ELEVENTH BIENNIAL TRANSMISSION ASSESSMENT 2020-2029

Staff Report

Docket No. E-00000D-19-0007

March 9, 2021

Prepared by Arizona Corporation Commission Staff

And

ESTA International, LLC

22525 Ridgetop Circle Suite 200

Herndon, Virginia, 20166-6510

Decision No. ________

[This page intentionally blank for formatting purposes]

Decision No. ________

FOREWORD

The Arizona Corporation Commission ("ACC" or "Commission") performs a biennial review of the ten-year transmission plans filed by parties who are responsible for transmission facilities in Arizona and issues a written decision regarding the adequacy of the existing and planned transmission facilities to reliably meet the present and future transmission system needs of Arizona.[1] This report by the Staff of the Commission's Utilities Division ("ACC Staff" or "Staff") is the Eleventh Biennial Transmission Assessment ("BTA" or "Eleventh BTA") and has been prepared in accordance with a contract agreement between ESTA International, LLC ("ESTA") and the Commission. This is a public document. Use of the report by other parties shall be at their own risk. Neither ESTA nor the Commission accepts any duty of care to such third parties.

Arizona's Eleventh BTA is based upon the Ten-Year Plans filed with the Commission by parties in January 2020. It also incorporates information and comments provided by interested stakeholders in the docket, at the BTA workshops, and during the report review process. The ACC Staff and ESTA appreciate the contributions, cooperation, and support of industry participants throughout the Eleventh BTA process.

[1] Arizona Revised Statute §40-360.02

Decision No. ________

[This page intentionally blank for formatting purposes]

Decision No. ________

EXECUTIVE SUMMARY

Arizona Revised Statute ("A.R.S.") § 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."* Staff, with the aid of ESTA, reviewed the Ten-Year Plans and related filings submitted to the Commission,[2] held open and transparent workshops on August 7, 2020, ("Workshop I") and February 19, 2021, ("Workshop II") to solicit industry participation, and drafted this Eleventh BTA report based on the results of these activities. The Ten-Year Plans and related filings that were reviewed by Staff and ESTA included utility transmission plans with supporting technical study work, merchant developer plans for transmission projects and generator interconnection tie-lines, and Commission-ordered technical studies, including the Ten-Year Snapshot and Extreme Contingency study. Staff and ESTA reviewed, analyzed, and questioned study work; however, the parties did not perform their own independent study.

In preparing the first draft of the Eleventh BTA report, Staff and ESTA also reviewed the Workshop I presentations and recordings.[3] One successive draft report of this Eleventh BTA was made available for industry and stakeholder comments; the comments received were considered in preparing the final report. This Eleventh BTA process assesses the adequacy of Arizona's transmission system to reliably meet the existing and planned transmission needs of the state by addressing four fundamental public policy questions asked during this BTA:[4]

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 2020-2029 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, Distributed Generation ("DG") and Energy Efficiency ("EE"), and Extreme Contingency studies filed as part of the Eleventh BTA provide useful and sufficient information in determining adequacy of the state's transmission system over the next 10 years?

---

2 Filings were made in Docket No. E-00000D-19-0007

3 Video of August 7, 2020, Workshop I is available at the ACC Public Meeting Archive https://azcc.granicus.com/player/clip/4058?view_id=3&redirect=true

4 This BTA does not establish Commission policy and is not final unless and until approved by a written decision of the Commission.

5 RMR Studies were not required for the Eleventh BTA based upon criteria set by the Commission in the Seventh BTA

3. **Adequacy of the system to reliably support the wholesale market**: Are the transmission planning efforts effectively addressing 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**: Do the plans and planning activities comport with transmission planning principles and good utility practices accepted by the power industry and the reliability planning standards established by the North American Electric Reliability Corporation ("NERC") and Western Electricity Coordinating Council ("WECC")?

Conclusions

The information provided by the utilities and other transmission developers for the Eleventh BTA was comprehensive and responsive to the statutory and Commission-ordered requirements. The information provided was used to develop the conclusions of the Eleventh BTA; where applicable, the conclusions were organized to answer the four key policy questions described above.

General Conclusions

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 seventeen filing entities and consists of fifty-eight transmission projects of approximately 864 miles in length. Fifty-five projects are beyond the ten-year horizon or have in-service dates that are yet to be determined and account for an additional 1,132 miles of new transmission.

2. As active members of the WestConnect Planning Management Committee, Arizona utilities have increased their situational awareness, cooperation, and coordination with neighboring utilities, sub-regional, and regional planning groups to address potential reliability issues that could affect Arizona, the desert southwest region, and other regions throughout the WECC. While the individual plans lean heavily toward addressing local load-serving needs, as they should, the plans also reflect a high level of coordination that addresses state and regional needs in a cohesive manner.

3. As Arizona continues to deploy more renewable generation, the electric utilities will need to increasingly work with neighboring utilities in both the state and the Western Interconnection to address new operational challenges in order to ensure the reliable operation of the power system in Arizona.

4. The development and implementation of the Affordable Clean Energy ("ACE") Rule will be closely followed by Staff and further updates, as related to transmission planning, will be provided in future BTAs. As more coal resources are retired throughout the West, this is an issue that utilities should continue to watch and should supply any relevant updates in future BTAs.

5. Appendix A presents the *Guiding Principles for ACC Staff Determination of Electric System Adequacy and Reliability* ("Guiding Principles") that Staff relies on to aid in determining the adequacy and reliability of both transmission and generation systems. There are no recommended revisions to the Guiding Principles from this Eleventh BTA.

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 process. Based upon the technical study work examined by Staff and ESTA, the existing and proposed transmission system meets the load-serving requirements of Arizona in a reliable manner for the 2020-2029 timeframe.

1. The 2020 level of summer preparedness of the utilities in Arizona as presented in the May 7, 2020, Special Open Meeting, demonstrated sufficient preparedness measures are being taken. The current transmission system in Arizona is judged to be adequate to reliably support the energy needs of the state in 2020.[6]

2. During the Eleventh BTA the Arizona utilities reported a Ten-Year Forecast that was, on average, 1.4 percent higher than what was reported during the Tenth BTA. The statewide forecast shows a projected growth rate of approximately 2.67 percent per year for the Ten-Year forecast period, which is slightly higher than the growth rate forecasted in previous years.

3. All SIL and MLSC studies, which measure planned local transmission systems' ability to serve load reliably in load pockets, show that the local transmission systems are adequate to meet the ten-year local load forecasts.

[6] Summer Preparedness for the Year 2020, May 07, 2020 at the ACC in Phoenix hearing room #1. https://azcc.granicus.com/player/clip/3887?view_id=3&redirect=true

Efficacy of Commission-Ordered Studies

The Commission has ordered utilities to perform the following studies as part of the BTA:

- SIL, MLSC, RMR (if certain triggers occur),
- Ten-Year Snapshot,
- Extreme Contingency Analysis, and
- Effects of EE/DG

The principal purpose of the Commission-ordered studies is to assure compliance with the conclusions and recommendations within the BTA. Each Commission-ordered study required for the Eleventh BTA is filed with the Commission.

Staff and ESTA 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. The SIL and MLSC studies show that the planned local transmission systems are adequate to meet ten-year local load forecasts.

2. In the Seventh BTA, Staff suspended the RMR studies and established criteria for restarting such studies based on a biennial review of specific triggering factors. None of these triggering factors occurred in the Eleventh BTA studies in any of the RMR areas.

3. The Ten-Year Snapshot study shows Arizona's transmission plan is robust and supports the statewide loads forecasted through 2029.

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/corridors. Arizona Public Service ("APS") and Tucson Electric Power ("TEP") performed the Extreme Contingency studies for projected 2020 and 2029 system conditions. APS's extreme contingency analysis shows that under specific extreme contingency outage in the long-term planning horizon, the ability to serve the forecasted peak load is restricted. While these load levels may not be fully realized by 2029, APS and SRP are coordinating study work to examine system upgrades that may be needed. Load shedding was not needed for any of the extreme contingencies studied in either 2020 or 2029. TEP's extreme contingency analysis study results were found to be satisfactory. The inclusion of the Southline Project in both the 2021 and 2029 heavy summer

cases helps not only to solve the powerflow case associated with the extreme contingencies but also reduces the thermal overloads and prevents any potential cascading.

5. The EE/DG studies satisfy the Commission's requirement to conduct a fifth-year technical study, down to the 115 kilo volt ("kV") level, on the impacts of DG and EE. The studies indicate that EE/DG have properly been studied in system planning and EE/DG do not impact the reliability of the transmission system belonging to Arizona's load-serving utilities.

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. This BTA addresses four major interstate EHV transmission projects filed in this BTA. Individually and collectively, these projects will improve the opportunity for interstate commerce.

2. Staff and ESTA conclude that the Arizona utilities are taking proper actions with respect to transmission planning impacts related to integrating renewable generation resources.

3. The Fifth BTA ordered the utilities to name their top three renewable transmission projects ("RTP"). No RTPs were undertaken by Arizona utilities for this planning cycle.

4. Federal Energy Regulatory Commission ("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 the regional transmission planning processes and cost allocation mechanisms in a cost-effective manner. The WestConnect Planning Management Committee ensures compliance with FERC Order No. 1000 requirements. WestConnect's 2020-2021 Regional Planning Cycle is currently underway; its Final Regional Study Plan for the 2020-2021 Planning Cycle was published on March 14, 2020. The draft Regional Needs Assessment and Model Development Report has been distributed to stakeholders for review. This process offers a readily accessible forum for stakeholders to be involved in planning transmission systems that will support a robust wholesale market.

Suitability of Utilized Planning Processes

Based upon information provided by the utilities, the Arizona utilities use significant and well-defined transmission planning processes:

1. The results of NERC/WECC Reliability Standard audits over the past two years show there was one possible Critical Infrastructure Protection ("CIP") violation and two possible Operation and Planning violations-all have been mitigated.[7] There is no concern that Arizona's bulk electric system ("BES") does not meet the applicable planning standards set by NERC/WECC.

2. Technical studies filed in the Eleventh BTA indicate a robust study process for assessing transmission system performance for the 2020-2029 planning period.

3. Arizona utilities communicate their transmission plans in an open and transparent manner at local, state, sub-regional, and regional transmission planning forums using public processes.

Recommendations

Staff offers the following recommendations for Commission consideration and action:

1. Staff recommends that the Commission support:

   a. The continued use of the "Guiding Principles for ACC Staff Determination of Electric System Adequacy and Reliability" as revised in the Eighth BTA.

   b. The use of collaborative transmission planning processes such as those that currently exist in Arizona, which help 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 the criteria for restarting such studies based on a biennial review of factors as outlined in the Seventh BTA.

   d. The continued suspension of the requirement that Arizona utilities, for each load-growth or reliability-driven transmission project, include the load level range at which each transmission project is needed, as directed in Decision

[7] This tally does not include TEP's WECC audit results which were provided under confidentiality agreement.

No. 74785. Utilities shall continue to describe, in general terms, the driving factor(s) for each transmission project in the Ten-Year Plan.

e. That any requirement set in a prior BTA will continue in force unless the Commission suspends such requirement in a succeeding BTA. Nevertheless, Staff recommends that the Commission emphasize the importance of these continuing requirements for Arizona utilities:

i. Inform each interconnection applicant of the need to contact the ACC about the filing requirements of the Power Plant and Transmission Line Siting Committee at the time the applicant files for interconnection.

ii. 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.

iii. Address the effects of DG and EE on future transmission needs in their Ten-Year Plan filings by evaluating the 5th year.

iv. Ensure that the Commission-ordered Ten-Year Snapshot study monitors transmission elements down to and including the 115 kV level for thermal loading and voltage violations.

v. 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.

f. The policy that the Load Serving Entity ("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 monitor any changes in Cochise County and Santa Cruz County system reliability by collecting applicable outage data from the respective utilities in future BTA proceedings.

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

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

ii. The RMR studies were not needed because none of the triggering factors occurred for the Eleventh 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 2029 for a comprehensive set of single contingencies ("n-1"), each tested with the absence of different major planned transmission projects.

v. The EE/DG study results containing the fifth-year contingency analysis with and without disaggregated DG and EE loads.

[This page intentionally blank for formatting purposes]

Decision No. ________

CONTENTS

FIGURES

TABLES

EXHIBITS

APPENDICES

1 OVERVIEW

1.1 Assessment Authority

Arizona statutes require every entity considering construction of any transmission line equal to or greater than 115 kilovolts ("kV") within Arizona during the next ten-year period to file a Ten-Year Plan with the Arizona Corporation Commission ("A.C.C." 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 A.C.C. 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 to offer an assessment of the adequacy of the existing and planned Arizona electric transmission system. This Eleventh Biennial Transmission Assessment evaluates the ten-year transmission plans filed with the Commission in January 2020.[13] This report fulfills the statutory obligation to review these transmission plans and assess whether the Arizona transmission system is, and will likely remain, adequate throughout the ten-year timeframe.

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 and ESTA reviewed the technical reports and documents filed with the Commission and other publicly available industry reports but did not perform independent technical study work in this matter.

In addition to the ten-year filings, the Commission ordered supplemental studies to be performed as a portion of this Eleventh BTA.[14] These studies include: a study on effects of distributed generation ("DG") and energy efficiency ("EE") installations on future transmission

---

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-19-0007. http://edocket.azcc.gov/search/docket-search/item-detail/22078

14 Decision No. 74785, Docket No. E-00000D-13-0002

needs, System Import Limit ("SIL")/Maximum Load Serving Capability ("MLSC"), Reliability Must Run ("RMR") if certain triggers are met, 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 relies on the "Guiding Principles for ACC Staff Determination of Electric System Adequacy and Reliability" ("Guiding Principles") for aid 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 through the Seventh BTA. In the Eighth BTA, Staff updated the guiding principles to reflect the current state of the industry within Arizona and nationally. The update specifically addressed mandatory, enforceable, updated reliability standards put in place following the Energy Policy Act of 2005. The Commission accepted the updated Guiding Principles in Decision No. 74785.

Staff and ESTA critically reviewed the Ten-Year Plan filings and addressed the following four key public policy questions:

- **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 2020-2029 timeframe in a reliable manner?

- **Efficacy of the Commission-ordered studies** - Do the Simultaneous Import Limit, Maximum Load Serving Capability, Reliability Must Run[16] (if certain triggers are met), Ten-Year Snapshot, Distributed Generation and Energy Efficiency, and Extreme Contingency studies filed as part of the Eleventh BTA provide useful and sufficient information in determining adequacy of the state's transmission system over the next 10 years?

- **Adequacy of the system to reliably support the wholesale market** - Are the transmission planning efforts effectively addressing concerns raised in earlier BTAs about the adequacy of the state's transmission system to reliably support the competitive wholesale market in Arizona?

- **Suitability of the transmission planning processes used** – Are the plans and planning activities consistent with transmission planning principles and good utility practices accepted by the power industry and the reliability planning standards established by NERC and WECC?

---

[15] A complete history of Commission-ordered Studies is found in Appendix B.

[16] RMR Studies were not required for the Eleventh BTA based upon criteria set by the Commission in the Seventh BTA

1.3 Assessment Process

The preparation of this Eleventh BTA report used a four-step approach. The first step was to conduct the Eleventh BTA Workshop I ("Workshop I"), during which each entity had 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 Eleventh BTA. The third step was developing, distributing, and posting a draft report for public comment. The final step included conducting the Eleventh BTA Workshop II ("Workshop II") during which Staff (with assistance from ESTA) presented the second draft of the report. The following sections describe each step of the BTA process.

1.3.1 Workshop I: Industry Presentations

Staff conducted a public workshop on August 7, 2020, held remotely due to COVID 19 restrictions in place at the Commission.[17] The Eleventh 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. Table 1 lists panels/topics presented during Workshop I.

Workshop I – Agenda Items/Panels	Presenters
Utility Ten-Year Transmission Plans	Arizona Public Service ("APS"), Salt River Project ("SRP"), Tucson Electric Power ("TEP")/UNS Electric ("UNSE"), Arizona Electric Power Cooperative ("AEPCO")
Interstate and Merchant Transmission Projects	SunZia, Ten West Link
Commission Ordered BTA Requirements	Ten Year Snapshot and Extreme Contingency Studies, EE and DG Studies presented by APS, SRP, TEP/UNSE
National and Regional Transmission Issues	Southwest Area Transmission ("SWAT")

TABLE 1 - SUMMARY OF WORKSHOP I PRESENTATIONS

Prior to Workshop I, each presenter was given a set of questions, as outlined in Appendix D, to address in their Workshop I presentation. Each presentation was grouped into the four panels as shown in Table 1. At the conclusion of each panel's presentations, an open discussion was held for questions and comments from Commissioners, Staff, and the audience. Staff concluded

[17] Video of the August 7, 2020, Workshop I is available at the ACC public meeting archive: https://azcc.granicus.com/player/clip/4058?view_id=3&redirect=true

Workshop I with an overview of the remaining steps in the BTA process and asked that Presenters file a copy of their presentations in the BTA docket.

1.3.2 Review of Industry Filings in Eleventh BTA

Staff and ESTA reviewed all filings made to date by utilities in the Eleventh BTA to ensure required data was filed. When deficiencies were found, data requests were issued to obtain required data.

Table 2 shows a matrix of the various categories of Ten-Year Planning information filed by utilities or Sub-Regional Transmission Planning Groups and received from data requests during the Eleventh BTA.[18]

Utility	Ten-Year Plan	2020-2029 Utility Technical Study Report	RMR Study Report	Planning Criteria & Ratings	DG & EE Study	Filings of Joint Study Report(s)
APS	X	X	Not Required in 11th BTA	X	X	Extreme Contingency Study
SRP	X	X	Not Required in 11th BTA	X	X	N/A
SWAT-AZ	N/A	N/A	N/A	N/A	N/A	Ten Year Snapshot
AEPCO	X	X	Not Required in 11th BTA	X	N/A	N/A
TEP	X	X	Not Required in 11th BTA	X	X	Extreme Contingency Study
UNSE	X	X	Not Required in 11th BTA	X	X	N/A

TABLE 2 - SUMMARY OF UTILITY DATA

1.3.3 Preparation of Draft Report and Industry Comment

Staff and ESTA filed a draft report of the Eleventh BTA for industry review and comment on December 28, 2020. This draft report was developed from data contained in the Ten-Year Plan submittals, information gathered at Workshop I, a review of industry reports and presentations, and subsequent replies to data requests from the utilities.[19] Staff requested comments in response

[18] Extreme Contingency Studies were performed by APS and TEP and coordinated through SWAT

[19] Extreme Contingency Studies were performed by APS and TEP and coordinated through SWAT – http://media-07.granicus.com:443/OnDemand/azcc/azcc_0e21c628-a065-40a0-9053-ded5de4b5197.mp4

to the draft report be filed by January 22, 2021. Staff and ESTA received, reviewed, and considered industry comments. The comments were collected, categorized, and presented at Workshop II.

1.3.4 Workshop II: Staff Presentation of Final Report

Workshop II was held remotely, due to COVID 19 restrictions in place at the Commission, on February 19, 2021.[20] The purpose of Workshop II was to discuss comments received in response to the draft of the Eleventh BTA. The final report presented to the Commission included comments, and clarification resulting from this workshop.

During Workshop II, Staff presented all comments received in response to the draft of the Eleventh BTA and informed stakeholders of planned changes to the Eleventh BTA. In addition, Staff requested feedback about the planned changes.

1.4 Terminology and Acronyms

Staff and ESTA have strived to define all industry acronyms and supply clarifying footnotes to industry language used throughout the report. Appendix F includes a listing of other terminology and acronyms.

1.5 Additional Resources

When more information was required than was included in the filing, Staff and ESTA used external resources. Appendix G lists the external information resources used in the BTA assessment.

2 TEN-YEAR PLANS

Seventeen entities formally filed Ten-Year Plans with the Commission in 2019; thirteen of those also filed in 2020 along with four new entities for a total of seventeen filings in 2020. The Ten-Year Plans for WestConnect and WAPA were also considered while preparing this assessment. Table 3 includes the parties that filed ten-year transmission plans.

Entity	**Ten-Year Plan Filed in**	
	2019	**2020**
AES Energy Storage	N	Y
Arizona Electric Power Cooperative Inc.	Y	Y
Ajo Improvement Company	Y	Y
Arizona Public Service	Y	Y

[20] Video of the February 19, 2021 Workshop II is available at the ACC public meeting archive: https://azcc.granicus.com/player/clip/4355?view_id=3&redirect=true

Big Chino Valley Pumped Storage	Y	N
Bowie Power Station	Y	Y
First Solar Sunstreams	N	Y
Chevelon Butte Wind	Y	Y
Gila Bend Power Partners	Y	Y
Hashknife	N	Y
Nogales Transmission Project	N	Y
North Gila Imperial Valley	Y	Y
RE Papago LLC	Y	N
Southline Transmission Project	Y	Y
sPower Development Co East Line Solar	Y	N
Salt River Project	Y	Y
SunZia Southwest Transmission Project	Y	Y
Ten West Link	Y	Y
Tucson Electric Power	Y	Y
UNS Electric, Inc.	Y	Y
Wilmont Properties, LLC	Y	N

TABLE 3 - LIST OF PARTIES FILING TEN-YEAR PLANS IN 2019 AND 2020

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 and reliability.[21] As directed, the projects filed in the Eleventh 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 Eleventh BTA examines the aggregate of these Ten-Year Plans.

Arizona Utilities perform technical analyses per NERC Transmission Planning ("TPL") and Transmission Operations ("TOP") standards, and their own internal planning criteria, guidelines and methods. These planning practices are used to ensure that their respective systems are planned to reliably supply customers under various system conditions.

2.1 Summary of Arizona Plan

The aggregate of the 2019 and 2020 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 seventeen filing entities and consists of fifty-eight transmission projects of approximately 864

[21] Decision No. 72031 (December 10, 2010)

miles in length.[22] Fifty-five projects are beyond the ten-year horizon or have in-service dates that are yet to be determined and account for another 1,132 miles of new transmission.[23] Seventeen of the projects reported have lengths estimated to be less than 1 mile in length; for the purposes of the Arizona Plan, those lengths have been assigned a length of one mile.

Table 4 shows the number of new transmission projects and associated mileage for each year of the Ten-Year Plan Projects; 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 counted as separate projects. As is typical in transmission planning, a majority of the Arizona Plan projects fall 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.

In-Service Date[24]	# of Projects	Mileage
2020	12	40.38
2021	15	170.4
2022	7	38.2
2023	14	545.2
2024	4	24
2025	2	20.5
2026	1	1
2027	2	9.75
2028	-	-
2029	1	14.3
Subtotal	58	863.73
TBD	55	1,131.9
Total	113	1,995.63

TABLE 4 - TRANSMISSION PROJECTS WITH MILEAGE BY YEAR

Table 5 shows 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 level of the project.[25]

As shown in Table 5, the Arizona Plan includes a considerable number of 345 & 500 kV transmission miles. Most of the 500 kV total transmission miles are attributable to four transmission projects: the Palo Verde – Saguaro line; SunZia Southwest Transmission Project; the

22 Two projects have lengths that are still to be determined.
23 Sixteen projects have lengths that are still to be determined.
24 Table 4 represents new transmission projects only. Planned reconductor projects, transformer capacity upgrade projects, and reactive power compensation facility additions at 115 kV and above have been excluded.
25 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.

Ten West Link Transmission Project; and the Westwing Substation – South Substation line.[26] Collectively, these projects account for 630 of the 939 total 500 kV miles shown in Table 5, below. Similarly, the proposed 345 kV system increase is primarily being driven by the Southline Transmission Project, which is 246 miles out of the total 402 miles planned. The Arizona Plan is listed in tabular form in Exhibits 12 and 13 by in-service date and voltage class, respectively.

Voltage Class	Number of Projects		Mileage
	2020-2029	Post 2029-TBD	
500 KV	6	12	939.8
345 kV	3	5	402.2
230 kV	19	29	322.10
138 kV	24	7	311.58
115 kV	6	2	20.995
Total	57[27]	55	1995.63

TABLE 5 - PLANNED TRANSMISSION PROJECTS BY VOLTAGE

The Arizona Plan includes ten merchant generators and one utility generator totaling 6,260 MW and requiring approximately 106 miles of generator tie-lines in Arizona and is summarized in Table 6. The utility generator being reported is the Reciprocating Engine Installation ("RICE") at TEP Irvington Campus, which was included in TEP's 2019 and 2020 Ten-Year Plans and placed into service during 2020.

Description	Maximum Output (MW)	Gen-Tie Length (Mi)
Bowie Power Station	1,000	15
RE Papago	300	2
Big Chino Pumped Storage Project	2,000	50
Gila Bend Power Plant	833	6
East Line Solar Project	100	3.5
Reciprocating Engine Installation (RICE) at TEP Irvington Campus	200	1
Wilmot project - Natural gas	500	4.5
Wilmot project - solar plus battery	65	4.5
Hashknife Energy Center	400	3.5
Chevelon Butte Wind Farm	477	12
Sun Streams Expansion Project	385	4
Total	6,260	106

TABLE 6 - SUMMARY OF MERCHANT GENERATION AND TIE-LINES

[26] Assumed to be 500 kV

[27] One project has a voltage level to be determined.

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

2.2 Plan Changes Since the Tenth BTA

Transmission plans predictably change over time. Significant changes may result from 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.

Since the Tenth BTA, no major changes have been reported for projects with EHV levels of 345 kV and above. APS has listed one conceptual project in its ten-year plan – the TS2l 500/230kV Substation project.

2.3 Driving Factors Affecting the Ten-Year Plan – Load Forecast

In reviewing the filings, projected future load growth was the chief determinant for the ten-year transmission plans in Arizona. Figure 1 shows the change in statewide non-coincident[28] demand forecasts among earlier BTAs and the current Eleventh BTA.

[28] Non-coincident demand is the sum of the individual utility forecasts which may or may not occur at the same time.

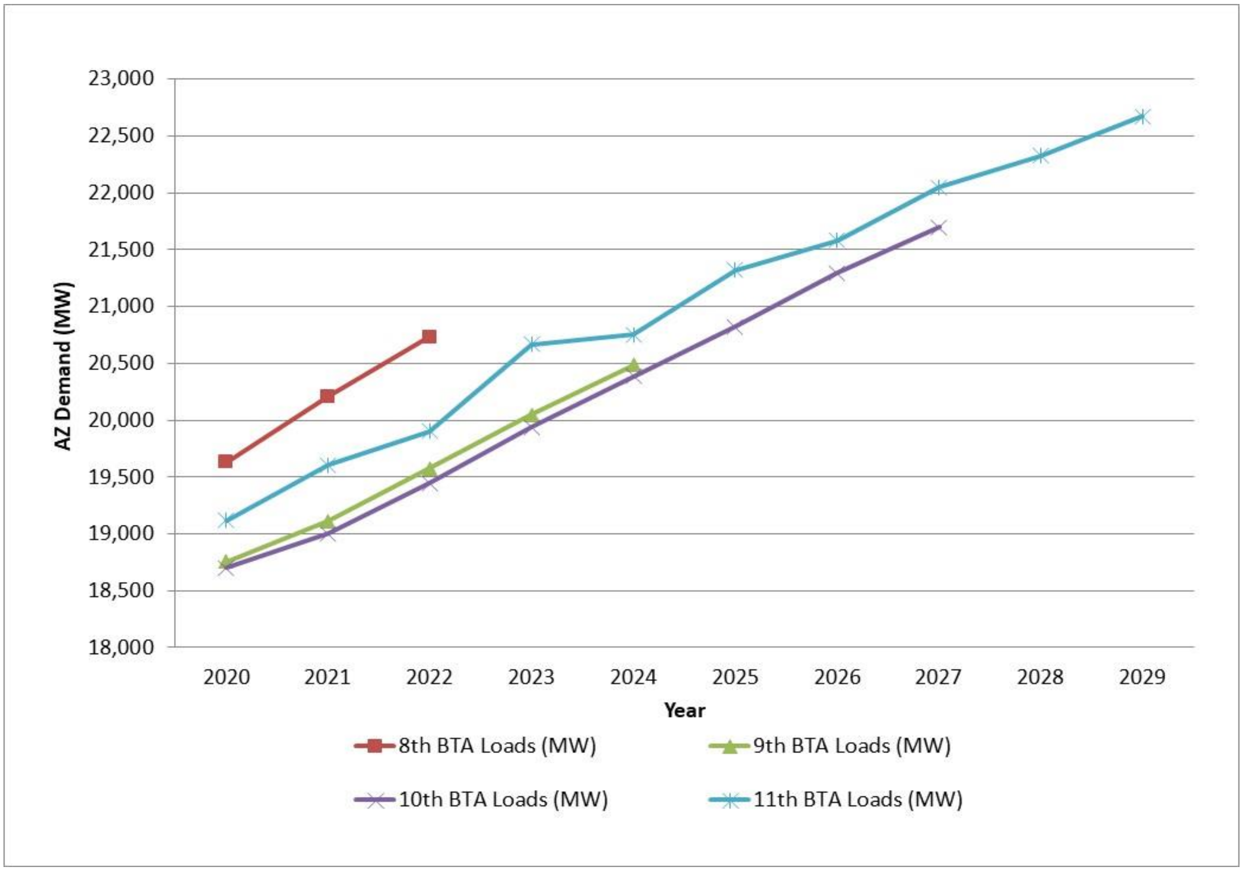

Figure 1: Change in Arizona Demand Forecast

During the Eleventh BTA the Arizona utilities reported a Ten-Year Forecast that was, on average, 1.4 percent higher than during the Tenth BTA. The statewide forecast shows a projected growth rate of approximately 2.67 percent per year for the Ten-Year forecast period, which is slightly higher than the growth rate forecasted in previous years.[29]

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."[30] Supplemental to the requirements of the Sixth BTA, in the Eighth BTA the Commission directed Arizona utilities with retail load to report the effects of DG and EE on future transmission needs. The study is to include a technical analysis performed on the fifth-year transmission plan and including a contingency analysis depicting the planned transmission system with and without disaggregated DG and EE load. The filed Ten-Year Plans for APS, SRP, and TEP/UNSE included the results of the technical study work and discussed

29 10-year average growth rate reported during the 10th BTA was 2.16 percent.
30 Decision No. 72031

the factors involved in developing the demand forecasts used in studies performed for the current Ten-Year Plans. Section 3.3.5.3 discusses the DG and EE technical study results in more detail.

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.[31] 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 reviewed each utility's active generation interconnection queues from the Tenth and Eleventh BTA, along with the difference between the two (see Table 7 and Exhibit 11). In parallel with 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.[32]

Utility	Approximate Capacity (MW) of Generators in Utility Queue		Interconnection Queues from Tenth to Eleventh
	Tenth BTA	Eleventh BTA	
APS	14,162	29,985	14,744
SRP	2,706	3,245	345
TEP/ UNSE	634	4,054	1,620
WAPA	1,435	1,440	(1,235)
AEPCO	200	550	350
Total	19,137	39,274	15,854

TABLE 7 - UTILITY GENERATION INTERCONNECTION QUEUES

Arizona's combined interconnection queues have increased significantly since the Tenth BTA. At the time of the Eleventh BTA, 39,274 MW of generation capacity is being contemplated for development, with over 75 percent of the interconnection queue generation coming from APS's queue. All active projects in the interconnection queues fall under Solar PV, Wind, Battery Storage, and Natural Gas based technologies. As shown in section 2.2, Arizona's load forecast does not solely support the need for this much additional generation. Several Western states have modified their renewable portfolio standards significantly and have also included clean energy or carbon reductions standards of 100 percent. Similarly, since the Tenth BTA, several Arizona utilities have voluntarily set higher renewable energy goals and have also established clean energy goals. In addition, the Commission has proposed Energy Rules which would require utilities to reduce carbon emissions by 100 percent below a baseline carbon emissions level by January 1, 2050.[33] These are all probable driving factors in generation development. Several proposed and

31 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.
32 ARS § 40-360.02C7
33 Decision No. 77829; https://docket.images.azcc.gov/0000202570.pdf?i=1614652810835

conceptual intra- and inter-state projects between Arizona and California included in this Eleventh BTA will, if built, increase transfer capability.

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 "2020 Summer 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 according to the NERC/WECC Planning Standards, guidelines set at the state level, and their own internal planning criteria, guidelines and methods. These planning practices are used to ensure that their respective systems are planned to provide reliable service to customers under various system conditions. These requirements also 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 Eleventh BTA utility study work filings, "The plans for any new facilities shall include a powerflow 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 complies with NERC TPL Standards. On October 17, 2013, FERC issued Order No. 786, adopting TPL standard TPL-001-4.[37] TPL-001-4 includes eight planning event categories. Table 8 provides information for each category.

---

34 Arizona Revised Statute § 40-360.02.G

35 Summer Preparedness for the Year 2020, May 07, 2020, at the ACC in Phoenix hearing room #1. https://azcc.granicus.com/player/clip/3887?view_id=3&redirect=true

36 ARS § 40-36.02.C.7

37 FERC ORDER No. 786. October 17, 2013. http://www.ferc.gov/whats-new/comm-meet/2013/101713/E-2.pdf

Planning Event Categories	**Description**
P0	System Intact
P1	Single Contingency (Fault of a shunt device- fixed, switched or SVC/STATCOM is new)
P2	Single event may result in multiple element outages. Open line w/o fault, bus section fault, internal breaker fault
P3	Loss of generator unit followed by system adjustments + P1. No load shed is allowed
P4	Fault + stuck breaker events
P5	Fault + relay failure to operate (new)
P6	Two overlapping singles (not generator)
P7	Common tower outages; loss of bipolar DC

TABLE 8 - STEADY STATE & STABILITY PERFORMANCE PLANNING EVENTS

There are eight Transmission System Planning Performance Requirements that are subject to NERC audits. In 2016, WECC updated the System Performance Criteria, TPL-001-WECC-CRT, to correspond with the new NERC standard.

Staff and ESTA have received and reviewed the required Ten-Year study work from each Arizona utility. Table 9 summarizes the findings from Staff and ESTA's review of the utility supplied Ten-Year Planning materials.

Utility	**Category P0 and P1 Steady State and Stability Performed**	**Category P0 Issues – No Contingency**	**Category P1 Issues – Single Contingency**	**Plans Developed to Resolve Problem**
APS	Yes	None	None	N/A
SRP	Yes	None	None	N/A
AEPCO	Yes	None	None	N/A
TEP	Yes	None	None	N/A

TABLE 9 - SUMMARY TABLE OF UTILITY STUDY WORK

Based on the results, the 2020 technical studies filed in the Eleventh BTA indicate a robust study process for assessing transmission system performance, both steady-state and transient, for the 2020-2029 planning period.[38]

[38] "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 after a system disturbance occurs, when the system is responding to the disturbance.

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."[39] Table 10 summarizes the related information filed in the Eleventh BTA.

Utility	Reliability Audit Finalized and filed with FERC Since Tenth BTA	Comments Related to Transmission Planning Standards
APS	No	In December 2019, WECC conducted an audit of APS's compliance with the NERC Reliability Standards, including Operations & Planning ("O&P") and Critical Infrastructure Protection ("CIP"). The scope of the audit included twenty (20) NERC Reliability Standards. WECC is currently processing the results of the audit pursuant to the NERC Rules of Procedure and Appendix 4C.
SRP	YES	SRP underwent a WECC reliability audit from February 19, 2019, to February 22, 2019. The audit assessed compliance for the period of July 13, 2016, to November 13, 2018, and included 28 CIP requirements and 28 O&P requirements. The result was 1 CIP Potential Non-Compliance ("PNC") finding and 2 O&P PNC findings. The CIP PNC was dismissed as it was determined that the finding did not have merit. SRP received notice from WECC in December 2020 that it will not pursue enforcement action regarding the O&P PNC findings. Both findings have been mitigated.
TEP	YES	TEP provided this information to Staff through a Confidential DR response.
AEPCO	YES	No WECC reliability audits have occurred since the 10th BTA period. AEPCO's next WECC reliability audit is scheduled to begin on January 25, 2021.

TABLE 10 - WECC AUDIT RESULTS

The results of NERC/WECC reliability standard audits over the past two years show that collectively, there was one possible CIP violation and two possible Operation and Planning

[39] Decision No. 72031

violations.[40] All possible violations have since been mitigated. There is no concern of Arizona's BES failing to comply with the applicable planning standards established by NERC/WECC.

3.3 Commission-Ordered Studies

Earlier BTA processes showed the need for Arizona utilities to perform supplemental studies. The purpose of the Commission-ordered studies is to assure compliance with the conclusions and recommendations within the BTA and to draw attention to potential transmission system concerns which need closer Commission scrutiny.

The Commission-ordered studies fall into five categories:

- Transmission load-serving capability,
- RMR,
- Ten-Year Snapshot,
- Extreme Contingency, and
- Energy Efficiency and Distributed Generation.

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
Energy Efficiency and Distributed Generation	Determine the impact of EE/DG on transmission system performance	Eighth BTA

TABLE 11 - SUMMARY OF COMMISSION-ORDERED BTA STUDIES[41]

[40] Represents information provided by SRP.
[41] 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.

Table 11 summarizes the history and purpose of Commission-ordered BTA studies. The following sections discuss the results of Commission-ordered BTA studies.

3.3.1 2020 Transmission Load-Serving Capability Assessment

Load-serving capability is 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, generation found within the load pocket must serve the share of the load that cannot be served via transmission from generation outside the load pocket. Often referred to as RMR (reliability must run), this type of generation is generation that must run out of merit order. The collective ability of transmission and generation facilities to serve a local area's load is 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.[42]

In the First BTA (2000), Staff found three load pockets in Arizona to examine for transmission import constraints: Phoenix, Tucson, and Yuma. The Second BTA (2002) added Mohave County and Santa Cruz County load pockets. Later BTAs examined import constraints in Pinal County and added it as a local area to watch.

The Fifth BTA (2008), also found that Cochise County import assessments needed to address continuity of service concerns. While the Phoenix, Tucson, Yuma, and Mohave County load pockets' focus has been and continues to be on load-serving capability during peak-load times, Cochise and Santa Cruz counties are different, shifting to monitoring the continuity of service (e.g., year-round reliability performance).

3.3.2 Cochise County Import Assessment

In the Fifth BTA (2008), Decision No. 70635, the Commission directed that studies be filed for Cochise County addressing "continuity of service" issues.[43] However, in the Seventh BTA (2012), Staff recommended suspending efforts to upgrade reliability to a continuity-of-service standard 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 suspending the filing of two more Cochise County Study Group ("CCSG") progress reports in 2012.

Staff further recommended that the CCSG participants continue observing the Cochise County reliability and propose any needed changes in future Ten-Year Plans. Staff also recommended that the Commission continue to collect applicable outage data from the respective utilities to monitor Cochise County system reliability in future BTA proceedings.

---

[42] See Appendix E, RMR Conditions and Study Methodology

[43] Decision No. 70635. http://docket.images.azcc.gov/0000091783.pdf

Cochise County loads are served by radial transmission sources operated by AEPCO, APS and TEP. The 2021 forecasted peak customer demand in the county is 238 MW.

Through a data request Staff and ESTA received Cochise County outage data for APS, TEP and AEPCO for 2018 through early 2020 as shown in Table 12. APS's service territory in Cochise County reported no sustained outages of five minutes or longer during this period. TEP reported two sustained transmission outages in 2018 and one sustained interruption in 2019. There were no sustained transmission outages year-to-date (through June 22, 2020). AEPCO reported an average of ten sustained outages in 2018, 22 sustained outages in 2019 and no sustained outage year-to-date (through June 22, 2020).

System	Year	Number of sustained outages	Average outage time (minutes)[44]	Average number of customers affected
APS	2014	0	0	0
	2015	2	79	13,887
	2016	0	0	0
	2017	0	0	0
	2018	0	0	0
	2019	0	0	0
	2020[45]	0	0	0
TEP	2014	1	586	1
	2015	0	0	0
	2016	0	0	0
	2017	2	0.25	1
	2018	2	39	1
	2019	1	30	1
	2020[46]	0	0	0
AEPCO	2014	0	0	0
	2015	2	23	16,192
	2016	3	42	9,121
	2017	1	47.5	16,620
	2018	10	32:36	483
	2019	22	14:20	1,751
	2020[47]	1	244	0

TABLE 12 - COCHISE COUNTY SUSTAINED OUTAGES DATA SUMMARY

44 In this context "average outage time" is calculated from the time to restore the last customer during each outage event in a given system and given year, divided by the number of outages in that system and year. If multiple customers were out of service, an individual customer's outage time might have been shorter.
45 Includes data through May 31, 2020
46 Includes data through June 22, 2020
47 Includes data through June 22, 2020

AEPCO is continuing its efforts with APS and Sulphur Springs Valley Electric Cooperative ("SSVEC") to develop the joint Schieffelin Project in Cochise County to effect reliability improvements in the area. To improve reliability in Cochise County, APS, Arizona Electric Cooperative ("AEPCO") and SSVEC have executed agreements to coordinate and jointly participate in a number of projects and upgrades within the Cochise County area. AEPCO now estimates a 2021 in-service date for the Schieffelin Project.

After reviewing the 2014-2020 outage data reported for Cochise County and the Ten-Year transmission expansion plans in the load area, Staff and ESTA did not find any significant cause for concern in the outage trend. Staff and ESTA find that Cochise County outage data should continue to be collected and monitored in future BTAs. Further, Staff and ESTA find the Cochise County import assessment requirement is satisfied for this Eleventh BTA.

3.3.2.1 Santa Cruz Import Assessment

Santa Cruz County, like Cochise County, is served by radial transmission. UNSE is the LSE in Santa Cruz County. The Eleventh BTA load forecast for Santa Cruz is 77 MW in 2020 and 118 MW in 2029. In the Fifth BTA, the Commission directed studies be filed for Santa Cruz County addressing "continuity of service" issues.[48] However, as with Cochise County, in the Seventh BTA (2012), Staff recommended suspending efforts to upgrade reliability to a continuity-of-service standard 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 UNSE 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 collecting applicable outage data from UNSE to monitor any changes in Santa Cruz County system reliability in future BTA proceedings.

Through data requests, Staff and ESTA received Santa Cruz County outage data from UNSE. Table 13 summarizes UNSE's responses. The outage data shows there was one momentary interruption in service and no sustained outages reported from 2014, increasing to six momentary interruptions and two sustained interruptions in 2017. In addition, there were two planned interruptions for construction work in in 2016 each affecting 10,183 customers with and average duration of 3.1 hours and two planned outages in 2017 also affecting 10,183 customers with an average duration of 4.25 hours per outage. These statistics show an increase in Santa Cruz County outage events in 2015-2017. However, there were no sustained or momentary outages where customers were lost, reported for the 2018-2020 period, which reveals significant decrease in Santa Cruz County outage events as compared to the previous years.

[48] Decision No. 70635; https://docket.images.azcc.gov/0000091783.pdf

Year	Number of sustained outages interruptions	Number momentary outages interruptions	Average outage time (minutes)[49]	Average number of customers affected
2014	0	1	n/a	n/a
2015	0	2	n/a	n/a
2016	0	4	n/a	n/a
2017	2	6	30	10,183
2018	1	4	2.6	0
2019	0	0	0	0
2020[50]	0	0	0	0

TABLE 13 - SANTA CRUZ SUSTAINED OUTAGES AND MOMENTARY INTERRUPTIONS DATA SUMMARY

UNSE has one planned EHV transmission project listed in its Ten Year-Plan for Santa Cruz County. This project is the Nogales Transmission, LLC owned Nogales Interconnection project, a 230 kV transmission line interconnecting the Western grid in the US and the Mexican grid. The remaining projects, including planned transmission and substation installations, are to facilitate this interconnection and reduce any system impacts. These projects also have the potential of reinforcing the reliability of the existing transmission grid in the Santa Cruz region.

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

3.3.3 Import Assessments Requiring RMR Studies

During some portions of the year, generating units within a load pocket might be required to operate out of merit order to serve a portion of the local load; this generation is designated as RMR generation.[51] The power generated from local generation may be more expensive than the power from outside resources and may be less environmentally desirable. During RMR conditions, transmission providers must dispatch RMR generation to relieve the congestion on transmission lines.

49 Excludes momentary outages (<5 min.) and planned outage events.
50 Includes data through May 2020
51 Merit order is the sequence of available energy sources, especially generation, in ascending order of their short-run marginal production costs. This merit order minimizes production cost by using those with the lowest marginal costs first and those with the highest cost last. Sometimes generating units must run out of merit order due to transmission congestion, system reliability or other reasons.

In the Seventh BTA, Staff suspended the requirement for performing RMR studies in every BTA and implemented criteria for restarting such studies based on a biennial review of factors such as:[52]

- An increase of more than 2.5 percent in an RMR pocket load forecast since the earlier BTA.[53]
- 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 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 percent of the peak demand in the pocket.

No updated RMR studies were needed for any of the five RMR areas for the Eleventh BTA because each Arizona utility reported that none of the criteria for triggering RMR studies occurred since the Tenth BTA.

3.3.3.1 Phoenix Metropolitan Area RMR Assessment

The interconnected transmission system serving the metropolitan Phoenix area is owned and operated by APS, SRP and WAPA. Transmission imports serve most of the Phoenix area ("Phoenix Valley") load. APS serves load in the north and west segment of the Phoenix Valley and SRP serves the load in the east and south. 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. APS reported that no triggering criteria for restarting the Phoenix Valley RMR studies have occurred since the Tenth BTA, therefore there are no updated results to report for the Eleventh BTA.

---

52 Decision No. 73625, December 12, 2012

53 For example, the final RMR study year filed in the Seventh BTA was 2021 and the Eighth BTA load forecast for 2021 was 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 was 14,209 MW in 2012 so the need for restarting RMR analysis would have been considered if 2014 BTA 2021 forecast had exceeded 14,209 x 1.025 = 14,564 MW.

3.3.3.2 Tucson Area RMR Assessment

The Tucson area connects to the EHV transmission system at the Tortolita, South, and Vail Substations. These three substations interconnect and supply energy to the local TEP 138 kV system. In December 2015, TEP completed the Pinal Central to Tortolita 500 kV transmission line, supplying added capacity from Palo Verde into TEP's northern service territory. 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 Tenth BTA.

3.3.3.3 Yuma Area RMR Assessment

An internal APS 69 kV sub-transmission network serves the Yuma area and supplies the entire APS load in the transmission-import-limited area. There are external ties to WAPA at the Gila Substation and to the Imperial Irrigation District ("IID") at the 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. Additionally, APS plans to construct the North Gila to Orchard 230kV transmission line that increases import capability in 2021. APS has reported that no triggering criteria for restarting the Yuma Area RMR studies have occurred since the Tenth BTA.

3.3.3.4 Santa Cruz County RMR Assessment

A radial transmission system serves Santa Cruz County. UNSE is the LSE in Santa Cruz County. UNSE reported that no triggering criteria for restarting the Santa Cruz County RMR studies have occurred since the Tenth BTA.

3.3.3.5 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. UNSE is the predominant LSE in Mohave County.[54] UNSE reported that no triggering criteria for Mohave County RMR studies have occurred since the Tenth BTA.

3.3.4 Ten-Year Snapshot Study

The SWAT subcommittee, Arizona Transmission System, ("SWAT-AZ") performed and filed a report documenting results of its Ten-Year Snapshot study. This study presents an assessment of the Ten-Year Plans proposed by Arizona transmission owners.[55] Thermal and

---

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

55 The SWAT-AZ partially includes the following transmission participants: APS, SRP, AEPCO, TEP, UNS Electric and Western.

voltage performance studies used NERC Standard TPL-001-4 steady state criteria and WECC Criterion TPL-001-WECC-CRT-3.2. The Ten-Year Snapshot study consists of conducting normal and single contingency (NERC "P0" and "P1" events) powerflow analyses that determine the adequacy of the planned transmission system in the tenth year of the planning period. The Ten-Year Snapshot study also assesses the effect of omitting selected individually planned transmission projects.[56]

Whereas some of the Arizona transmission owners have filed technical study reports for their respective areas of the system as part of the Eleventh BTA, the SWAT-AZ Ten-Year Snapshot study is a comprehensive assessment of 2029 Arizona transmission plans. Furthermore, the Ten-Year Snapshot study done in 2020 includes all transmission and generation projects statewide, making the report uniquely valuable for assessing the overall adequacy of Arizona transmission plans in 2029.

The 2029 case modeled a statewide load of 26,178 MW (excluding losses) which is 1,751 MW or 7.3 percent higher than the statewide load modeled in the previous Ten-year Snapshot study completed for the year 2027. Arizona system losses in the case were 953 MW. Arizona generation was dispatched at 30,498 MW which included 3,367 MW of generation (in excess of Arizona loads and losses) scheduled as exports to areas outside of Arizona. The 2029 base case model used for the study was based on the complete list of projects that were planned to be in service by 2029 at the time of base-case development, which took place from January to April 2019.

In all, a total of three base-case project-deferral scenarios were analyzed under both P0 and P1 conditions, including one project from APS, one from SRP, and one from TEP, to assess the impact of such deferrals on system performance. Each of the deferral scenarios involved planned projects at 230 kV. The purpose was to carry out project-delay scenarios of planned projects, one for each system, and assess the system performance. All Arizona transmission system facilities with nominal voltages of 115 kV or greater were monitored for compliance with steady-state thermal loading and voltage criteria for all contingencies tested.[57]

The Ten-Year Snapshot study reached the following major conclusions:

- Arizona's 2029 transmission plan is robust and supports the statewide load forecast.
- There were no steady-state BES violations with all lines in service in either the base case or deferral scenarios.

---

[56] Removal of an individual project in some cases involved the removal of multiple transmission lines and/or bulk power transformers.
[57] The Ten-Year Snapshot Study does not require stability analysis.

- Single contingency (P1) analysis showed no voltage violations occurring in the BES. The contingency analysis on the base case showed overloading of the two transmission facilities with the loss of a single transmission element. SRP is investigating both these overloads and has preliminary plans to help mitigate the overloads and is exploring mitigation options that include adding a transformer and reconductoring of 230 kV lines.

- An analysis was conducted to study the impact of delaying certain key projects planned in the ten-year plans using the 2029 powerflow base case. The impact study results revealed that in 2029 a limited number of potential thermal concerns exist in the Arizona BES if one project is delayed in the SRP service area and one project is delayed in the TEP service area. Additional studies are being conducted by SRP and TEP to develop mitigation plans to address these thermal concerns in case these projects are potentially delayed.

Staff and ESTA conclude the Ten-Year Snapshot study documents reliable performance of Arizona's planned statewide transmission system in 2029 for a comprehensive set of Pl contingencies, in both the base-case expansion scenario and in each of the three selected transmission project-deferral scenarios. Finally, Staff and ESTA have concluded that the Ten-Year Snapshot monitors transmission elements down to and including 115 kV as required by the Eighth BTA.

3.3.5 Extreme Contingency Study Work

3.3.5.1 Arizona Commission-ordered extreme contingencies

In the tenth BTA, the Commission directed the parties to continue addressing and documenting selected extreme contingency outages for key BES transmission corridors that deliver power from Arizona's major generation hubs, as well as extreme outage events at selected major transmission stations, and identify any associated risks or consequences (taking into account planned infrastructure improvements that may provide mitigation).[58] Studies have been filed in the Eleventh BTA in response to this Commission requirement. APS and TEP each conducted an extreme contingency study as coordinated through the SWAT-AZ subcommittee. APS and TEP performed analyses using 2020 and 2029 summer peak load models, and each included the filed Ten-Year Plan projects at the time the study was made. This analysis generally corresponds to an extreme contingency, loss of a corridor, and then a P0 through P1 event, excluding an assessment of transient stability performance.

EHV transmission line corridors outages chosen for study were based upon the corridors with the highest exposure to extreme events such as forest fires. APS performed studies for

[58] Decision No. 67457, January 4, 2005

corridor outages along major transmission paths bringing remote generation into the Phoenix metro region. In addition to the identified corridors, APS reviewed the outage of multiple transformers of the same voltage class within a substation. However, no transformer banks were identified as credible outages for this study because of the existing substation layout, transformer spacing and/or fire protection systems.

The TEP extreme contingency study examined both a major corridor outage involving several BES lines as well as transmission station outages involving multiple BES transformers.[59] In its extreme contingency scenarios, APS also modelled operational adjustments following each initial common corridor outage event and then ran a comprehensive set of subsequent P1 outage events (on top of the initial corridor outage) to examine any associated risks and consequences.

APS's extreme contingency analyses for 2020 show that the transmission system can withstand all outage scenarios while meeting the forecasted peak load, except in one scenario where the system's ability to serve the forecasted peak load for a prolonged time could be restricted.

APS's 2029 heavy summer case included significant large-scale customer additions, such as data centers, on both APS's and SRP's footprints. These customers totaled about 1,600 MW in the southwest and southeast parts of the Phoenix metropolitan area. This load is in addition to previously forecasted load growth. The 2029 study results with this additional load reveal that the system performance could be severely limited under certain system operating conditions. APS and SRP are working together to examine system upgrades to alleviate the impact of such a large new load under contingency conditions.

The extreme contingency analyses do show that specific outage scenarios will require generation redispatch and/or the operation of BES switchgear (transmission redispatch) at specific locations to alleviate overloads for both the 2020 and 2029 system conditions. For extreme contingencies that require generation redispatch, one of three methods may be applied:

1. Generation redispatch by an automatic remedial action scheme,

2. Grid-operator-directed redispatch based on established procedures for specific contingency conditions, or

3. Grid operator response to real-time contingency analysis indicating a reliability need for generation redispatch.

59 The details of the extreme contingencies performed by APS and TEP are confidential energy infrastructure information and therefore removed from this report.

Load shedding was not needed for any of the extreme contingencies studied in either 2020.[60] APS's extreme contingency analysis shows that under specific extreme contingency outages in the long-term planning horizon, the ability to serve the forecasted peak load is restricted.

The TEP and UNSE extreme contingency study examined both a major corridor outage involving several BES lines as well as transmission station outages involving multiple BES transformers.[61] UNSE does not have any corridors with more than two transmission lines or substations with more than two transmission transformers that would subject it to the ACC's extreme contingency study. The results of this study were found to be satisfactory.

Under 2021 heavy summer conditions with a certain level of local generation, the powerflow case did not solve for the loss of multiple transformers at one location or for the loss of a corridor with multiple EHV lines. However, increasing the local generation by 156 MW mitigated the simultaneous outage of multiple circuits on a corridor allowing the loadflow case to solve, but also reduce thermal overloads for the loss of multiple transformers at the location that was included in the extreme analysis.

Similarly, for the 2029 heavy summer conditions with a certain level of local generation, the powerflow did not solve for the loss of multiple transformers at two locations. Also, for the loss of multiple circuits on a corridor, one EHV line would overload. However, increasing the local generation by 156 MW resulted in reducing overloads for the loss of multiple EHV circuits on a corridor and for a loss of multiple transformers.

Furthermore, TEP simulated the same contingencies described above with the proposed "Southline" Project in service, which is scheduled for service in phases beginning 2022. The inclusion of the Southline Project in both the 2021 and 2029 heavy summer cases helps not only to solve the powerflow case associated with the extreme contingencies but also reduces the thermal overloads and prevents any potential cascading.

It should be noted that the set of 'extreme contingencies' analyzed in the Commission ordered study were developed over successive BTA's based on certain planning risks within the Arizona transmission system independent of NERC's definition of extreme events. While some overlap exists between the ACC and NERC extreme event sets, they are not intended to match. Staff and ESTA found the Extreme Contingency Analysis studies satisfy the requirements of Commission Decision No. 67457.

---

60 NERC transmission planning standard TPL-001-4 allows non-consequential (i.e., controlled) load shedding to take place for a simultaneous outage of adjacent transmission circuits on a common structure.

61 The details of the extreme contingencies performed by APS and TEP are confidential energy infrastructure information and therefore removed from this report.

3.3.5.2 NERC Extreme Events

The NERC standards fall into two major groups, those that must be planned for and extreme events. The 'P' standards describe events that utilities must plan for in their expansion planning studies. NERC Table 1 also describes the extreme events that utilities must assess. The standards state:

> *"Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2 [Studies shall be performed to assess the impact of the extreme events]. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted."* NERC Standard TPL001-4, requirement 3.5, 3 July 2018.

Some examples of these extreme events include:

- Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
- Local area events affecting the Transmission System such as:
    - Loss of a tower line with three or more circuits.
    - Loss of all transmission lines on a common right-of-way.
    - Loss of a switching station or substation (loss of one voltage level plus transformers).
    - Loss of all generating units at a generating station.
    - Loss of a large load or major load center.

These extreme events are more extensive than and supplement those required by the Arizona Corporation Commission. The Arizona utilities meet the NERC Standards.

3.3.5.3 Distributed Generation and Energy Efficiency

In the Eighth BTA, the Commission ordered jurisdictional utilities to study the effects of distributed generation and renewable efficiency programs on future transmission needs in their Ten-Year Plan filings.[62] The directives in the order were as follows:

> *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.*

In its Eleventh BTA filing on DG and EE impacts, APS reported fulfilling this requirement by examining two load scenarios. In the first scenario, APS utilized the 2024 power flow case that was used in APS's 2020-2029 Ten-Year Plan. APS reported that the combined total DG and EE impact on its 2024 system-peak forecast is 340 MW comprised of 82 percent EE and 18 percent DG (as compared to 86 percent EE and 14 percent DG in its Tenth BTA). APS's second scenario uses the forecasted load excluding the effects of projected increases in DG and EE between 2020 and 2024. APS states that this scenario is equivalent to disaggregating the utilities load forecasts from effects of DG and EE. APS's study monitored the loading impacts to the transmission system and performed reliability analysis similar to what is done in the ten-year planning process. APS reported that for the two cases, BES facilities (>100kV) are examined to ensure there are no thermal or voltage criteria violations and these facilities are examined with all lines in-service and for all single contingencies. The results show that with the projected 2024 DG and EE levels there were no new reliability planning criteria violations observed. Therefore, no APS project advancements or new projects would be required to reliably meet the increased load.[63] The report adds that the study "only addressed APS's BES facilities and there may be some impacts at the sub-transmission level due to variations in timing and quantity of implemented DG and EE." In addition, the report states that in 2024, with all of APS and SRP EE and DG delayed, or non-implemented, thermal concerns were noted on SRP and TEP's BES and are currently being investigated with preliminary plans for mitigation.

SRP submitted a filing on its DG and EE impacts based on analysis using a 2024 summer peak model derived from WECC's 2024HS2 (high summer load) base case. The analysis included base-case conditions and all BES single-contingencies within Arizona. SRP's DG and EE forecasting methodology included an assessment of historical DG/EE impacts on system energy usage to determine the effect of DG/EE on future energy and demand forecasts. The cases reflected system peak-load conditions with and without DG/EE. The 2024 load forecast included a peak load of 9,712 MW (excluding the impact of 764 MW of DG/EE) with a resulting net peak

---

[62] Decision No. 74785, October 24, 2014
[63] "APS Technical Study Effects of Distributed Generation and Energy Efficiency on Future Transmission Need", January 2020, p4.

load of 8,948 MW (including the impact of DG/EE). SRP modelled both scenarios. In the no-DG/EE scenario the missing generation came from other SRP system generation, mostly from northern Arizona. For both NERC P0 and P1 conditions, SRP's power flow analysis found no overloads or voltage violations. The report concludes that SRP's planned 2024 transmission system meets all SRP internal criteria and satisfies applicable WECC and NERC criteria regardless of the presence or absence of forecasted EE and DG.

TEP and UNSE's DG and EE impact analysis was performed using a 2024 study year model and included DG and EE load forecasts as of May 2019. For 2024 summer peak, TEP and UNSE forecasts a 113 MW combined contribution from DG and 221 MW combined contribution from EE.[64] A powerflow analysis was performed with and without the DG and EE loads to identify thermal overloads under P0 and P1 conditions. Contingencies included each BES element within the TEP and UNSE system plus each BES tie from the system to neighboring systems. The analysis followed NERC Reliability Standards and WECC System Performance Criteria.[65] The TEP study results revealed the need for two new projects and advancing the service date of one planned project if the DG and EE programs were not in effect.

Staff and ESTA conclude that the fifth-year technical studies on the impacts of DG and EE by APS, SRP and TEP, were conducted and reported correctly by the Arizona Utilities. APS and SRP utilized the same P1 events for use in the DG/EE analysis, Staff and ESTA conclude that the BES contingencies used are sufficiently robust to flag any significant DG/EE impacts on the individual utility transmission system expansion plans. The utilities should continue to report the impact of DG and EE on future transmission reliability in their Ten-Year Plans.

3.4 2020 Summer Energy Preparedness

The ACC has traditionally held a Summer Preparedness Meeting annually, and there have been two such meetings since the Tenth BTA. The most recent, the 2020 Summer Energy Preparedness meeting, occurred on May 7, 2020, at the ACC Phoenix offices. The 2020 Summer Energy Preparedness meeting was conducted as an ACC special open meeting where electric and natural gas utilities informed the Commission of their level of preparedness to deal with the ensuing summer peak season. The 2020 Summer Energy Preparedness meeting included presentations and comments by the following electric utilities: APS, SRP, TEP, UNSE, and AEPCO. The meeting also included presentations from the following interstate gas pipelines and utilities: Southwest Gas, Transwestern Pipeline Company, and Kinder Morgan. APS, SRP, TEP/UNSE, and AEPCO each indicated preparedness for the 2020 summer peak demand. This preparedness included information regarding the adequate availability of generation and reserves,

---

64 For study purposes, TEP adds an additional 5 percent to load pocket demand as a 'stability margin". After this adjustment, TEP modeled 2907 MW of system load in its 2023 case with DG / EE and 3241 MW of load in its case without DG / EE.

65 At the time of the study TEP's stability margin was based on WECC Regional Criteria TPL-001-WECC-CRT-3.2 system performance regional criteria, which has since been superseded by TPL-001-WECC-CRT-3.

and transmission capacity to withstand normal contingencies. Emergency plans are also in place to respond to extreme outage events, extreme system conditions, and events of natural disaster.

Staff attended the Summer Preparedness open meeting. APS indicated it was well prepared for the upcoming 2020 summer demand. In its presentation to the Commission, APS identified several reliability activities, such as:

- Annual inspection, maintenance, and upgrades of equipment, lines, and towers
- Predictive and preventive maintenance programs utilizing technology
- Transmission peak load studies
- Planning and preparation to elevated fire conditions

APS further elaborated on its Emergency Management and Fire Mitigation activities. APS provided information regarding its system peak demand, and stated it had adequate generation resources, fuel supplies, and transmission capacity in place to meet customer demand for the summer.

In its presentation to the Commission, SRP provided information regarding its actual and forecasted peak demand and adequacy of the resources that have been secured to meet expected demand. SRP provided details regarding purchased power, fuel status and market participation, stating that it has a robust plan and there will be sufficient capacity to meet the demand. In addition, SRP provided an update regarding its participation in the EIM, which it joined as a participant on April 1, 2020, and stated that the EIM and bilateral transactions will ensure access to low cost energy for customers. SRP also provided an update on transmission addition and replacements, which included new and replaced transformers substations circuit lines, breakers, and poles. SRP provided an update regarding its Reliability Coordinator and stated that it transitioned to RC West on November 1, 2019.

TEP presented on behalf of both TEP and UNSE at the meeting. TEP discussed its system demand and stated that both TEP and UNSE have system reserve margins at 20 percent for the summer based on beginning of year load projections. TEP discussed its planned maintenance activities and coordination efforts with the neighboring electric utilities. TEP also provided details regarding its maintenance and resiliency activities and listed some of the notable transmission system enhancements and investments in flexible generation and energy storage. Regarding its participation in regional markets and reliability organizations, TEP stated that it has transitioned from Peak Reliability Coordinator ("RC") to the Southwest Power Pool ("SPP") as Reliability Coordinator for reliability services in 2019 and is on track for participation in the California Independent System Operator ("CAISO") Energy Imbalance Market on April 1, 2022. TEP further detailed its emergency preparedness activities and the availability of emergency equipment on-hand. TEP stated it has a real-time outage map ready for customer notification and discussed automated customer notifications. The presentation noted that sufficient generation and transmission resources are available to meet both TEP's and UNSE's load.

Arizona G&T Cooperatives ("AZG&T"), which includes AEPCO, stated it has secured sufficient resources to meet the coincident peak demand for its All Requirements Members and its allocated capacity obligation to each of its Partial Requirements Members. During its presentation, AZG&T also provided a resource portfolio update, stating that most of the peak demand will be served by its resources while the remaining demand will be met with market purchases. In addition, AZG&T stated it maintains an annually updated plan in case of the loss of its single largest hazard under peak load conditions. AZG&T continues membership in the Southwest Reserve Sharing Group and also maintains transmission capacity to cover the largest unit outage and has additional arrangements with transmission counterparties for emergency market access for extended outages. In addition, AZG&T provided an update on fuel supply, generation maintenance and testing activities, transmission and distribution maintenance activities, provided a summary of recent transmission system upgrades, and discussed operational preparedness for emergency situations. AEPCO reported sufficient resources, fuel supply and transmission, and that it is operationally well prepared to meet the forecasted demand and energy needs. AZG&T detailed its transmission and substation maintenance and assessment activities, and operational preparedness. The presentation concluded that its transmission system is well-maintained and ready to serve the load of All Requirements and Partial Requirements Members.

Staff concludes that for 2020, the level of summer preparedness of the Arizona utilities as presented in the May 7, 2020, Special Open Meeting, demonstrated sufficient preparedness measures are being taken. The current transmission system in Arizona is judged to be adequate to reliably support the energy needs of the state in 2020.

3.5 Physical Security & Cybersecurity

FERC directed NERC to submit for approval reliability standards that will require transmission owners and operators to act or demonstrate that they have acted to address physical security risks and vulnerabilities related to the reliable operation of the BES. The proposed reliability standards should require owners or operators of the BES 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 the FERC directive, NERC developed the CIP-014-1 "Physical Security" standard which was formally adopted by NERC on May 13, 2014. On November 20, 2014, FERC issued an order approving CIP-014-01;[66] however, subsequent comments led to a revision of the standard. The final standard, CIP-014-2 Revision 2, was issued by NERC and approved by FERC on July 14, 2015.[67]

The standard includes six requirements and applies to substations operating at greater than 500 kV and selected substations operating between 200 kV and 499 kV that meet a specified criterion. Under the standard, transmission owners are required to conduct risk assessments, including verification by a third party, conduct an evaluation of potential threats and vulnerabilities of a physical attack at sites identified in the assessment, and prepare and implement a physical security plan for applicable sites.

At the request of Staff, 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. Based on this information, Staff concludes the Arizona utilities are taking actions to address the physical security risks to reasonably ensure the reliable operation of the Arizona transmission system.

There are 10 NERC CIP standards related to cyber security. FERC Order No. 822,[68] issued January 21, 2016, approved seven critical infrastructure protection ("CIP") Reliability Standards: CIP-003-6 (Security Management Controls), CIP-004-6 (Personnel and Training), CIP-006-6 (Physical Security of BES Cyber Systems), CIP-007-6 (Systems Security Management), CIP-009-6 (Recovery Plans for BES Cyber Systems), CIP-010-2 (Configuration Change Management and Vulnerability Assessments), and CIP-011-2 (Information Protection) which supersede previous versions of each respective standard. These reliability standards were designed to mitigate the cybersecurity risks to bulk electric system facilities, systems, and equipment, which, if destroyed, degraded, or otherwise rendered unavailable as a result of a cybersecurity incident, would affect the reliable operation of the Bulk-Power System.

Accordingly, Staff requested information from the Arizona utilities related to actions taken by the utilities to ensure transmission system reliability in the event of a cyber-attack, the details of which are considered confidential. Based on this information, Staff concludes the Arizona utilities are taking actions to address cybersecurity risks to reasonably ensure the reliable operation of the Arizona transmission system.

4 INTERSTATE, MERCHANT AND GENERATION TRANSMISSION PROJECTS

Wholesale market power purchases and sales rely on available interstate and merchant transmission. These interstate and merchant transmission projects make possible a competitive

[66] FERC Ruling approving Reliability Standard CIP-014-1 - https://www.ferc.gov/whats-new/comm-meet/2014/112014/E-4.pdf

[67] CIP-014-1 – Physical Security Standard – http://www.nerc.com/pa/Stand/Prjct201404PhsclScrty/CIP-014-2_Physical_Security_2015Jan30_clean.pdf

[68] https://www.nerc.com/FilingsOrders/us/FERCOrdersRules/Order%20Approving%20Revised%20CIP%20Reliability%20Standards.pdf

and healthy wholesale market while complementing the states' utilities electric infrastructure by providing additional import/export capability. Several market-access projects and merchant transmission projects are discussed in this BTA. This section of the BTA report highlights the status of 24 such planned projects that affect Arizona. This includes 15 projects which filed ten-year plans with the Commission since the Tenth BTA for the years 2019 and/or 2020, and nine projects which haven't filed a ten-year plan in this period but are noteworthy to include in this discussion. Exhibit 19 provides a tabular listing of the interstate, merchant and generation transmission projects.

4.1 Projects Filed or Presented in the Eleventh BTA

4.1.1 Ten West Link 500 kV Transmission Line

The Ten West Link, formerly referred to as the Delaney – Colorado River Transmission Project, would provide an additional interstate 500 kV interconnection between Arizona and California.[69] DCR Transmission, LLC filed a Ten-Year Plan for this project. This project was considered for the adequacy assessment and included in the Ten-Year Plan statistics compiled for this BTA. A Ten-Year Plan was received, and this project was presented and discussed at Workshop I. The Project has been previously reviewed by the ACC as part of its 2014 8th, 2016 9th, and 2018 10th Biennial Transmission Assessments. An overview map showing the general routing and interconnection points of this project is included as Exhibit 20.

The Ten West Link 500 kV line is planned as a 125-mile, 500 kV overhead transmission connection between APS's Delaney substation located in Tonopah, Arizona, and Southern California Edison Company's ("SCE") Colorado River substation located in Riverside County, California, west of the city of Blythe.

The Ten West Link project was studied as an economic project in the CAISO 2013-2014 Transmission Plan. The project demonstrated sufficient benefits when compared to the cost that it was recommended for approval by the CAISO Board.[70] 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, the ISO Board of Governors approved the Delaney – Colorado River 500 kV transmission line project at the July 16, 2014, meeting.[71] Following the approval, the CAISO conducted a Competitive Solicitation under FERC 1000 rules to select a Project Sponsor. On July 10, 2015, CAISO selected DCR Transmission as the preferred Project Sponsor, and the Approved Project Sponsor Agreement was executed on December 1, 2015.

---

69 The Arizona portion of the previously planned Palo Verde – Devers #2 Project of which SCE has already built the California portion.
70 http://www.caiso.com/Documents/Board-Approved2013-2014TransmissionPlan.pdf
71 http://www.caiso.com/Documents/DecisionDelaney-ColoradoRiverTransmissionProject-Motion-July2014.pdf

The Bureau of Land Management ("BLM") is acting as a lead federal agency for the National Environmental Policy Act ("NEPA") process and oversaw the required Environmental Impact Study ("EIS") process. The Draft EIS ("DEIS") and Technical Environmental Study were published on August 31, 2018. The Final EIS ("FEIS") was published on September 12, 2019, and the Record of Decision ("ROD") was issued on November 22, 2019. DCRT filed its Application for a Certificate of Environmental Compatibility ("CEC") from the ACC on December 9, 2019. Interconnection Agreements with the interconnecting utilities are expected to be executed by the end of Q3 2020, and based on current planning, this project is estimated to be placed in service by late 2021.

4.1.2 SunZia Southwest Transmission Project

The SunZia 500 kV transmission line project would provide an interstate 500 kV interconnection between Arizona and New Mexico. SunZia submitted a Ten-Year Plan 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, 5 and 22.

The SunZia Southwest Transmission Project is comprised of two 500 kV transmission lines, substations and termination facilities. The SunZia project is currently planned to consist of approximately 520 miles of two new 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, with 134 miles on state trust land, 50 miles on BLM land, and 16 miles on private land. 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 begin in 2020.

Milestones achieved over the course of this project include the ROD issued by the BLM on January 23, 2015. On September 2, 2015, SunZia applied for a CEC from the ACC. Thirteen days of hearings, including two field tours, were conducted by the Arizona Power Plant and Line Siting Committee ("LSC"). The LSC voted unanimously to approve the CEC application and the ACC accepted the CEC, without changes, on February 3rd 2016[72]. SunZia has federal and Arizona state approval. In March 2016, contracts were executed with the Department of Defense and Department of Army to mitigate all impacts. In March 2018, SunZia applied for location control permit and Right of Way ("ROW") width approval from the New Mexico Regulation Commission.

On October 22, 2018, SunZia filed an Application to amend ACC Decision No. 75464 to authorize an expansion of the Project's certificated corridor near the San Manuel airport which is

[72] ACC Decision No. 75464, February 3, 2016. http://images.edocket.azcc.gov/docketpdf/0000168504.pdf

owned and operated by Pinal County. This corridor expansion was necessitated to comply with a ruling of the Federal Aviation Administration ("FAA") issued to SunZia on February 5, 2018. The FAA required a realignment of the Project in a southwesterly direction to remove a hazard determination.

On January 27, 2015, WECC re-confirmed SunZia's accepted path rating of 3,000 MW. 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. On their official project website, SunZia states that they are currently in the 'Finalize Right-of-Way Acquisition' phase and expect construction and commercial operation of the project to occur in the 2022-2024 timeframe.

4.1.3 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 Cochise County, Arizona and will serve the load requirements of that area. A Ten-Year Plan was submitted for this project by the SouthWestern Power Group. 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 project is owned by Southwestern Power Group II, LLC ("SWPG"). During December 2014, SWPG became a member of WestConnect and plans to stay involved in the transmission planning activities in the region. 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.[73] The proposed alignment of the transmission line was also revised in 2008 to comply with the requirements of the Arizona State Land Department.[74] In September 2013, Bowie submitted a new Class I air quality application to the Arizona Department of Environmental Quality ("ADEQ") and the final five-year permit was issued on October 16, 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 and TEP completed a Large Generator Interconnection Agreement ("LGIA") on January 30, 2015. The Bowie Generator Interconnection Study Report and Facility Study were provided to Docket Control of the ACC on February 23, 2015. Bowie Power Station's Interconnection Agreement with TEP was cancelled on March 27, 2019. According to the ten-year plan filing made by Bowie

---

[73] Decision No. 71951, dated November 1, 2010, the ACC granted Bowie a second extension on the durations of the CECs through December 31, 2020.

[74] Decision No. 70588, dated November 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.

Power Station, LLC, the estimated operation date for the interconnecting transmission line is by December 31, 2020.

4.1.4 Gila Bend Power Partners

Gila Bend Power Partners ("GBPP") 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 and 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 various elements of the Project have been approved through three CECs, namely Case 106, Case 109 and Case 119 have been granted for the project and are approved through February 2025. The Ten-year filing included a System Impact Study report which demonstrates the flow and stability at the Watermelon switchyard point of interconnection for the GBPP line.

4.1.5 Southline Transmission Project

The Southline Transmission Project ("Southline") is a 345 kV line that would provide an interstate interconnection between Arizona and New Mexico. A Ten-Year Plan has been filed with the Commission for this project by Southline Transmission, LLC, a subsidiary of Hunt Power L.P. This project was considered for the adequacy assessment and included in the Ten-Year Plan statistics compiled for the Tenth BTA. An overview map showing the general routing and interconnection points of this project is included as Exhibit 21.

Southline is comprised of (1) a "New Build Section" of approximately 249 miles of 345-kV double-circuit transmission line and associated facilities and (2) an "Upgrade Section" of approximately 121 miles of existing 115-kW WAPA transmission line that will be upgraded to double-circuit 230-kV, along with short non-WAPA-owned segments necessary to interconnect the upgraded WAPA lines to existing substations. The project developer claims this line will bring several benefits, including improving reliability and redundancy of the regional grid, mitigate existing transmission congestion, facilitate renewable generation development, and increase the region's ability to meet demand growth.

On November 6, 2015, the BLM and WAPA, serving as joint lead agencies, released the Final Environmental Impact Statement for the project. The ROD was signed in April 2016. The ACC approved a CEC for the Project on February 24, 2017, in Decision No. 75978, and Southline is progressing with its Interconnection activities in Arizona. The capacity rights to the project are being allocated to customers by SU FERC LLC ("SU FERC"), an affiliate of Sharyland Utilities. SU FERC was granted negotiated rate authority by FERC and has initiated an open solicitation process on March 31, 2016. A final version of the WECC Phase 3 report has been issued.

Southline currently anticipates operations to be phased into service as portions of the line are completed, beginning in 2022. When completed, the Southline Project will add 1,000 MW of bidirectional transfer capability to the grid. Southline continues to actively participate in Arizona and regional transmission planning groups including WestConnect SWAT, SWAT-AZ, Planning Management Committee.

4.1.6 North Gila – Imperial Valley #2

The North Gila – Imperial Valley # 2 Project 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. A Ten-Year Plan has been filed with the Commission for this project by NGIV2, LLC a subsidiary of ITC Grid Developments. This project was considered for the adequacy assessment and included in the Ten-Year Plan statistics compiled for this BTA. The ten-year filing included a report (WECC Path 46 Rating Increase Final PRG Phase 2 Rating Report) to demonstrate power flow and transient stability analysis including the NG-IV#2 transmission line and establish a new WECC Path 46 rating. An overview map showing the general routing and interconnection points of this project are included within Exhibit 1.

The NGIV2 Project would consist of a new 500 kV transmission line in parallel with the existing North Gila - Imperial Valley 500 kV transmission line. The NGIV2 Project would run approximately 90 miles from the existing North Gila 500 kV substation in Yuma, into California where it would terminate at the existing Imperial Valley 500 kV substation in Imperial Valley. An approximately 14 miles long 500 kV tap of the NGIV2 Project would be constructed near Holtville, CA to loop in a proposed Dunes 500/230-kV substation plus a new 230 kV line from Dunes into the existing Imperial Irrigation District's 230 kV Highline substation. A new 500/230 kV transformer would be installed in the Dunes substation as part of the NGIV2 Project. Approximately 7 miles of the 90-mile NGIV2 Project would be located in Arizona and is currently proposed to be sited within an existing designated BLM corridor.

NGIV2 has completed the WECC Three Phase Path Rating Process to achieve a 1,250 MW increase in scheduling capacity (Arizona to California) on the West of River ("WOR") Path, also referred to as Path 46 in the WECC Path Rating Catalog. The Accepted Rating for the NGIV2 Project was achieved in September 2019. The NGIV2 Project will be resubmitted to the CAISO and WestConnect in February 2020 to be included in the 2020-2021 Western Inter-Regional Planning process. The NG-IV#2 Project has been actively involved with SWAT, WestConnect and CAISO transmission planning forums. The anticipated date of construction is Q1 2023 and expected in-service date is Q4 2024.

4.1.7 Wilmot Project

Wilmot, through its affiliates, is planning the construction of a natural gas-fired 470-500 MW electric generation peaking facility and/or a 65 MW alternating current solar facility with 50

MW/200 MW hours of battery storage on a site under option to Wilmot located in an unincorporated portion of Pinal County, Arizona. The Proposed Facility and/or the Solar Plus Utility-Scale Battery Facility will utilize a 230 kV electric transmission line which will connect the Proposed Facility and/or Solar Plus Utility-Scale Battery Facility to the existing 230 kV Santa Rosa substation and operated by APS, and it is anticipated that the Gen Tie Line will be approximately 4.5 miles in length. Alternatively, the project may be connected to the Pinal Central-Pinal West 230 kV transmission line owned and operated by SRP, and it is anticipated that the Gen Tie Line will be approximately 0.5 miles in length. A Ten-Year Plan has been filed with the Commission for this project by Wilmot. This project was considered for the adequacy assessment and included in the Ten-Year Plan statistics compiled for the Tenth BTA.

Wilmot intends to apply for a CEC with the ACC and is currently working to obtain right-of-way and determine the precise location and alignment of the Gen-Tie. Wilmot has submitted an interconnection request and is awaiting preliminary power flow and stability results which should be tentatively available in the first quarter of 2019. The currently estimated in-service date for the Proposed Facility and the Gen Tie Line is April 2023.

4.1.8 Big Chino Valley Pumped Storage Project

The Big Chino Valley Pumped Storage Project consists of three potential 500 kV transmission corridors that are being considered for interconnecting the 2,000 MW adjustable speed hydroelectric generation, otherwise known as “pumped storage hydro”. The project is being developed by Big Chino Valley Pumped Storage LLC ("Big Chino Valley") a subsidiary of ITC Holdings Corp. ("ITC"), which is majority owned by Fortis Inc. and minority owned by GIC Private Limited. A Ten-Year Plan has been filed with the Commission for this project by Big Chino Valley Pumped Storage LLC. This project was considered for the adequacy assessment and included in the Ten-Year Plan statistics compiled for this BTA.

This project was originally submitted in a ten-year transmission plan filing by Longview Energy Exchange, LLC in January 2014. Big Chino Valley purchased the rights to the Big Chino Valley Pumped Storage Project through an acquisition process in 2017. Feasibility, market assessment, and WECC firm resource studies were completed for the project by the previous owner. A new analysis of the project is underway by Big Chino Valley with results expected in 2018. A preliminary permit for the Big Chino Valley Project was approved by FERC on December 28, 2017. As part of the planning process, power flow analysis, short circuit and stability analysis are underway to determine the impacts to the network and determine any required upgrades to the network to maintain safe and reliable operation of the grid.

Big Chino Valley states that the Planning technical/economic analysis has been completed. ITC has begun the WECC 3- phase Path Rating Process to achieve increases on several existing Path Ratings. Generation and Transmission interconnection requests will be submitted between Q4 2019 to Ql 2020 with APS (GI and T-T at Yavapai), SCE (T-T at Eldorado), and WAPA (T-T at new 500 kV substation on Mead-Perkins line). Estimated in-service dates will vary depending upon changes in regulatory requirements, ROW acquisition, other utilities' plans, and general economic conditions. The anticipated date of construction is Q1 2022 and expected in-service date is Q4 2026.

4.1.9 AES Energy Storage Transmission Project

The AES Energy Storage Project ("AESES") proposes a new 230 kV overhead transmission line to connect APS Westwing substation with what will ultimately be a 200 MW battery energy storage system. The initial battery storage facility interconnecting to the Westwing substation will be sized at 100 MW, with another 100 MW facility planned to be added to the interconnection in the future. A Ten-Year Plan has been filed with the Commission for this project by AES Energy Storage, LLC, a subsidiary of The AES Corporation.

The transaction structure between APS and AESES has evolved since AESES's 2019 Ten-Year Plan filing, and APS is now going to construct and own most of the Project, which AESES will fund. AESES will own and construct the battery energy storage facilities and a single 400-foot span of the interconnecting transmission line. For this reason, and because the transaction structure may further evolve with time, both APS and AESES are including the Project in their respective Ten-Year Plans. AESES will require a CEC for this 230 kV interconnection, and APS has already completed a System Impact Study.

4.1.10 Sun Streams Expansion Solar Project Gen-tie Line Project

The Sun Streams Expansion Solar Project Gen-tie Line Project ("SSE Gen Tie Line") proposes a new a 500kV AC single-circuit gen-tie transmission line to interconnect the 385 MW Sun Streams Expansion Solar Project, which is located 0.5 miles east of the intersection of S Elliot Rd and W Elliot Rd, Arlington, Maricopa County, Arizona. The SSE Gen Tie Line will originate at the new 34.5/500kV substation to be constructed at the Solar Project generally located on the southwest comer of the Project. A Ten-Year Plan has been filed with the Commission for this project by Sun Streams Expansion, LLC ("SSE"), and included the system impact study prepared with respect to the facilities of this project.

The length of the line is approximately 1.5 - 4 miles from the Project Substation to the Chukar Shared Substation and will ultimately depend on the route selected and location of Project Substation. The anticipated date of construction is Q1 2021 and expected in-service date is Q1 2023.

4.1.11 Hashknife Solar Generation Tie Line Project

The Hashknife Solar Generation Tie Line Project proposes an approximately 3.5-mile 500kV transmission line that will span across unpopulated rangeland between the Hashknife Solar project and the APS Cholla Substation. A Ten-Year Plan has been filed with the Commission for this project by Hashknife Energy Center LLC ("Hashknife Solar"), a wholly owned subsidiary of Invenergy LLC.

The proposed Hashknife Solar Generation Tie Line Project will connect the proposed Hashknife Solar facility, a utility scale solar energy generating facility, to the APS owned Cholla Substation, and will transmit energy generated from the Hashknife Solar facility to the electrical grid to serve existing energy demand. On January 29, 2018, Hashknife Solar executed a Standard Large Generator Interconnection Agreement with APS, the managing agent for the Cholla Substation. Prior to executing the Interconnection Agreement, APS studied the effects of adding the Hashknife Solar facility to the existing transmission system using approved powerflow models. The studies concluded that the Project will have no significant impact on the existing transmission system. The Commission issued a CEC for this project in Decision Nos. 77888 and 77889. The Project is anticipated to be in-service by December 2022.

4.1.12 Chevelon Butte Wind Gen-Tie Project

The Chevelon Butte Wind Gen-Tie Project proposes a new electrical transmission line connecting the Chevelon Butte Wind Farm near Winslow, Arizona to the existing APS 345 kV Preacher Canyon - Cholla transmission line in Navajo County, Arizona (the "Chevelon Butte Wind Gen-Tie Project"). The existing transmission line bisects the eastern boundary of the Chevelon Butte Wind Farm, and the Chevelon Butte Wind Gen-Tie Project will span an unpopulated portion of Chevelon Canyon to interconnect with the existing APS transmission line. A Ten-Year Plan has been filed with the Commission for this project by sPower Development Company, LLC ("sPower"), of which this project is a wholly owned subsidiary.

The proposed transmission line will transfer energy resources collected by the proposed Chevelon Butte Wind Farm to the existing Preacher Canyon - Cholla transmission line and has the potential benefit of increasing access to renewable energy in the region. APS, the managing agent for the Preacher Canyon - Cholla transmission line, is currently in the process of preparing a power flow and stability analysis report for the project. Final findings from these studies will be provided to the Commission Staff when available. APS is undertaking its interconnection review process under Large Generator Interconnection Process Queue (Q)281. The ACC granted in Decision No. 77436, an approved CEC for this project. The first phase of the transmission line is expected to be in operation by December 2021.

4.1.13 East Line Solar Gen-Tie Project

The East Line Solar Gen-Tie Project proposes a new 230 kV electrical transmission line to interconnect the East Line Solar Plant I and II near Eloy, Arizona to the existing Pinal Central Substation in Pinal County, Arizona. Multiple route options for the electrical transmission line have been identified along either Tweedy Road or Eleven Mile Corner Road to the Pinal Central Substation. A Ten-Year Plan has been filed with the Commission for this project by sPower Development Company, LLC ("sPower"), of which this project is a wholly owned subsidiary.

The proposed transmission line will transfer energy resources collected by the proposed East Line Solar Projects to the existing Pinal Central Substation. The solar generating facilities comprising the East Line Solar Projects will utilize photovoltaic technology on tracker mounting supports. The generation of renewable solar electricity will supply the increasing demand for renewable energy in the region, and the facilities are proposed to operate year-round, producing electric power during the daytime hours. SRP, the managing agent for the Pinal Central Substation, is currently in the process of preparing a power flow and stability analysis report for the project. The findings from these studies will be provided to the Commission Staff when available.

4.1.14 Nogales Interconnection Project

The Nogales Interconnection Project primarily consists of a 230 kV transmission line, along with other project elements. A Ten-Year Plan has been filed with the Commission for this project by Nogales Transmission, L.L.C. ("Nogales Transmission"), an indirect subsidiary of Hunt Power, L.P. The Joint Application of Nogales Transmission and UNSE for a CEC to construct the Nogales Interconnection Project was approved by the Commission on November 17, 2017, in Decision Nos. 76468 and 76469.

The Project will consist of: (1) a UNSE 138 kV Gateway Substation and a Nogales Transmission 230 kV Gateway Substation, (2) a new, approximately three-mile double-circuit 138 kV transmission line to be constructed by UNSE - one circuit to extend the existing UNSE Vail to Valencia line from a point near UNSE's Valencia Substation to the proposed Gateway Substation, and one circuit to connect the proposed Gateway Substation to the existing Valencia Substation; and (3) a new, approximately two-mile single circuit 230 kV transmission line to be built by Nogales Transmission on double-circuit capable structures that will connect the proposed Gateway Substation to the U.S.-Mexico border ("Gateway to U.S.- Mexico Border 230 kV transmission line"), where it will interconnect with the Red Nacional de Transmission, the state-owned transmission grid operated by Centro Nacional de Control de Energia. The Gateway to U.S.-Mexico Border 230 kV transmission line portion of the Project is approximately 2.2 miles long. The Project will potentially provide bidirectional power flow and voltage support as well as emergency assistance, as needed, for the electric systems both north and south of the international border. Nogales Transmission currently anticipates an in-service date in 2021.

4.1.15 RE Papago Solar and Battery Storage Project and Gen-tie Line

The RE Papago Solar and Battery Storage Project and Gen-tie Line Project ("RE Papago Gen-Tie") includes a new 500 kV AC gen-tie transmission line to interconnect the RE Papago, a photovoltaic solar generating facility with battery storage proposed for development, which is located approximately 5.5 miles west of the community of Tonopah, Arizona. A Ten-Year Plan has been filed with the Commission for this project by RE Papago LLC and included the System Impact Study prepared with respect to these facilities.

The interconnection includes a 34.5/500 kV step up transformer and up to 1.8 miles of 500 kV AC Gen-tie transmission line from the high side of the step-up transformer to the existing

Delaney Substation near Tonopah, AZ. The Gen-tie will only serve an estimated 300 MW photovoltaic solar and battery storage facility. This Gen-Tie project will require a CEC approved by the Commission before it can commence construction. The expected in-service date is Q1 2021.

4.2 Noteworthy Projects Filed in Previous BTAs

Several noteworthy projects that have previously filed Ten-Year Plans and having in-service dates that fall within the planning period, continue to be monitored as part of the BTA process. The projects that have been selected to be included in this section represent sizable projects that may have material impacts on existing transmission paths and are included for informational purposes only. Inclusion of the selected projects does not equate to a judgment by Staff or ESTA on the likelihood of a project being developed.

Staff would strongly support a recommendation that projects, that have previously filed a Ten-Year Plan, provide an annual status report in the Ten-Year Planning docket highlighting the ongoing activity and efforts being made. Staff believes this would provide benefit to the BTA process.

4.2.1 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 through, and the potential for an interconnection point in, Arizona. No Ten-Year Plan was 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.

The Centennial West 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[75] and a preliminary Plan of Development with the BLM in 2011 and has completed the Project Coordination Review portion of the WECC path rating process[76]. Additionally, Centennial West Clean Line executed a Memorandum of Understanding ("MOU") with the New Mexico Renewable Energy Transmission Authority which is authorized by statute to acquire land for the project and own transmission facilities. Eighteen community leader workshops in four states and two tribal nations have been held to gather information about local routing opportunities and constraints.

---

[75] Application Form SF-299, "Application for Transportation and Utility Systems and Facilities on Federal Lands".

[76] The purpose of the Path Rating Process is to provide a formal process for project sponsors to attain an -Accepted Rating and demonstrate how their Project will meet NERC Reliability Standards and WECC Criteria. This three-phase process addresses planned new facility additions and upgrades, or the re-rating of existing facilities. It requires coordination through a review group comprised of the project sponsors and representatives of other systems that may be affected by the project

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. According to Staff's review, this project has been halted until further notice.

4.2.2 White Wing Ranch North

White Wing Ranch North, LLC, a wholly owned subsidiary of First Solar, is sponsoring the substation and gen-tie line associated with the proposed White Wing Ranch North Solar Project. The estimated 210 MW project is planned to include the construction of a 34.5/230 kV substation at the project site located in Yuma County. A Ten-Year Plan was not received 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. An overview map showing the general routing and interconnection points of this project is included within Exhibit 1.

The gen-tie line will be a 3.5-mile 500kV AC line originating at the project substation and terminating at the existing Hoodoo Wash Substation. The line would cross about 3 miles of BLM land. The proposed location of the line was determined in coordination with the BLM. It would be located entirely within either the Agua Caliente Solar Energy Zone (SEZ) or a BLM-designated utility corridor. A special use permit was issued at the March 7 Yuma County Board of Supervisors meeting allowing the project to move forward. A System Impact Study was prepared by APS and included in a previous Ten-Year Plan filing. The project received a CEC from the ACC on November 21, 2017, in Decision No. 75816. According to an Annual Self-Certification Letter from First Solar, filed on September 22, 2020, construction of the project has not commenced.

4.2.3 Buckeye Generation Center

The Buckeye Generation Center is a 650 MW natural-gas peaking facility to be located on a site within Maricopa County. A Ten-Year Plan was not received 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. The project has received the requisite Maricopa County Comprehensive Plan Amendment and Air Permit. Overview maps showing the general routing and interconnection points of this project are included within Exhibits 1 and 2.

The Buckeye Generation Center would include the development of a 1-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 location of the 230 kV gen-tie line has been determined, subject to final design. In addition, the project site will be connected to a 230/500 kV transformer to be located within the 69/230 kV substation, which will provide access to the ANPP 500 kV Jojoba substation.

The Buckeye Generation Center is sponsored by Buckeye Generation Center, LLC and is intended to add peaking power for Arizona electric utilities and to the interstate electrical grid. The estimated in-service date of this project is unknown at this time.

4.2.4 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. If developed, the 600 kV HVDC transmission line would include 730 miles of transmission lines. The transmission is proposed to originate near Sinclair, Wyoming near the Platte substation and to terminate in Southern Nevada in the Eldorado Valley near the Marketplace substation complex. TransWest Express plans call for the construction of a 3,000 MW line with 1,500 MW of terminal capacity initially; an additional 1,500 MW of terminal equipment, in parallel, is proposed to be added at a later date. Alternative configurations include the potential to build a third terminal to connect to the 345 kV bus at the Intermountain Power Project in Utah and to use 500kV AC technology in lieu of HVDC.[77]

The project is jointly being developed between TransWest Express, LLC, a wholly owned subsidiary of the Anschutz Corporation, and WAPA. The two entities released a draft EIS in July 2013, and the final EIS was published on May 1, 2015. The Record of Decision ("ROD") from BLM was issued in December 2016 and the ROD from WAPA was issued in January 2017. The project has made an Economic Planning Study request with the CAISO to be included with the ISO's 50 percent Renewable Energy Goals for 2030 Special Study. In November 2017, WECC granted an Accepted Rating for the first stage of the TransWest Express Transmission Project, further advancing the 600 kV project in the regional planning and rating process. PacifiCorp is performing studies for the northern interconnection and TransWest is performing studies for southern interconnections. On April 19, 2019, the State of Wyoming Industrial Siting Council unanimously approved a permit to construct and operate the transmission project. The permit was signed and granted on May 29, 2019. The project is estimated to be constructed during the period of 2022 – 2024.

4.2.5 EnviroMission

EnviroMission Inc. is sponsoring the development of a 200 MW Solar Tower located in La Paz County, south of Parker, Arizona. No Ten-Year Plan was received for this project. 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 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.

---

[77] https://www.caiso.com/Documents/TransWestExpressProjectOverview.pdf

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. According to a press release in April 2018, EnviroMission Limited has executed a financial advisory agreement with Atkins Acuity, a member of the SNC-Lavalin Group, to raise the development and project capital necessary to commercialize the first EnviroMission Solar Tower power station.

4.2.6 Harcuvar Transmission Project

The Harcuvar Transmission Project ("HTP") is sponsored by the CAWCD. 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 are included within Exhibit 1.

A Ten-Year Plan was last filed on April 2, 2015. In that plan, HTP is proposed to be developed in two distinct phases in close coordination with the EnviroMission La Paz Solar Tower Project. Phase 1 of the HTP would connect a new 230 kV substation to the Bouse 161 kV substation via a phase shifting transformer and transformation to WAPA's 161 kV service voltage. A new double circuit 230 kV line would connect the new substation to the 500/230 Delaney-Colorado River substation. In Phase 2 of the HTP, the 115 kV ties will be added at Bouse Hills Pumping Plant and Little Harquahala Pumping plant along with a 30-mile line underbuild on the 230 kV structures. The HTP was submitted to the CAISO process for analysis in its 2015-2016 Transmission Planning Cycle. No significant progress was observed in the Project since conclusion of the previous BTA process. The last reported in-service date for the project was Spring 2020.

4.2.7 High Plains Express

The High Plains Express project includes the planned development of a high-voltage, 2,500 mile, 500 kV AC transmission backbone which will add 4,000 MW of capacity import and export capability. A Ten-Year Plan was not 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.

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, WAPA, 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, and no significant progress was observed since the conclusion of the previous BTA process. The most recent predicted in-service date is 2030.

4.2.8 Mohave County Wind Farm Gen-Tie 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 at 345 kV. The Gen-Tie Project consists of approximately 6 miles of 345 kV generation inter-tie line and two new 34.5 kV to 345 kV step up substations, located in the White Hills of Mohave County, approximately 40 miles northwest of Kingman, Arizona. A Ten-Year Plan was not 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.

The Project will connect a new wind power facility ("Wind Plant") to a new switch yard that will connect to the existing 345 kV Liberty-Mead transmission line. The Wind Plant's original design intended to construct up to 243 wind turbines on Federal lands located in Mohave County, Arizona, near the city of Kingman, to deliver to load-serving entities yet to be determined. A ROD for the project was signed on June 28, 2013, approving the use of 35,329 acres of BLM-managed land and 2,781 acres of Reclamation-managed land for the development of the project. A CEC for the transmission line was granted by the Commission in November 2012; commercial operation was expected to begin by December 31, 2019, dependent on securing a customer. An interconnection request was filed with WAPA in March 2007. WAPA finalized the facility study in November 2017. The ten-year plan indicated that a Large Generator Interconnection Agreement was expected to be signed by March 2018. Appropriate feasibility and system impact studies will have to be filed in the Ten-Year Plan docket once the interconnection point has been finalized.

4.2.9 SolarReserve Project

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 not 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

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. In 2011, SolarReserve submitted a copy of the SIS as part of their 2011 Ten-Year Plan filing. In 2013, the Crossroads project withdrew from the APS interconnection study process and expects to re-enter that process at a future time; therefore, this project was not considered for the adequacy assessment being made in this BTA. Current forecasts are for a commercial operation date by the end of 2021.

5 REGIONAL AND NATIONAL TRANSMISSION ISSUES

Significant increases in distributed generation and energy efficiency penetration, and the integration of large renewable projects combined with the shuttering of conventional generation sources are challenging traditional transmission system planning and operation procedures. Arizona utilities may need to invest in advanced technology and improved communication and automation to enable the necessary flexibility and responsiveness in transmission and distribution systems to accommodate the variability of renewable wind and solar resources. Arizona utilities must also make generation resource decisions that balance increased wind and solar generation penetration with the need for adequate system inertia and voltage support. Natural gas generation resources are currently the energy source of choice to provide the needed quick-starting, flexible generation, however other options including battery storage and pumped hydro are also being studied and incorporated. The Ocotillo Modernization Project is cited by APS as an example of the type of balance needed to maintain grid reliability and operational flexibility, as are the RICE Units recently added to the TEP system. To help incorporate the growth of renewable generation, utilities across the region have joined the Western EIM, which has provided increased resource flexibility through market-based solutions. APS and SRP are currently participants in the EIM and TEP will be joining on April 1, 2022. UNSE and AEPCO are currently evaluating the economics of joining the EIM.

This section describes select regulatory and industry activities occurring on the national and regional stage, where Arizona Utilities are coordinating on transmission reliability issues related to the changing resource landscape. The descriptions are limited to those activities related to transmission infrastructure, regional and subregional transmission grid expansion, transmission reliability, and integration of renewable generation resources.

5.1 Regional Transmission Planning – WestConnect

WestConnect was established in 2001 as an organization of electric utility companies working 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 2007, and in response to FERC Order No. 890, WestConnect members collaborated formally regarding regional transmission planning efforts.[78] With the issuance of FERC Order No. 1000 on July 21, 2011, WestConnect's regional transmission planning activities conducted under the Planning Management Committee have expanded significantly and are described in greater detail in the subsequent sections.

[78] The WestConnect Project Agreement for Subregional Transmission Planning, effective May 23, 2007, was signed by 15 regional utilities, including APS, TEP, SRP, and AZG&T, formalizing regional planning activities and facilitated compliance with FERC Order No. 890.

The members of WestConnect include utility companies which provide transmission services within the western interconnection, particularly Arizona, New Mexico, Colorado, Wyoming, Nevada, California, and South Dakota as shown in Figure 2.[79]

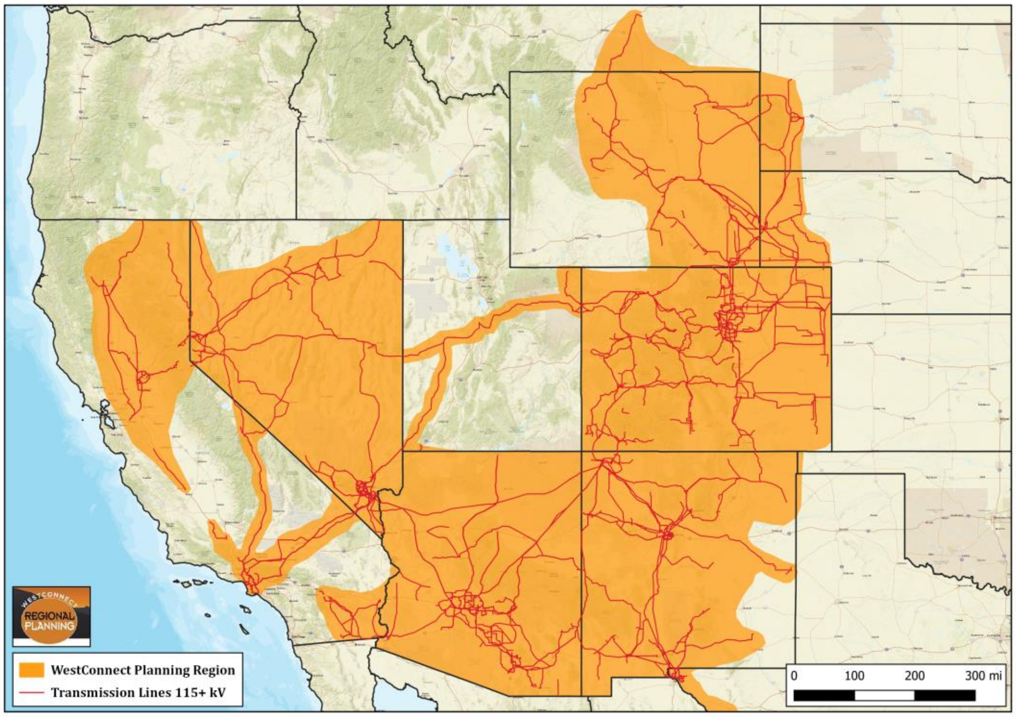

FIGURE 2: WESTCONNECT PLANNING REGION

APS, SRP, TEP, AZG&T, and WAPA actively participate and coordinate on planning activities through the WestConnect Planning Management Committee as well as through the Southwest Area Transmission Subregional Planning Group ("SWAT").

5.1.1 FERC Order No.1000

On July 21, 2011, FERC issued Order No. 1000, "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities".[80] 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

---

[79] Regional planning figure provided to Staff by WestConnect in August 2020.

[80] 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 ZE-6.pdf

public policy requirements, and to improve coordination between neighboring transmission planning regions to seek efficient interregional solutions. Order No. 1000 compliance has varied in its implementation across the U.S. and continues to be evaluated.

5.1.1.1 Role of WestConnect

In a March 22, 2013, Order on Compliance, FERC found that the proposed WestConnect planning region met the geographic scope requirements of Order No. 1000.[81] 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.

At Workshop #1 of the Tenth BTA, WestConnect presented the following regulatory update:

> *"All tariff revisions related to the regional planning requirements of Order 1000 were fully accepted by FERC on January 21, 2016. On August 8, 2016 the 5th Circuit Court of Appeals vacated FERC's compliance orders related to mandates regarding the role of the non-jurisdictional utilities in cost allocation. On November 16, 2017 FERC upheld its previous compliance orders and provided further explanation as to why its mandates will ensure just and reasonable rates between public and non-public utility transmission providers in the WestConnect region. Numerous requests for review have been filed with FERC."*

The appeal process described above is currently in abeyance. WestConnect's public and non-public transmission providers have agreed upon cost allocation principles which resolve the issue in front of the 5th Circuit Court of Appeals and are drafting Tariff Revisions to be submitted to FERC.

Under the Order No. 1000 planning process, the existing WestConnect planning efforts have 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-driven needs, and application of binding cost allocation methodologies for eligible projects. The WestConnect Planning Participation Agreement established a Planning Management Committee ("PMC") made up of one representative of each of the signatory parties.[82] Under the Order No. 1000 planning process proposed in the compliance filings, the PMC is tasked with ensuring that the WestConnect planning processes comply with Order No. 1000 and overseeing the development and approval of a regional transmission plan that includes application

---

[81] Order on Compliance Filings, 142 FERC ¶61,206 (2013).

[82] The WestConnect Planning Participation, effective January 1, 2015, was signed by seven public utility transmission providers, including APS and TEP, and was later signed by an additional 11 regional utilities including SRP and AEPCO, formalizing regional planning activities conducted in compliance with FERC Order No. 1000.

of cost allocation methodologies. The PMC is comprised of five Member Sectors including transmission owners, transmission customers, independent transmission developers, state regulatory commissions, and key interest groups. All entities who become members of the WestConnect PMC will have voting rights as defined in the transmission providers' Open-Access Transmission Tariffs and in the Planning Participation Agreement.

5.1.1.2 2016-2017 and 2018-2019 Regional Transmission Plans

The 2016-2017 regional transmission plan was the first full biennial Order No. 1000 regional planning process for WestConnect. On December 20, 2017, WestConnect approved it's 2016-2017 Regional Transmission Plan. All Arizona utilities and many other stakeholders participated in this regional study process intended to comply with FERC Order No. 1000 requirements. With the participation of stakeholders, WestConnect took WECC 2026 seed cases and modified them to serve as 2026 HS (Heavy Summer) and 2026 LS (Light Spring) base cases. The study scope included three distinct tranches of analysis: (1) a Regional Reliability Assessment; (2) a Regional Economic Assessment; and (3) a Regional Public Policy Assessment. For each assessment a set of additional base cases and sensitivity cases was developed. Unlike the other two tranches which used powerflow and transient-stability models, the Regional Economic Assessment used a production-costing model capable of estimating annual energy cost and grid congestion levels for the WestConnect region including Arizona.

The overarching goal of a regional planning process that is FERC Order No. 1000 compliant is to identify any additional regional transmission projects that may be needed in addition to those already proposed by utilities and other developers. WestConnect defines "regional projects" as projects that are required between two Transmission Owners. When a need for such a regional project is identified, FERC Order No. 1000 requires that a bid process be conducted for sponsors who propose such projects. Regional projects determined to be capable of meeting an identified regional need in a more efficient or cost-effective manner will be evaluated and selected from among competing solutions to determine the preferred solution or combination of solutions to satisfy the identified regional transmission needs between two or more transmission owners with load serving obligations.[83]

In addition to the planning scenarios addressed by its 2016-2017 planning cycle, WestConnect also included additional scenarios within its study scope for informational purposes only. Two of the informational scenarios included in the 2016-2017 cycle addressed possible "futures" that might result under the Federal "Clean Power Plan" ("CPP"), which was repealed in June, 2019, and replaced with the "Affordable Clean Energy Rule" ("ACE").

The 2018-2019 Regional Planning Cycle was the second planning cycle undertaken by WestConnect. WestConnect published the Final Regional Study Plan for the 2018-2019 Planning

83 WestConnect 2016-2017 Regional Transmission Plan, Dec. 20, 2017, p 1.

Cycle on March 14, 2018.[84] The Study Plan identified the scope and schedule of the study work that was to be performed during the planning cycle.

The Planning Management Committee approved two scenarios to be included in the 2018-2019 study plan, which included a Load Stress Study (Heavy Summer) and a CAISO Export Express Study:

- Load Stress Study (Heavy Summer)—Reliability study based on 2028 Heavy Summer case where regional peak load was increased 10 percent and the load/generation imbalance was filled with renewable capacity not dispatched in the Base Case, or incremental renewable capacity if no headroom was available. The analysis was designed to test robustness of the Base Transmission Plan against potential changes in load and incremental dispatch of renewable resources.

- CAISO Export Stress Study—Reliability study based on a regional model that was adjusted based on CAISO export conditions observed in regional production-cost model. The analysis was designed to evaluate reliability of the regional system of power flows from the CAISO to WestConnect during CAISO overgeneration conditions.

In addition, the 2018-2019 biennial study included selected inter-regional transmission projects ("ITP"s).

The WestConnect 2018-2019 Regional Transmission Plan concluded that "Based on the findings from the 2018-2019 cycle analyses performed for reliability, economic, and public policy transmission needs, no regional transmission needs were identified in the 2018-2019 assessment. As a result, the PMC did not collect transmission or non-transmission alternatives for evaluation since there were no regional transmission needs to evaluate the alternatives against and the 2018-2019 Regional Transmission Plan is identical to the 2018-2019 Base Transmission Plan."[85]

5.1.1.3 2020-2021 Regional Planning Cycle

The 2020-2021 Regional Planning Cycle is currently underway. WestConnect published the Final Regional Study Plan for the 2020-2021 Planning Cycle on March 18, 2020.[86] The study plan identifies the scope and schedule of the study work that is to be performed during the planning cycle. However, the Study Plan does not explain the entire process; the Business Practice Manual should be used as a reference for additional details.[87]

---

84 WestConnect 2018-2019 Final Regional Study Plan. https://doc.westconnect.com/Documents.aspx?NID=18068&dl=1

85 WestConnect 2018-2019 Regional Transmission Plan. https://doc.westconnect.com/Documents.aspx?NID=18530&dl=1

86 WestConnect 2020-21 Final Regional Study Plan. https://doc.westconnect.com/Documents.aspx?NID=18668&d1=1

87 WestConnect Regional Planning Process Business Practice Manual, February, 2016. https://westconnect.com/filestorage/02_17_17_regional_planning_process_business_pracatice_manual.pdf

The Planning Management Committee approved two scenarios to be included in the 2020-2021 study plan, which include a Committed Uses Study and a New Mexico Export Stress Study. Currently, the base regional planning models are being developed and scoping for the scenario studies has begun. The following two scenarios are currently envisioned:

- Committed Uses Study—An economic study based on the 2030 production cost model. The study will substitute contractual rights obtained from public sources and member inputs to replace transfer capability values. The study will allow an examination of the impacts of these different inputs and may potentially allow for improved modeling in the future. The goal is to explicitly model existing contracts to determine the impacts on WestConnect economic study findings.

- New Mexico Export Stress Study—Reliability study based on a regional model that will be adjusted based on a realistic New Mexico east-to-west export condition from the WestConnect 2030 Base Case production cost model. The analysis is designed to evaluate reliability of the regional system under such conditions.

In addition, the 2020-2021 Planning Cycle has accepted inter-regional transmission project submittals. The pending assessment of ITPs "first depends on a need being identified in the current planning cycle. A needs assessment will be conducted in Q4 2020. If needs are identified, an ITP will need to be resubmitted during the project submittal window (approximately Q5),"

5.1.2 SWAT Subregional Planning Group

SWAT, a WestConnect Subregional Planning Group, is a collaborative study group that has been created to meet the following purpose:

> *To provide an open and collaborative forum where stakeholders are encouraged to participate in the planning, coordination, and implementation of robust transmission systems within the SWAT footprint. The open participation in this process is intended to result in transmission expansion plans that meet a variety of needs and have a broad basis of stakeholder support.*

The scope of SWAT is transmission planning related topics in Arizona, New Mexico, southern Colorado, west Texas, southern Nevada and southern California. SWAT transmission planning focuses on the Bulk Electric System,[88] but may include some sub-transmission system areas that impact the BES or otherwise benefit from coordinated local planning.

[88] Bulk Electric System as defined in NERC's Glossary of Terms

Decision No. ________

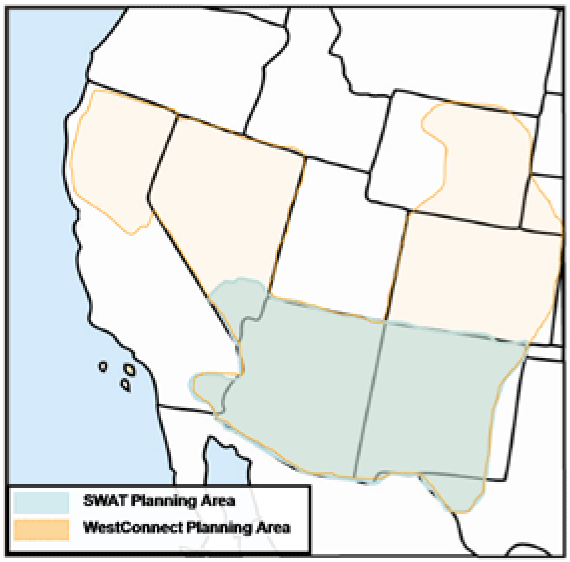

Figure 3: SWAT Footprint

The SWAT Oversight Committee generally meets quarterly and is open to all parties. Meeting notices and proposed agendas are emailed to the SWAT distribution list and are posted on the SWAT Website.[89] Currently, there are no subcommittees under SWAT and one task force – the Central Arizona Transmission System ("CATS") Task Force. Information on CATS is provided below.

5.1.2.1 Central Arizona Transmission Task Force

The CATS is a task force of the SWAT Subregional Planning Group. The purpose of CATS is to serve as a transmission planning forum for identifying long-term local and subregional transmission needs and to facilitate reliability in joint planning, development, and operation of the transmission system in central Arizona. The CATS study area is generally defined as the developable land between Phoenix and Tucson, the bulk of which is in Pinal County, one of the fastest growing counties in Arizona. Further complicating the transmission system in central Arizona is the large number of providers and load serving entities serving customers within a relatively small footprint.

Objectives of CATS include ensuring that the smaller load serving entities are being modeled correctly, and that the transmission providers' future plans are consistent with the Palo Verde-Pinal Central Project expansion. If needed, CATS will develop a high-level transmission plan of Pinal County while maximizing regional benefits and making more efficient use of the existing transmission system. Consideration will be made of a variety of alternatives to allow for a wide range of options and flexibility of alternatives.

---

[89] http://regplanning.westconnect.com/swat.htm

The task force proposed an open stakeholder process and will follow the SWAT Charter in coordinating and performing these local and subregional planning efforts. Further information regarding CATS can be found on the CATS Website.[90]

5.1.3 Interregional Coordination

The CAISO, Northern Grid, and WestConnect developed a multi-regional process to comply with Order No. 1000's requirements for interregional coordination. Interregional Coordination meetings are being held annually; the meetings provide the entities with the opportunity to share and coordinate each region's current planning efforts.[91] WestConnect's input included base cases and assumptions used in planning studies, planning models, and in identifying regional needs.

5.1.4 Relationship to the BTA Process

The WestConnect transmission planning process, with the enhanced FERC 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 and cost-allocation mechanisms. Where the ACC BTA emphasizes intrastate impacts of planned transmission projects, FERC Order No. 1000's wider regional approach also helps ensure the state's transmission owners consider regional and interregional transmission projects in assessing the most efficient and cost-effective means to meet transmission needs of their customers.

5.2 Federal Legislation

5.2.1 Affordable Clean Energy Rule

On March 28, 2017, President Donald Trump signed the Executive Order on Energy Independence (E.O. 13783), which called for a review of the Clean Power Plan ("CPP") and on October 10, 2017, EPA proposed to repeal the Clean Power Plan. On October 9, 2018, the United States Supreme Court issued a 5-4 ruling blocking any attempt to appeal the Trump Administration's decision to overturn the Clean Power Plan.

On August 21, 2018, the EPA announced the Affordable Clean Energy ("ACE") Rule which is planned to replace the Clean Power Plan.[92] The ACE Rule aims to reduce greenhouse gas

90 http://regplanning.westconnect.com/swat_cats.htm
91 The most recent meeting was held in Folsom, California on February 22, 2018. https://www.columbiagrid.org/O1000Inter-overview.cfm
92 https://www.epa.gov/sites/production/files/2018-08/documents/ace_overview_0.pdf

("GHG") emissions from existing coal-fired electric utility generating units and power plants across the country. This would be accomplished through four main actions:

- Defines the "best system of emission reduction" for GHG emissions from existing power plants as on-site, heat-rate efficiency improvements;
- Provides states with a list of "candidate technologies" that can be used to establish standards of performance and incorporated into their state plans;
- Updates EPA's New Source Review Permitting program to incentivize efficiency improvements at existing power plants; and
- Aligns Clean Air act section 111(d) general implementing regulations to give states adequate time and flexibility to develop their state plans.

EPA held a public hearing on the ACE Rule on Monday October 1, 2018. On June 19, 2019, EPA issued the final ACE rule, replacing the CPP with a rule that, according to the EPA, *"restores rule of law, empowers states, and supports energy diversity".* The ACE rule establishes emission guidelines for states to use when developing plans to limit carbon dioxide at their coal-fired electric generating units. In this notice, EPA also repealed the CPP, and issued new implementing regulations for ACE and future rules under section 111(d). The ACE Rule Directs States to Establish Performance Standards for Power Plants Based Solely on Heat Rate Improvements. Under the Act, the standards must reflect the emissions reductions that can be achieved through application of the "best system of emission reduction" ("BSER") for the pollutant and source. The BSER is the best technology or other measure that has been adequately demonstrated to improve emissions performance for a specific industry or process (a "source category"). In determining the BSER, EPA considers technical feasibility, cost, non-air quality health and environmental impacts, and energy requirements.

The ADEQ's Air Quality Division protects public health and the environment by controlling present and future sources of air pollution. On November 8, 2019, ADEQ held an initial stakeholder meeting to discuss the ACE Rule planning processes and plans to hold additional meetings during the development of Arizona's state plan. ADEQ is required by the Clean Air Act § 111(d), the ACE Rule, and Arizona Revised Statutes 49-459 to develop a state plan that establishes standards of performance for carbon dioxide emissions from certain fossil fuel fired electric generating units. On April 23, 2020, ADEQ and representatives from the affected coal-fired electric generation units commenced a technical working group. This group meets on a monthly basis to address technical issues regarding the heat rate improvement ("HRI") analysis of the EPA's identified BSER as mandated by the ACE Rule.

ADEQ plans to continue to engage in a robust stakeholder process and will hold future stakeholder meetings. On January 19, 2021, the D.C. Circuit vacated the Affordable Clean Energy Rule and remanded to the EPA for further proceedings consistent with its opinion. The development and implementation of the ACE Rule will be closely followed by Staff and further updates, as related to transmission planning, will be provided in future BTAs.

5.3 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 or other operational boundaries.

Increased regional and interregional coordination has been conducted because of FERC Order No. 1000, transmission planning requirements, and WECC Transmission Expansion Planning. Existing Seams transmission paths affecting Arizona are detailed on Exhibit 7 and illustrated in Exhibit 8. As the Western Interconnection transitions to multiple Reliability Coordinators following the announced wind-down of Peak RC, new seams may be needed across Reliability Coordinator boundaries for planning in the operational horizon. Current efforts to mitigate seams issues within Arizona occur within the context of WestConnect meetings and as required by NERC Reliability Standard TPL-001-4.

5.3.1 WECC Seams Activity

The WECC Planning Coordinating Committee established a Planning Coordinator Function Task Force ("PCFTF") to consider and address potential gap issues that were identified from the September 8, 2011, outage.[93] The PCFTF identified several issues surrounding the role of the Planning Coordinator, including the lack of formal arrangements among Planning Coordinators and area entities, proper inclusion of all facilities effecting the planning area, and differing definitions of the role between the NERC Rules of Procedure and NERC Function Model and its crossover with the Transmission Planner function that has led to inconsistency and confusion over the role and expectations of the Planning Coordinator. On September 14, 2015, the PCFTF issued a whitepaper making several recommendations including forming the Planning

[93]. As discussed in section 5.7.1 of the Eighth BTA.

Coordinator Gap Resolution Team ("PC-GRT").[94] The PC-GRT is now actively engaged in changing the NERC Functional Model clarifying roles and responsibilities of the Planning Coordinator and Transmission Planner. The PC-GRT looks to resolve gaps between the Planning Coordinator and Transmission Planner by accounting for every BES asset in their respective planning areas. The PC-GRT continues to work towards the recommendations of the PCFTF and reports back to the WECC Planning Coordination Committee and Board of Directors.

In the WestConnect 2015 Regional Transmission Plan, WestConnect coordinated with the CAISO on including the Delaney-Colorado River 500 kV and the Harry Allen-Eldorado 500 kV transmission lines in WestConnect's 2024 Regional Base Transmission Plan.[95] Both projects were included in the CAISO Ten-Year Planning Studies and were incorporated into WestConnect models to align the WestConnect Ten-Year Planning Studies with those of the CAISO.

Staff and ESTA have concluded that the utilities are properly coordinating with neighboring utilities to address seams related issues. Increased regional and sub regional coordination activities, including the PC-GRT and the SWAT CIWG, are important for coordinating transmission expansion projects and inter- and intra-regional transmission reliability concerns.

5.3.2 Western Interconnection Reliability Coordinator

In December 2019, "Peak Reliability, Inc.", the NERC approved Reliability Coordinator ("RC") for the Western Interconnection ceased its operation. Peak Reliability was serving under contract as the RC for all balancing authorities and transmission operators in the Western Interconnection. For this reason, CAISO became its own NERC-approved Reliability Coordinator called RCWest. Many utilities in the Western Interconnect, who were previously members of Peak Reliability Inc., have contracted and joined CAISO's RCWest Reliability Coordinator including APS and SRP. The remaining Arizona utilities, namely, AEPCO, TEP, and WAPA Desert have contracted and joined the NERC-approved RC Services, the Reliability Coordinator services provided by Southwest Power Pool ("SPP"). NERC approved these transitions by the Arizona utilities. In this role, RCWest and RC Services are now responsible to ensure that real-time conditions on the Western Interconnection remain in compliance with NERC operating reliability standards and that the aggregate impact of day to day and hour to hour operational actions/market actions by individual transmission operators/balancing authorities are consistent with these standards.

---

94. Planning Coordinator Function Task Force, Methodology for Defining Planning Coordinator Areas in the WECC Region, whitepaper, September 14, 2015. https://www.wecc.biz/Reliability/PCFTF%20White%20Paper_final_9-14-15.pdf

95 WestConnect 2015 Abbreviate Cycle Regional Transmission Plan, pgs 8-9. http://westconnect.com/filestorage/12%2016%2015%20wc%202015%20regional%20transmission%20plan.pdf

5.4 Additional Renewables Integration Efforts

5.4.1 Effects of High Levels of Renewable Generation Penetration

All solar PV and nearly all wind generation produce DC electricity. This must be converted to alternating current ("AC") to supply the electric grid. Power electronic inverters make the necessary conversion. While such inverters have been used in the industry for many decades, developments in the last decade have increased their capabilities and reduced their costs.

As is often the case with new technologies, these inverters introduced advantages and disadvantages in comparison to conventional generation. Software in the inverter control system controls the output of these inverters. The minimum software control is for the output to "follow" the system frequency and voltage with no natural response to changing system frequency or voltage conditions. Any response beyond this requires added programing of the control software. In addition, the designed capability of the inverter matches the maximum capability of the DC supply from the wind or solar generation. In general, these inverters can respond much faster than conventional generation.

5.4.1.1 Speed is a Double-Edged Sword

The potential response speed of power inverters can cause the system to operate improperly if the control software responds too rapidly to changes in system voltage or frequency. While power systems run at 60 Hertz ("Hz"), the inverter voltage and current are not completely "smooth" because there are constant pulses up and down as the many devices connected to the system operate. If the inverter control software is too sensitive, it will respond to innocuous changes and may introduce new control problems. If the setting is not sensitive enough, it may not work as desired or not respond as quickly as required by system conditions. Obviously, a balance must be struck, but the balance is unique to each system and requires very advanced modeling and analysis. In addition, the settings may need to be reevaluated as system conditions change in future years.

5.4.1.2 The Impact on Rotating Inertia

As more renewables penetrate the system, the operations of existing conventional fossil generators are affected; these plants are often either retired or not used as much to serve load. Traditionally, these types of generators, including hydro, provided significant amounts of rotating inertia in maintaining reliability immediately following a contingency. One of the greatest challenges in introducing high levels of inverter-based renewable energy generation ("REG") is providing enough rotating inertia for system operation inertia that was previously provided by conventional generators.

Rotating inertia is the resistance of a spinning object to changes in its rotating speed. Whether it is a fidget spinner or a large steam turbine, the spinning object does not naturally want to change speed. The spinning object requires added energy to increase its speed or added load to slow it down; slowing that releases energy into the system. The power system, and all its equipment, operates at 60 HZ. Inverter-based systems do not have this natural capability. Supplying the necessary rotating inertia is proving to be one of the greatest challenges in introducing high levels of REG.

When a generator trips in the system, conventional generation slows down slightly releasing more power into the system for a few seconds. This prevents system frequency from falling too quickly, allowing other system elements to support system frequency. This is especially important for the loss of a large power source as it allows time for under-frequency load-shedding systems ("UFLS") to work. The frequency will fall too quickly for the UFLS to work in systems with low rotating inertia.[96] UFLS are designed to match the characteristics of each system considering the largest loss and the rotating inertia of the system.

Even in normal operation, low rotating inertia will mean there will be larger frequency changes and reduced capability to control system frequency, jeopardizing the system reliability. This also means there will be a higher rate-of-change-of-frequency ("RoCoF")—frequency will change more quickly. Conventional generators and other equipment have limits as to how quickly system frequency can change without causing damage. High RoCoF levels have become a concern in a system with high levels of inverter-based REG.[97] Inverter vendors such as Siemens and ABB have been working to develop methods to provide "synthetic inertia" with their inverters.

Experience in California has shown that high levels of renewable generation also impose extremely high system ramp-rate requirements. This first became famous with CAISO's "duck curve" that showed the very high ramp-rates needed in the late afternoon each day.[98] System operators must arrange for enough generating capacity to provide the needed amount of fast ramping capability. As California has shown this can be a serious challenge.

Besides ramp rates, the duck curve challenges system operation in other ways. Conventional generators have minimum operating levels that can cause difficulties during the bottom of the duck curve. A 100 MW generator might have a minimum operating level of 60 MW. If such a generator were needed for the afternoon ramp, it must be available and running in the hours before, when system load is low. This may mean that there will be too much generation at the bottom of the duck curve, and frequent output cycling of fossil units.

Modern inverters can offer some frequency response (and voltage control). Realities of the marketplace, however, limit both. Such frequency control requires a generator to increase or decrease output as needed. Because renewable generation has operating costs near zero, they

---

96. UFLS are designed to shed load so that frequency does not fall so far that it is not possible to recover—usually result in large-scale uncontrolled blackouts. To prevent improper operation that would shed load when not needed, however, UFLS systems have a small delay built-in.

97. Eirgrid in Ireland has been an international leader in examining the impact of RoCoF on system equipment.

98. California ISO, *What the duck curve tells us about managing a green grid*, 2016, https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

generally run at their maximum capable output. This leaves no reserve to supply more power to help during low-frequency conditions; generally, the most critical frequency condition.[99]

5.4.1.3 Other Operating Issues

There are several other operating issues that high levels of REG introduce. One of these is related to fault current levels. During system faults, conventional generators can briefly supply more than four times their rated current. This surge in current makes it easier for protection systems to recognize that a fault has occurred. It is a basic assumption in existing protection systems. In contrast, the fault current from inverter-based generators is typically only about 5 percent above rated current. The output is limited by both the solar or wind output and the design of the inverter system is matched with the output of the generator. High levels of REG may not produce enough fault current for the protection system to recognize that a fault has occurred, they may not operate.

There are also stability problems introduced by high levels of REG. These are related to the low fault current and ride-through ability of the generation. Higher fault-current levels generally mean a stronger, more stable system. As just discussed, inverter-based systems supply lower fault currents. When a fault occurs, many inverter-based generators disconnect from the system, which is unhelpful during a supply shortage event. To be effective in such situations, the REG must be ready to reconnect moments later as soon as a fault clears.[100] This is low-voltage ride-through (low voltages occur during a fault).

The evolution of power systems offers various innovative solutions to some of the problems high levels of REG introduce. One is the use of energy storage. Whether in the form of hydroelectric, batteries, or other energy-storage devices, each can mitigate problems with frequency control, minimum generation, or shifting energy from times of high REG output (e.g. daytime) to times of lower output (e.g. nighttime).

Another innovative solution is using customer flexibility and load control/demand response to help system operation. This might also use customer electric vehicles for energy storage, or as a means of time shifting the load.

5.4.1.4 Likely Steps Moving Forward

As Arizona continues to deploy more renewable generation, the electric utilities will need to increasingly work with neighboring utilities in both the state and the Western Interconnection to address the issues described above in order to ensure the reliable operation of the power system in Arizona.

---

99. Recent FERC Orders (828, 841, and 842,) require new renewable generation to have voltage and frequency control capabilities.

100. NREL, *Impacts of High Levels of distributed PV and Load Dynamics on Bulk Power Transient Stability*, November 2–3, 2016, https://www.nrel.gov/docs/fy17osti/66971.pdf.

5.5 Renewable Transmission Action Plans ("RTAPs")

In the Fifth BTA the Commission ordered the Arizona utilities to each provide their top three renewable transmission projects ("RTPs"). None of the utilities identified any new RTPs in their Eleventh BTA filings. The list of identified RTPs since the Fifth BTA, and progress towards the development of the RTPs through this BTA, is summarized below.

Project name	APS	SRP	TEP	AZ G&T	Current status
Hassayampa - North Gila 500 kV	X				Completed / In-Service in May 2015
Palo Verde-Liberty & Gila Bend-Liberty 500 kV	X				Delayed Indefinitely; will be developed as reliability and resource needs arise
Delaney-Palo Verde 500 kV	X				Energized May 2016
Pinal West-Pinal Central 500 kV		X			Completed in June 2014
Pinal West – Duke – Pinal Central 500 kV		X			Completed in June 2014
Pinal Central – Browning 500 kV		X			Completed in June 2014
Pinal Central – Randolph 230 kV		X			Completed in June 2014
Palo Verde-Pinal West-Pinal Central		X	X		Completed in June 2014
Pinal Central-Tortolita 500 kV			X		Completed in October 2015
Western Apache-Tortolita 115 kV-230kV Upgrade			X		No longer being pursued, instead working with Western on Southline rebuild to 230 kV
San Manuel Interconnect Project				X	Being considered outside of Ten-Year Plan
Apache-Bicknell 230 kV Line Upgrade				X	Line re-rated; upgrade need moved outside of Ten-Year

					Plan
Western Saguaro-Apache 115 kV Line Upgrade				X	No longer being pursued, instead working with Western on Southline rebuild to 230 kV

TABLE 14 - SUMMARY OF RTP DEVELOPMENT STATUS

In its Eleventh BTA filing, APS advised that renewable resource expansion in their service territory, which is primarily solar, has been trending toward smaller projects which interconnect at lower voltage levels on their system (69 kV or below) rather than on the BES. As a result, APS does not now see a need for any new RTPs. Nevertheless, APS states that the one RTP from its original RTAP that has not yet been built (Palo Verde-Liberty and Liberty-Gila Bend 500 kV) "continues to be viable and will be developed as reliability and resource needs arise."

5.5.1 Energy Imbalance Market ("EIM")

On November 1, 2014, the CAISO and PacifiCorp launched the first western real-time energy balancing market as a way to balance load and generation in a more efficient manner and to share reserves and integrate renewable resources across a larger geographic region. An EIM creates a much shorter window market opportunity for balancing loads and resources and proposes to expand system-wide dispatch which can help with the variability and intermittency of renewable resources.

In the Third Quarter 2020 Western EIM Benefits Report, the benefits quantified from EIM activities include the following:[101]

- More efficient dispatch, both inter-and intra-regional, in the Fifteen-Minute Market ("FMM") and Real-Time Dispatch ("RTD"). Q3 estimated savings = $119.32 million.

- Reduced renewable energy curtailment. Q3 estimated reduction = 37,548 MWh displacing approximately 16,071 metric tons of CO_2.

- Reduced flexibility ramping reserves needed in all balancing authority areas. Q3 reduction = 906 MW – 925 MW in the upward direction and 956 MW – 969 MW in the downward direction.

According to the report, "since its inception in November 2014, the cumulative gross economic benefits have reached $1.11 billion."

[101] https://www.westerneim.com/Documents/ISO-EIM-Benefits-Report-Q3-2020.pdf

APS joined the EIM on October 1, 2016, SRP joined in April 2020, and TEP plans on joining on April 1, 2022. The EIM now serves more than 60 percent of WECC's total energy load.

Overall, it appears the EIM has helped facilitate renewable resource integration by reducing curtailment and may increase reliability by sharing information between balancing authorities on electricity delivery conditions across the EIM region. Based upon the information reviewed, Staff and ESTA conclude the Arizona utilities are taking enough action with respect to transmission planning impacts related to the integration of renewable generation resources.

6 CONCLUSIONS

This Eleventh 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 this BTA:[102]

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 2020-2029 timeframe in a reliable manner?

2. **Efficacy of the Commission-ordered studies**: Do the Simultaneous Import Limit, Maximum Load Serving Capability, Reliability Must Run, Ten-Year Snapshot, Distributed Generation and Energy Efficiency, and Extreme Contingency studies filed as part of the Eleventh BTA provide useful and sufficient information in determining adequacy of the state's transmission system over the next 10 years?

3. **Adequacy of the system to reliably support the wholesale market**: Are the transmission planning efforts effectively addressing concerns raised in earlier 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 used**: Do the plans and planning activities comport with transmission planning principles and good utility practices accepted by the power industry and the reliability planning standards established by NERC 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 ESTA, the existing and proposed

---

[102] This BTA does not establish Commission policy and is not final unless and until approved by a written decision of the Commission.

transmission system meets the load serving requirements of Arizona in a reliable manner for the 2020-2029 period from these eight findings:

1. The aggregate of the filed Ten-Year Plans is a comprehensive summary of 2020-2029 transmission expansion plans from a holistic perspective. The Arizona Plan includes seventeen filing entities and consists of fifty-eight transmission projects of approximately 864 miles in length. Fifty-five projects are beyond the ten-year horizon or have in-service dates that are yet to be determined and account for an additional 1,132 miles of new transmission.

2. The 2020 level of summer preparedness of the utilities in Arizona as presented in the May 7, 2020, Special Open Meeting, demonstrated sufficient preparedness measures are being taken. The current transmission system in Arizona is judged to be adequate to reliably support the energy needs of the state in 2020.

3. During the Eleventh BTA the Arizona utilities reported a Ten-Year Forecast that was, on average, 1.4 percent higher than what was reported during the Tenth BTA. The statewide forecast shows a projected growth rate of approximately 2.67 percent per year for the Ten-Year forecast period, which is slightly higher than the growth rate forecasted in previous years.

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 77 MW is less than the load serving capability of 159 MW.

    b. The CCSG participants monitored the reliability in Cochise County. AEPCO, APS, and Sulphur Springs Valley Electric Cooperative are developing the joint Schieffelin Project in Cochise County to improve reliability in the area, with an estimated in-service date of 2021. The 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.

5. Arizona utilities are taking steps to increase situational awareness, cooperation, and coordination with neighboring utilities, regional and sub regional planning groups to address potential interregional reliability issues. 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 concludes 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 and ESTA conclude that the fifth-year technical studies on the impacts of DG and EE by APS, SRP, TEP and UNSE, were conducted and reported correctly by the Arizona utilities. Staff and ESTA conclude that the BES contingencies used are sufficiently robust to flag any significant DG/EE impacts on the individual utility transmission system expansion plans. The utilities should continue to report the impact of DG and EE on future transmission reliability in their Ten-Year Plans.

8. As Arizona continues to deploy more renewable generation, the electric utilities will need to increasingly work with neighboring utilities in both the state and the Western Interconnection to address new operational challenges in order to ensure the reliable operation of the power system in Arizona.

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 Eleventh BTA has been filed with the Commission. Staff and ESTA conclude the Commission-ordered studies show that the Arizona transmission system is reasonably prepared to reliably serve local load in the ten-year timeframe from these five findings:

1. As shown 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 based on a biennial review of specific triggering factors. None of the triggering factors occurred for the Eleventh 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 2029. The Ten-Year Snapshot has also been adjusted to monitor system elements down to and including the 115 kV level, addressing any potential low voltage concerns. Major findings of the Ten-Year Snapshot include:

    a. Arizona's 2029 transmission plan is robust and supports the statewide load forecast.

b. There were no steady-state BES violations with all lines in service in either the base case or deferral scenarios.

c. Single contingency (P1) analysis showed no voltage violations occurring in the BES. The contingency analysis on the base case showed overloading of the two transmission facilities with the loss of a single transmission element. SRP is investigating both these overloads and has preliminary plans to help mitigate the overloads and is exploring mitigation options that include adding a transformer and reconductoring of 230 kV lines.

d. An analysis was conducted to study the impact of delaying certain key projects planned in the ten-year plans using the 2029 powerflow base case. The impact study results revealed that in 2029 a limited number of potential thermal concerns exist in the Arizona BES if one project is delayed in the SRP service area and one project is delayed in the TEP service area. Additional studies are being conducted by SRP and TEP to develop mitigation plans to address these thermal concerns in case these projects are potentially delayed.

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 analysis shows that under specific extreme contingency outages in the long-term planning horizon, the ability to serve the forecasted peak load is restricted. While these load levels may not be fully realized by 2029, APS and SRP are coordinating study work to examine system upgrades that may be needed.

b. TEP's extreme contingency analysis study results were found to be satisfactory. The inclusion of the Southline Project in both the 2021 and 2029 heavy summer cases helps not only to solve the powerflow case associated with the extreme contingencies but also helps in reducing the thermal overloads and prevent any potential cascading.

5. The EE/DG studies satisfy the Commission's requirement to conduct a fifth-year technical study, down to the 115 kV level, on the impacts of DG and EE. The studies indicate that EE/DG have properly been studied in system planning and EE/DG do not impact the reliability of the transmission system belonging to Arizona's load-serving utilities.

a. APS's 2024 system peak forecast includes 340 MW of EE and DG, comprised of 82 percent EE and 18 percent DG. The results show that with the projected 2024 DG and EE levels there were no new reliability planning criteria violations observed. The study report states that in 2024, with all of APS and SRP EE and DG delayed, or non-implemented, thermal concerns were noted on SRP and TEP's BES and are currently being investigated with preliminary plans for mitigation.

b. SRP's 2024 system peak forecast includes 764 MW of EE and DG. For both NERC P0 and P1 conditions, SRP's power flow analysis found no overloads or voltage violations. The results show that SRP's transmission system meets all of SRP's internal criteria and satisfies applicable WECC and NERC criteria regardless of the presence or absence of forecasted EE and DG.

c. TEP and UNSE's 2024 system peak forecast includes 221 MW of EE and 113 MW of DG. Analysis was done in compliance with NERC Reliability standards and WECC System Performance Criteria. The TEP study results revealed the need for two new projects and advancing the service date of one planned project if the DG and EE programs were not in effect.

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 from these five findings:

1. Four major interstate 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 SunZia 500 kV Project and the 345 kV Southline Transmission Project will provide additional transmission capacity between Arizona and New Mexico.

    b. The planned Ten West Link 500 kV project and the conceptual North Gila – Imperial Valley #2 500 kV project provide additional transmission capacity between Arizona and California.

2. Staff concludes 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 sufficiently participating in intra- and inter-regional planning efforts to coordinate on the integration of new renewable generation resources. Issues related to renewable integration are being identified and incorporated into future study plans.

   b. Arizona utilities are actively participating in or evaluating a market-based approach through Energy Imbalance Markets to aid in maximizing the renewable generation resources already constructed.

   c. Arizona utilities are evaluating the extent to which coal retirements may impact or limit the amount of renewable generation that the Arizona transmission grid can support.

3. The Fifth BTA ordered the utilities to provide their top three RTPs. No RTPs were undertaken by Arizona utilities for this planning cycle.

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 No. 1000 through the WestConnect Regional Transmission Planning process. WestConnect' s 2020-2021 Regional Planning Cycle is currently underway, and its Final Regional Study Plan for the 2020-2021 Planning Cycle was published on March 14, 2020. The draft Regional Needs Assessment and Model Development Report has been distributed to stakeholders for review.

6.4 Suitability of Utilized Planning Processes

Based upon information provided, the Arizona utilities use significant and well-defined transmission planning processes from these three findings:

1. The results of NERC/WECC reliability standard audits over the past two years indicate there was one possible CIP violation and two possible Operation and Planning violations.[103] All possible violations have since been mitigated. There is

[103] This tally does not include TEP's WECC audit results which were provided under confidentiality agreement.

no concern of Arizona's BES failing to comply with the applicable planning standards established by NERC/WECC.

a. APS's audit was performed in December 2019, WECC is currently processing the results of the audit pursuant to the NERC Rules of Procedure and Appendix 4C.

b. SRP's audit was performed in February 2019 and noted one CIP Potential Non-Compliance ("PNC") and two O&P PNC findings. The findings are very low risk to the BES, and both have been mitigated.

c. AEPCO's next WECC reliability audit is scheduled to begin on January 25, 2021, no WECC reliability audits have occurred since the 10th BTA period.

2. Technical studies filed in the Eleventh BTA indicate a robust study process for assessing transmission system performance for the 2020-2029 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 No. 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 have actively participated in and are members of the WestConnect PMC, a regional transmission planning group.

d. Arizona utilities have actively participated in WECC TEPPC and will continue to participate in the new WECC RAC planning process (which replaces the TEPPC process) as the regional approach to examine long-term, public transmission expansion planning in the Western Interconnection. 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.

7 RECOMMENDATIONS

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

1. Staff recommends that the Commission support:

   a. The continued use of the "Guiding Principles for ACC Staff Determination of Electric System Adequacy and Reliability" as revised in the 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 continued suspension of the requirement that Arizona utilities, for each load growth or reliability driven transmission project, include the load level range at which each transmission project is anticipated to be needed, as directed in Decision No. 74785. Utilities shall continue to describe, in general terms, the driving factor(s) for each transmission project in the Ten-Year Plan.

   e. That any requirement established in a prior BTA will continue in force unless the Commission suspends such requirement in a succeeding BTA. Nevertheless, Staff recommends that the Commission emphasize the importance of these continuing requirements for Arizona utilities:

      i. 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.

ii. 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.

iii. Address the effects of DG and EE on future transmission needs in their Ten-Year Plan filings by evaluating the 5th year.

iv. Ensure that the Commission-ordered Ten-Year Snapshot study monitors transmission elements down to and including the 115 kV level for thermal loading and voltage violations.

v. 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.

f. The policy that the LSEs 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 acceptance of the results of the following Commission-ordered studies provided as part of the Eleventh 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 Tenth 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 2029 for a comprehensive set of single contingencies (N-1), each tested with the absence of different major planned transmission projects.

v. The EE/DG study results containing the fifth-year contingency analysis with and without disaggregated DG and EE loads.