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Eleventh Biennial Transmission Assessment 2020-2029

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

Staff Review and Update of

Guiding Principles for Determination of System Adequacy and Reliability

Background

The Guiding Principles for Determination of System Adequacy and Reliability ("Principles") were developed in early 2000, adopted in the 1St BTA and have been re-adopted in every BTA since. The Principles were developed to provide a basis upon which ACC Staff could 1) assess and make recommendations on the determination of the adequacy and reliability of existing and planned transmission facilities in the Biennial Transmission Assessments called for by A.R.S §40-360.02E and 2) evaluate the impact of a generation application for a Certificate of Environmental Compatibility ("CEC") on system adequacy and reliability. The Principles were revised during the Eighth BTA to address the mandatory, enforceable, updated reliability standards put in place following the 2005 Energy Policy Act. The updated Principles adopted in Decision No. 74785 are included on the following pages.

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

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Guiding Principles for Determination of System Adequacy and Reliability Adopted in Decision No. 74785[2]

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

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

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

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

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

Transmission

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

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

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

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

Criteria and identify how any such violations would be mitigated. Mitigation could include a requirement for two generator tie-lines.

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

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

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

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

Generation

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

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

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

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

Appendix B – History of Commission Ordered Studies

Local Area Transmission Import Study Requirements

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

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

Santa Cruz County, on the other hand, is served by a single transmission line. The customer service and system impacts and risks associated with the loss of a single 115 kV line serving Santa Cruz County are well chronicled over prior BTA assessments and siting of the Gateway 345 kV transmission project.[3] A NEPA environmental impact study has been concluded but federal records of decision and a Presidential Permit for the new 345 kV transmission line are still pending with federal agencies. Therefore UNSE installed a 20 MW generator in Nogales in 2004 and

[3] ACC Decision No. 64356

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

TEP was required to file comments by June 30, 2007 to resolve concerns inside neighboring New Mexico and Western Area Power Administration ("WAPA") facilities identified in its preliminary study results for 2016.[4] In addition, technical studies are to be performed and results filed with the Commission for the Cochise County Area to mitigate extended customer outages that resulted from an N-1-1 outage in 2007. A subcommittee of the Southern Arizona Transmission Study ("SATS") subregional planning group has untaken this later task.

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

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

Reliability Must-Run Study Requirements

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

[4] ACC Decision No. 69389, March 14, 2007, page 6, section 2.b.iii

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

The Commission's generic electric restructuring docket established that existing Arizona transmission constraints would limit APS' and TEP's ability to deliver competitively procured power to less than the required 50% of Standard Offer Service's load.[5] The Commission stayed this requirement in its Track B proceedings. However, each UDC is still obligated to assure that adequate transmission import capability is available to meet the load requirements of all distribution customers within its service area.[6] Known transmission constraints result in APS and TEP being dependent upon local RMR generation to serve their peak load during certain hours of the year.

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

The Third BTA Decision No. 65476 approved a collaborative RMR study plan agreed to by all Arizona transmission providers.[7] The 2003 RMR study forum included only the transmission providers. In contrast, since 2004 the RMR process has been open to all interested parties through Arizona's subregional study forums. The Fourth BTA required that "RMR studies continue to be

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

performed and filed with ten year plans in even numbered years for inclusion in future BTA reports and that:

- Future RMR studies provide more transparent information on input data and economic dispatch assumptions, and
- Arizona utilities collaborate with the Staff to develop and effectively implement more stringent criteria as appropriate for RMR areas in the 2006 BTA."

In the Seventh BTA, Staff suspended the requirement for performing RMR studies in every BTA and implemented criteria for restarting such studies on a biennial review of factors such as: [8]

- An increase of more than 2.5% in an RMR pocket load forecast since the previous BTA.[9]
- Planned retirement or an expected long-term outage during the summer months of June, July or August of a key transmission or substation facility supplying an RMR load pocket, unless a facility being retired will be replaced with a comparable facility before the next summer season.
- Planned retirement or an expected long term outage during the summer months of June, July or August of a generating unit in an RMR load pocket that has been utilized in the past for RMR purposes, unless a generator being retired will be replaced with a comparable unit before the next summer season.
- A significant customer outage in an RMR load pocket defined as a sustained outage of more than one hour exceeding the greater of 100 MW or 10% of the peak demand in the pocket.

Extreme Contingency Study Requirements

Staff's concerns regarding the adequacy and reliability of the Arizona electric system began in 2000 with the rapid development of new generation projects interconnecting with the Palo Verde Nuclear Generating Station. These projects all proposed to interconnect at the new Hassayampa

[8] Decision No. 73625
[9] For example, the final RMR study year filed in the Seventh BTA is 2021 and future BTA load forecasts for 2021 would be compared to the Seventh BTA forecast amount for this year to determine the percent increase. Using the data for the Phoenix RMR area, the peak demand forecast for 2021 is currently 14,209 MW so the need for restarting RMR analysis would be considered if and when a revised 2021 forecast exceeds 14,209 x 1.025 = 14,564 MW.

500 kV switchyard but were not increasing the capacity of the existing transmission lines already connected to the Palo Verde marketing hub. Large quantities of generation capacity and energy were at risk of being interrupted or curtailed for single contingency outages or credible outages of multiple lines. In addition the generation projects were being developed solely for merchant's commercial interest without obligations to assure existing generation reserves were sufficient to cover the outage risks the projects posed.

Therefore the Utilities Division of the Commission developed "Guiding Principles for Determination of System Adequacy and Reliability"[10] for Staff's use in power plant and transmission line siting cases. The Commission endorsed this document via its Decision No. 65476 for the Second BTA. Then Condition No. 23 of the CEC was placed on APS and SRP in the Palo Verde to Rudd 500 kV siting case to formally require a study be performed to properly address the risks associated with interconnection developments at the Palo Verde Hub resulting in the 3rd BTA the adoption of the Palo Verde Hub interconnection criteria,

"Require all future interconnections proposed at the Palo Verde Hub, either new generation or new transmission lines, must perform a risk assessment of the Hub to ascertain to what degree the proposed project mitigates the pre-existing risks to extreme outage events. This assessment must precede a project's application for a CEC with the Commission. The recommendations of the Palo Verde Risk Assessment report should be followed if a proposed project would otherwise exacerbate the existing risk at the Hub." [11]

Since the initiation of the Commission's first BTA process Arizona has experienced several fire seasons with exposure to loss of multiple lines in a common corridor on forested lands. These events heightened the Commission's awareness of the state's vulnerability to loss of transmission lines in common corridors. These events were then upstaged by the major 500/230 kV transformer and 230/69 kV fires that occurred at Westwing and Deer Valley in 2004 and the Westwing 500/345 kV transformer fire in 2006. Therefore the third BTA required that the fourth BTA address and document extreme contingency outages studied for Arizona's major generation hubs and major

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

transmission stations including identification of associated risks and consequences if mitigating infrastructure improvements were not planned. This extreme contingency study requirement was reinforced further when the Commission ordered the same requirement for the fifth BTA.

Renewable Energy Transmission Assessment Requirement

In the Fourth BTA, the Commission ordered a Renewable Energy Assessment stating specifically, "in the next BTA, Commission regulated electric utilities, in consultation with the stakeholders, should prepare an assessment of ATC for renewable energy and prepare a plan, including a description of the location, amount and transmission needs of renewable resources in Arizona, to bring available renewable resources to load."[12] This newest study requirement is focused on exploring transmission delivery obstacles for renewable resources that may choose to develop within the state. This study requirement is intended to assure that Arizona utilities can successfully comply with the renewable portfolio standards adopted by the Commission in 2006.

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

The Commission's decision in the Sixth BTA (2010) addressed the ability of the Arizona transmission system to export renewable energy to neighboring states by directing the jurisdictional utilities to jointly conduct or procure a study to identify the barriers to and solutions for enhancing Arizona's ability to export renewable energy.[13] The study was to identify specific transmission corridors that should be built to accomplish this objective. The utilities were also to conduct stakeholder workshops in conjunction with the study.

[12] ACC Decision No. 69389, March 22, 2007, page 8
[13] Commission Decision No. 72031, 10 December 2010.

The study and results were filed as required at the Commission by November 1, 2011, and included as part of the scope of the Staff's assessment performed in the Seventh BTA proceeding.[14]

Coal Reduction Assessment Task Force Requirement

In the Eighth BTA, the Commission ordered TEP to file the SWAT Coal Reduction Assessment Task Force Study Report on behalf of the Arizona Utilities within 30 days of completion. The study was initiated by the SWAT stakeholders in February 2013 to determine if the known and projected retirement of coal generation resulting from anticipated EPA carbon pollution regulation, and the continual increase in solar photovoltaic and wind generation in the next five years would cause system stability issues.

Phase I of the study work was completed and a summary of the findings were included in the Eighth BTA. The results proved that high coal reduction with high renewable penetration significantly increases risk of system instability. Overall, there is a limit to the amount of coal plants that can be retired and gas fired replacement capacity, or other resources that compensate for loss of inertia and dynamic reactive capability, is key to maintaining system reliability. The CRATF report recommended greater consideration of intra- and inter-regional power transfers, additional coordination with regional planning groups and state processes, and a formal inclusion in the WestConnect study plan.

Since the Eighth BTA the EPA has released its' final ruling on *Carbon Pollution Emission Guidelines for Existing Stationary Sources*: *Electric Utility Generating Units*, known as the Clean Power Plan or "CPP". The ruling requires Arizona to achieve a 34% reduction in CO_2 emissions rate for affected power plants by 2030. SWAT has coordinated with WestConnect to coordinate the inclusion of study requests related to the CPP into the 2016-2017 formal study plan. SWAT members anticipate to receive the results of WestConnect's efforts in the Summer of 2017, at which point they intend to reconvene and determine how CRATF should move forward with the study results.

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

In the Ninth BTA, Decision No. 75817, the Commission suspended the requirement for TEP to file the SWAT CRATF report on behalf of the Arizona utilities within 30 days of completion as directed in Decision No. 74785. Rather, the Commission ordered the Utilities to participate in the WestConnect Regional Planning process and coordinate Arizona reliability studies with WestConnect study and scenario results. In addition, the Commission ordered TEP to report the findings on behalf of the utilities in future BTA Proceedings.

In the Tenth BTA, TEP filed the relevant portion of the WestConnect CPP Utility Plans Scenario study on behalf of the Arizona Utilities. The report was prepared from the WestConnect Planning Study 2016-2017 Cycle Regional Transmission Plan. The Arizona utilities originally submitted to WestConnect an "Arizona Utilities CPP Compliance" scenario during the December 2015 submittal window. That scenario was broadened to include all WestConnect participating utilities. In this scenario, approximately 1300 MW of coal resources and 400 MW of natural gas resources were replaced with approximately 600 MW of renewable resources and 1100 MW of natural gas resources. The results of the study show there are no regionally significant issues but there were local voltage issues and thermal overloads under the CPP compliance scenarios. There were no regional transmission overloads identified in the reliability assessment. Despite the increase in renewable penetration detailed in the study, the system was able to recover frequency appropriately and within WECC criteria. The retirement of significant amounts of coal generation did not appear to compromise the reliability of the system.

Effects of DG and EE Requirement

In the Eighth BTA, the Commission ordered Arizona utilities, with retail load, to conduct a study to more directly identify the effects of DG and EE installations and/or programs on future transmission needs.[15] The Commission provided specific instruction of how the report be conducted, specifically stating:

> *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*

[15] ACC Decision No. 74785, October 24, 2014, pgs 9-10.

> *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 1 15 kV level.*

In the Ninth and Tenth BTAs, the technical studies were filed and study results were included in utility presentations at each Workshop I.

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Appendix C - 2020 BTA Workshop I and II List of Attendees

Workshops I[16] & II[17] were conducted remotely on August 7, 2020 and February 19, 2021. Please refer to the recording of each event for attendee information.

[16] 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

[17] 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

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

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

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

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

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

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

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

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

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

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

7. Please identify any transmission projects that are seeking a WECC path rating and identify the progress made in the rating process.

8. Describe the extent to which replacement generation that is required to accommodate actual, planned, or potential coal generation retirements are being considered in your transmission planning process. Please identify any transmission projects that are directly related to actual, planned, or potential coal retirements.

9. Describe the extent to which renewable generation being added to comply with renewable portfolio standards in neighboring states are being considered in your transmission planning process. Please identify any transmission projects that are directly related to the impacts of the renewable portfolio standards in neighboring states.

10. Please identify what entity your utility is now using as a Reliability Coordinator. Describe any impacts the transition and current operation of your current Reliability Coordinator have on local, state, and regional transmission systems.

11. Describe the status of your participation in the EIM (or anticipated participation) and any impacts it may have on local, state, and regional transmission systems.

12. An Extended Day Ahead Market is currently under study by CAISO and utilities in the western grid system. Please comment on any impacts you feel might result from EDAM to local, state, and regional transmission.

Appendix E - RMR Conditions and Study Methodology

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

1. Define annual simultaneous import limits ("SIL") for each transmission import limited area.

2. Provide a listing of all local generation and associated operational attributes.

3. Define RMR conditions for each year of the Ten-Year Plan.

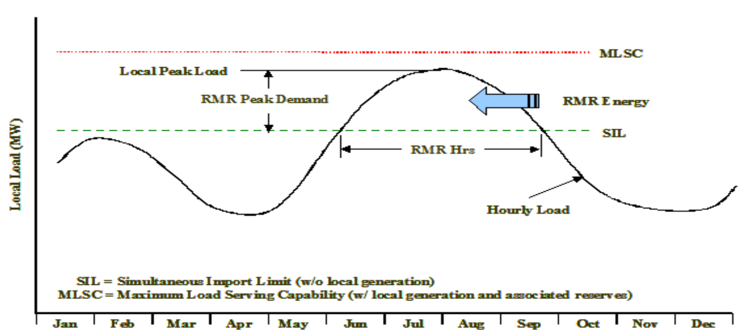
4. Provide a local generation sensitivity analysis.

5. Identify and study alternative solutions.

6. Perform comparative analysis and present worth analysis of alternative solutions.

RMR conditions, required from RMR studies, are defined in the 2002 BTA and graphically presented in the following Figure 1.[18]

Figure 1 – RMR Conditions



[18] 2002 BTA, Page 74-76

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

- RMR hours - The number of hours during which the local load is above the SIL,
- RMR energy - The amount of energy served from RMR generation,
- RMR peak demand - The maximum RMR amount of capacity that the RMR generators would be required to produce,
- RMR costs - The costs of out-of-merit-order dispatch from RMR

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

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

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

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

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

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

- The total expected cost, fixed and variable, for the local generation dispatch that results in the lowest local generation dispatch to mitigate annual RMR conditions.

- Total emission pollutants produced by the lowest local generation dispatch mitigating the annual RMR condition.

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

1. Hourly load forecast for the future years.

2. SIL by ensuring that:

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

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

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

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

3. RMR production costs by ensuring that:

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

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

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

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

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

Appendix F – Listing of Terminology and Acronyms[19] [20]

Terminology

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

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

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

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

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

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

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

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

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

[19] Listing of Acronyms obtained from Fourth Biennial Transmission Assessment, Page 1
[20] http://www.azcc.gov/divisions/utilities/electric/terms.asp

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Acronyms

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

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

Appendix G - Information Resources

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

Utilities' 2019 & 2020 Ten-Year Transmission Plans
Ajo Improvement Company
Arizona Public Service Company ("APS")
Salt River Project ("SRP")
Southwest Transmission Cooperative ("SWTC")
Public Service Company of New Mexico ("PNM")
Tucson Electric Power Company ("TEP")
El Paso Electric Company ("EPE")
UNS Electric, Inc. ("UNSE")

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

First, Second, Third, Fourth, Fifth, Sixth, Seventh, Eighth, Ninth, and Tenth BTA Reports, and 2020 Summer Preparedness Presentations
These reports and presentations can be found on the Arizona Corporation Commission website (http://www.azcc.gov/divisions/utilities/electric.asp)

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

N-1-1 and Extreme Contingency Study Documents
ACC 2020 BTA Workshop I N-1-1 and Extreme Contingency Presentations

Transmission and Generation Projects Reports
Centennial West Clean Line
Southline Transmission Project
Sun Streams
Tribal Solar
Buckeye Generation Center
Gila Bend Power Partners
Mohave County Wind Project
Ten West Link 500 kV Project (D-CR)
Bowie Power Station
SunZia Southwest Transmission Project – Southwestern Power Group

Regional Committees and Working Groups Materials

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

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

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

Western Electricity Coordinating Council (WECC) Standards and studies
The standards can be found on the WECC website (www.wecc.biz) under "Click here for library".

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

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

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

Integrated Resource Plans
2020 Arizona Public Service (APS)
2020 Tucson Electric Power (TEP)
2020 UNS Electric