten year plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project is included as Exhibit 25.

HTP is planned to consist of a 100 mile, 230 kV line originating at the proposed Delaney – Colorado River 500 kV line and terminating at the Harcuvar 230 kV substation. The project is dependent on interconnection to one or both Palo Verde – California lines at a proposed Salome substation, five miles of new 230 kV transmission line connecting the Salome substation with the Little Harquahala Substation, and a new transmission between Bouse Hills and Little Harquahala substations. The transmission capacity would be approximately 2,000 MW.

HTP originally proposed an in-service date of 2018; however, the project is currently suspended while undergoing configuration and needs review.

4.16 High Plains Express

The High Plains Express project intends to enhance reliability and increase access to generation resources across the transmission grid through Wyoming, Colorado, New Mexico, and Arizona. No ten year plan has been filed with the Commission for this project nor was this project specifically discussed at Workshop I. Therefore, this project was not considered for the adequacy assessment nor included in the ten year plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project is included as Exhibit 26.

The project includes the planned development of a high-voltage, 2500 mile, 500 kV AC transmission backbone which will add 4,000 MW of capacity import and export capabilities. The list of parties participating in the development of the High Plains Express includes Black Hills Corporation, Colorado Springs Utilities, Public Service Company of New Mexico, Public Service Company of Colorado ("Xcel Energy"), SRP, Tri-State Generation & Transmission ("Tri-State"), LS Power, NextEra Energy, Western, and Wyoming Infrastructure Authority ("WIA").

Participants completed a preliminary feasibility study in 2008. The High Plains Express Initiative finished Stage 2 in 2011 and issued a Stage 2 Report; however, the project is currently suspended. The most recent anticipated in-service date is 2030.

4.17 North Gila – Imperial Valley #2

The North Gila – Imperial Valley # 2 Project, sponsored by Southwest Transmission Partners, LLC, in participation with IID, would be a 500 kV transmission line, single or potentially double-circuit, interconnecting the existing North Gila Substation near Yuma, Arizona with the existing Imperial Valley Substation in the vicinity of El Centro, California. No ten year plan has been filed with the Commission for this project. Therefore, this project was not considered for the adequacy assessment nor included in the ten year plan statistics compiled for this BTA. This project was presented and discussed at Workshop I. An overview map showing the general routing and interconnection points of this project is included as Exhibit 27.

The line would be approximately eighty five miles in length, and parallel the Southwest Power Link ("SWPL") 500 kV line for much of its length. Depending on the final configuration, the project in all likelihood will increase total transfer capability ("TTC") up to 2,400 MW for Path 46 ("West of River") and up to 1,200 MW for Path 49 ("East of River"). The anticipated date of operation is the first quarter of 2019.

This project is new since the Seventh BTA. To date, the project participants have submitted the right of way ("ROW") application to BLM and initiated the WECC Three Phase Rating process, as well as participated in regional planning efforts. Over the next two years, the project participants intend to continue addressing the National Environmental Policy Act ("NEPA") and WECC rating processes.

4.18 Ocotillo Modernization Project

The Ocotillo Modernization Project ("OMP") involves the planned retirement of existing generators and subsequent addition of generation at the existing Ocotillo generating facility in Tempe, Arizona. A ten year plan was received and the project was presented and discussed at Workshop I. This project was considered for the adequacy assessment and included in the ten year plan statistics compiled for this BTA. An overview map showing the interconnection points of this project is within Exhibit 1.

The existing Ocotillo generating facility is comprised of two steam generators (110 MW net each) and two gas generators (55 MW net each) which have a total net output of 330 MW. The proposed project would retire the two steam generators and replace them with five new gas turbines, with a net increase of 290 MW of capacity. The OMP is proposed by APS and is estimated for in-service in 2018.

4.19 Abengoa

In 2013, Abengoa Solar Inc. completed construction of the 280 MW Solana Solar Generating Station near Gila Bend, Arizona. Interconnection of the plant was made to APS's Panda Substation via a 20 mile long, double-circuit 230 kV gen-tie line. Arizona Solar One and APS have executed a LGIA and a 30-year power purchase contract for the plant. The plant went into operation in October 2013.

5 Regional and National Transmission Issues

This section describes select regulatory and industry activities which occur on the national and regional stage. Only those activities related to transmission infrastructure, regional and subregional transmission grid expansion, and transmission reliability are described herein.

5.1 Regional Transmission Planning – WestConnect

The members of WestConnect include utility companies which provide transmission services within the western interconnection, particularly Arizona, New Mexico, Colorado, Wyoming, Nevada, and California.[63] The objective of WestConnect is to assess both stakeholder and market needs in a collaborative manner, with the end goal of developing cost-effective enhancements to the wholesale electricity market in the western United States. In the process, WestConnect coordinates with other regional industry efforts to ensure as much consistency as possible in the western interconnection. Initiatives that have been undertaken or are under way by WestConnect include:[64]

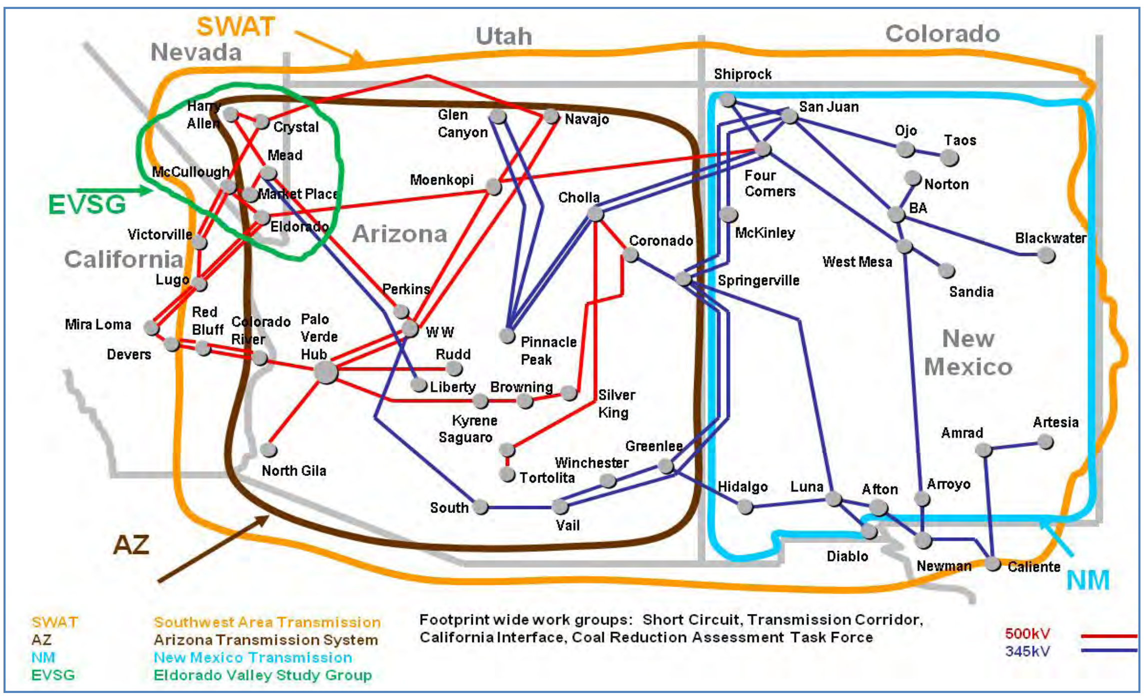
- FERC Order No. 890 OATT transmission planning through the WestConnect Project Agreement for Subregional Transmission Planning ("STP") effective May 23, 2007;[65]
- FERC Order No. 1000 implementation;
- Flow-based market investigations;
- Large generator interconnection process ("LGIP") refinements;
- Streamlining the large generator interconnection process;
- Non-pancaked hourly non-firm transmission service;
- An energy imbalance service ("EIS") investigation;
- TTC/available transfer capability ("ATC") group; and
- Virtual control area investigation.

[63] More information on the WestConnect membership can be found here http://www.westconnect.com/about_steeringcomm.php.
[64] WestConnect Initiatives - http://www.westconnect.com/initiatives.php
[65] WestConnect Project Agreement for STP - http://www.westconnect.com/filestorage/wc_regional_planning_project_agmt_exec_copy_052307_amended_obj_proc_011409.pdf

5.1.1 SWAT Subregional Planning Group

SWAT is a subregional transmission planning group within the WestConnect footprint. SWAT provides a forum for discussion of planning, coordination, and implementation of a robust transmission system in Arizona, New Mexico, and portions of Colorado, Texas, Nevada, and California. The process is open to interested stakeholders throughout the Desert Southwest and is intended to develop transmission expansion plans with a broad basis of support. SWAT participants include transmission users, environmental entities, transmission owners, transmission operators, transmission regulators and governmental entities. SWAT includes several subcommittees and workgroups under the overarching umbrella of the SWAT Oversight Committee. The planning area of SWAT and its subcommittees is depicted in Figure 2.

Figure 2 - SWAT and Subcommittees Footprints



SWAT and the efforts of its subcommittees have been central to the BTA process including providing the forum for coordinating the Ten Year Snapshot study and Extreme Contingency study Commission-ordered studies. SWAT has also undertaken on its own initiative the Coal Reduction Assessment discussed in Section 5.1.1.6.

Since the Seventh BTA, SWAT has discussed FERC Order No. 1000 ("Order No. 1000") implementation, hosted educational webinars and maintained maps and project listings. SWAT also provided a forum for the discussion of both new and existing transmission projects and coordinated on seams issues, as defined in Section 6.7, with other planning regions and coordinated on State and Federal issues related to transmission development. Other activities included support of other regional planning forums and submission of two Transmission Expansion Planning Policy Committee ("TEPPC") study requests. The activities of SWAT's subcommittees and workgroups are described below; more information on each is available through the WestConnect website.[66]

5.1.1.1 Arizona Subcommittee

SWAT-AZ was formed in February 2013 by the merger of Central Arizona Transmission System ("CATS"), Southeast Arizona Transmission Study ("SATS"), and Colorado River Transmission ("CRT") subcommittees. The objective of SWAT-AZ is to study the high voltage ("HV") and EHV systems throughout Arizona and on both sides of the Colorado River between Yuma and southern Nevada. Since its inception, SWAT-AZ activities include the coordination of several cases for SWAT and utilities' studies, and coordination of technical study work to support the BTA including the Ten Year Snapshot study and the Extreme Contingency study.

SWAT-AZ shares project updates, other technical updates, and hosts educational presentations on such topics as NERC planning standards, transmission planning tools, and environmental permitting resources. Going forward, SWAT-AZ may coordinate ten year base cases with WestConnect, prepare for NERC TPL Standards implementation, and assist in the WestConnect Order No. 1000 planning processes.

5.1.1.2 Short Circuit Working Group

The Short-Circuit Working Group ("SCWG") includes representatives of transmission owners, transmission operators, and other interested stakeholders. The objective of the SCWG is to promote regional short circuit studies and common methodologies for individually and jointly owned/operated transmission systems in the Desert Southwest. In the past two years, SCWG has

[66] See http://www.westconnect.com/planning_swat.php.

continued updating the CAPE and ASPEN cases for the SWAT planning area. SCWG's goal is to have a new ASPEN model working by September 2014.[67]

5.1.1.3 El Dorado Valley Study Group

The Eldorado Valley Study Group ("EVSG") serves as a forum for communication between and study work of interest to the owners of the electric system in Nevada's Eldorado Valley and nearby areas, and parties interested in interconnecting with the region's system. The El Dorado Valley system is interconnected with the Arizona transmission system and is located on the export path between Arizona and California. EVSG's recent activities include coordination of projects in the area, map development, and sharing updates. The EVSG also completed a high level fault duty study in February 2013 to analyze the base transmission system, and developed conceptual projects in the EVSG area, including a new conceptual substation dubbed the Agora Substation.

5.1.1.4 California Interface Work Group

The California Interface Work Group was formed in May 2013 with the objective of addressing seams issues between SWAT and California entities such as now-dissolved California Transmission Planning Group ("CTPG"), CAISO, and California Public Utility Commission ("CPUC"). The work group hosted several webinars to review transmission plans and studies by California entities and submitted data and comments to the 2014/2015 CAISO study plan. The work group plans to continue following the CAISO 2013/2014 transmission plan and 2014/2015 study plan processes, and assist with interregional coordination with the CAISO.

5.1.1.5 Transmission Corridor Work Group

The Transmission Corridor Work Group ("TCWG") interacts with State, Federal, and Tribal entities to facilitate awareness and cooperation among stakeholders affected by potential transmission projects, particularly from the perspective of improving siting and permitting processes. The TCWG's recent efforts have concentrated on the maintenance of general information for outreach and educational activities. The TCWG also began discussing the

[67] CAPE and ASPEN are short circuit programs used in system analysis.

opportunities and drawbacks of a potential transmission corridor along proposed interstate I-11; discussions on this subject may continue through 2014.

5.1.1.6 Coal Reduction Assessment Task Force

The Coal Reduction Assessment Task Force ("CRATF") was formed in February 2014 at the initiative of the SWAT stakeholders for the purpose of assessing the reliability impacts of anticipated as well as hypothetical coal retirements in the southwest. The ultimate goal is to provide feedback for the forthcoming EPA Rulemaking on CO_2 emissions control pursuant to Section 111(d) of the Clean Air Act, and the Presidential Climate Action Plan. More information on the CRATF is included in Section 5.6.

5.2 FERC Order 1000

On July 21, 2011, FERC issued Order No. 1000, "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities".[68] Order No. 1000 amended the transmission planning and cost allocation requirements established in FERC Order No. 890 to ensure Commission-jurisdictional services are provided at just and reasonable rates and without unduly discriminatory or preferential treatment. Order No. 1000 established criteria for transmission planning processes and required public utility transmission providers to participate in a regional coordinated transmission planning process, to consider transmission needs driven by public policy requirements, and to improve coordination between neighboring transmission planning regions to seek efficient interregional solutions.

5.2.1 Role of WestConnect

On October 12, 2012, FERC jurisdictional WestConnect participants submitted their regional compliance filings under their respective OATTs, requesting that the WestConnect transmission process be accepted as satisfying the requirements outlined in Order No. 1000.[69] On March 21, 2013, the FERC partially accepted the regional filings with further compliance requirements to be

[68] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 76 FR 49842 (Aug. 11, 2011), 136 FERC ¶ 61,051 (2011), available at- https://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf
[69] Links to each WestConnect entity's filing - http://www.westconnect.com/planning_order_1000_rc_filing.php

filed.[70] The subsequent regional compliance filings were filed on September 20, 2013, and are pending FERC acceptance.[71]

The compliance filings made on September 20, 2013, included updates of the participants' respective OATTs demonstrating formal enrollment in the WestConnect Order No. 1000 Planning Process which includes Arizona utilities APS, TEP, and UNS Electric. The filings provided clarification in regards to provisions for participation by non-jurisdictional transmission owners, planning considerations for public policy requirements, and cost allocation evaluation process considerations.

In FERC's March 22, 2013 Order on Compliance, FERC found that the proposed WestConnect planning region met the geographic scope requirements of Order No. 1000.[72] WestConnect since has worked to align its planning and organizational operations with the principles and guidelines as outlined by Order No. 1000 and the March 22, 2013 Order on Compliance.

Under the Order 1000 planning process proposed in the compliance filings the WestConnect Planning Management Committee ("PMC") will be responsible for ensuring that the WestConnect planning processes are in compliance with Order No. 1000 and overseeing the development and approval of a regional transmission plan that includes application of cost allocation methodologies. The PMC will be comprised of representatives from WestConnect, which includes transmission owners, transmission customers, independent transmission developers, state regulatory commissions and key interest groups. All entities who become members of WestConnect will have voting rights as defined in the transmission providers' OATTs and in the planning participation agreement.

Under the Order No. 1000 planning process the existing WestConnect planning efforts are expanded to include regional reliability assessments, production cost modeling to identify economic needs, analysis of proposed regional projects that meet reliability, economic and/or public policy needs and application of binding cost allocation methodologies for eligible projects. Presently a draft planning process has been completed and a planning participation agreement and a business

---

[70] ACC BTA Workshop I, May 15, 2014, WestConnect Update Presentation, slide 18 - http://www.azcc.gov/Divisions/Utilities/Electric/Biennial/2014%20BTA/WestConnect%20Overview%20Recent%20Planning%20Activities.pdf
[71] Links to each WestConnect entity's filing - http://www.westconnect.com/planning_order_1000_rc_filing.php
[72] *Order on Compliance Filings*, 142 FERC ¶ 61,206 (2013).

practice manual are being finalized. WestConnect is drafting planning procedures and identifying additional resources needed to execute the planning process.

Through the compliance filings, the FERC jurisdictional WestConnect participants are seeking an effective date for the WestConnect Order 1000 planning process, which will start on January 1 of the year following FERC's conditional or full acceptance of the compliance filings. Depending on FERC's decision on the effective date, the effective date could commence either on January 1, 2015 for an abbreviated first year planning process, or beginning on January 1, 2016 for a full biennial WestConnect transmission planning process. The biennial planning process will need to begin on an even-numbered year to align with its interregional neighboring planning regions and WECC's planning processes.

5.2.2 Interregional Coordination

The CAISO, ColumbiaGrid, Northern Tier Transmission Group ("NTTG"), and WestConnect developed a multi-regional process to comply with Order No. 1000's requirements for interregional coordination. CAISO, NTTG, and WestConnect submitted interregional compliance filings on May 10, 2013.[73] ColumbiaGrid made a similar filing on June 19, 2013.[74] Decisions on interregional compliance filings are pending at FERC. The planning regions met in Folsom, California on February 28, 2014, and shared the status of each region's current planning efforts. WestConnect's input included base cases and assumptions used in study plans, planning models and identification of regional needs.

5.2.3 Relationship to the BTA Process

The WestConnect transmission planning process, with the enhancement of Order No. 1000 planning requirements, provides additional coverage of regional transmission planning activities not currently covered under the ACC BTA process. FERC Order No. 1000 requires regional and interregional agencies to work collaboratively to improve regional transmission planning processes

[73] ACC BTA Workshop I, May 15, 2014, WestConnect Update Presentation, slide 25 - http://www.azcc.gov/Divisions/Utilities/Electric/Biennial/2014%20BTA/WestConnect%20Overview%20Recent%20Planning%20Activities.pdf

[74] ACC BTA Workshop I, May 15, 2014, WestConnect Update Presentation, slide 25 - http://www.azcc.gov/Divisions/Utilities/Electric/Biennial/2014%20BTA/WestConnect%20Overview%20Recent%20Planning%20Activities.pdf

and cost allocation mechanisms. Where the ACC BTA focuses on intrastate impacts of planned transmission projects, Order No. 1000 will also help ensure the state's transmission owners consider regional transmission projects in assessing the most efficient and cost effective means to meet transmission needs of their customers.

5.3 Western Area Power Administration Transmission Infrastructure Program

Western established the Transmission Infrastructure Program ("TIP") in February 2009 to implement Title III, Section 301 of the Hoover Power Plant Act of 1984, as amended by the American Recovery and Reinvestment Act of 2009 ("ARRA"). Section 402 of the ARRA provides Western with up to $3.25 billion in borrowing authority for the purpose of:

- Constructing, financing, facilitating, planning, operating, maintaining or studying construction of new or upgraded electric power transmission lines and related facilities with at least one terminus within the area served by Western; and
- Delivering or facilitating the delivery of power generated by renewable energy resources constructed or reasonably expected to be constructed after the date of enactment

In a Federal Register notice ("FRN") published on April 7, 2014, Western announced its revised TIP and made a new request for new project proposals.[75] Effective May 7, 2014, the FRN implements program revisions to revise project evaluation criteria, clarify the role of the DOE and Loan Programs Office, and establish distinct project development and project finance phases. Developers are also now responsible for payment of TIP costs related to project evaluation.

The latest FRN keeps the principles of TIP fundamentally the same as the original May 14, 2009 FRN that established TIP. TIP projects must meet the following criteria:

1. Facilitate the delivery of renewable energy;
2. Have at least one terminus within Western service territory;
3. Have a reasonable expectation the project will generate revenue to repay;
4. Demonstrate that it will not adversely impact system reliability; and

[75] FRN 79 FR 19065

5. Be in the public interest.

Four transmission projects, having passed the evaluation criteria, are currently being developed under the Western TIP program.

5.3.1 TIP Impacts on Arizona

A number of TIP projects will have a significant impact on Arizona. These projects include recently energized and planned facilities as summarized below:

- The Electrical District 5-Palo Verde Hub ("ED5-PVH") Project is a TIP financed project that connects Western's Parker-Davis Project transmission system to the Palo Verde market hub. The project includes:
    i. Capacity rights on the Southeast Valley Project ("SEV") from the Palo Verde market hub to the SEV Duke substation located near the City of Maricopa in Pinal County;
    ii. A 500/230 kV interconnection between the SEV Duke substation and the Western's Test-Track substation:
    iii. A new 230 kV circuit from Western's Test-Track substation to Western's ED5 substation located south Eloy in Pinal County. This project is in the execution phase and construction is nearing completion.
- The Southline Project, as discussed in section 4.8 of this report, is in the development phase. Western is participating in this project as current plans are to rebuild and upgrade approximately 130 miles of Western transmission lines between Apache and Saguaro Substations. The anticipated completion of the Southline Project is 2016.
- The TransWest Express Project, as discussed in section 4.9, is currently in the development phase with an anticipated planned completion date of 2017. Western and TransWest Express, LLC are each contribution $25M in funding during the development phase.
- The Clean Line Project, as discussed in section 4.3, is currently in the development phase with an anticipated completion date of 2020. Western and Centennial West Clean Line

LLC have entered into an advance funding agreement during the project development phase.

5.4 WECC Regional Transmission Expansion Planning

WECC is the regional entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection. In carrying out this responsibility WECC performs compliance monitoring and enforcement, standards development, operation of the Western Renewable Energy Generation Information System ("WREGIS"), reliability planning and performance analysis.

Planning studies are performed under the TEPPC, a WECC board-level committee. TEPPC has four main functions, including:

1) Oversight and maintenance of a public database for production cost and related analysis;
2) Develop and implement interconnection-wide expansion planning processes in coordination with the Planning Coordination Committee, other WECC committees, Subregional Planning Groups ("SPGs"), and other stakeholders;
3) Guide and improve the economic analysis and modeling of the Western Interconnection and conduct transmission studies; and
4) Prepare interconnection-wide transmission plans consistent with applicable NERC and WECC reliability standards.

The TEPPC 10-year regional transmission plan is part of a continual biennial planning cycle that relies on a nodal production cost model to evaluate the transmission grid on an economic basis. The current production cost model provides opportunity to focus study results on zonal or balancing authority levels of operation and allows for hourly or even sub-hourly analysis. The production cost simulation is also able to work in conjunction with powerflow models allowing for roundtrip analysis between the modeling software.[76]

The recent TEPPC 2013 ten year regional transmission plan was based on 2022 Common Case Transmission Assumptions ("CCTA") and additional scenarios which included an Arizona Stress

[76] "Roundtrip" will allow production cost model dispatching to be re-integrated into power flow analysis programs.

Test, a Southwest Resource scenario under high WECC loads, and a BLM Outside California Study on renewable energy. The 2022 CCTA assumptions were developed by the regional planning coordination group which includes state and sub-regional representatives such as SWAT. Criteria for determining new transmission lines to incorporate in the CCTA included a determination of whether the transmission line was regionally significant, whether the transmission was currently under construction and was expected to be in-service, and whether there were strong financial indicators that provided enough evidence that the transmission project would be financially sound enough to come to fruition.

At the Eighth BTA Workshop I, WECC provided the results of the recent 2013 WECC Ten Year Regional Transmission Plan and specifically the study scenario affecting Arizona, as outlined below:

1. The Arizona Stress Test evaluated the impacts of planned renewable resources to the state's resource mix. Solar generation made up the bulk of the resource additions with wind and pump storage generation were included in the resource mix as well. The resource additions offset the need for natural gas and combined cycle units which resulted in decreased production costs and carbon emissions throughout the state. The Arizona Stress Test also resulted in increased exports from Arizona to California.
2. The Southwest Resource scenario assumed an increase of 8% in WECC load. It also assumed an increase in renewable generation resources as utilities responded to meet their state-by-state renewable portfolio standards. The Southwest Resource scenario results demonstrated that the production costs would be amongst the lowest in the Western United States ("US") under certain combustion turbine ("CT") technology and cost assumptions.
3. The BLM Outside California Study evaluated the effect of adding additional renewable generation in particular areas outside of California. Four renewable generation projects were evaluated including two sites in Arizona and one site in Nevada, with the bulk of the generation coming from New Mexico. The initial results showed current transmission constraints would prevent available resources from making it to the grid resulting in dumped energy. Further transmission expansion sensitivity studies

incorporated the SunZia double 500 kV transmission line and the Armargosa to Northwest 500 kV transmission line. The addition of these two projects reduced transmission constraints leading to the offset of 1,500 GWh of Nevada and California combined cycle generation, negated all dump energy, and reduced variable productions cost by $80,000,000.

Major observations of the TEPPC ten year plan include:[77]

- Major transmission additions could be needed under futures with substantially greater renewable generation, particularly if development occurs in areas remote from load centers.
- High and low gas prices, high and low hydro conditions, and high loads produced varied impacts on projected transmission usage but did not indicate a strong requirement for major transmission additions.
- High EE and DG increased transmission flows out of the Northwest as low-cost generation is freed up for export to more distant high cost areas such as California.

TEPPC is moving forward on the next WECC ten year regional transmission plan. The 2013/2014 study program will continue to focus on the use and development of unified, foundational datasets and tools. The study program will focus on the transmission impacts of integrating renewable and distributed generation resources, and the retirement of coal-fired base load resources. Additionally, the study program will evaluate the critical relationship between water use and energy production to consider whether there is a breaking point. The 2013/2014 study program will rely on 2024 CCTA, being developed through the same bottom-up activities as regional study groups.

5.5 Renewables Integration and Energy Efficiency Impacts

Most Commission jurisdictional utilities are subject to the Commissions' Renewable Energy Standard ("RES") and Electric Energy Efficiency Standards ("EEES") requirements.[78] In addition, non-jurisdictional utilities, such as SRP, have adopted their own renewable energy and energy

[77] As presented in a 2013 Interconnection-wide transmission plan stakeholder presentation on September 24, 2013
[78] The Arizona Corporation Commission adopted the current RES rules in Decision No. 69127 and the current EEES rules in Decision No. 71819

efficiency goals. Integration of intermittent renewable resources impacts the grid and requires a more responsive and flexible system to meet the ramp rates and variability that is characteristic of intermittent renewable energy resources.

5.5.1 Steps to Integrate Renewables

During Workshop I, the utilities had the opportunity to provide an update on their current efforts to integrate renewable generation into their resource portfolio. Below is a summary of each Arizona utilities' response:

Individual Utility Integration Steps

APS is transitioning towards a resource portfolio that is increasingly flexible and responsive. APS estimates renewable energy will supply 12% of its retail sales by the end of 2015, more than double the RES 2015 target of 5%. [79] Customer resources such as roof-top solar and energy efficiency are projected to triple over the next 15 years. [80] Integration of renewable resources is driving the need to invest in advanced technology and communication and automation improvements to enable the transmission and distribution system to be more flexible and responsive to accommodate the variability of renewable resources. Natural gas generation resources are also becoming the energy source of choice to provide quick-starting, flexible generation at times when renewable generation is unavailable. The OMP, to begin going into service in 2017, was cited as an example of the type of quick-starting generation that is needed to maintain grid reliability and operational flexibility. APS participates in numerous forums to help assist utilities in the transition towards renewable integration.

SRP has set a goal to meet 20% of its retail electricity requirements through sustainable resources, including renewable and energy efficiency resource, by 2020.[81] SRP aims to accomplish this through development of renewable energy, including hydropower, conservation, energy efficiency, and pricing measures. SRP currently exceeds its fiscal year 2013 target of meeting

[79] APS 2014 IRP, pp 41 - http://www.azenergyfuture.com/getmedia/c9c2a022-dae4-4d1b-a433-ec96b2498e02/2014_IntegratedResourcePlan.pdf/?ext=.pdf
[80] APS 2014 IRP - http://www.azenergyfuture.com/getmedia/c9c2a022-dae4-4d1b-a433-ec96b2498e02/2014_IntegratedResourcePlan.pdf/?ext=.pdf
[81] SRP 2013 Annual Report - http://www.srpnet.com/about/financial/pdfx/FY13_SPP_Annual_Report_Final.pdf

10.375%.[82] SRP participates in forums discussing and analyzing the integration of renewable resources into power systems including the WECC Variable Generation Subcommittee ("VGS"), WECC TEPPC, and Electric Power Research Institute ("EPRI") variable integration programs.

TEP is currently in the early stages of evaluating variable energy resources. As of 2013 TEP's renewable energy standard ("RES") resources accounted for 5.6% of their 2014 retail sales.[83] TEP's efforts are focused largely on identifying and modeling utility scale projects and identifying feeders with residential or commercial rooftop solar installations. TEP is working directly with the University of Arizona ("U of A") to develop forecasts for renewable resources with a focus of projecting next hour and 3-day window estimates, incorporating the use of cloud measurement sensors, radar, and mathematical models. TEP's reference base case plan includes over 119 MW of renewable nameplate capacity by 2028. TEP's evaluation will include power flow and transient stability analysis.

SWTC relies on member load forecasts to conduct transmission analysis which would include the effect of energy efficiency and renewable resources. Currently SWTC's members are not reporting any significant variable energy resources connected to the SWTC system.

Southwest Variable Energy Resource Initiative ("SVERI")

In addition to individual utility renewable development, Arizona utilities are examining renewables through the SVERI. SVERI was organized in the fall of 2012 to evaluate likely penetration, location and operation characteristics of variable energy resources within the Southwest over the next 20 years. SVERI participants include Arizona Electric Power Cooperative ("AEPCO"), APS, EPE, Imperial Irrigation District ("IID"), PNM, SRP, TEP and the Western DSW.

SVERI seeks to evaluate and develop tools that may facilitate variable energy resources. One example includes SVERI's partnership with the U of A to collect, display and analyze generator output and real-time load data for all renewable generation from across the Desert Southwest. SVERI aims to quantify the capacity of renewable resources being developed in the Desert

82 http://www.srpnet.com/environment/earthwise/pdfx/ResourceStewardship.pdf
83 TEP 2014 Renewable Energy Standard and Tariff filing, Docket #E-01933A-12-0296 - http://www.azcc.gov/Divisions/Utilities/Electric/REST%20PLANS/2013/2013%20TEP%20REST.pdf

Southwest region over the next 20 years to address operational impacts for balancing authorities and to determine if and when the integration of variable resources will become problematic for the region. Analysis is still in the early stages of development but no current problems with integration have been identified.[84]

SVERI participants are different than other western US utilities in that they do not face the sheer volume of variable energy resources ("VERs") in California, the interplay between hydropower and wind in the Pacific Northwest, or the wind project development in Wyoming and Colorado.[85]

Renewable Transmission Plans ("RTPs")

In the Fifth BTA the Commission ordered the Arizona utilities to provide their top three RTPs. Progress towards the development of the RTPs is summarized in Table 16 below:

Project Name	APS	SRP	TEP	SWTC	Current Status
Palo Verde-North Gila 500kV	X				Under construction for in-service in 2015
Palo Verde-Liberty & Gila Bend-Liberty 500kV	X				Project need being monitored
Delany – Colorado River (Blythe) 500kV	X				Development being pursued
Delaney-Palo Verde 500KV	X				Under development for in-service in 2016, SRP no longer participating
Pinal West - Pinal Central 500kV		X			Under construction for in-service in 2014
Palo Verde-Pinal West-Pinal Central			X		Under construction for in-service in 2014
Pinal Central -Tortolita 500kV			X		Under development for in-service in 2016, SRP no longer participating
Western Apache – Tortolita 115kV-230 kV upgrade			X		Project need being monitored
San Manuel Interconnect Project				X	Project need being monitored
Apache - Bicknell 230kV line Upgrade				X	Line re-rated; upgrade need moved outside of ten year plan
Western Saguaro – Apache 115kV Line Upgrade				X	No longer being pursued; instead working with Western on Southline rebuild to 230 kV

Table 16 - Summary of RTP Development Status

Based upon the information reviewed, Staff and KRSA conclude the Arizona utilities are taking sufficient action with respect to transmission planning impacts related to the integration of renewable generation resources.

84 http://www.westgov.org/PUCeim/meetings/2013sprg/briefing/present/e_beck.pdf
85 SVERI Activity Summary, January 24, 2014 Presentation by Dave Slick, Salt River Project

5.5.2 Effect of EE/DG

A Commission requirement and question at Workshop I was to describe the impact of EE/DG on transmission adequacy.[86] Below is a summary of each Arizona utilities' response:

Presently, APS does not have any transmission projects that have been eliminated or delayed due to energy efficiency or distributed generation. APS filed in this docket their 2013 Updated Solar Photovoltaic ("PV") Value Report performed by SAIC. The findings of the report found that solar PV penetration may delay transmission projects for a maximum of one year under the Expected Penetration Case and up to two years under a High Penetration Scenario. However, a previous study noted that variable solar generation may adversely impact transient stability and spinning reserve requirements of the transmission system requiring grid improvements.[87]

SRP presently does not foresee any transmission related issues and has not delayed any projects as a result of increased EE/DG. While most of SRP's transmission projects identified within its plan are driven by specific large customer requests, SRP did perform a thermal analysis on the remaining two projects and found that DG and EE had no impact on the need date for those projects.

Analysis performed by TEP concluded that distributed generation or energy efficiency programs do not substantially delay any transmission or distribution projects being planned. Some load reductions attributed to EE/DG programs have allowed TEP to delay re-conductor projects, capacitor bank improvements, and line up-rates. However, TEP has not addressed the possibility of needing additional generation and distribution improvements that may be needed due to the variability of distributed generation. TEP's transmission planning includes screening for the impacts of EE/DG in their load forecasts.

SWTC has not quantified the effect of EE/DG as it relies on demand forecasts provided by its member utilities.

Staff concludes that while the utilities have included the effect of DG and EE standards, the impact of these standards on specific transmission needs has not been specifically identified. This is

[86] Decision No. 72031
[87] APS SAIC REPORT 2014

information that would benefit Staff and the Commission and should be provided by the utilities for the Ninth BTA.

5.6 Coal Reduction Assessment

At Workshop I, TEP and SWAT made a joint presentation on the status of the CRATF investigation into coal plant shutdowns. The investigation arose as a response to the EPA's proposed rulemaking on emissions from existing coal power plants, which was subsequently issued in June 2014.[88] Prior to release of the proposed rule, the EPA solicited feedback from WestConnect on their proposed guidelines from the perspective of transmission planning. This will assist the EPA in finalizing its guidelines, which are expected to be issued in June 2015, after a public comment period. States will then individually determine how to achieve the emission guidelines and will be required to submit plans describing how they will meet the guidelines as early as June 2016.

5.6.1 Background

The initial response to the EPA request for feedback was provided by the WestConnect PMC. The comments made by the PMC included the suggestions that the EPA consider the differences between the transmission planning timeframe and the timeframe of when regulations become effective, and that uncertainty about regulations adds a large degree of uncertainty to the transmission planning process. Furthermore, the impact of regulations should be considered not only in the context of the planning horizon but also the operating horizon. In addition, the PMC indicated that it was not aware of any regional studies currently underway which were evaluating the short-term impact of significant plant shutdowns as a consequence of emission guidelines. Additional feedback included the recommendations that the EPA meet with other federal agencies to gain an understanding of the timelines involved in the permitting of new transmission projects, and to consider how the EPA regions align with transmission planning regions. The PMC also emphasized that coordination between transmission planning regions and the states was necessary, and that states should be given as much flexibility as possible. The PMC stressed that grid reliability needs to be an important consideration in states' implementation plans.

---

[88] EPA Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units - http://www2.epa.gov/sites/production/files/2014-05/documents/20140602proposal-cleanpowerplan.pdf

The PMC took the technical study work to SWAT and SWAT's analysis of the impacts of coal retirement began with the identification of the amount of affected capacity. Within the SWAT footprint, this is estimated that approximately 25% of the 10 GW total installed coal capacity could be retired by 2019. This is in addition to San Onofre Nuclear Generating Station ("SONGS") and pending once-through cooling retirements in California. Further, based on publicly available information, of the total existing coal capacity of almost 11,000 MW, between 2,667 and 5,829 MW could potentially cease operation by 2019. SWAT determined technical study work would be required to examine potential transmission system impacts due to possible dynamic stability issues and path rating reductions as a result of projected retirements.

5.6.2 Technical Study Work

The CRATF has held eight conference calls and has developed a Phase 1 objective, study plan and assumptions. The objective of Phase 1 is to determine if reliability issues occur due to the loss of inertia associated with anticipated shutdowns and/or reduction in coal plant output. The key assumptions of this initial study work are that specific units will be modeled out of service to accurately simulate plant shutdowns in accordance with currently expected retirements, and specific generating units or locations to displace these retired units will be identified. Accordingly, the power flow model selected as the baseline is the 2019 peak load, Arizona coordinated base case, with renewable resources mapped to power flow buses consistent with the TEPPC case.

Various scenarios and sensitivity cases were studied, including a scenario where 5 GW of SWAT-footprint coal retirements were replaced with only renewable resources, existing uncommitted capacity and decreased power scheduled to California. This stressed scenario indicates that transient instability occurs under a severe contingency condition. However, the instability does not appear if approximately 25 percent of the retired coal-fired generating capacity is replaced by new natural gas-fired generation and the balance is replaced by renewable resources and existing uncommitted capacity. This improvement is likely due to the gas generation's contribution to lost inertia and dynamic reactive capability associated with the reduction in coal plant capacity.

At this point, the study's conclusions include:

- There is a limit to the number of coal-fired power plants that can be shut down without compromising system reliability.
- This limit is influenced by the availability of gas-fired replacement capacity.
- The amount of renewable resources that may be integrated is dependent upon the addition of gas-fired generation or resources that compensate for loss of inertia and dynamic reactive capability.

Future studies will be necessary to determine more specific inertial and dynamic reactive capability requirements after final decisions related to state and regional resource mix goals have been made.

The next steps for CRATF will be to review and comment on the initial study results, with modifications and re-runs as required and specified contingency and stability analysis on the base case with pre-coal reduction dispatch to establish the benchmark against the Baseline Scenario. Following that, CRATF will develop a study plan and scope for additional Phase 1 scenario analysis and develop the study plan and scope for Phase 2 Path Rating impacts analysis.

5.6.3 Coordination

CRATF has reached out to other groups within WestConnect and the CAISO; specific utilities have also expressed interest in participating in the process. CRATF has also made overtures in recent regional planning coordination meetings and technical sessions to solicit interest and feedback from entities across the west. CRATF believes the issue goes beyond the Arizona footprint and therefore proposed to coordinate with other regional groups who were conducting their own studies on coal reduction, such as TEPPC, which will be studying two coal retirement cases, and NREL's Western Wind and Solar Integration Study ("WWSIS").

The SWAT study was discussed at the WestConnect Planning Management Committee. A proposal to use a coal reduction scenario to establish regional transmission needs that may be evaluated through the WestConnect FERC Order 1000 regional planning process is under consideration.

Presentations of the SWAT coal reduction study were given to the WECC Transmission Expansion Planning Policy Committee in April 2014 and August 2014. In addition, Arizona transmission owners have initiated a similar analysis, assuming 2020 system conditions, on a broader western footprint through the WECC Planning Coordinating Committee. Coordination of these efforts will help ensure consistency in the studies while examining the coal reduction impacts from the local, sub-regional, regional, interregional and Western Interconnection perspectives. Timeframes for the studies range from 2020 (in accordance with the Environmental Protection Agency ("EPA") Clean Power Plan) to the 10-year planning horizon. The intention is to obtain information from the 2020 studies to inform comments to the EPA by October of this year. The longer term studies will take longer to complete.

Staff and KRSA feel the work the CRATF is investigating is critical to transmission system reliability. This is an issue that the Commission and Staff should follow closely and on which the utilities should report their findings to the Commission.

5.7 Seams Issues

Seams issues include differences in the electric energy market models, scheduling and congestion management protocols, planning, licensing, ownership and operational control of transmission facilities that cross state boundaries. Increased regional and interregional coordination has been conducted as a result of FERC Order No. 1000 transmission planning requirements and WECC Transmission Expansion Planning. Seams transmission paths affecting Arizona are illustrated in Exhibit 7. Presently, the primary seams issue in Arizona lies between Arizona and California across Path 49 which was highlighted during the September 8, 2011 outage.

5.7.1 September 8th Outage

On September 8, 2011 ("September 8th outage"), customers in Baja California, Mexico; southern California's Imperial, Orange, and San Diego counties, and a small portion of southwestern Arizona experienced a major power outage. The September 8th outage prompted a response by NERC pushing for increased cooperation and contingency planning across WECC. As a result, the WECC Reliability Coordinator ("RC") has developed monitoring procedures and established a website that provides a status of WECC' s [Peak Reliability] compliance to NERC's Key Categories of Findings and Recommendations.[89]

Arizona Utilities were asked to discuss during Workshop I their efforts as a result of the September 8th outage. In general, Arizona Utilities are working directly through WECC processes to increase coordination and operational awareness of neighboring systems. The WECC process is driving improvements in system adequacy planning and evaluation of WECC system operating limit requirements.

More specifically, APS indicated that as a result of the September 8th outage, it has increased situational awareness, cooperation, and coordination with neighboring utilities. Additionally, APS indicated it is developing a wider view of the system including monitoring neighboring systems for effects of outages on APS and determining the effects of APS system outages on neighboring systems.

Through their participation in WECC activities, SRP is incorporating additional detail to ensure the system is being modeled appropriately sharing relay trip settings with other WECC members, and has expanded planning cases to cover critical system conditions across the planning horizon. Relative to the September 8th outage, SRP has implemented, or is in the process of implementing, all recommendations resulting from the FERC/NERC investigation of the event.

TEP reported their response to the September 8th outage includes the addition of next-day studies, bi-weekly outage coordination calls and coordinated seasonal studies. TEP has increased their staff to accommodate the increased operational planning requirements.

SWTC continues to participate through WECC and conducts transmission planning in accordance to the NERC Planning Standards and the WECC System Performance Criteria. SWTC has reviewed WECC's recommendations that have stemmed from the September 8th outage and incorporated those that apply to their system planning and operations.

Staff and KRSA have carefully examined the utilities' actions resulting from the September 8th outage. As can be seen from the discussion above and from a detailed review of the FERC/NERC report on the outage and the WECC September 8 Event Recommendation Dashboard,[90] most of

[89] http://www.wecc.biz/About/sept8/Pages/default.aspx
[90] http://www.wecc.biz/About/sept8/Pages/default.aspx

the areas of concern are operational and operation planning in nature and do not directly impact long term transmission planning.

Staff and KRSA have carefully examined the utilities' transmission planning actions resulting from the September 8, 2011 outage and conclude the utilities are addressing the concerns raised by FERC/NERC, which should help prevent similar future outages. In addition to the steps laid out by the Arizona utilities, the planned development of the Hassayampa to North Gila #2 will help strengthen the Arizona – California transmission path.

6 Conclusions

This Eighth BTA assesses the adequacy of Arizona's transmission system to reliably meet the existing and planned energy needs of the state by addressing four fundamental public policy questions during the course of this BTA:[91]

1. Adequacy of the existing and planned transmission system to reliably serve local load - Does the existing and planned transmission system meet the load serving needs of the state during the 2014-2023 timeframe in a reliable manner?

2. Efficacy of the Commission-ordered studies - Do the SIL, MLSC, RMR [92], Ten Year Snapshot, and Extreme Contingency studies filed as part of the Eighth BTA comply with, and sufficiently meet, the intended goals of the Commission's orders?
3. Adequacy of the system to reliably support the wholesale market - Did 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?
4. Suitability of the transmission planning processes utilized - Did 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 and WECC?

6.1 Adequacy of the Existing and Planned Transmission System to Reliably Serve Local Load

The adequacy of the transmission system to reliably serve load is central to the BTA. Based upon the technical study work examined by Staff and KRSA, the existing and proposed transmission system meets the load serving requirements of Arizona in a reliable manner for the 2014-2023 timeframe.

---

91 This BTA does not establish Commission policy and is not final unless and until approved by a written decision of the Commission.
92 RMR Studies were not required for the Eight BTA based upon criteria set by the Commission in the 7th BTA

1. The aggregate of the filed ten year plans is a comprehensive summary of filed ten year transmission expansion plans from a holistic perspective. The Arizona Plan includes eighteen filing entities and consists of sixty transmission projects of approximately 907 miles in length. An additional twenty six projects are beyond the ten year horizon or have in-service dates that are yet to be determined and account for an additional 766 miles of new transmission.
2. The 2014 level of summer preparedness of the utilities in Arizona has been assessed and is sufficient. The current electric utility system in Arizona is judged to be adequate to reliably meet the energy needs of the state in 2014.
3. The statewide demand forecast has shifted downward by approximately one year since the Seventh BTA. Over the past three BTAs load forecasts have changed substantially along with the associated transmission projects. In order to provide the Commission with additional information on the impact on load forecasts on transmission projects, Staff concludes that for reliability or load growth driven transmission projects a system load level range at which a transmission project is needed should be reported along with the projected in-service year beginning with ten year transmission plans filed in January 2016.
    a. The utilities indicated that DG and EE were taken into account in demand forecasts, and that the main factor behind the drop in the forecast from 2012 to 2014 is the impact of the continuing economic recession.
    b. The overall Arizona load growth rate has remained relatively constant at between 1% and 2% per year.
4. The SIL and MLSC, measures of the transmission system ability to serve load reliably in load pockets, are adequate to meet ten year local load forecasts.
    a. Santa Cruz County load forecast of 81 MW is less than the load serving capability of 159 MW.
    b. The CCSG participants monitored the reliability in Cochise County, but did not offer any new future ten year plans. The Load Serving Entities ("LSE") in Cochise County continue to monitor the reliability in Cochise County and will propose any modifications that they deem to be appropriate in future ten year plans. Pinal County analysis has been incorporated into the SWAT-AZ Ten Year Snapshot Study. The Ten Year Snapshot Study did not identify specific concerns in Pinal County.

5. Staff and KRSA have carefully examined the utilities' transmission planning actions resulting from the September 8, 2011 outage and conclude the utilities are addressing the concerns raised by the FERC and NERC, which should help prevent similar future outages.
   a. Arizona utilities are working directly through WECC processes to increase coordination and operational awareness of neighboring systems. The WECC process is driving improvements in system adequacy planning and evaluation of WECC system operating limit requirements.
   b. Arizona utilities are taking steps to increase situational awareness, cooperation, and coordination with neighboring utilities. Specific improvements include developing a wider view of the system; providing additional detail to ensure the system is being modeled appropriately; the addition of next-day studies, bi-weekly outage coordination calls, coordinated seasonal studies; and increasing their staff to accommodate the increased operational planning requirements.
6. Each Arizona utility provided information and details on their plans to ensure physical security and resiliency of the Arizona electric system. Staff and KRSA conclude the Arizona utilities are taking actions to address the physical security risks to reasonably ensure the reliable operation of the Arizona transmission system.
7. Staff concludes that while the utilities have included the effect of DG and EE standards, the impact of these standards and related uncertainty on specific transmission needs has not been specifically identified. This is information that would benefit Staff and the Commission and should be provided by the utilities for the Ninth BTA.
8. Utilities, through the SWAT subregional planning group and its CRATF,[93] have begun to examine the potential impact on bulk electric system stability of actual and proposed coal plant retirements and their associated inertia coupled with increased use of solar photovoltaic and wind generation, which do not currently provide inertia benefits. This is an issue that the Commission and Staff should follow closely and on which the utilities should report their findings to the Commission as directed in the Recommendations section below.

[93] This study was initiated by the SWAT stakeholders to determine if the know and projected retirement of coal generation and the increase in solar photovoltaic and wind generation in the next five years may cause system stability issues.

6.2 Efficacy of Commission-Ordered Studies

The Commission has ordered the following studies to be performed as part of the BTA: SIL, MLSC, RMR, Ten Year Snapshot, and Extreme Contingency Analysis. The principal purpose of the Commission-ordered studies is to assure the certainty of the conclusions and recommendations within the BTA. Each Commission-ordered study required for the Eighth BTA is filed with the Commission. Staff and KRSA conclude the Commission-ordered studies demonstrate that the Arizona transmission system is reasonably prepared to reliably serve local load in the ten year timeframe.

1. As indicated previously, the SIL and MLSC are adequate to meet ten year local load forecasts.
2. In the Seventh BTA, Staff suspended the RMR studies and implemented requirement criteria for restarting such studies on a biennial review of specific triggering factors. None of the triggering factors occurred for the Eighth BTA which would require RMR study work in any of the RMR areas.
3. The Ten Year Snapshot study indicates Arizona's transmission plan is robust and supports the statewide load forecast through 2023. However, to address any potential low voltage issues, the future the Ten Year Snapshot study should monitor system elements down to and including the 115kV level.
    a. There were no overloaded transmission system elements or voltage violations in the 2023 normal operating base case. Single contingency outage analysis on the base case showed a single overloaded element that will need further investigation by the utilities in future studies.
    b. Delay of the Pinal Central-Tortolita 500 kV or SunZia Project beyond 2023 in all likelihood will have significant negative impact on system performance.
    c. Delaying any one of the other projects (not Pinal Central-Tortolita 500 kV or SunZia Project) beyond 2023 shows minimal impact on system performance.
4. The Extreme Contingency study satisfies the Commission's requirement to address and document extreme contingency outage studies for Arizona's major generation hubs and major transmission stations.

   a. APS's extreme contingency analyses indicate all load and local Phoenix reserve requirements can be met. These APS results are for both the 2014 and 2023 system conditions.
   b. TEP's extreme contingency analysis indicates TEP can withstand each extreme contingency outage. Study results show that TEP can withstand these extreme contingencies under the 2014 and 2023 system conditions.

6.3 Adequacy of System to Reliably Support Wholesale Market

Regional and sub-regional planning studies have effectively addressed the interconnected EHV transmission that is critical to a functional interstate wholesale market. Based upon the technical study work filed with the Commission and industry presentations, the existing and planned Arizona EHV system is adequate to support a robust wholesale market.

1. Seven major EHV transmission projects are proposed and have been addressed in this BTA. Individually and collectively these projects will improve the opportunity for interstate commerce.
   a. The 500 kV DC TransWest Express Project and High Plains Express Project conceptually interconnect the Desert Southwest with Wyoming.
   b. The SunZia 500 kV Project and Southline Transmission project will provide additional transmission capacity between Arizona and New Mexico.
   c. The planned Delaney – Colorado River 500 kV project, conceptual North Gila – Imperial Valley #2 500 kV project and the planned Hassayampa to North Gila No. 2 500 kV project also provide additional transmission capacity between Arizona and California.
   d. Western's TIP is involved in a number of the interstate transmission projects that will have a significant impact on Arizona's transmission system in the ten year time frame.
2. Staff and KRSA conclude the Arizona utilities are taking sufficient action with respect to transmission planning impacts related to the integration of renewable generation resources.
   a. Arizona utilities are on pace to meet renewable portfolio goals.
   b. Arizona utilities developed and participate in SVERI. SVERI evaluates likely penetration, locations and operation characteristics of variable energy resources within the Southwest over the next 20 years.

3. The Fifth BTA ordered the utilities to provide their top three RTPs. The Arizona utility RTPs are progressing with five of the RTPs planned to be in-service by 2016, one RTP being actively pursued for development and three RTPs are being monitored for development as reliability and resource needs arise. Additionally, one RTP is no longer being pursued, but is instead being worked on jointly as part of the Southline Project. Finally, one RTP has moved outside of the ten year plan window because the line was successfully re-rated without new transmission development.
4. FERC Order No. 1000 requires FERC jurisdictional transmission providers and encourages non-jurisdictional transmission providers to work collaboratively with stakeholders on a regional and interregional basis to improve regional transmission planning processes and cost allocation mechanisms in a cost-effective manner. All Arizona FERC jurisdictional transmission providers have made their compliance filings with the FERC to implement Order 1000 through the WestConnect Regional Transmission Planning process and are awaiting a FERC order to move forward with implementation. Staff has been an active stakeholder participant in the development of the recommended WestConnect Order No. 1000 transmission planning processes, and believes the results of the WestConnect regional transmission planning will be supportive, once available, in assessing transmission adequacy for the state in future BTAs.

6.4 Suitability of Utilized Planning Processes

Based upon information provided by the utilities, the Arizona utilities utilize significant and well defined transmission planning processes.

1. The results of NERC/WECC reliability standard audits over the past two years, as provided by the utilities in the Eighth BTA proceeding, indicate there were no concerns of Arizona's bulk electric system failing to comply with the applicable planning standards established by NERC/WECC.
    a. APS and SRP had audits performed in 2013 which received a report of "no findings".
    b. TEP reported the next scheduled audit is in August 2014.
    c. SWTC reported the next scheduled audit is in January 2015.
2. Technical studies filed in the Eighth BTA indicate a robust study process for assessing transmission system performance for the 2014-2023 planning period.

  a. Transmission planning criteria and methodologies provided to the Commission meet or exceed industry accepted performance standards.
  b. When reliability concerns were identified in the utility study work, effective mitigations were developed to address these concerns.

3. Utilities communicate their transmission plans in robust local, state, subregional and regional, open and transparent transmission planning forums using public processes.
  a. Arizona utilities hold semi-annual FERC Order 890 stakeholder meetings to discuss their current transmission plans, provide an opportunity for stakeholder input and alternatives and to provide updates on their transmission projects.
  b. Arizona utilities actively participate in SWAT to discuss transmission plans in a subregional transmission planning forum. The SWAT meetings include discussions on utility transmission plans and are open to stakeholder participation and input. Arizona utilities also actively participate and often take leadership positions in SWAT subgroups and task forces designed to address specific, localized transmission concerns.
  c. Arizona utilities actively participate in and are members of the WestConnect PMC, a regional transmission planning group.
  d. Arizona utilities actively participate in WECC TEPPC to examine long-term, public transmission expansion planning. Major EHV Arizona transmission plans are incorporated into the TEPPC transmission planning processes to facilitate and coordinate interconnection-wide, 10 and 20 year expansion studies.

[This page intentionally left blank for formatting purposes]

7 Recommendations

Based upon the conclusions, Staff offers the following recommendations for Commission consideration and action:

3. Staff recommends that the Commission support:
    a. The use of the "Guiding Principles for ACC Staff Determination of Electric System Adequacy and Reliability", as revised in this Eighth BTA.
    b. The use of collaborative transmission planning processes such as those that currently exist in Arizona, which help to facilitate competitive wholesale markets and broad stakeholder participation in grid expansion plans.
    c. The continued suspension of the requirement for performing RMR studies in every BTA and use of criteria for restarting such studies based on a biennial review of factors as outlined in the Seventh BTA.
    d. The policy that Arizona utilities advise each interconnection applicant, at the time the applicant files for interconnection, of the need to contact the Commission for appropriate ACC filing requirements related to the Power Plant and Transmission Line Siting Committee.
    e. The continued requirement for Arizona utilities to report relevant findings in future BTAs regarding compliance with transmission planning standards from NERC/WECC reliability audits that have been finalized and filed with FERC.
    f. The policy that the LSE in Cochise and Santa Cruz Counties continue to monitor the reliability in Cochise and Santa Cruz Counties, respectively, and propose any modifications that they deem to be appropriate in future Ten Year Plans. Staff also recommends that the Commission continue to collect applicable outage data from the respective utilities in order to monitor any changes in Cochise County and Santa Cruz County system reliability in future BTA proceedings.
    g. The requirements for Arizona utilities to include planned transmission reconductor projects, transformer capacity upgrade projects, and reactive power compensation facility additions at 115 kV and above in future ten year plan filings.

h. The acceptance of the results of the following Commission-ordered studies provided as part of the Eighth BTA filings:
   i. The SIL and MLSC are adequate to meet ten year local load forecasts.
   ii. The RMR studies were not required because none of the triggering factors occurred for the Eighth BTA that would require RMR study work in any of the RMR areas.
   iii. The Extreme Contingency analysis for Arizona's major transmission corridors and substations, and the associated risks and consequences of such overlapping contingencies.
   iv. Ten Year Snapshot study results documenting the performance of Arizona's statewide transmission system in 2023 for a comprehensive set of n-1 contingencies, each tested with the absence of different major planned transmission projects.

4. Staff recommends that the Commission order the following actions to resolve concerns arising from the Eighth BTA:
   a. Direct Arizona utilities to ensure the Commission-ordered Ten Year Snapshot study monitors transmission elements down to and including the 115 kV level for thermal loading and voltage violations.
   b. Direct Arizona utilities to describe the driving factor(s) for each transmission project in the Ten Year Plan. For each load growth or reliability driven transmission project, direct Arizona utilities to report, in addition to each transmission project in-service date, a system load level range at which each transmission project is anticipated to be needed. This requirement should first occur with the ten year plans filed in January 2016.
   c. Direct TEP to file the SWAT CRATF[94] study report on behalf of the Arizona utilities within 30 days of completion.
      i. If the CRATF study does not include specific recommendations on maintaining Arizona transmission system reliability, Staff recommends the Commission direct

[94] This study was initiated by the SWAT stakeholders to determine if the known and projected retirement of coal generation and the increase in solar photovoltaic and wind generation in the next five years may cause system stability issues.

Arizona utilities to jointly produce or procure an informational report to identify minimum transmission requirements to maintain adequate system reliability in a fifth year coal reduction scenario. Specific recommendations should include, but not be limited to, the definition of the Arizona system boundary, fifth year baseline Arizona system inertia, and identification of a range of minimum and recommended Arizona system inertia to maintain Arizona transmission system reliability under various system conditions.

ii. Staff provides the following guidelines to the Arizona utilities for the Arizona system boundary definition.

(1) Transmission lines or generation station assets located wholly or partially located in Arizona;

(2) Transmission lines or generation station assets owned wholly or partially owned by Arizona utilities;

(3) Generating station assets located outside of Arizona, but connected to a transmission line that meets requirements in 2.c.ii.(1) or 2.c.ii.(2).

d. Direct Arizona utilities with retail load to report, as part of the Ninth BTA, the effects of DG and EE installations and/or programs on future transmission needs. Staff recommends the Commission direct utilities to conduct or procure a study to more directly identify the effects of DG and EE installations and/or programs.

i. The technical study should be performed on the fifth year transmission plan by disaggregating the utilities' load forecasts from effects of DG and EE and performing contingency analysis with and without the disaggregate DG and EE. The technical study should at a minimum discuss DG and EE forecasting methodologies and transmission loading impacts. The study should monitor transmission down to and including the 115 kV level.

ii. Alternative methodologies or study approaches will be acceptable on condition that the study results satisfy the minimum requirements as outlined in 2.d.i.

iii. The study should be filed at the Commission in January 2016 in the Ninth BTA docket.

iv. This study is supplemental to the previous Commission Decision No. 72031 requiring Arizona utilities to address the effects of DG and EE on future transmission needs in their ten year plan filings.

Decision No. 74785

Eighth Biennial Transmission Assessment 2014-2023

Table of Exhibits[1]

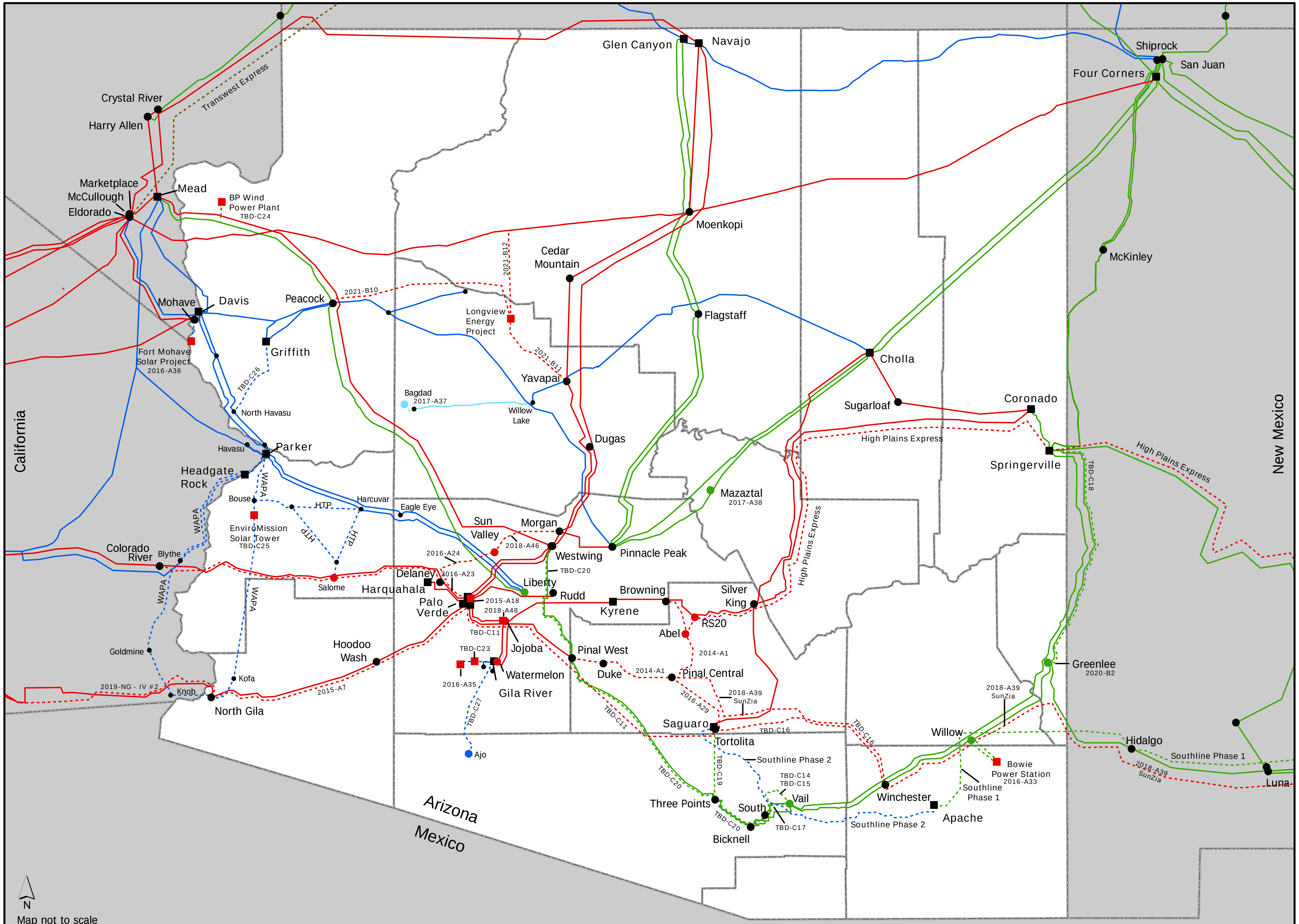
[1] Projects with identifiers that begin with the letter “A” are slated for development in 2014-2018; “B” are slated for developed in 2019-2023; “C” are slated for post-2023 or TBD.

Decision No. 74785

[This page intentionally blank for formatting purposes]

Existing and Planned Arizona EHV Transmission Map

Exhibit 1



Facilities

- Planned Power Plant
- Existing Power Plant
- Existing Substation

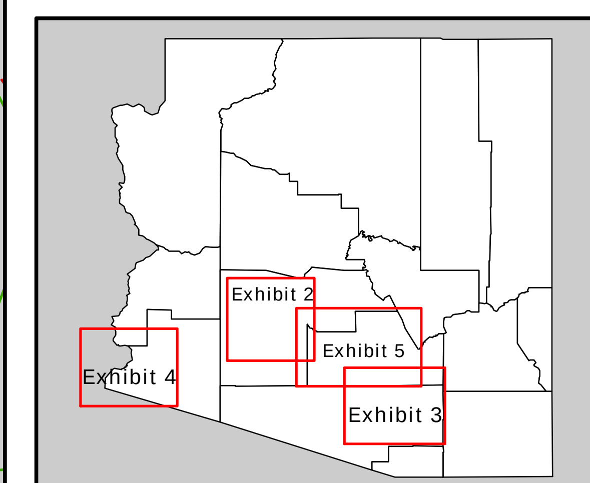
Planned/Upgraded Substations

- 500kV
- 345kV
- 115kV
- 230kV

Transmission

Planned	Existing
500kV DC	500kV AC
500kV AC	345kV AC
345kV AC	230kV AC
230kV AC	115kV AC
115kV AC	

Project Look-up ID Format [In Service Year- Table ID]
2017-A42 = In-Service in 2017, Look-up Table ID A42
TBD-C13 = In-Serivce "To-Be-Determined", Look-up Table ID C13



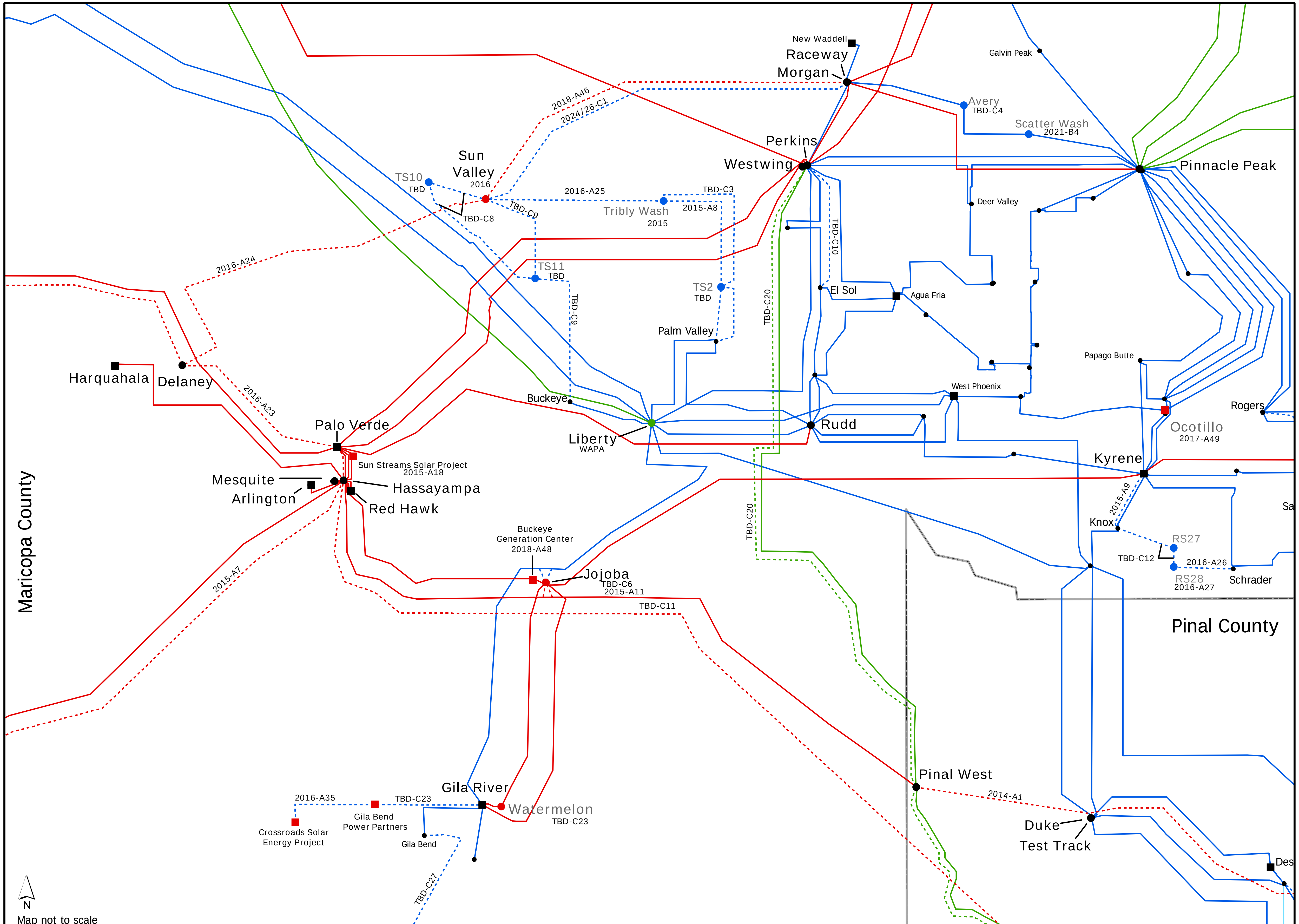
Notes
----
1. Only pertinent transmission voltage levels shown
2. Project identification refers to details on Project Lookup table
3. Routes locations of transmission lines are conceptual only

ACC Docket E-00000D-13-0002
8th Biennial Transmission Assessment

[This page intentionally blank for formatting purposes]

Phoenix Metro Transmission System Map

Exhibit 2



Facilities

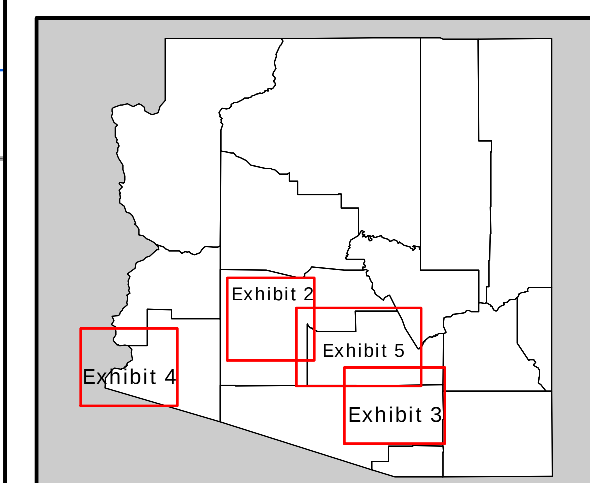
- Existing Power Plant
- Planned Power Plant
- Existing Substation

Planned/Upgraded Substations

- 500 kV
- 345 kV
- 230 kV
- 161 kV
- 138 kV
- 115 kV

Existing	Planned
500kV AC	500kV DC
345kV AC	500kV AC
230kV AC	345kV AC
161kV AC	230kV AC
138kV AC	138kV AC
115kV AC	115kV AC
69kV AC	

Project Look-up ID Format [In Service Year- Table ID]
2017-A42 = In-Service in 2017, Look-up Table ID A42
TBD-C13 = In-Serivce "To-Be-Determined", Look-up Table ID C13



Notes

1. Only pertinent transmission voltage levels shown
2. Project identification refers to details on Project Lookup table
3. Routes locations of transmission lines are conceptual only

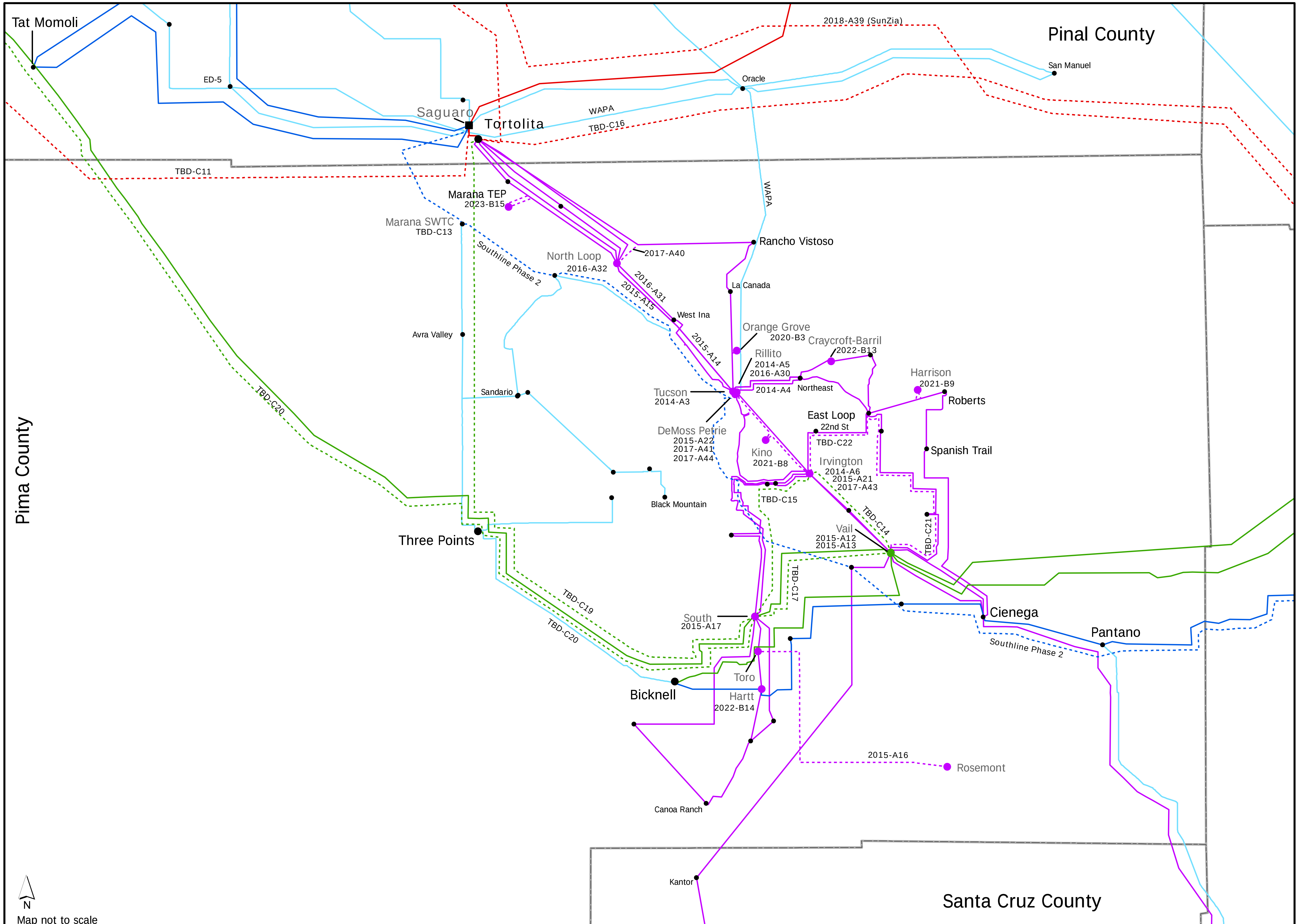
ACC Docket E-00000D-13-0002
8th Biennial Transmission Assessment

DISCLAIMER:
K.R. Saline & Associates P.L.C.
Does not warrant the accuracy or
location of the facilities shown

[This page intentionally blank for formatting purposes]

Southeastern Transmission System Map

Exhibit 3



Facilities

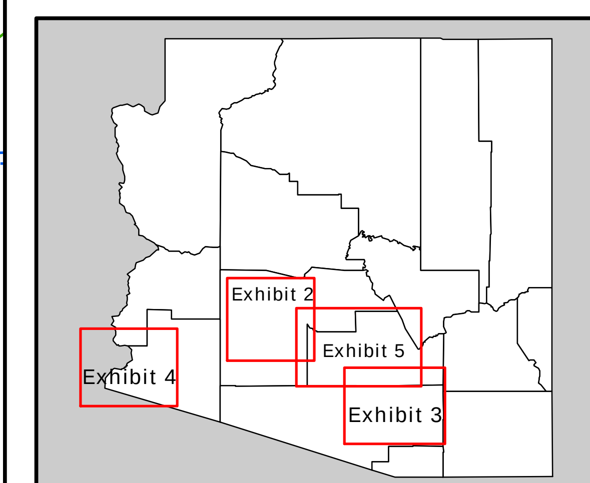
- Existing Power Plant
- Planned Power Plant
- Existing Substation

Planned/Upgraded Substations

- 500 kV
- 345 kV
- 230 kV
- 161 kV
- 138 kV
- 115 kV

Existing	**Planned**
500kV AC	500kV DC
345kV AC	500kV AC
230kV AC	345kV AC
161kV AC	230kV AC
138kV AC	138kV AC
115kV AC	115kV AC
69kV AC	

Project Look-up ID Format [In Service Year- Table ID]
2017-A42 = In-Service in 2017, Look-up Table ID A42
TBD-C13 = In-Serivce "To-Be-Determined", Look-up Table ID C13



Notes

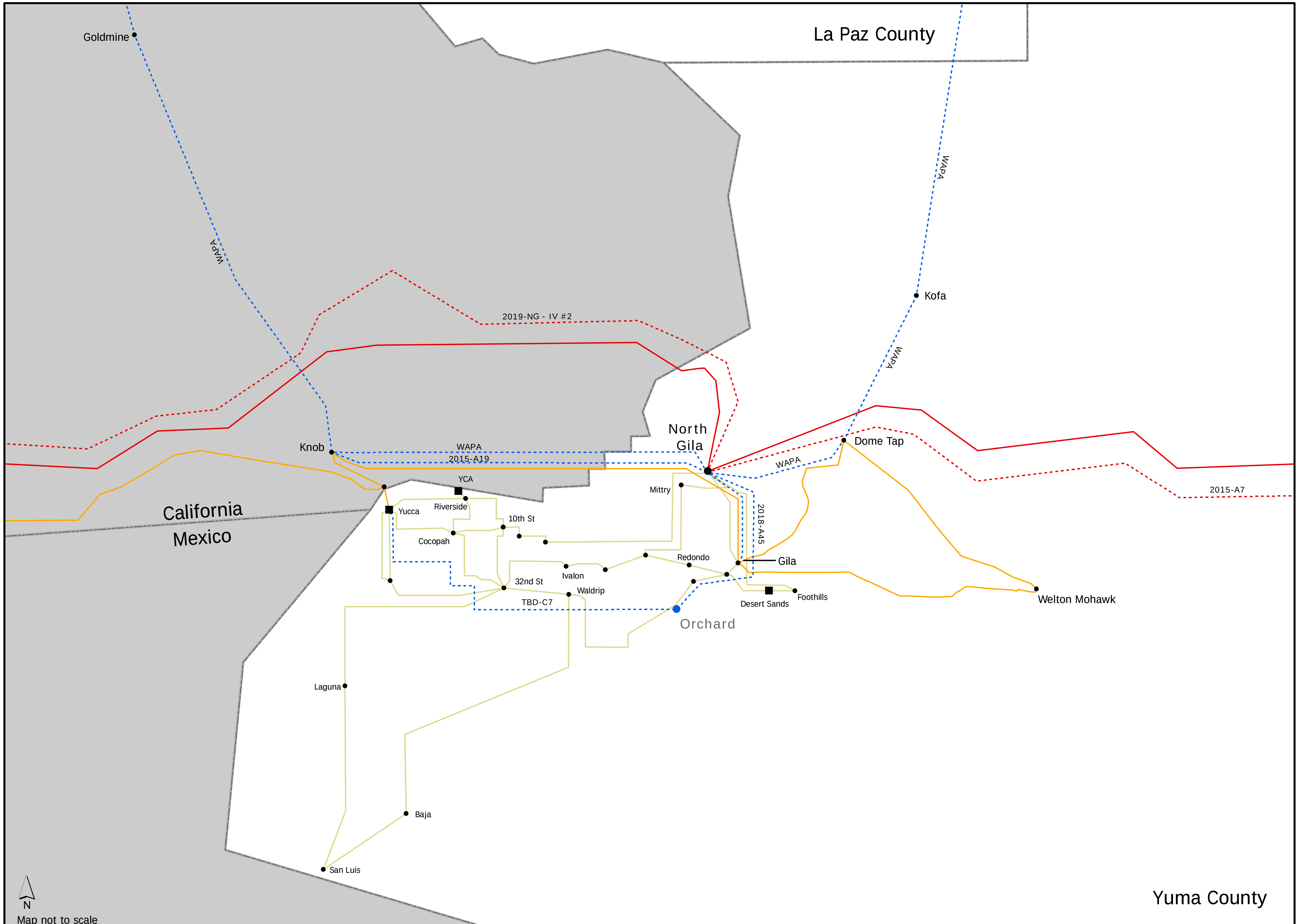
1. Only pertinent transmission voltage levels shown
2. Project identification refers to details on Project Lookup table
3. Routes locations of transmission lines are conceptual only

ACC Docket E-00000D-13-0002
8th Bienniel Transmission Assessment

[This page intentionally blank for formatting purposes]

Yuma Transmission System Map

Exhibit 4



Facilities

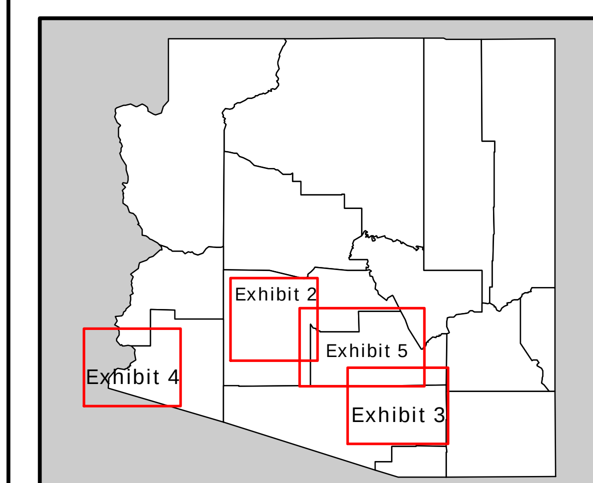
- ■ Existing Power Plant
- ■ Planned Power Plant
- ● Existing Substation

Planned/Upgraded Substations

- ● 500 kV
- ● 345 kV
- ● 230 kV
- ● 161 kV
- ● 138 kV
- ● 115 kV

Existing	Planned
500kV AC	500kV DC
345kV AC	500kV AC
230kV AC	345kV AC
161kV AC	230kV AC
138kV AC	138kV AC
115kV AC	115kV AC
69kV AC	

Project Look-up ID Format [In Service Year- Table ID]
2017-A42 = In-Service in 2017, Look-up Table ID A42
TBD-C13 = In-Serivce "To-Be-Determined", Look-up Table ID C13



Notes

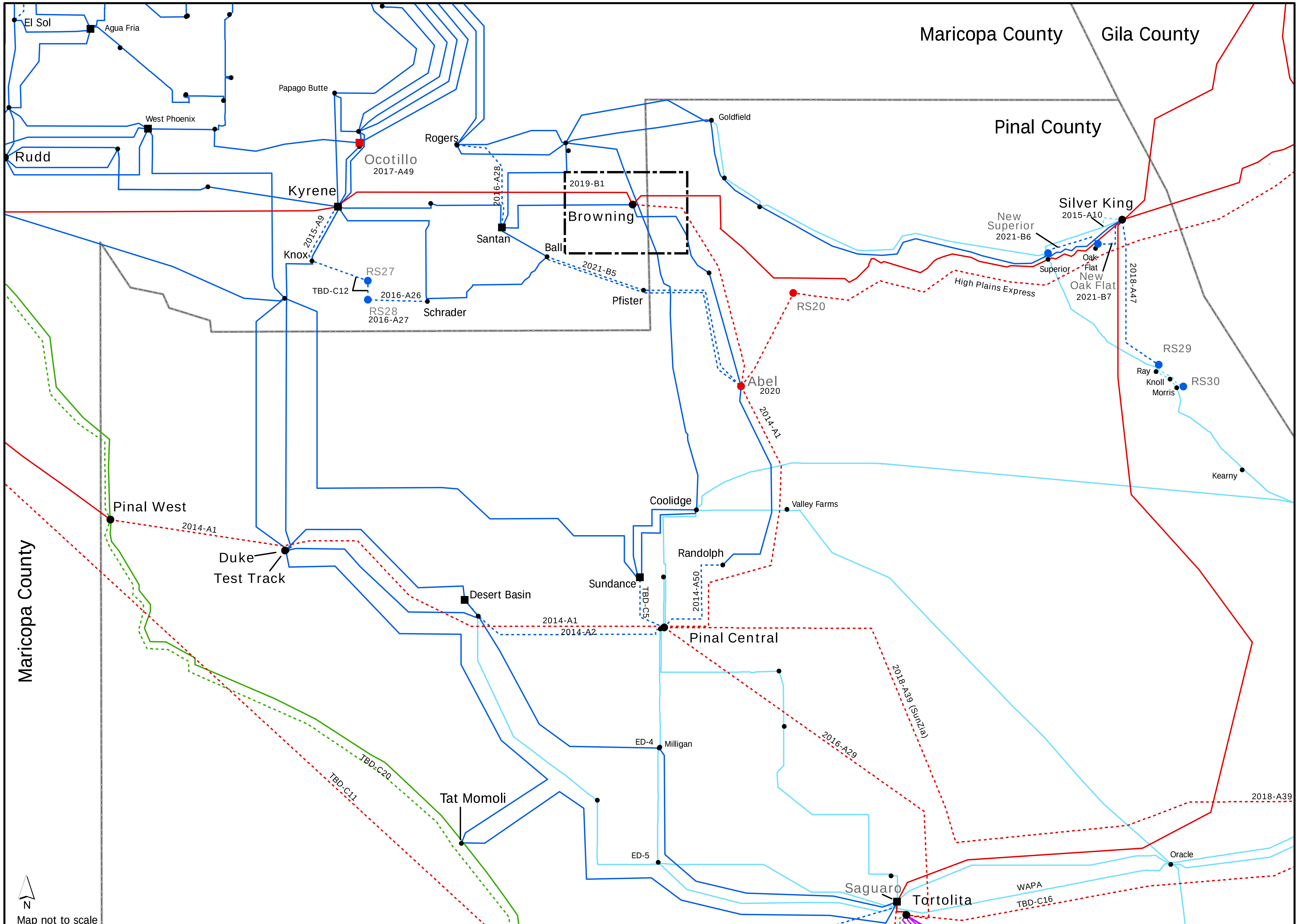
1. Only pertinent transmission voltage levels shown
2. Project identification refers to details on Project Lookup table
3. Routes locations of transmission lines are conceptual only

ACC Docket E-00000D-13-0002
8th Bienniel Transmission Assessment

[This page intentionally blank for formatting purposes]

Pinal County Transmission System Map

Exhibit 5



Facilities

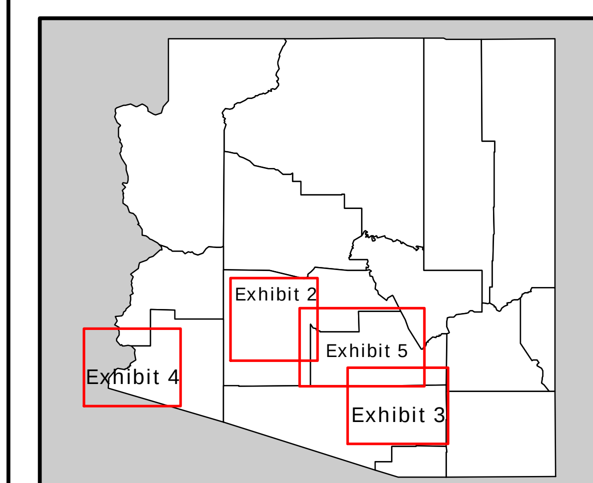
- Existing Power Plant
- Planned Power Plant
- Existing Substation

Planned/Upgraded Substations

- 500 kV
- 345 kV
- 230 kV
- 161 kV
- 138 kV
- 115 kV

Existing	Planned
500kV AC	500kV DC
345kV AC	500kV AC
230kV AC	345kV AC
161kV AC	230kV AC
138kV AC	138kV AC
115kV AC	115kV AC
69kV AC	

Project Look-up ID Format [In Service Year- Table ID]
2017-A42 = In-Service in 2017, Look-up Table ID A42
TBD-C13 = In-Serivce "To-Be-Determined", Look-up Table ID C13



Notes

----

1. Only pertinent transmission voltage levels shown
2. Project identification refers to details on Project Lookup table
3. Routes locations of transmission lines are concetputal only

ACC Docket E-00000D-13-0002

8th Bienniel Transmission Assessment

DISCLAIMER:
K.R. Saline & Associates P.L.C.
Does not warrant the accuracy or
location of the facilities shown

[This page intentionally blank for formatting purposes]

[This page intentionally blank for formatting purposes]

Exhibit 6 – Arizona Planned Project Lookup Table

ID	Description	Participants	Length (mi)	Permitting/Siting Status	Year	KV	Exhibit
A3	DeMoss Petrie - Tucson 138kV	TEP	2.5	Case # 157 - Decision #72231	2014	138	3
A4	DeMoss Petrie - Northeast 138kV Line Reconductor	TEP	6	CEC Not Required	2014	138	3
A5	Upgrade Rillito 138kV Capacitor Bank #1	TEP	N/A	CEC Not Required	2014	138	3
A6	Upgrade Irvington 138kV Capacitor Banks #1 and #2	TEP	N/A	CEC Not Required	2014	138	3
A2	Desert Basin - Pinal Central 230kV	SRP	21	CEC Approved – Decisions #68093, #68291, #69183 and #69647	2014	230	5
A50	Pinal Central - Randolph 230kV Line	SRP	9	CEC Approved - Case #126 - Decisions #68093, #68291	2014	230	5
A1	Pinal West - Pinal Central-Abel- Browning 500kV Line	SRP, TEP, ED2, ED3, ED4	100	CEC Approved - Case #126 - Decisions #68093, #68291	2014	500	1, 5
A10	Superior - Silver King 115kV Re-route	SRP	1	CEC Approved - Case #166 - Decision #73551	2015	115	5
A14	North Loop - Rillito 138kV Line Reconductor	TEP	11	CEC Not Required	2015	138	3
A15	DeMoss Petrie - North Loop 138kV Line Reconductor	TEP	14	CEC Not Required	2015	138	3
A16	Toro - Rosemont 138kV Line	TEP	13.2	Case # 164 Dependent upon approval of Mine Record of Decision from US Forestry Service	2015	138	3
A17	Upgrade South Loop 138kV Capacitor Bank #1	TEP	N/A	CEC Not Required	2015	138	3
A21	Addition and Upgrade Irvington Substation 138kV Capacitor Bank #3 (Phase 1)	TEP	N/A	CEC Not Required	2015	138	3
A22	Addition and Upgrade DeMoss Petrie Substation 138kV Capacitor Bank #2 (Phase 1)	TEP	N/A	CEC Not Required	2015	138	3

Exhibit 6 – Arizona Planned Project Lookup Table

ID	Description	Participants	Length (mi)	Permitting/Siting Status	Year	KV	Exhibit
A19	Gila - Knob Double Circuit Upgrade 230kV	APS, WAPA	1.5	Concurrent with APS Gila - Orchard 230kV Double-Circuit Transmission project.	2015	230	4
A8	Palm Valley - TS2 - Trilby Wash 230kV Line	APS	12	CEC Approved - Decision #73937	2015	230	2
A9	Price Road Corridor - Kyrene - Knox	SRP	24	CEC Not Yet Filed	2015	230	2, 5
A18	Sun Streams Solar 150MW Project	Sun Streams	TBD	CEC Not Yet Filed	2015	500	1, 2
A12	Series Capacitor Replacement at Vail 345kV (Springerville - Vail 345kV Line)	TEP	N/A	N/A	2015	345	3
A13	Series Capacitor Replacement at Vail 345kV (Winchester - Vail 345kV Line)	TEP	N/A	N/A	2015	345	3
A11	Hassayampa - Pinal West 500kV Line Loop-in to Jojoba	TEP	less than 3 spans	Case # 124	2015	500	2
A7	Hassayampa - North Gila 500kV #2 Line	APS	110	CEC Approved - Decision #74206	2015	500	1, 2, 4
A30	Northeast - Rillito 138kV Line Reconductor	TEP	5	CEC Not Required	2016	138	3
A31	North Loop Substation - West Ina 138kV Line Reconductor	TEP	6	CEC Not Yet Filed	2016	138	3
A32	Upgrade North Loop 138kV Capacitor Banks #1 & #2	TEP	N/A	CEC Not Required	2016	138	3
A26	Price Road Corridor - Schrader - RS28	SRP	24	CEC Not Yet Filed	2016	230	2, 5
A27	Price Road Corridor - RS28 Substation	SRP	24	CEC Not Yet Filed	2016	230	2, 5
A25	Sun Valley - Trilby Wash 230kV Line	APS	15	CEC Approved – Decision #67828	2016	230	2
A28	Rogers - Santan 230kV Line	SRP	9	CEC Not Required	2016	230	5
A35	Crossroads Solar Energy 150MW Project	Solar Reserve	12	CEC Approved - Decision #72186, #72187	2016	230	1, 2
A36	Fort Mohave Solar 310MW Project	Tribal Solar	TBD	CEC Not Yet Filed	2016	230	1

Exhibit 6 – Arizona Planned Project Lookup Table

ID	Description	Participants	Length (mi)	Permitting/Siting Status	Year	KV	Exhibit
A33	Bowie 1000MW Power Station	Southwestern Power Group, TEP	15	CEC Approved -Case #118 - Decision #70588 Amended 11/01/10 #71951	2016	345	1
A23	Delaney - Palo Verde 500kV Line	APS, CAWCD	15	CEC Approved – Decision #68063	2016	500	1, 2
A24	Delaney - Sun Valley 500kV Line	APS, CAWCD	28	CEC Approved – Decision #68064	2016	500	1, 2
A29	Pinal Central Substation - Tortolita Substation	TEP	40	Case # 165	2016	500	1, 5
A37	Bagdad 115kV Relocation Project	APS	5.5	CEC Approved - Case #143 - Decision #71217 Amended 11/21/12 Decision #73586	2017	115	1
A40	Reconfiguration of Tortolita - Ranch Vistoso 138kV to North Loop - Rancho Vistoso 138kV	TEP	22	CEC Not Yet Filed	2017	138	3
A41	Upgrade DeMoss Petrie 138kV Capacitor Bank # 1	TEP	N/A	CEC Not Required	2017	138	3
A43	Addition and Upgrade Irvington Substation 138kV Capacitor Bank #3 (Phase 2)	TEP	N/A	CEC Not Required	2017	138	3
A44	Addition and Upgrade DeMoss Petrie 138kV Capacitor Bank #2 (Phase 2)	TEP	N/A	CEC Not Required	2017	138	3
A49	Ocotillo Modernization Project	APS	1	CEC Not Yet Filed	2017	230	2, 5
A38	Mazatzal 345/69kV Substation	APS	0.95	CEC Approved - Decision #72302	2017	345	1
A45	North Gila - Orchard 230kV Line	APS	13	CEC Approved – Case #163 – Decision #72801	2018	230	4
A47	Eastern Mining Expansion	SRP	14	CEC Not Yet Filed	2018	230	5
A48	Buckeye Generation Center 650MW Natural Gas	Horizon Power	0.5	CEC Not Yet Filed	2018	230	1, 2
A39	SunZia Southwest Transmission 500kV Project	SunZia, SWPG, SRP, TEP, Shell, TSGT	198	CEC Not Yet Filed	2018	500	1, 5

Exhibit 6 – Arizona Planned Project Lookup Table

ID	Description	Participants	Length (mi)	Permitting/Siting Status	Year	KV	Exhibit
A46	Morgan- Sun Valley 500kV Line	APS, CAWCD	38	CEC Approved – Decision #70850	2018	500	1, 2
B1	Ellsworth Technology Corridor Expansion	SRP	TBD	CEC Not Yet Filed	2019	230	5
B3	Orange Grove Loop-in of La Canada - Rillito 138kV Line	TEP	Tap off existing line	CEC Not Yet Filed	2020	138	3
B2	Series Capacitor Replacement at Greenlee 345kV Substation (Springerville - Greenlee 345kV Line)	TEP	N/A	N/A	2020	345	1
B8	Irvington -Tucson 138kV Line #2 Loop-in with Kino	TEP	10.9	CEC Not Yet Filed	2021	138	3
B9	Harrison Loop-in of Roberts - East Loop 138kV Line	TEP	4	CEC Approved - Case # 9	2021	138	3
B4	Scatter Wash 230/69kV Substation	APS	less than 1	CEC Approved- Case #120 - Decision #65997	2021	230	2
B5	Abel- Pfister - Ball 230kV	SRP	20	CEC Approved - Case #148 - Decision #71441	2021	230	5
B6	New Superior - New Oak Flat 230kV	SRP	3.5	CEC Not Yet Filed	2021	230	5
B7	New Oak Flat - Silver King 230kV	SRP	3	CEC Not Yet Filed	2021	230	5
B10	Longview Energy Exchange 2000MW Pumped Storage Project (Line to Peacock 500kV)	LEE	50	CEC Pending - Environmental Study Routes	2021	500	1
B11	Longview Energy Exchange 2000MW Pumped Storage Project (Line to Yavapai 500kV)	LEE	40	CEC Pending - Environmental Study Routes	2021	500	1
B12	Longview Energy Exchange 2000MW Pumped Storage Project (Line to Moenkopi-Eldorado 500kV)	LEE	30	CEC Pending - Environmental Study Routes	2021	500	1
B13	Craycroft - Barrill Loop-in of Northeast - Snyder 138kV Line	TEP	Tap off existing	CEC Not Yet Filed	2022	138	3

Exhibit 6 – Arizona Planned Project Lookup Table

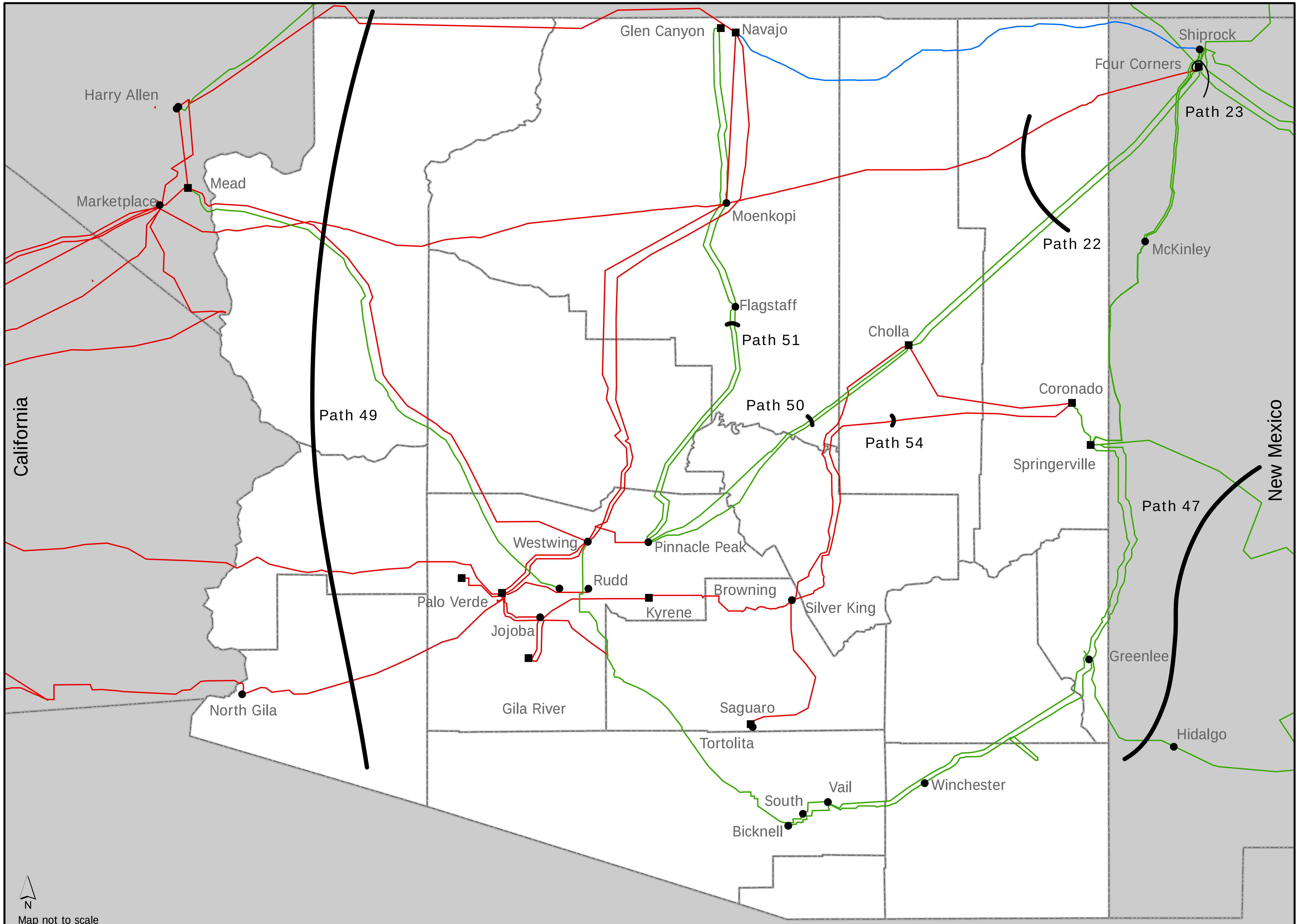
ID	Description	Participants	Length (mi)	Permitting/Siting Status	Year	KV	Exhibit
			line				
B14	Hartt Loop-in on Toro - Green Valley (South - Green Valley) 138kV Line	TEP	Tap off existing line	CEC Not Yet Filed	2022	138	3
B15	Marina Loop-in on Tortolita - North Loop 138kV Circuit	TEP	4	CEC Not Yet Filed	2023	138	3
C1	Morgan - Sun Valley 230kV Line	APS	38	CEC Approved – Decision #70850	2024-2026	230	2
C13	Saguaro to Tucson 115 kV Line Loop-in to Marana	SWTC	0.2	CEC Approved – Case #161 for original Marana Tap to Marana Project. This project would be a minor modification to this approved Case. Currently under study with WAPA	TBD	115	3
C21	Vail - East Loop - Phase 3 Line #3 138kV	TEP	22	CEC Approved - Case # 8	TBD	138	3
C22	Irvington - East Loop Project - Phase 3 (Irvington - 22nd Street #2 Line)	TEP	9	CEC Approved - Case # 66	TBD	138	3
C12	Price Road Corridor - Knox - RS27 - RS28	SRP	24	CEC Not Yet Filed	TBD	230	2, 5
C10	EI Sol- Westwing 230kV Line	APS	11	CEC Approved – Docket #U-1345	TBD	230	2
C26	Griffith - North Havasu 230kV Line	UNS Electric	40	CEC Approved - Case # 88	TBD	230	1
C3	Palm Valley - TS2-Trilby Wash 230kV Line # 2	APS	12	CEC Approved – Decision #67828	TBD	230	2
C4	Avery 230/69kV Substation	APS	1	CEC Approved - Case #120 - Decision #65997 Amended 4/10/2013 Decision #73824	TBD	230	2
C5	Pinal Central- Sundance 230kV Line	APS, ED2	6	CEC Approved – Case #136 – Decision #70325	TBD	230	5

Exhibit 6 – Arizona Planned Project Lookup Table

ID	Description	Participants	Length (mi)	Permitting/Siting Status	Year	KV	Exhibit
C6	Jojoba 230/69kV Substation	APS	0.95	CEC Approved – Decision #62960	TBD	230	2
C7	Orchard - Yucca 230kV Line	APS	19	CEC Approved – Case #163 – Decision #72801	TBD	230	4
C8	Sun Valley - TS10 - TS11 230kV Line	APS	TBD	CEC Not Yet Filed	TBD	230	2
C9	Buckeye - TS11- Sun Valley 230kV Line	APS	TBD	CEC Not Yet Filed	TBD	230	2
C14	Vail Substation - Irvington Substation	TEP	11	CEC Not Yet Filed	TBD	345	1, 3
C15	Irvington Substation - South Substation	TEP	16	CEC Not Yet Filed	TBD	345	1, 3
C17	Vail Substation to South Substation - 2nd Circuit	TEP	14	Case # 15	TBD	345	1, 3
C18	Springerville Substation - Greenlee Substation - 2nd Circuit	TEP	27	Case # 12, 30, 63 and 73	TBD	345	1
C19	Tortolita Substation - South Substation	TEP	68	Case # 50	TBD	345	1, 3
C20	Westwing Substation - South Substation - 2nd Circuit	TEP	178	Case # 15	TBD	345	1, 2, 3, 5
C25	EnviroMission 200MW Solar Tower	EnviroMissio n	0	CEC Not Yet Filed	TBD	230	1
C27	Ajo Improvement Project	AIC	47	CEC Approved - Decision	TBD	230	1
C11	Palo Verde - Saguaro 500kV Line	CATS	130	CEC Approved - Case #24 - Decision #46802	TBD	500	1, 2, 3, 5
C16	Tortolita Substation - Winchester Substation	TEP	80	Case # 23	TBD	500	1, 3
C23	Gila Bend 833MW Power Plant	GBPP	6	CEC Approved - Case #106, Case #109, Case #119	TBD	500	1, 2
C24	BP Wind Power Plant 500MW	BP Wind	6	CEC Approved - Decision #73584	TBD	500	1

WECC Paths Affecting Arizona Map

Exhibit 7

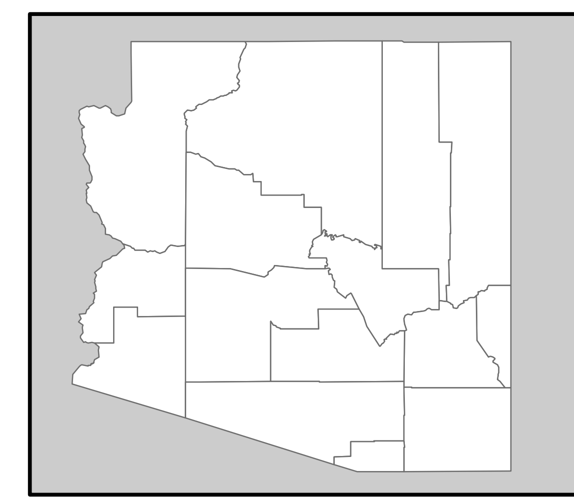


Facilities

- Existing Power Plant
- Existing Substation

Transmission

- 500kV AC Existing
- 345kV AC Existing
- 230kV AC Existing



Notes

----

1. Only pertinent transmission voltage levels shown
2. Project identification refers to details on Project Lookup table
3. Routes locations of transmission lines are concetputal only

ACC Docket E-00000D-13-0002

8th Bienniel Transmission Assessment

DISCLAIMER:
K.R. Saline & Associates P.L.C.
Does not warrant the accuracy or
location of the facilities shown

Exhibit 7 – WECC Path Affecting Arizona Map and Table

WECC Path	WECC Path Name	Components	Rating
22	Southwest of Four Corners	Four Corners - Moenkopi 500 kV Four Corners - Cholla 345 kV #1 Four Corners - Cholla 345 kV #2	East-West = 2325 MW West-East = Undefined
23	Four Corners 345/500 Qualified Path	Flow on 345/500 Transformer	345 to 500 kV = 1,000 MW 500 to 345 kV = 1,000 MW
47	Southern New Mexico	West Mesa - Arroyo 345 kV Springerville - Luna 345 kV Greenlee - Hidalgo 345 kV Belen - Bernardo 115 kV	Simultaneous Firm = 940 MW Non-simultaneous = 1,048 MW
48	Northern New Mexico	Four Corners - West Mesa 345 kV San Juan - BA 345 kV San Juan - Ojo 345 kV McKinley/Yah-Ta-Hey 345/115 kV Transformer Walsenburg - Gladstone 230 kV Bisti - Ambrosia230 kV *Minus flow on Belen – Bernardo 115 kV* *Minus flow on West Mesa – Arroyo 345 kV line*	Simultaneous Firm = 1849 MW Non-simultaneous = 1970 MW
49	East of Colorado River (EOR)	Navajo - Crystal - McCullough 500 kV Moenkopi - El Dorado 500 kV Liberty - Peacock - Mead 500 kV Palo Verde – Colorado River 500 kV Hassayampa – Hoodoo Wash 500 kV Perkins - Mead 500 kV	East-West = 9,300 MW West-East = Undefined
50	Cholla - Pinnacle Peak	Cholla – Preacher Canyon 345 kV Cholla - Pinnacle Peak 345 kV	East - West= 1,200 MW West - East = Undefined
51	Southern Navajo	Moenkopi – Cedar Mountain 500 kV Navajo – Dugas 500 kV	North - South = 2,800 MW South – North = Undefined
54	Coronado - Silver King	Coronado - Silver King 500 kV	Coronado – Silver King = 1,494 MW Silver King – Coronado = Undefined

[This page intentionally blank for formatting purposes]

Exhibit 8 – Arizona Demand Forecast Data

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
APS												
5th BTA Loads (MW)	8,575	8,834	9,096	9,355	9,624	9,888						
6th BTA Loads (MW)	7,536	7,764	8,047	8,264	8,591	8,922	9,229	9,539				
7th BTA Loads (MW)	7,015	7,063	7,204	7,271	7,442	7,614	7,797	7,979	8,160	8,307		
8th BTA Loads (MW)			7,004	6,993	7,113	7,265	7,436	7,620	7,784	7,972	8,185	8,400
Change in 8th BTA (MW)			-200	-278	-329	-349	-361	-359	-376	-335		
Change in 8th BTA (% of 7th BTA)			-2.78%	-3.82%	-4.42%	-4.58%	-4.63%	-4.50%	-4.61%	-4.03%		
SRP												
5th BTA Loads (MW)	8,253	8,519	8,786	9,054	9,323							
6th BTA Loads (MW)	7,502	7,720	7,955	8,194	8,428	8,702	8,984					
7th BTA Loads (MW)	6,769	6,852	6,952	7,062	7,201	7,354	7,528	7,694	7,858			
8th BTA Loads (MW)			6,968	7,088	7,221	7,404	7,608	7,846	8,075	8,403	8,661	
Change in 8th BTA (MW)			16	26	20	50	80	152	217			
Change in 8th BTA (% of 7th BTA)			0.23%	0.37%	0.28%	0.68%	1.07%	1.97%	2.77%			
SWTC												
5th BTA Loads (MW)	785	823	862	900	940	976						
6th BTA Loads (MW)	652	674	691	709	725	747	769	792				
7th BTA Loads (MW)	642	663	678	696	711	731	752	778	800	825		
8th BTA Loads (MW)			709	724	737	761	779	798	817	837	858	879
Change in 8th BTA (MW)			31	28	26	30	27	20	17	12		
Change in 8th BTA (% of 7th BTA)			4.62%	4.08%	3.71%	4.06%	3.60%	2.61%	2.11%	1.44%		
TEP and UNSE												
5th BTA Loads (MW)	3,392	3,502	3,612	3,722	3,829	3,936						
6th BTA Loads (MW)	2,977	3,029	3,087	3,144	3,197	3,251	3,304	3,355				
7th BTA Loads (MW)	2,885	2,936	2,904	2,947	2,984	3,024	3,062	3,102	3,147	3,206		
8th BTA Loads (MW)			2,782	2,799	2,891	2,919	2,955	2,980	3,019	3,059	3,091	3,096
Change in 8th BTA (MW)			-122	-148	-93	-105	-107	-122	-128	-147		
Change in 8th BTA (% of 7th BTA)			-4.20%	-5.02%	-3.12%	-3.47%	-3.49%	-3.93%	-4.07%	-4.59%		
AZ Total												
5th BTA Loads (MW)	21,005	21,678	22,356	23,031	23,716							
6th BTA Loads (MW)	18,667	19,187	19,780	20,311	20,941	21,622	22,286					
7th BTA Loads (MW)	17,311	17,514	17,738	17,976	18,338	18,723	19,139	19,553	19,965			
8th BTA Loads (MW)			17,463	17,604	17,962	18,349	18,778	19,244	19,695	20,271	20,795	
Change in 8th BTA (MW)			-275	-372	-376	-375	-360	-309	-270		20,795	0
Change in 8th BTA (% of 7th BTA)			-1.55%	-2.07%	-2.05%	-2.00%	-1.88%	-1.58%	-1.35%			

[1] Studies performed by SWTC for the 2012-2021 and 2014-2023 ACC Ten Year Plan were stressed using non-coincident load values for worst case scenario analysis.

[This page intentionally blank for formatting purposes]

Exhibit 9 - Plan Changes Between Seventh and Eighth BTA				
In-Service Date	**Project Description**	**Voltage Class (kV)**	**Status**	**Old Alias**
2012	3rd Kyrene 500/230kV Transformer	500	Complete	
2012	McKinley 345kV Reactor Addition	345	Complete	
2012	Vail 345/138kV Transformer T3	345	Complete	
2013	3rd Schrader 230/69kV Transformer	230	Complete	
2013	Canoa Ranch to Duval CLEAR 138kV Line	138	Complete	
2013	Rogers - Thunderstone 230kV Re-Conductor	230	Complete	
2013	Nogales Upgrade Existing Line to 138kV	183	Complete	
2013	Youngs Canyon 345/69kV Substation	345	Complete	
2014	DMP - Northeast 138kV Line Reconductor	138	Advanced TBD to 2014	
2014	Desert Basin - Pinal Central 230kV Line	230	APS No Longer Participating	
2014	Upgrade Rillito 138kV Capacitor Bank #1	138	New Project - 2014	
2014	Upgrade Irvington 138kV Capacitor Banks #1 & #2	138	New Project - 2014	
2015	Jojoba Loop-in of Hassayampa - Pinal West 500kV Line	500	New Project - 2015	
2015	North Loop - Rillito 138kV Line Reconductor	138	Advanced TBD to 2015	
2015	Toro - Rosemont 138kV Line	138	Deferred 2013 to 2015	
2015	Superior - Silver King Re-route	115	Deferred 2013 to 2015	
2015	DeMoss Petrie - North Loop 138kV Line Reconductor	138	New Project - 2015	
2015	Upgrade of South Loop 138kV Capacitor Bank #1	138	New Project - 2015	
2015	Springerville - Vail Series Capacitor Replacement at Vail	345	Deferred 2013 to 2015	
2015	Price Road Corridor	230	Advanced 2016 to 2015	East Valley Industrial Expansion
2016	Pinal Central - Tortolita 500kV Line	500	Deferred 2014 to 2016 & SRP Withdrawn	
2016	Delaney - Palo Verde 500kV Line	500	Deferred 2013 to 2016 & SRP Withdrawn	
2016	Delaney - Sun Valley 500kV Line	500	Deferred 2015 to 2016	

Exhibit 9 - Plan Changes Between Seventh and Eighth BTA				
In-Service Date	**Project Description**	**Voltage Class (kV)**	**Status**	**Old Alias**
			& SRP Withdrawn	
2016	Northeast - Rillito 138kV Line Reconductor	138	Advanced TBD to 2016	
2016	Sun Valley - Trilby Wash 230kV Line	120	Deferred 2015 to 2016	
2016	North Loop - West Ina 138 kV Line Reconductor	138	New Project - 2016	
2016	Upgrade North Loop 138kV Capacitor Banks #1 & #2	138	New Project - 2016	
2017	Reconfiguration of Tortolita - Ranch Vistoso 138kV to North Loop - Rancho Vistoso 138kV	138	Deferred 2015 to 2017	
2017	Orange Grove Loop-in of La Canada - Rillito 138kV Line	138	Deferred 2015 to 2017	
2017	Bagdad 115kV Line Relocation	115	Deferred 2014 to 2017	
2017	Ocotillo Modernization Project 230kV Generator Interconnections	230	New Project - 2017	
2017	Upgrade DeMoss Petrie 138kV Capacitor Bank #1	138	New Project - 2017	
2017	Mazatzal 345/69kV Substation	345	Deferred 2015 to 2017	
2017	Addition and Upgrade Irvington 138kV Capacitor Bank #3	138	New Project - 2015/2017	
2017	Addition and Upgrade DeMoss Petrie 138kV Capacitor Bank #2	138	New Project - 2015/2017	
2018	Sun Zia Transmission Project	500	Deferred 2016 to 2018	
2018	Sun Valley - Morgan 500kV Line	500	Deferred 2016 to 2018 & SRP Withdrawn	
2018	Eastern Mining Expansion	230	Deferred 2015 to 2018	
2018	North Gila - Orchard (TS8) 230kV Line	230	Deferred 2015 to 2018	
2019	Ellsworth Technology Corridor	230	New Project - 2019	
2020	Springerville - Greenlee Series Capacitor Replacement at Greenlee (Phil Young)	345	Deferred 2017 to 2020	
2021	Harrison loop-in of Roberts-East Loop 138 kV line	138	Deferred 2016 to 2021	
2021	Irvington Substation -Tucson 138kV #2 Line with Loop-in of Kino	138	Deferred 2017 to 2021	

Exhibit 9 - Plan Changes Between Seventh and Eighth BTA				
In-Service Date	**Project Description**	**Voltage Class (kV)**	**Status**	**Old Alias**
2021	Abel - Pfister - Ball	230	Deferred 2019 to 2021	
2021	New Oak Flat - Silver King	230	Deferred 2019 to 2021	
2021	New Superior - New Oak Flat	230	Deferred 2019 to 2021	
2021	New Silver King - New Pinto Valley	230	Withdrawn	
2021	Saguaro 230/69kV Substation	230	Scope Change	
2022	Craycroft-Barrill Loop-in of Northeast - Snyder 138kV Line	138	Deferred 2015 to 2022	
2022	Hartt Loop-in on Toro - Green Valley (South - Green Valley) 138kV Line	138	Deferred 2017 to 2022	
2023	Marina Loop-in on one Tortolita - North Loop 138kV Circuit	138	Deferred 2017 to 2022	
Postponed Indefinitely	Apache/Hayden - San Manuel 115kV Line	115	Deferred 2017 to Indefinitely	
Postponed Indefinitely	San Rafael 2nd 230/69kV Transformer	230	Deferred 2021 to Indefinitely	
Postponed Indefinitely	Sandario Tap to Three Points 115kV line Upgrade	115	Deferred 2015 to Indefinitely	
Postponed Indefinitely	Three Points to Bicknell 115kV Line Upgrade	115	Deferred 2020 to Indefinitely	
Postponed Indefinitely	Greenlee Switching Station through Hidalgo - Luna	345	Deferred TBD to Indefinitely	
TBD	Saguaro - Tucson 115kV Line Loop-in to Marana	115	Deferred 2013 to TBD	
TBD	Griffith - North Havasu 230kV Line	230	Deferred 2017 to TBD	
TBD	Pinal Central - Sundance 230kV Line	230	Deferred 2014 to TBD	
TBD	Palo Verde - Saguaro 500kV Line	500	SRP Withdrawn	
	Hassayampa - Pinal West 500kV Line #2	500	Deferred Indefinitely	
	Northeast Arizona - Phoenix 500kV	500	Deferred Indefinitely	
	Ball (RS17) 230kV Loop-in	230	Removed	
	Silver King - Browning 230kV	230	Removed	
	Superior 230kV Loop-in	230	Removed	
	Thunderstone - Browning 230kV	230	Removed	
	Pinnacle Peak - Brandow 230kV	230	Removed	
	Browning - Corbell 230kV	230	Removed	

Exhibit 9 - Plan Changes Between Seventh and Eighth BTA				
In-Service Date	**Project Description**	**Voltage Class (kV)**	**Status**	**Old Alias**
	Silver King - Knoll - New Hayden 230kV	230	Removed	
	New Hayden 115kV Station Loop-in	115	Removed	
	RS25 Project	115/230 /345	Removed	
	RS26 Project	115/230 /345	Removed	
	Toro STATCOM	138	Removed	
	Naranja Loop-in of North Loop - Rancho Vistoso (Tortolita - Ranch Vistoso) 138kV	138	Removed	
	UA Tech Park Loop-in of Irvington - Vail 138kV Line #2	138	Removed	
	Medina Loop-in of Midvale - South 138kV Line	138	Removed	
	Spencer Loop-in of Midvale - Medina (Midvale - South) 138kV Line	138	Removed	
	UA Med Loop-in of Irvington - Tucson 138kV #2 Line	138	Removed	
	Anaklam Loop-in of Santa Cruz - DMP 138kV Line	138	Removed	
	Raytheon Loop-in of South - Medina (Midvale - South)	138	Removed	
	Orange Grove - East Ina 138kV Line	138	Removed	
	Irvington - Robert Bills-Wilmont 138kV Line Reconductor	138	Removed	
	Los Reales - Pantano 138kV Line Reconductor	138	Removed	
	Los Reales - Vail 138kV Line Reconductor	138	Removed	
	Rancho Vistoso - La Canada 138kV Line Reconductor	138	Removed	
	Black Mesa Loop-in of the Parker - Davis 230kV #1 Line	230	Removed	
	Pinal Central - Abel - RS20 500kV Line	500	Removed	
	Greenlee 2nd 345/230kV Transformer	345	Removed	
	Bicknell 345/230kV Transformer Replacement	345	Removed	

Exhibit 10 – Listing of Queue Interconnection Generation Projects

Queue[1]	Location	MW (Maximum)	Generation Technology	Requested In-Service Date
APS Active	Moenkopi 500kV	1000	Wind	10/16/2017
APS Active	Hassayampa-HooDoo Wash 500 kV Line	300	ST	5/1/2014
APS Active	Hassayampa-HooDoo Wash 500 kV Line	99	PV	12/31/2013
APS Active	Hassayampa-HooDoo Wash 500 kV Line	99	PV	12/31/2013
APS Active	Hassayampa-HooDoo Wash 500 kV Line	40	PV	12/31/2013
APS Active	Moenkopi 500 kV Switchyard	500	Wind	8/31/2015
APS Active	Sugarloaf 69 kV Substation	50	PV	12/1/2012
APS Active	Baja Substation 12kV	12	PV	3/18/2016
APS Active	Baja Substation 12kV	8	PV	9/16/2015
APS Active	Delaney 500 kV Substation	300	PV	3/1/2017
APS Active	Baja Substation 12kV	16	PV	2/5/2016
APS Active	12kV to San Pedro Sub	20	PV	6/1/2012
APS Active	Jojoba 69 kV Switchyard	20	PV	5/1/2013
APS Active	500 kV Moenkopi-Yavapai line	360.8	Wind/PV	12/31/2013
APS Active	Horn substation 69kV line	20	PV	12/31/2014
APS Active	69kV line Broadway and 339 Ave	20	PV	12/31/2014
APS Active	Old Home Manor 69kV	20	PV	12/1/2013
APS Active	Desert Sands 69kv switchyard	35	PV	6/30/2014
APS Active	Four Corners 500kV Switchyard	1200	Conventional	1/1/2020
APS Active	Jojoba 230 kV Switchyard	634	Conventional	3/1/2018
APS Active	Fairview Substation 12 kV	20	PV	2015/2016
SRP Meadow Phoenix	Mead - Perkins	250	CSP	4/8/2013
SRP ANPP	Hassayampa 500 kV	175	PV	10/31/2014
SRP ANPP	Hassayampa 500 kV	175	PV	4/30/2016
SRP ANPP	Hassayampa 500 kV	175	PV	10/31/2017
SRP ANPP	Hassayampa 500 kV	125	PV	1/29/2016
SRP ANPP	Palo Verde 500 KV			10/1/2013
SRP ANPP	Hassayampa 500 kV			12/31/2014

Exhibit 10 – Listing of Queue Interconnection Generation Projects

Queue[1]	Location	MW (Maximum)	Generation Technology	Requested In-Service Date
SRP ANPP	Hassayampa 500 kV	200	PV	5/1/2013
SRP ANPP	Hassayampa 500 kV	150	PV	12/1/2016
SRP ANPP	Jojoba 500 KV	300	PV	12/31/2018
SRP ANPP	Jojoba 500 KV			4/1/2015
SRP Joint Participation	Pinal Central 230kV	125	PV	5/1/2014
SRP Joint Participation	Pinal Central 230kV	50	PV	8/1/2016
TEP	Greenlee345-Winchester345 kV line.	500	Combined Cycle	12/31/2016
TEP	Winchester 345 kV substation	51	Wind/PV	1/1/2014 10/1/14 5/2015
TEP	Pinal West 345 kV line	300	PV	12/30/2017
WAPA DSW	Glen Canyon to Pinnacle Peak 345-kV line	500	Wind	12/31/2013
WAPA DSW	Mead - Davis 230 kV Line	300	Wind	12/31/2009
WAPA DSW	Peacock Substation	425	Wind	10/1/2009
WAPA DSW	Bouse Gila 161 kV Line	110	ST	7/1/2013
WAPA DSW	Parker-Blythe 161 kV Line	150	ST	9/1/2015
WAPA DSW	Liberty-Mead 345 kV line	300	Wind	11/1/2013
WAPA DSW	Peacock-Mead 345kV	250	Wind/PV	6/1/2015
WAPA DSW	Mead 230kV Sub	180	PV	1/1/2016
WAPA DSW	Griffith 230kV Sub	45	PV	1/1/2016
WAPA DSW	Eagle Eye Sub 230Kv	100	PV	1/1/2016
WAPA DSW	Liberty-Mead 345 kV Line	300	PV	6/30/2017
SWTC	-	-	-	-

[1]All generation interconnection queue projects are subject to changes; please refer to the utility's current listing here The above queues reflect the following listing dates: APS 5/01/2014, SRP joint participation 5/02/2014, SRP ANPP 01/08/2014, SRP Meadow Phoenix 08/03/2011, SRP 4/11/2014, WAPA DSW 5/07/2014

Exhibit 11 – Listing of Projects Sorted by In-Service Date							
ID	**Description**	**Participants**	**Length (mi)**	**Permitting/Siting Status**	**Year**	**kV**	**Exhibit**
A3	DeMoss Petrie - Tucson 138kV	TEP	2.5	Case # 157 - Decision #72231	2014	138	3
A4	DeMoss Petrie - Northeast 138kV Line Reconductor	TEP	6	CEC Not Required	2014	138	3
A5	Upgrade Rillito 138kV Capacitor Bank #1	TEP	N/A	CEC Not Required	2014	138	3
A6	Upgrade Irvington 138kV Capacitor Banks #1 and #2	TEP	N/A	CEC Not Required	2014	138	3
A2	Desert Basin - Pinal Central 230kV	SRP	21	CEC Approved – Decisions #68093, #68291, #69183 and #69647	2014	230	5
A50	Pinal Central - Randolph 230kV Line	SRP	9	CEC Approved - Case #126 - Decisions #68093, #68291	2014	230	5
A1	Pinal West - Pinal Central-Abel- Browning 500kV Line	SRP, TEP, ED2, ED3, ED4	100	CEC Approved - Case #126 - Decisions #68093, #68291	2014	500	1, 5
A10	Superior - Silver King 115kV Re-route	SRP	1	CEC Approved - Case #166 - Decision #73551	2015	115	5
A14	North Loop - Rillito 138kV Line Reconductor	TEP	11	CEC Not Required	2015	138	3
A15	DeMoss Petrie - North Loop 138kV Line Reconductor	TEP	14	CEC Not Required	2015	138	3
A16	Toro - Rosemont 138kV Line	TEP	13.2	Case # 164 Dependent upon approval of Mine Record of Decision from United States Forestry Service	2015	138	3
A17	Upgrade South Loop 138kV Capacitor Bank #1	TEP	N/A	CEC Not Required	2015	138	3
A21	Addition and Upgrade Irvington Substation 138kV Capacitor Bank #3 (Phase 1)	TEP	N/A	CEC Not Required	2015	138	3
A22	Addition and Upgrade DeMoss Petrie Substation 138kV Capacitor Bank #2 (Phase 1)	TEP	N/A	CEC Not Required	2015	138	3

Exhibit 11 – Listing of Projects Sorted by In-Service Date

ID	Description	Participants	Length (mi)	Permitting/Siting Status	Year	kV	Exhibit
A19	Gila - Knob Double Circuit Upgrade 230kV	APS, WAPA	1.5	Concurrent with APS Gila - Orchard 230kV Double-Circuit Transmission project.	2015	230	4
A8	Palm Valley - TS2 - Trilby Wash 230kV Line	APS	12	CEC Approved - Decision #73937	2015	230	2
A9	Price Road Corridor - Kyrene - Knox	SRP	24	CEC Not Yet Filed	2015	230	2, 5
A18	Sun Streams Solar 150MW Project	Sun Streams	TBD	CEC Not Yet Filed	2015	500	1, 2
A12	Series Capacitor Replacement at Vail 345kV Substation (Springerville -Vail 345kV Line)	TEP	N/A	N/A	2015	345	3
A13	Series Capacitor Replacement at Vail 345kV Substation (Winchester - Vail 345kV Line)	TEP	N/A	N/A	2015	345	3
A11	Hassayampa - Pinal West 500kV Line Loop-in to Jojoba	TEP	less than 3 spans	Case # 124	2015	500	2
A7	Hassayampa - North Gila 500kV #2 Line	APS	110	CEC Approved - Decision #74206	2015	500	1, 2, 4
A30	Northeast - Rillito 138kV Line Reconductor	TEP	5	CEC Not Required	2016	138	3
A31	North Loop Substation - West Ina 138kV Line Reconductor	TEP	6	CEC Not Yet Filed	2016	138	3
A32	Upgrade North Loop 138kV Capacitor Banks #1 & #2	TEP	N/A	CEC Not Required	2016	138	3
A26	Price Road Corridor - Schrader - RS28	SRP	24	CEC Not Yet Filed	2016	230	2, 5
A27	Price Road Corridor - RS28 Substation	SRP	24	CEC Not Yet Filed	2016	230	2, 5
A25	Sun Valley - Trilby Wash 230kV Line	APS	15	CEC Approved – Decision #67828	2016	230	2
A28	Rogers - Santan 230kV Line	SRP	9	CEC Not Required	2016	230	5
A35	Crossroads Solar Energy 150MW Project	Solar Reserve	12	CEC Approved - Decision #72186, #72187	2016	230	1, 2
A36	Fort Mohave Solar 310MW Project	Tribal Solar	TBD	CEC Not Yet Filed	2016	230	1

Exhibit 11 – Listing of Projects Sorted by In-Service Date

ID	Description	Participants	Length (mi)	Permitting/Siting Status	Year	kV	Exhibit
A33	Bowie 1000MW Power Station	Southwestern Power Group, TEP	15	CEC Approved -Case #118 - Decision #70588 Amended 11/01/10 #71951	2016	345	1
A23	Delaney - Palo Verde 500kV Line	APS, CAWCD	15	CEC Approved – Decision #68063	2016	500	1, 2
A24	Delaney - Sun Valley 500kV Line	APS, CAWCD	28	CEC Approved – Decision #68064	2016	500	1, 2
A29	Pinal Central - Tortolita	TEP	40	Case # 165	2016	500	1, 5
A37	Bagdad 115kV Relocation Project	APS	5.5	CEC Approved - Case #143 - Decision #71217 Amended 11/21/12 Decision #73586	2017	115	1
A40	Reconfiguration of Tortolita - Ranch Vistoso 138kV to North Loop - Rancho Vistoso 138kV	TEP	22	CEC Not Yet Filed	2017	138	3
A41	Upgrade DeMoss Petrie 138kV Capacitor Bank # 1	TEP	N/A	CEC Not Required	2017	138	3
A43	Addition and Upgrade Irvington 138kV Capacitor Bank #3 (Phase 2)	TEP	N/A	CEC Not Required	2017	138	3
A44	Addition and Upgrade DeMoss Petrie 138kV Capacitor Bank #2 (Phase 2)	TEP	N/A	CEC Not Required	2017	138	3
A49	Ocotillo Modernization Project	APS	1	CEC Not Yet Filed	2017	230	2, 5
A38	Mazatzal 345/69kV Substation	APS	0.95	CEC Approved - Decision #72302	2017	345	1
A45	North Gila - Orchard 230kV Line	APS	13	CEC Approved – Case #163 – Decision #72801	2018	230	4
A47	Eastern Mining Expansion	SRP	14	CEC Not Yet Filed	2018	230	5
A48	Buckeye Generation Center 650MW Natural Gas	Horizon Power	0.5	CEC Not Yet Filed	2018	230	1, 2
A39	SunZia Southwest Transmission 500kV Project	SunZia, SWPG, SRP, TEP, Shell, TSGT	198	CEC Not Yet Filed	2018	500	1, 5
A46	Morgan- Sun Valley 500kV Line	APS, CAWCD	38	CEC Approved – Decision #70850	2018	500	1, 2

Exhibit 11 – Listing of Projects Sorted by In-Service Date

ID	Description	Participants	Length (mi)	Permitting/Siting Status	Year	kV	Exhibit
B1	Ellsworth Technology Corridor Expansion	SRP	TBD	CEC Not Yet Filed	2019	230	5
B3	Orange Grove Loop-in of La Canada - Rillito 138kV Line	TEP	Tap off existing line	CEC Not Yet Filed	2020	138	3
B2	Series Capacitor Replacement at Greenlee 345kV Substation (Springerville - Greenlee 345kV Line)	TEP	N/A	N/A	2020	345	1
B8	Irvington -Tucson 138kV Line #2 Loop-in with Kino	TEP	10.9	CEC Not Yet Filed	2021	138	3
B9	Harrison Loop-in of Roberts - East Loop 138kV Line	TEP	4	CEC Approved - Case # 9	2021	138	3
B4	Scatter Wash 230/69kV Substation	APS	less than 1	CEC Approved- Case #120 - Decision #65997	2021	230	2
B5	Abel- Pfister - Ball 230kV	SRP	20	CEC Approved - Case #148 - Decision #71441	2021	230	5
B6	New Superior - New Oak Flat 230kV	SRP	3.5	CEC Not Yet Filed	2021	230	5
B7	New Oak Flat - Silver King 230kV	SRP	3	CEC Not Yet Filed	2021	230	5
B10	Longview Energy Exchange 2000MW Pumped Storage Project (Line to Peacock 500kV)	LEE	50	CEC Pending - Environmental Study Routes	2021	500	1
B11	Longview Energy Exchange 2000MW Pumped Storage Project (Line to Yavapai 500kV)	LEE	40	CEC Pending - Environmental Study Routes	2021	500	1
B12	Longview Energy Exchange 2000MW Pumped Storage Project (Line to Moenkopi-Eldorado 500kV)	LEE	30	CEC Pending - Environmental Study Routes	2021	500	1
B13	Craycroft - Barrill Loop-in of Northeast - Snyder 138kV Line	TEP	Tap off existing line	CEC Not Yet Filed	2022	138	3
B14	Hartt Loop-in on Toro - Green Valley (South - Green Valley) 138kV Line	TEP	Tap off existing line	CEC Not Yet Filed	2022	138	3

Exhibit 11 – Listing of Projects Sorted by In-Service Date							
ID	**Description**	**Participants**	**Length (mi)**	**Permitting/Siting Status**	**Year**	**kV**	**Exhibit**
B15	Marina Loop-in on Tortolita - North Loop 138kV Circuit	TEP	4	CEC Not Yet Filed	2023	138	3
C1	Morgan - Sun Valley 230kV Line	APS	38	CEC Approved – Decision #70850	2024-2026	230	2
C13	Saguaro to Tucson 115 kV Line Loop-in to Marana	SWTC	0.2	CEC Approved – Case #161 for original Marana Tap to Marana Project. This project would be a minor modification to this approved Case. Currently under study with WAPA	TBD	115	3
C21	Vail - East Loop - Phase 3 Line #3 138kV	TEP	22	CEC Approved - Case # 8	TBD	138	3
C22	Irvington - East Loop Project - Phase 3 (Irvington - 22nd Street #2 Line)	TEP	9	CEC Approved - Case # 66	TBD	138	3
C12	Price Road Corridor - Knox - RS27 - RS28	SRP	24	CEC Not Yet Filed	TBD	230	2, 5
C10	EI Sol- Westwing 230kV Line	APS	11	CEC Approved – Docket #U-1345	TBD	230	2
C26	Griffith - North Havasu 230kV Line	UNS Electric	40	CEC Approved - Case # 88	TBD	230	1
C3	Palm Valley - TS2-Trilby Wash 230kV Line # 2	APS	12	CEC Approved – Decision #67828	TBD	230	2
C4	Avery 230/69kV Substation	APS	1	CEC Approved - Case #120 - Decision #65997 Amended 4/10/2013 Decision #73824	TBD	230	2
C5	Pinal Central- Sundance 230kV Line	APS, ED2	6	CEC Approved – Case #136 – Decision #70325	TBD	230	5
C6	Jojoba 230/69kV Substation	APS	0.95	CEC Approved – Decision #62960	TBD	230	2
C7	Orchard - Yucca 230kV Line	APS	19	CEC Approved – Case #163 – Decision #72801	TBD	230	4
C8	Sun Valley - TS10 - TS11	APS	TBD	CEC Not Yet Filed	TBD	230	2

Exhibit 11 – Listing of Projects Sorted by In-Service Date							
ID	**Description**	**Participants**	**Length (mi)**	**Permitting/Siting Status**	**Year**	**kV**	**Exhibit**
	230kV Line						
C9	Buckeye - TS11- Sun Valley 230kV Line	APS	TBD	CEC Not Yet Filed	TBD	230	2
C14	Vail Substation - Irvington Substation	TEP	11	CEC Not Yet Filed	TBD	345	1, 3
C15	Irvington Substation - South Substation	TEP	16	CEC Not Yet Filed	TBD	345	1, 3
C17	Vail Substation to South Substation - 2nd Circuit	TEP	14	Case # 15	TBD	345	1, 3
C18	Springerville Substation - Greenlee Substation - 2nd Circuit	TEP	27	Case # 12, 30, 63 and 73	TBD	345	1
C19	Tortolita Substation - South Substation	TEP	68	Case # 50	TBD	345	1, 3
C20	Westwing Substation - South Substation - 2nd Circuit	TEP	178	Case # 15	TBD	345	1, 2, 3, 5
C25	EnviroMission 200MW Solar Tower	Enviro-Mission	0	CEC Not Yet Filed	TBD	230	1
C27	Ajo Improvement Project	AIC	47	CEC Approved - Decision	TBD	230	1
C11	Palo Verde - Saguaro 500kV Line	CATS	130	CEC Approved - Case #24 - Decision #46802	TBD	500	1, 2, 3, 5
C16	Tortolita Substation - Winchester Substation	TEP	80	Case # 23	TBD	500	1, 3
C23	Gila Bend 833MW Power Plant	GBPP	6	CEC Approved - Case #106, Case #109, Case #119	TBD	500	1, 2
C24	BP Wind Power Plant 500MW	BP Wind	6	CEC Approved - Decision #73584	TBD	500	1

Exhibit 12 – Listing of Projects Sorted by Voltage Class

ID	Description	Participants	Length (mi)	Permitting/Siting Status	Year	kV	Exhibit
A10	Superior - Silver King 115kV Re-route	SRP	1	CEC Approved - Case #166 - Decision #73551	2015	115	5
A37	Bagdad 115kV Relocation Project	APS	5.5	CEC Approved - Case #143 - Decision #71217 Amended 11/21/12 Decision #73586	2017	115	1
C13	Saguaro to Tucson 115 kV Line Loop-in to Marana	SWTC	0.2	CEC Approved – Case #161 for original Marana Tap to Marana Project. This project would be a minor modification to this approved Case. Currently under study with Western Area Power Administration.	TBD	115	3
A3	DeMoss Petrie - Tucson 138kV	TEP	2.5	Case # 157 - Decision #72231	2014	138	3
A4	DeMoss Petrie - Northeast 138kV Line Reconductor	TEP	6	CEC Not Required	2014	138	3
A5	Upgrade Rillito 138kV Capacitor Bank #1	TEP	N/A	CEC Not Required	2014	138	3
A6	Upgrade Irvington 138kV Capacitor Banks #1 and #2	TEP	N/A	CEC Not Required	2014	138	3
A14	North Loop - Rillito 138kV Line Reconductor	TEP	11	CEC Not Required	2015	138	3
A15	DeMoss Petrie - North Loop 138kV Line Reconductor	TEP	14	CEC Not Required	2015	138	3
A16	Toro - Rosemont 138kV Line	TEP	13.2	Case # 164 Dependent upon approval of Mine Record of Decision from United States Forestry Service	2015	138	3
A17	Upgrade South Loop 138kV Capacitor Bank #1	TEP	N/A	CEC Not Required	2015	138	3

Exhibit 12 – Listing of Projects Sorted by Voltage Class							
ID	**Description**	**Participants**	**Length (mi)**	**Permitting/Siting Status**	**Year**	**kV**	**Exhibit**
A21	Addition and Upgrade Irvington Substation 138kV Capacitor Bank #3 (Phase 1)	TEP	N/A	CEC Not Required	2015	138	3
A22	Addition and Upgrade DeMoss Petrie Substation 138kV Capacitor Bank #2 (Phase 1)	TEP	N/A	CEC Not Required	2015	138	3
A30	Northeast - Rillito 138kV Line Reconductor	TEP	5	CEC Not Required	2016	138	3
A31	North Loop - West Ina 138kV Line Reconductor	TEP	6	CEC Not Yet Filed	2016	138	3
A32	Upgrade North Loop 138kV Capacitor Banks #1 & #2	TEP	N/A	CEC Not Required	2016	138	3
A40	Reconfiguration of Tortolita - Ranch Vistoso to North Loop - Rancho Vistoso 138kV	TEP	22	CEC Not Yet Filed	2017	138	3
A41	Upgrade DeMoss Petrie 138kV Capacitor Bank # 1	TEP	N/A	CEC Not Required	2017	138	3
A43	Addition and Upgrade Irvington 138kV Capacitor Bank #3 Phase 2	TEP	N/A	CEC Not Required	2017	138	3
A44	Addition and Upgrade DeMoss Petrie 138kV Capacitor Bank #2 Phase 2	TEP	N/A	CEC Not Required	2017	138	3
B3	Orange Grove Loop-in of La Canada - Rillito 138kV Line	TEP	Tap off existing line	CEC Not Yet Filed	2020	138	3
B8	Irvington -Tucson 138kV Line #2 Loop-in with Kino	TEP	10.9	CEC Not Yet Filed	2021	138	3
B9	Harrison Loop-in of Roberts - East Loop 138kV Line	TEP	4	CEC Approved - Case # 9	2021	138	3
B13	Craycroft - Barrill Loop-in of Northeast - Snyder 138kV Line	TEP	Tap off existing line	CEC Not Yet Filed	2022	138	3
B14	Hartt Loop-in on Toro - Green Valley (South - Green Valley) 138kV Line	TEP	Tap off existing line	CEC Not Yet Filed	2022	138	3
B15	Marina Loop-in on Tortolita - North Loop 138kV Circuit	TEP	4	CEC Not Yet Filed	2023	138	3

Exhibit 12 – Listing of Projects Sorted by Voltage Class

ID	Description	Participants	Length (mi)	Permitting/Siting Status	Year	kV	Exhibit
C21	Vail - East Loop - Phase 3 Line #3 138kV	TEP	22	CEC Approved - Case # 8	TBD	138	3
C22	Irvington - East Loop Project - Phase 3 (Irvington - 22nd Street #2 Line)	TEP	9	CEC Approved - Case # 66	TBD	138	3
A2	Desert Basin - Pinal Central 230kV	SRP	21	CEC Approved – Decisions #68093, #68291, #69183 and #69647	2014	230	5
A50	Pinal Central - Randolph 230kV Line	SRP	9	CEC Approved - Case #126 - Decisions #68093, #68291	2014	230	5
A19	Gila - Knob Double Circuit Upgrade 230kV	APS, WAPA	1.5	Concurrent with APS Gila - Orchard 230kV Double-Circuit Transmission project.	2015	230	4
A8	Palm Valley - TS2 - Trilby Wash 230kV Line	APS	12	CEC Approved - Decision #73937	2015	230	2
A9	Price Road Corridor - Kyrene - Knox	SRP	24	CEC Not Yet Filed	2015	230	2, 5
A26	Price Road Corridor - Schrader - RS28	SRP	24	CEC Not Yet Filed	2016	230	2, 5
A27	Price Road Corridor - RS28 Substation	SRP	24	CEC Not Yet Filed	2016	230	2, 5
A25	Sun Valley - Trilby Wash 230kV Line	APS	15	CEC Approved – Decision #67828	2016	230	2
A28	Rogers - Santan 230kV Line	SRP	9	CEC Not Required	2016	230	5
A35	Crossroads Solar Energy 150MW Project	Solar Reserve	12	CEC Approved - Decision #72186, #72187	2016	230	1, 2
A36	Fort Mohave Solar 310MW Project	Tribal Solar	TBD	CEC Not Yet Filed	2016	230	1
A49	Ocotillo Modernization Project	APS	1	CEC Not Yet Filed	2017	230	2, 5
A45	North Gila - Orchard 230kV Line	APS	13	CEC Approved – Case #163 – Decision #72801	2018	230	4

Exhibit 12 – Listing of Projects Sorted by Voltage Class

ID	Description	Participants	Length (mi)	Permitting/Siting Status	Year	kV	Exhibit
A47	Eastern Mining Expansion	SRP	14	CEC Not Yet Filed	2018	230	5
A48	Buckeye Generation Center 650MW Natural Gas	Horizon Power	0.5	CEC Not Yet Filed	2018	230	1, 2
B1	Ellsworth Technology Corridor Expansion	SRP	TBD	CEC Not Yet Filed	2019	230	5
B4	Scatter Wash 230/69kV Substation	APS	less than 1	CEC Approved- Case #120 - Decision #65997	2021	230	2
B5	Abel- Pfister - Ball 230kV	SRP	20	CEC Approved - Case #148 - Decision #71441	2021	230	5
B6	New Superior - New Oak Flat	SRP	3.5	CEC Not Yet Filed	2021	230	5
B7	New Oak Flat - Silver King 230kV	SRP	3	CEC Not Yet Filed	2021	230	5
C1	Morgan - Sun Valley 230kV Line	APS	38	CEC Approved – Decision #70850	2024-2026	230	2
C12	Price Road Corridor - Knox - RS27 - RS28	SRP	24	CEC Not Yet Filed	TBD	230	2, 5
C10	EI Sol- Westwing 230kV Line	APS	11	CEC Approved – Docket #U-1345	TBD	230	2
C26	Griffith - North Havasu 230kV Line	UNS Electric	40	CEC Approved - Case # 88	TBD	230	1
C3	Palm Valley - TS2-Trilby Wash 230kV Line # 2	APS	12	CEC Approved – Decision #67828	TBD	230	2
C4	Avery 230/69kV Substation	APS	1	CEC Approved - Case #120 - Decision #65997 Amended 4/10/2013 Decision #73824	TBD	230	2
C5	Pinal Central- Sundance 230kV Line	APS, ED2	6	CEC Approved – Case #136 – Decision #70325	TBD	230	5
C6	Jojoba 230/69kV Substation	APS	0.95	CEC Approved – Decision #62960	TBD	230	2
C7	Orchard - Yucca 230kV Line	APS	19	CEC Approved – Case #163 – Decision #72801	TBD	230	4
C8	Sun Valley - TS10 - TS11 Line	APS	TBD	CEC Not Yet Filed	TBD	230	2

Exhibit 12 – Listing of Projects Sorted by Voltage Class

ID	Description	Participants	Length (mi)	Permitting/Siting Status	Year	kV	Exhibit
C9	Buckeye - TS11- Sun Valley Line	APS	TBD	CEC Not Yet Filed	TBD	230	2
C25	EnviroMission 200MW Solar Tower	Enviro-Mission	0	CEC Not Yet Filed	TBD	230	1
C27	Ajo Improvement Project	AIC	47	CEC Approved - Decision	TBD	230	1
A12	Series Capacitor Replacement at Vail 345kV Substation (Springerville - Vail 345kV Line)	TEP	N/A	N/A	2015	345	3
A13	Series Capacitor Replacement at Vail 345kV Substation (Winchester - Vail 345kV Line)	TEP	N/A	N/A	2015	345	3
A33	Bowie 1000MW Power Station	Southwestern Power Group, TEP	15	CEC Approved - Case #118 - Decision #70588 Amended 11/01/10 #71951	2016	345	1
A38	Mazatzal 345/69kV Substation	APS	0.95	CEC Approved - Decision #72302	2017	345	1
B2	Series Capacitor Replacement at Greenlee 345kV Substation (Springerville - Greenlee 345kV Line)	TEP	N/A	N/A	2020	345	1
C14	Vail Substation - Irvington Substation	TEP	11	CEC Not Yet Filed	TBD	345	1, 3
C15	Irvington Substation - South Substation	TEP	16	CEC Not Yet Filed	TBD	345	1, 3
C17	Vail Substation to South Substation - 2nd Circuit	TEP	14	Case # 15	TBD	345	1, 3
C18	Springerville Substation - Greenlee Substation - 2nd Circuit	TEP	27	Case # 12, 30, 63 and 73	TBD	345	1
C19	Tortolita Substation - South Substation	TEP	68	Case # 50	TBD	345	1, 3
C20	Westwing Substation - South Substation - 2nd Circuit	TEP	178	Case # 15	TBD	345	1, 2, 3, 5
A1	Pinal West - Pinal Central- Abel-Browning 500kV Line	SRP, TEP, ED2, ED3, ED4	100	CEC Approved - Case #126 - Decisions #68093, #68291	2014	500	1, 5
A18	Sun Streams Solar 150MW Project	Sun Streams	TBD	CEC Not Yet Filed	2015	500	1, 2

Exhibit 12 – Listing of Projects Sorted by Voltage Class

ID	Description	Participants	Length (mi)	Permitting/Siting Status	Year	kV	Exhibit
A11	Hassayampa - Pinal West 500kV Line Loop-in to Jojoba	TEP	less than 3 spans	Case # 124	2015	500	2
A7	Hassayampa - North Gila 500kV #2 Line	APS	110	CEC Approved - Decision #74206	2015	500	1, 2, 4
A23	Delaney - Palo Verde 500kV Line	APS, CAWCD	15	CEC Approved – Decision #68063	2016	500	1, 2
A24	Delaney - Sun Valley 500kV Line	APS, CAWCD	28	CEC Approved – Decision #68064	2016	500	1, 2
A29	Pinal Central Substation - Tortolita Substation	TEP	40	Case # 165	2016	500	1, 5
A39	SunZia Southwest Transmission 500kV Project	SunZia, SWPG, SRP, TEP, Shell, TSGT	198	CEC Not Yet Filed	2018	500	1, 5
A46	Morgan- Sun Valley 500kV Line	APS, CAWCD	38	CEC Approved – Decision #70850	2018	500	1, 2
B10	Longview Energy Exchange 2000MW Pumped Storage Project (Line to Peacock 500kV)	LEE	50	CEC Pending - Environmental Study Routes	2021	500	1
B11	Longview Energy Exchange 2000MW Pumped Storage Project (Line to Yavapai 500kV)	LEE	40	CEC Pending - Environmental Study Routes	2021	500	1
B12	Longview Energy Exchange 2000MW Pumped Storage Project (Line to Moenkopi-Eldorado 500kV)	LEE	30	CEC Pending - Environmental Study Routes	2021	500	1
C11	Palo Verde - Saguaro 500kV Line	CATS	130	CEC Approved - Case #24 - Decision #46802	TBD	500	1, 2, 3, 5
C16	Tortolita Substation - Winchester Substation	TEP	80	Case # 23	TBD	500	1, 3
C23	Gila Bend 833MW Power Plant	GBPP	6	CEC Approved - Case #106, Case #109, Case #119	TBD	500	1, 2
C24	BP Wind Power Plant 500MW	BP Wind	6	CEC Approved - Decision #73584	TBD	500	1

Exhibit 13 - Arizona Public Service Project Summary							
ID	**Description**	**Participants**	**Length (mi)**	**Permitting/Siting Status**	**Year**	**kV**	**Exhibit**
A19	Gila - Knob Double Circuit Upgrade 230kV	APS, WAPA	1.5	Concurrent with APS Gila - Orchard 230kV Double-Circuit Transmission project.	2015	230	4
A8	Palm Valley - TS2 - Trilby Wash 230kV Line	APS	12	CEC Approved - Decision #73937	2015	230	2
A7	Hassayampa - North Gila 500kV #2 Line	APS	110	CEC Approved - Decision #74206	2015	500	1, 2, 4
A25	Sun Valley - Trilby Wash 230kV Line	APS	15	CEC Approved – Decision #67828	2016	230	2
A23	Delaney - Palo Verde 500kV Line	APS, CAWCD	15	CEC Approved – Decision #68063	2016	500	1, 2
A24	Delaney - Sun Valley 500kV Line	APS, CAWCD	28	CEC Approved – Decision #68064	2016	500	1, 2
A37	Bagdad 115kV Relocation Project	APS	5.5	CEC Approved - Case #143 - Decision #71217 Amended 11/21/12 Decision #73586	2017	115	1
A49	Ocotillo Modernization Project	APS	1	CEC Not Yet Filed	2017	230	2, 5
A38	Mazatzal 345/69kV Substation	APS	0.95	CEC Approved - Decision #72302	2017	345	1
A45	North Gila - Orchard 230kV Line	APS	13	CEC Approved – Case #163 – Decision #72801	2018	230	4
A46	Morgan- Sun Valley 500kV Line	APS, CAWCD	38	CEC Approved – Decision #70850	2018	500	1, 2
B4	Scatter Wash 230/69kV Substation	APS	less than 1	CEC Approved- Case #120 - Decision #65997	2021	230	2
C1	Morgan - Sun Valley 230kV Line	APS	38	CEC Approved – Decision #70850	2024-2026	230	2
C10	EI Sol- Westwing 230kV Line	APS	11	CEC Approved – Docket #U-1345	TBD	230	2
C3	Palm Valley - TS2-Trilby Wash 230kV Line # 2	APS	12	CEC Approved – Decision #67828	TBD	230	2

Exhibit 13 - Arizona Public Service Project Summary

ID	Description	Participants	Length (mi)	Permitting/Siting Status	Year	kV	Exhibit
C4	Avery 230/69kV Substation	APS	1	CEC Approved - Case #120 - Decision #65997 Amended 4/10/2013 Decision #73824	TBD	230	2
C5	Pinal Central- Sundance 230kV Line	APS, ED2	6	CEC Approved – Case #136 – Decision #70325	TBD	230	5
C6	Jojoba 230/69kV Substation	APS	0.95	CEC Approved – Decision #62960	TBD	230	2
C7	Orchard - Yucca 230kV Line	APS	19	CEC Approved – Case #163 – Decision #72801	TBD	230	4
C8	Sun Valley - TS10 - TS11 230kV Line	APS	TBD	CEC Not Yet Filed	TBD	230	2
C9	Buckeye - TS11- Sun Valley 230kV Line	APS	TBD	CEC Not Yet Filed	TBD	230	2

Exhibit 14 – Salt River Project Summary

ID	Description	Participants	Length (mi)	Permitting/Siting Status	Year	kV	Exhibit
A2	Desert Basin - Pinal Central 230kV	SRP	21	CEC Approved – Decisions #68093, #68291, #69183 and #69647	2014	230	5
A50	Pinal Central - Randolph 230kV Line	SRP	9	CEC Approved - Case #126 - Decisions #68093, #68291	2014	230	5
A1	Pinal West - Pinal Central- Abel-Browning 500kV Line	SRP, TEP, ED2, ED3, ED4	100	CEC Approved - Case #126 - Decisions #68093, #68291	2014	500	1, 5
A10	Superior - Silver King 115kV Re-route	SRP	1	CEC Approved - Case #166 - Decision #73551	2015	115	5
A9	Price Road Corridor - Kyrene - Knox	SRP	24	CEC Not Yet Filed	2015	230	2, 5
A26	Price Road Corridor - Schrader - RS28	SRP	24	CEC Not Yet Filed	2016	230	2, 5
A27	Price Road Corridor - RS28 Substation	SRP	24	CEC Not Yet Filed	2016	230	2, 5
A28	Rogers - Santan 230kV Line	SRP	9	CEC Not Required	2016	230	5
A47	Eastern Mining Expansion	SRP	14	CEC Not Yet Filed	2018	230	5
A39	SunZia Southwest Transmission 500kV Project	SunZia, SWPG, SRP, TEP, Shell, TSGT	198	CEC Not Yet Filed	2018	500	1, 5
B1	Ellsworth Technology Corridor Expansion	SRP	TBD	CEC Not Yet Filed	2019	230	5
B5	Abel- Pfister - Ball 230kV	SRP	20	CEC Approved - Case #148 - Decision #71441	2021	230	5
B6	New Superior - New Oak Flat 230kV	SRP	3.5	CEC Not Yet Filed	2021	230	5
B7	New Oak Flat - Silver King 230kV	SRP	3	CEC Not Yet Filed	2021	230	5
C12	Price Road Corridor - Knox - RS27 - RS28	SRP	24	CEC Not Yet Filed	TBD	230	2, 5

Exhibit 15 – Southwestern Power Group Project Summary							
BTA 8 Project ID	**Description**	**Participants**	**Length (mi)**	**Permitting/Siting Status**	**Year**	**Voltage (kV)**	**Exhibit**
A33	Bowie 1000MW Power Station	Southwestern Power Group, TEP	15	CEC Approved -Case #118 - Decision #70588 Amended 11/01/10 #71951	2016	345	1

Exhibit 16 – Southwest Transmission Cooperative Project Summary							
ID	**Description**	**Participants**	**Length (mi)**	**Permitting/Siting Status**	**Year**	**kV**	**Exhibit**
C13	Saguaro to Tucson 115 kV Line Loop-in to Marana	SWTC	0.2	CEC Approved – Case #161 for original Marana Tap to Marana Project. This project would be a minor modification to this approved Case. Currently under study with Western Area Power Administration.	TBD	115	3

[This page intentionally blank for formatting purposes]

Exhibit 17 - Tucson Electric Power Project Summary							
ID	**Description**	**Participants**	**Length (mi)**	**Permitting/Siting Status**	**Year**	**kV**	**Exhibit**
A3	DeMoss Petrie - Tucson 138kV	TEP	2.5	Case # 157 - Decision #72231	2014	138	3
A4	DeMoss Petrie - Northeast 138kV Line Reconductor	TEP	6	CEC Not Required	2014	138	3
A5	Upgrade Rillito 138kV Capacitor Bank #1	TEP	N/A	CEC Not Required	2014	138	3
A6	Upgrade Irvington 138kV Capacitor Banks #1 and #2	TEP	N/A	CEC Not Required	2014	138	3
A1	Pinal West - Pinal Central- Abel-Browning 500kV Line	SRP, TEP, ED2, ED3, ED4	100	CEC Approved - Case #126 - Decisions #68093, #68291	2014	500	1, 5
A14	North Loop - Rillito 138kV Line Reconductor	TEP	11	CEC Not Required	2015	138	3
A15	DeMoss Petrie - North Loop 138kV Line Reconductor	TEP	14	CEC Not Required	2015	138	3
A16	Toro - Rosemont 138kV Line	TEP	13.2	Case # 164 Dependent upon approval of Mine Record of Decision from United States Forestry Service	2015	138	3
A17	Upgrade South Loop 138kV Capacitor Bank #1	TEP	N/A	CEC Not Required	2015	138	3
A21	Addition and Upgrade Irvington Substation 138kV Capacitor Bank #3 (Phase 1)	TEP	N/A	CEC Not Required	2015	138	3
A22	Addition and Upgrade DeMoss Petrie Substation 138kV Capacitor Bank #2 (Phase 1)	TEP	N/A	CEC Not Required	2015	138	3
A12	Series Capacitor Replacement at Vail 345kV Substation (Springerville - Vail 345kV Line)	TEP	N/A	N/A	2015	345	3
A13	Series Capacitor Replacement at Vail 345kV Substation (Winchester - Vail 345kV Line)	TEP	N/A	N/A	2015	345	3
A11	Hassayampa - Pinal West 500kV Line Loop-in to Jojoba	TEP	less than 3 spans	Case # 124	2015	500	2
A30	Northeast - Rillito 138kV Line	TEP	5	CEC Not Required	2016	138	3

Exhibit 17 - Tucson Electric Power Project Summary							
ID	**Description**	**Participants**	**Length (mi)**	**Permitting/Siting Status**	**Year**	**kV**	**Exhibit**
	Reconductor						
A31	North Loop Substation - West Ina 138kV Line Reconductor	TEP	6	CEC Not Yet Filed	2016	138	3
A32	Upgrade North Loop 138kV Capacitor Banks #1 & #2	TEP	N/A	CEC Not Required	2016	138	3
A33	Bowie 1000MW Power Station	Southwestern Power Group, TEP	15	CEC Approved -Case #118 - Decision #70588 Amended 11/01/10 #71951	2016	345	1
A29	Pinal Central Substation - Tortolita Substation	TEP	40	Case # 165	2016	500	1, 5
A40	Reconfiguration of Tortolita - Ranch Vistoso 138kV to North Loop - Rancho Vistoso 138kV	TEP	22	CEC Not Yet Filed	2017	138	3
A41	Upgrade DeMoss Petrie 138kV Capacitor Bank # 1	TEP	N/A	CEC Not Required	2017	138	3
A43	Addition and Upgrade Irvington Substation 138kV Capacitor Bank #3 (Phase 2)	TEP	N/A	CEC Not Required	2017	138	3
A44	Addition and Upgrade DeMoss Petrie 138kV Capacitor Bank #2 (Phase 2)	TEP	N/A	CEC Not Required	2017	138	3
A39	SunZia Southwest Transmission 500kV Project	SunZia, SWPG, SRP, TEP, Shell, TSGT	198	CEC Not Yet Filed	2018	500	1, 5
B3	Orange Grove Loop-in of La Canada - Rillito 138kV Line	TEP	Tap off existing line	CEC Not Yet Filed	2020	138	3
B2	Series Capacitor Replacement at Greenlee 345kV Substation (Springerville - Greenlee 345kV Line)	TEP	N/A	N/A	2020	345	1
B8	Irvington -Tucson 138kV Line #2 Loop-in with Kino	TEP	10.9	CEC Not Yet Filed	2021	138	3
B9	Harrison Loop-in of Roberts - East Loop 138kV Line	TEP	4	CEC Approved - Case # 9	2021	138	3
B13	Craycroft - Barrill Loop-in of Northeast - Snyder 138kV Line	TEP	Tap off existing	CEC Not Yet Filed	2022	138	3

Exhibit 17 - Tucson Electric Power Project Summary							
ID	**Description**	**Participants**	**Length (mi)**	**Permitting/Siting Status**	**Year**	**kV**	**Exhibit**
			line				
B14	Hartt Loop-in on Toro - Green Valley (South - Green Valley) 138kV Line	TEP	Tap off existing line	CEC Not Yet Filed	2022	138	3
B15	Marina Loop-in on Tortolita - North Loop 138kV Circuit	TEP	4	CEC Not Yet Filed	2023	138	3
C21	Vail - East Loop - Phase 3 Line #3 138kV	TEP	22	CEC Approved - Case # 8	TBD	138	3
C22	Irvington - East Loop Project - Phase 3 (Irvington - 22nd Street #2 Line)	TEP	9	CEC Approved - Case # 66	TBD	138	3
C14	Vail Substation - Irvington Substation	TEP	11	CEC Not Yet Filed	TBD	345	1, 3
C15	Irvington Substation - South Substation	TEP	16	CEC Not Yet Filed	TBD	345	1, 3
C17	Vail Substation to South Substation - 2nd Circuit	TEP	14	Case # 15	TBD	345	1, 3
C18	Springerville Substation - Greenlee Substation - 2nd Circuit	TEP	27	Case # 12, 30, 63 and 73	TBD	345	1
C19	Tortolita Substation - South Substation	TEP	68	Case # 50	TBD	345	1, 3
C20	Westwing Substation - South Substation - 2nd Circuit	TEP	178	Case # 15	TBD	345	1, 2, 3, 5
C16	Tortolita Substation - Winchester Substation	TEP	80	Case # 23	TBD	500	1, 3

Decision No. 74785

[This page intentionally blank for formatting purposes]

Exhibit 18 - UniSource Electric Project Summary							
ID	**Description**	**Participants**	**Length (mi)**	**Permitting/Siting Status**	**Year**	**kV**	**Exhibit**
C26	Griffith - North Havasu 230kV Line	UNS Electric	40	CEC Approved - Case # 88	TBD	230	1

[This page intentionally blank for formatting purposes]

Exhibit 19 – Ajo Improvement Company Project Summary

ID	Description	Participants	Length (mi)	Permitting/Siting Status	Year	kV	Exhibit
C27	Ajo Improvement Project	AIC	47	CEC Approved - Decision	TBD	230	1

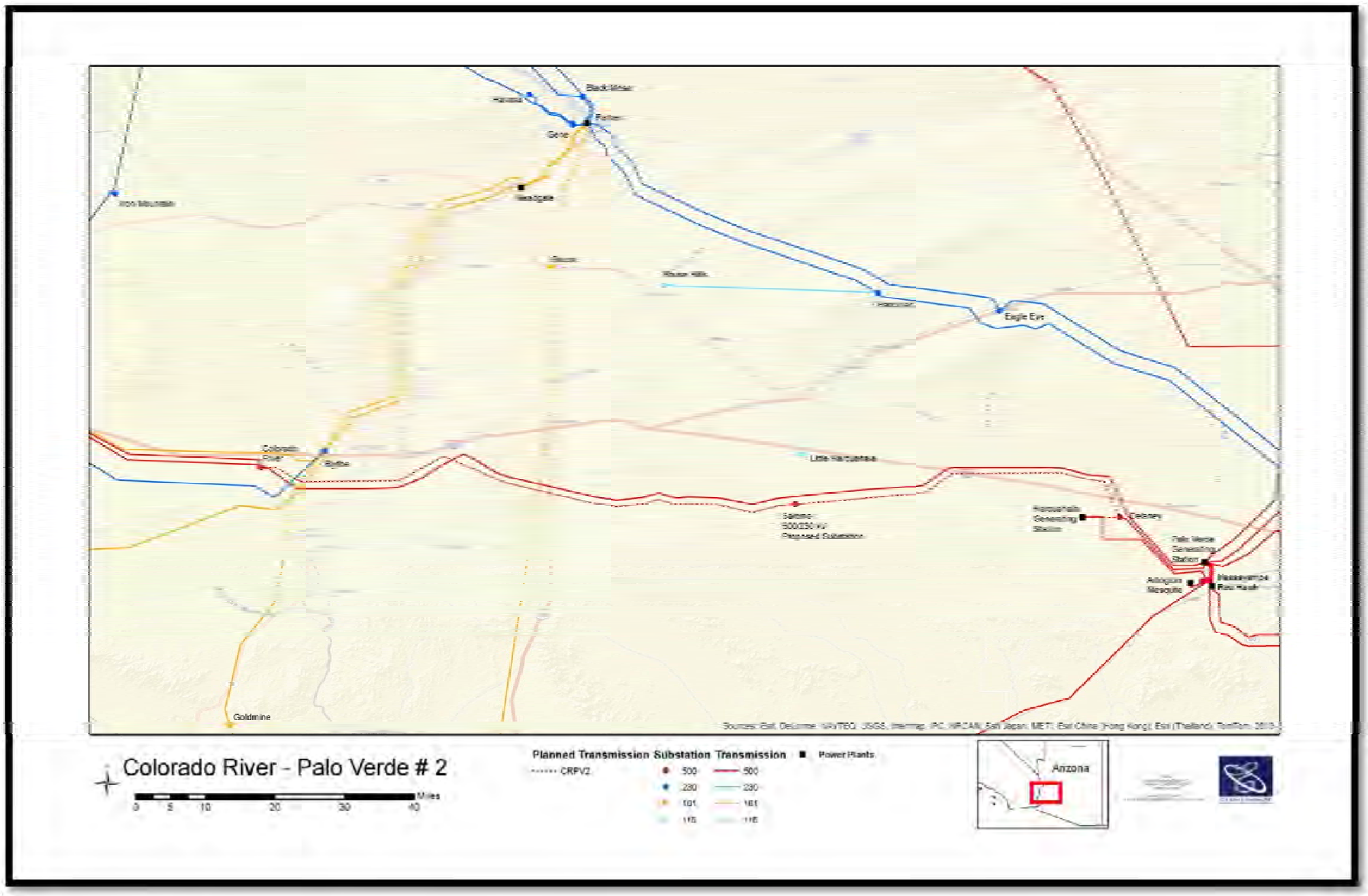
Decision No. 74785

[This page intentionally blank for formatting purposes]

Exhibit 20 – Merchant Transmission and Generation Project Summary by In-Service Date							
ID	**Description**	**Participants**	**Length (mi)**	**Permitting/Siting Status**	**Year**	**kV**	**Exhibit**
A18	Sun Streams Solar 150MW Project	Sun Streams	TBD	CEC Not Yet Filed	2015	500	1, 2
A35	Crossroads Solar Energy 150MW Project	Solar Reserve	12	CEC Approved - Decision #72186, #72187	2016	230	1, 2
A36	Fort Mohave Solar 310MW Project	Tribal Solar	TBD	CEC Not Yet Filed	2016	230	1
A33	Bowie 1000MW Power Station	Southwestern Power Group, TEP	15	CEC Approved -Case #118 - Decision #70588 Amended 11/01/10 #71951	2016	345	1
A48	Buckeye Generation Center 650MW Natural Gas	Horizon Power	0.5	CEC Not Yet Filed	2018	230	1, 2
A39	SunZia Southwest Transmission 500kV Project	SunZia, SWPG, SRP, TEP, Shell, TSGT	198	CEC Not Yet Filed	2018	500	1, 5
B10	Longview Energy Exchange 2000MW Pumped Storage Project (Line to Peacock 500kV)	LEE	50	CEC Pending - Environmental Study Routes	2021	500	1
B11	Longview Energy Exchange 2000MW Pumped Storage Project (Line to Yavapai 500kV)	LEE	40	CEC Pending - Environmental Study Routes	2021	500	1
B12	Longview Energy Exchange 2000MW Pumped Storage Project (Line to Moenkopi-Eldorado 500kV)	LEE	30	CEC Pending - Environmental Study Routes	2021	500	1

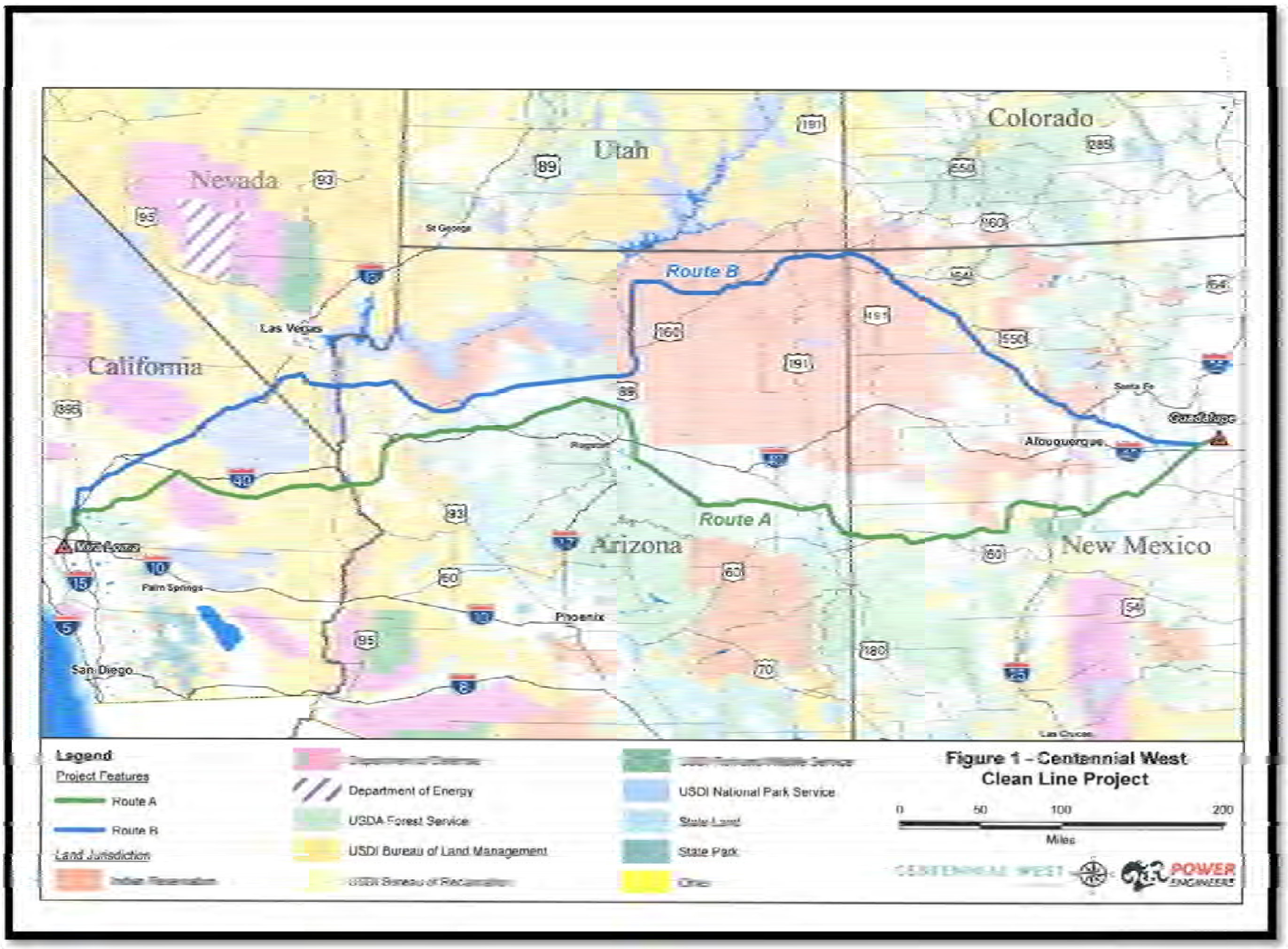
Exhibit 20 – Merchant Transmission and Generation Project Summary by In-Service Date							
ID	**Description**	**Participants**	**Length (mi)**	**Permitting/Siting Status**	**Year**	**kV**	**Exhibit**
C25	EnviroMission 200MW Solar Tower	Enviro-Mission	0	CEC Not Yet Filed	TBD	230	1
C23	Gila Bend 833MW Power Plant	GBPP	6	CEC Approved - Case #106, Case #109, Case #119	TBD	500	1, 2
C24	BP Wind Power Plant 500MW	BP Wind	6	CEC Approved - Decision #73584	TBD	500	1

Exhibit 21 – Overview Map of Delaney – Colorado River 500 kV Project



Decision No. 74785

Exhibit 22 – Overview Map of Centennial West Clean Line Project



Decision No. 74785

Exhibit 23 – Overview Map of Southline Transmission Project

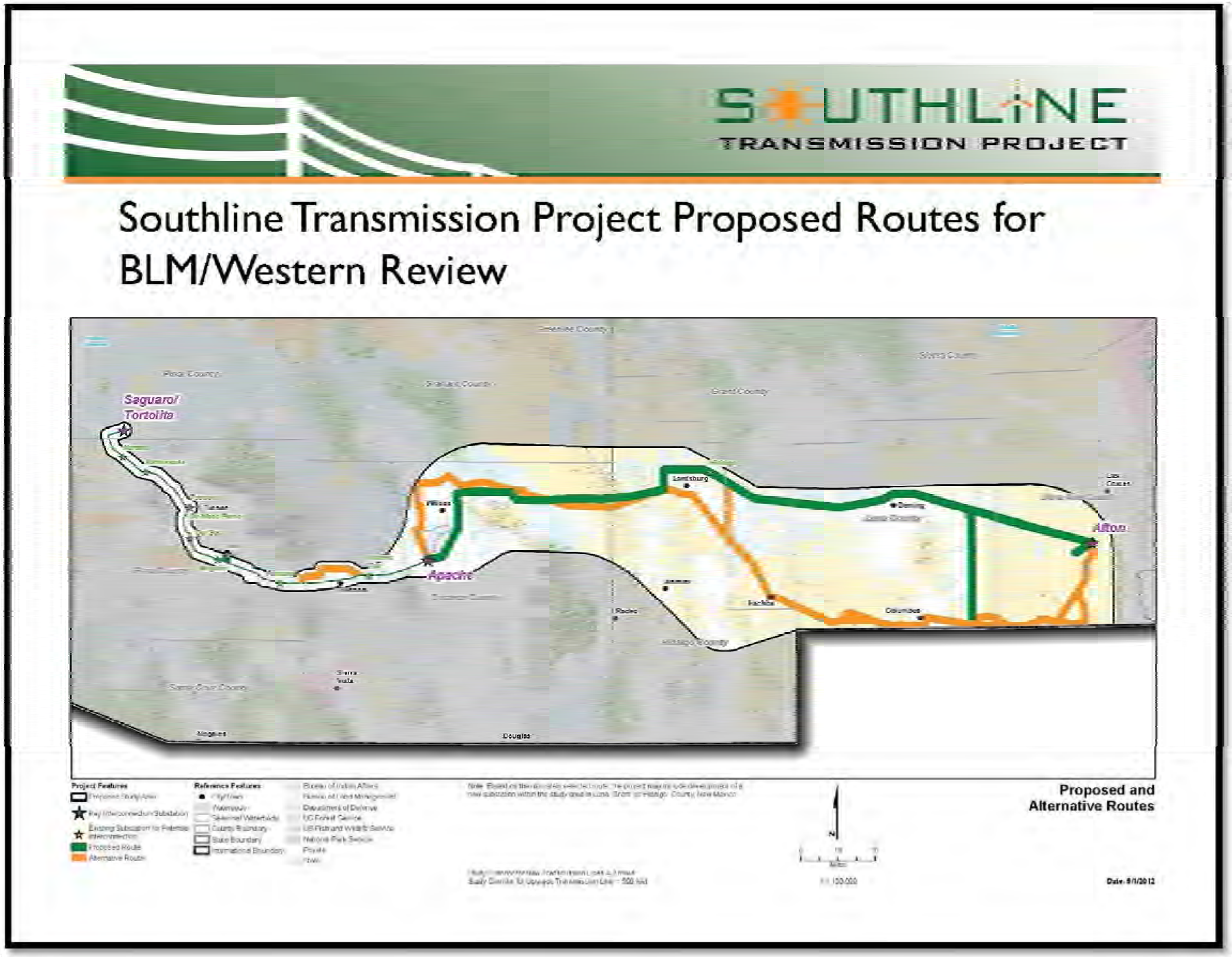


Exhibit 24 – Overview Map of TransWest Express Project

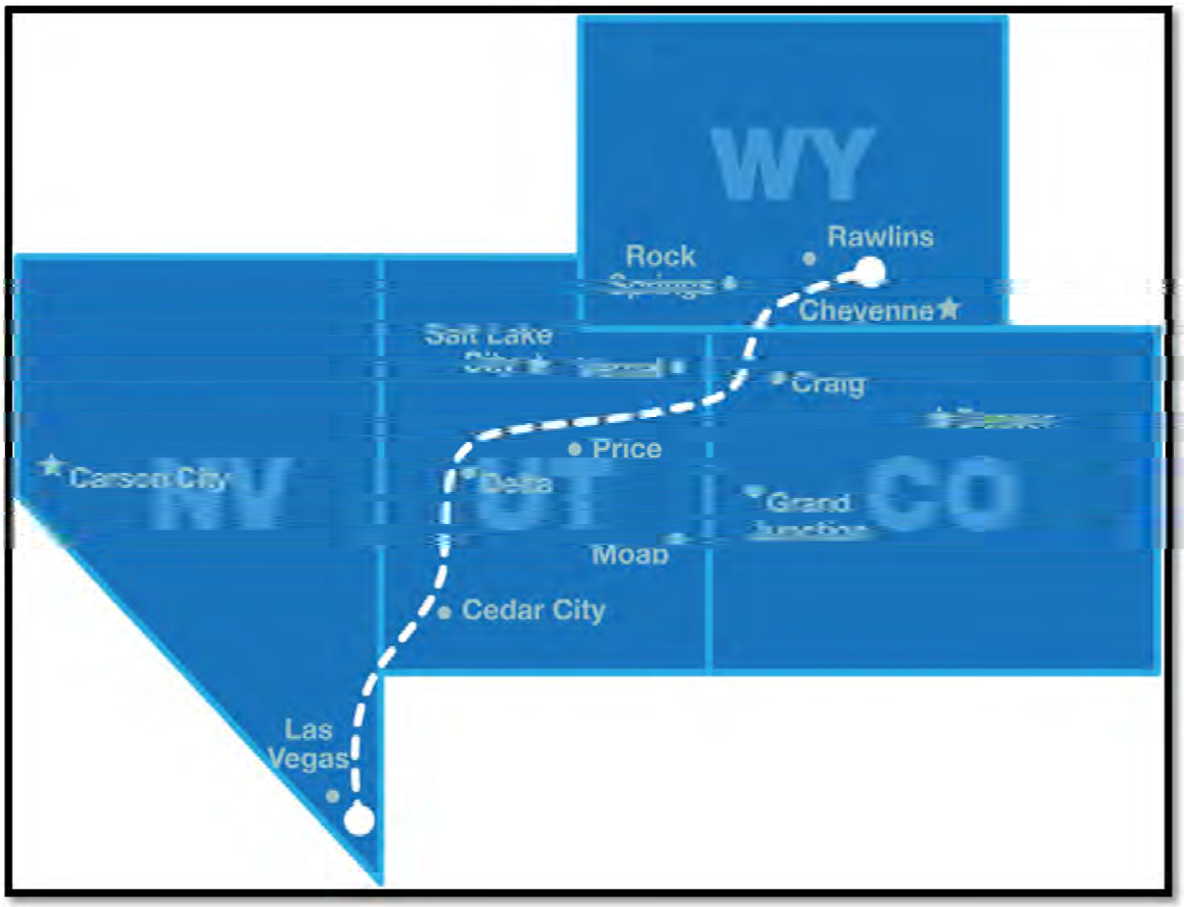


Exhibit 25 – Overview Map of Harcuvar Transmission Project

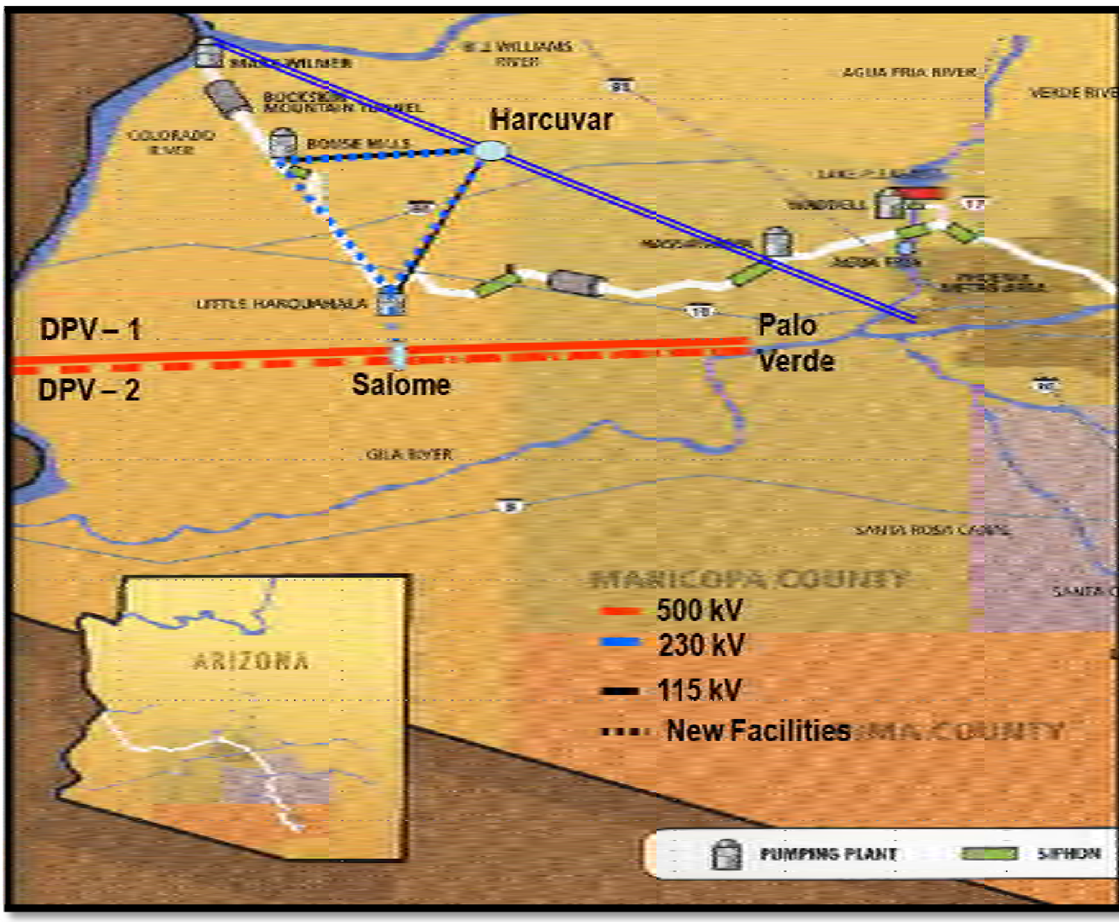


Exhibit 26 – Overview Map of High Plains Express Project

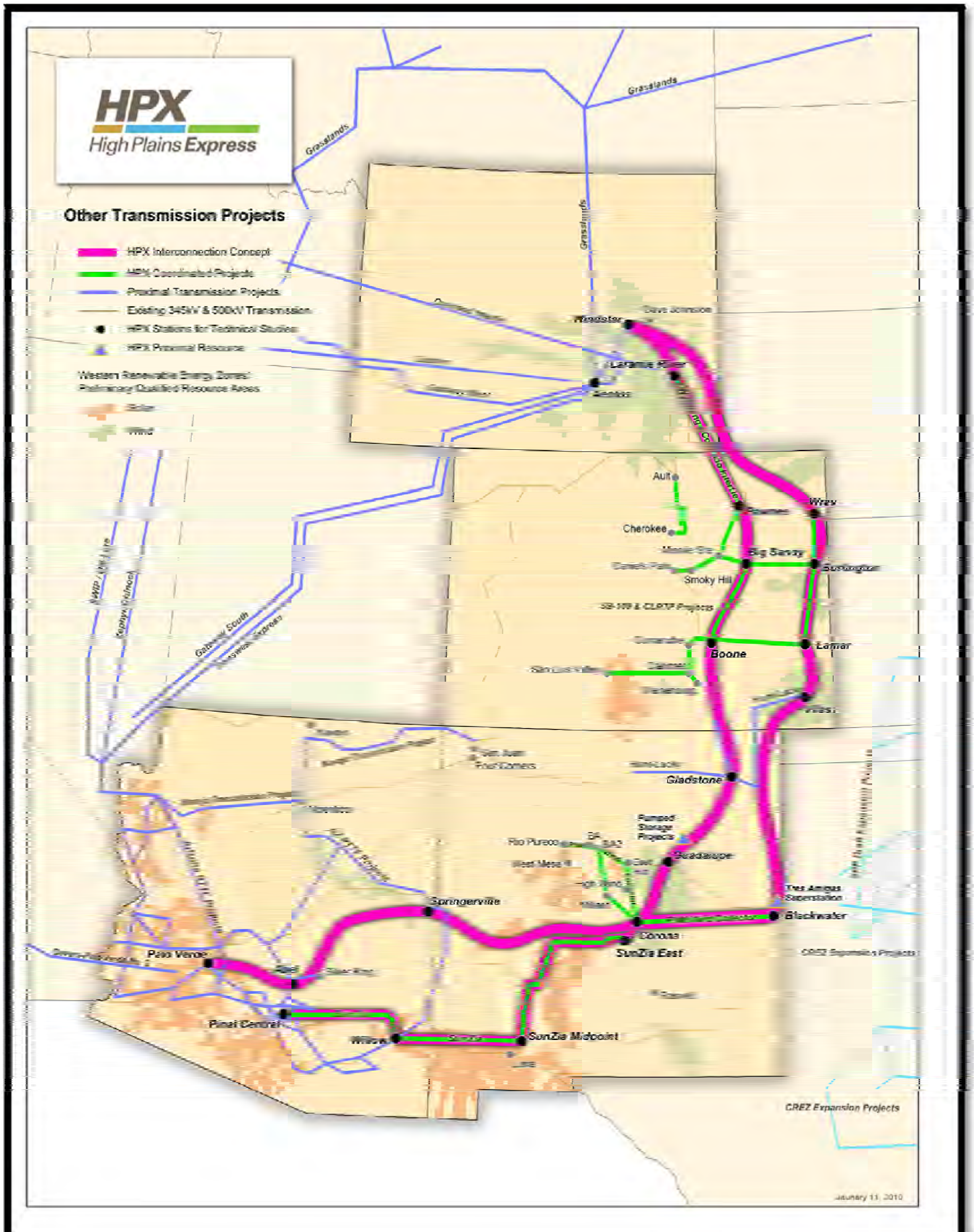
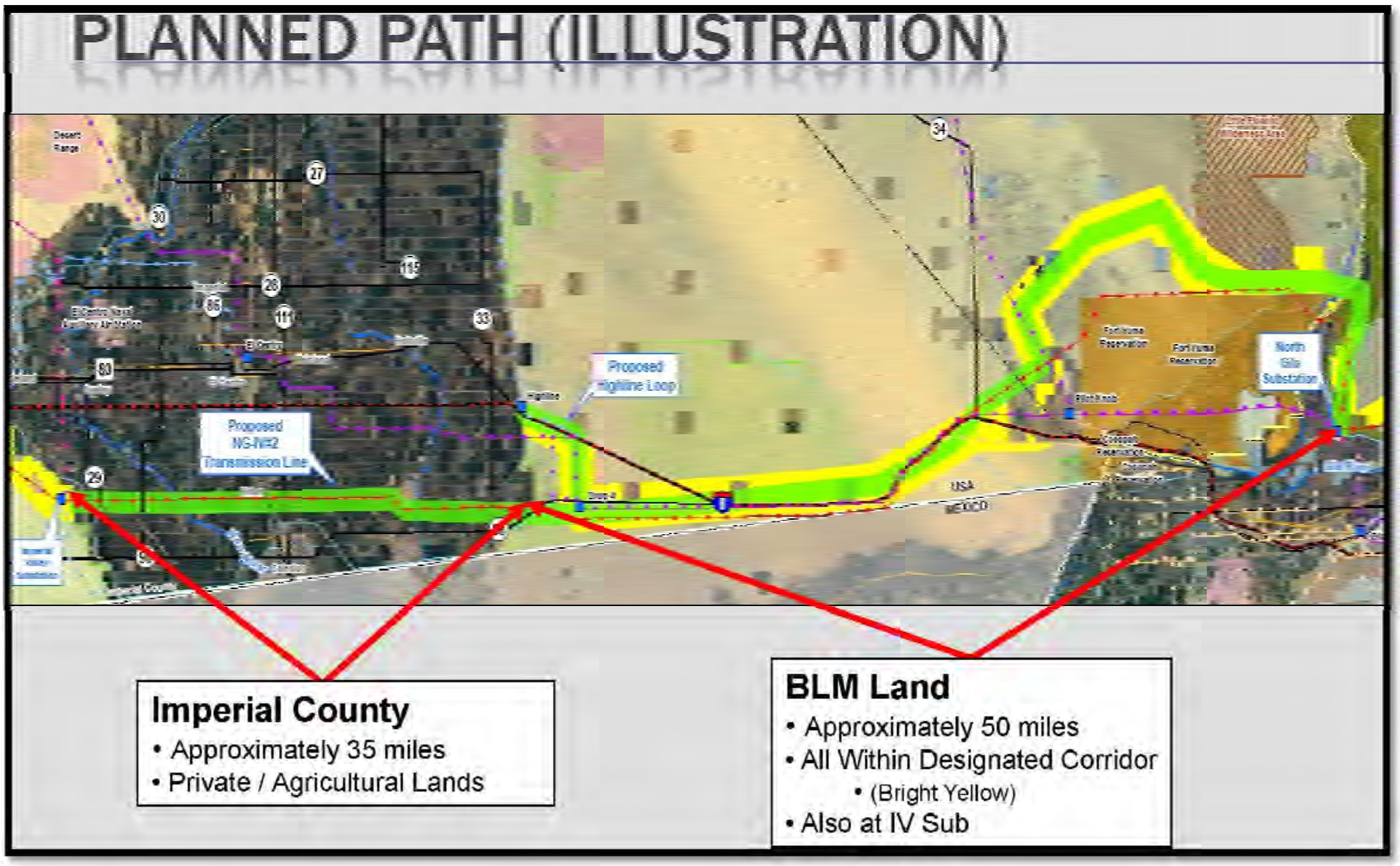


Exhibit 27 – Overview Map o f North Gila – Imperial Valley #2 500kV Project



[This page intentionally blank for formatting purposes]

Eighth Biennial Transmission Assessment 2014-2023

Table of Appendices

[This page intentionally left blank for formatting]

Appendix A - Guiding Principles for Determination of System Adequacy and Reliability [1]

Staff Review and Update of

Guiding Principles for Determination of System Adequacy and Reliability

Background

The Guiding Principles for Determination of System Adequacy and Reliability ("Principles") were developed in early 2000, adopted in the 1st BTA and have been re-adopted in every BTA since. The Principles were developed to provide a basis upon which ACC Staff could 1) assess and make recommendations on the determination of the adequacy and reliability of existing and planned transmission facilities in the Biennial Transmission Assessments called for by A.R.S §40-360.02E and 2) evaluate the impact of a generation application for a Certificate of Environmental Compatibility ("CEC") on system adequacy and reliability.

The Principles were developed in an era of retail competition being implemented in Arizona, merchant gas fired generation being interconnected at the Palo Verde hub, voluntary reliability standards, and non-standard generator interconnection processes.

What Has Changed

Since 2000 many things have changed that impact the Principles:

- Arizona does not have retail electric competition
- Phelps Dodge Decision[2]
- Mandatory, enforceable, updated reliability standards (Energy Policy Act 2005)
- FERC Order 2003 – Standard Large Generator Interconnection Procedures and Agreement
- FERC Order 2006 - Standard Small Generator Interconnection Procedures and Agreement
- Interconnection of utility scale renewable resources that do not require a CEC
- Federal Policies Encouraging Merchant Transmission Development

[1] Guiding Principles for ACC Staff Determination of Electric System Adequacy and Reliability: 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

[2] Phelps Dodge Decision 207 AR12.95(2004) refers to the decision by the Court of Appeals that invalidated certain portions of the Commission Retail Electric Competition Rules – R14-2-1601 through R14-2-1618.

Because of these changes, Staff undertook a review of the Principles and is proposing revisions reflective of the current state of the industry.

The proposed draft revised Principles are attached. Highlights of the proposed changes and the reason for the change are provided below:

Highlights of the proposed changes to
"Guiding Principles for Determination of System Adequacy and Reliability"

Recommended Change	Reason
Eliminate reference to Western Systems Coordinating Council *Reliability Criteria for System Planning and Minimum Operating Reliability Criteria*. **Replace** with references to the mandatory NERC & WECC Standards, Criteria & Regional Business Practices	The previously referenced voluntary criteria documents have been replaced by mandatory NERC/WECC Standards and Criteria.
Eliminate Principle related to compliance with A.A.C. R14-2-1609.B. This provision of the Retail Electric Competition Rules deals with a Utility Distribution Company retaining the obligation to assure adequate transmission system import and distribution system capability to meet their load requirements.	Per discussion with Legal Department of the ACC ("Legal"), this item of the Rules was found by the courts in the Phelps Dodge Decision to require Attorney General certification, which was never sought. This provision, therefore, is not currently effective. Legal recommended removing any reference to it.
Eliminate the mandatory requirement of two or more transmission lines emanating from each power plant switchyard ("gen-ties"). **Replace** with a review of the generation interconnection study filed as part of the pre-CEC filing for all gen-ties (even for generator interconnections where the generator does not require a CEC) and acknowledge that redundant gen-ties are one possible mitigation approach.	A review of practices in other areas found that the requirement for redundant gen-ties is evaluated as part of the generator interconnection process. Requiring redundant gen-ties is one way to mitigate one condition that could result in the loss of the resource and the impact it would have on the system.
Eliminate the Principle that required a condition in generator CECs that all plants located inside a transmission import limited zone "must offer" all "Electric Service Providers" and "Affected Utilities" serving load in the constrained load zone sufficient energy to meet load requirements in excess of the transmission import limit.	This requirement appears to be related to the Retail Competition Rules of the A.A.C Chapter 2, Article 16 where these terms are defined. Since AZ has does not currently have Retail Competition there is no need for this Principle. If Retail Competition is ever implemented in AZ, the "must offer" issue should be addressed for all generators located inside a transmission import limited zone as well as new generators seeking a CEC.

Recommended Change	Reason
Eliminate the Principle that required a condition in generator CECs of the plant applicant becoming a member of WECC, or its successor, and filing a copy of its WECC *Reliability Criteria Agreement* or *Reliability Management System ("RMS") Generator Agreement* **Replace** with a requirement of a condition that the applicant follow the most current NERC/WECC, or their successors, Standards, Criteria, and Regional Business Practices applicable to Generation Owners and Generation Operators as defined in the NERC Standards.	The WECC Reliability Criteria Agreement and Reliability Management System ("RMS") Generator Agreement are no longer in use and have been replaced by mandatory NERC/WECC standards for Generator Owners ("GO") and Generator Operators ("GOP"). GOs and GOPs are obligated to follow the applicable standards whether they join WECC or not.
Eliminate the Principle that required a condition in generator CECs of the plant applicant becoming a member of the Southwest Reserve Sharing Group.	There are now mandatory NERC/WECC standards related to Balancing Authorities and Reserve Sharing Groups. Generator participation would and should be handled through their commercial arrangements with the BA in which they reside.

Decision No. 74785

PROPOSED
Guiding Principles for Determination of System Adequacy and Reliability Update September XX 2014[3]

This document serves the dual purpose of providing the guiding principles for Arizona Corporation Commission ("ACC") Staff determination of electric system adequacy and reliability in the two areas of transmission and generation.

A.R.S §40-360.02.G obligates the ACC to biennially make a determination of the "adequacy of existing and planned transmission facilities in this state to meet the present and future energy needs of this state in a reliable manner." Current state statutes and ACC rules do not establish the basis upon which such a determination is to be made.

In addition, pursuant to A.R.S. §40-360.07, when considering requests for Certificates of Environmental Compatibility for transmission lines and generating plants the ACC shall balance, in the broad public interest, the need for adequate, economical and reliable supply of electric power with the desire to minimize the effect thereof on the environment and ecology of this state." The laws of physics dictate that generation and transmission facilities are inextricably linked when considering the reliability of service to consumers.

Therefore, ACC Staff will use the following guiding principles to make the required adequacy and reliability determination until otherwise directed by state statutes or ACC decisions or rules.

[3] Guiding Principles for ACC Staff Determination of Electric System Adequacy and Reliability were originally developed and presented in pre-filed comments of Jerry D. Smith, ACC, for the Gila Bend Power Plant Hearing, Docket No. E-00000V-00-0106, November 9, 2000. The original Guiding Principles were adopted in the 1st Biennial Transmission Assessment in 2000 and have been re-adopted in each subsequent BTA through 2012. These Updated Guiding Principles were developed as part of the 8th BTA process in 2014 to reflect changes that have occurred within Arizona and within the wholesale electric industry as a whole since the adoption of the original Guiding Principles. Examples of those changes include the institution of mandatory reliability standards related to planning and operating the Bulk Electric System, Arizona's decision to not institute electric competition, and standardization of generator interconnection procedures and requirements.

Transmission

ACC Staff evaluation of ten year transmission plans and transmission line Certificate of Environmental Compatibility ("CEC") applications will be evaluated at a minimum as provided in items T.1 through T.3 below:

T.1. Transmission system adequacy will be evaluated based upon compliance with North American Electric Reliability Corporation ("NERC") and Western Electricity Coordinating Council ("WECC"), or their successors, Standards, Criteria, and Regional Business Practices related to transmission system. Staff will evaluate all transmission plans and CEC applications based upon these Standards, Criteria, and Regional Business Practices regardless of the transmission owners' or CEC applicants' Federal Energy Regulatory Commission-jurisdictional status.

T.2. Transmission planning and operating practices used by Arizona electric utilities will apply when more restrictive than NERC and WECC Standards, Criteria, and Regional Business Practices.

T.3. Per §40-360.02.A "Every person contemplating construction of any transmission line within the state during any ten year period shall file a ten year plan with the commission on or before January 31 of each year." In addition, per §40-360.02.C.7 that filing must include the results of power flow and stability studies. In the case of a transmission line application proposing a generator tie-line for a generator which does not require a CEC, Staff will expect such studies to be based upon the generator interconnection study completed in accordance with the transmission provider's Open Access Transmission Tariff (or equivalent) generator interconnection procedures with whom the generator is interconnecting. Staff will review these studies to ensure they include analysis that demonstrates the generator plant interconnection will satisfy all applicable NERC and WECC Standards and Criteria and identify how any such violations would be mitigated. Mitigation could include a requirement for two generator tie-lines.

ACC Staff support of transmission line CEC applications, including those for generator interconnection tie-lines, will further be contingent upon the CEC being conditioned at a minimum as provided in items T.4 through T.6 below:

T.4. A transmission line applicant shall participate in good faith in state and regional transmission study forums to coordinate transmission expansion plans related to its transmission facilities.

T.5. A transmission line applicant shall follow the most current NERC and WECC Standards, Criteria, and Regional Business Practices applicable to Transmission Owners and Transmission Operators.

T.6. When project facilities are located parallel to and within 100 feet of any existing natural gas or hazardous liquid pipeline a standard electrical induction study condition shall be included in the CEC requiring the evaluation of the risk to any existing natural gas or hazardous liquid pipelines. The study shall recommend appropriate remediation to address any material adverse impact that is found.

Generation

ACC Staff support of power plant Certificate of Environmental Compatibility applications will be conditioned at a minimum as provided in items G1 through G3 below:

G.1. Per §40-360.02.B a power plant applicant must file a plan with the ACC ninety days prior to filing a CEC application and per §40-360.02.C.7 that filing must include the results of power flow and stability studies (i.e., the generator interconnection study completed in accordance with the transmission provider's Open Access Transmission Tariff (or equivalent) generator interconnection procedures with whom the generator is interconnecting.) Staff will review these studies to ensure they include analysis that demonstrates the generator plant interconnection will satisfy all applicable NERC/WECC Standards and Criteria and identify how any such violations would be mitigated. Mitigation could include a requirement for two generator tie-lines.

G.2. The CEC is conditioned upon the plant applicant following the most current NERC and WECC, or their successor's, Standards, Criteria, and Regional Business Practices applicable to Generation Owners and Generation Operators.

G.3 The Certificate of Environmental Compatibility is conditioned upon the plant applicant submitting to the ACC an interconnection agreement with the transmission provider with whom they are interconnecting.

Appendix B – History of Commission Ordered Studies

Local Area Transmission Import Study Requirements

In the First BTA, Staff identified three load pockets in Arizona that shall be monitored for transmission import constraints: Phoenix, Tucson and Yuma. The Second BTA added a fourth and fifth load pocket: Mohave County and Santa Cruz County. Prior BTAs examined import constraints in Pinal County and identified it as a local area that needed to be monitored. Inclusion of Pinal County was prompted by the necessity of transmission providers to implement a remedial action scheme ("RAS") or special protection scheme ("SPS") for single contingencies with operation of the new Desert Basin and Sundance power plants and additional gas turbines at Saguaro Power Plant. In the Fifth BTA, Cochise County was identified for needing to address continuity of service concerns.

Cochise County and Santa Cruz County are served by radial transmission lines that result in interruption of service to significant numbers of customers for the outage of any one of the radial transmission lines serving these two counties. A study of the Cochise County Area was documented in the second BTA. At that time no Commission action was deemed necessary because local transmission switching capability was sufficient to minimize the outage time for customers. The Fourth BTA granted Southwest Transmission Cooperative ("SWTC") a time extension until January 2008 to resolve N-1 contingency violations for loss of the Apache to Butterfield or the Butterfield to San Rafael 230 kV line in its 2015 planning study and to file expansion plans to resolve those issues as part of its 2008-2017 ten year plan.

Santa Cruz County, on the other hand, is served by a single transmission line. The customer service and system impacts and risks associated with the loss of a single 115 kV line serving Santa Cruz County are well chronicled over prior BTA assessments and siting of the Gateway 345 kV transmission project.[4] A NEPA environmental impact study has been concluded but federal records of decision and a Presidential Permit for the new 345 kV transmission line are still pending with federal agencies. Therefore UNSE installed a 20 MW generator in Nogales in 2004 and upgraded

[4] ACC Decision #64356

the existing 115 kV line to 138 kV in December 2013 as interim solutions to ensure the ability to restore service.

TEP was required to file comments by June 30, 2007 to resolve concerns inside neighboring New Mexico and Western Area Power Administration ("WAPA") facilities identified in its preliminary study results for 2016.[5] In addition, technical studies are to be performed and results filed with the Commission for the Cochise County Area to mitigate extended customer outages that resulted from an N-1-1 outage in 2007. A subcommittee of the Southern Arizona Transmission Study ("SATS") subregional planning group has untaken this later task.

The simultaneous import limit ("SIL") and maximum load serving limits ("MLSC") of each of the Arizona load pockets is generally established in conjunction with RMR studies. The Commission approved SIL and MLSC definitions and methodology for performing RMR studies is documented in Appendix C. Arizona's subregional planning forums have also been performing a tenth year snapshot study of the state's transmission system. Those studies have traditionally considered N-0 and N-1 contingencies and provide additional information regarding the transmission capability of each local load pocket.

The Third BTA required that future studies also demonstrate compliance with the WECC and NERC single contingency criteria overlapped with the bulk power system facilities maintenance ("N-1-1") for the first year of the BTA analysis. Staff agreed with the subregional planning groups to limit the N-1-1 analysis to the tenth year for the 4th BTA. The tenth year N-1-1 assessment now only considers designated 230 kV and above planned projects as not in service and then N-1 contingencies are performed. This analysis is more strenuous than the NERC N-1-1 criteria. However, it does determine the possible system impact of a planned project either not getting built as planned or being delayed beyond the tenth year of the plan.

Reliability Must-Run Study Requirements

Previous BTAs also identified several of the local load pockets in Arizona where the load cannot be served using a normal economic merit order generation dispatch due to transmission limitations. During some portions of the year, generation units within the load pocket must be operated out of

[5] ACC Decision #69389, March 14, 2007, page 6, section 2.b.iii

merit order to serve a portion of the local load. Such a resource requirement is often referred to as Reliability-Must-Run ("RMR") generation. The RMR power generated from local generation may be more expensive than the power from outside resources; and may be environmentally less desirable. During RMR conditions, transmission providers must dispatch RMR generation to relieve the congestion on transmission lines.

The Commission's generic electric restructuring docket established that existing Arizona transmission constraints would limit APS' and TEP's ability to deliver competitively procured power to less than the required 50% of Standard Offer Service's load.[6] The Commission stayed this requirement in its Track B proceedings. However, each UDC is still obligated to assure that adequate transmission import capability is available to meet the load requirements of all distribution customers within its service area.[7] Known transmission constraints result in APS and TEP being dependent upon local RMR generation to serve their peak load during certain hours of the year.

In order to provide the Arizona load pockets access to potentially less costly power, the ACC Track A Decision No. 65154 ordered the Arizona utilities to work with Staff to develop a plan to resolve RMR concerns, and include the results of such a plan in the 2004 BTA. The same Decision ordered APS and TEP to file annual RMR study reports with the Commission in concert with their January 31 ten-year plan, for review prior to implementing any new RMR generation strategies, until the 2004 BTA is issued. The utilities readily responded and began providing RMR studies in 2003.

The Third BTA Decision No. 65476 approved a collaborative RMR study plan agreed to by all Arizona transmission providers.[8] The 2003 RMR study forum included only the transmission providers. In contrast, since 2004 the RMR process has been open to all interested parties through Arizona's subregional study forums. The Fourth BTA required that "RMR studies continue to be performed and filed with ten year plans in even numbered years for inclusion in future BTA reports and that:

- Future RMR studies provide more transparent information on input data and economic dispatch assumptions, and

[6] Direct Testimony of Jerry D. Smith and rebuttal testimony of Cary Deise, Docket No. E-00000A-02-0051
[7] A.A.C. R14-2-1609.B
[8] Appendix C

- Arizona utilities collaborate with the Staff to develop and effectively implement more stringent criteria as appropriate for RMR areas in the 2006 BTA."

In the Seventh BTA, Staff suspended the requirement for performing RMR studies in every BTA and implemented criteria for restarting such studies on a biennial review of factors such as:[9]

- An increase of more than 2.5% in an RMR pocket load forecast since the previous BTA.[10]

- Planned retirement or an expected long-term outage during the summer months of June, July or August of a key transmission or substation facility supplying an RMR load pocket, unless a facility being retired will be replaced with a comparable facility before the next summer season.

- Planned retirement or an expected long term outage during the summer months of June, July or August of a generating unit in an RMR load pocket that has been utilized in the past for RMR purposes, unless a generator being retired will be replaced with a comparable unit before the next summer season.

- A significant customer outage in an RMR load pocket defined as a sustained outage of more than one hour exceeding the greater of 100 MW or 10% of the peak demand in the pocket.

Extreme Contingency Study Requirements

Staff's concerns regarding the adequacy and reliability of the Arizona electric system began in 2000 with the rapid development of new generation projects interconnecting with the Palo Verde Nuclear Generating Station. These projects all proposed to interconnect at the new Hassayampa 500 kV switchyard but were not increasing the capacity of the existing transmission lines already connected to the Palo Verde marketing hub. Large quantities of generation capacity and energy were at risk of being interrupted or curtailed for single contingency outages or credible outages of multiple lines. In addition the generation projects were being developed solely for merchant's commercial interest without obligations to assure existing generation reserves were sufficient to cover the outage risks the projects posed.

[9] Decision No. 73625

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

Therefore the Utilities Division of the Commission developed "Guiding Principles for Determination of System Adequacy and Reliability"[11] for Staff's use in power plant and transmission line siting cases. The Commission endorsed this document via its Decision No. 65476 for the Second BTA. Then Condition No. 23 of the CEC was placed on APS and SRP in the Palo Verde to Rudd 500 kV siting case to formally require a study be performed to properly address the risks associated with interconnection developments at the Palo Verde Hub resulting in the 3rd BTA the adoption of the Palo Verde Hub interconnection criteria,

"Require all future interconnections proposed at the Palo Verde Hub, either new generation or new transmission lines, must perform a risk assessment of the Hub to ascertain to what degree the proposed project mitigates the pre-existing risks to extreme outage events. This assessment must precede a project's application for a CEC with the Commission. The recommendations of the Palo Verde Risk Assessment report should be followed if a proposed project would otherwise exacerbate the existing risk at the Hub." [12]

Since the initiation of the Commission's first BTA process Arizona has experienced several fire seasons with exposure to loss of multiple lines in a common corridor on forested lands. These events heightened the Commission's awareness of the state's vulnerability to loss of transmission lines in common corridors. These events were then upstaged by the major 500/230 kV transformer and 230/69 kV fires that occurred at Westwing and Deer Valley in 2004 and the Westwing 500/345 kV transformer fire in 2006. Therefore the third BTA required that the fourth BTA address and document extreme contingency outages studied for Arizona's major generation hubs and major transmission stations including identification of associated risks and consequences if mitigating infrastructure improvements were not planned. This extreme contingency study requirement was reinforced further when the Commission ordered the same requirement for the fifth BTA.

Renewable Energy Transmission Assessment Requirement

In the Fourth BTA, the Commission ordered a Renewable Energy Assessment stating specifically, "in the next BTA, Commission regulated electric utilities, in consultation with the stakeholders, should prepare an assessment of ATC for renewable energy and prepare a plan,

[11] Appendix A
[12] ACC Decision No. 67457, December 14, 2004, page 4, section 7.e

including a description of the location, amount and transmission needs of renewable resources in Arizona, to bring available renewable resources to load."[13] This newest study requirement is focused on exploring transmission delivery obstacles for renewable resources that may choose to develop within the state. This study requirement is intended to assure that Arizona utilities can successfully comply with the renewable portfolio standards adopted by the Commission in 2006.

In the Fifth BTA, the Commission significantly expanded the scope of Arizona Renewable Transmission assessment activities and filing requirements, including determination of an initial set of Renewable Transmission Projects ("RTPs") as described in detail in Section 3.0 of the Sixth BTA Staff report. While a separate docket was opened for this activity, discussions regarding the filings in that docket were included in the workshops for the Sixth BTA and Seventh BTA.

The Commission's decision in the Sixth BTA (2010) addressed the ability of the Arizona transmission system to export renewable energy to neighboring states by directing the jurisdictional utilities to jointly conduct or procure a study to identify the barriers to and solutions for enhancing Arizona's ability to export renewable energy.[14] The study was to identify specific transmission corridors that should be built to accomplish this objective. The utilities were also to conduct stakeholder workshops in conjunction with the study.

The study and results were filed as required at the Commission by November 1, 2011, and included as part of the scope of the Staff's assessment performed in the Seventh BTA proceeding.[15]

[13] ACC Decision No. 69389, March 22, 2007, page 8
[14] Commission Decision No. 72031, 10 December 2010.
[15] *Enhancing Arizona's Ability to Export Renewable Energy, A Report to Address the Arizona Corporation Commission's Sixth Biennial Transmission Assessment, Commission Decision 72031*, PDS Consulting, PLC, October 2011 (http://images.edocket.azcc.gov/docketpdf/0000130865.pdf).

Appendix C - 2014 BTA Workshop I and II List of Attendees[16]

Last	First	Title	Representing	Phone	Email	Workshop I	Workshop II
Black	Patrick		Fennemore Craig	602-916-5400	pblack@fclaw.com	X	
Benally	Linda	Attorney	Pinnacle West Energy Corp.	602-250-3363	linda.benally@pinnaclewest.com	X	X
Belval	Ron	Mgr. TP	Tucson Electric Power Co.	520-745-3420	rbelval@tep.com	X	X
Bernosky	Greg	Mgr. State Reg.	APS	602-250-4849	greg.bernosky@aps.com	X	X
Brandt	Jana	Reg Policy	SRP - MS PAB221	602-236-5028	jana.brandt@srpnet.com	X	X
Bronner	Eric	VP Strategy-Origin.	Entegra Power	813-301-4908	ebronner@entegrapower.com	X	
Brownlee	Benjamin	Staff Engineer	WECC	8/01-819-7643	bbrownlee@wecc.bizpower.com	X	
Calkins	Ian	Public Affairs	Copper State Consulting Grp	602-229-1010	ian@copperstate.net	X	X
Charters	Jim	Manager	Western State Energy SOL LLC	623-572-7972	jcharters@msn.com	X	X
Chen	Kaicheng	Engineer	WAPA (TIP)	720-962-7713	chen@wapa.gov	X	
Cobb	Steven	Dir. Trans Planning	SRP	602-316-3915	sccobb@srpnet.com		X
Cole	Brian	Director, Eng.	Arizona Public Service Co.	602-371-7185	Brian.cole@aps.com		X
Cordes	John	Power Developer	C.G.S.	480-285-9457	cgs.jcordes@gmail.com	X	
Dolynivk	Jerry	Section CDR	Arizona Public Service Co.	602-371-6587	jerry.dolynivk@aps.com	X	X
Etherton	Mark	Director	Power Engineers	480-838-1427	mark.etherton@powereng.com	X	X
Evans	Bruce	Power Engineer	Southwest Transmission Coop	520-586-5336	bevans@swtransco.coop	X	
Fecke-Stoudt	Chris	Engineer	K.R. Saline & Associates, PLC	480-610-8741	cmf@krsaline.com	X	X
Foreman	John		Office of the Attorney General	602-592-7902	johnforeman@azag.gov	X	
Francis	Jeff	ACC Staff	Arizona Corp. Commission		jfrancis@azcc.gov		X
Freeman	Cindy	Asst Proj Manager	Sunzia/SWPG	602-808-2004	cfreeman@southwestempower.com		X

[16] BTA Workshop I was held on May 15, 2014 and BTA Workshop II was held on <<Insert>>

Grake	Robert	Staff	ACC Legal Division	602-542-5402	rgrake@azcc.gov		X
Haenichen	Jack		Governor's Office	480-993-7266	jhacuichen@az.gov		X
Harwood	Patrick	Engineer	Western Area Power Admin.	602-605-2883	harwood@wapa.gov	X	X
Huber	Lon	Admin	RUCO	928-380-5540	lhuber@ruco.gov	X	
James-King	Suzanne	Acct Manager	3M	818-723-2470	sljames-king@mmm.com	X	
Lloyd	Rick	Utilities Staff	Arizona Corp. Commission			X	
Keel	Brian	Manager	Salt River Project	602-236-0970	brian.keel@srpnet.com	X	
Kelly	Jason	BD Director	Power Engineers	248-227-8353	jason.kelly@powereng.com	X	
Kidd	Susan	GM T&D Eng.	Arizona Public Service Co.	602-531-7912	susan.kidd@aps.com	X	
Knudsen	Thomas	Manager	Freeport	602-540-9149	thomas.knudsen@fmi.com	X	
Little	Toby	Staff	Arizona Corp. Commission	602-542-1519	mlittle@azcc.gov	X	
Grake	Robert	Staff	ACC Legal Division	602-542-5402	rgrake@azcc.gov		X
Haenichen	Jack		Governor's Office	480-993-7266	jhacuichen@az.gov		X
Harwood	Patrick	Engineer	Western Area Power Admin.	602-605-2883	harwood@wapa.gov	X	X
Huber	Lon	Admin	RUCO	928-380-5540	lhuber@ruco.gov	X	
James-King	Suzanne	Acct Manager	3M	818-723-2470	sljames-king@mmm.com	X	
Lloyd	Rick	Utilities Staff	Arizona Corp. Commission			X	
Keel	Brian	Manager	Salt River Project	602-236-0970	brian.keel@srpnet.com	X	
Kelly	Jason	BD Director	Power Engineers	248-227-8353	jason.kelly@powereng.com	X	
Kidd	Susan	GM T&D Eng.	Arizona Public Service Co.	602-531-7912	susan.kidd@aps.com	X	
Knudsen	Thomas	Manager	Freeport	602-540-9149	thomas.knudsen@fmi.com	X	
Little	Toby	Staff	Arizona Corp. Commission	602-542-1519	mlittle@azcc.gov	X	
Grake	Robert	Staff	ACC Legal Division	602-542-5402	rgrake@azcc.gov		X
Haenichen	Jack		Governor's Office	480-993-7266	jhacuichen@az.gov		X
Harwood	Patrick	Engineer	Western Area Power Admin.	602-605-2883	harwood@wapa.gov	X	X
Huber	Lon	Admin	RUCO	928-380-5540	lhuber@ruco.gov	X	

James-King	Suzanne	Acct Manager	3M	818-723-2470	sljames-king@mmm.com	X	
Lloyd	Rick	Utilities Staff	Arizona Corp. Commission			X	
Keel	Brian	Manager	Salt River Project	602-236-0970	brian.keel@srpnet.com	X	
Kelly	Jason	BD Director	Power Engineers	248-227-8353	jason.kelly@powereng.com	X	
Kidd	Susan	GM T&D Eng.	Arizona Public Service Co.	602-531-7912	susan.kidd@aps.com	X	
Knudsen	Thomas	Manager	Freeport	602-540-9149	thomas.knudsen@fmi.com	X	
Little	Toby	Staff	Arizona Corp. Commission	602-542-1519	mlittle@azcc.gov	X	
MacDermid	Gary	Engineer	Western Area Power Admin.	602-605-2660	MacDermid@wapa.gov		X
Mirich	Gary	Director	Energy Strategies	602-253-5581	gmirich@energystrategies.com		X
Mejia	Roni	Engineer	SCE	909-294-1632	roni.mejia@sce.com	X	
Miller	Lynn	PM	Power Engineers	206-718-4369	lynn.miller@powerengineers.com	X	
Olson	Mike		Western Area Power Admin.	602-605-2617	olson@wapa.gov	X	
Ormond	Amanda		Western Grid Group	480-491-3305	asormond@msn.com	X	X
Otter	Elna		Sierra Club, Cascabel W.G.	520-212-9736	elna.otter@gmail.com	X	
Patterson	Doug	Prj. Manager	Southern Transmission	415-944-0656	doug@blackfootpartners.com	X	
Pike	Madison	GIS Tech.	K.R. Saline & Associates, PLC	480-610-8741	mnp@krsaline.com		X
Reinhold	Charles		Electric Resource Strategies	208-253-6916	reinhold@ctc.net	X	
Ruiz	Reuben		Central Arizona Project	625-869-2370	rruiz@cap-az.com		X
Russell	Charles	Engineer	Salt River Project	602-236-0975	chuck.russell@srpnet.com	X	X
Saline	Ken	Engineer	K.R. Saline & Associates, PLC	480-610-8741	krs@krsaline.com		X
Scott	Deb	Attorney	Arizona Public Service Co.	602-250-5508	Deb.Scott@pinnaclewest.com		X
Shultz	Martin	Senior Pol. Director	BHFS	602-382-4060	mshultz@bhfs.com	X	
Simer	Kent		K.R. Saline & Associates, PLC	480-610-8741	kes@krsaline.com		X
Smith	Bob	Director	Arizona Public Service Co.	602-351-6919	robert.smith@aps.com	X	
Smith	Jerry D.	Engineer	P&R Consulting-Hensel Phelps	480-634-8692	PNRConsulting@cox.net	X	X
Smith	Shasta	Reg. Affairs	Arizona Public Service Co.	602-250-2372	shasta.smith@aps.com	X	X

Sparks	Keith	Director	Clean Line Energy Partners	281-687-9864	ksparks@cleanlineenergy.com	X		
Spitzkoff	Jason	Planning Engr.	Arizona Public Service Co.	602-250-1651	jason.spitzkoff@aps.com	X		X
Stewart	Ryan	Planning Engr.	Arizona Public Service Co.	602-250-1714	ryan.stewart@aps.com			X
Stiens	Bob		Southern California Edison	626-302-4974	Robert.stiens@sce.com	X		
Trent	Gary	TransPlanningEngr	Tucson Electric Power Co.	520-745-3168	gtrent@tep.com	X		
Tumarin	Boris	Mgr. Trans.Planning	Southwest Transmission Coop		btumarin@ssw.coop			X
Stewart	Ryan	Engineer	Arizona Public Service Co.	602-850-1714	ryan.stewart@aps.com	X		
Stoneburg	Ed	Staff	Arizona Corp. Commission		estoneburg@azcc.gov	X		X
Tumarin	Boris	Mgr Trans. Planning	Southwest Transmission Coop		btumarin@ssw.coop	X		
Turner	Rebecca	V.P. Reg	Gila River Power	813-301-4925	rturner@entegra.com	X		
Udall	Larry	Attorney	CG SUS	602-393-1200	ludall@cgsuslaw.com	X		
Walker	Paul	Consultant	Insight	602-703-4205	paul@arizonainsight.com			X
Watson	Mark	Prj. Development	Longview Energy Exchange	602-914-2628	mwatson@henselphelps.com	X		
Woodall	Laurie	Attorney	Arizona Corp. Commission	602-542-3621	lwoodall@azcc.gov	X		X
Wray	Tom	Project Manager	Sunzia/SWPG	602-808-2004	twray@southwestempower.com			X

Appendix D - Questions Posed to Industry and Stakeholders – Workshop I

To help facilitate Workshop discussion the following questions were posed to all prospective workshop attendees and participants:

1. What transmission related topics or policy issues do you desire to have added to the proposed agenda?

Questions posed specifically to all parties that filed ten year plans, for addressing during their Workshop presentations included:

2. Describe all technical studies that were performed in support of your filed transmission plan.

3. List all reports that exist for the studies identified in item 1 and identify which reports were not included in your ten year plan filing.

4. Identify all transmission projects in your transmission plan for which power flow and stability analyses have not been performed or for which reports have not been filed. Describe how and when do you intend to respond with the required studies and reports.

5. Describe any stakeholder input and review that occurred regarding your transmission plan.

6. Please identify the subregional transmission planning forum(s) in which your transmission plan was addressed. Were your project(s) or planned facilities studied in that forum? Did your project(s) or plan undergo a peer review in that subregional forum and were they incorporated in the subregional plan?

7. Identify all projects in your filed transmission plans that were not addressed in a subregional transmission planning forum.

8. Describe which transmission projects have been avoided or delayed by the effects of distributed generation and energy efficiency programs.

9. Describe the steps being taken to evaluate the transmission system adequacy impacts of the potential coal plant closures resulting from Environmental Protection Agency regulations.

10. Describe how the Arizona-Southern California September 8, 2011 outage has affected transmission system adequacy planning within your company.

11. Describe the steps being taken to evaluate the impacts on transmission system adequacy, including transmission system ancillary service requirements, of the increasing penetration of variable energy resources.

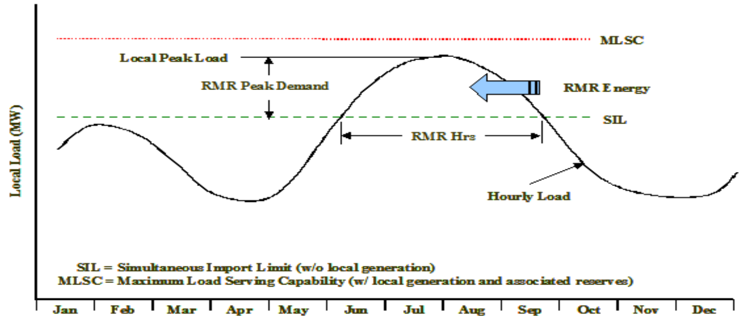
Appendix E - RMR Conditions and Study Methodology

In the 2002 BTA, Staff proposed that any UDC currently relying on local generation, or foreseeing a future time period when utilization of local generation may be required to assure reliable service for a local area, should perform and report the findings of an RMR study as a feature of their Ten-Year Plan filing with the Commission in January, 2003 and 2004. The 2002 BTA defined a Generic RMR Study Plan that required utilities to:

1. Define annual simultaneous import limits ("SIL") for each transmission import limited area.
2. Provide a listing of all local generation and associated operational attributes.
3. Define RMR conditions for each year of the Ten-Year Plan.
4. Provide a local generation sensitivity analysis.
5. Identify and study alternative solutions.
6. Perform comparative analysis and present worth analysis of alternative solutions.

RMR conditions, required from RMR studies, are defined in the 2002 BTA and graphically presented in the following Figure 1.[17]

Figure 1 – RMR Conditions



[17] 2002 BTA, Page 74-76

Essential RMR indicators that the Commission intends to receive from the RMR studies are:

- 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 dispatch from RMR

The 2002 BTA established specific RMR procedures. The transmission system's simultaneous import limit ("SIL") for each local constrained area is established for single contingencies ("n-1") with no local generation in operation. An RMR condition exists during those times when the local load served by a UDC, or group of UDCs, exceeds that SIL. If no local generation exists for an RMR condition then the UDC(s) would have to utilize a load-shedding scheme for those contingencies that establish the SIL. This would imply a violation of WECC planning criteria since reliability practices are founded on the principle of continuity of service for single contingency outages.

When local generating units within the local load pocket are owned or under the operational control of the UDC(s), they are viewed as RMR units for the duration of the RMR condition. A local generating unit that is neither owned or under operational control of the UDC(s) may be considered a non-RMR unit. In some instances, a non-RMR unit may have a "must-offer" requirement to assure that system reliability is maintained. A local non-RMR unit that is operational during the hours an RMR condition exists will have the automatic effect of mitigating the constraint to the extent it serves local load or its capacity and energy is scheduled out of the local load pocket.

Local generation, irrespective of its composition of RMR and non-RMR units, may offer an acceptable planning solution to RMR conditions. The local RMR condition is essentially mitigated when local generation capacity and its associated voltage regulation ability is equal to or greater than that required to reliably serve the local RMR peak load. The question that needs to be answered is whether such dependence on local generation is prudent and in the consumers' best interest.

The maximum load serving capability ("MLSC") of the local system is established by operating all local units at capacity, less local reserve requirements. The local MLSC equals to the SIL when there is no local generation. When local generation exists, the local MLSC is greater than the SIL but may fail to exceed the RMR peak load requirement. Such an RMR condition would require new transmission improvements or new local generation to assure reliable service to local consumers. When the MLSC is greater than the local peak demand, then the RMR condition is mitigated and there is less risk that local load would be interrupted for local transmission or generation outages.

Utilization of reactive devices such as high voltage shunt capacitors, static or dynamic var compensators, or Flexible AC Transmission System ("FACTS") control devices should be considered for voltage and var margin constrained SIL conditions. Similarly, maintaining a unity power factor at the sub-transmission bus of distribution substations and seasonal tap changes for transformers lacking automatic tap changer under load capability should be considered as a means of resolving voltage or var margin deficiencies. Advancing planned transmission lines or construction of previously unplanned lines should be among the alternatives studied for thermal and stability constrained SIL conditions.

A comparative analysis of all alternative solutions, including using local generation that mitigates the local RMR condition is to be documented. The following factors should be considered when documenting the merits of the various alternatives: impact on SIL, system reliability implications, system losses, operational flexibility, environmental effects, implementation requirements and lead-time, and opportunity for consumer benefits from competitive wholesale market. The following should also be identified in the comparative analysis of alternatives:

- The total expected cost, fixed and variable, for the local generation dispatch that results in the lowest local generation dispatch to mitigate annual RMR conditions.
- Total emission pollutants produced by the lowest local generation dispatch mitigating the annual RMR condition.

A present worth analysis of all alternative solutions is also to be performed. The cost analysis is to include an assessment of the total expected cost of operating local units versus remote units in combination with some transmission solution. Local and remote generation cost assumptions must be documented. The accuracy of RMR conditions depends upon technical studies, engineering assumptions and validity of data needed to determine:

1. Hourly load forecast for the future years.

2. SIL by ensuring that:

    - Aggregate local area load is the total substation load actually impacted by the transmission constraint;

    - RMR generation within the local area is accurate; o With RMR generation modeled out-of-service, the transmission system meets required normal ("n-0") reliability criteria, showing no thermal and/or voltage limit violations;

    - With RMR generation modeled out-of-service, the transmission system meets required reliability criteria for all single contingency outages showing no thermal and/or voltage criteria violations; and

    - With RMR generation modeled out-of-service, the transmission system remains stable and shows no voltage instability.

3. RMR production costs by ensuring that:

    - Analysis is done using industry recognized production-cost model.

    - Production-cost model database contains projected generation additions as accurate as possible, knowing in advance that future generation additions and unit commitments are dependent on many factors and are subject to change.

    - Hydro generation modeling reflects actual operating conditions as accurately as possible.

    - Thermal generation modeling reflects the current projection of variable operating and maintenance costs.

4. Comparison of the present worth of RMR production costs and present worth of transmission alternative costs.

Appendix F – Listing of Terminology and Acronyms[18] [19]

Terminology

Arizona Power Plant and Transmission Line Siting Committee: The committee that reviews proposals to construct power plants and transmission lines in Arizona. In 1971, the Arizona Legislature required that the Commission establish a power plant and line siting committee. The Committee provides a single, independent forum to evaluate applications to build power plants (of 100 megawatts or more) or transmission projects (of 115,000 volts or more) in the state. The Committee holds meetings and hearings that are open to the public.

Bundled service: Electric service provided as a package to the consumer including all generation, transmission, distribution, ancillary and other services necessary to deliver and measure useful electric energy and power to consumers.

Certificate of Convenience & Necessity (CC & N): A document granting operating authority to utilities.

Competitive services: All aspects of retail electric service except those services specifically defined as "Noncompetitive Services" pursuant to Corporation Commission Rules R14-2-1601(29) or noncompetitive services as defined by the Federal Energy Regulatory Commission.

Demand: The rate at which power is delivered during any specified period of time. Demand may be expressed in kilowatts, kilovolt-amperes or other suitable units.

Distribution lines: The utility lines operated at distribution voltage, which are constructed along public roadways or other bona fide rights-of-way, including easements on customer's property.

Distribution service: The delivery of electricity to a retail consumer through wires, transformers, and other devices that are not classified as transmission services subject to the jurisdiction of the Federal Energy Regulatory Commission. Distribution service excludes metering services, meter reading services and billing and collection services, as those terms are used herein.

Electric Service Provider (ESP): A company supplying, marketing or brokering at retail any competitive services pursuant to a Certificate of Convenience and Necessity approved by the Corporation Commission.

Environmental Portfolio Standard (EPS): A ruling by the Commission that requires any company serving electricity to an end-user to generate a portion of that electricity through renewable technologies such as wind, solar, biomass generators or landfill gas recovery.

Federal Energy Regulatory Commission (FERC): An independent regulatory agency within the US Department of Energy that, among other things, regulates interstate oil, natural gas and power transmission sales.

[18] Listing of Acronyms obtained from Fourth Biennial Transmission Assessment, Page 1
[19] http://www.cc.state.az.us/divisions/utilities/electric/terms.asp

Generation: The production of the actual megawatts of electricity or purchase of electricity through the wholesale market.

Green pricing: A program offered by an Electric Service Provider where customers elect to pay a rate premium for renewable generated electricity.

Pancaking: A term used to describe the layering of multiple tariff rates in point to point transactions.

PV Hub: Palo Verde power plant and switchyard, the Hassayampa switchyard, and the threre 500 kV tie lines connecting the two switchyards.

Interruptible electric service: Electric service that is subject to interruption as specified in the utility's tariff.

Kilowatt (kW): A unit of power equal to 1,000 watts.

Kilowatt-hour (kWh): The electric energy equivalent to the amount of electric energy delivered in 1 hour when delivery is at a constant rate of 1 kilowatt.

Megawatt (MW): A unit of power equal to 1,000,000 watts.

Meter service: All functions related to measuring electricity consumption, including installation and repair of meters, but not including meter reading.

Point of Delivery: The point where facilities owned, leased or under license by a customer connects to the utility's facilities.

Power: The quantity of electricity being generated, transferred or used at any instant in time, usually expressed in kilowatts.

Service area: The territory in which the utility has been granted a Certificate of Convenience and Necessity and is authorized by the Commission to provide electric service.

Tariffs: The documents filed with the Corporation Commission which list the services and products offered by the utility and which set forth the terms and conditions and a schedule of the rates and charges for those services and products.

Utility: The public service corporation providing electric service to the public in compliance with state law, except in those instances set forth in Corporation Commission Rules, R14-2-1612 (A) and (B).

Utility Distribution Company (UDC): The electric utility entity regulated by the Commission that operates, constructs, and maintains the distribution system for the delivery of power to the end user point of delivery on the distribution system.

Acronyms

AC	Alternating Current	MORC	Minimum Operating Reliability Criteria
ACC	Arizona Corporation Commission	MOU	Memorandum of Understanding
ANPP	Arizona Nuclear Power Project	MVA	Megavolt-Ampere
APS	Arizona Public Service	MVAR	Megavolt-Ampere Reactive
ATC	Available Transfer Capability	MW	Megawatt
AZ	Arizona	n-0	No Contingency
AZNM	AZ-NM EHV Subcommittee	n-1	Single Contingency
BTA	Biennial Transmission Assessment	n-1-1	Overlapping Contingency
BTU	British Thermal Unit	n-2	Double Contingency
CA	California	NERC	North American Electric Reliability Corporation
CAO	Control Area Operator	NG	Natural Gas
CATS	Central Arizona Transmission System	NM	New Mexico
CAWCD	Central AZ Water Conservation District	NOI	Notice of Inquiry
CC	Combined Cycle	NOPR	Notice of Proposed Rulemaking
CDEAC	Clean and Diversified Energy Advisory Committee	NTP	Navajo Transmission Project
CEC	Certificate of Environmental Compatibility	OASIS	Open Access Same Time Information System
CRT	Colorado River Transmission Subcommittee	OATT	Open Access Transmission Tariff
DOE	Department of Energy	PJM	Pennsylvania-New Jersey-Maryland (ISO)
DPA	Dine Power Authority	PNM	Public Service of New Mexico
DSW	Desert Southwest Region	PURPA	Public Utilities Regulatory Policy Act
ED	Electric District	PV	Palo Verde
EFOR	Equivalent Forced Outage Rate	RMR	Reliability Must Run
EHV	Extra High Voltage	RMS	Reliability Management System
EOR	East of (Colorado) River	RTO	Regional Transmission Organization
EPACT	Energy Policy Act	SCE	Southern California Edison
EPS	Environmental Portfolio Standards	SCED	Security Constrained Economic Dispatch
ERO	Electric Reliability Organization	SDG&E	San Diego Gas and Electric
FACTS	Flexible AC Transmission System	SEV	South East Valley
FERC	Federal Energy Regulatory Commission	SIL	Simultaneous Import Limit
FOR	Forced outage rate	SRP	Salt River Project
FPA	Federal Power Act	SSG-WI	Seams Steering Group – Western Interconnection
GT	Gas Turbine	ST	Steam Turbine
HV	High Voltage	STEP	Southwest Transmission Expansion Planning Group
HVDC	High Voltage Direct Current	SWAT	Southwest Area Transmission Study Group
HY	Hydro	SWPG	Southwest Power Group

I/S	In-Service	SWTC	Southwest Transmission Cooperative
IID	Imperial Irrigation District	TEP	Tucson Electric Power
IPP	Independent Power Producer	TEPPC	Transmission Expansion Planning Policy Committee
ISO	Independent System Operator	TNMP	Texas-New Mexico Power Company
KRSA	K.R. Saline and Associates, PLC	TTC	Total Transfer Capability
kV	Kilovolt	UDC	Utility Distribution Company
kWh	Kilowatt-Hour	UNS	UniSource Energy Corp.
LSE	Load Serving Entity	WAPA	Western Area Power Administration ("Western")
MISO	Midwest Independent System Operator	WECC	Western Electricity Coordinating Council
MLSC	Maximum Load Serving Capability	WGA	Western Governors' Association

Appendix G - Information Resources

Transmission Planning Studies and related documents, used to develop this Eighth BTA report, were assembled from the following reports, presentations, and dockets:

Utilities' 2014 Ten-Year Transmission Plans
Ajo Improvement Company
Arizona Public Service Company ("APS")
Salt River Project ("SRP")
Southwest Transmission Cooperative ("SWTC")
Public Service Company of New Mexico ("PNM")
Tucson Electric Power Company ("TEP")
El Paso Electric Company ("EPE")
UniSource Electric ("UNSE")
Western Area Power Administration ("Western") - Unfiled

First Draft Comments and Workshop II Comment Summary Presentation
All comment in their entirety or the summary presentation can be found on ACC Commission Docket (http://edocket.azcc.gov/)

First, Second, Third, Fourth, Fifth, Sixth and Seventh BTA Reports and 2014 Summer Preparedness Presentations
These reports and presentations can be found on the Arizona Corporation Commission website (www.cc.state.az.us/utility/electric/index.htm)

Arizona Corporation Commission's Docket Control
Items related to previous and present filings (http://edocket.azcc.gov/)

N-1-1 and Extreme Contingency Study Documents
ACC 2014 BTA Workshop I N-1-1 and Extreme Contingency Presentations

Transmission and Generation Projects Reports
SolarReserve
Centennial West Clean Line
Southline Transmission Project
Sun Streams
Tribal Solar
Longview Energy Exchange
Buckeye Generation Center
Gila Bend Power Partners
EnviroMission
BP Wind Energy
Delaney – Colorado River 500 kV Project (D-CR)
Harcuvar Transmission Project (HTP)

Bowie Power Station
SunZia Southwest Transmission Project – Southwestern Power Group
High Plain Express
North Gila – Imperial Valley #2 500 kV Project (NG-IV2)
Abengoa
TransWest Express Initiative

Regional Committees and Working Groups Materials
WestConnect Documents (www.westconnect.com)
Southwest Area Transmission (SWAT)
Arizona Group (SWAT-AZ)
Short Circuit Working Group (SCWG)
El Dorado Valley Study Group (EVSG)
California Interface Work Group (CIWG)
Transmission Corridor Work Group (TCWG)
Coal Reduction Assessment Task Force (CRATF)

Federal Energy Regulatory Commission (FERC)
FERC Reliability Standards (www.ferc.gov)

North America Electric Reliability Council (NERC)
NERC Reliability Standards (www.nerc.com)

Western Electricity Coordinating Council (WECC) Standards and studies
The standards can be found on the WECC website (www.wecc.biz) under "Click here for library".
WECC 2013 Path Rating Catalog,
http://www.wecc.biz/library/Pages/Path%20Rating%20Catalog%202013.pdf

Western Governors Association (WGA)
Support documents and Report documents (www.westgov.org)

California Independent System Operator (CAISO)
Support documents and Report documents
(http://www.caiso.com/planning/Pages/TransmissionPlanning/Default.aspx)

Large Generator Interconnection Queues (http://www.oatioasis.com/cwo_default.htm)
Arizona Public Service Company (APS)
Salt River Project (SRP)
Tucson Electric Power (TEP)
Southwest Transmission Cooperative (SWTC)
Western Area Power Administration (WAPA)

Integrated Resource Plans
2014 Arizona Public Service (APS)