Arizona Corporation Commission Fourth Biennial Transmission Assessment – 2006-2015

Arizona Corporation Commission Fourth Biennial Transmission Assessment
for 2006-2015,
Docket No. E-00000D-05-0040

Arizona Corporation Commission Utilities Division

KEMA, Inc.

Arizona Corporation Commission

Docket No. E-00000D-05-0040

Decision No. _______

Fourth Biennial Transmission Assessment

2006-2015

January 30, 2007

Arizona Corporation Commission Staff

and

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Common acronyms

AC	Alternating Current
ACC	Arizona Corporation Commission
ANPP	Arizona Nuclear Power Project
APS	Arizona Public Service
ATC	Available Transfer Capability
AZ	Arizona
AZNM	AZ-NM EHV Subcommittee
BTA	Biennial Transmission Assessment
BTU	British Thermal Unit
CA	California
CAO	Control Area Operator
CATS	Central Arizona Transmission System
CAWCD	Central AZ Water Conservation District
CC	Combined Cycle
CDEAC	Clean and Diversified Energy Advisory Committee
CEC	Certificate of Environmental Compatibility
CRT	Colorado River Transmission Subcommittee
DOE	Department of Energy
DPA	Dine Power Authority
DSW	Desert Southwest Region
ED	Electric District
EFOR	Equivalent Forced Outage Rate
EOR	East of (Colorado) River
EPACT	Energy Policy Act
EPS	Environmental Portfolio Standards
ERO	Electric Reliability Organization
EHV	Extra High Voltage
FACTS	Flexible AC Transmission System
FPA	Federal Power Act
FERC	Federal Energy Regulatory Commission
FOR	Forced outage rate
GT	Gas Turbine
HV	High Voltage
HVDC	High Voltage Direct Current
HY	Hydro
IID	Imperial Irrigation District
IPP	Independent Power Producer
I/S	In-Service
ISO	Independent System Operator
KV	Kilovolt
KWh	Kilowatt-Hour
LSE	Load Serving Entity
MISO	Midwest Independent System Operator
MLSC	Maximum Load Serving Capability
MORC	Minimum Operating Reliability Criteria
MOU	Memorandum of Understanding
MVA	Megavolt-Ampere
Mvar	Mega-var
MW	Megawatt
n-0	No Contingency
n-1	Single Contingency
n-2	Double Contingency
n-1-1	Overlapping Contingency
NERC	North American Electric Reliability Council
NG	Natural Gas
NM	New Mexico
NOI	Notice of Inquiry
NTP	Navajo Transmission Project
NOPR	Notice of Proposed Rulemaking
OASIS	Open Access Same Time Information System
OATT	Open Access Transmission Tariff
PJM	Pennsylvania-New Jersey-Maryland (ISO)
PNM	Public Service of New Mexico
PURPA	Public Utilities Regulatory Policy Act
PV	Palo Verde
RMR	Reliability Must Run
RMS	Reliability Management System
RTO	Regional Transmission Organization
SCE	Southern California Edison
SCED	Security Constrained Economic Dispatch
SDG&E	San Diego Gas and Electric
SEV	South East Valley
SIL	Simultaneous Import Limit
SRP	Salt River Project
SSG-WI	Seams Steering Group – Western Interconnection
ST	Steam Turbine
STEP	Southwest Transmission Expansion Planning Group
SWAT	Southwest Area Transmission Study Group
SWPG	Southwest Power Group
SWTC	Southwest Transmission Cooperative
TEP	Tucson Electric Power
TEPPC	Transmission Expansion Planning Policy Committee
TNMP	Texas-New Mexico Power Company
TTC	Total Transfer Capability
UDC	Utility Distribution Company
UNS	UniSource Energy Corp.
WAPA	Western Area Power Administration (“Western”)
WECC	Western Electricity Coordinating Council
WGA	Western Governors’ Association

Executive summary

A.R.S. §40-360.02.E states "The (Ten-Year) plans shall be reviewed biennially by the commission and the commission shall 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." This Fourth Biennial Transmission Assessment (BTA) was undertaken by the Arizona Corporation Commission (ACC or "Commission") Staff ("Staff") to fulfill the above stated statutory obligation.

The Ten-Year transmission plans filed in January 2005 and 2006 under Docket No. E-00000D-05-0040 are the subject of this assessment. Of particular interest are the many activities related to the collaborative regional planning process. Reliability Must Run (RMR) studies were submitted by industry to address concerns identified in earlier BTAs and are also the topic of this assessment.

Staff's approach in organizing the BTA remained the same as for the previous BTA. Staff relied on analyzing the Ten-Year studies, RMR Studies, and other technical reports and documents filed with the Commission by the various organizations rather than performing technical studies of their own. Staff hired a consulting organization, KEMA, to assist in this effort.

Staff uses a set of guiding principles to determine whether the Arizona transmission system will be adequate during the next ten-year period. Staff's guiding principles are based upon best engineering practices established in Arizona, coupled with the use of regional and national reliability council criteria and standards, and related state and federal policies.

This report by Arizona Corporation Commission Staff is intended to inform the Commission regarding the adequacy of the existing and planned transmission facilities in the state to meet the present and future energy needs of the state in a reliable manner pursuant to the obligation stated by A.R.S. §40-360.02, Title 40, Chapter 2, paragraph G.

The reliability of an existing or planned electric system under existing, alternative or future operating conditions can only be determined by technical simulation studies, including load flow, stability and short circuit analysis. Such studies require the application of a set of study criteria to measure the system's performance. In assessing the Arizona transmission system adequacy, Staff and KEMA critically reviewed and analyzed the transmission planning documents assembled by Staff and addressed the following questions:

1. Do the proposed Arizona transmission system plans meet the load serving requirements of the state during the 2006-2015 time period in a reliable manner?
2. Was the transmission planning process conducted in accordance with the transmission planning principles and good utility practices accepted by the power industry?

3. What steps were taken in the new transmission planning studies to effectively address the Commission's concerns raised in the earlier BTAs about the adequacy of the state's transmission system to reliably support the competitive wholesale market emerging in Arizona?
4. Do the generation interconnection practices in Arizona adequately reflect technical aspects of the generation interconnection policies as defined in Federal Energy Regulatory Commission (FERC) Orders?
5. Do the transmission plans adequately reflect North American Electric Reliability Council's (NERC) latest activities related to compliance with the transmission planning standards, as well as compliance with Western Electricity Coordinating Council (WECC) reliability standards?

This transmission assessment represents the professional opinion of Commission Staff and the Commission's Consultant, KEMA. The BTA is not an evaluation of individual transmission provider's facilities or quality of service. This BTA report does not set Commission policy and does not recommend specific action for any individual Arizona transmission provider. It assesses the adequacy of Arizona's transmission system to reliably meet existing and future energy needs of the state. This transmission assessment will not become official unless and until it is adopted by Commission Decision.

Commission Staff is pleased to report that the collaborative process between the Commission and Arizona utilities, which began in previous BTAs, has continued to evolve in a constructive manner during the Fourth BTA. Transmission owners have been responsive to many issues raised by Staff in prior BTAs, including the level of ability of the Palo Verde transmission system to handle full generation output at the Palo Verde Hub, Palo Verde Hub reliability issues and the economic viability of generators at the Hub, clarifying the criteria and study processes Arizona utilities utilize to formulate their RMR plans, and a number of other issues that are discussed in this report.

Extensive regional planning studies have been conducted in a collaborative process for 2006-2015. Studies for more localized service areas within the state were also included. In addition to addressing normal system conditions with all lines in service (n-0), this year's filings also included analysis of significant overlapping or concurrent outage events (n-1-1 and n-2 events, respectively). Current and planned transmission projects are increasing the Palo Verde Hub transmission capacity to both the east and the west. Phoenix and Yuma area RMR concerns raised in the Third BTA have been satisfactorily addressed. In addition, several major future interstate projects were identified in this BTA for Commission and stakeholder review.

As evidence of the collaborative long-term planning and expansion process taking place in Arizona, at least eight major projects in the ten year filing period have multiple utility sponsors. Collaborative long-term planning studies were also conducted by the utilities; including a study of the collective impact of individual transmission owner expansion plans in the Central Arizona region. A collaborative study approach was used to determine the 2006 Phoenix area RMR requirements. Collaborative planning efforts are also leading to expanded delivery capability from Arizona to southern California across Path 49, as defined by WECC. Major n-1-1 overlapping contingency events and n-2 extreme contingency events were addressed for the first time in the Fourth BTA. Such analysis is consistent with WECC/NERC reliability standards and the Staff's vision of expanded studies to address certain types of more extreme events.

The Fourth BTA also concludes that short-term upgrades on Path 49 and addition of two planned Arizona 500 kV projects (Hassayampa-Pinal West-Santa Rosa in 2008 and Palo Verde-TS5 in 2009) will significantly increase the outlet capability of the Palo Verde Hub. The Path 49 upgrades will also help to remedy market limitations between Arizona, California and Southern Nevada.

Staff offers the following conclusions for Commission consideration:

1. The electric industry in Arizona has been very responsive to concerns raised in the Commission's previous BTAs.
2. Extensive regional studies addressing the interstate transmission needs have been conducted in a collaborative process.
3. Transmission providers have performed RMR studies for each local transmission import constrained area they serve and have complied with RMR requirements of the previous BTAs.
4. In general, the existing and proposed Arizona transmission system meets the load serving requirements of the state in a reliable manner:
    a. Many planned 345 kV and 500 kV Extra High Voltage (EHV) and 115 kV and 230 kV High Voltage (HV) projects will increase transmission system capability to support increased interstate power transfers, and to provide reliable transfers within the state of Arizona.
    b. The planned EHV system appears to be adequate throughout the study period. As is often the case, plans for the later years of the period are less well defined than those in the early years. Future reports should include more discussion of alternate additions considered for the final five years of the study period. This will allow the Commission and public to be better informed regarding future possibilities.
    c. The RMR studies show that the RMR areas will have load-serving capacity sufficient to provide reliable supply during the next ten-year period. The 2006 RMR study analyzed expected 2008 and 2015 system conditions and concludes that projected reserves in the Phoenix area in both years are greater than the 99% reliability reserve requirement of 865 MW. These results appear to resolve the Staff's concern from the 2004 study. However, regarding the Mohave County RMR study results, the situation remains unclear. As discussed in §6.2.5 (page 111) this is due in large part to the absence of filings by Western Area Power Administration in the BTA process.
    d. The RMR studies show no economic justification for additional transmission projects as an alternative to dispatch of local area generation. Concerns

raised in the last BTA concerning extreme contingencies and data transparency have been satisfactorily addressed in this BTA.

e. The planned Arizona transmission system meets the WECC and NERC single contingency criteria (n-1).

f. Since interconnection of merchant plants commenced at the Palo Verde Hub, the Palo Verde east transmission system capability has increased from 3,810 MW to 6,970 MW as a result of several transmission upgrades. Several new 500 kV transmission line projects within Arizona are proposed as additional reinforcements in 2008 through 2012 that will significantly increase the outlet capability of the Palo Verde Hub to Arizona and California.

5. Short-term upgrades to Path 49 have added 505 MW to the pre-existing 2,800 MW Palo Verde west transmission system for power delivery to California. However, transmission from Palo Verde to California is inadequate to allow all new Palo Verde Hub generation full access to the California market. Several 500 kV transmission projects are being studied to remedy such market limitation between Arizona, California and Nevada.

6. Some new power plants are interconnected to Arizona's bulk transmission system via a single transmission line or tie rather than using Arizona's best engineering practices of multiple lines emanating from power plants. As interconnection of new transmission lines are considered for the Palo Verde Hub, they should be encouraged to terminate at these new power plant switchyards in order to mitigate this regional reliability concern.

Concerns outlined by Staff in the above conclusions are not easily or quickly resolved. The public's best interest warrants effective and decisive remedies. Therefore, Staff offers the following recommendations for Commission consideration and action:

1. Continue to support use of:

    a. *Guiding Principles for ACC Staff Determination of Electric System Adequacy and Reliability* (attached as Appendix A) to aid Staff in its determination of adequacy and reliability of power plant and transmission line projects,

    b. NERC and WECC criteria and FERC policies for adequacy and reliability assessments of the transmission system, and

    c. Collaborative planning study forums of transmission providers, merchant plant developers, and other interested parties for the purpose of ensuring consumer benefits of generation additions and cost-effective transmission enhancements and interconnections.

2. Endorse Staff's recommendations that:

    a. RMR 10-year study results are to be filed with ten-year transmission plans by January 31, of even number years, to coincide with the associated ACC obligation to perform a Biennial Transmission Assessment.

    b. All future interconnections proposed at the Palo Verde Hub, either new generation or new transmission line, 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 Certificate of Environmental Compatibility (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.

    c. Arizona utilities should continue performing RMR studies for all transmission import constrained local areas:

        i. Utilizing a collaborative study forum;

        ii. Improving economic analysis of RMR mitigation;

        iii. Clarifying projected system peak load and supply conditions in Mohave County beyond 2012 and appropriate mitigation measures, if any;

        iv. Clarify anticipated generation retirements in each constrained load area and the impact of such retirements on the RMR requirements.

1. Overview

1.1 Assessment authority

Arizona statutes require every organization contemplating construction of any transmission line within Arizona during a ten-year period to file a ten-year plan with the Arizona Corporation Commission (ACC) on or before January 31 of each year.[1] In 1999, the Arizona state legislature placed a statutory obligation with the ACC to biennially review the plans filed with the Commission and "issue a written decision regarding the adequacy of the existing and planned transmission facilities in Arizona to meet the present and future energy needs of the state in a reliable manner."[2]

In 2001, the Arizona legislature further modified the Arizona Power Plant and Transmission Line Siting statutes resulting in two new statutory requirements related to filing of plans with the Commission. Every organization contemplating construction of a new power plant within Arizona is now required to file a plan with the Commission 90 days before filing an application for a Certificate of Environmental Compatibility (CEC).[3] Additionally, all plans filed with the Commission are to be accompanied by power flow and stability analysis reports showing the effect of plant interconnections on the current *(and future)* Arizona electric transmission system.[4]

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[1] A.R.S. § 40-360.02.A

[2] A.R.S. § 40-360.02.G

[3] A.R.S. § 40-360.02.B

[4] A.R.S. § 40-360.02.C.7

1.2 Summary of previous Biennial Transmission Assessments

1.2.1 First BTA 2000-2009

Staff of the ACC initiated its First Biennial Transmission Assessment (BTA) in 2000, under Docket No. E-00000A-01-0120. A written decision of that assessment was rendered in July 2001. In the First BTA, Staff determined that the State of Arizona (State) transmission system was not adequate[1] to provide reliable supply to the State electrical load, neither for the present nor for the future conditions. Staff recommended two standards for measuring transmission adequacy and security:

1. There should be sufficient transmission import capability to reliably serve all loads in a utility's service area without limiting access to more economical or a less polluting remote generation.
2. New power plants must have sufficient interconnected transmission capacity to reliably deliver their full output without use of remedial action schemes or displacing existing generation at the same interconnection for single contingency (n-1) outages.

1.2.2 Second BTA 2002-2011

The Staff initiated its Second BTA in 2002, under Docket No. E-00000A-02-0065. Written Decision No. 65476 of that assessment was rendered on December 19, 2002. In this BTA, Staff concluded that the electric industry had been very responsive[2] to concerns raised by Staff in the First BTA. The BTA process was built upon an extensive collaborative transmission planning process open to all stakeholders. In addition, some merchant power plant developers had begun proposing transmission system reinforcements to resolve transmission barriers to the wholesale market. Transmission providers had agreed to participate in a RMR study process for transmission-constrained areas with which they are interconnected. Most importantly, numerous new transmission projects had been announced and filed with the Commission since its First BTA.

[1] BTA 2002-2011, Page 2

[2] BTA 2002-2011, Executive Summary, Page ii

Staff concluded that the existing and planned Arizona transmission system generally met the load serving requirements of the State in a reliable manner. However, Staff had several concerns about the adequacy of the State's transmission system to reliably support the competitive wholesale market emerging in Arizona. These concerns included:

- Limited access by competitive wholesale generators to local Arizona markets due to local transmission import constraints that result in local RMR generation requirements;
- Failure of planned Palo Verde transmission system additions to accommodate the full output of all new power plants connected at the Palo Verde Hub;
- Limited additional long-term firm transmission capacity available to export or import energy over Arizona's transmission system; and
- A single transmission line or tie being used to connect some new power plants to Arizona's bulk transmission system rather than using Arizona's best engineering practices of multiple connections from power plants.

Staff recognized that the above concerns were not easy to resolve, and offered the following recommendations for Commission consideration and action:

1. Continue to support use of the "Guiding Principles for ACC Staff Determination of Electric System Adequacy and Reliability" to aid Staff in its determination of adequacy and reliability of power plant and transmission line projects.
2. Request Staff to commence rule making proceedings to determine how:
   a. Utility distribution companies (UDCs) should ensure sufficient transmission import capacity to reliably serve all loads in its service area without limiting access to more economical or less polluting remote generation[1], and
   b. New power plants should demonstrate sufficient transmission capacity exists to reliably and economically deliver their full output without use of remedial action schemes for single contingency (n-1) outages or displacing existing generation at the interconnection.
3. Encourage transmission providers to continue to investigate and study, in a collaborative fashion, local area import constraints in accordance with the RMR Study Plan outlined in Section 7.2 of the BTA 2002.

[1] Each utility distribution company also has an obligation to assure that adequate transmission import capability is available to meet the load requirements of all distribution customers in its service area. This requirement is also coupled with a requirement that Arizona utilities competitively procure 100% of their standard offer requirements, with at least 50% procured through competitive bidding. This later requirement was stayed by the Commission in Decision No. 61969, for Staff to determine the proper level of competitive solicitation. Staff used these guiding principles, criteria, standards and rules for this biennial transmission assessment.

4. Continue to encourage collaborative study activities between transmission providers and merchant plant developers for the purpose of:

   a. Ensuring consumer benefits of generation additions and cost–effective transmission enhancements and interconnections, and

   b. Facilitating restructuring of the electric utility industry to reliably serve Arizona consumers at just and reasonable rates via a competitive wholesale market.

1.2.3 Third BTA 2004-2013

The Staff initiated its Third BTA in 2004, under Docket No. E-00000D-03-0047. Written Decision No. 67457 of that assessment was rendered on January 4, 2005. In this BTA, Staff concluded that the electric industry had been very responsive to concerns raised in the Staff's second BTA. [1]

Staff concluded that the existing and planned Arizona transmission system generally met the load serving requirements of the State in a reliable manner. However, Staff had several concerns about the adequacy of the State's transmission system to reliably support the competitive wholesale market emerging in Arizona. These concerns included:

- No transmission improvements had been made to the pre-existing 2,800 MW Palo Verde west transmission system capability to deliver power to California. Therefore, transmission from Palo Verde to California is inadequate to allow all new Palo Verde Hub generation full access to the California market. Three 500 kV transmission projects are being studied to remedy such market limitation between Arizona, California and Nevada.

- There was very little existing long-term firm transmission capacity available to export or import energy over Arizona's transmission system. Studies investigating transmission additions required between Arizona and California and between New Mexico and Arizona continue to explore the scope, participation and timing of alternative projects.

- Some new power plants had interconnected to Arizona's bulk transmission system via a single transmission line or tie rather than using Arizona's best engineering practices of multiple lines emanating from power plants. As interconnection of new transmission lines are considered for the Palo Verde Hub, they should be encouraged to terminate at these new power plant switchyards in order to mitigate this regional reliability concern.

[1] BTA 2004-2013, Executive Summary

Staff recognized that the above concerns were not easy to resolve, and offered the following recommendations for Commission consideration and action:

- Continue to support use of:

  a. "Guiding Principles for ACC Staff Determination of Electric System Adequacy and Reliability" (attached as Appendix A) to aid Staff in its determination of adequacy and reliability of power plant and transmission line projects,

  b. NERC and WECC criteria and FERC policies for adequacy and reliability assessments of the transmission system, and

  c. Collaborative planning study forums of transmission providers, merchant plant developers, and other interested parties for the purpose of ensuring consumer benefits of generation additions and cost–effective transmission enhancements and interconnections.

- Endorse Staff's recommendation that:

  a. RMR studies continue to be performed and filed with ten year plans in even numbered years for inclusion in future BTA reports and that:

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

  b. 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.

  c. The Fourth BTA address and document:

     - Compliance with single contingency criteria overlapped with the bulk power system facilities maintenance (n-1-1) (for the first year of the BTA analysis) as required by WECC and NERC.
     - Extreme contingency outages studied for Arizona's major generation hubs and major transmission stations including identification of associated risks and consequences if mitigating infrastructure improvements are not planned.

1.3 Fourth Biennial Assessment – Purpose and Framework

1.3.1 Purpose

Staff undertook the Fourth BTA, which evaluates the utilities' 2006-2015 transmission plans filed in January 2006, under Docket No. E-00000D-05-0040. This report fulfills the Staff's statutory obligation to review these transmission plans and assess whether the Arizona transmission system is adequate. The 2005 and 2006 RMR Studies are also the subject of this assessment. Of particular interest are the adjustments made by the industry to address the concerns identified in the Staff's First, Second and Third BTAs. Staff hired a consulting organization, KEMA Inc. to assist Staff in this effort.

The adequacy of an existing or planned electric system is determined by technical simulation studies. Such studies require the use of databases, software and transmission planning reliability standards, and planning assumptions. In the BTA process the Arizona transmission utilities conduct their own studies, participate in the collaborative regional planning process, and present the study results in their ten-year plan reports and at public workshops. Staff and KEMA reviewed and analyzed all these study reports assembled by Staff, and organized two workshops. Staff relied on the technical reports and documents filed with the Commission by the various organizations, rather than performing technical studies of their own.

Staff used a set of guiding principles to aid it in determining the adequacy and reliability of both transmission and generation systems.[1] Staff's guiding principles are based upon best engineering practices established in Arizona coupled with the use of WECC and NERC planning standards.[2] Staff and KEMA critically reviewed and analyzed the transmission planning documents assembled by Staff and addressed the following questions:

- Do the proposed Arizona transmission system plans meet the load-serving requirements of the state during the 2006-2015 period, in a reliable manner?
- Was the transmission planning process conducted in accordance with the transmission planning principles and good utility practices accepted by the power industry and the reliability standards established by NERC and WECC?
- What steps were taken in the new transmission planning studies to effectively address Staff concerns raised in previous BTAs about the adequacy of the state's transmission system to reliably support the competitive wholesale market in Arizona?

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

[2] http://www.wecc.biz/modules.php?op=modload&name=Downloads&file=index&req=viewsdownload&sid=101, and http://www.nerc.com/~filez/standards/Reliability_Standards.html

- Do the generation interconnection practices in Arizona adequately reflect technical aspects of the generation interconnection policies as defined in FERC Orders?

- Do the transmission plans adequately reflect NERC latest activities related to compliance with the transmission planning standards, as well as compliance with WECC reliability standards?

1.3.2 Framework

Staff and KEMA made use of a three-stage process to facilitate the electric industry's participation in the fourth BTA:

1. Workshop 1: industry presentation;
2. Preparation of Initial Draft Report and industry comments on draft; and
3. Workshop 2: Staff/KEMA presentation and Final Report.

An overview of each stage is described below.

1.3.2.1 Workshop 1: industry presentation

Staff and KEMA organized and facilitated a one-day public Workshop on June 6, 2006. Transmission Providers and Regional Planning Groups presented information regarding their transmission expansion plans and related activities to supply native load customers for the next ten-years. In addition, merchant transmission and wind generator developers reported on their development plans.[1] The Workshop provided an informal setting to promote effective discussions of the presentations from transmission providers and merchant plant developers. The Workshop I participants are listed in Appendix B.

The workshop was organized in six presentations by the following entities:

1. Southwest Area Transmission Planning (SWAT), Central Arizona Transmission System (CATS), Extra-high voltage (EHV)—Gary Romero;
2. Arizona Public Service—Bob Smith;
3. Diné Power Authority—Steve Begay;
4. Salt River Project—Chuck Russell;
5. Southwest Transmission Cooperative (SWTC)—Bruce Evans; and
6. Tucson Electric Power—Ed Beck.

[1] The Workshop presentation materials are located on the ACC website.

An open period of discussion and audience questions followed each presentation.

Staff's opinion is that the Transmission Providers presented enough information to allow a suitable assessment of the status of Arizona's transmission system reliability.

1.3.2.2 Preparation of initial draft report and industry comment on draft

Staff and KEMA provided the first draft of the 2006 BTA report for industry review and comment. The first draft of the report was based on the utilities' filed plans and the participants' responses to questions raised at Workshop 1.[1] The draft report and industry comments were placed on the Commission website to expedite the review process.

1.3.2.3 Workshop 2: Staff/KEMA presentation and final report

Workshop 2, organized on September 8, 2006, presented the Staff's response to industry comments on the first draft of the 2006 BTA Report and allowed for discussion and questions.[2] The Workshop again provided an informal setting to promote effective discussions of the presentations from transmission providers and merchant plant developers. The list of Workshop 2 participants is included in Appendix B.

The workshop was organized in one main session followed by an open period of discussion and audience questions. To facilitate focused and meaningful presentations and discussions at the Workshop, Staff provided a copy of the draft report several weeks before the Workshop.

The Staff and their consultant presented 6 major issues and 6 less significant issues for discussion. The 6 major issues were:

1. Palo Verde Hub transmission constraints.
2. Palo Verde Hub connection issues—addressed issues related to connection requirements for new generators in Arizona.
3. FERC/ACC jurisdictional issues in regard to Palo Verde Hub reliability criteria (raised in written comments)—all parties agreed that NERC and WECC set minimum criteria and that states and individual utilities can set more stringent criteria.
4. Non-transmission options included in the BTA—written comments questioned why demand-side and renewable options were not included in the BTA. It was generally agreed that the BTA should discuss and clarify how renewables and demand-side options have been included in the BTA.

[1] Transcripts of June 30, 2004 Workshop I

[2] The Workshop presentation materials are located on the ACC website.

5. The adequacy of total Arizona import/export capability—it was agreed that completed projects and projects now underway should provide enough capability to meet known needs.
6. The inclusion of more conceptual interstate projects in the BTA. A number of additional interstate projects should be mentioned including Inland Northern Lights, Harry Allen to Mead 500kV lines #1 and #2, and the Robinson Summit to Harry Allen 500kV line.

The six less significant issues were:

1. The Energy Policy Act of 2005 (EPAct-05) and recent FERC Orders might be better shown in an Appendix.
2. A specific section should be added regarding WECC activities, actions, and initiatives including Resource Adequacy and West-wide System Model and mention the Regional Planning Initiative, Planning Principles with SWAT & CCPG, and WestConnect Objectives & Procedures for Regional Transmission Planning.
3. A discussion of what aspects of recent actions regarding the PV risk assessment can be added to the report. The public portions of the Palo Verde Hub Risk Assessment study as part of the Palo Verde Hub-TS5 500kV project should be noted in the BTA report.
4. A discussion of the Staff's continued concern about generation-only control areas and their ability or willingness to fulfill their reliability obligations. Comments at the meeting indicated that Staff was less concerned about this than in past years; however, the issue needs to maintain some visibility into the future.
5. The need for new capacity in the Phoenix area by 2012 in regard to RMR studies as discussed in the draft BTA report.
6. Several suggestions to revise the text:
    - The conclusions should include a statement that installed generation has more than kept pace with the growth in retail sales. KEMA/Staff agree.
    - The last bullet of §4.3.1 in the draft BTA report recommended that the ACC siting standards require a generator to "offer up to 10% of plant capacity for ancillary services to the local Control Area Operator (CAO) or RTO with which it interconnects.
    - The draft report stated that no evaluations appear to be made of NERC category C or D criteria – multiple and extreme contingencies. This statement is not true and will be removed from the text.

- Various typographic errors identified in various written comments will be corrected.

All the issues presented were resolved successfully as a result of the Workshop discussions and are reflected in this final report.

2. Related regulatory activities and Arizona industry response

This section describes selected regulatory and industry activities since the 2004 BTA. Only those activities related to transmission infrastructure, transmission grid expansion at regional and sub-regional levels, transmission congestion, transmission reliability, and transmission rights and pricing are described. This section considers how such industry activities relate to the transmission expansion, siting and analysis in Arizona.

2.1 Federal regulatory activities

2.1.1 Energy Policy Act of 2005

EPAct-05 encourages investment in the nation's energy infrastructure, and was intended to establish a comprehensive, long-range energy policy. The Act is meant to enhance protections for electricity consumers, and to encourage energy efficiency and conservation. It provides incentives for conservation, traditional energy production, and newer, more efficient, energy production technologies. EPAct-05 is more than 1,700 pages long and contains hundreds of provisions.

The major provisions that impact directly on electricity transmission siting include:

1. Title XII – Electricity, Subtitle A – Reliability Standards
2. Title XII – Electricity, Subtitle B – Transmission Infrastructure Modernization
3. Title XII – Electricity, Subtitle C – Transmission Operation Improvements

Additional provisions that have an impact on Electricity include Subtitle D – Transmission Rate Reform, Subtitle E – Amendments to PURPA, Subtitle F – Repeal of PUHCA, Subtitle G – Market Transparency, Enforcement, and Consumer Protection, Subtitle J – Economic Dispatch, and Title XVIII – Studies.

2.1.2 Relevant FERC Orders and actions

2.1.2.1 Electric reliability—Docket No. RM05-30-000

In response to EPAct-05 requirements FERC issued a Notice of Proposed Rulemaking (NOPR) on September 1, 2005, that contained proposed regulations concerning Electric Reliability Organization (ERO) certification, the process for developing and enforcing reliability standards, delegation of ERO authority to regional reliability entities, ERO funding and other matters necessary to implement FPA §215. FERC received approximately 1,700 pages of comments on the NOPR and made a number of changes to its proposed regulations based on these comments. On February 3, 2006, FERC issued its final rule as Order 672.

The regulations adopted by Order No. 672 establish:

- Criteria that an entity must satisfy to qualify as the ERO;
- Procedures for the ERO to propose new or modified reliability standards for FERC review;
- Procedures for timely resolution of any conflict between a reliability standard and a FERC-approved Tariff or Order;
- Procedures for resolving an inconsistency between a state action and a reliability standard;
- Regulations pertaining to ERO funding;
- Procedures governing an enforcement action by the ERO, regional entity or FERC;
- Criteria for delegating ERO authority to regional entities;
- Regulations governing the issuance by the ERO of periodic reports assessing the reliability and adequacy of the North American bulk-power system; and
- Procedures for creating regional advisory bodies composed of representatives of state governments and formed to advise FERC, the ERO or regional entities on reliability matters.

The formal implementation process began on April 4, 2006.

On July 20, 2006, NERC was certified as the ERO with some modifications and clarifications to NERC's proposed governance structure, funding, reliability standards development process, enforcement program and pro forma Regional Entity delegation agreement. FERC directed NERC to make several improvements to its proposed standardized agreement for delegating enforcement authorities to Regional Entities, including clarification of due process and other steps associated with enforcement of reliability standards. FERC also directed NERC to make changes to the ERO's procedural rules, and to speed the process for developing new reliability standards in response to a FERC-imposed deadline.

All proposed reliability standards must be submitted by the ERO to FERC for its approval. Only reliability standards approved by FERC are enforceable. FERC expects to undertake a rulemaking later in 2006 as part of its review of the 102 reliability standards submitted by NERC for FERC review.

On April 20, 2006, FERC granted a petition from the governors of Arizona, California, Colorado, Montana, Nevada, New Mexico, Oregon, Utah, Washington and Wyoming to establish a regional advisory body, as provided for under EPAct-05. The Western Interconnection Regional Advisory Body (WIRAB) may provide advice to FERC, the ERO and a Regional Entity on specific issues affecting that region, and FERC may give deference to the advice of the regional advisory body.

WIRAB was created by Western Governors under Section 215 of the Federal Power Act and was approved by FERC in July 2006. The WIRAB is to advise WECC, the ERO and FERC on whether proposed reliability standards and the governance and budgets of the ERO and WECC are in the public interest as well as to consult with DOE on the designation of national interest transmission corridors. FERC may request that WIRAB provide advice on other topics. Members include representatives from the states of Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, South Dakota, Utah, Washington and Wyoming, the Canadian provinces of Alberta and British Columbia, and Mexico.[1]

2.1.2.2 Transmission monitoring report to Congress

The Department of Energy (DOE) and FERC issued a report to Congress on February 2, 2006 on Transmission System Monitoring, i.e., the steps which must be taken to establish a system to make available to all transmission owners and regional transmission organizations (RTOs) in the Eastern and Western interconnections real-time information on the functional status of all transmission lines within the interconnections.

The study assessed technical means for implementing a transmission information system and to identify the steps FERC or Congress would need to take to require implementation of such a system. The analysis identified nine steps that could be taken to establish, and two steps that could be taken to implement, an interconnection-wide real-time monitoring system that could give a near-instant picture of the transmission system's health.

2.1.2.3 Long-term transmission rights

EPAct-05 required FERC to implement the subsection which requires FERC to exercise its authority under the FPA in a manner that facilitates planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities (LSEs) to satisfy their native load obligations and enables LSEs to secure firm transmission rights on a long-term basis for long-term power supply to meet their service needs. On July 20, 2006, FERC adopted seven guidelines in response. The final rule requires independent transmission organizations such as regional transmission organizations and independent system operators that oversee organized electricity markets to make long-term firm transmission rights available to all transmission customers.

2.1.2.4 Promoting transmission investment

On July 20, 2006, FERC implemented incentive based rate treatments for transmission of electric energy in interstate commerce. For the most part, the final rule adopts the proposals put forth in FERC'S November 2005 proposed rulemaking.

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[1] More information on WIRAB can be found on their website at http://www.westgov.org/wieb/site/wirab/wirabindex.htm.

2.1.2.5 Regional joint boards

FERC was required to convene regional joint boards to study security-constrained dispatch in various market regions and submit to Congress a report on the recommendations of the joint boards. FERC designated the market regions for the joint boards, established the joint boards, designated a FERC Commissioner to chair each board, requested that each state nominate a board representative to the appropriate joint board and submit their name and contact information. The Canadian provinces, Canada and Mexico were also invited to participate, as observers, on the appropriate joint boards.

FERC identified four regions: the South (Texas and the states in the southeast and Southwest Power Pool); the West (states in the Western Interconnection); the Northeast (New York and the states in New England); and PJM/MISO (states that are served primarily by PJM Interconnection, LLC and Midwest Independent Transmission System Operator, Inc.). Studies and recommendations were submitted to FERC by each of the regional joint boards between May 12, 2006 and July 11, 2006.

The West region consists of Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, South Dakota (a portion of this state is in the Western Electricity Coordinating Council), Utah, Washington and Wyoming.

The West Region analysis of security constrained economic dispatch (SCED) discusses the basics of SCED and how it functions in the Western Interconnection. It also addresses three recommendations made to the Joint Boards by the DOE in *The Value of Economic Dispatch, A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005*.

There were nine major issues considered by the West Region Joint Board:

1. Independence of dispatcher.
2. Utility dispatch of third party power through contracts.
3. Transparency of dispatch information and processes.
4. Consolidation of control areas in a region.
5. Import/export schedule changes within an hour.
6. Some practical limitations on economic dispatch.
7. First DOE Recommendation: review dispatch practices.
8. Second DOE Recommendation: standardize dispatch contract terms.
9. Third DOE Recommendation: review dispatch tools.

2.1.2.6 Demand response and advanced metering survey

FERC was required to publish an annual report, by region, that assesses demand response resources. The report reviews and identifies on a regional basis, the following issues: saturation and penetration of advanced metering communication systems; existing demand response and time based rate programs; annual resource constitution of demand resources; potential for demand response as a quantifiable, reliable resource for regional planning purposes; steps taken to ensure that demand resources are provided equitable treatment in regional transmission expansion planning and operations; and, finally, regulatory barriers to improved customer participation in demand response, peak reduction, and critical peak pricing programs.

2.1.2.7 Electric energy market competition

FERC required a five-member inter-agency task force (the "Electric Energy Market Competition Task Force") to submit to Congress a report on competition within wholesale and retail markets for electric energy in the U.S. The Draft *Report To Congress On Competition In The Wholesale And Retail Markets For Electric Energy* was issued on June 5, 2006.

2.1.2.8 Ensuring timely and coordinated review and permitting of electric transmission facilities

DOE and heads of all federal agencies with authority to issue federal authorizations for electric transmission facilities must enter into an MOU to ensure timely and coordinated review and permitting of electric transmission facilities. FERC states on its website that this action has been initiated; however there is no additional information as to the progress or current status of this action.

2.1.2.9 Rules for applications for national transmission corridor permits

EPAct-05 2005 adds a new section to the Federal Power Act (FPA), providing for federal siting of electric transmission facilities under certain circumstances. On June 16, 2006, FERC issued a NOPR on Regulations for Filing Applications for Permits to Site Interstate Electric Transmission Corridors.

EPAct-05 provides for federal backstop siting authority of certain electric transmission facilities in order to increase transmission capacity and maintain system reliability. Upon the Secretary of Energy's designation of national interest electric transmission corridors experiencing electric transmission capacity constraints or congestion that adversely affects consumers, FERC may issue permits to construct or modify electric transmission facilities.

A proposal to build or expand electric transmission facilities brought before FERC must be used for interstate commerce, be consistent with the public interest, significantly reduce transmission congestion in interstate commerce, be consistent with national energy policy, and maximize as much as possible existing towers and structures.

2.1.2.10 FERC Open Access Transmission Tariff (OATT) reform

A Notice of Inquiry (NOI) regarding the *pro forma* open access transmission tariff reform requiring comparable open access by non-regulated transmission utilities was issued by FERC on September 15, 2005. Response to the NOI included over 4,000 pages of comments and reply comments from all types of industry stakeholders.

FERC released a NOPR for OATT reform on May 18, 2006, with comments due by August 7, 2006, and Reply Comments due by September 20, 2006.

The proposed major reforms include:

- Greater consistency and transparency in Available Transfer Capability (ATC) calculation
- Open, coordinated and transparent planning
- Reform of energy imbalance penalties
- Reform of rollover rights policy
- Clarify tariff ambiguities
- Increase transparency and customer access to information
- Core elements of Order No. 888 being retained:
- Comparability requirement
- Protection of native load
- States jurisdiction over bundled retail load
- Functional unbundling to address undue discrimination
- Reciprocity

2.2 Western Governors Association efforts

The Western Governors' Association (WGA) is an independent, nonpartisan organization of Governors representing 18 Western states, and three U.S.-flag Pacific islands. While it is not a regulatory body, the WGA is currently exploring clean and diversified energy options; encouraging pro-active transmission expansion; promoting coordinated permitting of needed interstate transmission expansion; developing a renewable energy tracking system; and urging the adoption of federal legislation to make reliability standards mandatory. Recent actions that took place in the West to advance the Governors' energy policies for the region include the following:[1]

2.2.1 Proactive regional transmission planning

The WGA responded to the requirement in the EPAct-05 that federal agencies designate energy corridors on federal lands and identify transmission congestion. The Governors noted that if such federal efforts are done well, they could contribute to the Governors' efforts to develop needed transmission. However, if done poorly the federal intervention into state siting has the potential to slow down the development of needed transmission.

It was noted in the WGA 2006 Annual Report that the pace of transmission planning and development has accelerated in the West and that many major transmission proposals are under development.

In April of 2006, the WECC assumed interconnection-wide transmission planning responsibilities. WECC's efforts will supplement proactive transmission planning underway within the sub-regions of the Western Interconnection.

- A joint task force of Western states, provinces and industry has been working with DOE to evaluate transmission congestion in the Western Interconnection as stipulated in EPAct-05. (See §2.1.2.5, above.)
- Implementation of the transmission recommendations of the WGA Clean and Diversified Energy Advisory Committee can further strengthen transmission planning and development processes.

2.2.2 Clean and diversified energy initiative

The WGA launched the Clean and Diversified Energy Initiative with the adoption of a resolution that established three goals for the West:

1. Develop an additional 30,000 MW of clean energy by 2015 from both traditional and renewable sources;
2. Achieve a 20% increase in energy efficiency by 2020; and
3. Ensure a reliable and secure transmission grid for the next 25 years.

The Clean and Diversified Energy Advisory Committee (CDEAC) was commissioned in 2004 by the Western Governors to identify technically and financially viable policy mechanisms, stressing non-mandatory, incentive-based approaches, to meet the goals established in the Governors' resolution. On June 11, 2006, the CDEAC released a report and recommendations

[1] Western Governors' Association 2005 Annual Report and Western Governor's Association 2006 Annual Report..

for achieving and possibly exceeding the WGA's clean and diversified energy objectives. The report included specific recommendations regarding Transmission, as follows[1]:

"To ensure adequate transmission for the region to tap its vast clean and diversified energy resources, Western Governors should adopt and take necessary steps to implement the following actions. The recommendations are grouped according to federal, regional, state and local entities and industries that would implement the recommendations.

1) FERC's ongoing review of its open access transmission policy under Order 888 provides an excellent venue to urge FERC to make needed reforms. The Western Governors should engage FERC to make changes to its transmission policies to:

    a. Promote a conditional-firm, priority non-firm and other transmission service products;

    b. Encourage transparent review and assessment of ATC;

    c. Eliminate rate pancaking (i.e. access fees imposed on transmission customers contracting for service across multiple control areas) in the transmission system in a manner that addresses concerns about financial impacts such as recovery of costs and cost shifting;

    d. Promote control-area consolidation on a case-by-case basis, where an analysis finds that benefits exceed the costs and there are no significant adverse impacts on reliability;

    e. Encourage congestion management systems that allow access to least-cost generation within reliability security constraints;

    f. Encourage common Web sites for Open Access Same Time Information Systems (OASIS) to facilitate transmission transactions;

    g. FERC code of conduct rules should ensure that the transmission planning processes include as much information about future and existing resources as possible. Given different industry interpretations of code-of-conduct rules, FERC should clarify the rule to allow transmission planners and resource planners of a vertically integrated utility to participate in joint discussions at transparent regional planning meetings and state-approved resource planning and acquisition process; and

    h. Request that FERC convene a technical conference to develop needed reforms of interconnection and transmission queuing processes.

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[1] *Clean Energy, a Strong Economy and a Healthy Environment*, June 11, 2006. (www.westgov.org/wga_reports.htm)

2) The Western Governors should take an active leadership role to promote state and regional policies in collaboration with state legislatures to:

   a. Ensure resources to enable state participation in regional transmission planning;

   b. Encourage the electric power industry to make the existing proactive, transparent interconnection-wide and sub-regional transmission planning processes a priority;

   c. Review, and if necessary, amend state laws to require PUCs and public power boards to consider regional transmission needs;

   d. Support the goal of a regional planning capability that can yield critical information for stakeholders and regulators to allow rigorous evaluation of large, long-term investments in transmission;

   e. Bring together stakeholders and forge solutions to regional transmission needs, cost allocation and siting where RTOs or Independent System Operators (ISO) do not exist, and ensure state participation in such activities by existing RTOs/ISOs;

   f. Promote use of an open season process by project developers as a means of demonstrating demand for and value of new transmission projects, and expand project participation;

   g. Urge FERC and PUCs to form joint panels on transmission cost recovery that would explicitly consider risks and needs for incentives, such as forms of preapproval, higher rates of return on transmission investments, and quicker cost recovery of transmission investments;

   h. States should consider adopting funding mechanisms to support research, development and demonstration of advanced technologies in the public interest;

   i. Urge transmission operators to develop workable agreements at seams between ISO and non-ISO systems to enable effective grid operations;

   j. Ensure that there are resources and political commitments to successfully implement the WGA Transmission Permitting Protocol and the Midwest Electric Transmission Protocol for new interstate transmission proposals; and

   k. Evaluate the option of forming an interstate compact for creation of a regional siting agency pursuant to Section 1221 of the Energy Policy Act of 2005, and encourage consistent siting processes within their states through use of standardized applications, joint data and studies, coordinated schedules and deadlines and other mechanisms, where possible.

3) Western Governors should urge state public utility commissions to adopt policies and promote legislation, if necessary, to:

   a. Establish tiered standards of review for prudency and application of transmission incentives for transmission expansion costs featuring a lower standard for screening studies and planning, a moderate standard for permitting and the acquisition of rights-of-way, and a higher standard for construction costs;

   b. For states with mandatory renewable portfolio standards (RPS), regulatory commissions should make public Interest findings associated with cost effective transmission projects that will enable states to attain energy policy goals;

   c. Expand transmission in advance of generation to enable the modular development of location-constrained, clean and diversified resource areas to meet cost-effective Renewable Portfolio Solicitations, Integrated Resource Plans and state goals, similar to recent Texas and Minnesota legislation for new transmission and the renewable trunk line (Tehachapi) model for new transmission;

   d. Coordinate multi-state review of transmission projects by developing common principles for cost allocation and cost recovery, and adopt a common Western procedural process that would identify and coordinate the applications, forms, analyses and deadlines; and

   e. Promote cost-effective transmission expansion by accommodating both non-dispatchable and dispatchable resources.

4) Western Governors should collaborate with the appropriate federal agency to implement the Energy Policy Act provisions to designate energy corridors on federal lands by:

   a. Committing state agency resources to participate in the federal effort and to identify contiguous corridors on adjacent state lands;

   b. Urging Congress to fund federal land management agency corridor planning efforts; and

   c. Fostering designation of corridors on lands not owned by the federal government or the states to ensure continuity in corridors. Designation and preservation of transmission corridors is important in rapidly urbanizing parts of the region.

d. Western Governors should encourage the Western electric power industry to:

   i. Synchronize regional transmission planning efforts to resource acquisition plans of LSEs and plans of generators;

   ii. Support and collaborate with state infrastructure authorities that have been created to facilitate transmission expansion; and

   iii. Ensure institutional homes for regional transmission planning."

2.2.3 Western Renewable Energy Generation Information System

Western Renewable Energy Generation Information System (WREGIS) is a voluntary, independent renewable energy registry and tracking system for the Western Interconnection. It is being developed and is sponsored by the WECC, Western Governors' Association and the California Energy Commission. It is similar in scope to renewable tracking systems already implemented in ISO-New England, PJM and the Electric Reliability Council of Texas (ERCOT). The WREGIS charter was approved by the WECC in December 2004. Stakeholder Advisory Committee officers were elected in July 2006. Administrative operations for WREGIS are located at the WECC offices in Salt Lake City, Utah and the first WREGIS administrator was hired in October 2006.

Participation is open to regulators and all market participants including load-serving entities, generators, marketers, brokers/wholesalers, end-users and others. The Stakeholder Advisory Committee which consists of 85 elected members includes the Arizona Corporation Commission, Arizona Power Authority, Western Area Power Administration, APS, SRP, TEP, and the Arizona Electric Power Cooperative, Inc.

WREGIS was initiated in response to the need for a tracking and verification system for renewable energy in the Western Interconnection and to ensure that renewable energy producers are counted properly for the purpose of Renewables Portfolio Standard portfolios in each of the western states. The target date for operational status is mid-2007. When fully implemented WREGIS will include the capability for issuing renewable energy certificates, based on each MWh of renewable energy produced. These certificates are expected to have value in meeting regulatory requirements (compliance with state and provincial programs) as well as in voluntary commodity markets. The implementation of a regional system such as WREGIS provides economies of scale that would not be possible with individual state/province systems.

2.2.4 Western Interconnection Regional Advisory Body

The WIRAB was created by Western Governors and was discussed above in §2.1.2.1.

3. Transmission planning

Individual utilities within the state of Arizona plan and design their bulk transmission systems in accordance with the NERC, WECC regional Reliability Criteria for System Planning and Minimum Operating Reliability, guidelines established at the state level, and their own internal planning criteria, guidelines and methods. These planning practices are utilized to ensure that their respective systems are planned to provide reliable service to customers under various system conditions. In addition, they ensure that neighboring utilities and neighboring states plan their systems in a coordinated manner by following a consistent set of standards, guidelines and criteria in order to provide an economical and reliable supply of electricity.

This Chapter addresses the standards and processes used by the Arizona utilities in developing transmission.

3.1 Transmission reliability standards

3.1.1 NERC reliability standards

The interconnected bulk electric systems in the United States, Canada, and the northern portion of Baja California, Mexico are comprised of many individual systems. Each system has its own: electrical characteristics; set of customers; geographic, weather, and economic conditions; and regulatory and political climates. By their very nature, the bulk electric systems involve multiple parties. Since all electric systems within an integrated network are electrically connected, whatever one system does can affect the reliability of the other systems. Therefore, to maintain the reliability of the interconnected bulk electric systems, all electric industry participants are required to comply with the NERC Planning Standards.

The NERC Planning Standards define the reliability of the interconnected bulk electric systems using the following two terms:

> **Adequacy** — The ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
>
> **Security** — The ability of the electric systems to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

It is usually considered that adequacy is related to system planning and security is related to system operation.

NERC requires that systems must be planned to withstand the probable forced outage and maintenance outage system contingencies at projected customer demand and anticipated electricity transfer levels. Extreme but less probable contingencies measure the robustness of the electric systems and should be evaluated for risks and consequences. NERC has four basic planning standards:[1]

> *S1. The interconnected transmission systems shall be planned, designed, and constructed such that with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the network can deliver generator unit output to meet projected customer demands and provide contracted firm (non-recallable reserved) transmission services, at all demand levels, under the conditions defined in Category A of* Table 1*.*
>
> *S2. The interconnected transmission systems shall be planned, designed, and constructed such that the network can be operated to supply projected customer demands and contracted firm (non-recallable reserved) transmission services, at all demand levels, under the conditions of the contingencies as defined in Category B of* Table 1*.*
>
> *The transmission systems also shall be capable of accommodating planned bulk electric equipment maintenance outages and continuing to operate within thermal, voltage, and stability limits under the conditions of the contingencies as defined in Category B of* Table 1*.*
>
> *S3. The interconnected transmission systems shall be planned, designed, and constructed such that the network can be operated to supply projected customer demands and contracted firm (non-recallable reserved) transmission services, at all demand levels, under the conditions of the contingencies as defined in Category C of* Table 1*. The controlled interruption of customer demand, the planned removal of generators, or the curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard.*
>
> *The transmission systems also shall be capable of accommodating planned bulk electric equipment maintenance outages and continuing to operate within thermal, voltage, and stability limits under the conditions of the contingencies as defined in Category C of* Table 1*.*
>
> *S4. The interconnected transmission systems shall be evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of* Table 1*.*

In summary, NERC requires that transmission systems should be planned to withstand both single contingency (Category B), and double or multiple contingencies (Category C). In addition NERC requires that transmission systems should be planned to withstand the same set of contingencies with one bulk facility out of service for planned maintenance. The extreme contingencies (Category D), require that transmission systems be evaluated for the risks and consequences, but not for planning reinforcements.

[1] NERC Planning Standards, September 16, 1997, page 9-10: www.nerc.com/pub/sys/all_updl/pc/pss/ps9709.pdf

Table 1: NERC transmission system standards-normal and contingency conditions

	Contingencies		System Limits or Impacts				
Category	Initiating event(s) and contingency element(s)	Elements out of service	Thermal limits	Voltage limits	System stable	Loss of demand or curtailed firm transfers	Cascading outages[c]
A - No Contingencies	All facilities in service	None	Applicable Rating [a] (A/R)	Applicable Rating [a] (A/R)	Yes	No	No
B - Event resulting in the loss of a single element.	Single line ground (SLG) or 3-phase (3Ø) fault, with normal clearing:						
	1. Generator	Single	A/R	A/R	Yes	No [b]	No
	2. Transmission circuit	Single	A/R	A/R	Yes	No [b]	No
	3. Transformer	Single	A/R	A/R	Yes	No [b]	No
	Loss of an element without a Fault.	Single	A/R	A/R	Yes	No [b]	No
	Single pole block, normal clearing[f]: 4. Single pole (DC) line	Single	A/R	A/R	Yes	No[b]	No
C - Event(s) resulting in the loss of two or more (multiple) elements.	SLG fault, with normal clearing[f]:						
	1. Bus section	Multiple	A/R	A/R	Yes	Planned/controlled[d]	No
	2. Breaker (failure or internal fault)	Multiple	A/R	A/R	Yes	planned/controlled[d]	No
	SLG or 3Ø fault, with normal clearing[f], manual system adjustments, followed by another SLG or 3Ø fault, with normal clearing[f]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Multiple	A/R	A/R	Yes	Planned/controlled[d]	No
	Bipolar block, with normal clearing[f]:						
	4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[f]:	Multiple	A/R	A/R	Yes	Planned/controlled[d]	No
	5. Any two circuits of a multiple circuit towerline[g]	Multiple	A/R	A/R	Yes	Planned/controlled[d]	No
	SLG Fault, with delayed clearing[f] (stuck breaker or protection system failure):						
	6. Generator 8. Transformer	Multiple	A/R	A/R	Yes	Planned/controlled[d]	No
	7. Transmission 9. Bus Section circuit	Multiple	A/R	A/R	Yes	Planned/controlled[d]	No
D [e] - Extreme event resulting in two or more (multiple) elements removed or cascading out of service	3Ø Fault, with delayed clearing [f] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission 4. Bus Section 5. Circuit 3Ø Fault, with normal clearing[f]: breaker (failure or internal fault) Other: 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large load or major load center 12. Failure of a fully redundant special protection system (or remedial action scheme) to operate when required Operation, partial operation, or misoperation of a fully redundant special protection system (or remedial action scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from disturbances in another Regional Council.	Evaluate for risks and consequences. May involve substantial loss of customer demand and generation in a widespread area or areas. Portions or all of the interconnected systems may or may not achieve a new, stable operating point. Evaluation of these events may require joint studies with neighboring systems.					

a) Applicable rating refers to the applicable normal and emergency facility thermal rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable ratings may include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All ratings must be established consistent with applicable NERC Planning Standards addressing facility ratings.
b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the faulted element or by the affected area, may occur in certain areas without impacting the overall security of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) electric power transfers.
c) Cascading is the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.
d) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.
e) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
f) Normal clearing is when the protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer (CT), and not because of an intentional design delay.
g) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.
Source: NERC Planning Standards, June 15, 2001

3.1.2 WECC reliability standards

WECC provides the coordination that is essential for operating and planning a reliable and adequate electric power system for the western region of the continental USA, Canada, and Mexico. The WECC member systems' transmission facilities are planned in accordance with the NERC/WECC Reliability Criteria for Transmission System Planning. These criteria establish the performance levels intended to limit the adverse effects of each member's system operation on others, and recommend that each member system provide sufficient transmission capability to serve customers, to accommodate planned inter-area transfers, and to meet its transmission obligation to others.

The *WECC Reliability Criteria* adopted all the NERC criteria mentioned in section 3.1.1 and asks its members to comply with several additional requirements, two of which are more stringent than those in some other NERC regions:[1]

WECC-S2 *The NERC Category C.5 initiating event of a non-three-phase fault with normal clearing shall also apply to the credible common mode contingency of two adjacent circuits on separate towers. The credibility of such an outage depends upon the credibility of the common mode failure. The credible outage of two circuits could result from a lightning storm or forest fire. Considerations in the determination of credibility should include line design; length; location, whether forested, agricultural, mountainous, etc.; outage history; operational guidelines; and separation between circuits.*

WECC-S3 *The common mode simultaneous outage of two generator units connected to the same switchyard, not addressed by the initiating events in NERC Category C, shall not result in cascading.*

In summary, WECC requires that the outage of two adjacent circuits on different towers or the outage of two units at the same plant meet NERC Category C performance standards. This is in addition to the requirement that transmission systems should be capable of withstanding the same set of contingencies with one bulk facility out of service for planned maintenance. WECC also adds voltage dip and frequency deviation requirements for the effects of outages on neighboring systems. All except two WECC planning standards are at least as stringent as the NERC standards. The two exceptions are C2 and C9.[2] WECC currently has been granted a waiver for these standards and analysis is ongoing to determine whether NERC should grant a variance.[3] This exception is not required by the Arizona utilities as they comply with NERC's C2 and C9 standards.

[1] NERC/WECC Planning Standard, August 8-9, 2002, Page 11

[2] C2-Breaker Failure, C9-Bus Section Failure

[3] Prepared by the Resource and Transmission Adequacy Task Force of the NERC Planning Committee NERC Board of Trustees June 15, 2004, Table 2 Transmission Adequacy, (Revised 2/23/04) ftp://www.nerc.com/pub/sys/all_updl/pc/rtatf/RTATF_ReportBOTapprvd_061504.pdf

WECC'S Reliability Management System (RMS) agreement establishes a process to manage compliance with the established criteria. This process includes compliance monitoring, annual study reports, a project review and rating process, and an operating transfer capability policy group process. Compliance is ensured with regard to control performance, operating reserve and operating transfer capability, and disturbance control. While WECC members self-declare their compliance, WECC conducts compliance reviews through random audits. The RMS includes system operator requirements for managing transactions within major transmission path operating limits. WECC also addresses the unscheduled flow mitigation scheme approved by FERC.

For reliable operation of the western interconnection, WECC requires all entities to comply with their Minimum Operating Reliability Criteria (MORC)[1]. Staff supports the MORC, which applies to system operation under all conditions even when facilities required for secure and reliable operation have been delayed or forced out of service. MORC principles applicable to the transmission system operation are:

- The interconnected power system shall be operated at all times so that system instability, uncontrolled separation, cascading outages, or voltage collapse will not occur as a result of single or multiple contingencies of sufficiently high likelihood.
- Continuity of service to load is the primary objective of the MORC. Preservation of interconnections during disturbances is a secondary objective except when preservation of interconnections will minimize the magnitude of load interruption.

Since electric system reliability is so vital to Arizona, Staff contends that it is appropriate to apply the more stringent of either NERC or WECC criteria for planning of the Arizona system.

3.1.2.1 Transmission paths in the WECC

A grouping or set of transmission lines connecting two areas is often referred to as a transmission path. Transmission paths consist of one or more lines emanating from a common location or between two regions. The performance of each transmission line within a transmission path is interdependent upon the performance of other lines in the same path. The adequacy and security of the whole transmission system is often determined by the performance of key and critical transmission paths.

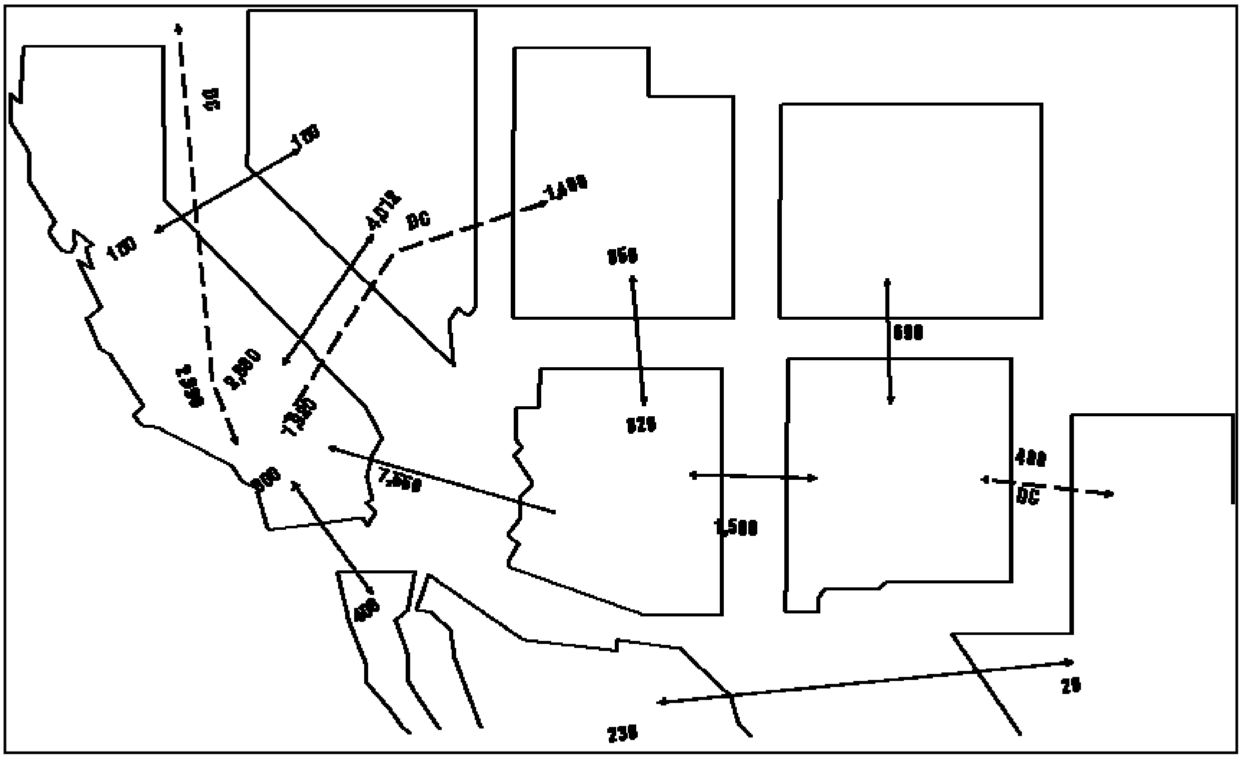
Transmission lines and paths are also rated in terms of their Total Transfer Capability (TTC). The TTC is the reliability limit of a transmission line or path. This rating is established by technical studies that consider the network topology and operational conditions affecting the

[1] http://www.wecc.biz/sdpp.html

adequacy and security of the transmission line or path. The thermal rating and the stability limit of transmission lines are both considered when establishing the TTC of transmission facilities.

WECC has an established process for determining the TTC of major transmission paths in the western interconnection. The transmission path consisting of lines between Arizona and California has the largest TTC of any established path in the Western Interconnection. The map in Figure 1 shows the non-simultaneous TTC of the Arizona area for 2008.[1]

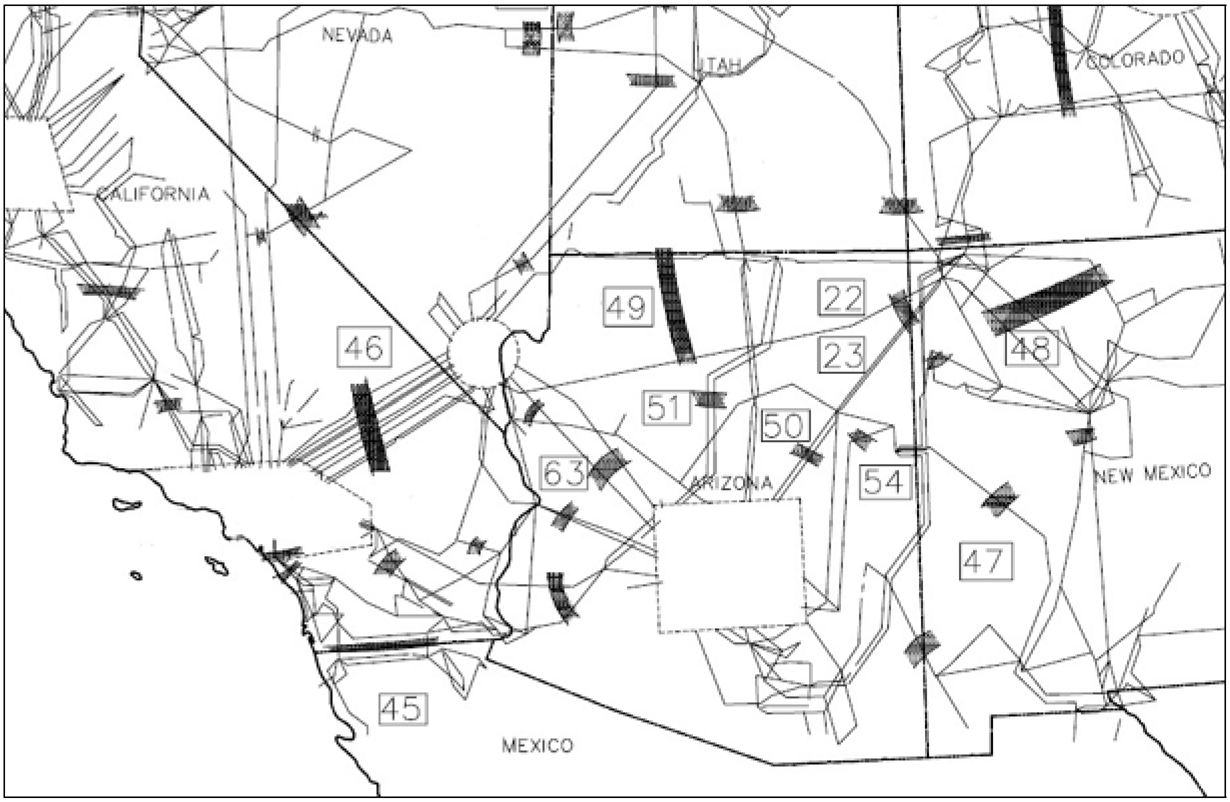
Figure 1: Total transfer capabilities for key WECC transmission paths (2005)



[1] WECC Ten –Year Coordinated Plan Summary, June 2005, page 54.

The paths of interest to Arizona are shown in Figure 2, and are defined below in Table 2.[1] A path of particular interest to Arizona is Path 49, East of Colorado River (EOR) that connects Arizona, Nevada, and California. Paths 22, 23, 50 and 51 all lie between Four Corners/San Juan and the Phoenix area.

Figure 2: WECC Paths affecting Arizona



[1] *Western Interconnection Transmission Path Flow Study*, Planning Work Group, Seams Steering Group – Western Interconnection, February 2003.

Table 2: WECC paths effecting Arizona

WECC path	WECC path name
22	Southwest of Four Corners Four Corners – Moenkopi Four Corners – Cholla #1 Four Corners – Cholla #2
23	Four Corners 345/500 kV Qualified Path
45	SDG&E – CFE
46	West of Colorado River (WOR)
47	New Mexico -Greenlee
48	Northern New Mexico (NM2)
49	East of Colorado River
50	Cholla - Pinnacle Peak
51	Southern Navajo
54	Coronado - Silver King – Kyrene
63	Perkins-Mead-Marketplace 500 kV Line

3.1.2.2 WECC initiatives since the last BTA

The key WECC-led initiatives currently in progress or completed over the past two years (since the last BTA) include:

- Funding the Westwide System Model
  - Consolidate real-time and planning models
  - Provide Interconnection-wide real-time and near-time Contingency Analyses and other network applications
- Funding the Western Interchange Tool
  - Utilize existing E-Tag platform to ensure interchange schedules are reconciled
  - Provide Reliability Coordinators with better tools to monitor interchange scheduling
- Develop a Reliability Coordination Strategy
  - Ensure compliance with NERC Standards
  - Significantly improve effectiveness
- Completion of 2003 Northeast Blackout Recommendations
  - Integration of recommendations as appropriate

- Continued comprehensive review of disturbances within the Western Interconnection
    - Detailed and Abbreviated Disturbance Reporting process.
- Development of regional mandatory standards
- Significant interaction with FERC and NERC
    - Discussions with FERC Staff concerning standards and compliance
    - Development of the NERC-ERO Delegation Agreement
- Operating Reserve Standards
- Formation of Transmission Expansion Planning Policy Committee (TEPPC)
- Reconstitution of the L&R Subcommittee
- Development of Resource Adequacy Criteria

3.1.3 Arizona utilities transmission planning standards

The utilities in Arizona plan their system facilities by following NERC and WECC reliability standards. In addition, each utility in the State develops its own internal reliability criteria and planning processes to assist in planning its EHV-345kV and above, HV transmission system, and local areas. Each utility plans the transmission system to operate with no thermal overloads on lines and equipment, and voltages within defined limits under normal and emergency conditions. The Arizona transmission system is planned based on NERC and WECC single contingency criteria.[1] These criteria require that there should be no loss of load on the system for a single element contingency. There are credible disturbances, which are not probable, for which it is not economically feasible to protect against. These criteria recognize the need for direct load tripping for more severe disturbances, but the load tripping should be controlled to limit the adverse impact of the disturbance. Uncontrolled load shedding is unacceptable even under the most adverse, credible disturbance.

The Arizona utilities have provided detailed information regarding the assumptions, studies performed and criteria used in their 10-year plans. The studies include power-flow, stability, and short-circuit analyses (although short-circuit analysis is usually not filed in the BTA). Consistent with industry practice, it appears that the plans are primarily developed to meet NERC category A and B criteria—normal and single contingency conditions. In some cases, the utility's studies include evaluations of NERC category C & D – multiple and extreme contingencies. Chapter 8 addresses the results of such studies performed in the fourth BTA.

[1] Workshop I Transcript, Page 165, Lines 9-17

As is discussed later in chapter 6 of this report, the utilities also perform companion studies of transmission and generation requirements for local load pockets that are constrained by limited import capability and depend to some extent on local generation to support customer reliability. Such generation is typically referred to as reliability must-run (RMR) generation. It is not unusual in U.S. transmission planning practices that transmission systems supplying large urban areas (RMR areas) have more stringent criteria than used for the rest of the system. Staff and the Arizona utilities are making a collaborative effort to develop and effectively implement appropriate criteria for RMR areas.

3.1.4 Transmission ratings

Transmission facilities can be loaded up to their continuous or emergency ratings. The ratings may be set by thermal, stability, or voltage conditions. Thermal limits are set depending on the characteristics of the individual components, while stability and voltage limits depend on the topology and characteristics of the combined generation-transmission-load network.

3.1.4.1 Thermal limits

Thermal limits relate to heating of equipment. High temperatures cause physical damage to the equipment and shorten the life of the equipment. In extreme heating conditions, the equipment can be damaged or destroyed. Utilities and manufacturers set temperature standards that are applied to different pieces of the transmission system to limit loss of life and prevent destroying equipment.

Each transmission line has a utility-defined thermal rating based upon size and type of conductor, and its design and construction. The capability of the line will also be impacted by required spacing and clearances for trees, shrubs, buildings, animals and various human activities. Each transmission line has a thermal rating based on its current carrying capacity measured in amperes. Such ratings are dependent upon ambient weather, temperature, wind, and atmospheric conditions. Other devices connected to a circuit such as switches, connectors, and metering equipment may also thermally limit transmission lines. The most restrictive device rating in series with the transmission line establishes the thermal rating used for that transmission line.

Circuit breakers and transformers are other major devices that have thermal ratings. These ratings are set by the manufacturers to prevent damage or destruction of the equipment. While thermal ratings are set based on ampere loading, they are usually converted to a megawatt rating assuming nominal voltage conditions. Thermal ratings are time dependent and may range from a short time emergency rating to a continuous rating.

3.1.4.2 Stability limits

The limit of a group of transmission facilities may also be determined by stability or voltage limits. These represent limits on the system's ability to successfully respond to contingencies, even if no thermal limits are exceeded.

For many system contingencies generators in different parts of the power system will "speed up" slightly while others will "slow down" slightly. The two areas will be briefly operating at slightly different frequencies when this happens. In nearly all cases, the transmission system is strong enough to keep the two parts of the system connected so that they quickly return to normal speed (frequency). In these cases the system remains stable.

For a few system configurations and contingencies, the transmission system is not strong enough to maintain the two areas' frequencies in balance. In these cases the two areas will separate from each other and operate isolated. This is an example of an unstable system condition.

In most cases, however, one or more of the islands will experience partial or full loss of load. This occurs because one, or more, of the areas will be importing from the others. Thus, when the transmission connection is lost, the importing area will be unbalanced, with more load than generation. When the imbalance is large, the only option for the importing area is to shed load; causing a partial blackout. If the imbalance is very large a complete blackout of the island will occur. It is also possible for the exporting area to experience problems when the islands form.

There are situations in many systems, especially those in the western United States, where transfers are limited by stability problems before any thermal limits are reached. In these cases the transfer will be stability limited. These stability (and voltage) limits are established via technical studies that determine the maximum power that can be transferred over a group of lines.

3.1.4.3 Voltage limits

For nearly all system contingencies different parts of the power system will experience changes in voltages. In some areas voltages rise; while in others voltages will fall. Usually equipment and system operators are able to adjust the voltages to maintain acceptable levels. If voltages rise too much, however, equipment can be damaged due to insulation or other hardware failures. If the voltages fall too low it may not be possible to control, and voltage will continue to fall, resulting in a blackout. The greatest risk is usually to an importing area where the lowest voltages will usually be experienced.

3.2 Arizona transmission planning processes

Planning methods and guidelines are used as the basis for the development of future transmission facilities. Transmission plans are updated on a continuous basis to determine the projected facilities needs for each year over a ten-year period.

In addition to planning their transmission systems to meet their internal needs, the utilities in the State actively engage in a coordinated regional planning of transmission facilities in order to ensure that (a) the best coordinated approach is being used for expanding the interconnected system, (b) opportunities for joint projects and resulting cost savings to customers are identified, and (c) the EHV and HV transmission facilities are planned in the broader context of the needs of the State, and to take advantage of the diverse locations of load centers and generation complexes in the State.

The utilities in the State are also coordinating the planning activities with the utilities in the neighboring states to identify and construct interstate transmission facilities in order to take advantage of the import and export of competitive energy that would benefit the customers.

Since the 2002 BTA, with the encouragement of the ACC and its Staff, the planning process has become much more collaborative and regional. This is a significant improvement in the Arizona planning process. While individual transmission providers remain responsible for their individual transmission projects, the planning process has become so regional that plans are best presented on a regional basis, rather than by individual companies.

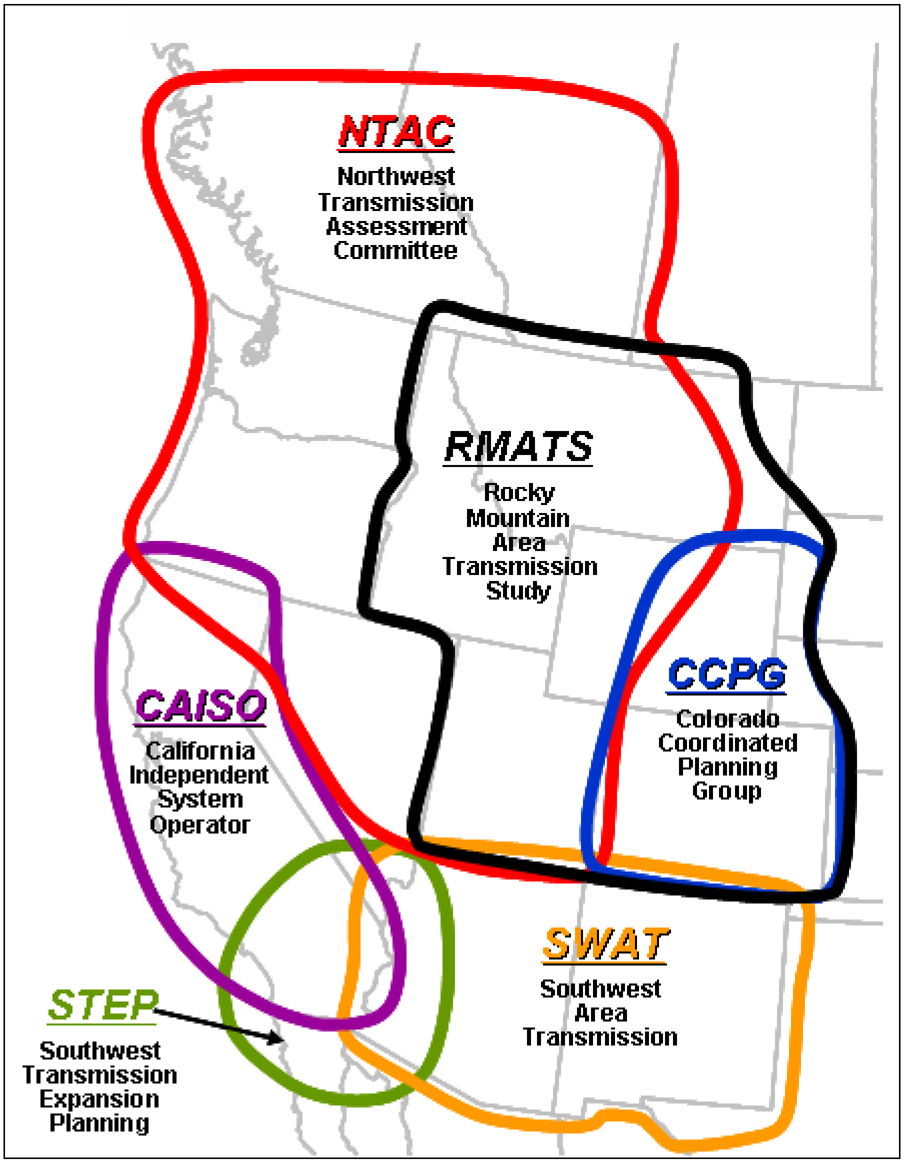
3.2.1 Regional transmission planning affecting Arizona

Coordinated regional planning in Arizona dates back at least to the late 1960s when the NERC and its regional Councils were formed. The Arizona utilities were part of one of these regional Councils, the Western Systems Coordinating Council (WSCC). In the years since that time many regional planning coordinating groups have formed and evolved. The WECC has succeeded the WSCC. And there are now six regional transmission-planning groups active in the WECC as shown in Figure 3.[1] As shown on the figure, the sub-regional groups that are directly involved with transmission planning in Arizona are the Southwest Transmission Expansion Planning group (STEP) and the Southwest Area Transmission group (SWAT).

[1] Web sites for these groups are:

RMATS –http://psc.state.wy.us/htdocs/subregional/home.htm
SWAT – http://www.azpower.org/swat
CAISO – http://www.caiso.com/thegrid/planning/index.html
STEP – http://www.caiso.com/docs/2002/11/04/2002110417450022131.htmp
NTAC – http://www.nwpp.org/ntac
CCPG – http://ccpg.basinelectric.com

Figure 3: Six sub-regional planning groups in the WECC



3.2.1.1 Southwest Transmission Expansion Planning (STEP) group

STEP was created as an ad-hoc group to coordinate transmission plans in the Arizona, Southern Nevada, Southern California, and Northern Mexico area. STEP first met in November 2002 and has met periodically since. Participants include representatives from utilities, independent power producers, state agencies/regulators and other stakeholders with an interest in the transmission system in Southern Nevada, Arizona and Southern California. STEP's focus is on economically driven expansion projects that support the development of seamless west-wide markets while satisfying established reliability standards.

STEP goals and functions

The group adopted the following common goal:

> To provide a forum where all interested parties are encouraged to participate in the planning, coordination, and implementation of a robust transmission system between the Arizona, Southern Nevada, Mexico, and Southern California areas that is capable of supporting a competitive, efficient, and seamless west-wide wholesale electricity market while meeting established reliability standards. The wide participation envisioned in this process is intended to result in a plan that meets a variety of needs and has a broad basis of support.

STEP performs 12 basic planning functions:

1. Produces a long-term bulk transmission expansion plan biennially.
2. Identifies current and future transmission congestion that is an impediment to the efficient operation of the western market.
3. Develops, through a collaborative process, strategic transmission options and specific alternative plans for reinforcing the transmission system and for reducing or eliminating congestion.
4. Reviews project-sponsored studies, if requested by the Project Sponsor.
5. Relies, as much as possible, on the technical studies conducted by Project Sponsors and studies conducted in other forums.
6. Performs technical studies without duplicating work performed by others.
7. Shares the study work and will normally be documented in a report.
8. Provides a forum to facilitate stakeholder development of projects through the planning effort.
9. Facilitates the phased implementation of completed plans.
10. Works closely with regulatory and governmental agencies in developing facility plans.
11. Closely coordinates with the other regional planning and reliability groups.
12. Provides a forum for discussing different approaches for funding potential transmission projects.

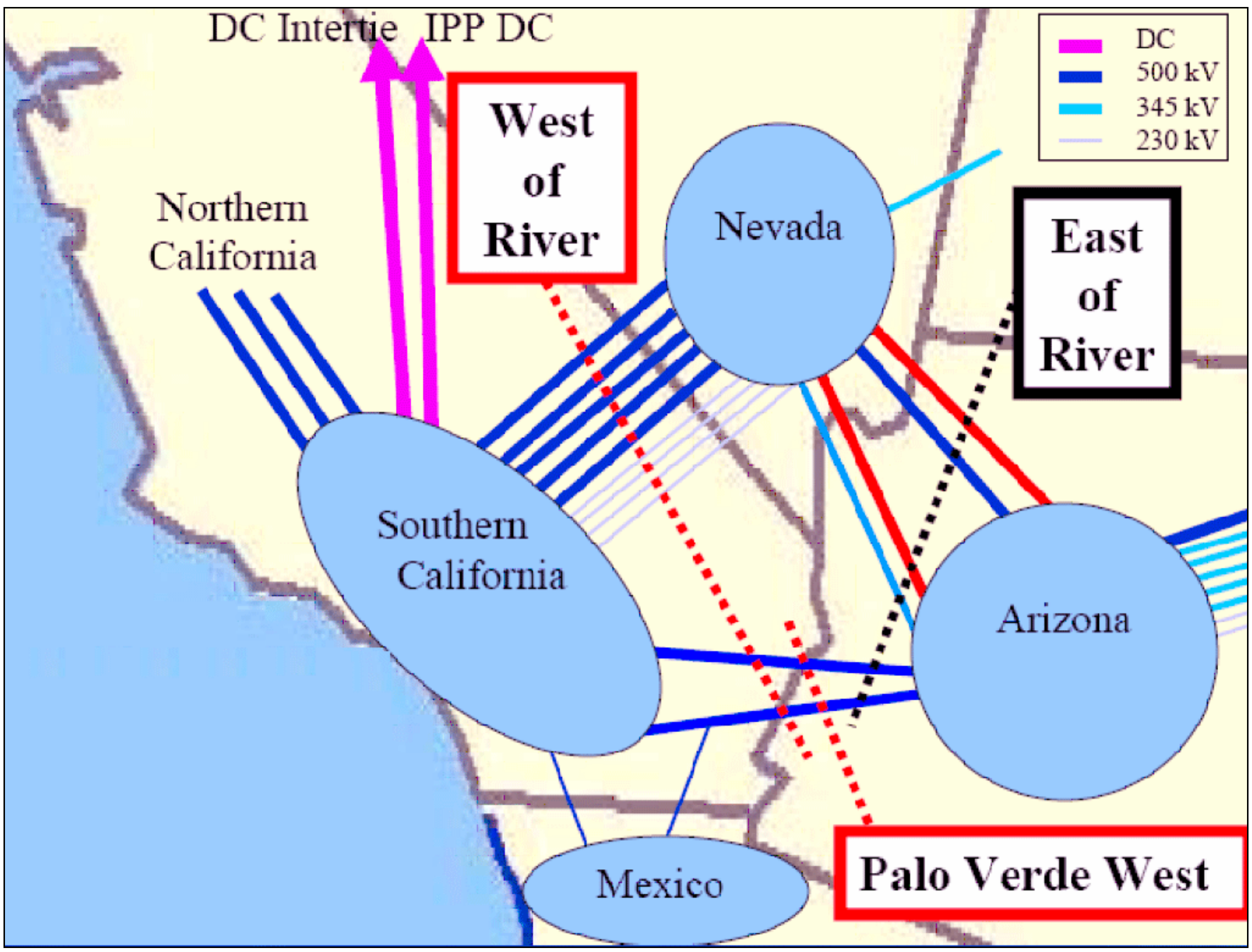
Since its inception, STEP has been a valuable forum for sharing both technical and economic studies to develop transmission projects to mitigate inefficient congestion on the system. Although early STEP efforts focused to a large extent on shorter-term alternatives to increase the Arizona-California transfer capability, the focus has expanded considerably and now includes activities such as:

- Major California ISO planning issues for a the whole southern California region;
- SWAT/STEP coordination of the Colorado River Transmission system planning;
- Eastern Nevada transmission studies;
- Transmission for delivery of renewable resources in the region; and
- Other major generation proposals in the region, including Baja California.

STEP Arizona-California

The focus of the STEP Arizona-California (STEP-AC) group is on the transmission transfer capability between Arizona and California. This means that there is some geographic overlap with other groups that are focused on the "internal" transmission needs of the areas within Arizona and California. Numerous Arizona to California upgrade alternatives have been, and continue to be coordinated, through the efforts of STEP. The first of these upgrades, the Short-term Path 49 ("East of River") upgrade project was placed in service in 2006 raising transfer capability by 505 MW.

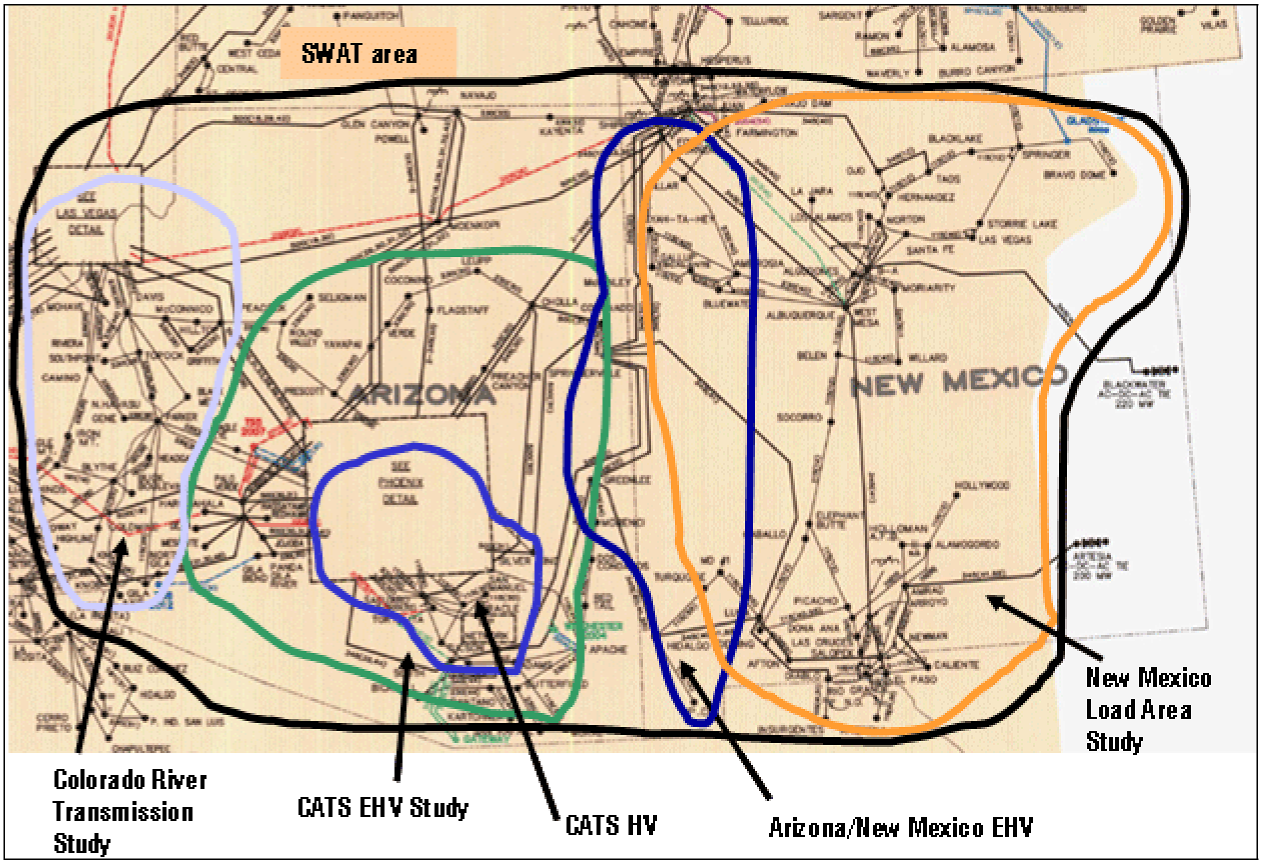
Figure 4: Transmission area of STEP-AC planning group



3.2.1.2 Southwest Area Transmission (SWAT) Study Group

SWAT is divided into five study areas as shown in Figure 5 each with its own study group. Four of these include facilities in Arizona (the exception is the New Mexico area). Each of these areas is a logical transmission region that involves multiple transmission providers. In each case, a participating SWAT member (typically a transmission provider or consultant) is designated as the lead entity that coordinates the necessary computer analyses.

Figure 5: Areas covered by SWAT study groups



Central Arizona Transmission System (CATS) Study Group

Historically, Arizona's EHV transmission system has been developed to interconnect large generation resources to major load centers located in the Phoenix and Tucson metropolitan areas. The resultant transmission development within Arizona was a system that moved power to these two load centers from coal-fueled generation in the northeast and the Palo Verde nuclear plant.

In the past, each utility in Arizona developed their individual plans using a common system model of the transmission system. Some regional planning was also performed in the past for joint projects such as the Arizona Nuclear Power Project (ANPP). The individual utility expansion (e.g., ten-year) plans were shared among the utilities before the annual filings with the ACC. This process has been improved by becoming more collaborative and open as a result of the efforts of the utilities, the Arizona Commission, and other stakeholders. This improved collaboration and openness has made it possible for the utilities to better identify joint solutions to meet future needs of Arizona and the region.

Part of this process includes the formation of the Central Arizona Transmission System (CATS) study group. CATS is comprised of two subcommittees:

- CATS-EHV — to investigate the extra-high voltage (345 and 500 kV) transmission network in central Arizona; and
- CATS-HV — to investigate high voltage (115, 138 and 230 kV) transmission network needs in the Phoenix/Tucson area. In addition to APS and SRP, this study area includes facilities of irrigation districts, electric cooperatives, Native American tribal lands, and small Arizona communities.

SWAT Arizona-New Mexico (SWAT-AZ-NM) Study Group

This subgroup was formed in 2004 and there have been several long-standing groups studying portions of the AZ-NM region. The SWAT AZ-NM is focused on the transmission needs of the eastern Arizona-Western New Mexico region, including possible generation projects for the region that could total about 7,500 MW over the next 10 years. Recent discussions within the subgroup have centered on development of the Desert SW Regional Black-start Plan in conjunction with the WECC Rocky Mountain/Desert Southwest Reliability Center. The group has also started reviewing new EHV transmission projects from New Mexico to Arizona to deliver new thermal and renewable resources being developed in New Mexico, such as the Navajo Transmission Project in the north and the SunZia SW Transmission Project in southeastern Arizona.

SWAT Colorado River Transmission (SWAT-CRT) Study Group

SWAT-CRT was created as a sub region to the SWAT planning group. Its basic intent is to look at the needs for transmission and the current status of the transmission systems within western Arizona and southern Nevada. Membership, as with SWAT, is completely open. This group is merged with the STEP-AC group. The merged group reports to both SWAT & STEP. There are more than 20 entities that are participating or monitoring the CRT-AC meetings and activities.

The study group is now pursuing a two-phased approach:

1. First, stressing the existing East of River path to investigate what can be done to increase transmission capability into northwestern Arizona and southern Nevada with the existing facilities.
2. Second, investigating a new switchyard (Harquahala Junction) that would connect APS' proposed TS-5 project with the proposed Palo Verde – Devers #2 line for this purpose.

They coordinated various proposed projects that increased capacities of Devers/Palo Verde, East of River to 9,000 MW and also the APS TS-5 project.

Other SWAT Study Groups

In addition to the above groups, the SWAT-New Mexico Work Group continued its efforts to address joint AZ/NM regional planning issues, and two new work groups have recently been formed - the SWAT Short Circuit Work Group and the SWAT Black Start and Restoration Work Group.

Other areas within Arizona

While there have been laudable activities by the various stakeholders to encourage and participate in regional coordinated transmission planning, not all transmission needs are regional. There are other areas not covered by a regional study group. There are also purely local transmission needs within the areas covered by the regional study groups. These areas are the responsibility of the utility serving the area. The needs of these areas have been included in the BTA filings of the Arizona utilities. These facilities have been planned based on the individual utility criteria. Examples include the 115 kV and 138 kV projects in the state and the several reconductoring projects proposed by TEP. (These projects are discussed later, in Chapter 5.)

3.2.1.3 Seams Steering Group

The Seams Steering Group-Western Interconnection (SSG-WI) committee was formed by the three western RTOs to facilitate reviews of issues related to the interfaces between the RTOs in the WECC. A planning work group (PWG) was formed within SSG-WI to establish a collaborative planning mechanism to coordinate the transmission plans of Western RTOs. The Group's scope addresses long term congestion issues and scheduling timelines that impact the marketing of energy between RTOs in the West. The SSG-WI issued its first interconnection wide transmission plan, *Framework for Expansion of the Western Interconnection Transmission System,* in October of 2003. The SSG-WI has been terminated and the planning activities have been incorporated into the WECC Transmission Expansion Planning Policy Committee responsibilities.

3.2.1.4 WECC Transmission Expansion Planning Policy Committee (TEPPC)

During 2005 the WECC Board of Directors voted to establish a new committee with a focus on transmission expansion planning policy issues. The TEPPC is intended to fill this role. TEPPC is still in the formative stages and as such is unlikely to have any measurable impact on the current 10-year plans under review as part of the Fourth BTA. Even so it appears that parties from Arizona are becoming significantly involved in the TEPPC. Mr. David Areghini of SRP, who also serves as a WECC Board Member, has been appointed as the TEPPC Co-Chairman. Mr. Prem Bahl of the ACC has been appointed as the regulatory representative on TEPPC. Mr. Robert

Kondziolka, Mr. Robert Smith, and Mr. Harlow Peterson, all from the state of Arizona, have been appointed to positions on the Committee. Given this level of involvement by Arizona parties it can be reasonably assumed that any policies or decisions developed through the TEPPC process will be appropriately reflected in future 10-year plan submittals to the ACC. The TEPPC expects to focus on economically driven transmission expansion planning policies and processes.

3.2.2 WestConnect

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

WestConnect is pursuing a number of initiatives that could potentially enhance wholesale electricity markets in the west. Some of these efforts include:

- Flow-Based Market Investigations;
- Market Monitoring;
- Pricing;
- Regional Planning;
- Transmission Products;
- TTC/ATC Process; and
- Virtual Control Area.

A number of work groups are actively developing proposals for enhancements. Consensus products from work groups are taken to the Steering Committee for approval and implementation.

3.2.3 Arizona planning practices for local area transmission constraints

In the 2003 RMR study the transmission providers worked collectively to quickly develop studies to respond to the Track B proceeding needs. Due to the short time available there was no opportunity to develop a collaborative process. There were numerous comments about the deficiencies of the 2003 “closed” process. The lessons learned from the 2003 process were:

- Open the study process to all stakeholders, not just the transmission providers.
- Provide opportunities for stakeholders to review and critique RMR results before the ACC workshop.

- Reach an agreement, to the extent possible, regarding the modeling of load and generation included in the Phoenix area.
- Evaluate the extent to which operation of the various Phoenix-area generation mitigate Phoenix area import constraints.
- Solve the confusion regarding implications of Mohave County RMR Study conclusions.

The 2004 RMR studies were much more collaborative. The study forum became integral to the regional CATS study program. The 2004 process allowed for input and/or participation from all groups of stakeholders. In comparison to the 2003 RMR study, the 2004 study:

- Had a process and reviews open to all stakeholders and facilitated a review and comments at each stage of the process.
- Used improved modeling and definition of the load and generation included in the Phoenix area.
- Showed that the planned transmission improvements appear to mitigate the RMR concerns for the Yuma, Phoenix and Tucson areas.
- Found that local Phoenix area generation reserve was an issue beginning in 2013.
- Was unable to agree completely on whether Mohave County is an RMR area or if it is a contractually limited system.
- Found additional transmission lines are needed in Santa Cruz County by 2008 to serve peak load so that the county is no longer susceptible to extended outages for transmission events. The county becomes transmission import constrained by 2010 even with the proposed second transmission line to Nogales.

It seems clear that the hard work of the transmission providers and the other stakeholders during the last two BTA's has resulted in an improved work product and a more collaborative study process. This collaborative process has continued in 2006 as evidenced by the joint APS/SRP RMR study of the Phoenix load area. The latest study indicates that RMR costs for the Phoenix area are expected to remain under $1 million per year through at least 2015. These costs are too small to support capital projects to eliminate the Phoenix area RMR requirements.

The result of the following four RMR study process recommendations, which were included as part of the 2004 Biennial Transmission Assessment was noted by Staff in the 4th BTA:

1. GOAL – "All of the Arizona utilities should continue performing RMR studies for all transmission import constrained local areas using a collaborative process similar to what occurred in 2004." RESULT - Staff is satisfied with the degree to

which this was included in the 2006 planning process, especially for the Phoenix metropolitan area.

2. GOAL – "Improvements should be made in some aspects of the economic analysis that accompanies these types of studies. Data and assumptions should be consistent among the various utilities' studies. To this end, the Staff suggests using the SSG-WI, or another common publicly available, database. In addition, there should be more transparency regarding the data input, assumptions used and the results of the economic analyses." RESULT - Staff observes that there has been progress in this regard in the 4th BTA, and encourages continued efforts to make these economics as transparent and consistent as possible.
3. GOAL – "Conditions in Mohave County must be reviewed in order to understand whether mitigation is required due to constraints on the physical system or whether it can be managed through contractual or commercial practices." RESULT - Staff concludes that the 2006 BTA process has not fully resolved this question and better documentation is needed for Mohave County in future BTA's to confirm that Western's system has sufficient transmission capacity to meet the projected loads in the area.
4. GOAL – "The RMR 10-year study results should be filed with the 10-year transmission plans by January 31 of even numbered years to coincide with associated commission obligation to perform a BTA." RESULT - For the 2006 BTA, APS filed its RMR report covering the greater Phoenix and Yuma load areas on January 30, 2006. SRP did not file a separate RMR study, but relied on the APS filing for the Phoenix load area. Tucson Electric completed it submittal for the Tucson local area on February 3, 2006. UniSource Energy did not update its RMR analysis for Santa Cruz County in the 2006 BTA due to permitting issues that are pending before Federal agencies. No party in the 2006 BTA filed an RMR analysis for Mohave County.

4. Adequacy of the existing system

Adequacy, as discussed earlier, is the ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account 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. This section of the report addresses the adequacy of the existing Arizona transmission system.

The adequacy of an electric system is evaluated using computer simulation studies. These studies use: databases, assumptions, and reliability criteria. The Arizona transmission utilities conduct these studies, participate in the collaborative regional planning process, and present the study results in the ten-year plan reports and at public workshops. Staff and KEMA reviewed and analyzed all these study reports relying on these reports and documents filed with the Commission by the various organizations, rather than performing technical studies of their own.

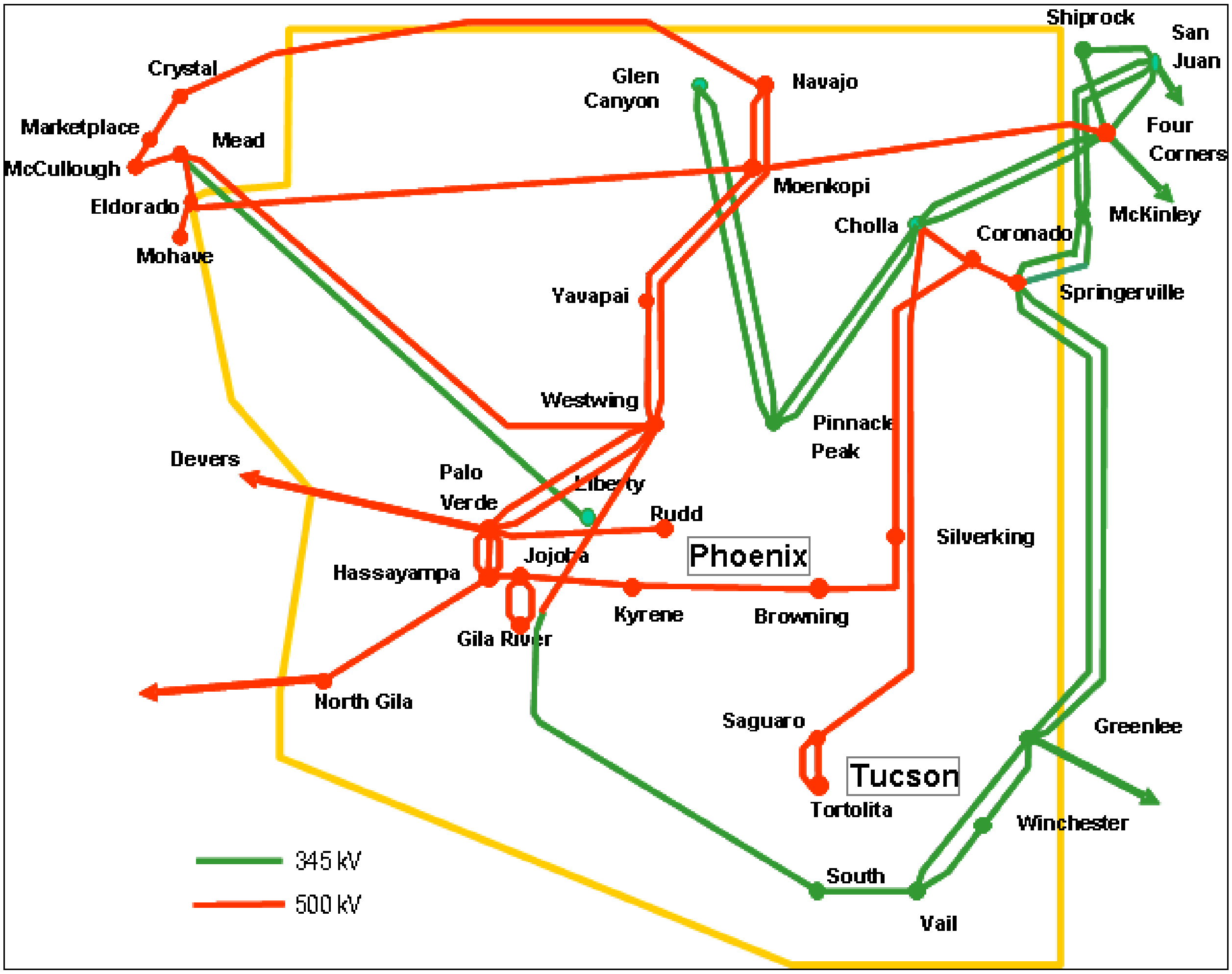
4.1 System description

The demand for electricity continues to grow in Arizona reaching a 2006 non-coincident peak of 19,289 MW.[1] Installed generation has more than kept pace with the growth in demand. As of May of 2006, installed generating plants that deliver their generation to the transmission grid that were operating within the State of Arizona provided a total of 24,249 MW of summer capacity. Approximately 70% of this capacity is owned by Arizona or federal utilities. Non-utility generators and utilities that are not located in Arizona own the remainder. Data on the generating plants operated within the State of Arizona are provided in Appendix C.

With a few exceptions (e.g. Palo Verde-Devers 500 kV, Hassayampa-North Gila 500 kV, and Navajo-Crystal 500 kV), the existing transmission facilities within the state of Arizona are owned and operated by APS, SRP, TEP, UniSource Energy Services, SWTC and Western Area Power Administration (WAPA). Figure 6 illustrates the existing EHV transmission facilities in the State of Arizona. EHV facilities, rated at a nominal system voltage of 345 kV and 500 kV, are the backbone of the Western Interconnection transmission system.

[1] Source: WECC preliminary 2006 summer loads and resources assessment of non-coincident July control area peaks.

Figure 6: Arizona EHV transmission system



All new transmission lines that have been added since the Third BTA are listed in Table 3.

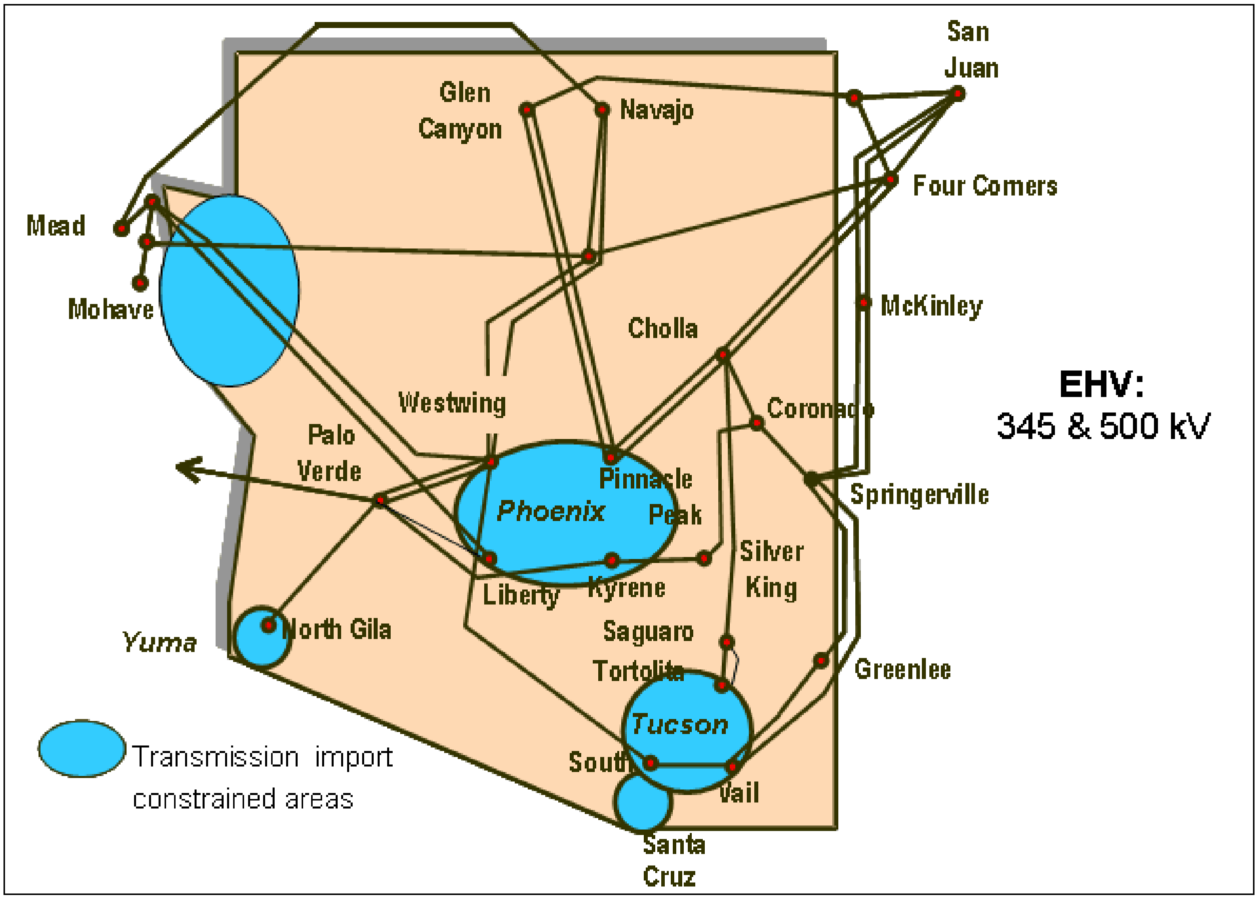
Table 3: Major new transmission lines and stations added since the third BTA

Year	Description	Voltage
2004	Loop-in of existing Greenlee-Vail 345 kV line to new Winchester 345 kV switchyard	345 kV
2005	Saguaro-Tortolita #2 line	500 kV
	Gavillan peak loop-in of Pinnacle Peak- Prescott	230 kV
	Browning substation	230 kV
2006	Loop in of existing Irvington station to Vail substation #1 line through Robert Bills -Wilmot Substation.	138 kV

4.2 Local area transmission constraints

In addition to the overall needs of the Arizona transmission system, there are five local transmission constraints as shown in Figure 7. To address this issue, a method was established to address these load pockets. The 2002 BTA defined local load pockets as geographic locations in an electric system where the load cannot be served using a normal economic merit-order generation dispatch due to transmission limitations. Handling these load pockets is discussed later, in §6.2 (page 91).

Figure 7: Local areas with transmission constraints



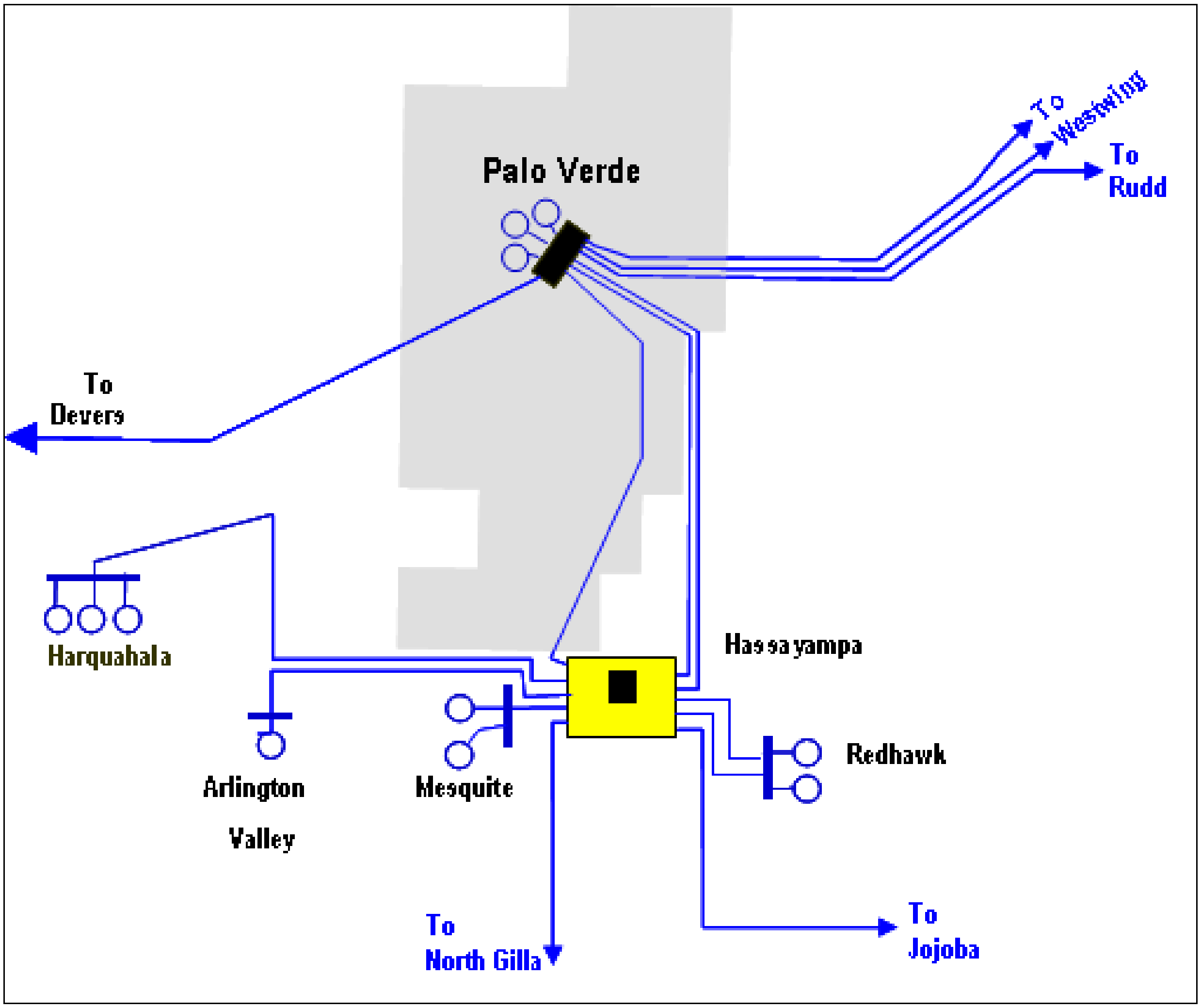
4.3 Palo Verde Hub operational issues

To support bilateral power trading, numerous electricity-trading hubs have emerged over the past few years. A hub is a location on the power grid representing a delivery point where power is sold and ownership changes hands. Potentially, each control area on the power grid could become a trading hub, but 10 hubs account for the bulk of power trading. Of these 10 major trading hubs, five of them are located in the western United States. One of these is the Palo Verde hub that represents an important access point to the California market.

4.3.1 Palo Verde Hub transmission constraints

The Palo Verde Nuclear Generating Station is located approximately 35 miles southwest of the Phoenix Metropolitan area. It is comprised of three nuclear generating units with a total output of approximately 3,974 MW. Four merchant generator plants with an aggregate net output capacity of 4,118 MW are interconnected to the Palo Verde Hub via the Hassayampa Switchyard. Additional merchant generation with a net capacity of 2,080 MW is connected to Jojoba. All of these generators deliver their output through the Palo Verde transmission system. The Palo Verde transmission system, as illustrated in Figure 8, consists of six 500 kV transmission lines.

Figure 8: Palo Verde Transmission System



The total generation interconnected to the hub is shown in Table 4.

Table 4: Gross Generation Interconnected to the Hub

Plant name	Installed capacity (MW)	In-service date
Palo Verde	3,974	Upgrade: (steam generators replaced) PV 2 2003 PV 1 2005
Redhawk #1, #2	1,020	2002
Arlington Valley 1	600	2002
Mesquite	1,350	2003
Harquahala	1,048	2003
Gila River Power, LP	2,080	2003
Total	**10,172**	

The changes in generation and transmission capability connected to the Hub are shown in Table 5. The transmission capability at the hub appears to be adequate in 2006 and increasing in future years.

Table 5: Palo Verde transmission and generation capability

Year	Generation capability (MW) Actual or expected	Transmission capability (MW) West 500 kV path	East 500 kV path	Combined total[7]	Reason for change
2000	3,810	2,800	3,810	6,610	No changes - historical values
2001	3,810	2,800	4,750	7,550	Study work by APS/SRP updated East path rating based on "actual" vs. "scheduled" flows
2002	5,600	2,800	4,750	7,550	Addition of Red Hawk & Arlington Valley generation
2003	7,971	2,800	5,120	7,920	Addition of Mesquite & Harquahalla generation., and refined Path rating study work by APS/SRP
	9,939	2,800	6,620	9,420	New PV to Rudd 500 kV line and addition of Gila River Power, L.P. Generation
	9,900	2,800	6,970	9,770	Refined 500kV East Path rating study work by APS/SRP with addition of the 500/230kV interconnection at Gila River
	9,990	2,800	6,970	10,207	Capability of the Gila River 500/230 kV interconnection added 437 MW to total Palo Verde transmission capacity
	10,045	2,800	6,970	10,207	PV 2- Generation upgrade (new steam generator)
2005	10,103	2,800	6,970	10,207	PV 1- Generation upgrade (new steam generator)
2006	10,172	3,305	6,970	10,712	Path 49 short term upgrade
2007	10,230	3,305	6,970	10,712	PV 3 generation upgrade (new steam generator)
2008	10,230	3,305	8,010	11,752	New PV–Pinal West–Santa Rosa line[1]
2009	10,230	3,305	8,550	12,292	New PV-TS5 lines[2]
	10,230	4,505	8,550	13,492	New PV – Devers II line[3]
2010	10,230	4,505	8,915	13,857	New Raceway– Pinnacle Peak line
2011	10,230	4,505	9,280	14,222	New Santa Rosa – Pinal South – Browning line[4]
2012	10,230	4,505	9,780	14,722	New TS5 – Raceway line [5]
	10,230	5,105	9,780	15,322	New Hassayampa – North Gila line[6]

Notes: (Estimates based on SRP and/or APS preliminary study results.)

1. Estimated 1,040 MW increase.
2. Estimated 540 MW increase.
3. Accepting rating of 1200 MW was approved by WECC.
4. Estimated 365 MW increase by extending the SEV line to Browning.
5. Estimated 600 MW increase studies for the impact of .TS5 – Raceway line (2012) are incomplete.
6. Estimated 600 MW increase.
7. Starting in 2003 includes the additional Gila River to Phoenix 230kV capability of 437 MW

Staff has been concerned in recent years that the Palo Verde transmission system needs to maintain adequate capability to deliver the full power output of interconnected generators.

Consequently, Staff has taken the position that, in addition to the transmission providers, merchant power plants, should share the responsibility and obligation to resolve Arizona transmission constraints.

4.3.2 Palo Verde Hub outlet capacity and risk assessment

Operation of the Palo Verde Hub and interconnected generation has been and continues to be a subject of much interest to Staff. In the Third BTA, Staff observed that the transmission outlet capacity at Palo Verde was inadequate for the delivery of all capacity from power plants located at this key Hub. Based on information provided during the Fourth BTA, it appears that this situation is being mitigated by transmission expansion plans from 2006-2009.

With the completion of WECC Path 49 upgrades this year, the West of Palo Verde Hub path capability has increased by 505 MW to a new limit of 3,305 MW. In combination with the East of Palo Verde path rating of 6,970 MW this yields a combined transmission capability out of the Hub of 10,712 MW. The total output of the existing generation at Palo Verde (Table 4) is 10,172 MW. Thus, the maximum transmission capability now slightly exceeds the available generation at the Hub. This is an encouraging development, however, Staff also observes that a portion of the transmission capability at the Hub will often be unavailable due to unscheduled flows ("loop flows") occurring on the WECC interconnection. These unscheduled flows result from power flowing from remote generators over the multiple parallel paths of the interstate grid. These flows can run in the hundreds of MW at the Hub. They are particularly prevalent in the westbound direction at Palo Verde. These unscheduled flows reduce the scheduling capability out of the Hub on a one for one basis.

Staff believes that such loop flows can still be expected to cause some level of transmission constraints at the Hub, even though it appears this situation will continue to improve with the planned transmission upgrades as shown in Table 5. Transmission outages and derations will also have some affect on the available transmission capability out of the Hub. However, Staff assumes that these will be offset by outages and derations of generation at the Hub. Finally, the Hub is located between two widely disparate markets (Arizona to the east vs. California to the west) and this will, to some extent, frustrate efforts to fully capture the simultaneous transmission capacity available out of the Hub. In summary, Staff concludes that more of the generation at the Hub will now get to market, but congestion (and market anomalies) will continue to constrain dispatch to some degree at the Hub. Furthermore, it appears this dispatch constraint should be fully mitigated with the completion of transmission projects out of the Hub in the next few years.

The 3rd BTA summarized Staff's concerns for the Palo Verde Hub as:

- Hub interconnected generation capacity comparable to entire WECC operating reserve requirement;
- Plants interconnecting to the Hub via single line;
- Common pipeline for gas fired plants;
- Transmission deliverability for the full (combined) output of all proposed plants at the Hub has not been demonstrated;
- NERC category D studies are not being performed; and
- Generator-only control areas emerging at Palo Verde hub.

In response to Staff concerns, in siting the Palo Verde to Rudd transmission line, the applicants, APS and SRP, agreed to facilitate an industry review and work to achieve consensus with Staff on the reliability and system security measures appropriate for a large commercial hub such as Palo Verde.[1] Such measures were to be recommended to WECC for consideration and adoption. If and when consensus is achieved between applicants and Staff, then the applicants were to work with Staff to initiate action to implement those measures on a statewide basis independent of the WECC action. Staff is encouraged by the response of the utilities to the above concerns since the 3rd BTA, discussed in more detail later in this section.

For the initial Palo Verde risk assessment performed in 2003, APS, SRP and Staff, considered the potential causes of extreme events, and those were viewed to fall into one of four categories:[2]

1. Intentional acts;
2. Weather related;
3. Nature initiated; and
4. Equipment or human. To analyze system response under these extreme events, the study team analyzed the set of NERC/WECC category D extreme contingencies:

- Palo Verde switchyard;
- Hassayampa switchyard;

[1] Palo Verde to Rudd Transmission Line Siting Case, Arizona Corporation Commission Case No. 115 Certificate of Environmental Compatibility: "Condition No. 23 – Applicants agree to facilitate an industry review and work to achieve consensus with Staff on the reliability and system security measures appropriate for a large commercial hub such as the Palo Verde Hub. Such measures shall be recommended to WECC for consideration and adoption. If and when consensus is achieved between Applicants and Staff, Applicants shall work with Staff to initiate action to implement such measures on a statewide basis independent of WECC action." Condition and study work does not include nor address contractual, regulatory, commercial, business or operational issues.

[2] Palo Verde Hub Risk Assessment Study, Phase I Results, 5/06/03, Confidential Results were not presented

- Palo Verde Hub ties;
- Common gas pipeline; and
- Railroad event.

Although these are low probability events, if they were to occur, three to four thousand megawatts of generation at the hub would be lost, as well as the hub associated transmission lines. The study results show that the system will become unstable. It was determined that several thousand megawatts of load would have to be shed in order to maintain system stability. Consequently, in order to avoid increased risk at the hub, Staff recommends that:

- Future generation or transmission projects seeking interconnection with the Palo Verde system should consider risk mitigation for extreme events.
- For overall diversity, performance and risk mitigation, future transmission lines should consider terminating at generating stations interconnected at the hub rather than at the Palo Verde or Hassayampa Switchyards.
- Future generators desiring to interconnect at the Palo Verde hub should also be interconnected to at least one other location in the transmission network.

In addition to the above Staff recommendations, presented to the Corporation Commission and the industry, Staff also recommends for WECC consideration a planning guide applicable to all generation hub station that includes:

- NERC Category B (n-1-1), C (n-1-2) [1] and D, risks and consequences, type evaluations should be performed on all generation hub substations. All types of initiating events applicable to a particular generation hub station should be considered in order to determine how to model the associated disturbances, likely duration of the common substation outage and the cumulative risk and consequences of such an outage. System consequences of hub substation outages may be severe and warrant mitigation measures. Evaluations of future generation or new transmission interconnections to such generation hub substations shall consider the effect of the proposed interconnection on the cumulative risk and consequences of a common event outage of the generation hub substation. Alternatives to be considered should include the following:
    - Terminating the new line at different power plant substations currently connected to the generation hub.
    - Interconnecting new generation at more than one substation. Mitigation

measures include load-shedding schemes. The WECC process is still on going. However,

[1] "n-1-1" and "n-1-2 " refers to the criteria where a bulk facility is out of service before a single or double contingency occurs.

Staff developed a generic model of a generation hub concept to be used for the generation interconnection at major hubs (See Figure 9).

Figure 9: Generic model of hub concept

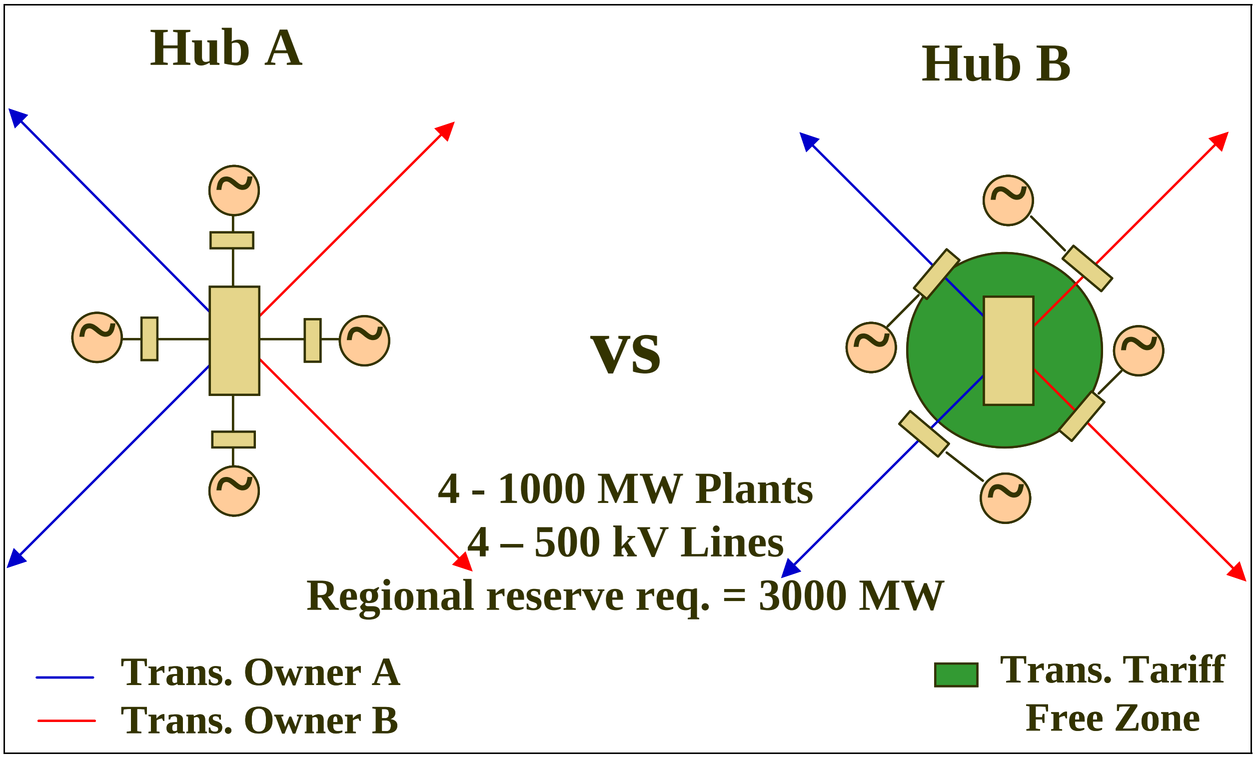


Figure 9 shows the Hub A concept, which has four power plants, each of 1,000 MW interconnected at a common switchyard. The switchyard has four 500 kV transmission lines interconnected. Two lines are owned by Transmission Provider A (shown in blue), and the other two are owned by Transmission Provider B (shown in red). What will happen if that common switchyard is lost, assuming that the regional reserve requirement is 3,000 MW? The 4,000 MW of generation, which is in excess of the reserve criteria for the region, is lost with the loss of the switchyard. This jeopardizes security of the operation of the whole network. Consequently, Staff concluded that this type of hub configuration, as more generation is added, becomes flawed.

As an alternative, Staff proposes that the industry consider the Hub B concept. The transmission lines are still interconnected to a common switchyard, the hub, but the generators have the transmission lines looped through the generator power plant switchyards. Now when the common switchyard is lost, each of the power plants is still interconnected to the line that is looped through it. However, in solving reliability concerns with this type of configuration, a commercial issue is left unresolved.

In Hub A, all of the generators were able to deliver to the hub without any transmission tariff implications, and it was a "come and get it" market concept. With the Hub B concept, the party that is buying from a power plant connected to one of the blue lines will have to pay the blue transmission provider's transmission tariff to get power to the hub. And if the party that is buying the power is taking service, on the red line they will also have to pay the red line tariff, resulting in a pancaking of the transmission rate.

The solution to this is to redefine the transmission tariff, by creating a transmission tariff free zone from the hub all the way out to the interconnection of the power plants. Staff has had some conversation with FERC staff regarding these concepts, and, in preliminary discussions, collectively concluded that there is a need for policy and regulations that balance reliability needs and market interests at these types of large hubs. Staff and FERC Staff have also agreed that generator-only control areas are acceptable only if reliability obligations and purposes are also being maintained.

In the 3rd BTA Staff raised several issues relative to the Palo Verde Interconnection Study efforts and the siting of all new power plants desiring to interconnect at Palo Verde. Consistent with the Commission's "Guiding Principles for ACC Staff Determination of Electric System Adequacy" (see Appendix A) the Staff expects that as new plants are constructed they will file a study report with the Commission prior to commercial operation that demonstrates the plant can deliver at full output to a market without causing curtailment of the existing generation at the Palo Verde hub. The Commission's guidelines also specify that new generation or transmission facilities throughout the state meet the following obligations:

- Arizona's best engineering practices: at least two transmission lines out of every plant;
- Meet WECC n-1 planning criteria without the use of remedial action, i.e., generation curtailment, unit tripping or load shedding; and
- All plants located inside a transmission import limited zone must offer sufficient energy to meet load requirements in excess of the applicable transmission import limit.

In addition to these established guidelines, the Staff expects new plants to comply with the following measures:

- WECC member/RMS agreement compliance; and
- Seek Southwest Reserve Sharing Group membership.

Staff also recommends that the Commission should require all future interconnections proposed at the Palo Verde Hub, either new generation or new transmission lines, to perform a risk assessment of the Hub to ascertain to what degree the proposed project mitigates the pre-existing risks to extreme contingency events. 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.

Staff also proposes that those exempt wholesale generator substations and embedded lines that have network function, should be reclassified as network facilities, and placed under an Arizona transmission provider's control, because they operate as part of the transmission network. In addition, Staff proposes that tariffs should be developed to avoid pancaking of transmission rates as new interconnections are made at those substations.

Finally, Staff proposes that the exempt wholesale generator substations and embedded lines that currently are not involved in the transmission network should have the same obligation to requested interconnections as a transmission provider has. For example, Staff proposes that regulations be developed so that power plants like Harquahala would not have the right to refuse an interconnection, but should have the right to require that reliability be maintained for the interconnection.

The Staff intends to interact with FERC as may be required to fully implement and enforce such interconnection standards in Arizona.

In regard to Palo Verde Hub risk assessment it should be noted that since the 3rd BTA three major filings have also addressed these issues and concerns as follows:

- SRP's PV—SE Valley
- APS's PV—TS5, and
- SCE's PV—Devers 2.

The Staff believes that these risk assessment issues should be addressed as part of all future interconnection filings at the Palo Verde Hub.

5. Adequacy of the future system

Every organization considering construction of a transmission line in Arizona during the next ten-years must file a ten-year plan with the ACC.[1] The plan must be filed on or before January 31 of each year and must provide:

1. The size and proposed route of any new transmission lines.
2. The purpose to be served by each new transmission line, and
3. The estimated date by which each transmission line will be in operation.

A compilation of planned transmission line additions filed in January 2006 that comprises the Ten-Year Plans for 2006-2015 is provided in Appendix F and Appendix G. Changes in Transmission plans since the 2004 BTA are provided in the Appendix E.

State statutes require that Staff determine the adequacy of these planned facilities to meet the energy delivery needs of Arizona in a reliable manner. This section of the report documents a review of the ten-year plans filed by the Arizona utilities, and Staff's assessment of how those plans differ from plans addressed in the third BTA.

While Ten-Year plans were filed by individual utilities, the underlying studies were performed in a collaborative process by geographic region as discussed in section 3.1.4. Since the studies for this BTA were performed by geographic region, the reviews are reported here by region in a way that parallels the collaborative studies.

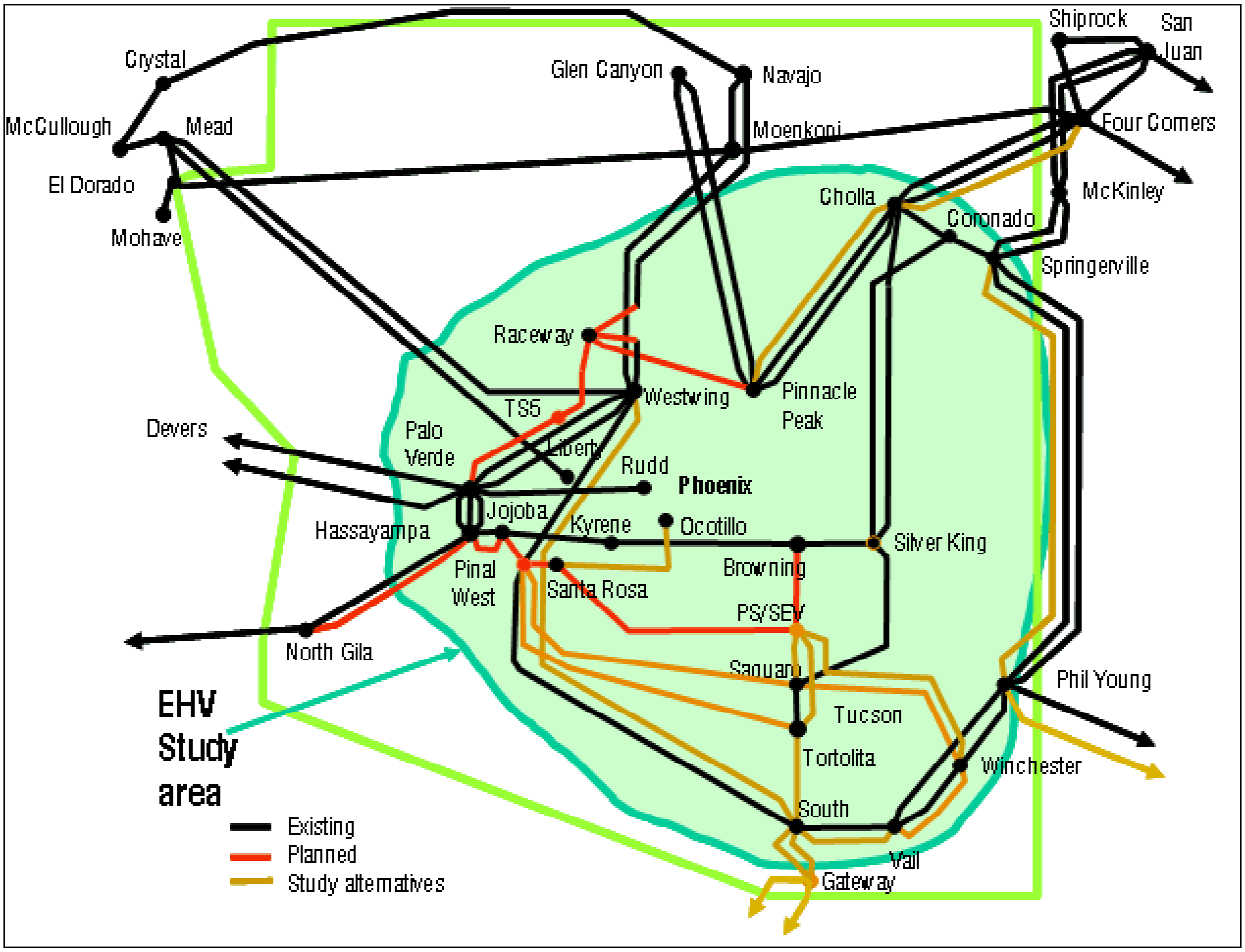
5.1 EHV system assessment

The existing Arizona EHV transmission system and planned additions are shown in Figure 10. The existing system is shown in black and the planned additions are shown in red. As can be seen in the figure the planned additions strengthen the connections between the Palo Verde area and western and southeastern Phoenix area, northern Pinal County and northwestern Tucson. The figure also shows many facilities in brown. These are alternatives that were evaluated by the utilities as part of CATS Phase III studies.

Some of the alternatives shown on Figure 10 are not listed in the ten-year plans but have been identified as being considered by the utilities in SWAT. These are mostly circuits between Phoenix and Four Corners. It is possible that as conditions change, some of these options may be included in future plans as a result of the SWAT process. The study alternatives, in total, strengthen the system east and northeast of Phoenix and north of Tucson.

[1] A.R.S. §40-360.02

Figure 10: Arizona EHV transmission area system and plans

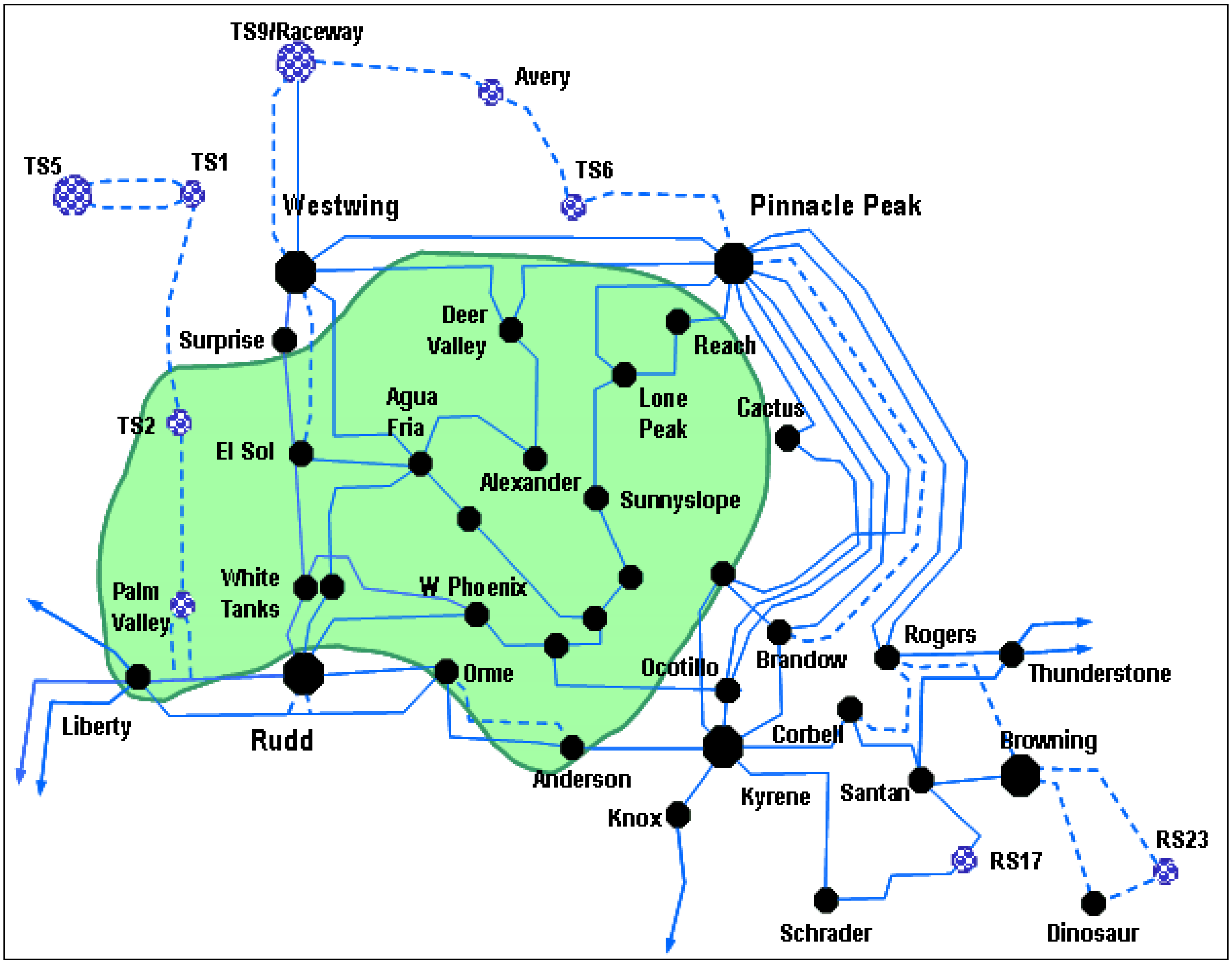


The individual EHV additions and reasons they are required are listed in Appendix F.

5.2 Metropolitan Phoenix area

The metropolitan Phoenix area including Scottsdale, Tempe and other surrounding cities and incorporated areas is currently the single largest load basin in the state with approximately 12,600 MW of peak electric demand. Major elements of the local HV transmission system for the Phoenix area are shown on Figure 11. The facilities in this area are operated by Arizona Public Service (APS), Salt River Project (SRP) and WAPA.

Figure 11: Phoenix metropolitan area HV transmission system



The HV individual additions and reasons they are required are listed in Appendix G.

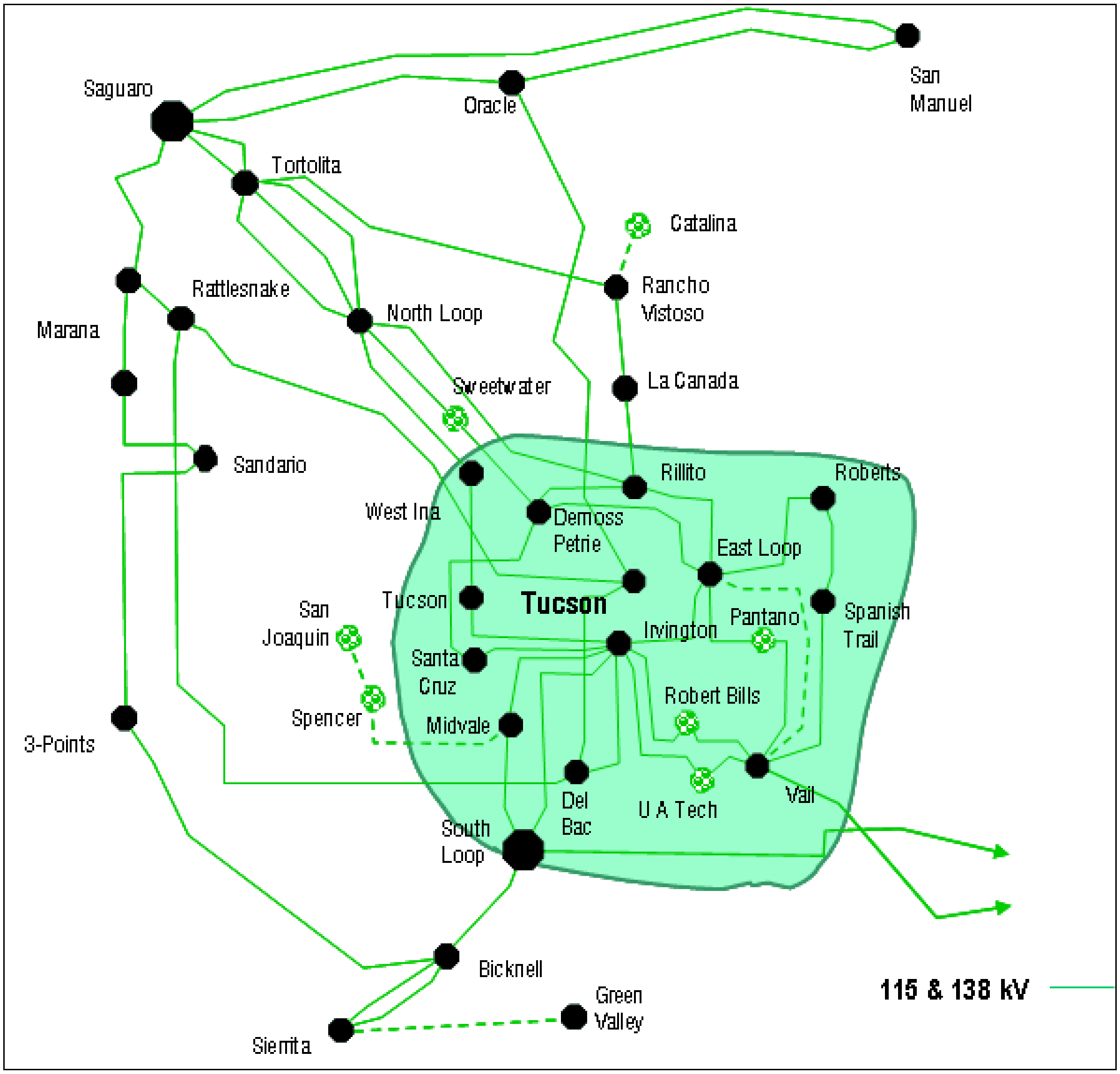
The 10 year plans submitted in the 4th BTA anticipate continued strong growth in the metropolitan area and include plans for at least 226 miles of new 500kV lines, 167 miles of new 230 kV, about 20 new bulk power transformers and other lower voltage facilities. Many of these new projects are joint efforts of APS and SRP. Based on estimates provided by APS these projects are expected to increase the delivery (import) capability into the metropolitan Phoenix area by nearly 5,000 MW. Over the same 10-year period the peak electrical demand in the area is forecast to grow about 3,500 MW. To the extent that the growth in import capability exceeds the load growth it will help to reduce customer energy costs and increase customer reliability.

Upon completion of the 500 kV projects identified in the current 10 year plans, a 500 kV transmission loop will be nearly completed around the metropolitan area. This partial loop will extend from the Northeast corner of the metropolitan area at Pinnacle Peak around the North, West and South sides of the metropolitan area to the Browning/Southeast Valley area. An additional 500 kV link on the East side of the metropolitan area, if added in future 10 year plans, would complete the full 500 kV metropolitan loop and provide enhanced reliability to the whole urban area.

5.3 Tucson and Nogales Areas

These neighboring areas in southeastern Arizona are both served by UniSource Energy Corp. (UNS). The focus of Tucson Electric Power's (TEP) 10-year expansion plan is to reinforce the EHV supply into Tucson from the north and install a new 345/138 kV source at the Gateway substation into the Nogales area. Various 345 kV and lower voltage transmission projects are also planned to address local load growth and RMR requirements. Once these projects are constructed a complete 500/345 kV transmission loop will be established around the Tucson load area. The existing and planned additions to the HV system are shown in Figure 12.

Figure 12: Tucson area HV transmission system



TEP, a UNS subsidiary, and SWTC are participants in the jointly owned Hassayampa-Pinal West 500kV project, which is planned to be in service in 2008. TEP's and SWTC's jointly owned Westwing-South 345kV line will loop in and out of the new Pinal West 500/345kV Substation. This loop-in will require less than one mile of new 345kV line construction and will provide TEP and SWTC with increased access to resources out of the Palo Verde area. TEP is also considering two alternative reinforcements from the north into Tortolita Substation in 2012. One is a new 500kV line from Pinal West to Tortolita Substation at the northern edge of the TEP service territory. The other option under review is a new 500 kV line from the proposed Pinal South Substation to Winchester or Tortolita. Both alternatives were reported in this 10-year plan with the caveat that only one of the two will ultimately be selected as the preferred 2012 plan. Regardless of the option chosen, TEP plans to extend 500 kV from Tortolita to Winchester Substation on the eastern edge of its service area.

Pursuant to Siting Case No. 111, TEP proposes to construct a double circuit 345 kV line to interconnect its system with Comision Federal de Electricidad at the U.S.-Mexico border. The timing of this project is dependent on the Federal permitting process. The line would originate at South Substation near Tucson and proceed southward to a new Gateway 345/138 kV substation near Nogales, then continue on to the border with Mexico. Looping the new line into a new 345/138 kV substation at Gateway would provide a strong transmission source into Nogales. UNS proposes to build two 138/115 kV lines from Gateway into Nogales over the next 20 years. The first line would be built from Gateway to Valencia Substation during the next 10 years, in conjunction with the TEP-CFE interconnection project, with a second line added from Gateway to Sonoita Substation beyond the 10 year plan. Both lines from Gateway into Nogales may initially be operated at 115 kV, and eventually converted to 138kV operation. UNS also plans to upgrade its existing 115 kV line from Vail Substation into Nogales to increase its operating voltage to 138 kV in 2012, and establish the new Gateway Substation as the southern terminus of this line.

The existing and future HV transmission system for the Tucson area is shown on Figure 12. The facilities in this region are operated by TEP, (SWTC) and WAPA. There are fewer new facilities in the Tucson area than in the Phoenix area. They are also more evenly distributed around the Tucson area to serve load in Tucson and to the northeast.

The planned HV transmission additions are listed in Appendix F. This Appendix includes a few facilities not shown in Figure 10 or Figure 12. These facilities are in the area between Phoenix and Tucson, as well as the area west of Tucson and the mining regions lying along the eastern edge of the area. There are also a number of “reconductoring” projects planned by TEP that are not listed in Appendix F since these projects use existing towers and substation facilities—they do not require new right-of-way for transmission.

5.4 Yuma area

Plans to reinforce the bulk power supply to the Yuma area in the 2006-2015 period focus on completion of a second Palo Verde-North Gila 500 kV line. The area is resource constrained at peak loads and depends on imports to serve the demand. Yuma’s peak demand is forecasted to grow from under 400 MW today to 563 MW in 2015. By 2008 the Yuma load is expected to exceed import capability by as much as 1,703 hours per year. This increases the dependence of the area on local RMR units. Most of these imports are delivered to Yuma over the APS owned share of the existing Palo Verde (Hassayampa)-North Gila 500 kV line, which was upgraded in 2006 as part of a joint Arizona-California EHV transmission system upgrade. The addition of 100 MW of new generation in Yuma in 2008 plus construction of second 500 kV line from the

Palo Verde/Hassayampa area to North Gila in 2012, along with a 230 kV line from North Gila to the Yuma load center, will add 395 MW to serve the area's load growth.

The proposed second Palo Verde/Hassayampa-North Gila 500 kV line offers a good example of the type of collaboration that can be achieved between transmission providers in Arizona. The project is sponsored by APS with participation from SRP, Welton-Mohawk Irrigation and Drainage District (WMIDD), and the Imperial Irrigation District (IID). As previously discussed, APS proposes the line in order to increase Yuma's transmission import capability and serve growing peak demand in the Yuma area. On the other hand, SRP is participating in the line in order to access geothermal resources in the Yuma area that are available for export during off-peak load periods. WMIDD is participating in the line in order to increase its transmission import capability. The increase will allow WMIDD to serve growing peak demand in its service area and gain access to independent and geothermal resources.[1] Achieving such synergies increases the value of transmission projects to Arizona.

5.5 Arizona-California EHV system assessment

The transmission facilities between Arizona and southern California have been an important part of the western electric power grid for several decades. This importance has grown in recent years as considerable independent generation has been built in Arizona, Utah and Nevada. Of particular importance, have been the transmission facilities that cross the Colorado River between Arizona, California and southern Nevada—known as Path 49. This Path continues to be an important factor limiting power transfers in the West. This Path was an important part of the analysis made by STEP, as discussed in the previous chapter. Arizona entities hold significant ownership interests in several of the key lines that make up this path (e.g., Mead-Liberty, Mead-Perkins and Navajo-Crystal). However, except for the APS share of the Hassayampa-North Gila 500kV line, which supplies APS loads in the Yuma area, the remainder of the Arizona-California EHV (Path 49) transfer capability has no direct impact on supply to customers located in Arizona. Nevertheless, Path 49 is a major flowgate for the export of generation from Arizona to California, including resources in Arizona that are owned by California utilities.

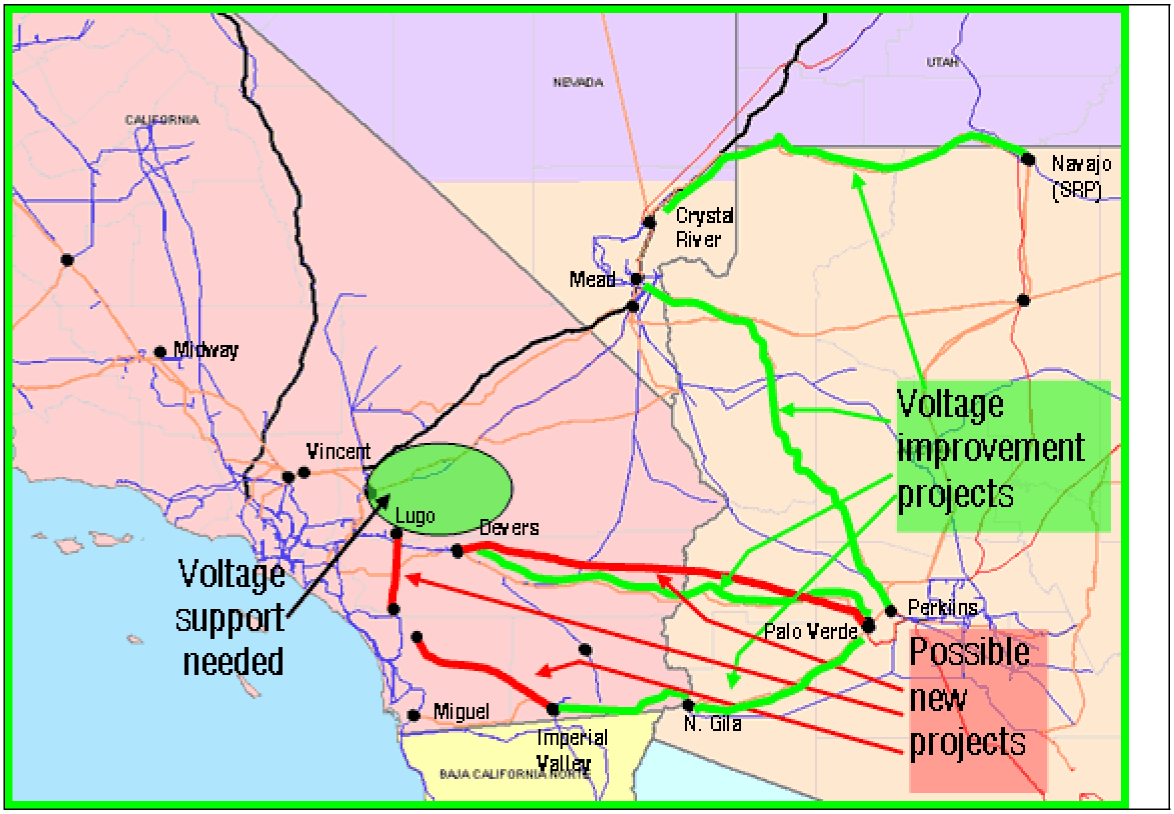
The area studied by STEP and the general options they identified are shown on Figure 13. The map reflects the three basic options identified by the STEP study team:

- Short-term upgrades on Path 49 – Series capacitor upgrades, second Devers 500/230 kV transformer, voltage support, and installation of flow control apparatus on Imperial Valley to El Centro 230kV (in California);
- Palo Verde-Devers #2 500 kV Line; and

1 In addition to participation in the second Palo Verde-North Gila 500 kV line, WMIDD is evaluating several other 230, 161, and 69 kV transmission additions to provide reliable electrical service to its customers.

- Upgrade of Path 49 to 9300 MW—(series capacitor upgrades on Mead-Perkins and Navajo-Crystal 500kV lines, etc.)

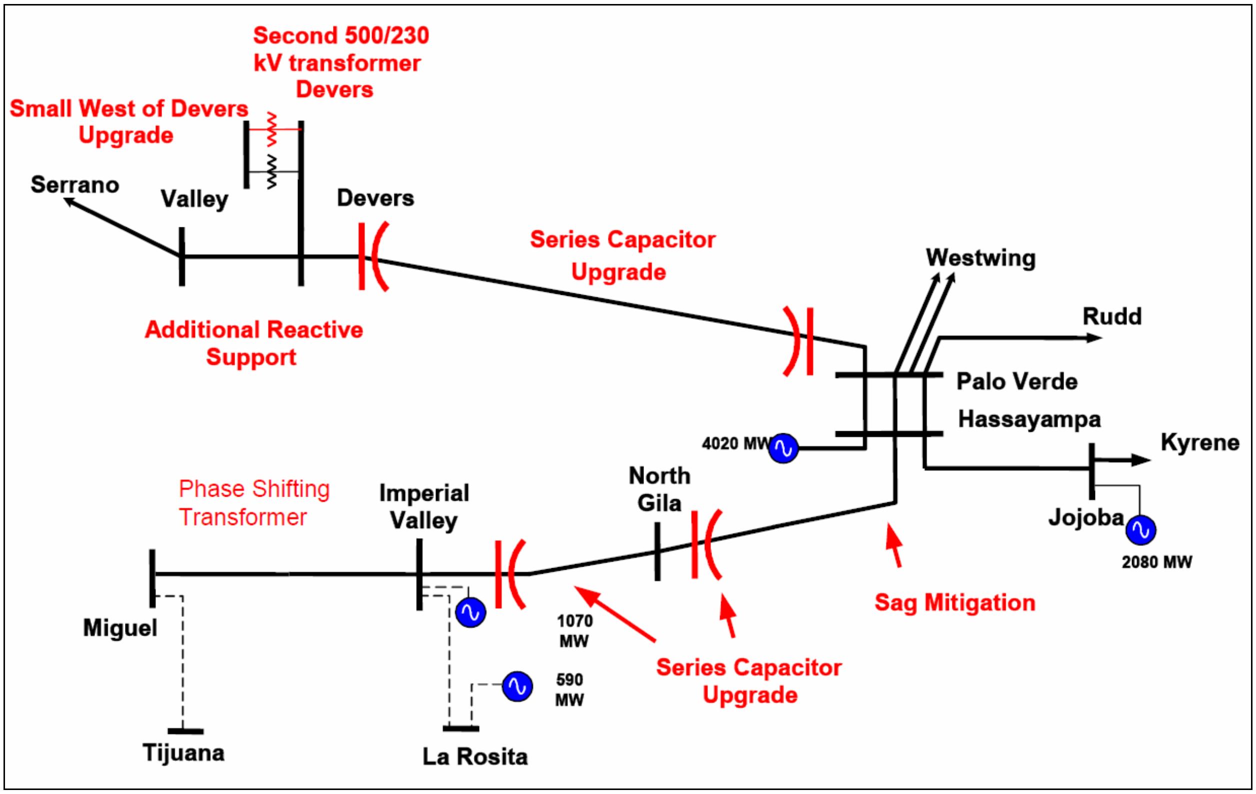
Figure 13: Arizona-California area transmission system



All of the planned short-term upgrades on Path 49 are now complete except for the Imperial Valley-El Centro phase shifter. However, the WECC granted a seasonal rating increase of 505 MW on Path 49 for Summer 2006 based on implementation of suitable operating procedures until this apparatus is installed.

A more detailed picture of these short-term Path 49 improvements is shown in red in Figure 14. These upgrades were completed in 2006 and will result in year-round increase of the Path 49 rating from 7,550 MW to 8,055 MW.

Figure 14: Arizona-California short-term transmission improvements

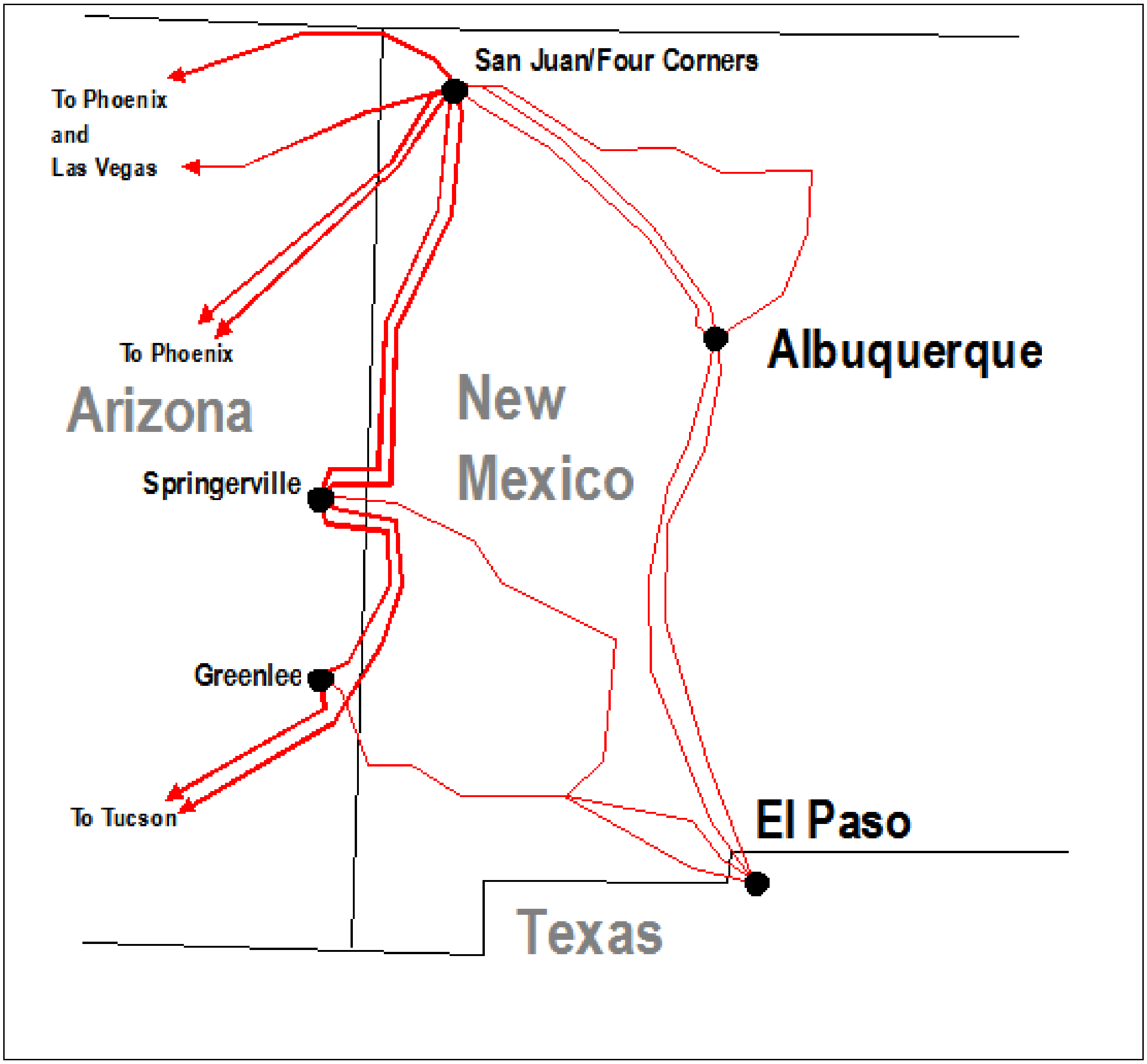


In the longer-term, the next new addition expected to occur by 2008 is the EOR (Path 49) 9,300 MW upgrade project. This involves upgrades of series capacitors in Arizona, as noted above, and is expected to increase the path rating by 1,250 MW. The project is currently in the final stage of WECC's path rating review process. The next major line addition planned is a second Palo Verde – Devers 500 kV transmission line sponsored by the Southern California Edison Company, with a planned in-service date of 2009. The project is still in licensing. If built, it will add a minimum of 1,200 MW of capability to Path 49 (based on the WECC approved path rating study). Recent studies show that that the transfer capacity increase due to the Palo Verde – Devers No. 2 line could be significantly higher. A subsequent 500kV line addition, also in licensing, is proposed from Imperial Valley to the west by San Diego Gas and Electric. It has a planned completion date of 2010, but should have minimal impact if any on the Path 49 rating.

5.6 Arizona-New Mexico EHV system adequacy

Arizona has limited interconnections with New Mexico as can be seen on Figure 15. The major generation in New Mexico is at San Juan/Four Corners and the output of the plants is shared by both Arizona and New Mexico utilities.

Figure 15: Major Arizona-New Mexico EHV Transmission



A SWAT subcommittee is evaluating this portion of the Western power system. The subcommittee goals are to:

- Align "common interest" projects

- Develop base case (starting with 2012)
- Develop "long-term" AZ-NM system
- Study particular "common interest" projects of Interested parties
- Bring results together for technical review and comments
- Incorporate into a single plan report

They are evaluating several specific projects including three coal projects (2,400 MW total), one wind project (100 MW), one new 500 kV line (NTP), and one new 345 kV line (PNM). Various parties are interested in a number of new generation possibilities for the region to serve load in Arizona, New Mexico, Utah, Colorado, and Nevada as shown in Table 6.

Table 6: Long-range transmission "needs" of parties in the AZ-NM region

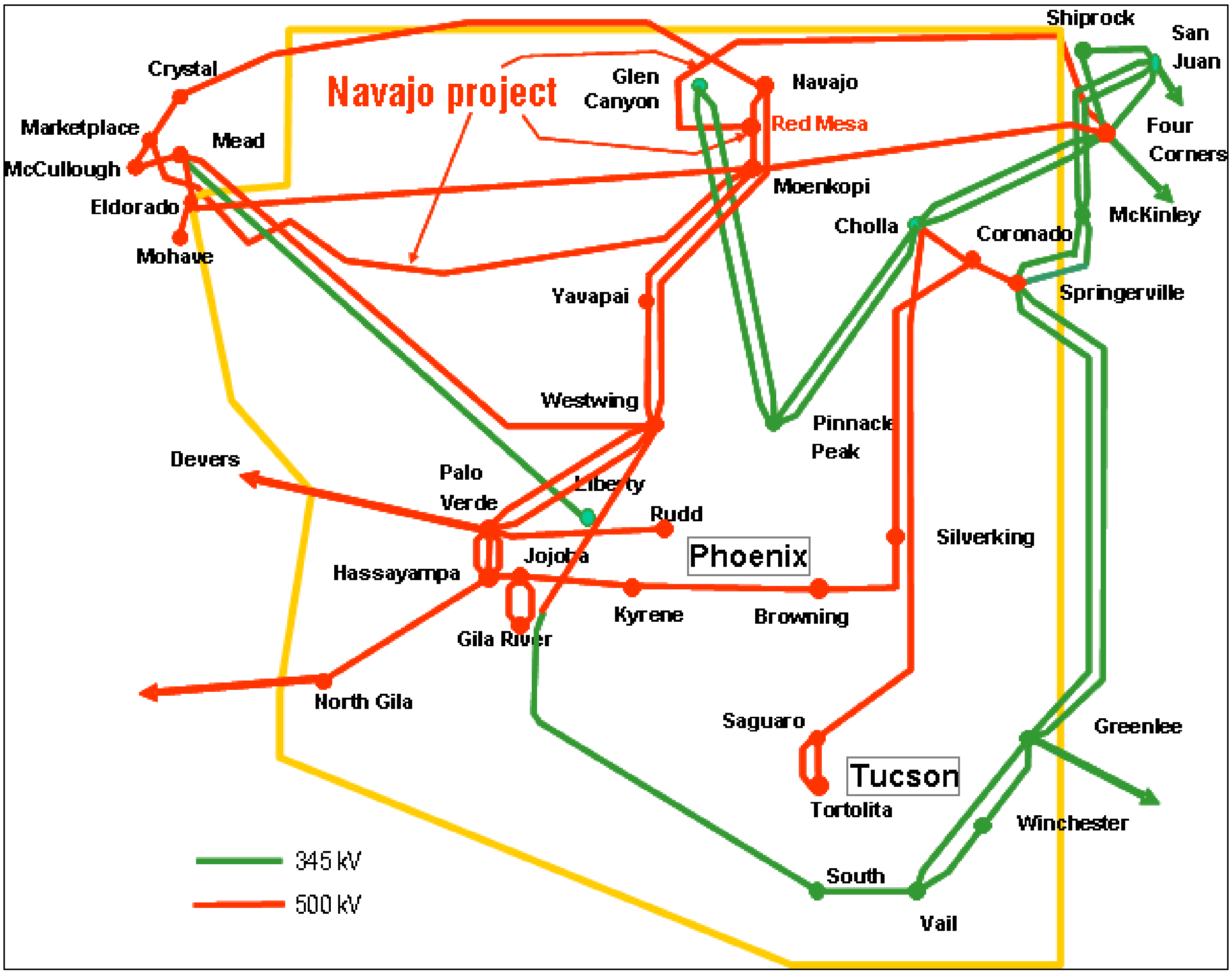
Interested party	Delivery amount desired	Desired market
AZ Electrical Districts	200 MW	Four Corners to CATS Area
Tri-State	200 MW	Springerville to Colorado
APS	1,000 MW	Four Corners to Phoenix
SRP	600 MW	Springerville to Phoenix
EPE	300 MW	Upgrade on WECC Path 47
TEP	500 MW	Springerville to Tucson
PNM	400 MW	Four Corners to Albuquerque
Pacific Corp.	500 MW	Four Corners to Utah
WAPA (SLC)	100 MW	Four Corners to Glen Canyon
SWTC	200 MW	Four Corners towards Tucson
NTP	1,500 MW	Four Corners to PHX and LV
BHP (Merchant Generator)	500 MW	Four Corners to PHX and ALB
STEAG (Merchant Generator)	1,400 MW	Four Corners to Phoenix
Western Wind (Merchant Generator)	100 MW	Coronado to Phoenix

5.7 Navajo Transmission Project

The Navajo Transmission Project is a 460- mile, 500 kV line with an expected capacity of 1,200 to 1,800 MW. It will interconnect the Four Corners, Moenkopi and Market Place substations, and traverse portions of three states as shown in red on Figure 16. The Diné Power Authority (DPA) is developing the transmission project in conjunction with its coal-fired Desert Rock

Energy Project in the Four Corners area of New Mexico.[1] DPA is partnering with Sithe Global Power on the transmission project. A significant portion of the right-of-way in Arizona is within the Navajo Nation, which includes 60% of the line length from Four Corners to Moenkopi substation.

Figure 16: Navajo Transmission Project concept



The Navajo Transmission Project has three distinct segments or phases, which are all being permitted together at this time. The sequence of the three segments is as follows:

- A 500 kV circuit from Four Corners (or a new station nearby) to Red Mesa (or a new substation nearby) to be place in-service in 2010;

[1] Diné Power Authority is an enterprise of the Navajo Nation. It was created in 1985 by the Navajo Tribal Council for the purpose of developing electric transmission and generation projects within the Navajo Nation. RockPort Capital Partners (RockPort) is a venture capital firm that is assisting DPA in the Project Development Activities. Steven Begay is the DPA General Manager and Alexander (Hap) Ellis III is a Partner in RockPort.

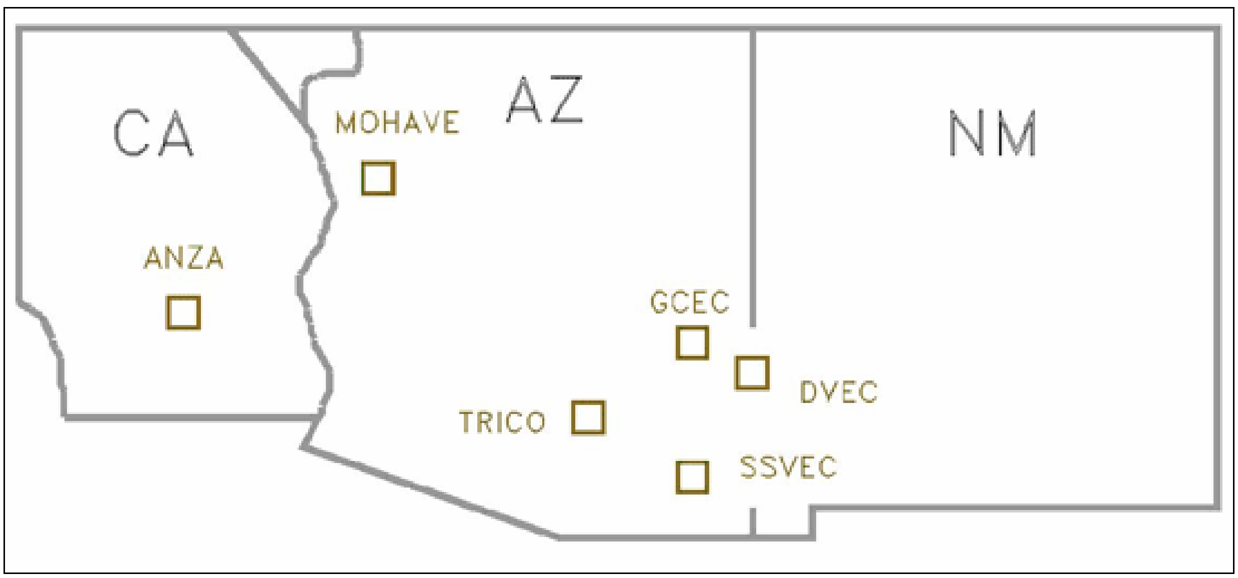
- Optional development of a 500 kV circuit from Red Mesa to Moenkopi; and
- Planned development of a 500 kV circuit from Moenkopi to an existing substation in the Las Vegas area, likely over the next ten years.

Diné's current plan is to construct Segment 1 first including the eastern terminal near the Four Corners Power Plant and to construct the Red Mesa Substation for interconnection to the central Arizona 500 kV grid. The Red Mesa Substation will intercept and loop-in only the Navajo – Moenkopi 500 kV line to achieve the interconnection. It is expected that system studies will indicate a project rating of 1,200-1,500 MW.

5.8 Southwest Transmission Cooperative

Southwest Transmission Cooperative, Inc. (SWTC) owns over 600 miles of transmission assets and serves over 550 MW of member system loads. Most of these facilities and member systems are located in Arizona as indicated in Figure 17. SWTC customer systems in Arizona include Mohave Electric Cooperative, Sulphur Springs Valley Electric Cooperative, Trico Electric Cooperative, Graham County Electric Cooperative, and Duncan Valley Electric Cooperative.

Figure 17: SWTC member systems



Many of SWTC's transmission assets operate at 230kV and 115kV, but they are also a participant in the proposed Hassayampa-Pinal West 500kV line and Pinal West-Santa Rosa 500kV line. SWTC participates in the SWAT Planning Group and subcommittees, including CATS-EHV, CATS-HV, the Colorado River Transmission Subcommittee (CRT) and the Arizona-New Mexico EHV Subcommittee (AZNM).

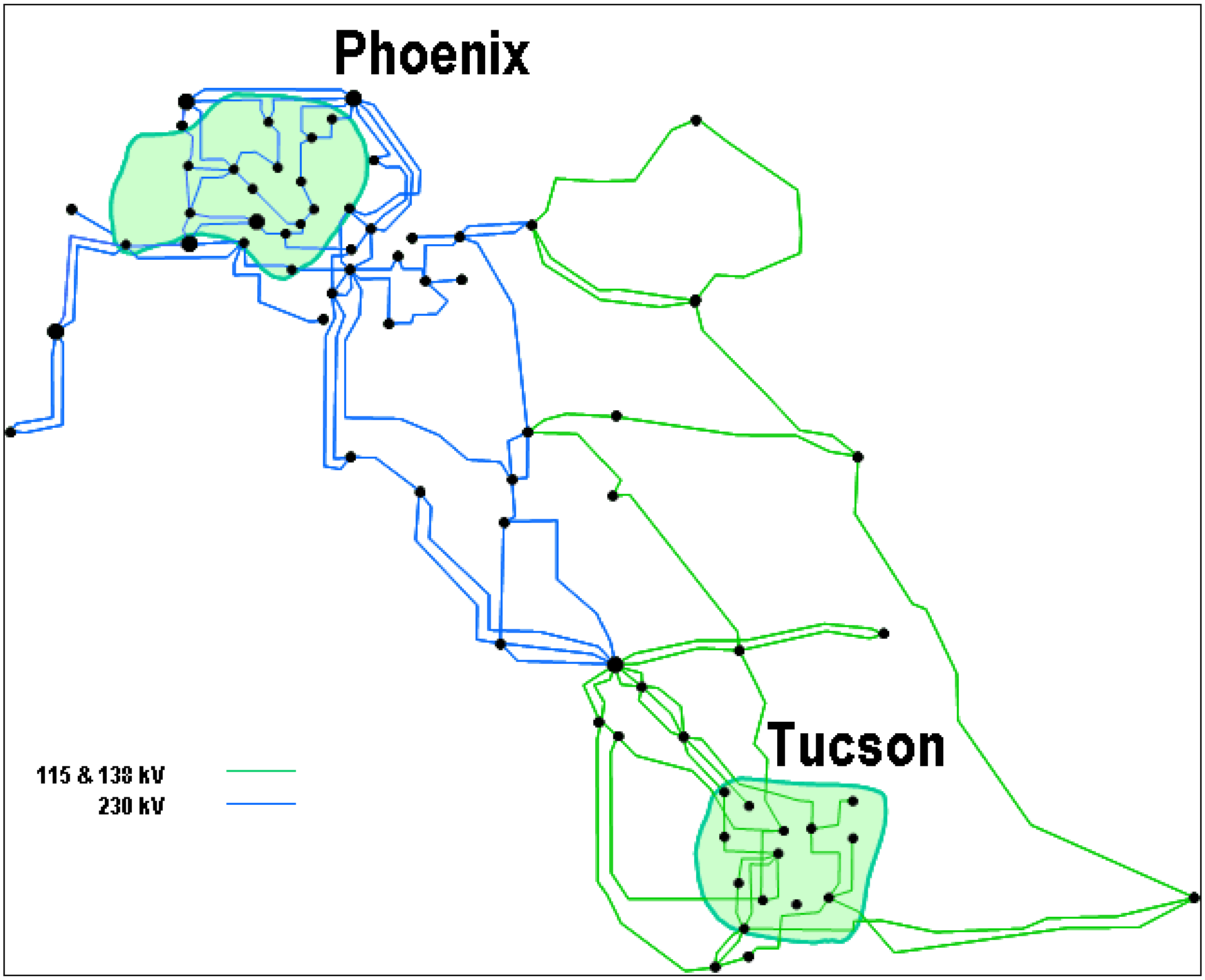
SWTC filed a 10 year plan with the Commission on February 2, 2006 and after consultation with the Commission staff SWTC filed an amended 10 year plan on July 28, 2006. The amended filing adds three new projects that were not contemplated in SWTC's original filing, as necessitated by rapid load growth in its Western and Southern service areas. SWTC's 10 year plan includes construction of new 230/69kV substations tapped into the Dos Condado-Morenci 230kV line and Butterfield-Pantano 230kV line and a new 230/24.9kV substation tapped into the Pantano-Sahuarita 230kV line. These projects and others included in SWTC's 10 year plan are driven by customer load growth.

Power flow and stability analysis conducted for 2006 and 2015 confirmed compliance with SWTC's n-0 and n-1 planning criteria, with the exception of these three n-1 contingencies: loss of the Apache-Butterfield 230 kV line; the Butterfield-San Rafael 230 kV line; or loss of the Pantano-Kartchner 115 kV line. For these outages SWTC studies show that performance violations occur in the 2015 case as a result of an unanticipated increase in a customer load forecast. The violations cannot be resolved through remedial action schemes. All three n-1 outages could result in a loss of load if they occurred during summer peak conditions. The load-serving entities APS, TEP, SWTC, and the Sulphur Springs Valley Electric Coop are working together to mitigate these contingencies and expect to provide an update of these plans in an upcoming 10-year filing.

5.9 Central Arizona EHV/HV system assessment

The existing Arizona HV (230, 138 and 115 kV) transmission system is shown in Figure 18. The 230 kV system is shown in blue and the 138 and 115 kV system is shown in green. Their primary role is to serve load in the areas between the cities rather than interconnect them (the two areas are also interconnected by existing and planned 345 kV and 500 kV EHV circuits.)

Figure 18: Phoenix-Tucson area HV transmission system



Participants in the 4th BTA presented two studies regarding the Central Arizona Transmission System (CATS). The first of these was a joint SWAT-CATS-EHV study for 2015 in which APS, SRP, SWTC, TEP and Western participated. The second was an Interim Report for the CATS-HV Study of Pinal County, conducted by a SWAT sub-committee. The latter study looked at an ultimate buildout of Pinal County as a load basin and developed a corresponding transmission plan to serve this load. SRP served as the study coordinator, but both of these studies were collaborative processes involving many participants. The CATS-HV study group was also very dependent on input regarding land use plans from municipalities and public agencies.

The SWAT-CATS-EHV study participants developed a joint 2015 base case for Central Arizona in order to assess the collective reliability impact of the transmission plans of individual transmission owners on the Central Arizona system. There were no base case or single contingency (n-1) problems found in the EHV system within the study area. However, some problems were identified in lower voltage systems, which will be addressed in the respective short-term planning processes of the individual owners. The participants intend to repeat this collaborative study process every two years to coincide with future BTA's.

The interim report for the second study, CATS-HV, was included by SRP as Appendix 1 to its 10-year plan (2006-2015) BTA filing. The study developed an ultimate HV transmission plan that would satisfy reliability criteria for an ultimate load basin demand of 10,400 MW in a study area of approximately 5,200 square miles between Phoenix and Tucson outside of the current metropolitan areas. This area is mostly in Pinal County, although portions are located in Maricopa and Pima Counties. The current electric demand in the area is approximately 500 MW. The study does not predict when the load area will be fully developed (saturated), nor is it an optimization study that determines the minimum number of lines and substations required to serve the ultimate load. The study assumed that the majority of resources to serve area load will come from outside the county. Overloads on transmission elements outside the study area were noted, but not mitigated. The interim report summarizes the study results as follows:

> "The transmission solution studied to serve the expanded load in the Pinal County study area required the addition of 16 new 230kV substations, numerous 230kV lines, an a few 500kV lines. The 230kV lines added were a combination of 115kV transmission line upgrades to 230kV and new 230kV lines. The 500kV lines included the South East Valley (SEV) project and the Winchester-Pinal South 500kV line."

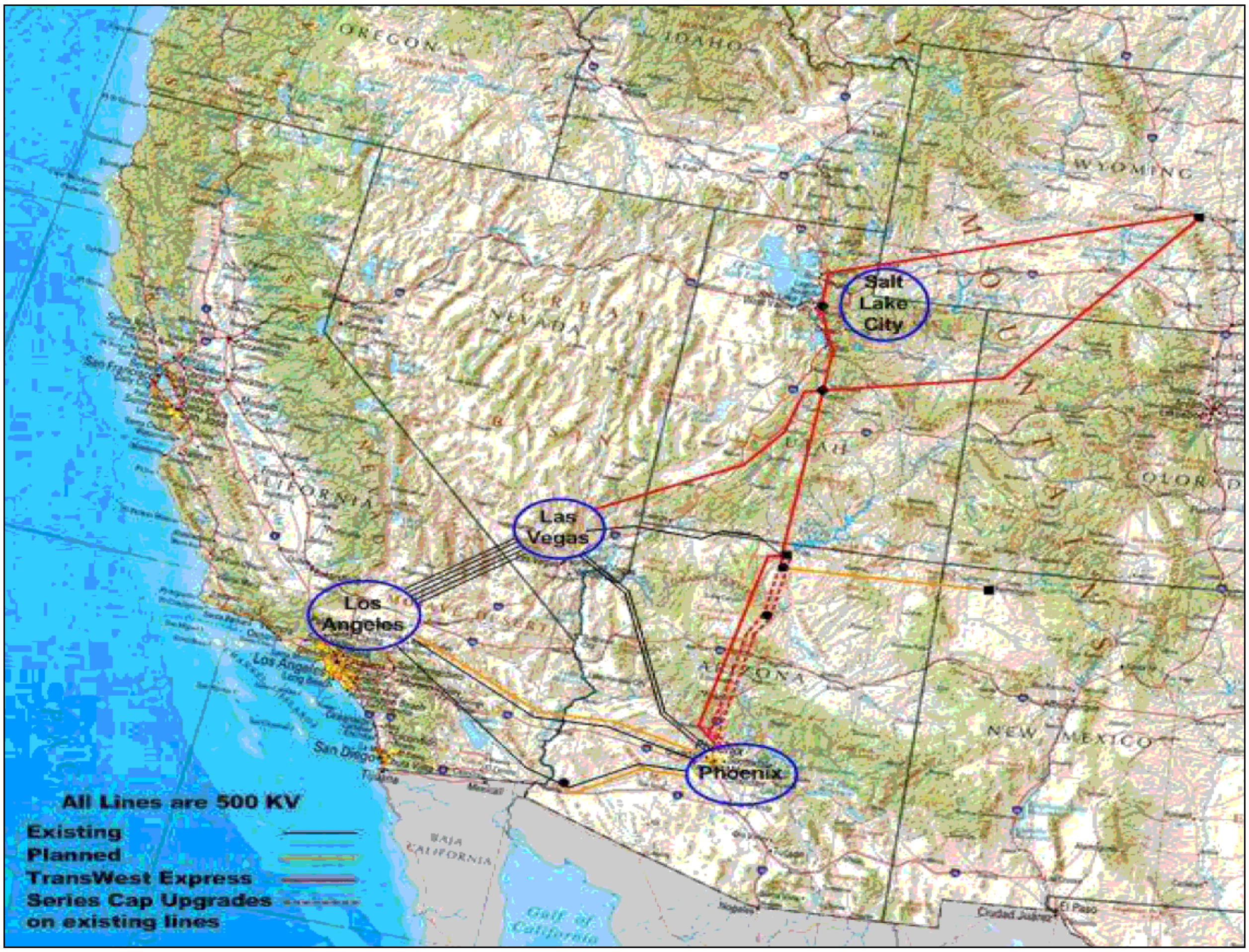
Participants in the CATS-HV study have recommended that the work be revisited every 5-10 years as General Plans of the communities in the study area are updated, major transmission and generation changes become known, or as significant land use changes occur.

5.10 Conceptual interstate transmission projects

A number of EHV transmission projects are under development in eastern Nevada that would not connect directly into the Arizona system, but may still increase Arizona's access to the electricity market in Nevada over existing interstate ties. These projects include the Harry Allen-Mead 500 kV line scheduled for completion in 2007, and the Inland Northern Lights project. A Robinson Summit-Harry Allen 500 kV line and second Harry Allen-Mead line are also under consideration. Furthermore, since the conclusion of the Third BTA, two significant conceptual interstate transmission projects have been announced that may have potential benefits to Arizona. The scope of both projects, still in the formative stages, would involve construction of interstate High Voltage Direct Current (HVDC) and/or EHV (500 kV or 765 kV) Alternating Current (AC) lines from Wyoming into the Pacific Southwest/Desert Southwest region. Both projects could potentially have significant impacts and benefits to the Arizona system.

One of these proposals, the TransWest Express Project, is sponsored by Arizona Public Service. The project involves construction of new transmission from Wyoming to Arizona or southern Nevada as shown in Figure 19. The goal of this proposal is to provide the Desert Southwest with access to coal and wind resources being developed in Wyoming. APS has conducted preliminary studies and initiated a series of meetings to develop stakeholder participation.

Figure 19: Conceptual TransWest Express Project



The second transmission proposal, referred to as the Frontier Project, was initiated in large part through efforts of the Western Governors Association and has similar objectives to the TransWest Project. However, the scope of the Frontier Line is somewhat broader and includes new transmission into northern California as well as the Pacific Southwest/Desert Southwest region. A consortium of sponsors is supporting preliminary studies and stakeholder meetings for the Frontier Project.

As the sponsor for TransWest Express Project, APS is also exploring potential opportunities for a collaborative project scope with sponsors for the Frontier Project. Staff encourages continued discussion along these lines along with a transparent, regional stakeholder planning process to fully explore alternatives and benefits of these closely related interstate transmission proposals.

5.11 Conclusions on adequacy of EHV and HV Arizona transmission system

The Arizona EHV and HV transmission system expansion plans appear to be adequate in the 10 year study period addressed by this BTA (2006-2015), except for two local n-1 contingencies in SWTC's 2015 study (i.e., loss of the Apache-Butterfield 230kV line or the Butterfield-San Rafael 230kV line). Planned facilities identified in the 10-year planning process are consistent with good utility practice. Given the number of alternative projects identified in the longer range plans it should be possible to meet future needs for supplying Arizona's electric system loads in an economical and reliable fashion. SWTC will continue its review of expansion options for the two n-1 contingency violations reported in its 2015 study and contemplates providing updated plans to mitigate these issues in its next 10-year filing to the Commission due 31 January 2007.

The 2006-2015 expansion plans include proposals for certain economically driven regional projects that may both provide economic benefits to Arizona consumers and increase transmission system capability beyond a level required just to maintain reliability. Commission Staff welcomes such proposals and encourages parties to pursue projects that provide economic benefits to Arizona consumers.

The CATS-HV interim study has identified a significant number of new HV and EHV lines and substations that could potentially be needed as soon as the next 10-15 years if the population and load in the area grow at high rates. Performing this study in order to identify an ultimate transmission plan for this potentially high growth area is a proactive approach to planning, but the conceptual transmission plan developed in the study for the greater Pinal County load basin will need continued refinement in coming years as growth patterns and other impacts become clearer. Since the rate of population and load growth in the area of study could be quite rapid, revisiting the study every 3-5 years would be preferable to the 5-10 year cycle suggested in the report. Continued collaboration between the transmission owners and the municipalities/public agencies in the study area in order to coordinate public land planning and utility land needs would also be highly desirable.

6. Local-area transmission system

6.1 Arizona reliability must-run generation requirements

Previous BTA's have defined a number of local load pockets in Arizona where the load cannot be served using a normal economic merit-order generation dispatch due to transmission limitations. During some portions of the year, generation units within the load pocket must be operated out of 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 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.[1] The Commission stayed this requirement in its Track B proceedings.. 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.[2] Known transmission constraints result in APS and TEP being dependent upon local reliability-must-run (RMR) generation to serve their peak load during certain hours of the year.

In order to provide the Arizona load pockets access to 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.

Beginning in 2003, the utilities readily responded with RMR studies. The third BTA Decision No. 65476 approved a collaborative RMR study plan agreed to by all Arizona transmission providers. The 2003 RMR study forum included only the transmission providers. Since 2004 the RMR process, in contrast, has been open to all interested parties through the CATS study forum.

6.1.1 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

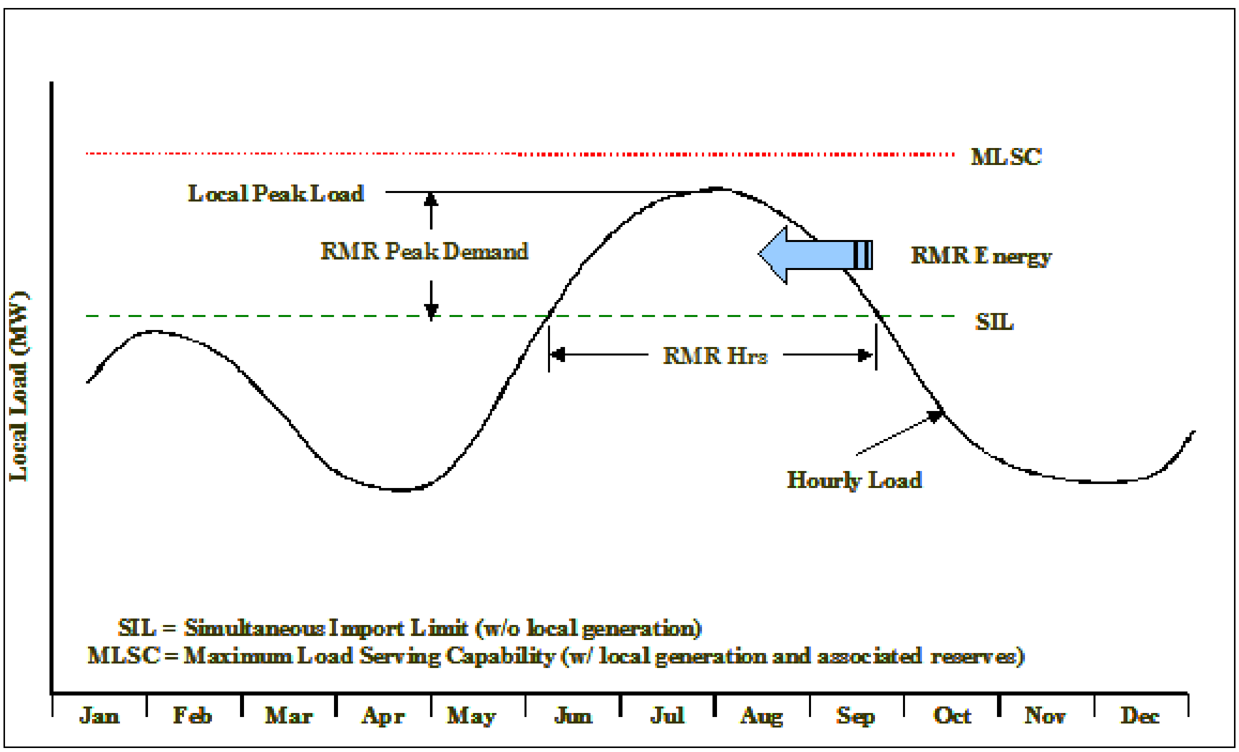
[1] Direct Testimony of Jerry D. Smith, and rebuttal testimony of Cary Deise, Docket No. E-00000A-02-0051.
[2] A.A.C. R14-2-1609.B

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 determine at least six RMR components 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 Figure 20.[1]

Figure 20: RMR Conditions



[1] 2002 BTA, Page 74-76

Essential indicators that the Commission intended to receive as a result 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;

- 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.

6.1.2 Summary of the RMR studies process

There were two unresolved issues with the 2004 RMR studies:

1. Staff remained concerned with local generation reserves for the Phoenix area post 2008.
2. Confusion remained regarding implications of Mohave County RMR Study results.

The 2006 RMR study analyzes expected 2008 and 2015 conditions and concludes that projected reserves in the Phoenix area in both years are greater than the 99% reliability reserve requirement of 865 MW. These results appear to resolve the Staff's concern from the 2004 study. However, regarding the Mohave County RMR study results, the situation remains unclear. As discussed in §6.2.5 (page 111) this is due in large part to the absence of filings by Western Area Power Administration in the BTA process.

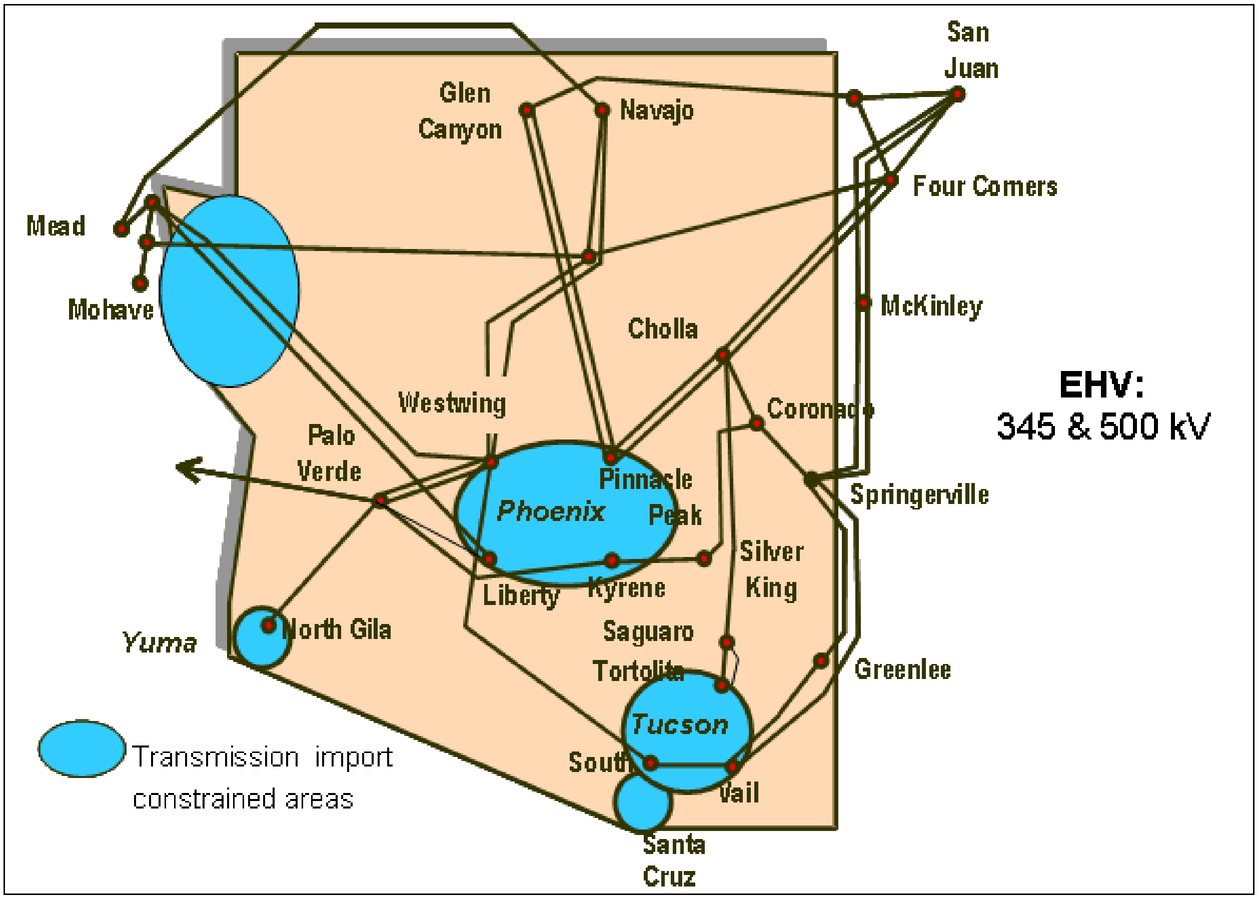
Based on the 2006 RMR study results Staff recommends that:

- Arizona utilities should continue performing RMR studies for all transmission import constrained local areas:
    - Utilizing a collaborative study forum;
    - Improving economic analysis of RMR mitigation;
    - Clarifying projected system peak load and supply conditions in Mohave County beyond 2012 and appropriate mitigation measures, if any;
    - Clarify anticipated generation retirements in each constrained load area and the impact of such retirements on the RMR requirements.
- RMR 10-year study results are to be filed with ten-year transmission plans by January 31, of even number years, to coincide with the associated ACC obligation to perform a Biennial Transmission Assessment.

6.2 Transmission import constraint areas

The previous BTAs identified five load pockets: Phoenix, Tucson, Yuma, Santa Cruz County and Mohave County. The issues and concerns in each of these five load pockets remain the subject of this BTA. Load pocket areas as identified in the previous BTAs are shown on Figure 21 (same as Figure 7 on page 55).

Figure 21: 2006 BTA Arizona load pocket areas



There is also a sixth constraint area in southeastern Arizona. The 160 MW load, from Ft. Huachuca to Douglas, is served via four radial transmission 115 kV lines. The loss of any one of these lines during summer peak could result in the inability of one or more of the load serving entities in this area to serve their entire load without some period of service interruption. These loading problems are being addressed by the recently formed Southeast Area Transmission System Study Group (SATS).

6.2.1 Phoenix area RMR conditions and imports assessment

6.2.1.1 Phoenix existing and future transmission system

The interconnected transmission system serving the metropolitan Phoenix area is owned and operated by APS, SRP and WAPA. A majority of the Phoenix Valley load is served by transmission imports. Load growth occurring in the North and West Valley is served by APS and the load growth in the East and South Valley is served by SRP.

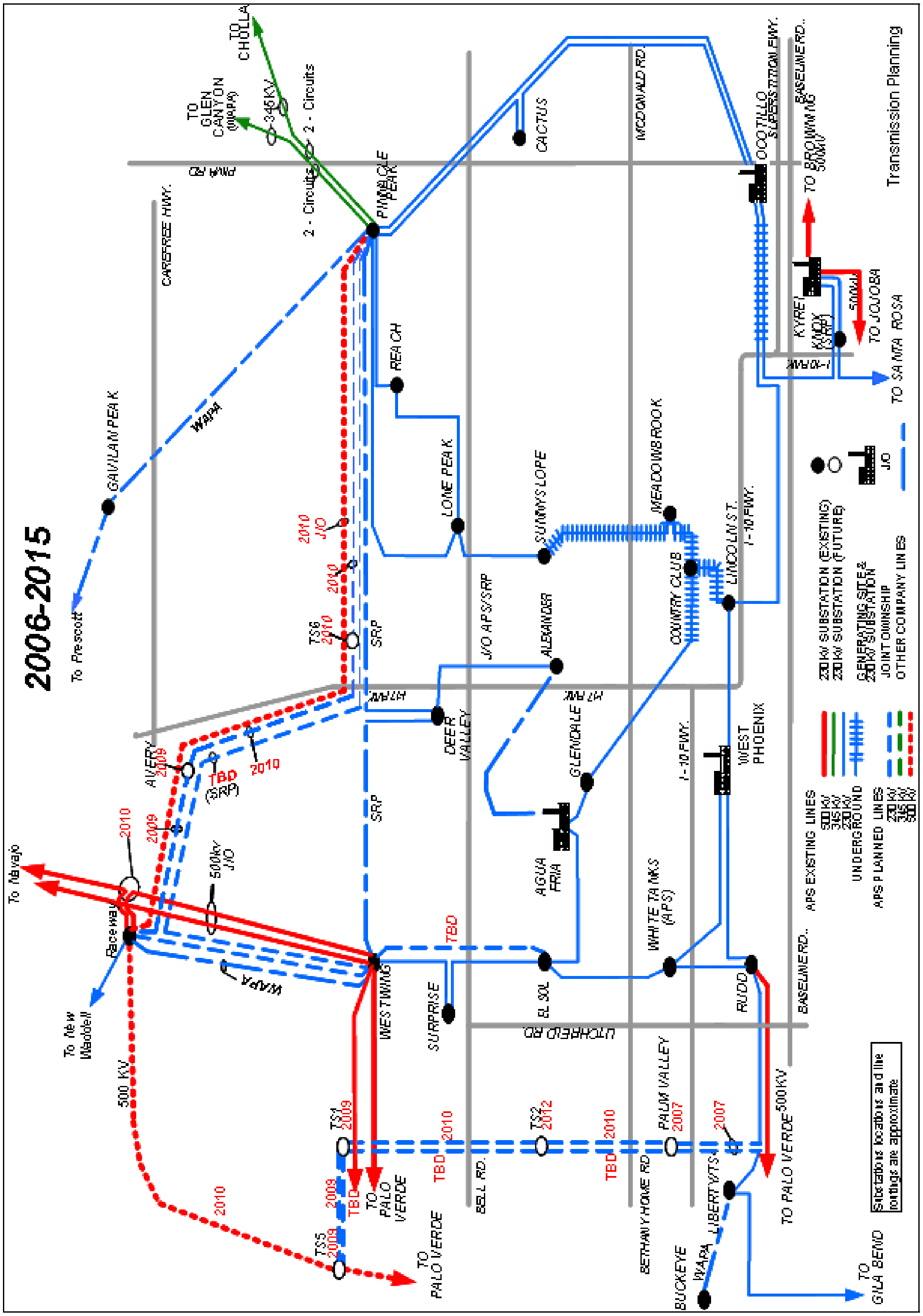
In its 2004 RMR Study, APS reported that the load flow and voltage stability analyses were done in order to determine Phoenix area critical outages as required by transmission planning criteria. APS conducts their analyses assuming that enough operating reserve will be available within the Phoenix area to respond during single contingencies.[1] By maintaining an operating reserve within the load pocket, APS performs contingency analysis under more critical conditions than just (n-1) category. These criteria require transmission planning to accommodate maintenance outages while still being able to meet the n-1 criteria during a subsequent forced outage. The nature of the Phoenix area load is such that during the eight month period of October-May, any line or local area generator can be taken out of service for maintenance with adequate import capability and local area generation remaining to meet the n-1 criteria. Maintenance outages of 12-14 hours can also be taken during the summer at night. This capability will be documented in future 10-year plan filings.

The voltage stability study was performed using Q-V analysis on the most reactive deficient buses in the Phoenix area. These buses were the Kyrene 500-kV, Kyrene 230-kV, Browning 230-kV, Westwing 230 kV, and the Pinnacle Peak 230-kV buses. A Q-V analysis is performed by adding reactive load at the critical bus until the voltage reaches a minimum value, which indicates potential voltage instability. The voltage stability import limit is determined as the lesser of 95% of the import with zero reactive margin, or 100% of the import with a 5% voltage drop following the worst single-contingency per WECC planning criteria.

At present the Phoenix area is served from the following major EHV substations: Westwing, Pinnacle Peak, Kyrene, Rudd, Browning, and Silverking. These EHV stations form the "cornerstones" of an extensive internal network of 230-kV transmission lines that constitute the high voltage system within the Phoenix load area. By summer 2009, the new TS5 EHV substation will be added in the northwestern Phoenix area. The 4th BTA filings anticipate that two more EHV substations will be added to help supply load growth in the Phoenix area by 2015, the South East Valley (SEV) substation and the Raceway substation on the north side of Phoenix. Figure 22 illustrates these existing EHV substations and the key planned additions.

[1] APS 2004 RMR Study, Page 8

Figure 22: New APS projects strengthening the Phoenix-area transmission system



6.2.1.2 Phoenix area – SIL and RMR conditions for 2008 and 2015

The Phoenix area is a tight network of APS and SRP loads, resources, and transmission facilities. Because the Phoenix system is highly integrated, it was imperative that the import limits be determined for the combined area. The SWAT planning group was utilized to facilitate the public stakeholder process for completing this 2006 Phoenix area RMR study.

The SIL and the RMR conditions for the Phoenix area were performed for 2008 and 2015. These particular years were selected because the Seams Steering Group-Western Interconnection (SSG-WI) was preparing publicly available databases through a broad stakeholder process for those two specific years and they fit well within the 10-year planning horizon of the 4th BTA.

Base case and contingency power flow, stability, and voltage stability analyses were performed to determine import limitations. SIL and RMR conditions of the Phoenix area transmission network resulted in area import limits based on the analysis discussed above. The study process, representative years, and base cases were properly selected. After the SIL for the Phoenix area was determined, RMR conditions were evaluated. The evaluation was based on the area import limits, the area load, and local generation owned by APS and SRP. It should be noted that since the previous RMR study, the local generation that was owned by Pinnacle West Energy Corporation (PWEC) has been transferred to APS.

Table 7 shows the Phoenix-area MLSC for the two years studied and compares the MLSC to the forecasted peak demand. The MLSC is determined by adding the SIL and the local generation minus the local reserve requirement. APS determined the Phoenix area reserve requirements by performing a probabilistic analysis considering the size and forced outage rates of the local generating units that resulted in 99 percent reliability for serving all loads. This analysis resulted in the reserve requirements shown in Table 7 and on Figure 23.

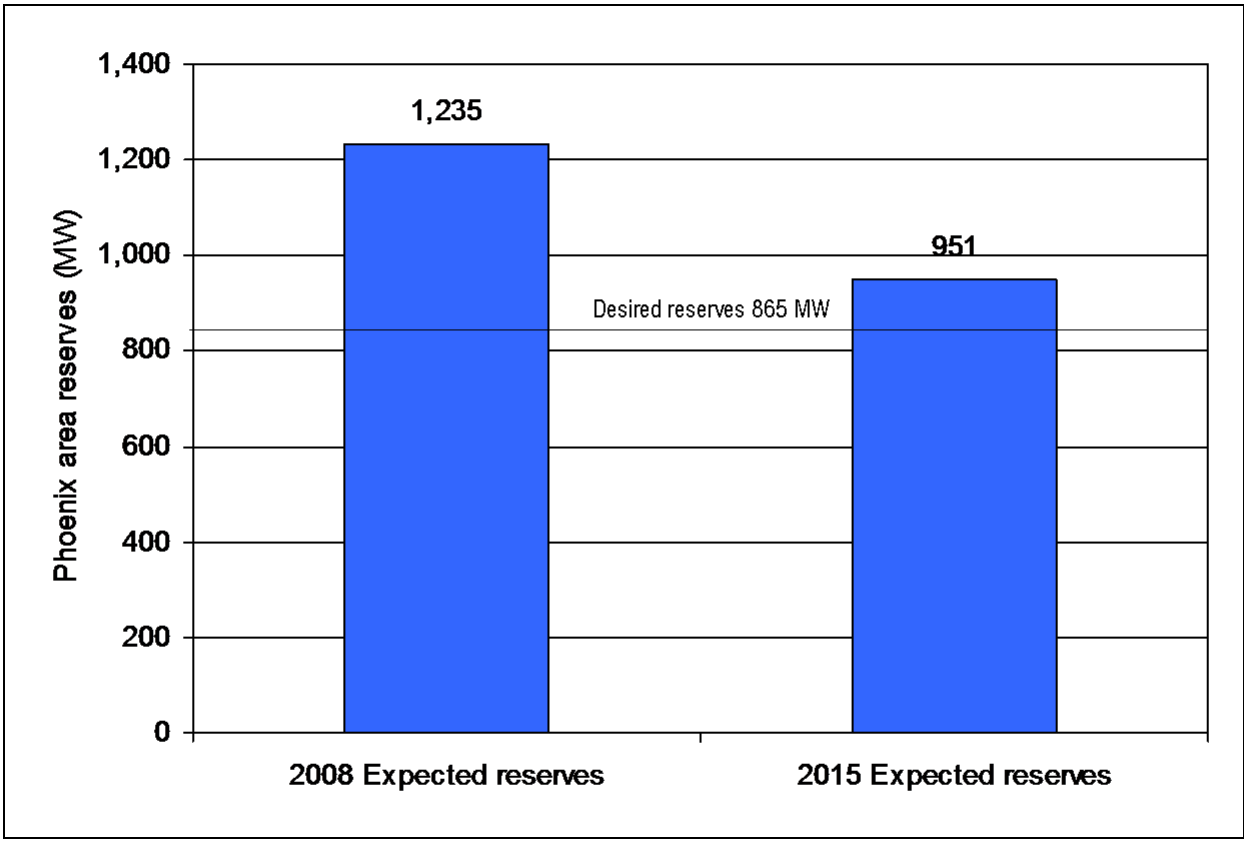
Table 7: Phoenix Area Maximum Load Serving Capability

Year	SIL	Local generation	Required reserves	MLSC	Peak demand (MW)	Projected reserves
2008	9,700	3,674	865	13,860	12,625	1,235
2015	13,004	3,674	865	17,051	16,100	951

Based on these results, and the planned addition of the new TS5 substation in 2009 it appears the MLSC will exceed Peak Demand throughout the 10 year planning horizon. In the previous RMR study it was observed that the projected 2012 reserve margin of 346 MW was less than the required reserve margin of 865 MW. Staff concludes that, APS and SRP transmission plans filed in the 2006 BTA increase import capability sufficiently to eliminate this reserve deficiency concern.

It should be noted that due to the calculation method used by APS, the MLSC does not equal the direct summation of SIL and Local Generation. APS determines the MLSC graphically by determining an operating nomogram for each year. The maximum amount of load that can be served is then determined from the highest point on the nomogram, which does not necessarily occur at the point of maximum local generation.

Figure 23: Phoenix area reserves



To determine the RMR costs for the Phoenix area, an economic analysis was performed using a regional production cost model. The production cost was determined for two scenarios:

- Phoenix load supplied by local area generation with the existing transmission system import limit; and
- Phoenix load supplied by local area generation without the existing transmission import system limit.

The difference between the production costs from these two cases shows the RMR cost of the transmission constraint.

These two cases were simulated with a detailed regional production-costing model that includes the generation and transmission system of the entire WECC. The model dispatches all generators on an economic basis to meet the overall WECC system load within constraints for control area reserve requirements and transmission limitations. The model also determines sales of economic generation to, and economic purchases from, other utilities in the region subject to regional transmission constraints. The accuracy of the RMR costs depends upon accuracy of the forecasts for load, generation heat rates and forced outage rates, fuel costs, and other costs. Because these costs are not easy to predict, Staff recommends that for the 2008 RMR Study, production cost analysis be conducted assuming low and high fuel cost scenarios, as well as a variation of the other cost components.

Based on the results of the 2006 Phoenix area RMR economic analysis as summarized in Table 8 below, Staff concludes that RMR costs will have a negligible impact on Arizona ratepayers in the 2006-2015 timeframe:

Table 8: Phoenix area RMR conditions and costs

Year	SIL[1] (MW)	Peak demand (MW)	Max RMR[2] (MW)	RMR[3] Hours	RMR energy[4] (GWh)	RMR energy (% of total)	RMR cost[5] ($M)
2008	9,700	12,625	2,853	845	650	1.1	0.0
2015	13,004	16,100	2,811	548	419	0.6	0.0

Table Key:

[1] SIL – System Simultaneous Import Limit is the maximum amount of capacity that can be reliably imported into the area with no local generation operating.

[2] Max RMR – The amount of local generation required to meet the area peak demand (Peak Demand minus Import Capability).

[3] RMR Hours – The number of hours that the area's demand exceeds the SIL, thus requiring the use of local generation to meet load, even if otherwise economically dispatched.

[4] RMR Energy – The annual energy that must be met by local generation (in excess of the SIL).

[5] RMR Cost – The difference in annual generation cost with and without the transmission limitation.

In the 3rd BTA, Staff recommended that APS (and others required to perform the 2006 RMR Studies) make available to the Staff the list of the actual generation unit data used in the model and generation units energy production calculated by the model. The Phoenix area generation summary from the 2006 RMR report is shown in Table 9.

Table 9: Phoenix Area Generation in 2006 RMR Study

Owner	Plant	Type	Summer capability	Minimum load	Minimum up time	Minimum down time	FOR	EFOR	Fuel type
APS	Ocotillo 1	ST	110	20	8	8	4%	6%	NG
APS	Ocotillo 2	ST	110	20	8	8	4%	6%	NG
APS	Ocotillo GT1	GT	55	4	2	1	10%	12%	NG
APS	Ocotillo GT2	GT	55	4	2	1	10%	12%	NG
APS	West Phoenix GT1	GT	55	4	2	1	10%	12%	NG
APS	West Phoenix GT2	GT	55	4	2	1	10%	12%	NG
APS	West Phoenix CC1	CC	85	20	8	6	3.5%	7%	NG
APS	West Phoenix CC2	CC	85	20	8	6	3.5%	7%	NG
APS	West Phoenix CC3	CC	85	55	8	6	3.5%	7%	NG
APS	West Phoenix CC4	CC	110	77	8	3	5%	7%	NG
APS	West Phoenix CC5	CC	525	160	8	6	8%	10%	NG
SRP	Aqua Fria 1	ST	113	57	8	8	4%	6%	NG
SRP	Aqua Fria 2	ST	113	57	8	8	4%	6%	NG
SRP	Aqua Fria 3	ST	181	92	8	8	4%	6%	NG
SRP	Aqua Fria 4	GT	73	35	1	8	10%	12%	NG
SRP	Aqua Fria 5	GT	73	32	1	8	10%	12%	NG
SRP	Aqua Fria 6	GT	73	32	1	8	10%	12%	NG
SRP	Crosscut Hydro1	HY	3	N/A	N/A	N/A	0%	0%	WAT
SRP	Kyrene 1	ST	34	14	8	8	4%	6%	NG
SRP	Kyrene 2	ST	72	29	8	8	4%	6%	NG
SRP	Kyrene GT4	GT	59	25	1	8	10%	12%	NG
SRP	Kyrene GT5	GT	53	24	1	8	10%	12%	NG
SRP	Kyrene GT6	GT	53	24	1	8	10%	12%	NG
SRP	Kyrene CC1	CC	250	161	4	4	8%	8%	NG
SRP	Santan 1	CC	92	35	3	8	3.5%	7%	NG
SRP	Santan 2	CC	92	35	3	8	3.5%	7%	NG
SRP	Santan 3	CC	92	36	3	8	3.5%	7%	NG
SRP	Santan 4	CC	92	35	3	8	3.5%	7%	NG
SRP	Santan 5	CC	550	330	4	4	8%	8%	NG
SRP	Santan 6	CC	275	165	6	4	8%	8%	NG
SRP	South Consolidated 1	HY	1						WAT
SRP	Transport GT1	GT	4						NG
Phoenix Total			**3,674**						

The general data used in the production cost model is shown in Table 10.[1]

Table 10: Generating unit operational characteristics

(Average values – AZ-NM-S. NV)

Fuel Type	Technology	Size MW	Install Date	Heat Rate Btu/kWh	VOM $/MWH	EFOR%
Gas/Oil	Steam			12,000	2.0	6%
Gas	SC	<100	Pre 2000	14,000	4.1	10%
Gas	SC	>100	Post 2000	10,500	4.1	5%
Gas	CC	<100	Pre 2000	8,700	2.0	5%
Gas	CC	500	Post 2000	7,000	3.0	5%
Coal	Steam	<500		11,200	1.4	7%
Coal	Steam	>500		10,000	1.4	9%

RMR cost analysis as well as Phoenix area Air Emission Reductions analysis show that removal of the transmission constraints could provide only negligible impact. Consequently, there are no alternatives proposed for reinforcing the Phoenix area transmission system to increase the transmission import limit other than the projects already planned.

6.2.1.3 Phoenix 2006 RMR Study Findings

The Phoenix area 2006 RMR study findings:

- All planned transmission expansion and available generation is needed to reliably serve Phoenix area peak loads in the 2006-2015 timeframe.
- Phoenix area load is expected to exceed import capability for less than 900 hrs/yr in 2008 and less than 600 hrs/yr in 2015. RMR energy represents approximately 1% of the total energy.
- Estimated cost to run local generation outside of economic dispatch is negligible and does not justify any advancement of the proposed Phoenix area construction projects to relieve RMR.
- Removing the transmission constraint would reduce emissions in the Phoenix area by a minimal amount in 2008 and 2015.

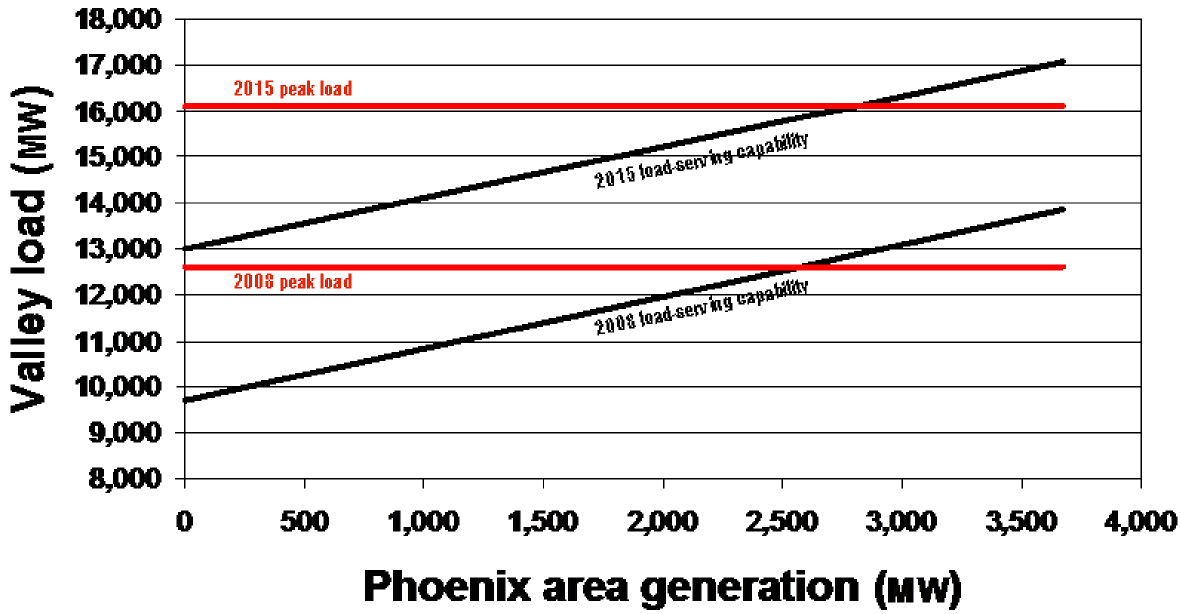
6.2.1.4 Staff observation

This section provides Staff's observations of the SIL and RMR components for the Phoenix Area. The Phoenix valley load and load-serving capabilities are shown in Figure 24. Staff accepts the conclusions of the report as summarized above, and concludes that based on the study results reported for the two years examined (2008 and 2015), RMR costs and emission impacts should

[1] APS 2004 RMR Study, Appendix A, Page 1

be negligible throughout the 2006-2015 period. Furthermore, based on the 2006 study results, there is no longer a concern about a resource margin deficiency in 2012 as raised in the 2004 BTA.

Figure 24: Phoenix area load serving capability



Staff concludes that the SIL and MLSC increases are attributable to the planned transmission improvements described in the 2006 BTA filings by APS and SRP. (See Appendix E and Appendix F.)

6.2.2 Yuma area RMR conditions and import assessment

6.2.2.1 Yuma existing and future transmission system

The Yuma area is served from three transmission sources:

- The first is the APS' North Gila 500/69 kV substation, which is located east of Yuma.
- The second is WAPA's Gila 161/69 kV station, which is also located east of Yuma.
- The third is APS' Yucca 161/69 kV station, which is located on the west side of Yuma near the Colorado River. APS' local generation is located at this station, along with an interconnection to IID's 161 kV system through two 161/69 kV

transformers. The IID 75 MW steam-generating unit is also located at this substation.

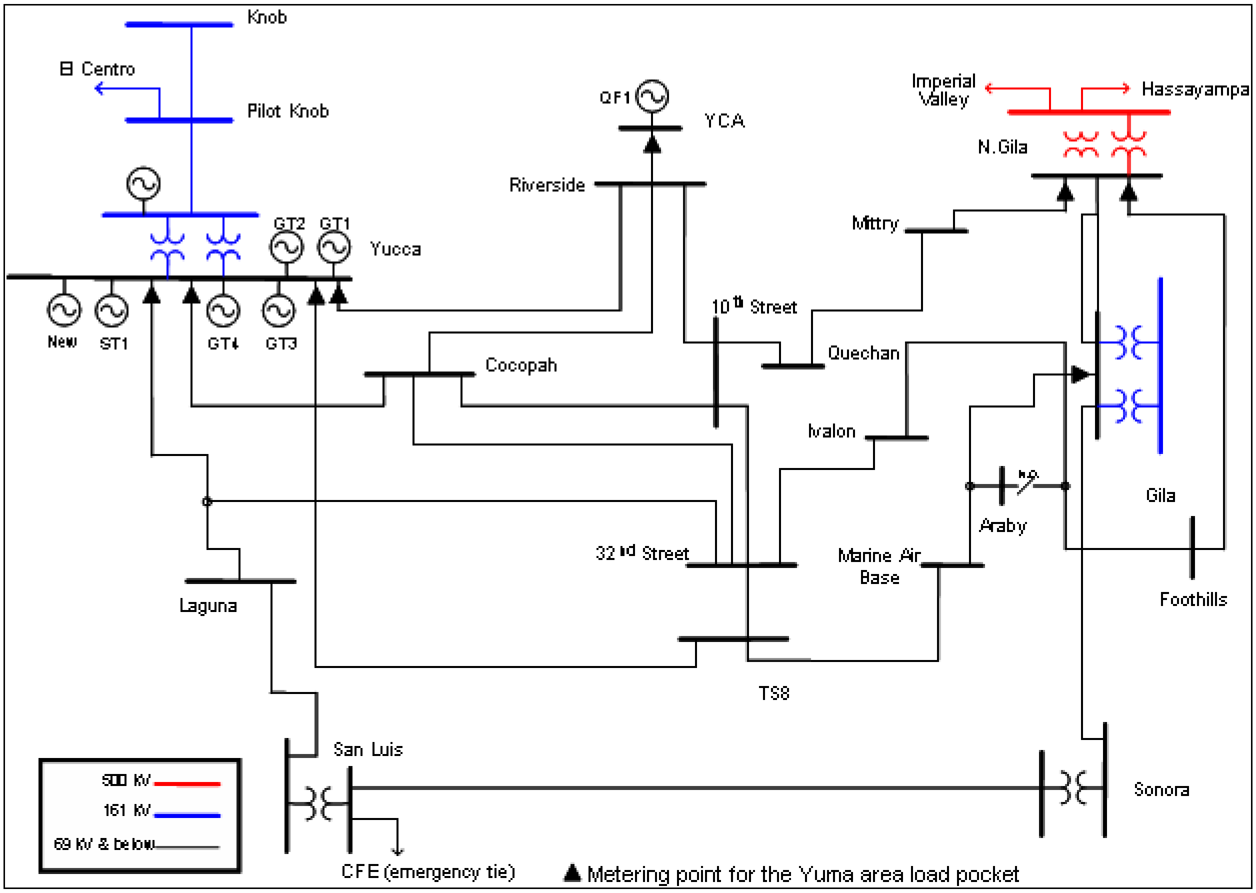
In its 2006 RMR Study, APS reported that load flow and voltage stability analysis were done to determine Yuma-area critical outages as required by transmission planning criteria. APS conducts contingency analysis based on single contingency (n-1) criteria.

Recent and planned additions in the Yuma area included in the 2008 RMR analysis were as follows:

- A second North Gila 500/69-kV transformer was installed in 2005 as a result of the 2003 RMR study.
- The Welton-Mohawk interconnection facilities and generators, which are planned for 2006, were modeled in the 2008 case. The interconnection facilities will consist of a 161-kV line and a third 161/69-kV transformer to WAPA's Gila substation, along with a 161-kV line and 161/69-kV to APS' North Gila 69-kV substation.
- 100 MW of new APS owned generation at Yucca Substation.

The planned 2008 Yuma area system and interconnections are shown in Figure 25:

Figure 25: APS Yuma area in 2008

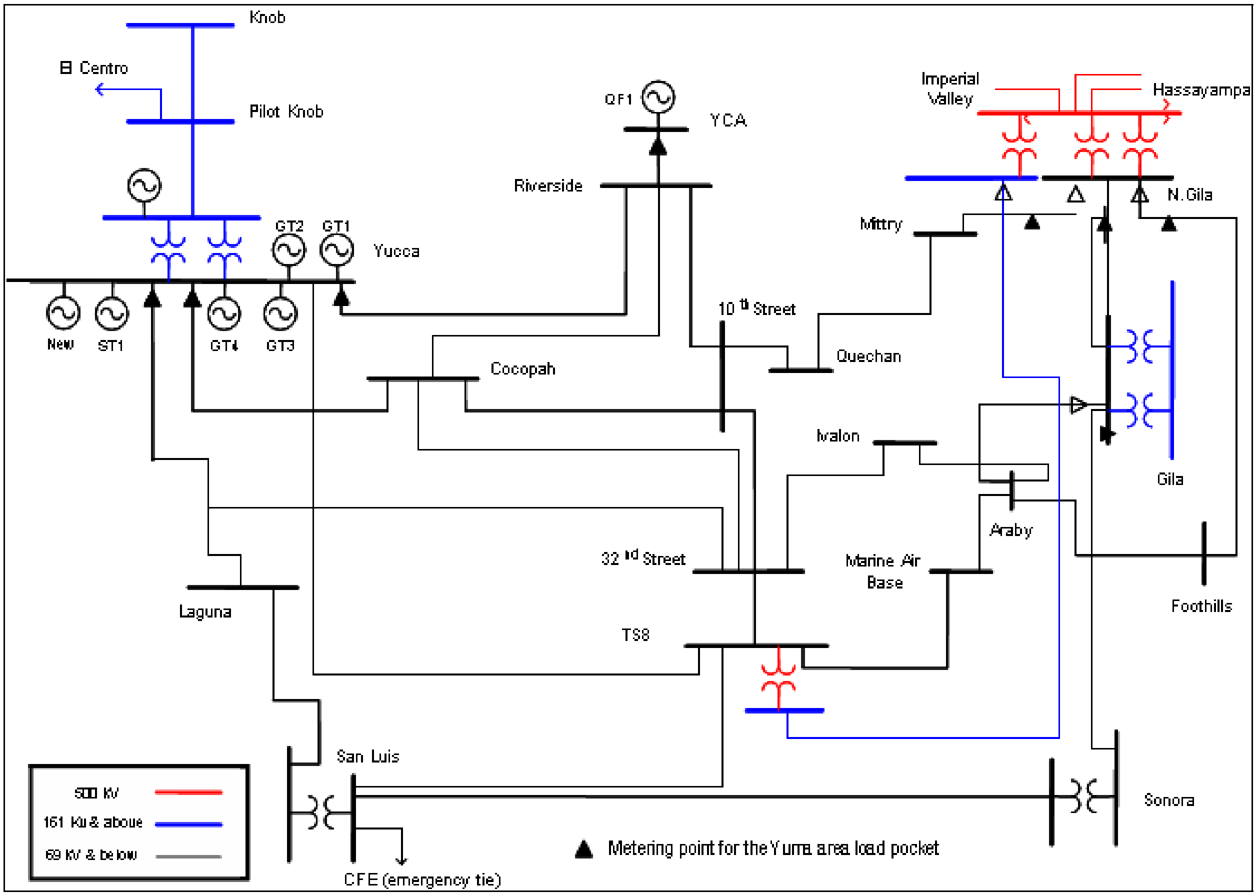


Planned additions in the Yuma area from 2008 to 2015 were modeled as follows:

- A North Gila 500/230kV transformer.
- A 230kV line from North Gila to a new TS8 230/69kV Substation in Yuma.
- A second 500kV line from the Palo Verde area to North Gila.

The resulting 2015 system and planned interconnections area shown in Figure 26.

Figure 26: APS Yuma area in 2015



6.2.2.2 Yuma area – SIL and RMR conditions for 2008 and 2015

With planned system additions for the Yuma area, along with some accelerated projects the SIL and MLSC for the Yuma area will increase enough to serve the rapidly growing load and maintain the desired generation reserves.

It should be noted that due to the calculation method used by APS, the MLSC does not equal the direct summation of SIL and Local Generation. APS determines the MLSC graphically by determining an operating nomogram for each year. The maximum amount of load that can be served is then determined from the highest point on the nomogram, which does not necessarily occur at the point of maximum local generation.

Several critical contingencies exist affecting the determination of the system import limit for the Yuma area in the 2008 through 2015 timeframe. For the 2008 period, the critical event is loss of the Hassayampa-N. Gila 500 kV line and the limiting element is the Pilot Knob-Yucca

161 kV line. In 2015, the critical outage is loss of the Cocopah-Riverside 69-kV line and the limiting element is the Riverside-10th Street 69kV line[1].

To determine the RMR costs for the Yuma area, an economic analysis was performed using a regional production–cost model, just as for Phoenix. The comments Staff provided in Section 6.2.1.2 are applicable to Yuma RMR cost calculation.

The analysis indicated that the Yuma import limit would be constraining for 336 hours in 2005, 2 hours in 2008, and zero hours in 2012. The energy associated with these hours amounts to 8 GWh. The cost of this constraint in 2005 is approximately $500,000.[2] APS found that it would be more economical to import cheaper power either from APS units outside the Yuma area or from the wholesale market.

The Yuma RMR cost analysis as well as the Yuma area Air Emission Reductions analysis shows that advancement of the transmission projects are not justified. Consequently, there are no alternatives proposed for reinforcement of the Yuma area transmission system in order to increase the transmission import limit other than projects already planed.

6.2.2.3 Yuma 2008 and 2015 RMR Study Findings

The Yuma area 2006 RMR study findings are as follows:

- All existing and planned Yuma area generation and transmission projects are needed to reliably serve the area.
- APS load is expected to exceed imports in 2008 by 1,703 hours. As a result of the second Palo Verde to North Gila 500kV line and other upgrades, this figure drops to 553 hours in 2015.
- Estimated annual cost to run local generation out of economic merit order is approximately $1.3 million in 2008, but due to the expansion plans from 2008 to 2015 these costs will be negligible in 2015.
- Removing the remaining transmission constraints would have a negligible impact on Yuma area air emissions in the 10 year plan period.

6.2.2.4 Staff observation

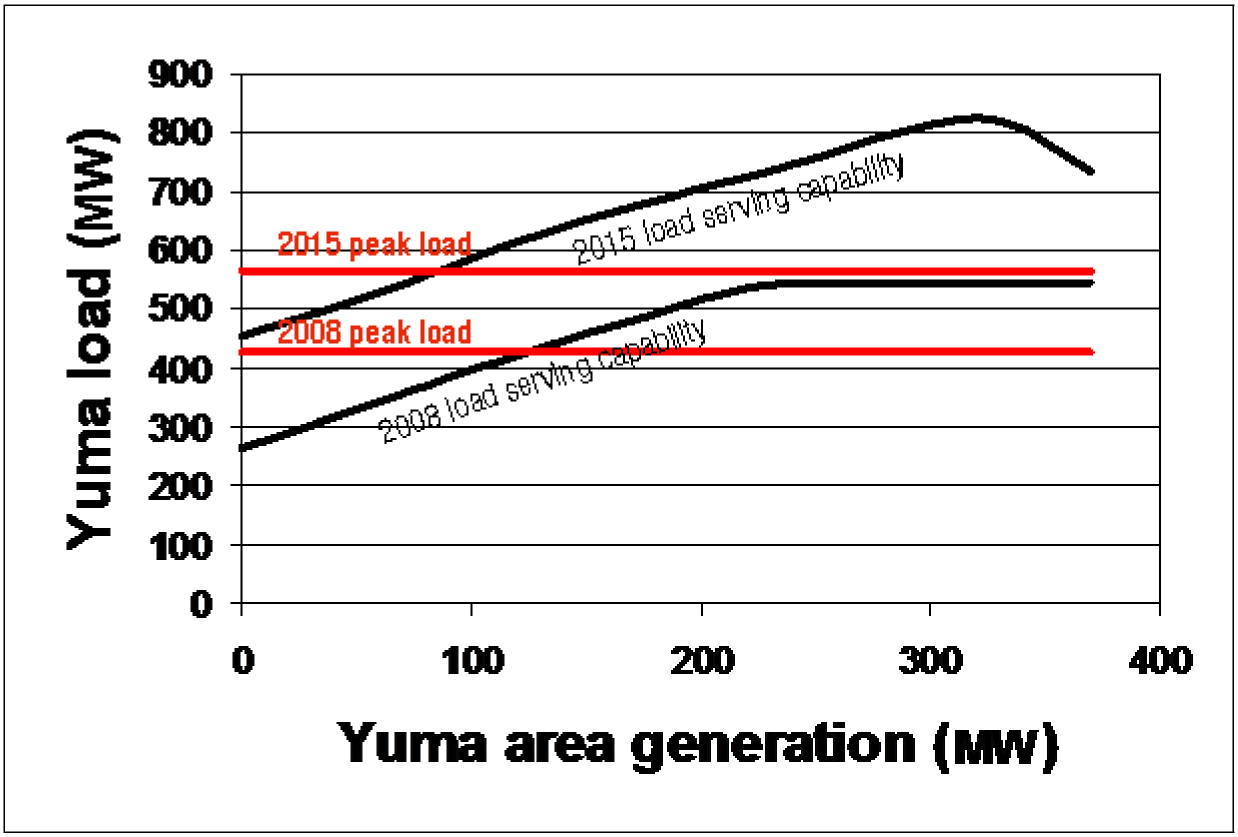
In this section, Staff provides its observations of the SIL and RMR components for the Yuma area. Addition of the second North Gila 500/69 kV transformer in 2005, the planned Yucca 100 MW generation addition and the proposed 500 kV Palo Verde-North Gila line appears to

[1] The description of the critical contingency for 2015 was revised in APS comments on the draft 4th BTA filed 9-1-06.

[2] APS 2004 RMR Study, Table 17, Page 49.

effectively manage RMR conditions in Yuma area.[1] With the planned additions, the future Yuma area load serving capability is shown in Figure 27. The crossover point of the MLSC line and the forecast load line determines the amount of RMR generation required at peak area load in the respective years of the graph. At load levels below the intersection of the MLSC line and the left axis RMR generation operation is no longer needed for reliability purposes, but may in fact still be dispatched economically on a merit order basis given the system mix of resources.

Figure 27: Yuma Area Load Serving Capability



6.2.3 Tucson area RMR conditions and import assessment

The Tucson area is located in a large valley surrounded by mountains and, until 1969, was served only by local generation. Now, imported power is transmitted from the Westwing substation in the northwest to the South substation in Tucson, and the Four Corners area and eastern Arizona power stations to both the Tortolita and the Vail substation in Tucson. TEP's 2006-2015 plan calls for increased access to resources from the Palo Verde area through the addition of new EHV tie points to TEP's system at either Pinal West or Pinal South substations.

[1] However, the RMR Study results may no longer be current given that the Welton-Mohawk interconnection facilities and generators described on page 100 are not occurring.

For single contingencies, the most economical combination of local generation and reactive devices is utilized to ensure that contingencies meet WECC/NERC reliability criteria. TEP also uses its own internal voltage criterion: 0.98 per unit post-outage 138 kV voltage. The TEP control area has historically been voltage-stability constrained. Local Var-responsive steam units and combustion turbines can be committed in the Tucson area to supply reactive support and to lower imports as necessary. In addition, TEP has an automated remedial action scheme (RAS) that responds to selected n-1 and n-2 contingencies with pre-determined switching of reactive devices and/or direct load tripping. Approximately 45% of TEP's load is available for tripping via this RAS. However, TEP does not have any planned load dropping for n-1 events.

TEP plans and operates its system to meet the WECC/NERC Reliability Criteria for level B (n-1), Level C (n-2; n-1-1), and Level D (n-2) contingencies, as well as the WECC Voltage Stability Criteria.

All base cases were co-developed by APS, SRP, TEP, WAPA, and SWTC. Planned system configuration changes for all these utilities were used to develop the various cases. Table 11 gives a description of the planned TEP projects.

Table 11: TEP area facility additions

	2005	2006	2008	2009	2012	Undetermined
		Pinal-West 345 kV substation § and interconnection to Westwing-South 345 kV line §	Rillito/LaCanada 138kV line upgraded from 340 MVA to 356 MVA	Irvington / South 138kV line upgraded from 309 MVA to 394 MVA	Tortolita – South 345 kV transmission line and associated 500/345 kV transformer at Tortolita (TBD)	Gateway 345kV substation connecting to Citizens/Unisource 115 kV system at Valencia via a 345/115 kV transformer
			North Loop /Rillito 138kV line upgraded from 287 MVA to 339 MVA §	Irvington / Vail #1 138kV line upgraded from 287 MVA to 356 MVA	Pinal West – Tortolita 500 kV line (TBD)	Two 345 kV transmission lines between TEP's South and Gateway substations
	Twenty-second / Irvington 138kV line upgraded from 331 MVA to 444 MVA (2005)			Irvington / Vail #2 138kV line upgraded from 287 MVA to 356 MVA		

6.2.3.1 Tucson Area – SIL and RMR Conditions for 2008 and 2015

All base cases used were co-developed by APS, SRP, TEP, WAPA, and SWTC. Planned system configuration changes for all these utilities were used to develop the various cases. RMR conditions are founded on the principle of continuity of service for single contingency transmission outages (n-1). TEP's 2006 filing states that both its 2008 and 2012 RMR cases are based on thermal constraints, rather than voltage constraints. Tucson-area critical RMR outage cases are shown in Table 12, below.

Table 12: TEP area critical RMR outage conditions

Year	Critical Outage	Nature of Constraint
2008	Saguaro-Tortolita 345kV (line #1 or #2)	Thermal (loss of either line overloads the other line)
2015	Winchester-Vail 345kV line	Thermal (loads Vail T2 at 100% of emergency rating)

The addition of the South T3 transformer eliminates the thermal constraint reported in the 2004 RMR study caused by loss of the South T2 transformer, which overloaded the 138 kV Irvington-Vail lines. The South T3 bank was determined to be the preferred solution, in place of the previous plan to upgrade the Irvington-Vail 138 kV lines.

As more IPPs continue to go in service, it is theoretically possible that TEP could import all power at peak and generate none locally, if sufficient 138 kV transmission line upgrades and sufficient Mvar availability could be made available either through SVC or synchronous condenser mode. TEP transmission import limit depends on local generation primarily because of the need for reactive power support. TEP plans to install a static var compensator in 2008 to address voltage stability and has also improved clearances on its critical sag limited lines to mitigate import constraints since the Third BTA. Although voltage stability limits still exist in the case without any local generation on line, if local generation is running the import limit reverts to a thermal constraint.

6.2.3.2 TEP area conclusions

- With TEP's recent installation of the South T3 transformer bank and other planned transmission projects shown in its 2006-2015 expansion plan filing, Tucson area RMR requirements can be met by the operation of Sundt Generating Units #3 and 4 in 2008, and Units #2-4 in 2015. TEP transmission import limits depend on local generation, primarily because of the need for reactive power support.
- TEP's expected RMR costs are under $1.5 million per year.

- TEP has not done long-term cost-benefit analysis for upgrades that might eliminate the RMR requirements, but based on the low RMR costs significant upgrades may not be cost justified.
- The analysis of air emissions provided subsequent to TEP's 2006 filing is as follows[1]:

Table 13: Assumptions used in air emission analyses

	Estimated SO_2	Estimated NOx	Estimated PM	Estimated CO
2008 RMR Environmental Output Sundt Steam Gas (lbs)	89	29,851	783	17,705,209
2015 RMR Environmental Output Sundt Steam Gas (lbs)	66	22,198	582	13,166,183

6.2.3.3 Staff observation

It is possible that, with incremental transmission improvements above those identified in TEP's 2006-2015 plan, the future Tucson area RMR requirements could be eliminated and the load area could have essentially unlimited access to lower cost resources from the outside market. However, it is unknown if such incremental upgrades are economically justified from the standpoint of customer rates. Staff recommends that TEP provide an economic analysis of this option in its 2008 BTA filings.

6.2.4 Mohave area RMR conditions and import assessment

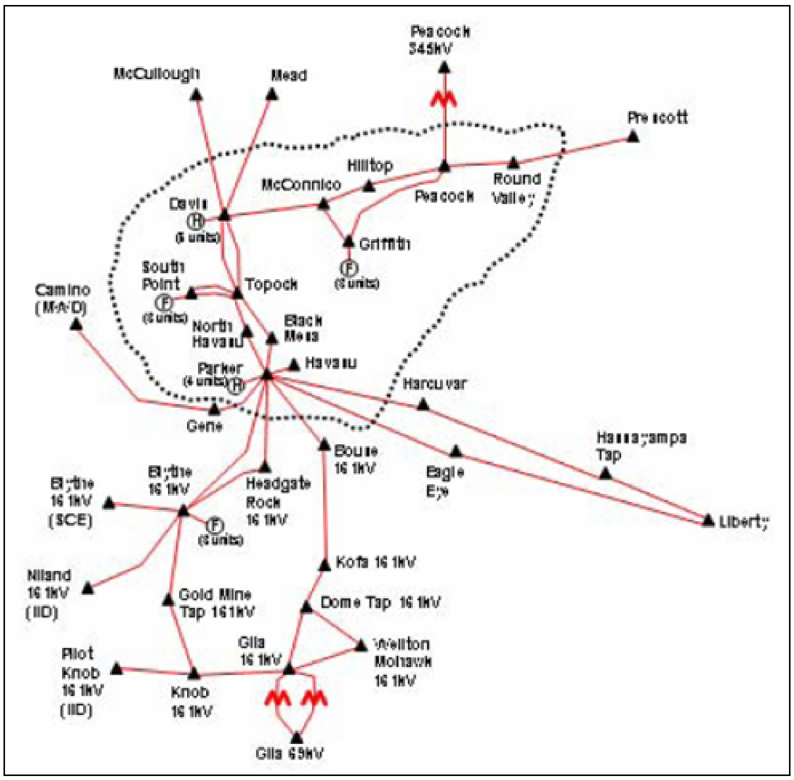
6.2.4.1 Mohave existing and future transmission system

The transmission system depicted in Figure 28, serves the cities of Kingman, Havasu, Bullhead, Mohave Indian Reservation, the City of Needles, California and the City of Parker and surrounding regions. Western's transmission serves the Mohave County area with inbound transmission, and Mohave Electric Cooperative, UniSource Energy Services, Aha MACV Power Service, City of Needles, and Arizona Public Service Company provide local transmission and distribution. Western's transmission systems provide import from Mead Substation in southern Nevada, Western's 345 kV transmission line from Liberty Substation to Peacock Substation, Western's Pinnacle Peak Substation to Peacock Substation to Davis Dam Substation, and two 230 kV lines from Liberty Substation to Parker Dam Substation.

[1] Data per email from TEP's Mary Tilford to TEP's Ed Beck dated 8-2-06.

While there would seem to be significant transmission into the area, the lines are also used to conduct energy through the area and beyond to south of Phoenix (Central and Southeastern Arizona) and to Yuma. The 2002 BTA reported that the paths into the area and beyond are contracted to their limits such that there is no additional transmission that can be contracted into the load pocket.

Figure 28: Study System for Mohave County



6.2.4.2 Mohave Area – SIL and RMR Conditions for 2005, 2008, and 2012

In response to a request from the Staff, in 2004 the Desert Southwest Region (DSW) of Western Area Power conducted a RMR Study of the transmission system in Mohave County for projected years 2005, 2008 and 2012. DSW owns and operates all the facilities of the transmission facilities that are used to import power into this load area. Distribution systems embedded on the DSW transmission network within the Study System include the following:

- Aha Macav;
- Arizona Public Service (APS);
- Central Arizona Water Conservation District (CAWCD);
- Mohave Electric Cooperative; and

- Unisource Energy Services (UES).

The SIL is limited by a WECC 5% post-transient voltage deviation at the Black Mesa 230 kV station. The MLSC is limited by a WECC 5% post-transient voltage deviation at the Black Mesa 230 kV station for the single contingency outage of the Parker-Black Mesa 230 kV line. In its filing for the 4th BTA, UES proposes to construct one new project in this area, a double circuit 230/69 kV line from Griffith Substation to North Havasu Substation. Both substations are internal to the Mohave County load area so it is unlikely they will affect the SIL for the area. However, this should be verified by further study in conjunction with Western. The stated purpose of the line is to reinforce the local system and provide a direct connection between two currently disconnected UES load centers in Mohave County.

6.2.4.3 Staff observation

According to the 2004 RMR study, Mohave should not be considered a transmission import constrained area through at least 2012. Other than contractual issues, the 2004 study concluded there is no technical limitation to importing outside generation in this timeframe. However, the situation beyond 2012 is unclear because the RMR study was not updated in 2006. For example, if peak demand in the load pocket grows by more than 3% per year from 2012 to 2015 it appears that demand will exceed the "contractually constrained" SIL of 647 MW triggering an RMR requirement. Given these uncertainties, Staff concludes that the adequacy of the Mohave supply system beyond 2012 is uncertain and should be addressed in detail in the 2008 BTA. This study should clarify the scheduling rights of each of the parties serving customers in the Mohave County load area versus the contractual SIL and provide options to mitigate this scheduling constraint.

6.2.4.4 Santa Cruz County RMR conditions and import assessment

At the present time the load in the Santa Cruz County area, Nogales in particular, is served by a single 115 kV line operated by UNS Electric. UNS Electric has generation located in the Nogales area that it runs on an emergency basis. When the single 115 kV line is out of service the local generation is used to pickup the load. During storm seasons, the local generation is started, but not brought on line until after a power outage occurs. The County is susceptible to transmission outages of a prolonged nature, and the Commission ordered[1] the construction of a second transmission line, known as the Gateway Project. The UNS Electric long-term plan to improve reliability for the Santa Cruz service territory is to construct that redundant transmission line from the new Gateway 345/115 kV substation (located about 3 miles from the Valencia substation near Nogales) to the Valencia substation.

[1] ACC Decision No. 62011, November 2, 1999

The second transmission line has been sited and approved by the state Power Plant and Line Siting Committee and the Commission. It is, at the present, going through the final stages of its environmental impact statement with the federal approval process. The Staff's estimate is that the project, when approved, will likely need three years to be placed in service.

6.2.4.5 Santa Cruz County – SIL and RMR conditions

TEP last completed the RMR study work for UNS Electric relative to the Santa Cruz County area in 2004, and did not update that study in 2006. The local peak load for Santa Cruz County grows from 63.6 megawatts in 2005 to 79.2 megawatts in 2012. The system import limit is 50 megawatts until 2012, at which time their studies assumed there were two lines supplying the area.

6.2.4.6 Santa Cruz County 2004 RMR study findings

The RMR peak load demands are 13 MW and 20 MW in the first two study years, and there are no RMR requirements in 2012. This is based on the assumption that the additional transmission line has been built by that time period.

6.2.4.7 Staff observation

With the second transmission line in service, the 3rd BTA concluded that a RMR condition is expected to exist in Santa Cruz County by the summer of 2008. Specifically, the RMR operation of the Valencia units will be required by the summer of 2008. Furthermore, the RMR operation of the Valencia units will become inadequate when the Santa Cruz County load reaches approximately 75 MW. The 75 MW load level is projected by the summer of 2010.

Until the second 115 kV line is constructed, UNS Electric and TEP will implement the approved "Outage Response Plan"[1]. Staff believes that the Outage Response Plan is sufficient to improve the restoration of service following a transmission line outage for Santa Cruz County customers of UNS Electric, but cannot assure continuity of service for outage of a transmission line.

In conclusion, since the 3rd BTA concluded that an RMR constraint may develop in Santa Cruz County by 2008 and no update to this forecast has been filed during the 4th BTA, Staff recommends that the Commission require UNS to file a detailed update of this RMR analysis with the Commission by January 2008.

[1] ACC Docket No. E-01032A-99-0401, TEP an UES " Supplemental Response to Commission Questions and Updated Outage Response Plan for Santa Cruz County", April 30, 2004

6.2.5 Overall Staff observations and recommendations on RMR

Staff raised a concern during the 3rd BTA regarding the available resource margin in the greater Phoenix load area for the 2012 timeframe. Based on revised expansion plans identified in filings by APS and SRP in the 4th BTA, Staff concludes that the resource margin in the Phoenix area should be adequate throughout the 2006-2015 timeframe. As a result of its 2006 RMR study for the Yuma area, APS has initiated a solicitation for 100 MW of new generation to be installed at the Yucca plant site by 2008. Based on the results of the 2006 Phoenix area and Yuma area RMR analyses, Staff concludes that these RMR costs will have a negligible impact on rates in the 2006-2015 timeframe. However, this does not take into account costs associated with the new generation solicitation that APS is conducting for the Yuma area, which is the subject of a separate proceeding before the Commission.

TEP projects an RMR requirement in the Tucson area of 160 MW in 2008 growing to 300 MW in 2015. They estimate the costs to dispatch these units (i.e., incremental costs above merit order dispatch) will be $1.37 million in 2008 and $1.02 million in 2015[1].

Although no RMR analysis was filed in the 4th BTA for Mohave County, participants are of the opinion that the Western Area Power Administration transmission system supplying Mohave County should be sufficient to meet the area's requirements. However, Staff concludes that the adequacy of the Mohave supply system beyond 2012 is uncertain due to contractual constraints and this issue should be addressed in detail in the 2008 BTA. The 2008 study should also determine if the proposed UES Griffith-North Havasu 230/69kV line will impact Mohave County import capability.

In the 2008 BTA, Arizona utilities should clarify how they intend to define future RMR boundaries given projected load growth and facility expansion in the greater Phoenix area as well as Pinal County to the south.

Staff observes that parties in the 4th BTA have referred to SIL in terms of both technical and contractual limits. The correlation between these two dimensions of SIL is unclear. For the next round of RMR studies due in January 2008 the parties should include a comparison of the technical SIL value against projected transmission ownership/scheduling rights into each constrained load area in Arizona during the 2008-2009 period.

Staff also observes that the calculation of MLSC and reserve margin values in the 2006 RMR studies is not transparent. In the 2008 RMR study, the parties should agree on a consistent and transparent methodology for computing the load serving capability/resource reserve margin values.

[1] Reflects revised data per TEP email from Mary Tilford to Ed Beck dated 8-2-06.

7. Future generation

7.1 2003 and 2004 generation interconnection requests

The FERC generation interconnection rule requests that each transmission provider post the generation interconnection queue on its OASIS website. Accordingly, the Arizona utilities are posting generation interconnection requests at their OASIS websites. The current queues are summarized below:

Table 14: Large Generators in Interconnection Queues[1]

Company	Maximum interconnect capacity (MW)	Location	Interconnection point	Projected in-service date	Type of facility
APS	700 (Unit 1)	San Juan County, NM	Four Corners 500kV Switchyard	1/10/2008	Coal
	700 (Unit 2)	San Juan County, NM	Four Corners 500kV Switchyard	4/1/2009	Coal
	60	Cococino County, AZ	Cholla-Cococino 69kV Line	12/31/2008	Wind
	128	Cococino County, AZ	Cholla-Zeniff-Show Low Western 69kV Line	12/31/2007	Wind
	22	Cococino County, AZ	Cholla-Zeniff-Show Low Western 69kV line	6/1/2007	Biomass
	99	Yuma County, AZ	Near MCAS 69kV Substation	4/1/2008	Gas Engine Generators
	100	Yuma County, AZ	Yucca 69kV Substation	6/1/2007	Combustion Turbine
	252 (net increase over existing interconnect capacity at site)	Maricopa County, AZ	Gila River 500kV Switchyard	Undocumented	Combined Cycle
	270	Cococino County, AZ	Seligman 230kV Switchyard	5/2/2008	Wind
	600	Navajo County, AZ	Chollas Power Plant Switchyard	5/1/2014	Coal (Unit 5)
	600	Navajo County, AZ	Chollas Power Plant Switchyard	5/1/2015	Coal (Unit 6)
SRP	None in queue				
TEP	15	Kingman, AZ	Dolan Springs Substation	Undocumented	Wind
	95	St. Johns, AZ	Co Spr	12/31/2007	Undocumented
	20	Nogales, AZ	Valencia Power Plant Switchyard	Undocumented	Undocumented

[1] The queues can be found in: www.oatioasis.com/AZPS/AZPSdocs/LGIP_Queue.pdf and www.oatioasis.com/TEPC/TEPCdocs/Inter_Requests.pdf

7.2 Impacts of renewable energy sources on the transmission network

The BTA does not specifically address the implementation of renewable energy resources. This information is included in the studies as projected resources to match projected loads and to be consistent with the resources requirements of the Environmental Portfolio Standards (EPS), and the recently approved Renewable Energy Standard and Tariff (REST) rules. While this is consistent with the requirements of the BTA, it could be useful to include a summary in future BTAs of the location of the resources, amounts included in the studies, and any specific transmission used to enable them, to the extent such information is known and is not confidential.

In Europe, substantial wind penetration exists today and is likely to increase over time. The impacts on the transmission network are viewed not as an obstacle to development, but rather as "speed bumps" that must be addressed.

Issues related to integrating larger amounts of renewable resources into utility plans have received increasing interest during the past few years. As an example a 2006 report to the Western Governors' Association made three transmission-related recommendations regarding incorporating renewable energy resources:[1]

1. "Ensure that targeted energy efficiency, central heating and power, and other demand-side resources are incorporated into state transmission planning.
2. "Ensure that utility interconnection policies best facilitate the use of a wide range of clean energy resources.
3. "Urge utilities to assess available transmission capacity and opportunities to make better use of the existing transmission systems."[2]

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[1] *Clean Energy, a Strong Economy and a Healthy Environment*, a report of the Clean and Diversified Energy Advisory Committee to the Western Governors Association, 11 June 2006.

[2] *ibid*, page 4.

8. Study of n-1-1 and extreme contingencies

The Commission directed that as part of the 4th BTA parties address and document:

1. Compliance with single contingency events overlapping bulk power system maintenance outages (n-1-1) criteria for the first year of the BTA study period, consistent with WECC and NERC requirements.
2. Extreme contingency outage studies for Arizona's major generation hubs and major transmission stations, and associated risks and consequences, if mitigating infrastructure improvements are not planned.

APS, SRP and TEP filed n-1-1 studies of planned pre-summer 2006 maintenance conditions with the Commission in the first quarter 2006, pursuant to Protective Agreements.

TEP included selected overlapping and extreme contingency analysis for the Tucson area in its Ten Year Plan filing dated February 2, 2006. In addition, APS and TEP made presentations on overlapping and extreme contingency analysis at Workshop I of the 4th BTA held at the Commission on June 6, 2006. SRP service area results were included in the APS analysis. The extreme contingency cases are intended to address the consequence of two categories of events, specifically (1) common corridor line outages (n-2), and (2) concurrent transformer outages (n-2) at major EHV substations. The February 2, 2006 and June 6, 2006 reports were released as non-protected, public information; the results are summarized in Table 15 and Table 16.

Table 15: Overlapping contingency results

Company	Area(s) studied	Year(s) studied	Conditions studied	Results	Action plan (if applicable)
APS	Phoenix area (including SRP load)	Fall 2005 through Spring 2006	n-1-1 with Westwing Transformer #4 out of service	Maximum load serving capability exceeded the APS/SRP Phoenix Valley Load Forecast	Not needed
		Spring 2006	West Phoenix-Lincoln St 230kV out of service	Maximum load serving capability exceeded the APS/SRP Phoenix Valley Load Forecast	Not needed
TEP	TEP service area	2006 peak load	All EHV n-2 contingencies (TEP studied n-2 events in lieu of less severe n-1-1 events)	All cases met voltage criteria, but some overloads observed as noted below:	
			Winchester-Vail 345kV & Vail 345/138kV bank	SWTC Bicknell 345/230kV transformer overload	Not needed. Both TEP & SWTC can survive a trip of the Bicknell bank
			Saguaro-Tortolita 500kV & Tortolita 500/138kV bank	Avra-Marana and Avra-Sandario 115kV lines overload	Open either line to relieve the overload
			PYoung-Winchester 345kV & PYoung-Copper Verde 345kV	Green-SW 345/230kV transformer overload	Bank is included in Phelps-Dodge load-shedding scheme
			Springerville-PYoung 345kV & Springerville-Luna 345kV	Several 115kV line overloads in New Mexico	This has been referred to the appropriate utilities in New Mexico

Table 16: Extreme contingency results

Company	Area(s) studied	Year(s) studied	Conditions studied	Results	Action plan (if applicable)
APS	Phoenix area (including SRP loads)	2006 & 2016 (summer peak)	Cholla-Saguaro & Coronado-Silverking 500kV corridor outage	All load served and reserve requirements met.	Redispatch generation if needed
			Navajo South 500kV corridor outage	All load served and reserve requirements met.	Redispatch generation if needed
			Four Corners-Cholla-Pinnacle Peak 345kV corridor	All load served and reserve requirements met.	Redispatch generation, reconfigure system or shed up to 200 MW of load.
			Glen Canyon-Flagstaff-Pinnacle Peak 345kV corridor	All load served and reserve requirements met.	Redispatch generation, reconfigure system or shed up to 200 MW of load.
			Loss of all Kyrene 500/230kV banks	All load served and reserve requirements met.	Redispatch generation if needed
			Loss of all Browning 500/230kV banks	All load served and reserve requirements met.	Redispatch generation if needed
TEP	Tucson area	2008 (summer peak)	Loss of all Tortolita 500/138kV banks	No problems reported	
			Loss of all Vail 345/138kV banks	Shiprock transformer overload	This has been referred to WAPA
			Loss of all South 345/138kV banks	No problems reported	

Outage of the Palo Verde East corridor was not studied because there is no forestation. Westwing 500/230 kV multiple bank outage was not studied because they have additional spacing, fire walls, fire suppression and oil retention pits. Rudd 500/230 kV multiple bank outage was not studied because it is equivalent to loss of the Palo Verde-Rudd 500 kV line. Pinnacle Peak 345/230 kV multiple transformer bank outage was not studied because it is equivalent to outages of the 345 kV common corridor lines into the substation.

Staff concludes that these cases adequately address the key extreme contingencies of interest, but TEP should continue its review of the specific items as noted in the tables above and inform the Staff of their conclusions. It should be noted that the TEP n-2 line outages included in Table 15 are also extreme contingency events.

9. Conclusions

Staff offers the following conclusions for Commission consideration:

1. The electric industry in Arizona has been very responsive to concerns raised in Staff's Third BTA. In particular, the industry has performed studies and advanced projects that address Palo Verde Hub reliability issues, Palo Verde's transmission system capability to handle full generation output, and RMR concerns in the Phoenix and Yuma load areas.

2. The efforts of transmission providers and other stakeholders in the BTA continue to result in an improved work product and more collaborative study processes. Extensive regional studies addressing transmission needs have been conducted in a proactive and collaborative manner. This has also led to numerous jointly sponsored projects and synergies that increase the value of transmission projects to Arizona. The jointly sponsored projects in this 10-year plan are shown in Table 17.

Table 17: Jointly sponsored projects in this 10-year plan

Project	Voltage (kV)	Year in-service (est.)	Participants
Palo Verde-TS5 line	500	2009	APS, SRP & CAWCD
TS5-Raceway	500	2012	APS, SRP & CAWCD
Loop-in Navajo-Westwing at Raceway	500	2010	APS, SRP & CAWCD
Raceway-Pinnacle Peak	500	2010	APS, SRP
Hassayampa-Pinal West	500	2008	SRP, TEP, SWTC, ED2, ED3, and ED4.
Pinal West-Southeast Valley/Browning	500/230	2007-2011	SRP, TEP, SWTC, ED2, ED3, and ED4.
Desert Basin-Pinal South/Santa Rosa	230	2011	SRP, et al
Palo Verde-North Gila #2	500	2012	APS, SRP, IID & WELTON MOHAWK

3. Numerous new transmission and generation projects have been constructed, announced and filed with the Commission since the prior BTAs. Some transmission projects filed in prior BTAs have been cancelled, delayed or advanced based on changes in load, generation and import conditions. Staff finds these changes acceptable.

4. While there have been laudable efforts by stakeholders in support of coordinated regional planning activities, Staff recognizes that not all

transmission projects are regional in nature. In fact many smaller projects which are essential to serve local load areas or generators, by their very nature, do not require the participation of other stakeholders.

5. Transmission providers have performed updated RMR studies for each local transmission import constrained area (except Santa Cruz County and Mohave County) and have addressed the Third BTA RMR requirements. Uncertainty exists regarding RMR requirements in Santa Cruz County beginning 2008 and Mohave County beginning 2012, which should be addressed in filings due January 2008 for the 5th BTA.

6. In general, the existing and proposed Arizona transmission system meets the load serving requirements of the state in a reliable manner:

   a. Many planned Extra High Voltage (EHV) and High Voltage (HV) projects will increase transmission system capability to support increased interstate power transfers and provide reliable transfers within the state of Arizona.

   b. The EHV system appears to be adequate throughout the study period and the planned facilities identified in the ten-year planning process appear to be consistent with good utility practice. As is often the case, plans for the later years of the period are less well defined than those in the early years. As requested in the Third BTA, this new round of reports includes more discussion of alternate additions considered for the final five years of the study period. Given the number of alternative projects identified in the longer range plans it should be possible to supply future Arizona electric system loads in an economical and reliable fashion. Early identification of such alternatives in the BTA process allows the Staff and public to be better informed regarding future possibilities and should continue in future filings.

   c. The RMR studies show that the RMR areas will have load-serving capacity sufficient to provide reliable supply during the next ten-year period (with the exceptions noted in Conclusion 5.) Problems identified during the Third BTA in the Yuma area in 2004 and the Phoenix area in 2013 are addressed and resolved in the 2006 RMR study.

   d. For the Phoenix and Yuma areas, based upon the study results reported for the two years examined (2008 and 2015), Staff concludes that the RMR costs and emission impacts should be negligible throughout the 2006-2015 period. For the Phoenix metropolitan area, Staff concludes the SIL and MLSC increases are attributable to the transmission improvements described in the 2006 BTA filings by APS and SRP. Installation of a second North Gila 500/69 kV transformer in 2005, along with the proposed Yucca 100 MW generation addition and second 500 kV Palo Verde-North Gila line appear to effectively meet RMR requirements in the Yuma area.[1] It is possible that Tucson area RMR requirements could be eliminated and the load area could have unlimited access to lower cost resources from the outside market if incremental upgrades are economically justified. Staff requests that TEP provide an economic analysis of this option in its 2008 BTA filing.

e. The planned Arizona transmission system meets the WECC and NERC single contingency criteria (n-1). Satisfactory performance of the system has also been demonstrated during the Fourth BTA for significant overlapping contingencies (n-1-1 and n-2) as requested in the Third BTA.

f. Arizona transmission providers are doing an effective job of planning transmission upgrades and additions that improve access to capacity from merchant plants at Palo Verde in a reliable manner, which in the past has been stranded to some extent when the market has desired access. Some improvement has already been achieved in 2006 and significant improvement is expected with the addition of the Hassayampa-Pinal West-Santa Rosa 500 kV and Palo Verde-TS5 500 kV line additions in 2008 and 2009, respectively. In conjunction with other proposed transmission upgrades, these projects should significantly mitigate market limitations between Arizona, California and southern Nevada.

g. The Fourth BTA also concludes that after the addition of Hassayampa-Pinal West-Santa Rosa 500 kV and Palo Verde-TS5 500 kV lines the need for load shedding in Arizona following a common corridor outage of 500 kV lines leaving the Palo Verde Hub will be eliminated.

7. Studies investigating transmission expansion options between Arizona, southern Nevada and New Mexico continue to explore the scope, participation and timing of alternative projects. Other transmission expansion projects proposed in Nevada may bring additional resources closer to the borders of Arizona. APS has also initiated regional

[1] It should be noted that APS's Yucca generation solicitation is the subject of a separate proceeding before the Commission.

stakeholder discussions for a conceptual TransWest Express 500kV Project that could significantly increase import capability into Arizona from future coal and wind resources in Wyoming. Such regional projects may provide both economic and reliability benefits to Arizona consumers and increase import/export capabilities between Arizona and surrounding markets. Staff welcomes such proposals which could bring significant benefits to Arizona in the 2006-2015 timeframe or beyond.

8. Some new power plants have interconnected to Arizona's bulk transmission system via a single transmission line or tie rather than using Arizona's best engineering practices of multiple lines emanating from power plants. As interconnection of new transmission lines are considered for the Palo Verde Hub, the concerned parties should be encouraged to terminate at these new power plant switchyards in order to mitigate this regional reliability concern.

9. The SWAT-CATS-EHV study participants conducted a joint 2015 "Tenth Year Snap-Shot (N-1) Study" for Central Arizona to assess the collective impact of individual transmission owner plans for the area. The study determined that there are no n-1 violations in the planned EHV system. Some problems were identified in lower voltage systems, however. These will need to be addressed in the respective planning processes of the individual transmission owners. Certain n-1 contingency violations occurring in the SWTC 2015 planning study and certain n-2 and extreme contingency results in TEP's 2016 case still need to be resolved. These issues occur at or beyond the last year of the current 10-year plan and there is still sufficient time to satisfactorily resolve these concerns.

10. The Commission Staff concludes that the direction of collaborative planning processes by transmission providers and stakeholders in Arizona is consistent with the spirit of the requirements for transmission planning described in EPAct-05 and FERC Order 888. This collaborative planning processes is reinforced by the recent decision of the WECC to form a Transmission Expansion Planning Policy Committee to provide a transparent West-wide stakeholder process for related data and studies.

11. Regarding the CATS-HV interim study; since the rate of population and load growth in the area of study could be quite rapid, revisiting the study every 3-5 years would be preferable to the 5-10 year cycle suggested in the report.

12. Based on the 2006 RMR study results Staff recommends that:

- Arizona utilities should continue performing RMR studies for all transmission import constrained local areas:
    - Utilizing a collaborative study forum;
    - Improving economic analysis of RMR mitigation;
    - Clarifying projected system peak load and supply conditions in Mohave County beyond 2012 and appropriate mitigation measures, if any;
    - Clarify anticipated generation retirements in each constrained load area and the impact of such retirements on the RMR requirements.

- RMR 10-year study results are to be filed with ten-year transmission plans by January 31, of even number years, to coincide with the associated ACC obligation to perform a Biennial Transmission Assessment.

10. Recommendations

Concerns outlined by Staff in the above conclusions are not easily or quickly resolved. The public's best interest warrants effective and decisive remedies. Therefore, Staff offers the following recommendations for Commission consideration and action:

1. Continue to support use of:
    a. "Guiding Principles for ACC Staff Determination of Electric System Adequacy and Reliability" to aid Staff in its determination of adequacy and reliability of power plant and transmission line projects,
    b. NERC and WECC criteria and FERC policies regarding the transmission system reliability, and
    c. Collaborative study activities between transmission providers and merchant plant developers for the purpose of:
        1. Ensuring consumer benefits of generation additions and cost–effective transmission enhancements and interconnections, and
        2. Facilitating restructuring of the electric utility industry to reliably serve Arizona consumers at just and reasonable rates via a competitive wholesale market.
2. Endorse Staff's recommendations that:
    a. RMR studies continue to be performed and filed with ten year plans in even numbered years for inclusion in future BTA reports and that
        1. Future RMR studies continue to provide more transparent information on input data and economic dispatch assumptions,
        2. More stringent study criteria and assumptions be explored and implemented for RMR areas as has been done in other jurisdictions for recognized load pocket areas,
    b. Accept the results of the following studies provided as part of the Fourth BTA filings:
        1. Compliance with single contingency criteria overlapped with the bulk power system facilities maintenance (n-1-1) for the first year of the BTA analysis period as required by WECC and NERC.
        2. Extreme contingency outages studied for Arizona's major generation hubs and major transmission stations and associated risks and consequences documented if mitigating infrastructure improvements are not planned.

3. TEP should file comments by June 30, 2007, to resolve concerns inside neighboring New Mexico and WAPA facilities identified in its preliminary study results for 2016.

c. Generation interconnections should be granted a Certificate of Environmental Compatibility by the Commission only when they meet regional and national reliability criteria and the requirements of the Commission's decisions in the 2004 BTA and Track A related to power plant interconnections.

d. Grant SWTC an extension to January 2008 to resolve certain n-1 contingency violations in its 2015 planning study and to file expansion plans to resolve these issues as part of its 2008-2017 plan.

e. Regarding potential RMR requirements in Santa Cruz County beginning 2010 and Mohave County beginning 2012, UNS and SWTC should be directed to file updated RMR studies in their filings due January 2008 for the 5th BTA.

Appendices

Appendix A: Guiding principles for ACC staff determination of electric system adequacy and reliability

This document serves the dual purpose of providing the guiding principles for Staff determination of electric system adequacy and reliability in the two areas of transmission and generation.

A.1 Transmission

A.R.S §40-360.02E obligates the ACC to biennially make a determination of the adequacy and reliability of existing and planned transmission facilities in the state of Arizona. Current state statutes and ACC rules do not establish the basis upon which such a determination is to be made. Therefore, Staff will use the following guiding principles to make the required adequacy and reliability determination until otherwise directed by state statutes or ACC rules.

1. Transmission facilities will be evaluated using WECC, or its successor's, Reliability Criteria for System Planning and Minimum Operating Reliability Criteria.
2. Transmission planning and operating practices traditionally utilized by Arizona electric utilities will apply when more restrictive than WECC criteria.
3. Compliance with A.C.C. R14-2-1609.B[1] will be established by analysis of power flow and transient stability simulation of single contingency outages (n-1) of generating units, EHV and local transmission lines of greater than 100 kV nominal system voltage, and associated transformers. Relying on remedial actions such as generator unit tripping or load shedding for single contingency outages will not be considered an acceptable means of complying with this rule.

A.2 Generation

Pursuant to A.R.S. §40-360.07, the ACC must balance, in the broad public interest, the need for adequate, economical, and reliable supply of electric power with the desire to minimize the effect on the environment and ecology of the state when considering the siting of a power plant or transmission line. The laws of physics dictate that generation and transmission facilities are inextricably linked when considering the reliability of service to consumers. Therefore, it is appropriate that both components must be considered when siting a power plant. Staff will

[1] R14-2-1609.B refers to the obligation of Utility Distribution Companies to assure that adequate transmission import capability and distribution system capacity are available to meet the load requirements of all distribution customers within their service area.

use the following guiding principles to make the required adequacy and reliability determination for siting generation until otherwise directed by state statutes or ACC rules.

The best utility practices historically exhibited in the evolution of Arizona's generation and transmission facilities should be continued in order to promote development of a robust energy market. Non-discriminatory access to transmission and fair and equitable business practices must also be maintained and the service reliability to which the state is accustomed must not be compromised. Therefore, Staff support of power plant Certificate of Environmental Compatibility applications will be conditioned as set forth below.

Staff support of power plant Certificate of Environmental Compatibility applications will be contingent upon the applicant providing, either in the application or at the hearing, evidence of items 1-3 below:

1. Two or more transmission lines must emanate from each power plant switchyard and interconnect with the existing transmission system. This plant interconnection must satisfy the single contingency outage criteria (n-1) without reliance on remedial action such as generator unit tripping or load shedding.
2. A power plant applicant must provide technical study evidence that sufficient transmission capacity exists to accommodate the plant and that it will not compromise the reliable operation of the interconnected transmission system.
3. All plants located inside a transmission import limited zone "must offer" all Electric Service Providers and Affected Utilities serving load in the constrained load zone, or their designated Scheduling Coordinators, sufficient energy to meet load requirements in excess of the transmission import limit.

Staff support of power plant Certificate of Environmental Compatibility applications will further be contingent upon the Certificate of Environmental Compatibility being conditioned as provided in items 4-6 below:

4. 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.
5. The Certificate of Environmental Compatibility is conditioned upon the plant applicant becoming a member of WECC, or its successor, and filing a copy of its WECC Reliability Criteria Agreement or Reliability Management System (RMS) Generator Agreement with the ACC.
6. The Certificate of Environmental Compatibility is conditioned upon the plant applicant becoming a member of the Southwest Reserve Sharing Group, or

its successor, thereby making its units available for reserve sharing purposes.

Approved by:

(Original Signed by Deborah R. Scott)

Deborah R. Scott
Director
Utilities Division This date: (2/8/00)RS/jds:ESAR.doc

Appendix B: 2006 BTA Workshops 1 and 2 list attendees

	Name		Representing	Phone number	E-mail address	Workshops attended[1]
1	Jerry D.	Smith	ACC	(602) 542-7271	jsmith@cc.state.az.us	1
2	Ken	Bagley	Genesee	(480) 367-4282	kbagley@cox.net	1 & 2
3	Prem	Bahl	ACC	(602) 542-7269	pbahl@cc.state.az.us	1 & 2
4	Ed	Beck	TEP	(520) 745-3276	ebeck@tep.com	1 & 2
5	Steven C.	Begay	Dine Power Authority		dpasteve@citlink.net	1
6	Patrick	Black	Fennemore Craig		pblack@felaw.com	1 & 2
7	Jane	Brandt	SRP		jkbrandt@srpnet.com	1 & 2
8	Ian	Calkins	Copper State Consulting Group		ian@copperstate.net	1
9	Jim	Charters	Retired	(623) 572-7972	j_charters@msn.com	1 & 2
10	Brian	Cole	APS		Brian.Cole@aps.com	1 & 2
11	David	Couture	TEP		dcouture@tep.com	1 & 2
12	Michael	Curtis	Mohave Electric	(602) 248-0392	mcurtis401@aol.com	1
13	Cary	Deise	APS	(602) 250-1232	cary.deise@aps.com	1 & 2
14	Chris Clark	DeSchene	Dine Power Authority		clarkdeschene@att.net	1
15	Mark	Etherton	SWAT/AZNM	(602) 809-0707	mle@krsaline.com	1
16	Bruce	Evans	SWTC	(520) 586-5336	bevans@swtransco.coop	1 & 2
17	Linda	Fisher	Corp. Commission - Legal		Lfisher@AZCC.gov	1
18	Commissioner	Gleason				1
19	Charles	Hains	Corp. Commission - Legal		Chaines@AZCC.gov	1 & 2
20	Thomas A.	Hine	Mohave Electric		thineesq@yahoo.com	1
21	Chairman	Hutch-Miller				1
22	Gary T.	Ijams	CAWCD	(623) 869-2362	gijams@cap-93.com	2
23	Joshua	Johnston	Western Area Power Admin.		jjohnston@wapa.gov	1
24	Robert	Kondozoilka	SRP	(602) 236-0971	rekondzi@srpnet.com	1 & 2
25	David M.	Korinek	KEMA		David.Korinek@kema.com	1 & 2
26	Peter	Krzykos	APS		Peter.Krzykos@aps.com	1 & 2
27	Steven	Mavis	sce	(626) 302-8175	steven.mavis@sce.com	1
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29	Jeff	Palermo	KEMA	(703) 631-6912	jpalermo@kema.com	1 & 2
30	Greg	Patterson	AZCPA		greg@azcpa.org	1 & 2
31	Milt	Percival	WSES for 3M	(602) 352-2794	mperc7439@aol.com	1 & 2

[1] Workshop I was held on June 6, 2006; Workshop II was held on September 8, 2006

	Name		Representing	Phone number	E-mail address	Workshops attended[1]
32	Harlow	Peterson	USE Consulting		harlowpeterson@useconsulting.com	1
33	Karilee	Ramaley	APS		KSR@pinnnaclewest.com	1 & 2
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35	Charles	Reinhold	WestConnect	(520) 253-6916	reinhold@globalcrossing.net	2
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42	LeeAnn	Torkelson	SWAT(CATS) HV		LVT@krsaline.com	1 & 2
43	Kevin	Torrey	acc	(602) 542-6031	Ktorrey@azcc.gov	2
44	Rebecca	Turner	Gila River Power, L.P		Rturner@entegrapower.com	1
45	Jennie	Vega	APS		Jennie.Vega@aps.com	1 & 2
46	Scott	Wakefield	RUCO		swakefield@azruco.gov	1
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48	Laurie	Woodal	AZ Atty. General		Laurie.Woodall@azag.gov	1
49	Tom	Wray	swpg	(602) 808-2004	twray@southwesternpower.com	2
50	Leonard	York	Western Area Power Admin.		York@wapa.gov	1 & 2

Appendix C: Existing Arizona power plants

Plant name	Switchyard voltage (kV)	No. units	Primary energy source	Total summer capacity (MW)	AZ capacity under contract (MW)	AZ capacity share (%)	2005 annual net generation (MWh)
Abitibi Consolidated Snowflake		1	SUB	27.2	0	0%	411,664
		1	SUB	43.3	0	0%	
Agua Fria		1	NG	113	113	100%	141,617
		1	NG	113	113	100%	
		1	NG	181	181	100%	
		1	NG	73	73	100%	
		1	NG	73	73	100%	
		1	NG	73	73	100%	
		1	SUN	0.2	0.2	100%	
Apache Station		1	NG	10.2	10.2	100%	2,876,049
		1	NG	18.5	18.5	100%	
		1	NG	60	60	100%	
		1	NG	40	40	100%	
		1	NG	72	72	100%	
		1	SUB	175	175	100%	
		1	SUB	175	175	100%	
Arlington Valley Energy Facility		1	NG	165	165	0%	1,336,932
		1	NG	165	165	0%	
		1	NG	250	250	0%	
Biosphere 2 Center		1	DFO	1.5	0	0%	n/a
		1	NG	1.6	0	0%	
Cholla		1	SUB	110	110.0	100%	7,577,568
		1	SUB	260	260.0	100%	
		1	SUB	260	260.0	100%	
		1	SUB	380	0	0%	
Cogeneration 1		1	NG	8.3	0	0%	n/a
Coronado		1	SUB	395	395	100%	6,070,915
		1	SUB	390	390	100%	
Davis Dam		1	WAT	51.7	51.7	100%	992,230
		1	WAT	51.7	51.7	100%	
		1	WAT	48	48	100%	
		1	WAT	51.7	51.7	100%	
		1	WAT	51.7	51.7	100%	
Demoss Petrie		1	NG	72.2	72.2	100%	18,762
Desert Basin		1	NG	161	161	100%	2,446,371
		1	NG	161	161	100%	
		1	NG	253	253	100%	
Douglas		1	DFO	15	15	100%	n/a

Plant name	Switchyard voltage (kV)	No. units	Primary energy source	Total summer capacity (MW)	AZ capacity under contract (MW)	AZ capacity share (%)	2005 annual net generation (MWh)
Gila River Power Station		1	NG	146	0	0%	4,546,967
		1	NG	146	0	0%	
		1	NG	146	0	0%	
		1	NG	146	0	0%	
		1	NG	146	0	0%	
		1	NG	146	0	0%	
		1	NG	146	0	0%	
		1	NG	146	0	0%	
		1	NG	223	0	0%	
		1	NG	223	0	0%	
		1	NG	223	0	0%	
		1	NG	223	0	0%	
Glen Canyon Dam		1	WAT	165	0	100%	3,299,429
		1	WAT	157	0	100%	
		1	WAT	165	0	100%	
		1	WAT	157	0	100%	
		1	WAT	165	0	100%	
		1	WAT	165	0	100%	
		1	WAT	157	0	100%	
		1	WAT	165	0	100%	
Harquahala		1	NG	206.4	0	0%	461,267
		1	NG	200	0	0%	
		1	NG	200	0	0%	
		1	NG	148.8	0	0%	
		1	NG	148.8	0	0%	
		1	NG	137.6	0	0%	
Headgate Rock		1	WAT	6.5	6.5	100%	n/a
		1	WAT	6.5	6.5	100%	
		1	WAT	6.5	6.5	100%	
Hoover Dam		1	WAT	2.7	2.7	100%	1,879,235
		1	WAT	130	130	100%	
		1	WAT	130	130	100%	
		1	WAT	130	130	100%	
		1	WAT	130	130	100%	
		1	WAT	127	127	100%	
		1	WAT	130	130	100%	
		1	WAT	130	130	100%	
		1	WAT	61.5	61.5	100%	
		1	WAT	68.5	68.5	100%	

Plant name	Switchyard voltage (kV)	No. units	Primary energy source	Total summer capacity (MW)	AZ capacity under contract (MW)	AZ capacity share (%)	2005 annual net generation (MWh)
Horse Mesa		1	WAT	10	10	100%	63,065
		1	WAT	10	10	100%	
		1	WAT	10	10	100%	
		1	WAT	119	119	100%	
Kyrene		1	NG	34	34	100%	828,589
		1	NG	72	72	100%	
		1	NG	59	59	100%	
		1	NG	53	53	100%	
		1	NG	53	53	100%	
		1	NG	144	144	100%	
		1	NG	107	107	100%	
Mesquite Generating Station		1	NG	146.2	0	0%	6,724,135
		1	NG	144.5	0	0%	
		1	NG	146.2	0	0%	
		1	NG	146.2	0	0%	
		1	NG	245.1	0	0%	
		1	NG	245.1	0	0%	
Mormon Flat		1	WAT	11	11	100%	27,229
		1	WAT	57	57	100%	
Navajo		1	BIT	750	506.2	67.49%	17,030,674
		1	BIT	750	506.2	67.49%	
		1	BIT	750	506.2	67.49%	
North Loop		1	NG	25	25	100%	n/a
		1	NG	25	25	100%	
		1	NG	23	23	100%	
		1	NG	23	23	100%	
Ocotillo		1	NG	110	110	100%	145,500
		1	NG	110	110	100%	
		1	NG	50	50	100%	
		1	NG	50	50	100%	
		1	SUN	0.1	0.1	100%	
		1	SUN	0.1	0.1	100%	
		1	SUN	0.4	0.4	100%	
Palo Verde		1	NUC	1243	775.5	62.39%	25,807,446
		1	NUC	1314	819.8	62.39%	
		1	NUC	1247	778.0	62.39%	
PPL Griffith Energy Project		1	NG	148	0	0%	786,882
		1	NG	148	0	0%	
		1	NG	292	0	0%	
Sundance Energy		1	NG	41	41	100%	63,993
		1	NG	41	41	100%	

Plant name	Switchyard voltage (kV)	No. units	Primary energy source	Total summer capacity (MW)	AZ capacity under contract (MW)	AZ capacity share (%)	2005 annual net generation (MWh)
		1	NG	41	41	100%	
		1	NG	41	41	100%	
		1	NG	41	41	100%	
		1	NG	41	41	100%	
		1	NG	41	41	100%	
		1	NG	41	41	100%	
		1	NG	41	41	100%	
		1	NG	41	41	100%	
Prescott Airport		1	SUN	2.1	0	100%	n/a
Red Hawk		1	NG	163.5	0	100%	3,849,124
		1	NG	163.5	0	100%	
		1	NG	163.5	0	100%	
		1	NG	163.5	0	100%	
		1	NG	183	0	100%	
		1	NG	183	0	100%	
Roosevelt		1	WAT	36	36	100%	n/a
Saguaro		1	NG	110	110	100%	50,334
		1	NG	110	110	100%	
		1	NG	76	76	100%	
		1	NG	50	50	100%	
		1	NG	50	50	100%	
Santan		1	NG	92	92	100%	2,078,088
		1	NG	92	92	100%	
		1	NG	92	92	100%	
		1	NG	92	92	100%	
		1	NG	525	525	100%	
		1	NG	290	290	100%	
South Consolidated		1	WAT	1.4	1.4	100%	n/a
South Point Energy Center		1	NG	180	0	0%	1,481,306
		1	NG	180	0	0%	
		1	NG	190	0	0%	
Springerville		1	SUB	400	400	100%	5,577,373
		1	SUB	400	400	100%	
		1	SUN	5.1	5.1	100%	
Stewart Mountain		1	WAT	13	13	100%	n/a
Sundt		1	SUB	156	156	100%	1,152,849
		1	NG	24	24	100%	
		1	NG	25	25	100%	
		1	NG	81	81	100%	
		1	NG	81	81	100%	
		1	NG	105	105	100%	

Plant name	Switchyard voltage (kV)	No. units	Primary energy source	Total summer capacity (MW)	AZ capacity under contract (MW)	AZ capacity share (%)	2005 annual net generation (MWh)
Tri Cities		1	LFG	0.8	0.8	100%	n/a
		1	LFG	0.8	0.8	100%	
		1	LFG	0.8	0.8	100%	
		1	LFG	0.8	0.8	100%	
		1	LFG	0.8	0.8	100%	
Valencia		1	NG	14.7	14.7	100%	n/a
		1	NG	14.7	14.7	100%	
		1	NG	14.7	14.7	100%	
Waddell		1	WAT	10	10	100%	n/a
		1	WAT	10	10	100%	
		1	WAT	10	10	100%	
		1	WAT	10	10	100%	
West Phoenix		1	NG	80	80	100%	2,299,621
		1	NG	80	80	100%	
		1	NG	80	80	100%	
		1	NG	71	71	100%	
		1	NG	36	36	100%	
		1	NG	172	172	100%	
		1	NG	172	172	100%	
		1	NG	186	186	100%	
		1	NG	50	50	100%	
		1	NG	50	50	100%	
Yucca		1	NG	18	18	100%	245,392
		1	NG	18	18	100%	
		1	DFO	20	0.0	0%	
		1	NG	52	52	100%	
		1	DFO	51	51	100%	
		1	NG	75	0	56.65%	
Yuma Axis		1	DFO	22	22	100%	n/a
Yuma Cogeneration Associates		1	NG	35.14	0	0%	n/a
		1	NG	17.12	0	0%	
46 Plants Total		**191**		**24,593**	**13,884**	**70.6%**	**100,270,606**

Source: U.S. Department of Energy, Energy Information Administration, Form EIA-860, Form EIA-906, Form EIA-920.

Primary energy sources:
- BIT Anthracite Coal, Bituminous Coal
- DFO Distillate Fuel Oil (includes all Diesel and No. 1, No. 2, and No. 4 Fuel Oils)
- LFG Landfill Gas
- NG Natural Gas
- NUC Nuclear (Uranium, Plutonium, Thorium)
- SUB Subbituminous Coal
- SUN Solar (Photovoltaic, Thermal)
- WAT Water (Conventional, Pumped Storage)

Appendix D: Information resources

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

D.1 Utilities' 2005 and 2006 Ten-Year Transmission Plans

1. Arizona Public Service Company (APS)
2. Salt River Project (SRP)
3. Southwest Transmission Cooperative (SWTC)
4. Southwestern Power Group II (SWPG)
   a. Toltec
   b. Bowie
5. Southern California Edison (SCE)
6. Texas – New Mexico Power Company (TNMP)
7. Tucson Electric Power Company (TE")
8. El Paso Electric Company
9. UniSource Electric (UNS)

D.2 Generation interconnection studies and related FERC interconnection standards and compliance documents

10. FERC Order 2003 and 2003-A, Standard Interconnection Agreements & Procedures for Large Generators
11. Arizona Utilities Compliance Documents regarding FERC Order 2003 and 2003-A

D.3 Arizona Corporation Commission documents

12. ACC Docket No. E-0000A-02-0051, Decision 65743, Track B

D.4 Reliability Must-Run workshop

13. ACC 2006 RMR Workshop Presentations and Reports
14. FERC Related orders (PL04-2 policy related to bid based market)

D.5 Transmission projects reports

15. Central Arizona Transmission System (CATS) Phase 3 Report[1]

16. Southwest Transmission Expansion Plan (STEP) 2003 Final Report[2]

D.6 Regional committees and working groups materials

17. Southwest Area Transmission (SWAT) subcommittee organization and study plans[3]

18. Seam Steering Group – Western Interconnection (SSG-WI) Planning Work Group 2003 Transmission Report[4]

D.7 North America Electric Reliability Council (NERC) assessments studies and reliability standards related materials

19. NERC Reliability Standards[5]

20. 2004 SUMMER ASSESSMENT Reliability of the Bulk Electricity Supply in North America[6]

21. Reliability Readiness Audit Reports for the relevant Control Areas

D.7.1 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".

D.7.2 First, Second, and third BTA Reports

These reports can be found on the Arizona Corporation Commission website (www.cc.state.az.us/utility/electric/index.htm).

[1] http://www.azpower.org/cats/

[2] http://www.caiso.com/docs/2004/03/08/2004030814004810105.doc

[3] http://www.azpower.org/swat/

[4] http://www.ssgwi.com/documents/316-ferc_Filing___103103___FINAL_TransmissionReport.pdf

[5] http://www.nerc.com/standards/

[6] ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/summer2004.pdf

Appendix E: List of new projects and project changes

In service date	Project	Voltage	Status
2005	Gavilan Peak	230kV	Completed
2005	TS3 230/69kV substation	230/69kV	Named Palm Valley
2005	Irvington Station - Vail Substation #1 loop-in through Robert Bills -Wilmot (formerly Littletown) Substation.	138-kV	Placed in-service August 26,2005
2005	Irvington Station - Vail Substation #1 loop-in through Robert Bills -Wilmot (formerly Littletown) Substation.	138-kV	Completed
2006	Southeast Valley 500kV project—Hassayampa-Pinal West & Pinal West-Santa Rosa-Browning	500kV	Removed from APS plan - APS no longer participating
2007	Dinosaur (RS19)	230kV	Advanced from 2008
2007	Rudd-Palm Valley-TS4 230kV	230kV	Changed to I/S date of 2007
2007	Hassayampa to Pinal West	500 kV	Delayed from 2007 to 2008
2007	Hackberry 230/69 kV Substation	230/69 kV	New Project
2007	Vail - East Loop cut-in of line through future Pantano and Los Reales Substations.	138-kV	2006 (Phase II, Phase I completed)
2007	West Ina Substation - Tucson Station cut-in through Del Cerro (formerly Sweetwater) Substation.	138-kV	New Project
2008	Southeast Valley 500kV project—Palo Verde Pinal West	500 kV	Delayed from 2006
2008	Southeast Valley 500kV project—Pinal West – Santa Rosa	500 kV	Delayed from 2007
2008	PV Hub-TS5 500kV	500kV	Changed to I/S date of 2009 and added interconnection options
2008	Naviska to Saguaro	230 kV	Scope change; in-service date changed to 2008; 30 kV changed to 115 kV; Red Rock changed to Naviska 115 kV Projects
2008	Gordon Sloan 230/69 kV Substation	230/69 kV	New Project
2008	Southeast Valley 500kV project—Pinal West to Santa Rosa	500 kV	New SWTC participation
2009	Second Knoll	500 kV	SRP/APS
2009	Second Knoll 500/69kV	500/69kV	Interconnect moved from CO-SK line to CO-CH line
2009	Flagstaff 345/69kV interconnection	345/69kV	Changed to I/S date of 2009
2009	TS5-TS1 230kV	230kV	Changed to I/S date of 2009
2009	Raceway-Avery 230kV	230kV	Changed to I/S date of 2009
2009	TS5-TS1 230kV	230kV	Changed to I/S date of 2009
2009	VV1 500/69kV	500/69kV	New Project
2009	Naviska to Thornydale 115 kV Line	115 kV	New Project
2009	Southeast Valley 500kV project—Pinal West - Southeast Valley 500 kV	500 kV	New Project
2009	Devers-Palo Verde No. 2	500 kV	Delayed from 2008 to 2009
2009	Rancho Vistoso Substation to future Catalina Substation	138 kV	New Project
2010	Raceway – Pinnacle Peak	500 kV	New project
2010	TS1-TS2-Palm Valley 230kV w/TS2 I/S of 2012	230kV	Changed to I/S date of 2010
2010	Pinnacle Peak -TS6-AV 230kV	230kV	Changed to I/S date of 2010
2010	TS9-Pinnacle Peak 500kV	500kV	New Project
2010	Palo Verde Hub to IID Service area, Northern (Reference SCE DPV2 Line Designation)	500kV	New Project
2010	Palo Verde Hub to IID Service area, Southern (Reference APS Palo Verde to Yuma Project)	500kV	New Project
2010	Moenkopi –Eldorado capacitor upgrade	500 kV	Delayed from 2006 to 2010
2010	Vail - Wentworth 138 kV - two circuits	138 kV	New Project
2011	Pinal South	500 kV	Additional facility to SEV Project
2011	Desert Basin – Pinal South	230kV	New project
2011	Desert Basin – Santa Rosa	230kV	New project
2011	Jojoba cut-in of TS4-Panda 230kV	230kV	Changed to I/S date of 2011
2011	Mazatzal 345/69kV	345/69kV	Changed to I/S date of 2011
2011	Thornydale to CAP Twin Peaks 115 kV Line	115 kV	New Project

In service date	Project	Voltage	Status
2011	Valencia to CAP Black Mountain	115 kV	Delayed from 2008 to 2011
2011	Sundt Station - Vail Substation #2 loop-in line through future University of Arizona Tech Park Substation.	138 kV	Delayed from 2010 to 2011; construction to start 2010
2012	TS5 – Raceway	500 kV	Delayed from 2010
2012	Gila Bend-TS8 230kV	230kV	Replaced with second PV Hub-N.G. 500kV
2012	N.G.-TS8 230kV	230kV	New Project
2012	Sandario to CAP Brawley 115 kV Line	115 kV	New Project
2012	Picture Rocks to Twin Peaks	115 kV	In-service date changed from 2013 to 2012
2012	Pinal West – Tortolita	500 kV	now under review; was 2012
2012	Upgrade existing 115kV transmission line to Nogales	138 kV	New Project
2012	Sandario to San Joquin	115 kV	New Project. Bopp changed to San Joaquin
2013	Adonis 115/24.9 kV Substation	115 kV	New Project
2013	Naviska to Picture Rocks	115 kV	Scope change – name change and new project
2014	Fountain Hills	230kV	Delayed from 2012
2014	New Tucson 230/24.9 kV Substation	230/24.9 kV	New Project
2015	Camino de Manana 115/24.9 kV Substation	115 kV	New Project
2015	Upgrade of Marana-Avra Line	115 kV	Delayed from 2010 to 2015
TBD	South substation to future Gateway substation (2 ckts.) TEP-UES- 345 kV Interconnection Line	345-kV	Depends on permitting
Phase 3 - under review	Vail -East Loop (through Houghton Loop Switching Station*, Spanish Trail and Roberts Substations).	138-kV	Construction started 1976 Phase 1 - 1977 (Completed) Phase 2 - 1983 (Completed)
TBD	West Wing-Raceway 230kV	230kV	Changed to I/S date of TBD
TBD	West Wing-EEstrella 230kV	230kV	Changed to I/S date of TBD
TBD	Yucca-TS8 230kV	230kV	New Project
TBD	Sana Rosa-Pinal South 230kV	230kV	New Project
TBD	Riviera Two Substation to Riviera	230 kV	Delayed indefinitely
TBD	Greenlee Switching Station through Hidalgo to Luna (Deming area)	345 kV	Postponed indefinitely
Under review	Green Valley - Cyprus-Sierrita loop-in line through Canoa Ranch (formerly Desert Hills) Substation.	138 kV	New Project
Under review	Pinal South Substation to Tortolita Substation	500-kV	New Project
Under review	South Substation to Cyprus Sierrita Extension Switchyard through future Canoa Ranch (formerly Desert Hills) Substation and Green Valley Substation.	138 kV	New Project
Under review	South Substation to DeMoss Petric Substation	138-kV	New Project
Under review	Springerville Substation to Greenlee Substation - 2nd circuit	345-kV	New Project
Under review	Tortolita Substation to South Substation.	345-kV	New Project
Under review	Tortolita-Rillito 138 kV	138 kV	New Project
Under review	Westwing Substation to South Substation (2nd circuit)	345-kV	New Project
Under review	Griffith-North Havasu Transmission	230 kV, 69 kV	New Project
Under review	Vail-Nogales Transmission Line #2	138 kV	New Project

Appendix F: Arizona planned EHV transmission additions

Status	Project	Justification	CEC needed
2006 completion			
2005 construction start	Palo Verde-Devers #1 and Hassayampa–North Gilla 500 kV line upgrades	The upgrading of the series capacitors allows for the increase in transfer capability among Arizona, Southern Nevada and Southern California and has an economic value from an adequacy stand point.	Not required
2008 completion			
2007 construction start	Hassayampa-Pinal West 500 kV line	Southeast Valley Project—To accommodate load growth and access to energy sources in the central Arizona area. To provide access to resources from the Palo Verde area generation to the future (beyond this Ten-Year Plan) 500/69 kV station located at the Pinal West substation.	CEC Ordered in Case 124, Issued May 24, 2004
	Pinal West-Santa Rosa 500 kV		CEC Ordered in Case 126, Issued August 25, 2005
	Pinal West - Southeast Valley 500 kV		
2007 construction start	Interconnection of Westwing - South 345 kV via new Pinal West 500/345 kV Substation	To reinforce Tucson Electric Power Company's EHV system and to provide a higher capacity link for the flow of power from the Palo Verde area into TEP's service territory. SWTC, ED2, ED3, and ED4 are also participants.	Included in Siting Case #124
2009 construction start	EOR 9300MW Upgrade Project	To increase East of River (Path 49) transfer capability by 1250MW by upgrading series compensation on Mead-Perkins & Navajo-Crystal 500kV lines, by-passing Perkins phase-shifting transformer, etc. SRP is project sponsor representing multiple owners.	Not required
2009 completion			
2008 construction start	Flagstaff 345/69kV Interconnection	This project will serve projected need for electric energy in APS' northern service area. The project will improve reliability and continuity of service for the growing communities in northern Arizona.	A Certificate of Environmental Compatibility is not needed for this project.
2009 construction start	Palo Verde-TS5 500kV line	This line will serve projected need for electric energy in the area immediately north and west of the Phoenix Metropolitan area. It will increase the import capability to the Phoenix Metropolitan area as well as increase the export capability from the Palo Verde hub. This is an APS/SRP joint participation project with APS as the project manager.	Certificate of Environmental Compatibility issued 8/17/05 (Case No. 128, Decision No. 68063, Palo Verde Hub to TS5 500kV Transmission project). APS, as project manager, holds the CEC.
2009 construction start	Second Knoll loop-in of Coronado-Cholla 500kV line	This project will be needed to serve projected need for electric energy in Show Low and the surrounding communities.	A Certificate of Environmental Compatibility is not needed for this project.
2009 construction start	VV1 loop-in of Navajo-Westwing 500kV line	This project will serve projected electrical needs and provide support to the existing subtransmission system in the Verde Valley and Prescott areas.	A Certificate of Environmental Compatibility is not needed for this project.
2009 construction start	Devers-Palo Verde No. 2 500 kV Line	This 500 kV line will increase transfer capability between Arizona and Southern California.	Application #L-00000A-06-0295-00130 filed May 2006

Status	Project	Justification	CEC needed
2008 construction start	Upgrade Coronado 500kV Transmission System	Add series compensation to Coronado-Silverking 500kV line.	Not required
2010 completion			
2008 construction start	Raceway-Pinnacle Peak 500kV line	This line is a result of joint planning through the SWAT forum. The project is needed to increase the import capability to the Phoenix Metropolitan area and strengthen the transmission system on the east side of the Phoenix Metropolitan valley. This will be an APS/SRP joint participation project with APS as the project manager. The loop-in of a Navajo-Westwing 500kV transmission line into the Raceway 500kV substation will be part of this project.	An application for a Certificate of Environmental Compatibility was filed in 2006.
2008 construction start	Series Capacitor Upgrade Project on Navajo Southern 500 kV Transmission System	The upgrading of the series capacitors allows for the increase in transfer capability from northern Arizona to central Arizona and has an economic value from an adequacy stand point. APS, SRP, TEP, WAPA are participating.	No information filed
2011 completion			
2009 construction start	Pinal West - Southeast Valley/Browning 500 kV line (Reference SRP Ten-Year Plan 2006 filing)	Southeast Valley Project—To accommodate load growth and access to energy sources in the central Arizona area. To provide access to resources from the Palo Verde area generation to the future (beyond this Ten-Year Plan) 500/69 kV station located at the Pinal West substation.	CEC Ordered in Case 126, Issued August 25,2005
2010 construction start	Mazatzal loop-in of Cholla-Pinnacle Peak 345kV line	This substation will serve projected need for electric energy in the area of Payson and the surrounding communities. Additionally, improved reliability and continuity of service will result for the growing communities in the Payson area.	A Certificate of Environmental Compatibility is not needed for this project.
2012 completion			
2008 construction start	Palo Verde-North Gila #2 500kV	This line is expected to be an APS/SRP joint project. As a new transmission path to Yuma area, this 500kV line will provide transmission capacity required to supplement limited transmission and generation resources in the Yuma area.	An application for a Certificate of Environmental Compatibility has not yet been filed.
2010 construction start	TS5-Raceway 500kV line	This line will be needed to serve projected need for electric energy in the area immediately north and west of the Phoenix Metropolitan area. It will increase the import capability to the Phoenix Metropolitan area as well as increase the export capability from the Palo Verde hub and provide support for multiple Westwing 500/230kV transformer outages. This will be a joint participation project with APS as the project manager.	An application for a Certificate of Environmental Compatibility has not yet been filed.

Status	Project	Justification	CEC needed
Undetermined during 2006-2015 period			
Dependent upon permitting	TEP-Unisource Energy Services 345 kV Interconnection Line--South Substation to future Gateway Substation (2 ckts.)	To provide an alternate transmission path to Unisource Energy Services in Nogales, Arizona pursuant to ACC order.	Siting Case #111
Dependent upon permitting	Gateway Substation to Comision Federal de Electricidad (CFE) (2 ckts.) 345 kV	To interconnect to the Comision Federal de Electricidad in Sonora, Mexico.	Siting Case #111
Postponed indefinitely	Greenlee Switching Station through Hidalgo to Luna (Deming area) 345 kV	To provide additional interconnection with the Arizona Utilities and into southern New Mexico	Issued in October, 1975
TBD	Palo Verde-Saguaro 500kV line	This line is the result of the joint participation CATS study. The line will be needed to increase the adequacy of the existing EHV transmission system. It is anticipated the line will be a joint participation project.	Certificate of Environmental Compatibility issued 01/23/1976 (Case No. 24, Decision No. 46802).
Under Review	Pinal West Substation to Tortolita Substation 500 kV	To reinforce Tucson Electric Power Company's EHV system and to provide a higher capacity link for the flow of power from the Palo Verde area into TEP's northern service territory.	Yes
Under Review	Pinal South Substation to Tortolita Substation 500 kV	To reinforce Tucson Electric Power Company's EHV system and to provide a higher capacity link for the flow of power from the Palo Verde area into TEPs northern service territory.	Yes
Under Review	Tortolita Station to Winchester Station 500 kV	To reinforce Tucson Electric Power Company's EHV system and to provide a higher capacity link for the flow of power from the Palo Verde area into TEPS eastern transmission system.	Siting Case No. 23
Under Review	Winchester Substation to Vail Substation - 2nd circuit 345 kV	To reinforce Tucson Electric Power Company's EHV system and to provide additional transmission capacity from the future Winchester Station into Tucson	Yes
Under Review	Vail Station to South Station - 2nd circuit 345 kV	To reinforce Tucson Electric Power Company's EHV system and to provide additional transmission capacity between Vail and South Substations	No
Under Review	Springerville Substation to Greenlee Substation - 2nd circuit 345 kV	To deliver power and energy from major TEP interconnections in the Four Corners and Eastern Arizona regions.	Issued in 1975,1977,1982 and 1986
Under Review	Tortolita Substation to South Substation.	To reinforce Tucson Electric Power Company's EHV system and to provide a high capacity link for the flow of power in Southern Arizona.	Siting Case #50
Under Review	Westwing Substation to South Substation (2nd circuit) 345 kV	To deliver power and energy from major TEP interconnections in the Northwest Phoenix region.	Siting Case # 15

Status	Project	Justification	CEC needed
Under Review	Gateway 345/115 kV Substation	The proposed substation facilities provide an interconnection and source for UNS Electric's second transmission line to UNS Electric's Santa Cruz Service Area and a future distribution substation.	Yes

Appendix G: Arizona planned HV transmission additions

Status	Project	Justification	CEC needed
2006 completion			
Construction completed in 2006	Sandario Substation loop-in of Avra Valley to Three Points 115 kV line	To provide for anticipated load growth in the certificated service area of Trico Electric Cooperative, Inc. in Northwest Tucson	Yes. The Commission in Case 125 issued a Certificate of Environmental Compatibility for the project (Decision No. 67432) on December 3, 2004
Construction start 2006	Saddlebrooke Ranch 115 kV Substation	To provide for anticipated load growth in the certificated service area of Trico Electric Cooperative, Inc. in Southern Pinal County	No
2007 completion			
Construction start 2006	Browning-Dinosaur 230kV line	Serves new substation at Dinosaur, a key source to new load development in the Apache Junction area. Line will be installed in the extra conductor position on Pinal West-Browning 500/230kV towers.	Siting Case #124
Construction start 2006	Orme-Anderson 230kV line	Reconfigure existing parallel-circuit tower line into a double-circuit arrangement to relieve 230kV transmission overloads.	Not required. Original construction of this line predates the siting statute
Construction start 2006	Loop-in of Liberty-Orme 230kV line into Rudd Substation	Loop-in of Libert-Orme into existing Rudd Substation to relieve 230kV transmission overloads.	Not required. Predates siting statute and loop-in is contained within the station site.
Construction start 2006	Loop existing West Ina Substation to Tucson Station line through Del Cerro (formerly Sweetwater) Substation. 138 kV	To provide additional electric service to the western part of Tucson Electric Power Company's service area and to reinforce the local distribution system.	Siting Case #62
Construction start 2006	Hackberry 230/69 kV Substation	To provide transmission service to PD's Safford mining operations in Graham County and to provide for enhanced service reliability to the existing Graham County 69 kV system.	No
Construction start 2007	Rudd-Palm Valley-TS4 230kV line	This project will provide a source for the Palm Valley 230/69 kV substation and 69 kV substations planned in the western and southwestern Phoenix Metropolitan area to accommodate the growing need for electric energy in the area. Increased reliability and quality of service will result for customers served by the 230/69 kV substation.	Certificate of Environmental Compatibility issued 2/12/02 (Case No. 11 5, Decision No. 64473, Southwest Valley Project). Revised on 4/9/02, Decision No. 64704. This CEC is for the 230kV line, Rudd-Liberty, running east and west on the same poles as the Palo Verde-Rudd 5OOkV line. The portion of line running from the existing Rudd-Liberty line to the Palm Valley substation and Project and a Certificate of Environmental Compatibility was issued 12/24/03 (Case No. 122, Decision No. 66646, West Valley South 230kV Transmission Line Project).

Status	Project	Justification	CEC needed
Construction start 2007	Marana 115 kV Line Upgrade	To mitigate various thermal overloads and/or voltage criteria violations due to n-1outages on the 115 kV system between Bicknell and Marana and to provide for anticipated load growth in the certificated service area of Trico Electric Cooperative, Inc.	No
Construction start 2006 (Phase II, Phase I completed)	Loop existing Vail Substation to East Loop Substation line through future Pantano and Los Reales Substations. 138 kV	To provide additional electric service to the eastern part of Tucson Electric Power Company's service area and to reinforce the local distribution system.	No
2008 completion			
Construction start 2007	Naviska to Saguaro 115 kV	To provide for anticipated load growth in the certificated service area of Trico Electric Cooperative, Inc. in Northern Pima and Southern Pinal Counties	Yes
Construction start 2008	Valencia to CAP Black Mountain 115 kV Line	To provide an additional source to the SWTC 115 kV system and for the Valencia Substation which is currently served by a radial 115 kV line from Three Points Substation	Yes
Construction start 2008	Gordon Sloan 230/69 kV Substation	To provide for anticipated load growth in the certificated service area of Sulphur Springs Valley Electric Cooperative, Inc	No
Construction start 2008	Apache to Hayden 115 kV line to APS San Manual Substation	Provide for increased transfer capability and voltage support in Southern Pinal County and to provide for anticipated load growth in the certificated service area of Trico Electric Cooperative, Inc.	Yes
2009 completion			
Construction start 2008	Naviska to Thornydale 115 kV Line	Provide for increased transfer capability and voltage support in Southern Pima County and to provide for anticipated load growth in the certificated service area of Trico Electric Cooperative, Inc.	Yes
Construction start 2007	TS5-TS1 230kV line	This project is required to serve the increasing need for electric energy in the western Phoenix Metropolitan area, providing more capability to import power into the Phoenix Metropolitan area along with improved reliability and continuity of service for growing communities such as El Mirage, Surprise, Youngtown, and Buckeye. The first circuit is scheduled to be in-service for the summer of 2009 and the in-service date for the second circuit will be evaluated in future planning studies.	Certificate of Environmental Compatibility issued 5/5/05 (Case No. 12 7, Decision No. 67828, West Valley North 230kV Transmission Line project).

Status	Project	Justification	CEC needed
Construction start 2008	Raceway-Avery 230kV line	This line will serve projected need for electric energy in the area immediately north of the Phoenix Metropolitan area. Additionally, improved reliability and continuity of service will result for the area's growing communities such as Anthem, Desert Hills and New River. The first circuit is scheduled to be in-service for the summer of 2009 and the in-service date for the second circuit will be evaluated in future planning studies by SRP as part of their planned Westwing-Pinnacle Peak 230kV project.	Certificate of Environmental Compatibility issued 6/18/03 (Case No. 120, Decision No. 64473, North Valley Project).
Construction start 2008	Rancho Vistoso Substation to future Catalina Substation 138 kV	To provide additional electric service to the south-central part of Tucson Electric Power Company's service area.	Under Review
Construction start 2008	Valencia to San Joaquin 115 kV Line	Provide for increased transfer capability and voltage support in Southern Pima County and to provide for anticipated load growth in the certificated service area of Trico Electric Cooperative, Inc.	Yes
2010 completion			
Construction start 2004	Pinnacle Peak-TS6-Avery 230kV line	This project will serve projected need for electric energy in the area immediately north of the Phoenix Metropolitan area. Additionally, improved reliability and continuity of service will result for the growing communities in the areas of Anthem, Desert Hills, New River, and north Phoenix. The first circuit is scheduled to be in-service for the summer of 2010 and the in-service date for the second circuit will be evaluated in future planning studies by SRP as part of their planned Westwing-Pinnacle Peak 230kV project.	Certificate of Environmental Compatibility issued 6/18/03 (Case No. 120, Decision No. 64473, North Valley Project).
Construction start 2008	Palm Valley-TS2-TS1 230kV line	This project is required to serve the increasing need for electric energy in the western Phoenix Metropolitan area, providing more capability to import power into the Phoenix Metropolitan area along with improved reliability and continuity of service for growing communities such as El Mirage, Surprise, Youngtown, and Buckeye. The first circuit is scheduled to be in-service for the summer of 2010 and the in-service date for the second circuit will be evaluated in future planning studies.	The Palm Valley-TS2 230kV line portion was sited as part of the West Valley South 230kV Transmission Line project and a Certificate of Environmental Compatibility was issued 12/24/03 (Case No. 122, Decision No. 66646). The TSI -TS2 230kV line portion was sited as part of the West Valley North 230kV Transmission Line project and a Certificate of Environmental Compatibility was issued 5/5/05 (Case No. 127, Decision No. 67828).
Construction start 2009	Raceway 500kV to 230kV substation 230kV line	The Raceway 500kV substation will be located north of the existing Raceway 230kV substation due to physical/geographic constraints. The 500/230kV transformers will be located at the Raceway 500kV substation, therefore 230kV lines are needed between the 500/230kV transformers and the Raceway 230kV substation.	An application for a Certificate of Environmental Compatibility has not yet been filed. It is anticipated that this project will be filed with the Raceway-Pinnacle Peak 500kV Transmission project.

Status	Project	Justification	CEC needed
Construction start 2010	Vail - Wentworth 138 kV - two circuits	Required to serve load at the new Wentworth 138/13.8 kV Substation locate approximately 7.5 miles due east of the Vail Substation Circuit 1: utilize conductor that was installed in the past but left de-energized, install - 3.0 miles of new conductor east from Vail on existing structures to make connection to this existing conductor Circuit 2: tap the existing Vail-Fort Huachuca or Vail- Spanish Trail line	Yes
2011 completion			
Construction start 2009	Desert Basin-Pinal South 230kV line	Will provide capacity for the delivery of Desert Basin power plant output to the valley and allow for possible capacity expansion at the plant. Majority of line to be strung in vacant position of 500kV towers.	SRP will file a CEC application in Fall 2006 fort the tap or loop-in Desert Basin, but the authority for the portion of the line strung on the 500kV structures is provided for in Case No. 126 granted in 2005.
Construction start 2008	Western Parker-Davis 115 kV Upgrades to 230 kV (Reference Western Ten-Year Plan 2003 filing)	Expected to deliver lower cost energy via additional capacity over the upgraded 230 kV System, and to provide redundancy to bulk receiving stations.	No. Western will upgrade existing 115 kV facilities to 230 kV.
Construction start 2010	Jojoba loop-in of TS4-Panda 230kV line	This substation will be needed to serve projected need for electric energy for the growing communities in the areas of Buckeye, Goodyear, and Gila Bend.	Certificate of Environmental Compatibility issued 1 0/16/00 (Case No. 102, Decision No. 62960, Gila River Transmission Project).
Construction start 2010	Loop existing Irvington Station to Vail Substation #2 line through future University of Arizona Tech Park Substation.	To provide additional electric service to the south-central part of Tucson Electric Power Company's service area.	Yes
Construction start 2010	Thornydale to CAP Twin Peaks 115 kV Line	Provide for increased transfer capability and voltage support in Southern Pima County and to provide for anticipated load growth in the certificated service area of Trico Electric Cooperative, Inc.	Yes
2012 completion			
Construction start 2009	Upgrade existing 115kV transmission line to Nogales	The upgrade of the transmission line increases transmission system reliability and provides additional load serving capacity to UNS Electric Santa Cruz Service Area.	
Construction start 2010	North Gila-TS8 230kV line	This project is required to serve the increasing need for electric energy in the city of Yuma. Additionally, improved reliability and continuity of service will result for the fast growing Yuma County.	An application for a Certificate of Environmental Compatibility has not yet been filed.

Status	Project	Justification	CEC needed
Construction start 2011	Sandario to San Joaquin 115 kV Line	Provide for increased transfer capability and voltage support in Southern Pima County and to provide for anticipated load growth in the certificated service area of Trico Electric Cooperative, Inc.	Yes
Construction start 2011	Picture Rocks to CAP Twin Peaks 115 kV Line	Provide for increased transfer capability and voltage support in Southern Pima County and to provide for anticipated load growth in the certificated service area of Trico Electric Cooperative, Inc.	Yes
Construction start 2011	Sandario to CAP Brawley 115 kV Line	Provide for increased transfer capability and voltage support in Southern Pima County and to provide for anticipated load growth in the certificated service area of Trico Electric Cooperative, Inc.	Yes
2013 completion			
Construction start 2012	Adonis 115/24.9 kV Substation	Provide for increased transfer capability and voltage support in Southern Pima County and to provide for anticipated load growth in the certificated service area of Trico Electric Cooperative, Inc.	No
2014 completion			
Construction start 2013	New Tucson 230/24.9 kV Substation	Provide for increased transfer capability and voltage support in Southern Pima County and to provide for anticipated load growth in the certificated service area of Trico Electric Cooperative, Inc.	No
2015 completion			
Construction start 2014	Camino de Manana 115/24.9 kV Substation	Provide for increased transfer capability and voltage support in Southern Pima County and to provide for anticipated load growth in the certificated service area of Trico Electric Cooperative, Inc.	No
Construction start 2015	Upgrade of Marana to Avra Valley 115 kV Line	To mitigate various thermal overloads and/or voltage criteria violations due to n-1 outages on the 115 kV system between Bicknell and Marana and to provide for anticipated load growth in the certificated service area of Trico Electric Cooperative, Inc.	Yes

Status	Project	Justification	CEC needed
Undetermined			
Construction started 1985 Phase 1 - 1994 (Completed) Phase 2 - 2000 (Completed)	Irvington Substation to East Loop Substation (through 22nd Street Substation).	To provide additional electric service to the central area of Tucson Electric Power Company's service area and to reinforce the local transmission system.	Siting Case #66
Construction started 1985 Phase 1 - 1987 (Completed)	East Loop Substation to Northeast Substation (through Snyder Substation)	To provide additional electric service to the northeastern area of Tucson Electric Power Company's service area.	Siting Case #47
Construction started 1976 Phase 1 - 1977 (Completed) Phase 2 - 1983 (Completed)	Vail Substation to East Loop Substation (through Houghton Loop Switching Station*, Spanish Trail and Roberts Substations).	To provide additional electric service to the eastern portion of Tucson Electric Power Company's service area and to reinforce the local transmission system.	Siting Case #8
TBD	Santa Rosa-Pinal South 230kV line	This line will serve increasing loads in Pinal County and will improve reliability and continuity of service for the rapidly growing communities.	Authority for the 230kV line strung on the 500kV structures was granted in the Certificate of Environmental Compatibility issued in 2005, Case No. 126, Decision Nos. 68093 and 68291.
TBD	Westwing-El Sol 230kV line	This line will increase system capacity to serve growing demand for electric energy in the Phoenix Metropolitan area, while maintaining system reliability and integrity for delivery of bulk power from Westwing south into the APS Phoenix Metropolitan area 230kV transmission system.	Certificate of Environmental Compatibility issued 7/26/73 (Case No. 9, docket No. U-1345). Note that this Certificate authorizes two double-circuit lines. Construction of the first double circuit line was completed in March 1975. Construction of the second line, planned to be built with double-circuit capability but initially operated with a single circuit, is described above.
TBD	Westwing-Raceway 230kV line	This line will serve increasing loads in the far north and northwest parts of the Phoenix Metropolitan area and provide contingency support for multiple Westwing 500/230kV transformer outages. The in-service date for the first circuit will continue to be evaluated in future planning studies by APS and the in-service date for the second circuit will be evaluated in future planning studies by SRP.	Certificate of Environmental Compatibility issued 6/18/03 (Case No. 120, Decision No. 64473, North Valley 230kV Transmission Line Project).
TBD	Yucca-TS8 230kV line	This project would serve the increasing need for electric energy in the city of Yuma. Additionally, improved reliability and continuity of service will result for the fast growing Yuma County.	An application for a Certificate of Environmental Compatibility has not yet been filed.

Status	Project	Justification	CEC needed
Under Review	Extend 138-kV line from Midvale Substation through future Spencer Switchyard to future San Joaquin Substation.	To provide additional electrical service to the far western portion of Tucson Electric Power Company's service area and to reinforce the local distribution system.	Under Review (dependent upon use of federal and/or Tohono r/w)
Under Review	South Substation to DeMoss Petric Substation 138 kV	To provide additional electrical service to the far western portion of Tucson Electric Power Company's service area and to reinforce the local distribution system.	Yes
Construction started 1995 Phase I completed 1997; phase 2a completed 2006; phase 2b under review	South Substation to Cyprus Sierrita Extension Switchyard through future Canoa Ranch (formerly Desert Hills) Substation and Green Valley Substation. 138 kV	To provide additional electrical service to southern area of Tucson Electric Power Company's service area and to reinforce the local transmission & distribution system.	Siting Case #84 (Extension to Certificate being sought due to delayed load growth and condemnation issues)
Under Review	Loop Green Valley to Cyprus-Sierrita line through Canoa Ranch (formerly Desert Hills) Substation. 138 kV	To provide additional electric service to the south-central part of Tucson Electric Power Company's service area.	No
Under Review	Tortolita-Rillito 138 kV	Required to fully utilize increased import capability of additional EHV capacity into Tortolita Substation (Pinal West - Tortolita).	Yes
Under Review	Griffith-North Havasu Transmission 230 kV, 69 kV	Reinforce the existing transmission grid and provide interconnection between UNS Electric load centers in Mohave County.	
Under Review	Nogales Transmission Line #2 115 kV	The additional transmission line increases transmission system reliability and provides additional load serving capacity to UNS Electric Santa Cruz Service Area.	
Under Review	Valencia 115 kV Substation Expansion	The proposed substation facilities provide an interconnection and source for UNS Electric's second transmission line to UNS Electric's Santa Cruz Service Area and a future distribution substation as provided for in CEC.	

Appendix H: Federal government regulatory actions

H.1 Energy Policy Act of 2005

Signed into law on August 8, 2005, H.R. 6, the Energy Policy Act of 2005 (EPAct-05), this legislation encourages investment in the nation's energy infrastructure, was intended to establish a comprehensive, long-range energy policy. The Act is meant to enhance protections for electricity consumers, and to encourage energy efficiency and conservation. It provides incentives for conservation, traditional energy production, and newer, more efficient, energy production technologies. EPAct-05 is more than 1,700 pages long and contains hundreds of provisions.

The major provisions that impact directly on electricity transmission siting include:

1. Title XII – Electricity, Subtitle A – Reliability Standards
   - Section 1211. Reliability – creates a new Federal Power Act Section 215. Electric reliability. This section gives FERC jurisdiction within the United States over an electric reliability organization (ERO), any regional entities and all users and operators of the "bulk power system," including the entities listed in FPA Section 201(f) (i.e., government-owned utilities and certain electric cooperatives), for purposes of approving and enforcing reliability standards.
   - Section 215(d) Reliability Standards – The ERO must file proposed reliability standards with FERC. FERC may approve the standard if it is just, reasonable, not unduly discriminatory, and in the public interest. If FERC disapproves a standard, it is to remand it to the ERO for reconsideration. FERC can also order an ERO to submit a proposed standard on a specific matter.
2. Title XII – Electricity, Subtitle B – Transmission Infrastructure Modernization
   - Section 1221. Siting of Interstate Electric Transmission Facilities – creates a new Federal Power Act Section 216.
   - Section 216(a) Designation of National Interest Electric Transmission Corridors – Within one year of enactment, and every three years thereafter, DOE in consultation with affected states, is to conduct a study of transmission congestion. After input from interested parties, appropriate regional reliability entities and comment from the states, DOE may designate "any geographic area experiencing transmission capacity constraints or congestion that adversely affects consumers" as a "national interest electric transmission corridor."

- Section 216(b) Construction Permit – FERC is authorized, after notice and an opportunity to comment, to issue permits for the construction or modification of transmission facilities in a national interest electric transmission corridor if FERC finds that:

  (1) (A) a state in which the facilities are to be constructed is without authority to approve the siting of the facilities or to consider the interstate benefits expected to be achieved by the project; (B) the applicant for a permit is a transmitting utility under the FPA but does not qualify for a permit under state law because it does not serve end-use customers; or (C) the state has siting authority but (i) has withheld approval for the later of one year after the filing of an application or one year after the designation of the relevant national interest electric transmission corridor; or (ii) conditioned approval in such a way that the proposed construction will not significantly reduce transmission congestion or is not economically feasible.

  (2) the facilities covered by the permit will be used for interstate electric transmission;

  (3) the proposed project is consistent with the public interest;

  (4) the proposed project will significantly reduce interstate transmission congestion and protects or benefits consumers;

  (5) the proposed project is consistent with sound national energy policy and will enhance energy independence; and

  (6) the proposed modification will maximize, to the extent reasonable and economical, the transmission capacity of existing towers or structures.

- Section 216(h)(1)-(4) Coordination of Federal Authorizations for Transmission Facilities – DOE shall act as lead agency to coordinate all federal authorizations and environmental reviews required to site a transmission facility, including coordination with state siting authorities and Indian tribes. "Federal authorizations" means permits, authorizations or other approvals needed to site a transmission facility under federal law. DOE is required to set deadlines for the review and authorization decisions. DOE is to ensure that once an application with all data considered necessary by the Secretary has been submitted, all permit decisions and environmental reviews under federal laws shall be completed within one year, or if another requirement of federal law makes this impossible, as soon thereafter as is practicable. DOE shall provide an expeditious pre-application mechanism for prospective applicants to confer with agencies involved.

- Section 1222. Third Party Finance. For both existing and new facilities, DOE, acting through WAPA or Southwest Power Authority (SWPA), may participate with other entities in designing, developing, constructing, operating, maintaining or owning an electric power transmission facility and related facilities needed to upgrade existing transmission facilities owned by WAPA and Southwest Power Authority.
- Section 1223. Advanced Transmission Technologies. FERC shall encourage advanced transmission technologies that increase the capacity, efficiency or reliability of existing or new transmission facilities. These technologies include energy storage devices, controllable load, distributed generation and mobile transformers and mobile substations.

3. Title XII – Electricity, Subtitle C – Transmission Operation Improvements

- Section 1231. Open Non-Discriminatory Access – creates a new Section 211A of the Federal Power Act – Open Access by Unregulated Transmitting Utilities.
- Section 211A(a) An "unregulated transmitting utility" means an entity that owns or operates facilities used for the transmission of electric energy in interstate commerce and is an entity described in FPA section 201(f) (a government-owned utility or electric cooperative that owns or operates facilities used for transmission of electric in interstate commerce).
- Section 211A(b) Transmission Operation Services – Subject to Section 212(h) (which prohibits mandatory retail wheeling), FERC may, by rule or order, require an "unregulated transmitting utility" to provide transmission service at rates that are comparable to those it charges itself and on terms and conditions that are comparable to those under which the unregulated transmitting utility provides transmission service to itself and that are not unduly discriminatory or preferential.
- Section 1232. Federal Utility Participation in Transmission Organizations. Federal Power marketing agencies and Tennessee Valley Authority are authorized to voluntarily join a Transmission Organization.

Additional provisions that have an impact on Electricity include Subtitle D – Transmission Rate Reform, Subtitle E – Amendments to PURPA, Subtitle F – Repeal of PUHCA, Subtitle G – Market Transparency, Enforcement, and Consumer Protection, Subtitle J – Economic Dispatch, and Title XVIII – Studies.

H.2 Relevant FERC Orders and actions

H.2.1 Electric reliability – Docket No. RM05-30-000

The EPAct-05 required FERC to issue a final rule implementing the new reliability provisions within 180 days of EPAct-05 enactment.

The Commission issued a Notice of Proposed Rulemaking (NOPR) on September 1, 2005 that contained proposed regulations concerning ERO certification, the process for developing and enforcing reliability standards, delegation of ERO authority to regional reliability entities, ERO funding and other matters necessary to implement FPA section 215. The Commission received approximately 1,700 pages of comments on the NOPR and made a number of changes to its proposed regulations based on these comments. On February 3, 2006 the Commission issued its final rule, which has been designated Order No. 672.

The regulations adopted by Order No. 672 establish:

- Criteria that an entity must satisfy to qualify as the ERO;
- Procedures for the ERO to propose new or modified reliability standards for Commission review;
- Procedures for timely resolution of any conflict between a reliability standard and a Commission-approved tariff or order;
- Procedures for resolving an inconsistency between a state action and a reliability standard;
- Regulations pertaining to ERO funding;
- Procedures governing an enforcement action by the ERO, regional entity or the Commission;
- Criteria for delegating ERO authority to regional entities;
- Regulations governing the issuance by the ERO of periodic reports assessing the reliability and adequacy of the North American bulk-power system; and
- Procedures for creating regional advisory bodies composed of representatives of state governments and formed to advise the Commission, the ERO or regional entities on reliability matters.

On March 30, 2006, the Commission issued an order on rehearing in which it clarified certain aspects of the regulations issued in Order No. 672. The Commission received no comments on this order, and the rulemaking process initiated on September 1, 2005 is now complete. The formal implementation process began on April 4, 2006.

On that date NERC filed an application for certification as the ERO and a petition seeking approval of its current voluntary reliability standards as the mandatory standards specified in FPA section 215. The Commission received no other requests for ERO certification or standards approval. On July 20, 2006, NERC was certified as Electric Reliability Organization (ERO), pursuant to the Energy Policy Act of 2005, and accepted, with some modifications and clarifications, NERC's proposed governance structure, funding, reliability standards development process, enforcement program and pro forma Regional Entity delegation agreement.

The Commission reviewed NERC's April 4, 2006, application according to criteria spelled out in Order No. 672, the Commission's February 2, 2006, final rule outlining the requirements for certification of the ERO established under EPAct-05. As the ERO, NERC will be responsible for developing and enforcing mandatory electric reliability standards under the Commission's oversight. The standards will apply to all users, owners and operators of the bulk-power system.

On April 20, 2006, the Commission also granted a petition from the governors of Arizona, California, Colorado, Montana, Nevada, New Mexico, Oregon, Utah, Washington and Wyoming to establish a regional advisory body, as provided for under the Energy Policy Act. The Western Interconnection Regional Advisory Body may provide advice to the Commission, the ERO and a Regional Entity on specified issues affecting that region, and the Commission may give deference to the advice of the regional advisory body. The Commission agreed that the Western Interconnection Regional Advisory Body may receive funding for the reasonable costs of activities it pursues under section 215(j) of the Federal Power Act.

The specific conditions, revisions and clarifications spelled out in the ERO certification order will require NERC to make a compliance filing. The Commission directed NERC to make several improvements to its proposed standardized agreement for delegating enforcement authorities to Regional Entities, including clarification of due process and other steps associated with enforcement of reliability standards. The Commission also directed NERC to make changes to the ERO's procedural rules, and to speed the process for developing new reliability standards in response to a Commission-imposed deadline.

Both the ERO and Regional Entities will be reviewed periodically to assure the statutory qualifying criteria are maintained on an ongoing basis. This will entail a self-assessment of performance three years after certification and every five years thereafter. Regional entities can recommend performance improvements for the ERO.

All proposed reliability standards must be submitted by the ERO to the Commission for its approval. Only reliability standards approved by the Commission are enforceable under the new section 215 of the Federal Power Act. The Commission may approve a proposed reliability standard if it determines the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.

The Commission expects to undertake a rulemaking later in 2006 as part of its review of the 102 reliability standards submitted by NERC for Commission review (RM06-16-000). The rulemaking will determine which of NERC's standards meet statutory requirements and which require further development. In anticipation of the pending reliability standards rulemaking, the Commission on May 11, 2006, released a preliminary staff assessment of NERC's standards and convened a technical conference on July 6, 2006.

The ERO and Regional Entities must monitor compliance with the reliability standards. They may direct violators to comply with the standards, and impose penalties for violations, subject to review by, and appeal to, the Commission. While the ERO is responsible for compliance and enforcement under Commission oversight, the statute provides that the Commission can investigate compliance and impose penalties independently of the ERO.

H.2.2 Submitted Transmission Monitoring report to Congress

Within 180 days of the enactment of EPAct-05, the Department of Energy (DOE) and FERC were to issue a report to Congress on Transmission System Monitoring, i.e., the steps which must be taken to establish a system to make available to all transmission owners and regional transmission organizations (RTOs) in the Eastern and Western interconnections real-time information on the functional status of all transmission lines within the interconnections. The report was issued on February 2, 2006.

The study was to assess technical means for implementing a transmission information system and to identify the steps the Commission or Congress would need to take to require implementation of such a system.

The report found that:

- Technology currently exists that could be used to establish a real-time transmission monitoring system to improve the reliability of the nation's bulk power system; and
- Emerging technologies hold the promise of greatly enhancing transmission system integrity and operator situational awareness, thereby reducing the possibility of regional and inter-regional blackouts.

The analysis identified nine steps that could be taken to establish, and two steps that could be taken to implement, an interconnection-wide real-time monitoring system that could give a near-instant picture of the transmission system's health.

The report recommended that the following nine steps should be taken if an interconnection-wide real-time monitoring system is to be pursued:

1. Define what a real-time monitoring system is, what it should accomplish, and how to accomplish this goal, including an explanation of the terms "real-time information" and "functional status."
2. Evaluate existing real-time monitoring technologies and their limitations.
3. Identify the communications infrastructure required and related security and operating issues.
4. Define data requirements.
5. Identify promising emerging technologies.
6. Decide what data should be shared, with whom, and when.
7. Decide who should operate, use, and maintain the system.
8. Identify potential participants involved in establishing a real-time monitoring system.
9. Consider cost and funding issues.

The Commission identified two steps that could be followed if an interconnection-wide real-time monitoring system is to be implemented, as noted below.

1. Research and study efforts to determine feasibility, cost, and benefits of a real-time transmission monitoring system for the Eastern and Western Interconnections.
2. Based on the findings from Step 1 above, possible development of real-time monitoring system reliability standards.

H.2.3 Long-term transmission rights – Docket Nos. RM06-8-000 & AD05-7-000

Within one year, by rule or order, FERC was required to implement the subsection which requires FERC to exercise its authority under the FPA in a manner that facilitates planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities (LSEs) to satisfy their native load obligations and enables LSEs to secure firm transmission rights on a long-term basis for long-term power supply to meet their service needs. In response, on July 20, FERC adopted the following seven guidelines:

1. The long-term firm transmission right should specify a source (injection node or nodes) and sink (withdrawal node or nodes), and a quantity;
2. The long-term firm transmission right must provide a hedge against day-ahead locational marginal pricing congestion charges or other direct assignment of congestion costs for the period covered and quantity specified. Once allocated,

the financial coverage provided by a financial long-term right should not be modified during its term (the "full funding" requirement) except in the case of extraordinary circumstances or through voluntary agreement of both the holder of the right and the transmission organization.

3. Long-term firm transmission rights made feasible by transmission upgrades or expansions must be made available upon request to any party that pays for such upgrades or expansions in accordance with the transmission organization's prevailing cost allocation methods for upgrades or expansions.
4. Long-term firm transmission rights must be made available with term lengths (and/or rights to renewal) that are sufficient to meet the needs of load serving entities to hedge long-term power supply arrangements made or planned to satisfy a service obligation. The length of term of renewals may be different from the original term. Transmission organizations may propose rules specifying the length of terms and use of renewal rights to provide long-term coverage, but must be able to offer firm coverage for at least a 10-year period.
5. Load-serving entities must have priority over non-load serving entities in the allocation of long-term firm transmission rights that are supported by existing transmission capacity. The transmission organization may propose reasonable limits on the amount of existing transmission capacity used to support long-term firm transmission rights;
6. A long-term transmission right held by a load-serving entity to support a service obligation should be re-assignable to another entity that acquires that service obligation;
7. The initial allocation of the long-term firm transmission rights shall not require recipients to participate in an auction.

The final rule requires independent transmission organizations such as regional transmission organizations and independent system operators that oversee organized electricity markets to make long-term firm transmission rights available to all transmission customers. The availability of such rights will provide an added measure of certainty to load-serving entities that wish to enter into long-term power supply arrangements to serve their load, which in turn should allow load-serving entities to more readily obtain financing for new infrastructure. Consistent with current practice, the guidelines also require that long-term firm transmission rights be available to entities that pay for upgrades or build expansions.

The final rule, "Long-Term Firm Transmission Rights in Organized Markets," takes effect 30 days after publication in the *Federal Register*. Transmission organizations subject to the rule are required to make compliance filings within 180 days of the final rule's publication in the Federal Register.

H.2.4 Promoting transmission investment – Docket No. RM06-4-000

EPAct-05 directed the Commission to develop incentive based rate treatments for transmission of electric energy in interstate commerce, adding a new section 219 to the Federal Power Act. The final rule was adopted on July 20, 2006. The final rule implements this new statutory directive.

For the most part, the final rule adopts the proposals put forth in the Commission's November 2005 proposed rulemaking. Key provisions of the rule include:

- Incentive rates of return on equity for new investment by public utilities (both traditional utilities and stand-alone transmission companies, or transcos);
- Full recovery of prudently incurred construction work in progress;
- Full recovery of prudently incurred pre-operations costs;
- Full recovery of prudently incurred costs of abandoned facilities;
- Use of hypothetical capital structures;
- Accumulated deferred income taxes for transcos;
- Adjustments to book value for transco sales/purchases;
- Accelerated depreciation;
- Deferred cost recovery for utilities with retail rate freezes; and
- A higher rate of return on equity for utilities that join and/or continue to be members of transmission organizations, such as (but not limited to) regional transmission organizations and independent system operators.

All rates approved under the rules would be subject to Federal Power Act rate filing standards, the Commission noted. The rule does not grant utilities all of the listed incentives, but rather allows utilities on a case-by-case basis to select and justify the package of incentives needed to support new investment. Additionally, the rule provides expedited procedures for the approval of incentives to provide utilities greater regulatory certainty and facilitate the financing of projects.

The Commission is adopting an annual reporting requirement, FERC Form 730, which will be required from utilities that have received incentive rate treatment for specific transmission projects. The annual reporting requirement would include projections and related information that detail the level of transmission investment.

The final rule, "Promoting Transmission Investment through Pricing Reform," takes effect 60 days after publication in the Federal Register.

H.2.5 Regional joint boards – Docket No. AD05-13-000

Within one year, FERC was required to convene regional joint boards under sec. 209 of the FPA to study security constrained dispatch in various market regions and submit to Congress a report on the recommendations of the joint boards. A member of the Commission was to chair each board and participate.

On September 30, 2005, the Commission issued an order that designated the market regions for the joint boards, established the joint boards, designated a Commissioner to chair each board, requested that each state nominate a board representative to the appropriate joint board and submit their name and contact information to the Commission, targeted November 2005 for the first meetings of the joint boards, recommended that the joint boards take into account the Department of Energy's report on the benefits of economic dispatch and required the joint boards to submit their recommendations to the Commission no later than May 2, 2006. The Canadian provinces, Canada and Mexico were also invited to participate, as observers, on the appropriate joint boards.

In the September 30, 2005 order, the Commission identified four regions: the South (Texas and the states in the southeast and Southwest Power Pool); the West (states in the Western Interconnection); the Northeast (New York and the states in New England); and PJM/MISO (states that are served primarily by PJM Interconnection, LLC and Midwest Independent Transmission System Operator, Inc.).

The West region consists of Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, South Dakota (a portion of this state is in the Western Electricity Coordinating Council), Utah, Washington and Wyoming.

In order for the Commission to submit a report to Congress regarding the recommendations of the joint boards on or before August 7, 2006, the boards were requested to submit their reports and recommendations to the Commission no later than May 2, 2006.

The initial joint board meetings for the West and South regions were held on November 13, 2005; the PJM/MISO region on November 21, 2005; and the Northeast Region on November 29, 2005. On January 6, 2006, the Commission announced that it planned to hold further joint board meetings. Additional meetings were held on February 12 and 13, 2006.

Studies and recommendations were submitted to FERC by each of the regional joint boards between May 12, 2006 and July 11, 2006. A final report to Congress has yet to be issued.

H.2.5.1 West Region report

The West Region analysis of security constrained economic dispatch (SCED) began with the Commission's definition in the Order: "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities." The West Region Report discusses the basics of SCED and how it functions in the Western Interconnection. It also addresses three recommendations made to the Joint Boards by the DOE in *The Value of Economic Dispatch, A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005*.

Short summaries of the nine major issues considered by the West Region Joint Board and its recommendations to the Commission are:[1]

1. **Independence of dispatcher.** The Board examined the suggestion that independent transmission dispatch was needed to ensure fairness and the full integration of the all generation facilities into the dispatch without regard to ownership of those facilities.

   Recommendation: It was recommended that independent dispatch entities not be created for their own sake. The Board did not recommend further analysis at the time of the report, but did note that if any further analysis is deemed warranted, it must include an investigation of the potential benefit to consumers. If further work appears justified on the facts, the affected states and relevant utilities should determine the nature of the dispatching entity to be considered. Where public, cooperative and privately owned entities serve the market under consideration, their participation should be encouraged.

2. **Utility dispatch of third party power through contracts.** The Board examined the question of whether the relationship between dispatching utilities and IPPs should be governed by contract to ensure the high level of reliability and responsiveness needed for the dependable dispatch of contract units as fully functional integrated grid resources.

   Recommendation: The Board encouraged, but did not wish to duplicate, the efforts of EPSA and EEI in developing standard contractual language addressing reliability, dispatchability and other issues. The Joint Board recommended the use of contractual commitments by IPPs to provide capacity, energy and ancillary services in a manner consistent with an LSE's dispatch needs. Integrating IPPs into the dispatch in the Western Interconnection should be overseen by WECC on an interconnection-wide basis, or subregionally by an appropriate entity.

3. **Transparency of dispatch information and processes.** The Board examined the question of whether a central entity, dispatching all of the resources in a

[1] Taken in whole or in part from *Study & recommendation regarding security constrained economic dispatch by the joint board for the West Region under AD05-13*. Submittal 20060526-0064, Docket Number AD05-13-000. Submitted 5/19/2006.

region, that had more timely access to high quality information could function more efficiently and better realize the value of SCED. For competitive reasons, some entities are reticent about sharing confidential dispatch and load information with a non-independent dispatching entity.

Recommendation: Achieving transparency is not sufficient by itself to justify the creation of an independent dispatch entity. The Board recommended that the Department of Energy study ways to improve the accuracy of forecasting to improve economic dispatch and identify savings that could be achieved thereby.

4. **Consolidation of control areas in a region.** The Board looked at the question of whether consolidation of control areas might yield better information which might, in turn, enable more efficient dispatch than would be the case if several control areas simply shared information. The benefits of larger control areas for renewable technologies such as wind were discussed as was the range of information available from WECC and otherwise to smaller control areas.

   Recommendation: The Board recommended that the states, individually or jointly, consider further consolidation of control areas. Further studies should take into account [i] the value of larger control areas for renewables such as wind, and [ii] solving the problems of large control areas in scheduling within the hour. The Board further stated that any consolidation decision should be based on the needs of consumers and the region's economy for reliable and affordable power; and recommended that consolidation not be thought of as a goal in itself. Enlargements should be approached on a case-by-case basis with the assistance of WECC and possibly the WSPP.

5. **Import/export schedule changes within an hour.** The Board learned that large changes in load and large amounts of imported power make it difficult to schedule efficiently for the hour in some markets. Slow ramp rates can cause imbalances when scheduling for the hour.

   Recommendation: The Board recommended that the WECC develop a standard west-wide protocol to address the need for scheduling before, during and after the hour.

6. **Some practical limitations on economic dispatch.** The Board recognized that the physical makeup of the grid, the demands placed on it and the available generation resources sometimes impose cost, reliability and other limitations on economic dispatch to assure that the needs of the public are accommodated. Various state and regional policies also emphasize goals that go beyond "pure" economic dispatch.

Recommendation: The Board recommended that the definition of security constrained economic dispatch be flexible and broadened to include other public policies, values and physical and operational constraints as well as costs.

7. **First DOE Recommendation: review dispatch practices.** The DOE recommended that the Joint Boards review selected dispatching entities to determine how they conduct economic dispatch and document the rationale for deviations from "pure" least-cost economic dispatch.

   Recommendation: The Board recommended that this study not be pursued. "Such a study would take us deeply into variables and deviations from "pure" economic dispatch without providing much value. It is at odds with our fundamental conclusion that economic dispatch must remain a flexible concept."

8. **Second DOE Recommendation: standardize dispatch contract terms.** The DOE recommends that it and FERC encourage stakeholders to develop more standard contract terms concerning price stability, dispatchability, reliability, and penalties for not meeting performance standards.

   Recommendation: The Board recommended that the standardization of dispatch contract terms be pursued on a regional basis rather than on a national basis. The regional variances in transmission grid operating parameters throughout the Western Interconnection make a strong case for allowing development to go forward on a regional basis.

9. **Third DOE Recommendation: review dispatch tools.** Existing economic dispatch technology, including software and data used and the underlying algorithms and assumptions, deserve scrutiny.

   Recommendation: The Board recommended the development and refinement of technological tools to make the best use of existing and proposed facilities.

H.2.6 Demand response and advanced metering survey – Docket No. AD06-2-000

FERC was required to publish an annual report, by region, that assesses demand response resources. The Commission was charged to prepare a report that reviews and identifies on a regional basis, the following issues: saturation and penetration of advanced metering communication systems; existing demand response and time based rate programs; annual resource constitution of demand resources; potential for demand response as a quantifiable, reliable resource for regional planning purposes; steps taken to ensure that demand resources are provided equitable treatment in regional transmission expansion planning and operations;

and, finally, regulatory barriers to improved customer participation in demand response, peak reduction, and critical peak pricing programs. The report is to be filed within one year of ratification of the EPAct-05.

A survey on the saturation and penetration of advanced meters was proposed and implemented on March 16, 2006, and a technical conference, with comments, on issues raised by EPAct-05 section 1252(e)(3) was held on January 25, 2006. Additionally, comments were filed in response to early requests for comments.

The Staff assessment of demand response and advanced metering was presented on July 20, 2006. The main conclusions of the Staff's assessment are: demand response is important for both wholesale and retail markets; current demand response capability represents between 3% to 7% of peak demand in most regions; and there is a low penetration of enabling technologies. A report to Congress will be published on August 7, 2006.

H.2.7 Electric energy market competition – Docket No. AD05-17-000

Within one year, a five-member inter-agency task force (the "Electric Energy Market Competition Task Force"), which will include one employee from FERC appointed by the Chairman, shall submit to Congress a final report on competition within wholesale and retail markets for electric energy in the U.S. The Draft *Report To Congress On Competition In The Wholesale And Retail Markets For Electric Energy* was issued on June 5, 2006. Comments on the report were due into FERC on June 26, 2006.

H.2.8 MOU to ensure timely and coordinated review and permitting of electric transmission facilities

Not later than one year, DOE and heads of all federal agencies with authority to issue federal authorizations for electric transmission facilities shall enter into an MOU to ensure timely and coordinated review and permitting of electric transmission facilities. FERC states on its website that this action has been initiated, however there is no additional information as to the progress or current status of this action.

H.2.9 Issue Rules for applications for national transmission corridor permits

Section 1221 of EPAct-05 2005 adds a new section 216 to the Federal Power Act (FPA), providing for federal siting of electric transmission facilities under certain circumstances. On June 16, 2006, FERC issued a NOPR on Regulations for Filing Applications for Permits to Site Interstate Electric Transmission Corridors.

The Energy Policy Act provides for federal backstop siting authority of certain electric transmission facilities in order to increase transmission capacity and maintain system reliability. Upon the Secretary of Energy's designation of national interest electric transmission corridors experiencing electric transmission capacity constraints or congestion that adversely affects consumers, the Commission may issue permits to construct or modify electric transmission facilities if the Commission finds:

> (1) a state in which a facility is located does not have siting authority, or state law precludes consideration of interstate benefits;
>
> (2) the applicant for the facility does not qualify to apply for siting approval in the state because the applicant does not serve end-use customers in the state;
>
> (3) the state with siting authority takes longer than one year after the application is filed to act; or
>
> (4) the state imposes conditions on a proposal such that it will not significantly reduce transmission congestion or it is not economically feasible.

The Secretary of the Department of Energy, effective May 16, 2006, determined that the Commission's expertise in siting energy facilities would prove beneficial to this process and, as a result, delegated to the Commission certain aspects of the coordination of federal authorizations and related environmental review.

A proposal to build or expand electric transmission facilities brought before the Commission must be used for interstate commerce, be consistent with the public interest, significantly reduce transmission congestion in interstate commerce, be consistent with national energy policy, and maximize as much as possible existing towers and structures.

In the proposed rule, the Commission seeks to facilitate maximum participation from all interested stakeholders through a Public Participation Plan and an extensive pre-application and post-application process. The proposed participation plan would provide all interested parties, including affected landowners, with information on all aspects of the proposed project, including national and local benefits and environmental impacts. The participation plan ensures ample opportunity for public involvement during the pre-filing and application processes. The participation plan would be accessible in a central location in each county through which the proposed project would be located.

The proposed pre-filing process includes a consultation with the Director of the Office of Energy Projects (OEP), the start of environmental review under the National Environmental Policy Act, numerous public participation opportunities, and a determination by the Director of OEP that an application is ready to be filed for Commission consideration. Once an application is filed, the proposed rule calls for notifying the public of the application, issuing and soliciting comments on the draft environmental document, preparing and issuing a final environmental document, reviewing the record and issuing a final decision by the Commission.

Comments on the proposed rule are due 60 days from publication of the NOPR in the Federal Register.

H.2.10 FERC Open Access Transmission Tariff (OATT) reform

FERC may by rule or order require comparable open access to be provided by non-regulated (FPA sec. 201(f)) transmission utilities. (sec. 1231) Docket No. RM05-25-000 (Order 888 Reform) a Notice of Inquiry (NOI) regarding pro forma open access transmission tariff needs reform was issued on September 15, 2005. There were 23 topics requested industry response:

1. ***Undue Discrimination Generally:*** In Order No. 888, the Commission adopted a functional unbundling approach as a remedy for undue discrimination. Since that time, the Commission has found that the incentive and opportunity for undue discrimination nonetheless continues to exist. The Commission therefore encouraged the structural separation of generation from transmission through RTOs, ISOs and similar organizations. The Commission is interested in receiving comments on whether there are remedies other than structural separation that would adequately address undue discrimination.
2. ***Transmission Pricing:*** The Commission is interested in receiving comments on whether any reforms to the Commission's transmission pricing policies should be considered as part of OATT reform.
3. ***Network and Point-to-Point Transmission Service:*** In Order No. 888, the Commission required each public utility to offer transmission services that it is reasonably capable of providing, not just those services that it is currently providing to itself or others. In this NOI the Commission invited comments on whether reforms to the Commission's transmission pricing policies should be considered as part of OATT reform.
4. ***Untimely Processing of Requests for Transmission Service:*** Some of the deadlines for transmission provider responses to requests for transmission service are not clearly specified and have been implemented in different ways. FERC asked whether reforms are needed to better define the obligations of public utility transmission providers, whether current time frames are adequate, and whether transmission customers have encountered delays that were unduly discriminatory or preferential.
5. ***Remedies, Penalties and Enforcement:*** The EPAct of 2005 gives FERC civil penalty authority for violations of the Federal Power Act. The Commission is interested in receiving comments on whether it should address the issue of remedies or penalties as part of OATT reform.
6. ***Hourly Firm Transmission Service:*** The pro forma OATT provides that the minimum term for firm point-to-point transmission service be one day, but some transmission providers have filed to allow for one hour service. FERC asks whether transmission providers should be required to offer hourly firm point-to-point transmission service and how it should be implemented if so required.

7. ***Changes in Receipt and Delivery Points (Redirects):*** FERC asked if transmission customers had been unduly discriminated against in attempting to modify receipt and delivery points, and whether there were problems with the pro forma OATT section 22.2 that needed correction, or if it were a matter of enforcement.

8. ***Rollover Rights:*** FERC asked if the rollover rights provisions of the pro forma OATT section 2.2 need to be revised, clarified, or reconsidered.

9. ***Rules, Standards and Practices Governing the Provision of Transmission Service:*** FERC noted that many of the "rules, standards, and practices" affecting transmission service were not specified in the OATT. FERC asks whether such rules, standards, and practices should be included in a public utility's OATTs. Additionally, FERC asked if rules, standards and practices not required to be included in OATTs be required to be posted on public utilities' OASIS to increase transparency.

10. ***Joint Transmission Planning:*** FERC asks if the requirement to pay credits for jointly planned facilities paid for by transmission customers has the effect of discouraging joint planning. Additionally, FERC asked if joint transmission planning should be mandatory, and what reporting obligations should accompany joint transmission planning. FERC also asked if credits should be paid for transmission facilities built by point-to-point transmission customers and if the credits should be provided only for point to point of a longer term, such as five years.

11. ***Obligation to Expand Capacity:*** The pro forma OATT requires public utility transmission providers to expand capacity, if necessary, to satisfy the needs of network transmission customers and point-to-point transmission service customers. FERC asks whether these requirements are meeting transmission customer needs, what changes are needed if not, and if there are other changes needed to encourage the building of transmission.

12. ***Joint Ownership:*** In Order No. 888-A, the Commission required each public utility that owns interstate transmission facilities with a non-jurisdictional entity to offer open access transmission service over its share of the joint facilities. Order No. 888 did not address the possibility of existing transmission customers participating with the transmission provider in the joint ownership of new transmission facilities FERC asks if public utility transmission providers should be required to offer customers the opportunity to participate in the joint ownership of new transmission facilities and network upgrades?

13. ***Tariff Compliance Reviews:*** The Commission has relied on transmission customer complaints and staff audits to identify OATT violations. The Commission asks whether it should establish a systematic tariff review process

to monitor compliance, or continue to rely on transmission customer complaints and staff audits to identify violations.

14. ***Hoarding of Transmission Capacity:*** FERC asks if there is evidence of hoarding of transmission capacity or anticompetitive practices, and if changes in pricing policies would encourage transmission providers to make additional non-firm transmission service available.

15. ***Curtailments:*** FERC stated that complaints have been made regarding improper curtailment of service by transmission providers and FERC has found cases of improper curtailment in the past. FERC asks if there is evidence of improper curtailment and if OATT provisions governing curtailments require reform.

16. ***Reservation Priority:*** FERC if the "first-come, first-served" approach to capacity reservation has been fair and equitable when the transmission systems are oversubscribed and if there are alternative approaches that should be implemented.

17. ***Designation of Network Resources:*** The Commission described some of the OATT features governing designation of network resources, and asked if there are problems with designating network resources and if better alternatives are available.

18. ***Queuing for Long-Term Transmission Service:*** The pro forma OATT did not explicitly address queuing issues. FERC asked if there are problems associated with queuing procedures for long-term interconnection and transmission delivery services and if reform is needed. FERC also asks whether clustering of transmission requests should be required, and if customers try to manipulate the queuing processes.

19. ***Ancillary Services:*** FERC noted that it generally adopted the NERC recommendations for ancillary services, and asked if the current set of required ancillary services are the correct services needed to provide open access transmission. FERC also asked if ancillary service pricing issues should be addressed in OATT reform.

    - ***i). Energy Imbalances:*** The current pro forma OATT allows the Commission to approve energy imbalance service pricing provisions on a case-by-case basis. FERC asked if penalty charges should be revised based on the level of threat to reliability. Additionally, FERC asked if changes are needed to the energy imbalances requirements, and if energy imbalance practices have resulted in unduly discriminatory or preferential treatment.

    - ***ii). Generator Imbalances:*** The Commission did not include generator imbalance provisions in the pro forma OATT. FERC asked whether such provisions should be incorporated into the OATT to ensure comparable treatment of transmission customers, and how generator imbalances should be priced.

20. ***Pro Forma OATT Definitions:*** FERC asked whether existing pro forma OATT terms and definitions are sufficient to ensure not unduly discriminatory transmission, or whether reforms and additional terms are needed. FERC also asked if there was any reason to not include the definition of reliable operation provided by EPAct of 2005 in the pro forma OATT.

21. ***ISO, RTO, and ITC Tariffs:*** FERC asked which issues raised in the NOI, if any, did not need to be applied to ISO, and RTO tariffs. FERC also asked which issues raised in the NOI, if any, did not need to be applied to ITCs (Independent Transmission Company).

22. ***Open Access by Unregulated Transmitting Utilities:*** The Section 1231 of EPAct authorizes FERC to require non-public utilities ("unregulated transmitting utilities") to provide open access transmission service. FERC invited comments on how best to implement this authority.

H.2.10.1 NOI comments and reply comments

Response to the NOI included over 4,000 pages of comments and reply comments from all types of industry stakeholders. FERC allowed reply comments to be filed. A total of 47 parties filed reply comments in the proceeding. The comments received were taken under consideration, and FERC released a NOPR for OATT reform.

H.2.10.2 NOPR released May 18, 2006 – Docket nos. RM05-25-000 and RM05-17-000

On May 18, 2006 FERC released a NOPR with comments due by August 7, 2006. Reply Comments due by September 20, 2006. The following summary of the NOPR is from the FERC NOPR Fact Sheet:

> The Commission proposes amendments to its regulations and to the pro forma open access transmission tariff (pro forma OATT), adopted in Order Nos. 888 and 889, to address deficiencies in the pro forma OATT that have become apparent since the issuance of Order Nos. 888 and 889.
>
> **The purpose of the proposed rule**
>
> To strengthen the pro forma OATT to ensure that it achieves its original purpose of remedying undue discrimination.
>
> To provide greater specificity in the pro forma OATT to reduce opportunities for the exercise of undue discrimination, make undue discrimination easier to detect, and facilitate the Commission's enforcement.

To increase transparency in the rules applicable to planning and use of the transmission system.

Brief overview

Major proposed reforms:

- Greater consistency and transparency in ATC calculation
- Open, coordinated and transparent planning
- Reform of energy imbalance penalties
- Reform of rollover rights policy
- Clarify tariff ambiguities
- Increase transparency and customer access to information
- Core elements of Order No. 888 being retained:
- Comparability requirement
- Protection of native load
- States jurisdiction over bundled retail load
- Functional unbundling to address undue discrimination
- Reciprocity

The applicability of the proposed rule

The proposed rule applies to all public utility transmission providers, including RTOs and ISOs.

As with Order No. 888, a public utility may propose terms and conditions of open access service that are consistent with or superior to the pro forma OATT.

The purpose of the proposed rule is not to redesign approved, fully-functional RTO or ISO markets. The Commission does not expect that substantial changes to those markets would be required as a result of this NOPR.

Significant proposed reforms

Available Transfer Capability (ATC)

ATC is the transfer capability remaining on a transmission provider's transmission system that is available for further commercial activity over and above already committed uses. Transmission providers currently calculate the ATC for their systems using different assumptions and methodologies. After concluding that the absence of a consistent ATC methodology increases the discretion of transmission providers and the opportunities for undue discrimination in application of the pro forma OATT, the Commission proposes:

To ensure consistency in the ATC calculation components, data inputs and modeling assumptions as well as consistency in the exchange of data between transmission providers

To order public utilities, working through NERC and the North American Energy Standards Board, to develop appropriate standards within 6 months of the final rule

To increase the transparency of ATC calculations through the inclusion in each transmission provider's OATT of its specific ATC calculation methodology, and through posting of relevant data and models on each transmission provider's open access same-time information system (OASIS)

To order transmission providers to post on OASIS metrics relating to transmission requests that are approved and rejected

Coordinated, open and transparent transmission planning

The Nation has experienced a decline in transmission investment relevant to load growth since Order No. 888 was issued, which has increased congestion and reduced access by customers to alternative sources of energy. The Commission concludes that transmission providers have a disincentive to remedy transmission congestion on a nondiscriminatory basis and that the current pro forma OATT does not adequately address these problems. Therefore, the NOPR proposes to require that:

Transmission providers participate in a coordinated, open and transparent planning process

Each transmission provider's planning process meet the Commission's eight planning principles, which are set forth in the NOPR and include coordination (regular meetings), openness, transparency, information exchange (including review of draft plans), comparability (plan must meet service requests and treat customers comparably), dispute resolution, regional coordination, and congestion studies (each transmission provider must prepare studies annually)

Each transmission provider must describe its planning process in its tariff.

The Commission will allow regional differences in planning processes

Transmission pricing

Pricing of imbalances – The Commission proposes to reform the pricing of imbalances (i.e., energy and generator imbalances) to ensure that it is related to the cost of correcting the imbalance, to encourage efficient scheduling behavior, and to account for the special circumstances presented by intermittent generators, such as by waiving the higher ends of the imbalance penalties.

Credits for customer-owned transmission facilities – With respect to credits available to customers that own network transmission facilities that are integrated with the transmission provider's facilities, the NOPR proposes to clarify that the transmission provider, in designing its rates for OATT service, must treat its own facilities on a comparable basis, and proposes to eliminate the requirement that new facilities can receive credits only if they are "jointly planned" because this requirement may provide a disincentive to coordinated planning.

Capacity reassignment – For capacity reassignments by transmission customers, the NOPR proposes to eliminate the price cap (which currently is the higher of the original rate, the maximum tariff rate or the customer's opportunity cost capped at the cost of expansion) and allow negotiated rates between the customer and its assignee, but not for capacity reassigned by the transmission provider or its affiliates.

Non-Rate Terms and Conditions

Redispatch obligation – The Commission proposes to clarify that when a transmission provider determines that its system lacks capacity to fulfill a request for point-to-point service, a transmission provider must use all of its available redispatch options to satisfy a request for firm point-to-point service and, at the transmission customer's option, these redispatch options must be studied before the customer is obligated to incur the costs and time delays associated with a study of system-expansion options. The Commission also seeks comment on whether, alternatively, it should modify the nature of point-to-point service to require that transmission providers offer a "conditional firm" service that would be subject to curtailment prior to firm service only a limited number of hours of the year.

Rollover rights (right of first refusal) – The Commission proposes to revise the rollover provision in the pro forma OATT, which grants an ongoing right to transmission customers to renew or "rollover" their contracts, to apply to contracts that have a minimum term of five years, rather than the current minimum term of one year. The NOPR proposes that a customer must exercise its right of first refusal to renew the contract no less than one year prior to the expiration date of the transmission service agreement, rather than within the current 60-day period.

Hourly firm point-to-point service – The Commission proposes to require transmission providers to offer hourly firm point-to-point service under the pro forma OATT.

Designated network resources – The NOPR makes a number of clarifications related to the types of agreements that may be designated as network resources, the process for verifying whether agreements meet the requirements in the pro forma OATT, and the requirement for transmission providers to designate and undesignated network resources on OASIS.

Reservation priority – The Commission proposes to change the reservation priority rules to give priority to pre-confirmed transmission service requests submitted in the same time period as non-confirmed requests.

Examples of proposed increases in transparency

In addition to the increased transparency included in the ATC and planning reforms described above, the Commission proposes to require transmission providers to post on OASIS all business rules, practices and standards that relate to transmission services provided under the pro forma OATT, and to include credit review procedures in their OATTs.

The Commission proposes to require transmission providers and their network customers to use the transmission provider's OASIS to request designation of a new network resource and to terminate the designation of an existing network resource.

Proposed reforms to facilitate enforcement of the pro forma OATT:

The Commission proposes a number of posting and reporting requirements that will provide the Commission and market participants with information about each transmission provider's performance of pro forma OATT obligations. For example, the Commission proposes to require transmission providers to post specific performance metrics related to their completion of studies required to evaluate certain transmission requests under the pro forma OATT.

Comments on this NOPR are due by August 7, 2006. Reply Comments are due by September 20, 2006.