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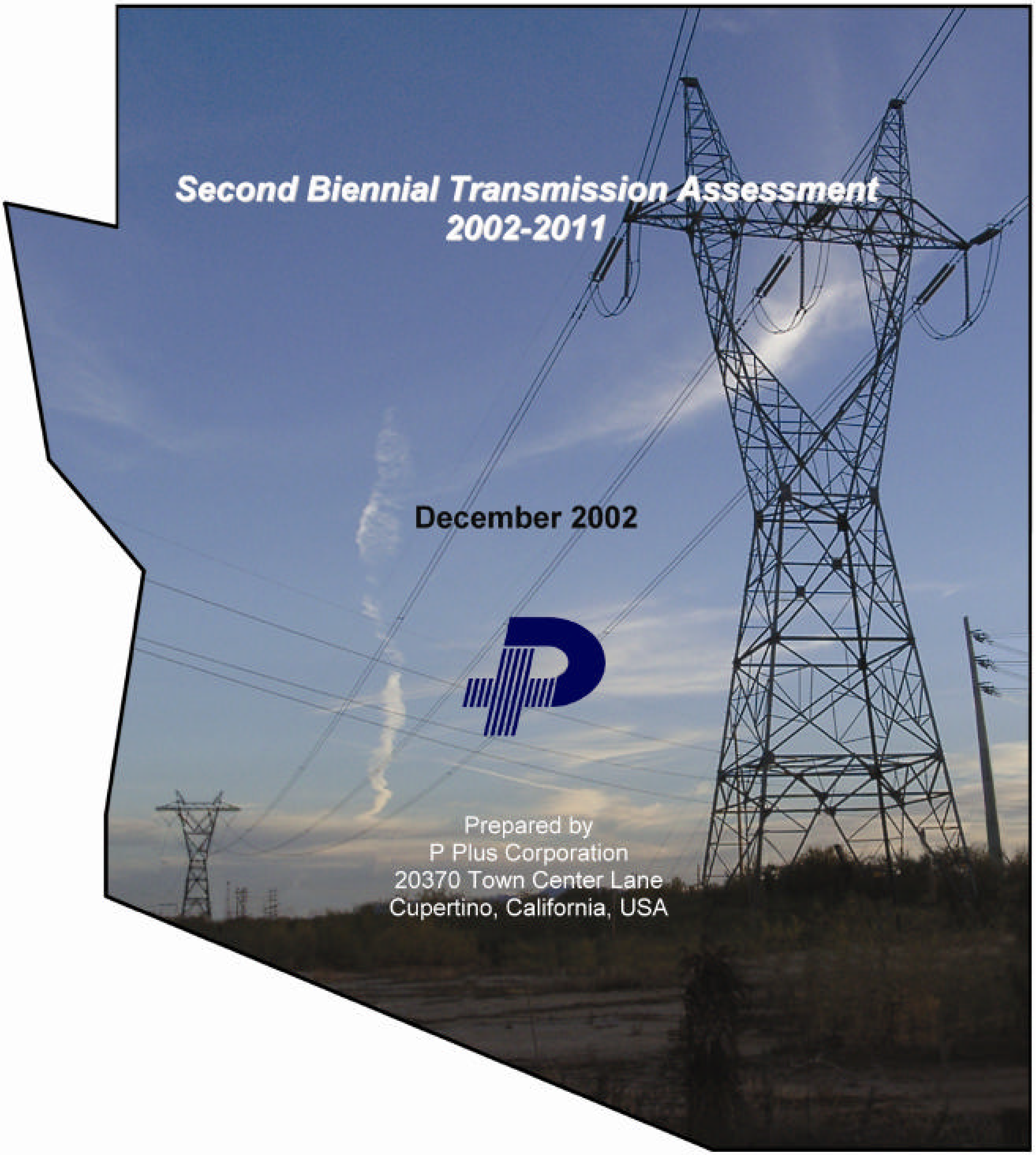

Second Biennial Transmission Assessment 2002-2011

December 2002

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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 second Biennial Transmission Assessment (BTA) was undertaken by the Arizona Corporation Commission (ACC or Commission) Staff (Staff) to fulfill the above stated statutory obligation. The 2002-2011 transmission plans filed in January 2002 under Docket No. E-00000D-02-0065 are the subject of this assessment. Of particular interest are the many activities related to restructuring of the electric industry and actions taken by the industry to address concerns identified in Staff's first BTA.

Adequacy and security of an existing or planned transmission system cannot be determined by merely reviewing the Ten-Year Transmission Plans filed with the Commission. The reliability of an existing or planned electric system under existing, alternative or future operating conditions can only be determined by technical simulation studies. Such studies require the application of a set of study criteria to measure the system's performance. Staff used a set of guiding principles to aid in its determination of adequacy and reliability of power plant and transmission line projects. 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. Staff relied on analyzing the technical reports and documents filed with the Commission by the various organizations rather than performing technical studies of their own. To assist Staff in this effort, Staff hired a consulting organization, P Plus Corporation (PPC) from California, for this second BTA.

This transmission assessment represents the professional opinion of Commission Staff and its consultant PPC. 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. Staff offers the following conclusions for Commission consideration:

- The electric industry in Arizona has been very responsive to concerns raised in Staff's first BTA. For example:
    - Arizona has received national acclaim for its collaborative transmission planning process which is open to all stakeholders. The planning model is being proposed for a study addressing Arizona and California interstate transmission needs.
    - Some Merchant power plant developers are beginning to propose transmission improvements to resolve transmission barriers to the wholesale market.
    - Transmission providers have agreed to participate in a reliability-must-run (RMR) study process for each local transmission import constrained area with which they are interconnected.
    - Numerous new transmission projects have been announced and filed with the Commission since its first BTA.

- In general the existing and planned Arizona transmission system meets the load serving requirements of the state in a reliable manner. Several geographic areas do require and have planned transmission construction within the next ten-year period in order to continue serving local load in such a reliable manner. Mohave County was recently identified as a transmission import constrained area and studies have since commenced to determine available solutions. It is the only region for which transmission expansion has not been defined to reliably serve the local load projected for the area.

- Staff remains concerned about the adequacy of the state's transmission system to reliably support the competitive wholesale market emerging in Arizona. This conclusion is supported by the following findings:
    - Competitive wholesale generators' access to local Arizona markets is limited by local transmission import constraints that results in local RMR generation requirements. (See recommendations 2.a, 3 and 4)

- Planned Palo Verde transmission system additions fail to accommodate the full output of all new power plants interconnecting at the Palo Verde Hub. Two plant developers (Gila Bend Power Partners and TECO/Panda Gila River) have recently identified new transmission projects to help resolve anticipated curtailments and schedule restrictions. (See recommendation 2.b.)
- There is very little additional long-term firm transmission capacity available to export or import energy over Arizona's transmission system. Studies to investigate transmission additions required between Arizona and California are being organized. (See recommendations 2.b and 4.)
- Some new power plants are being interconnected to Arizona's bulk transmission system via a single transmission line or tie rather than continuing Arizona's best engineering practices of multiple lines emanating from power plants. (See recommendation 2.b.)

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 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 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 a priori 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.
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.

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1. Overview of Assessment

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 for an application for a Certificate of Environmental Compatibility ("CEC").[3] Secondly, 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]

1.2 First Biennial Transmission Assessment

The Utilities Division Staff ("Staff") of the ACC initiated its first biennial transmission assessment of existing and planned transmission system in 2000. A written decision of that assessment was rendered in July 2001. In its first biennial transmission assessment, Staff determined the adequacy of existing Arizona transmission lines and additions planned between

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

2000 and 2010. Staff investigated the ability of Arizona's transmission system to adequately deliver energy to the state's retail consumer markets as well as import energy from or export energy to the regional transmission grid with which it is interconnected. Staff's report was filed under Docket No. E-00000A-01-0120, and is also located on the ACC website.[5]

Staff concluded in its first biennial transmission assessment that the State of Arizona did not have adequate existing or planned transmission facilities to deliver the energy needs of the state in a reliable manner. The planned transmission enhancements were found to be both inadequate and untimely. These conclusions were based upon the following findings:

- There was very little additional long-term firm regional transmission capacity available to export or import energy over Arizona's transmission system.
- Southeastern Arizona utilities relied upon restoration of service rather than continuity of service following transmission outages due to service via radial transmission lines.
- There were transmission import constraints for three geographical load zones in Arizona: the Phoenix metropolitan area, Tucson, and Yuma. Planned transmission enhancements fail to resolve this situation in a timely manner.
- The existing and planned additions to the Palo Verde transmission system fail to accommodate the full output of all new power plants proposing to interconnect at Palo Verde, requiring procedures to be developed for curtailment and scheduling restriction.
- Some proposed power plants are being interconnected to Arizona's bulk transmission system via a single transmission line or tie rather than continuing Arizona's best engineering practice of multiple lines emanating from power plants.

Staff recommended in its first Biennial Transmission Assessment the following two different standards for the measurement of transmission adequacy and security due to the different environment of electricity industry restructuring:

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 less polluting remote generation.

   Staff is not suggesting that local generation or distributed generation should be excluded from a utility's resource mix. This is evidenced by the fact that Staff has supported local generation in the siting hearings for the Kyrene and Santan plants**.** Staff did not intervene in the West Phoenix siting hearing, but Staff supported the project.

[5] http://www.cc.state.az.us/utilities/electric/biennial/smn.pdf

2. New power plants must have sufficient interconnected transmission capacity to reliably deliver its full output without use of remedial action schemes or displacing a priori generation at the same interconnection for single contingency (N-1) outages.

1.3 Purpose and Framework of the Second Biennial Assessment

This second Biennial Transmission Assessment (BTA) is undertaken by Staff to fulfill the statutory obligation to biennially review the plans filed with the Commission. The 2002-2011 transmission plans filed in January 2002 under Docket No. E-00000D-02-0065 are the subject of this assessment. Of particular interest are the corrective actions taken by the industry to resolve the conclusions identified in the Staff's first BTA.

Adequacy and security of an existing or planned transmission system cannot be determined by merely reviewing the Ten-Year Transmission Plans filed with the Commission. The reliability of an existing or planned electric system under existing, alternative or future operating conditions can only be determined by technical simulation studies. Such studies require the application of a set of study criteria to measure the system's performance. Staff once again used a set of guiding principles to aid in its determination of adequacy and reliability of power plant and transmission line projects. A copy of these guiding principles is attached as Appendix A. Staff's guiding principles are based upon best engineering practices established in Arizona[1] coupled with the use of regional[2] and national reliability council[7] criteria and standards.

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.[6] 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.[7] 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.

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[6] A.A.C. R14-2-1609.B

[7] A.A.C. R14-2-1606.B

Staff has again relied on analyzing the technical reports and documents filed with the Commission by the various organizations rather than performing technical studies of their own. To assist Staff in this effort, Staff hired a consulting organization, P Plus Corporation from California, for this second biennial transmission assessment. P Plus Corporation (PPC) assisted Staff in the following work areas.

PPC assumed a lead role in reviewing and analyzing technical study reports already collected by Staff and applicable to the Arizona transmission system, with dates succeeding the Commission's first biennial assessment. These study reports include, but are not limited to:

- Reports filed as exhibits for new power plants and transmission projects approved for construction in Arizona via Siting cases, or reports accompanying a party's 2001 and 2002 ten-year plans filed with the Commission by January 31, 2002.
- Numerous studies performed by NERC, WECC, NARUC, Western Governor's Association, RTOs, state regulatory agencies, and any electric industry workgroup or local utility.

Staff was able to assemble and review a broad spectrum of information and technical reports addressing transmission assessments from a national, Western Interconnection (WI), regional, state and local utility perspective. All referenced technical material is listed in Appendix D of this report.

PPC and Staff made use of a three-stage process to facilitate the electric industry's participation in the Commission's second biennial transmission assessment. The first stage consisted of a two-day workshop to gather input from the industry. The second stage consisted of Staff and PPC drafting a report and providing it for industry review and comment. The third phase consisted of a second workshop for Staff to respond to the industries comments on the draft report. An overview of each stage of the process is described below.

In the first stage of the process, PPC organized and facilitated a two-day workshop on July 30 and 31, 2002, to get updates from:

- Transmission Providers on transmission expansion related activities to ensure adequate load serving capability for native load customers, and to ensure power grid reliability for future years.

- Merchant Plant Developers on transmission interconnection studies and on actual plant performance.

The recent study results and transmission plans were presented and discussed at the workshop. The workshop presentation materials are located on the ACC website.[8] Staff and PPC utilized the workshop proceedings along with the reports filed with the Commission in performing this second biennial transmission assessment.

The workshop participants included Arizona Transmission Providers, Merchant Plant Developers, members of the Siting Committee, and the Service List members. The list of workshop participants is included in Appendix E. In order to facilitate focused and meaningful presentations and discussions at the workshop, Staff requested Transmission Providers and Merchant Plant Developers to come prepared to discuss the following topics at the workshop.

Transmission Providers:

- An update on Ten-Year Transmission Plans, giving details on the transmission additions/upgrades/revisions since the first biennial transmission assessment.
- Parties involved in the Central Arizona Transmission System (CATS) studies were requested to provide an update on the extra high voltage (EHV) Transmission system studies, and the new high voltage (HV) study of the 230kV/115kV system between Phoenix and Tucson that is being facilitated by Arizona Power Authority (APA).
- Updates on the State of Arizona EHV Transmission projects and studies such as the Palo Verde (PV) Hub Risk Assessment, Palo Verde Area Transmission studies and Navajo Transmission project.
- Updates on the import constraints in the five load pockets, namely, Phoenix, Tucson, Yuma, Santa Cruz County, and Mohave County.
- Updates on the local transmission issues in the local areas, namely, Central Arizona, Northern Arizona, Tucson, and Southeastern Arizona.

Merchant Plant Developers:

- Updates on Ten-Year generation expansion Plans filed with the ACC, giving details on plant/unit additions, capacity revisions, and plant/unit refurbishment since the first biennial transmission assessment.
- Updates on the operational experience of plants in operation.

[8] http://www.cc.state.az.us/meetings/agendas/ag07-30s.htm

- Updates on the status of their ongoing projects, including status of construction and commencement of operation.
- Updates on the technical study results related to Siting/Compliance filing requirements related to ACC's Certificate of Environmental Compatibility (CEC) which, among others, include updates on self-certification and WECC Reliability Management System (RMS) requirements.

With regard to the above requests, Staff's assessment is that the Transmission Providers met Staff's needs, whereas the responses from Merchant Plant Developers were not as thorough or complete. The workshop provided an informal setting to promote effective discussions on the presentations from transmission providers and merchant plant developers.

The second stage of the process was for Staff and PPC to provide the first draft of the BTA report for industry review and comment. The first draft of the report on the Second Biennial Transmission Assessment (BTA) was based on the analysis of the reports and documents filed with the Commission by the Transmission Providers and Merchant Plant Developers,[8] – [31] the July 30 and 31 Workshop material[9] and participants' responses to questions raised at the workshop. The draft report was placed on the Commission website to facilitate the review process. Similarly, industry comments were placed on the website as well.

The third stage of the process consisted of a second workshop on October 18, 2002 to facilitate presentation and discussion of Staff's response to industry comments on the first draft of the report. The workshop was well attended and attendees are listed in Appendix E. Consensus was achieved on most industry comments by presenting and discussing Staff's responses. This has enabled Staff and PPC to finalize the 2002 BTA report with the confidence that the industry will find it a fair and accurate analysis of the existing and planned Arizona transmission system.

The details of the transmission assessment are presented in the following Sections 5 through 10.

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[9] Transcripts of July 30-31, 2002 Workshop proceedings

2. Related Industry Activities

This section describes various electricity industry activities that have occurred since Staff's first Biennial Transmission Assessment. Only those electricity industry initiatives and 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 the state of Arizona.

2.1 FERC Standard Market Design

The US Federal Energy Regulatory Commission (FERC) proposed on July 31, 2002 a Standard Market Design (SMD) to standardize the structure and operation of competitive wholesale power markets, and to reform and prevent exercise of transmission market power. SMD expands on FERC Order No. 2000's encouragement of all transmission owners to transfer control of their transmission facilities to independent operators. The SMD is intended to restore confidence in competitive power markets by assuring adequate generation resources and establishing a standard framework for market transactions and a single form of transmission services.[45] FERC anticipates that the SMD Notice of Proposed Rulemaking (NOPR) would be approved in 2003.

SMD's fundamental market elements include active monitoring and mitigation to prevent market abuses, and a spot market (or day-ahead market) that complements a market for long-term power supplies, with price discovery and market transparency.

FERC also claims its SMD is designed to prevent the following forms of discrimination in today's wholesale electric markets:

- Preference for Native Load Growth
- Delays in Requests for Service
- Scheduling advantages
- Imbalance resolution

- Inaccurate posting of Available Transfer Capability (ATC)
- Inaccurate Open Access Same Time Information System (OASIS) postings
- Capacity benefit margin manipulation
- Discretionary Transmission Loading Relief
- Enron-type trading strategies

Under the SMD, Independent Transmission Providers (ITPs) will administer spot markets for wholesale power, ancillary services and transmission congestion rights, a real-time "balancing" market to maintain reliable operations of the power grid, and a separate "day-ahead" market. These will complement bilateral contracts for long- and short-term energy purchases. FERC states that the market standardization proposal proclaims to create the following:

- New Transmission Tariff with Congestion Pricing: Creates a market for financial transmission rights, and lets the market assign a value to the congestion that signals investment needed to relieve the bottleneck. Incorporates Locational Marginal Pricing (LMP), which provides price signals indicating where investment in generation and transmission is needed to improve grid operations. LMP minimizes opportunities for market manipulation.
- SMD provides an incentive for power grid enhancement by allowing the companies that invest in new transmission to retain the financial rights to the added power transfer capacity.
- The congestion pricing and management approach should dramatically reduce the need for curtailment of transactions as a means of preserving power-grid reliability/operability.
- All transmission uses fall under a single network tariff, that is, transmission service in support of both wholesale and retail transactions will fall under a common tariff.
- Generation Resource Adequacy: The design requires "Load-serving entities" to arrange sufficient supply and demand reduction resources to meet peak demand plus 12% reserve margin.
- Demand Responsiveness: The design proposes that demand reduction to meet generation adequacy requirement be bid into the spot market in addition to power supply.
- Efficient Rate design: With seamless trading across regional markets and between markets, avoid pancaked rates for customers.
- Market Monitoring and Price mitigation: Each ITP–administered regional power market will have an independent market monitor to alert about anticompetitive problems.
- Market administrators will have price mitigation tools to impede market manipulation efforts.

FERC's SMD is being reviewed by all stakeholders, including the utilities in the state of Arizona, regarding its applicability to their situation, its effectiveness in providing for non-discriminatory access to transmission services, and the implications of Locational Marginal Pricing (LMP) as a congestion management tool. Similarly, the Commission is also reviewing FERC's proposal along with other state utility regulators to ascertain in what ways the SMD solves actual local and regional transmission delivery concerns, adequately manages market abuses, assures consumers reliable service at reasonable and prudent prices, and avoids dual jurisdictional creep.

2.2 Department of Energy National Grid Study

The U.S. Department of Energy (DOE) conducted an independent assessment of the electric transmission system in 2001 to examine the benefits of establishing a national transmission grid and to identify the transmission bottlenecks and measures to address them.[46] The study concluded that eliminating transmission constraints or bottlenecks is essential to ensuring reliable and affordable electricity. The interregional transmission congestion costs the consumers hundreds of millions of dollars annually, and relieving these bottlenecks could save consumers millions of dollars annually. The DOE report contains the following recommendations:

- Increase regulatory certainty by completing the transition to competitive regional wholesale markets.
- Develop a process for identifying and addressing transmission bottlenecks of national interest.
- Avoid or delay the need for new transmission facilities by improving system operations and by fully utilizing the existing facilities. Regional planning processes must consider transmission and non-transmission alternatives to eliminate bottlenecks.
- Create opportunities for customers to reduce electricity demand voluntarily, and targeted energy efficiency and distributed generation should be coordinated within regional markets.
- Ensure mandatory compliance with reliability rules by including enforceable penalties for non-compliance.
- DOE should take increased leadership role in Transmission R&D.

The DOE study determined that as a result of supply and demand patterns, utilities in the West rely more on transporting electricity over long distances to meet local demand than in the East.

Electricity traded as a percentage of demand in the West reaches nearly 30% during some periods. The DOE study is of particular relevance to this project in that it emphasizes the study and analysis of the transmission grid so as to relieve bottlenecks.

2.3 Western Governors Association Efforts

The Western Governors Association (WGA) performed a western market and infrastructure assessment and addressed the factors affecting electric reliability and prices.[47] Some of the key points made by that Group that are relevant to this project are summarized below:

- The overall energy infrastructure in the West is insufficient relative to the projected energy demand, and additional infrastructure expansions are needed to support a competitive market.
- Imports and exports of electricity between regions are limited by constrained transmission paths.
- The timing of the Southwestern region's economic recovery will be pivotal to determining the adequacy of the infrastructure to satisfy the corresponding increase in electricity and natural gas demand.
- Transmission bottlenecks constrain the efficient distribution of resources and directly affect cost differentials.
- RTO participation should be supported for consistent, non-discriminatory grid management.
- New Transmission construction has to be expedited in congested areas.
- Any expansion of the transmission system must maintain reliability, support both load and resource diversity in the western interconnection, and enable an efficient wholesale electricity market. Without the transmission expansion projects, the existing transmission system may not be adequate to meet peak load, integrate new planned generation and maintain sufficient levels of reliability.
- Increasing the energy trading over transmission systems must not reduce system reliability.
- System reliability is maintained by establishing and implementing rigorous standards for system operations and planning. Transmission system operators are responsible for maintaining adequate reserves on-line and keeping line flows within established ratings.

Many of the factors above are germane to evaluating the adequacy and reliability of the transmission system of Arizona.

2.4 Western Electricity Coordinating Council (WECC)

Western Electricity Coordinating Council (WECC) was formed on April 18, 2002 through the consolidation of the former Western Systems Coordinating Council (WSCC) that had responsibility for addressing the reliability issues of the West, and the Regional Transmission Associations (RTAs) that were dealing with the commercial practices of the West. WECC is one of the nine regional councils of the North American Electric Reliability Council (NERC).

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. WECC continues to focus its efforts on promoting the reliability of the interconnected bulk power system, which is comprised of transmission systems 230 KV and above. Criteria have been developed and adopted for use by member systems for day-to-day operation and system planning. As the electricity industry undergoes changes, WECC has taken proactive steps to implement an open process for membership and criteria modifications.

The member systems' transmission facilities are planned in accordance with the WECC Reliability Criteria for Transmission System Planning,[3] which establishes the performance levels intended to limit the adverse effects of each member's system operation on others, and recommends 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.

WECC has established a process to manage compliance with the established criteria. This process includes compliance monitoring, annual study reports, project review and rating process, and an operating transfer capability policy group process. In addition, through a Reliability Management System (RMS) agreement, compliance is ensured with regard to control performance, operating reserve and operating transfer capability, and disturbance control.[4] RMS includes requirements of system operators for managing transactions within major transmission path operating limits. Also WECC addresses the unscheduled flow mitigation scheme approved by FERC.

The transmission planning activities in the State of Arizona have to be performed in a coordinated manner with other members of the Western system in accordance with the WECC standards, guidelines, and compliance requirements.

2.5 ACC Generic Electric Restructuring

The Commission issued a procedural order on January 22, 2002, which opened a generic docket on electric restructuring.[10] A subsequent procedural order issued on February 8, 2002, served the purpose of consolidating the generic docket with the following related cases already active before the Commission:

- Docket No. E-01345A-01-0822, APS variance request to A.A.C. R14-2-1606,
- Docket No. E-01933A-02-0069, TEP variance request to certain competition rule compliance dates,
- Docket No. E-01933A-98-0471, TEP application for approval of its stranded cost recovery, and
- Docket No. E-00000A-01-0630, Proceedings concerning the Arizona Independent Scheduling Administrator (AzISA).

Commissioners posed a variety of questions relating to electric restructuring in the generic restructuring case. A Staff Report was issued on March 22, 2002 that summarized intervening parties' responses to the Commissioners' questions and contrasted Staff's own responses to the same questions. The report documented the experience of other states that have or are undergoing electric restructuring. The Staff report also addressed the following topics: 1) status of retail competition in Arizona, 2) competitive resource bidding, 3) transmission access and constraints, 4) distributed generation, 5) stranded utility investments, 6) market power of transmission providers and utilities owning generation assets, 7) the role of the AzISA and regional transmission organizations (RTOs) that are being formed in the West, and 8) the impact of recent market events.

[10] ACC Staff Report on the Generic Electric Restructuring, Docket No. E-00000A-02-0051, March 22, 2002

Following a Special Open Meeting to consider the APS and TEP variance requests, the Commission issued a procedural order on May 2, 2002, staying the hearings scheduled in the variance proceedings and establishing two concurrent tracks to review major restructuring issues. Issues identified by the Commission for consideration in "Track A" were market power concerns, transfer of utility generation assets, Code of Conduct and Affiliate Interest Rules, and jurisdictional concerns. The concurrent "Track B" was established to consider competitive procurement of resources. Track B proceedings were still in progress at the time this report was written.

The Track A proceeding concluded with a decision rendered by the Commission on September 10, 2002.[11] The opinion and order approved by the Commission was in general agreement with Staff's recommendations on transmission issues and encouraged an industry-wide planning process to resolve transmission constraints.[12] The Commission also believes that both transmission providers and merchant power plants should share the burden and obligation to resolve Arizona's transmission constraints.

The Commission's retail electric competition rules, in place since September 29, 1999, require that at least 50% of the power supply for Standard Offer Service by an investor owned utility distribution company (UDC) will be purchased through a competitive bid process.[13] That same UDC has the obligation to assure that adequate transmission import capability is available to meet the load requirements of all distribution customers within its service area. At the Track A hearing, APS agreed that all generators designated network resources, including both utility and merchant generators, would have access to transmission currently used by the utilities to serve their native load customers. There was also testimony establishing that existing transmission constraints in Arizona will limit APS' (and TEP's) ability to deliver competitively procured supply to less than the required 50% of Standard Offer Service load.

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[11] Decision No. 65154, Docket No. E-00000A-02-0051, et al., September 10, 2002.

[12] Ibid, page 25 at line 23.

[13] A.A.C R14-2-1606.B, Decision No. 61969.

The transmission constraints limiting APS' and TEP's ability to comply with the aforementioned Commission rules result from their dependence upon local reliability-must-run (RMR) generation to serve their peak load during certain hours of the year. RMR needs result from an economic decision to balance local generation and transmission capabilities to serve loads in the most economical manner. In its Track A order, the Commission stayed Rule 14-2-1606.B and required APS and TEP to competitively procure no less than all of Standard Offer Service requirements that they could not supply from utility-owned resources.[14]

The Track A order stipulates that APS and TEP are to work with Staff to develop a 2002 study process to resolve RMR generation concerns and that such study plan results are to be included in the 2004 Biennial Transmission Assessment.[15] This includes studying and analyzing the merits of existing dependence on RMR generation instead of building transmission to resolve transmission import constraints, and the merits of any future contemplated utilization of RMR to defer transmission projects. Until the 2004 Biennial Transmission Assessment is issued with RMR study plan results resolved, APS and TEP are to file annual RMR study reports with the Commission in concert with their January 31 annual ten-year plan for review prior to implementing any new RMR generation strategies.[16]

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[14] For this analysis, APS generation does not include the Redhawk and West Phoenix units owned by PWEC.

[15] Decision No. 65154, Docket No. E-00000A-02-0051, et al., September 2002.

[16] Ibid, Finding of Fact 41.

3. Transmission Planning Standards and Processes

Individual utilities within the state of Arizona plan and design their bulk transmission systems in accordance with the 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 developed to ensure that the systems are planned to provide reliable service to customers under various system conditions. In addition, it ensures 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.

3.1 NERC/WECC Planning Standards

The reliability of interconnected bulk electric systems is defined by NERC with two terms: Adequacy and Security. Adequacy is the ability of the electric systems to supply the aggregate electricity demand and energy requirements of their customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. Security is the ability of the electric systems to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.[5]

Security of a system is judged by its ability to accommodate the loss of system elements and continue to provide adequate service. Loss of a single generator, transmission line or transformer is referred to as single contingency criteria or (N-1) criteria. NERC and WECC consider such outages to be Category B events. The system is judged to be secure if the system response to even the most critical single contingency is such that system adequacy is maintained and system parameters such as frequency, voltage and power flows remain within predetermined acceptable ranges. System security is achieved by maintaining sufficient generation reserves and sufficient transmission capacity throughout the electric system to enable loss of the most critical single contingency while maintaining an adequate system supply and delivery of energy to all customers.

Loss of multiple system elements can be more disruptive than single contingencies. NERC and WECC classify such multi-element outage events into two additional categories: C, and D. Less stringent system performance requirements exist for Category C, and D contingencies than for Category B (N-1) contingencies. A higher level of system security is achieved when an adequate supply and delivery of energy to consumers is maintained for disturbances involving the loss of multiple system components. The least stringent system security requirement is classified as Category A with all facilities in service. Arizona utilities are required to conform to all such NERC and WECC planning and reliability criteria.

While these definitions might have been appropriate for the traditional, regulated environment of the past, the new competitive electricity environment is fostering an increasing demand for transmission services, and new definitions of reliability might be needed. With the focus of transmission systems to support increased competitive electric power transfers, electrical limitations of transmission systems and their capability to support a wide variety of transfers take on a new significance.

In the new competitive environment, the challenge is to plan and operate the future transmission systems to provide the requested power transfers while maintaining overall system reliability. Hence, all industry participants must recognize the importance of planning their systems in a manner that promotes reliability.

It is Staff's opinion that these definitions of Adequacy and Security also do not take into consideration the environmental impact of older and more polluting generation. Staff believes that a better approach is to have standards of measuring transmission capacity instead of merely defining the terms "transmission adequacy" and "security".

To maintain the reliability of bulk systems, the regions and their members are required to comply with the NERC planning standards.[5] NERC/WECC stipulate that the systems must be planned, designed and constructed to operate reliably within thermal, voltage, and stability limits while achieving their major purposes of delivering electric power to areas of customer demand, providing flexibility for changing system conditions, reducing installed generating capacity, and allowing economic exchange of electric power among systems.

Electric power transfers have a significant effect on the reliability of interconnected transmission systems, and must be evaluated in the context of other functions of the system. In some areas, portions of transmission systems might get loaded to their stability limits.

In the planning of transmission systems, NERC/WECC stipulate that the systems should be planned to move electricity from areas of generation to areas of demand under a variety of expected system conditions (e.g., forced and planned outages, varying demands, etc.), while continuing to operate reliably within the thermal, voltage and stability limits of the equipment and electric system. In addition, NERC/WECC stipulate that electric systems must be planned to withstand the more probable forced and planned outage system contingencies at projected customer demand and anticipated electricity transfer levels.

In addition, NERC/WECC Guides for planning are of relevance to planning transmission at a regional level.[5] Some of the guidelines of relevance to AZ transmission planning are described below:

- The planning, development, and maintenance of transmission facilities should be coordinated with neighboring systems to preserve reliability benefits of interconnected systems.
- Studies affecting more than one system owner or user should be conducted on a joint basis.
- The interconnected transmission systems should be designed and operated such that reasonable and foreseeable contingencies do not result in the loss or unintentional separation of a major portion of the network.
- The interconnected transmission systems should be planned to avoid excessive dependence on any one circuit or substation.
- Reliability assessments should examine post-contingency steady state conditions as well as stability, overload, cascading, and voltage collapse conditions. Pre-contingency system conditions chosen for analysis should include contracted firm transmission services.
- Annual updates to transmission assessments should be performed, as needed, to reflect anticipated changes in system conditions.

3.2 WECC Minimum Operating Reliability Criteria

For reliable operation of the western interconnection, WECC requires all entities to comply with the WECC Minimum Operating Reliability Criteria (MORC). MORC is applicable to system operation under all conditions even when facilities required for secure and reliable operation have been delayed or forced out of service.[6] 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 most specific and stringent criteria, WECC's Minimum Operating Reliability Criteria.

3.3 Regional Planning: Seams Steering Group (SSG-WI) Planning Work Group

A Seams Steering Group - Western Interconnection (SSG-WI) committee was formed and consists of representatives from three RTOs: WestConnect, CAISO, and RTO West. The SSG-WI is facilitating review of functional issues related to coordinating and developing the interface between the three RTOs so that the West functions as one seamless wholesale market. A planning work group (PWG) was formed within SSG-WI with the goal of establishing a collaborative planning mechanism that functions to coordinate the transmission plans of Western RTOs as if there were a single RTO in the West. The scope includes addressing congestion issues and scheduling timelines that impact the marketing of energy between RTOs in the West. The PWG is being used as an industry forum to address a number of transmission planning issues in the West in a collaborative manner prior to the formation of RTO West and WestConnect. Activities of the PWG include:

- Continue analysis of congested paths previously identified by Western Interconnection Coordination Forum (WICF).
- Identify tools available to evaluate the benefits of projects to expand access to electricity markets and resources.
- Identify and evaluate future solutions to resolve uneconomic congestion.
- Develop strategic development options.
- Address the following "Next Steps" identified in the WGA study:

- Refine the modeling analysis by:
  - Evaluating alternative growth scenarios that affect implementation of end-use load management, energy efficiency and distributed generation resulting from consumers receiving closer-to-real-time signals on electricity price
  - Expanding the sensitivity analysis to examine the impacts of natural gas prices on electricity prices and load growth
  - Conducting an incremental transmission addition study to better quantify transmission levels and costs
  - Expanding the analysis by including DC transmission options
  - Evaluating the market power mitigation and operational flexibility benefits of either (a) additional generation in transmission constrained area or (b) the addition of more transmission, and
  - Evaluating additional generation scenarios including combinations of wind and peaking resources
- Evaluate the use of additional emerging technology-based solutions such as Flexible AC Transmission System (FACTS) controllers in increasing transfer capability in the existing transmission system among RTOs.

3.4 WestConnect RTO

WestConnect is an RTO intended to manage the operation of transmission assets in the Southwestern portion of the USA. Its applicants claim to have created an RTO structure that offers flexible participation options for transmission owners with different strategic visions, and that are in different stages of restructuring. The FERC SMD NOPR will modify Order No. 2000's requirements regarding RTOs such as RTO rate design and RTO tariffs.

WestConnect filed a petition with the FERC in October 2001 for a declaratory order that it met the elements of being an RTO. The FERC acted on the WestConnect petition on October 10, 2002.[17] WestConnect is formed as a for-profit entity so that if a transmission owner elects not to build a facility, then WestConnect can build its own. FERC approved WestConnect as an RTO in October 10, 2002. WestConnect's operational start date is estimated to be early 2006.

The WestConnect planning process consists of (a) developing annual regional transmission expansion plans, (b) following both WECC and NERC reliability standards, and (c) coordinating with WECC to integrate expansions with other facilities in WECC. There is one key difference

[17] FERC Docket No. EL02-9-000, WestConnect RTO, LLC.

between the WestConnect and individual transmission owners' planning processes. WestConnect is looking at what expansion is needed to support a competitive marketplace throughout the West, and that goes beyond looking at the reliability aspects of the transmission system and whether one can survive a contingency situation or an outage without affecting a neighboring system. WestConnect will incorporate the expansion plans of all transmission owners within WestConnect. That way, WestConnect will be able to avoid duplication of facilities.

The objectives of WestConnect's planning process are to conform to applicable criteria, meet forecasted demand, identify expansion needed to support competitive wholesale markets, incorporate new generators, and conform to local reliability practices. WestConnect's ten-year plans will identify upgrades, avoid duplication of facilities, ensure a reliable and efficient expansion system, encourage robust wholesale markets, and analyze economic alternatives. WestConnect will have responsibility for regional transmission planning, short-term operations and short-term reliability. It will also be responsible for managing congestion, calculation of Total Transfer Capability (TTC) and Available Transfer Capability (ATC) and operation of a regional Open Access Same-Time Information System (OASIS). It will also approve and manage generator interconnections.

The key functions of WestConnect insofar as it relates to Arizona utilities are:

- Planning and expansion: Provide an open and transparent planning process under the direction and control of WestConnect. WestConnect will have the final responsibility for the regional transmission plan. WestConnect's planning and system expansion process will enable it to provide efficient, reliable and non-discriminatory transmission service, and should encourage market driven operating and investment actions for preventing and relieving congestion.
- Interregional Coordination: WestConnect becomes a member of WECC. WestConnect is participating in an RTO task force formed to address seams issues and other coordination issues among the three RTOs in the West.

WestConnect will address local utilities' needs only at the transmission level; that is, the local utilities needs have to be related to wholesale transactions.

3.5 Arizona Independent Scheduling Administrator

The Arizona Independent Scheduling Administrator (AzISA) is a non-profit corporation, created in 1998 under the laws of the state of Arizona, for the purpose of facilitating the development and function of competitive retail markets in Arizona. AzISA was created according to a Commission rule which stipulates that the affected utilities that own and operate Arizona transmission facilities shall form an Arizona independent scheduling administrator.[18] AzISA is focused on administrating Arizona retail transmission transactions according to protocols on file with FERC while WestConnect will be focused on all transmission transactions that occur within the RTO and with other RTOs.

The following planning related functions are required of AzISA, under R14-2-1609 (D):

- The AzISA shall implement a transmission planning process that includes all AzISA participants and aids in identifying the timing and key characteristics of required reinforcements to Arizona transmission facilities to assure that the future load requirements of all participants will be met.

  The AzISA Board adopted a staged implementation of its functions based on the extent to which a robust retail market would develop, and the status of implementing a Desert Star or WestConnect RTO. As a result of this staged implementation, the planning functions were postponed to Phase II of AzISA's implementation plans. Important functions such as dispute resolution for those serving the competitive load in Arizona, and monitoring of OASIS functions, are included in Phase I of AzISA's implementation.

- AzISA was also to participate in state transmission planning studies such as those of the Central Arizona Transmission System (CATS) and Western Area Transmission System (WATS) study groups. AzISA's role in such studies is to ensure that CATS satisfactorily addresses retail transmission needs and identifies transmission enhancements that would increase the load-serving capability in Arizona.

3.6 Central Arizona Transmission System (CATS) Study Group

Historically, Arizona's Extra High Voltage (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 from the northeastern and northwestern portions of the state to these load centers. The implementation of these practices also resulted in strong ties to neighboring states.

[18] A.A.C. R14-2-1609.D.

Over the past decade Arizona has experienced substantial growth in the business and residential sectors, particularly in the Phoenix and Tucson metropolitan areas. Structural changes in the electric power market have created tremendous growth in the interest to site merchant generation resources to serve loads both inside and outside of the state of Arizona. The Palo Verde switchyard has become very attractive as a market hub because of the connections to Arizona and California metropolitan load centers and the availability of a nearby gas pipeline.

Salt River Project (SRP), Arizona Public Service (APS) and Tucson Electric Power (TEP) met to discuss how the utilities should move forward to plan for the anticipated growth in transmission capacity needs. In principle, the utilities agreed that a regional transmission planning effort was needed to assess the EHV transmission needs and opportunities in the central Arizona area. Through these joint efforts a Central Arizona Transmission System (CATS) study group was formed in June 2000.[19] The primary participants included all of the Arizona transmission utilities and Staff. To ensure that the process identified the needs of all stakeholders, invitations to participate were sent to the erstwhile Southwest Regional Transmission Association (SWRTA) members, and any other parties that may be interested. Many merchant power plant and transmission developers responded to the invitation.

CATS was created as a forum for open exchange and sharing of ideas. It is a focal point for communications among generators, transmission developers and distribution companies, striving to form a common vision of a long-range regional transmission plan for future development in central Arizona. It has promoted development of joint regional transmission projects benefiting Arizona's retail customers and facilitating market opportunity for an emerging new wholesale power plant industry in Arizona.

The following planning objectives were established by members of the initial CATS study team:

- Improve the use of the existing transmission system to meet future load growth in the Phoenix and southern Arizona areas

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[19] SRP Ten-Year Plan, 2002-2011, Appendix 1, Report on the Phase 1 Study of the CATS, July 20-21, 2001.

- Increase the power transfer import level into the Phoenix area
- Increase the power transfer import level into the Tucson area
- Increase the power transfer capability between the Phoenix and Tucson areas
- Encourage future generation additions south of Phoenix and north of Tucson
- Provide additional transmission capacity to and from the Palo Verde hub
- Increase import capability to Phoenix and Tucson from the Coronado/Springerville area where plans for new generation sites are being considered.

This collaborative study forum has also resulted in formation of a subcommittee to investigate future 69 kV through 230 kV high voltage (HV) transmission needs south of Phoenix and north of Tucson. This HV study area involves facilities serving a number of irrigation districts, electric districts, native American tribal lands, and small Arizona communities. CATS participants have also indicated a desire for similar EHV studies to be performed to investigate the California/Arizona transmission interface. The results of CATS' study efforts are described in greater detail in Section 6.

3.7 Evaluation of Planning Processes Active in Arizona

Each utility in the State of Arizona develops its own internal guidelines and criteria to assist in planning its EHV (345kV and above) and HV transmission system. These guidelines and criteria can be found in their entirety in each utility's website. The 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.

The utilities in the state of Arizona plan their system facilities by following WECC and internal reliability criteria, coupled with sound engineering judgment. The utilities plan their system to be secure in accordance with performance requirements of each of the four WECC planning Categories A, B, C, and D. This ensures that there are no thermal overloads on lines and equipment, and that the system voltages stay within normal limits under normal and emergency conditions. Similarly, frequency control is maintained and stable generating unit responses to disturbances are appropriately achieved. The utilities perform the required power flow and stability analysis under various system load conditions and contingencies by utilizing the state of the art simulation tools that can represent the bulk transmission system with sufficient detail. The utilities are also engaged in numerous interconnection study requirements for new power plants, such as the Palo Verde Interconnectors' Study.

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) there are no duplicate or redundant facility additions, and (b) 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. These planning activities again are performed in accordance with the WECC Reliability Criteria.

APS chaired the WGA transmission study. SRP is chair of CATS, and APS chairs a Western Area Transmission Study (WATS) forum for the Palo Verde and Navajo power plants and transmission providers. Western Area Power Administration (WAPA or Western) facilitates a joint planning study with its customers. APS, SRP, TEP and Western are participating in the SSG-WI planning group. Such efforts demonstrate the exemplary planning leadership these utilities provide in the West.

Hence, the planning processes active in Arizona are based on established reliability criteria, and sound engineering practices.

4. Existing Arizona Transmission System

4.1 System Description

The information on existing power plants constructed, owned, and operated by the electric utilities within the State of Arizona, and the existing transmission facilities within the state of Arizona, were supplied by APS, SRP, TEP, Citizens, SWTC and Western in response to a formal request by Staff. Figure 4.1 illustrates the existing EHV transmission facilities in the state of Arizona, and shows the three areas with import constraints. EHV facilities are rated at a nominal system voltage of 345 kV and 500 kV.

All new transmission lines and all new power plants constructed since the fist BTA are incorporated as existing Arizona system facilities in this report. The utilities responses relative to their existing power plants are summarized in Table 4.1. Table 4.2 depicts the new transmission lines added since the first BTA. Table 4.3 illustrates the changes in the status of merchant power plants since the first BTA.

4.2 Transmission Paths and Their Ratings

Transmission facilities are rated in a variety of ways. Each transmission line or device has a thermal rating based upon its current carrying capacity measured in amperes. Such ratings are often converted to common power ratings in units of megawatts (MW) or megavolt-amperes (MVA) at nominal system voltage typically measured in kilovolts (kV). Thermal ratings are time dependent and may range from a short time emergency rating to a continuous rating. Such ratings are dependent upon ambient weather and atmospheric conditions.

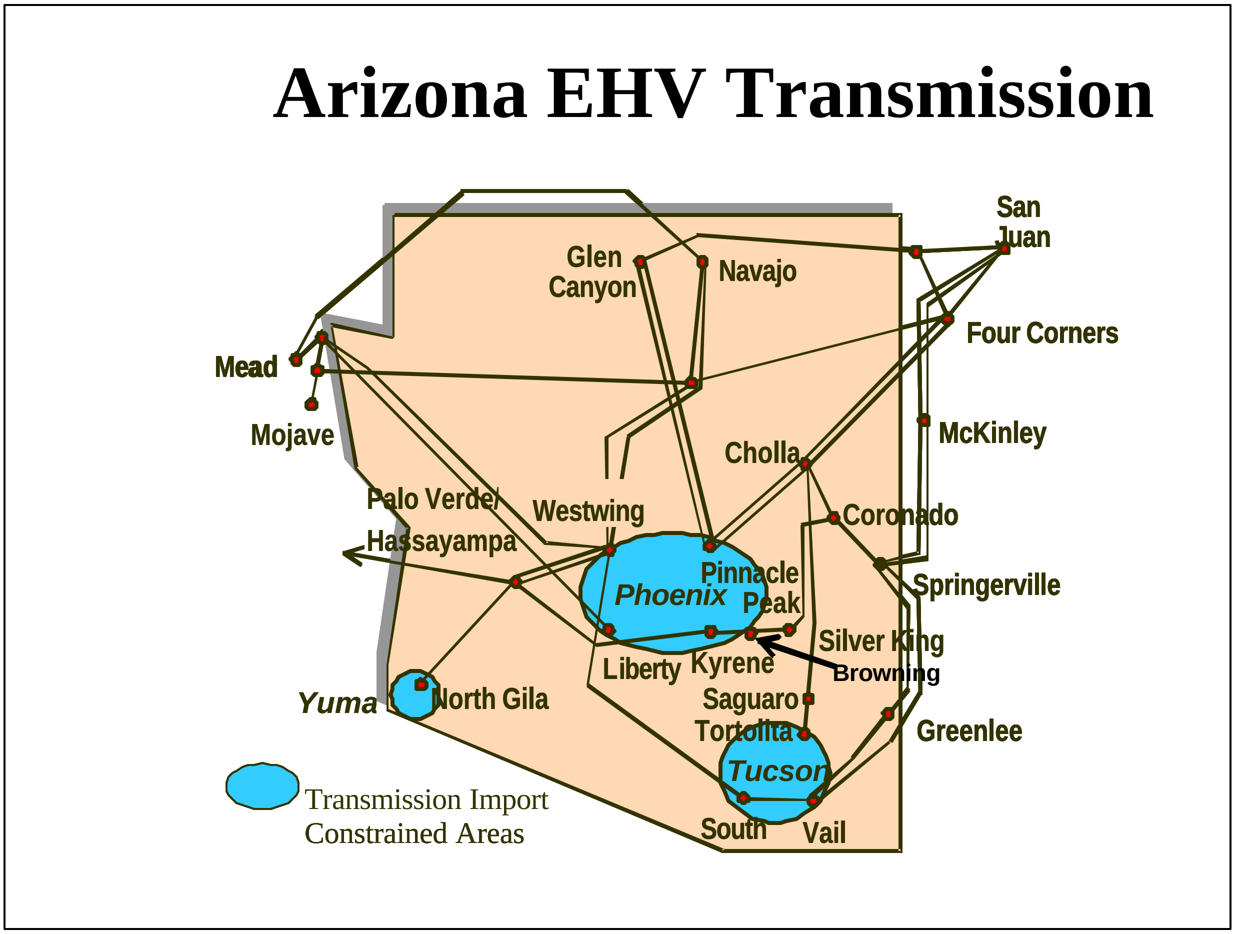
A series of devices is generally connected to either end of transmission lines for switching, protective control, voltage control, or metering purposes. The most restrictive device rating in series with the transmission line establishes the thermal rating used for that transmission line.

Table 4.1
Summary of Existing Power Plants Owned by Arizona Utilities

Plant	Switchyard Voltage (kV)	No. Units	Capacity (MW)*	AZ Utility Capacity (MW)*	AZ Utility Capacity (%)
Agua Fria	230	3	142	142	100.00%
	69	3	407	407	100.00%
Apache	230	2	388	388	100.00%
	115	2	140	140	100.00%
	69	2	30	30	100.00%
Childs/Irving	69	4	5	5	100.00%
Cholla	500	3	995	615	61.81%
	230	1	116	116	100.00%
Coronado	500	2	730	730	100.00%
Four Corners	500	1	740	587	79.32%
	345	1	740	587	79.32%
	230	3	560	560	100.00%
Fairview	69	1	16	16	100.00%
Horse Mesa	115	4	128	128	100.00%
Irvington	138	4	310	310	100.00%
	46	2	162	162	100.00%
Kyrene	230	2	101	101	100.00%
	69	3	163	163	100.00%
Mormon Flat	115	2	58	58	100.00%
Navajo	500	3	2,255	1,522	67.49%
North Loop	46	3	95	95	100.00%
Ocotillo	230	1	54	54	100.00%
	69	3	275	275	100.00%
Palo Verde	500	3	3,810	2,377	62.39%
Roosevelt	115	1	36	36	100.00%
Saguaro	115	5	400	400	100.00%
San Juan	345	4	1,614	314	19.45%
Santan	230	2	157	157	100.00%
	69	2	156	156	100.00%
Springerville	345	2	800	800	100.00%
Stewart Mountain	115	1	13	13	100.00%
YCA	69	1	55	0	0%
Yucca	69	5	173	98	56.65%
	161	1	22	0	0%
W. Phoenix	230	3	240	240	100.00%
	69	3	94	94	100.00%
24 Plants Total		**88**	**16,142**	**11,838**	**73.30%**

* Per WECC Existing Generation Data Base

Figure 4.1



Arizona EHV Transmission
San Juan
Glen Canyon
Navajo
Four Corners
Mead
Mojave
McKinley
Cholla
Palo Verde/ Hassayampa
Westwing
Coronado
Springerville
Phoenix
Pinnacle Peak
Silver King
Browning
Liberty
Kyrene
Yuma
North Gila
Saguaro
Tortolita
Greenlee
Tucson
South
Vail
Transmission Import Constrained Areas

Table 4.2
New Transmission Lines and Stations
Added Since the First BTA

Year	Description	Voltage
2001	WhiteTanks-West Phoenix #1 and #2	230 kV
2001	Browning Substation	500kV/230 kV
2002	Redhawk-Hassayampa #2	500 kV
2002	Palo Verde/Hassayampa Common Bus	500 kV
2002	Gila River-Jojoba #1 and #2	500 kV

Table 4.3
Updated Status of Plants Since the First Biennial Transmission Assessment

Facility	Estimated Online Date	Output (MW)
West Phoenix (Phase 1)	08/01/2001	120
Desert Basin	10/01/2001	510
Griffith Energy Project	07/01/2001	650
South Point	06/01/2001	540
	Yearly Subtotal	**1,820**
Kyrene	10/01/2002	250
Arlington Valley 1	08/01/2002	580
Redhawk 1	06/01/2002	530
Redhawk 2	06/01/2002	530
Sundance Energy Project #1	06/01/2002	450
Gila River 1	04/01/2003	520
Gila River 2	08/01/2003	520
West Phoenix (Phase 2)	Early summer 2003	500
	Yearly Subtotal	**3,880**

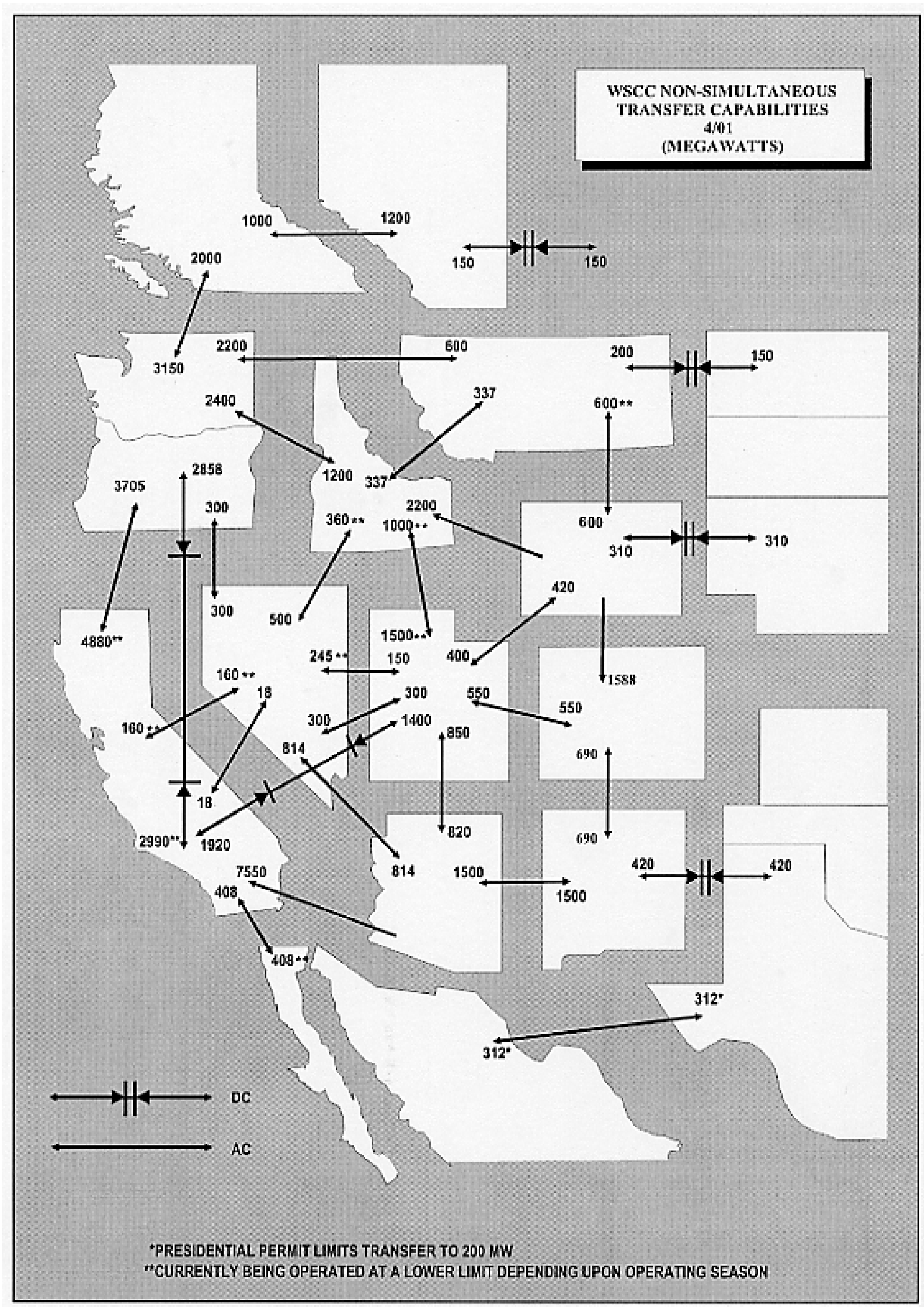
The thermal ratings for many existing Arizona transmission lines are listed in Appendix B. These ratings were extracted from a Palo Verde Interconnection Study report.

Another means of rating transmission facilities is by determining the stability limit for a group or set of lines. A stability limit is established via technical studies that determine the maximum power that can be transferred over a group of lines. An electric system is considered stable when excursions in frequency, power and voltage remain within predetermined ranges over time during changing operating conditions or system disturbances.

A grouping or set of transmission lines 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 at any point in time. This rating is established by technical studies that consider the network topology and operational conditions affecting the 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. In fact, the 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 4.2 depicts the TTC for key WECC paths for 2001. This map is slightly different from the map of TTC for 2000 that was included in the first BTA report. For instance, the TTC on the path between Montana and Utah has changed from 600 to 400, and the TTC on the Path from Washington to Montana has changed from 800 to 500, because of changes in system configuration and changes in generation dispatch patterns.

Figure 4.2
TTC for Key WECC Transmission Paths for 2001



The paths of interest to Arizona are shown in Figure 4.3, and are defined below in Table 4.4. A path of particular interest to Arizona is Path 49, East of Colorado River (EOR). Figure 4.4 illustrates the actual hourly flow on Path 49 during 2001, which shows the flow pattern for the 8760 hours in the year 2001. As can be seen, the flow ranges between 80% and 20% of the path's Operating Transfer Capability (OTC) rating of 7550 MW on a daily basis for the year. This is in contrast to the flows reported in the first BTA for the week of December 2-9, 2000, that ranged between 90% and 75% of the path OTC rating.[20] This leads one to conclude that no unforeseen system alert conditions occurred on the western system in 2001, and that the California ISO, which contributed to heavy flows on Path 49 during the week of December 2-9, 2000, has taken measures to avoid the recurrence of alert conditions on the California system.

Table 4.4
WECC Paths in Arizona

WECC Path #	WECC Path Name
22	Southwest of Four Corners
23	Four Corners 345/500 kV Qualified Path
49	East of Colorado River (EOR)
50	Cholla - Pinnacle Peak
51	Southern Navajo

[20] ACC Revised Biennial Transmission Assessment, Docket No. E-00000A-01-0120, July 2002, page 25.

Figure 4.3
Western Interconnection Paths

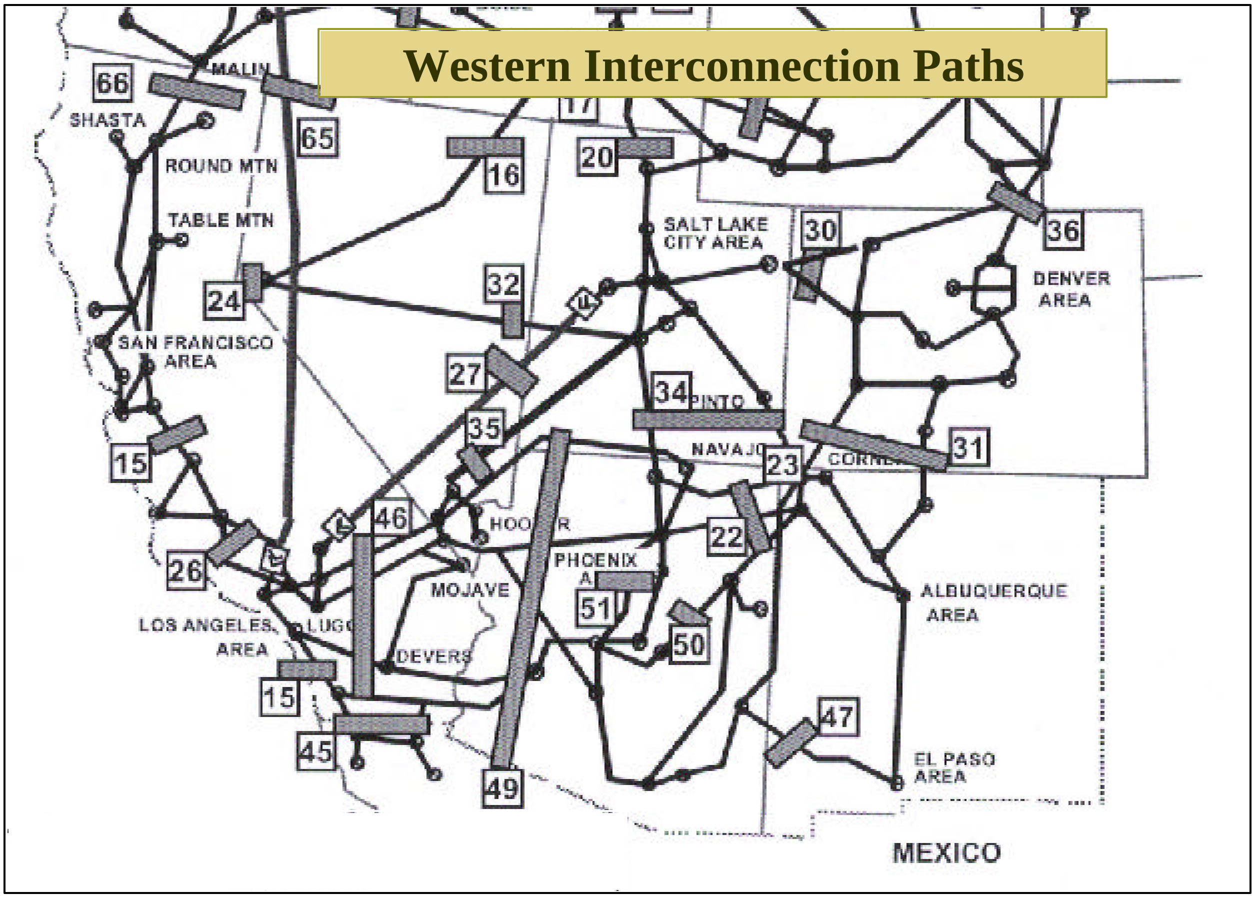
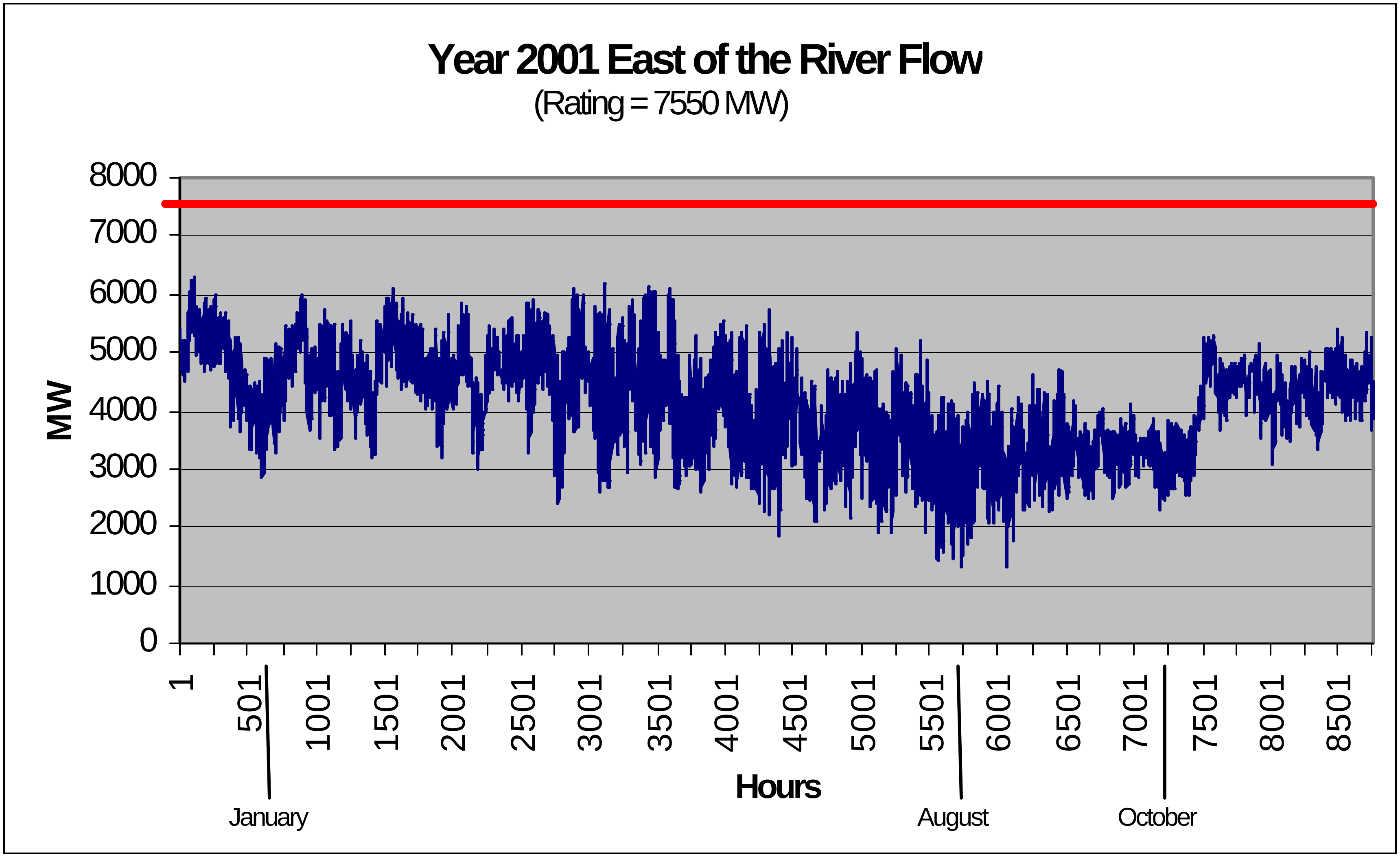


Figure 4.4


Year 2001 East of the River Flow
(Rating = 7550 MW)
MW
8000
7000
6000
5000
4000
3000
2000
1000
0
1
501
1001
1501
2001
2501
3001
3501
4001
4501
5001
5501
6001
6501
7001
7501
8001
8501
Hours
January
August
October

5. Ten-Year Plans

5.1 2002-2011 Updates Filed January 2002

A.R.S. §40-360.02 states that every organization contemplating construction of any transmission line within the state during any ten-year period shall file a ten-year plan with the ACC on or before January 31 of each year. Each plan shall provide:

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

A compilation of planned transmission line additions filed in January 2002 that comprises the Ten-Year Plans for 2002-2011 is provided in Appendix C. The transmission lines are listed chronologically by projected in-service dates and by the entity that filed the planned addition, and also by transmission voltage level. 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 first BTA.

Figures 5.1 through 5.7 illustrate the planned transmission facilities for the state of Arizona, and for the Phoenix, Tucson, Southeastern Arizona, Northern Arizona, Southern Arizona and Mohave County areas.

Figure 5.1
Arizona Planned EHV Transmission
2002-2011

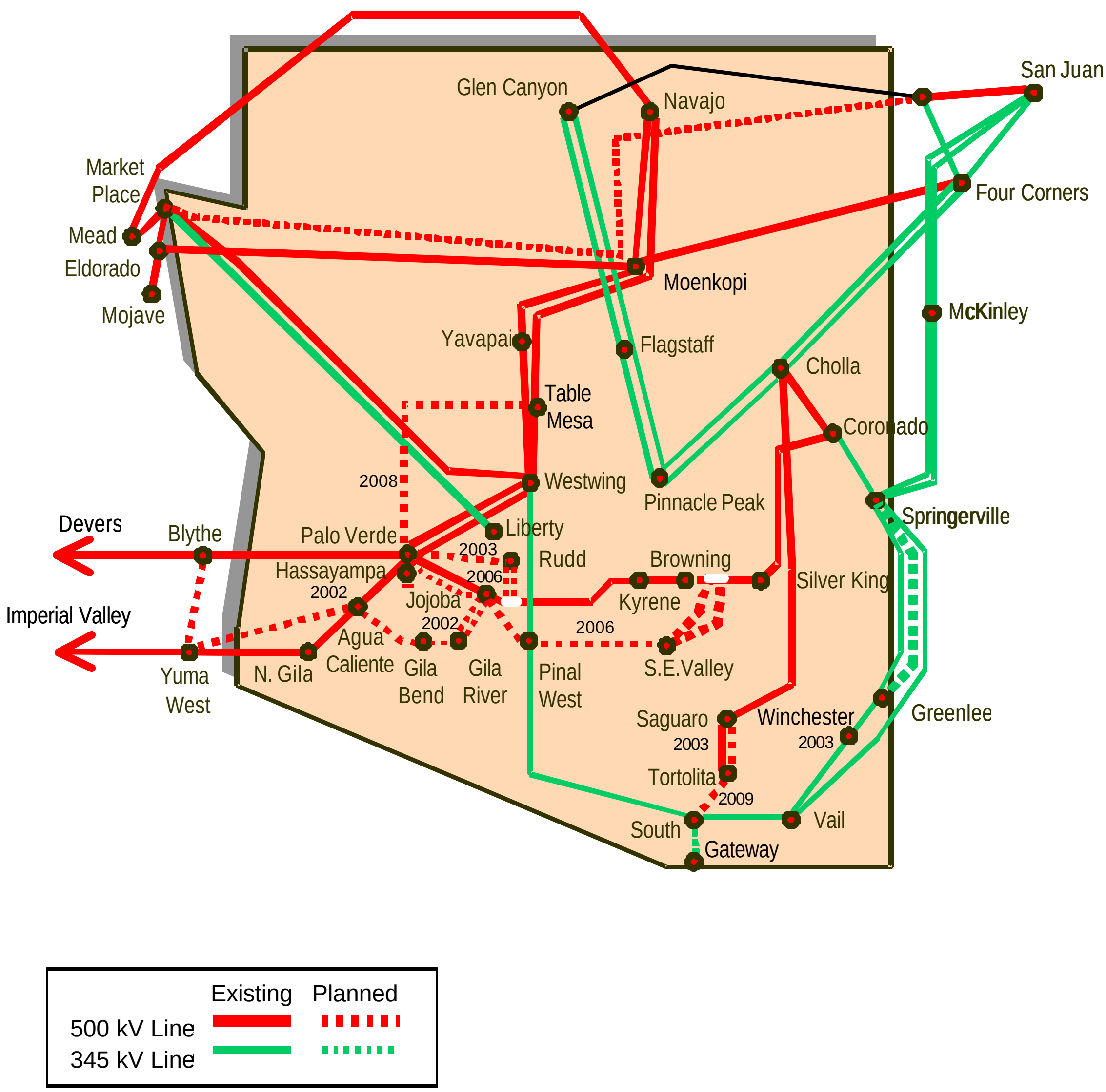


Figure 5.2
230 kV Transmission Map : Phoenix Metropolitan Area

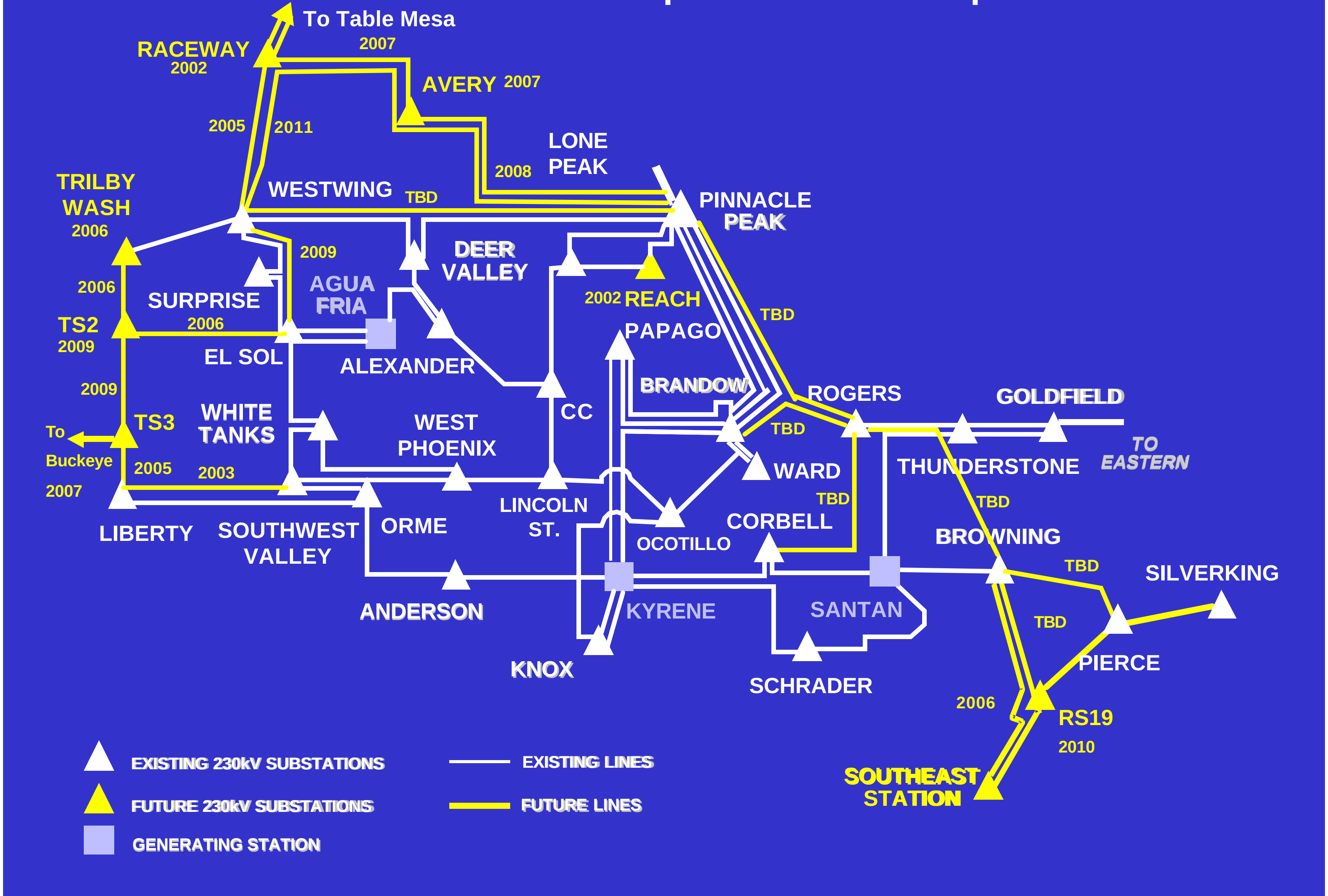
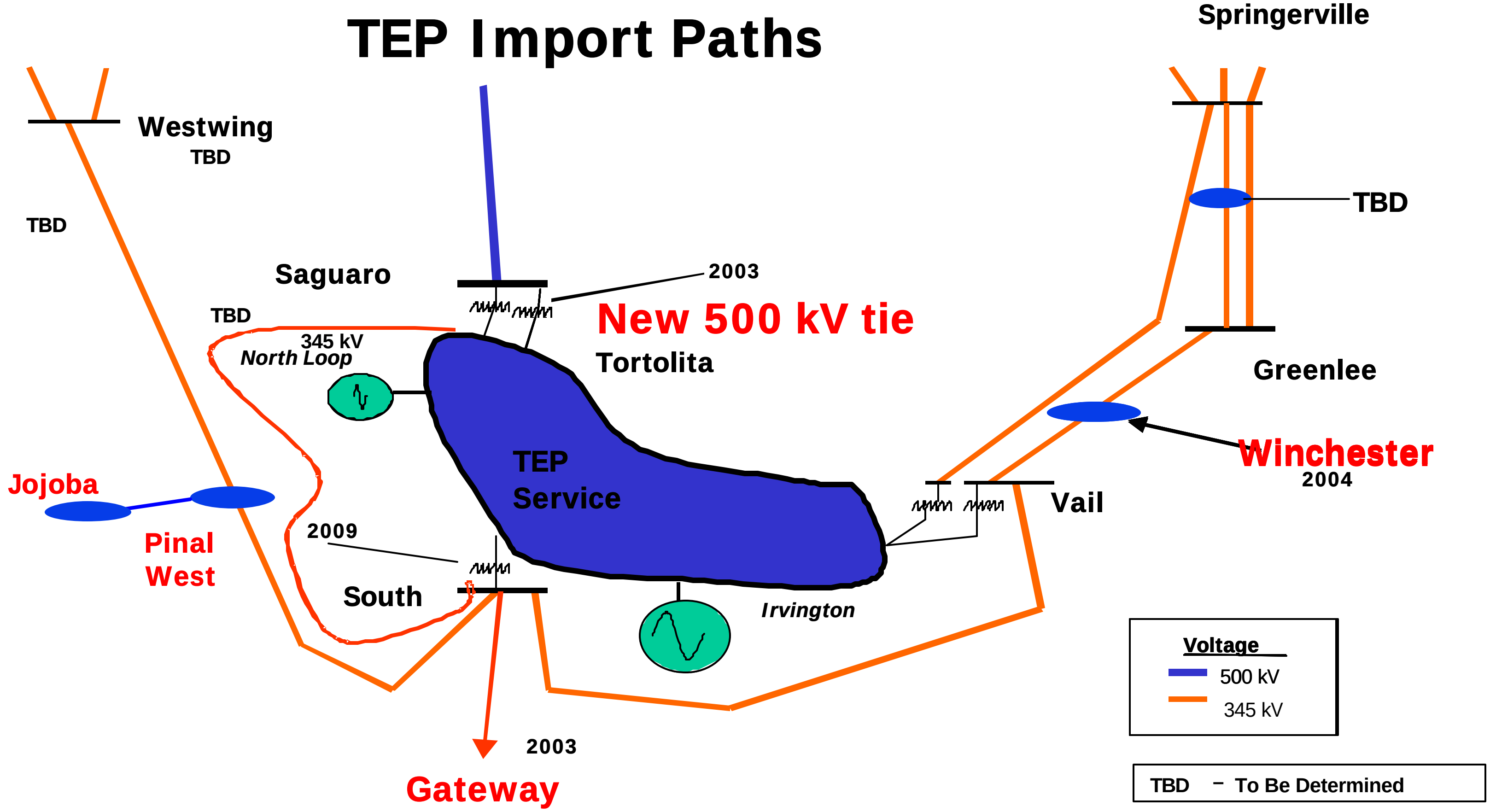
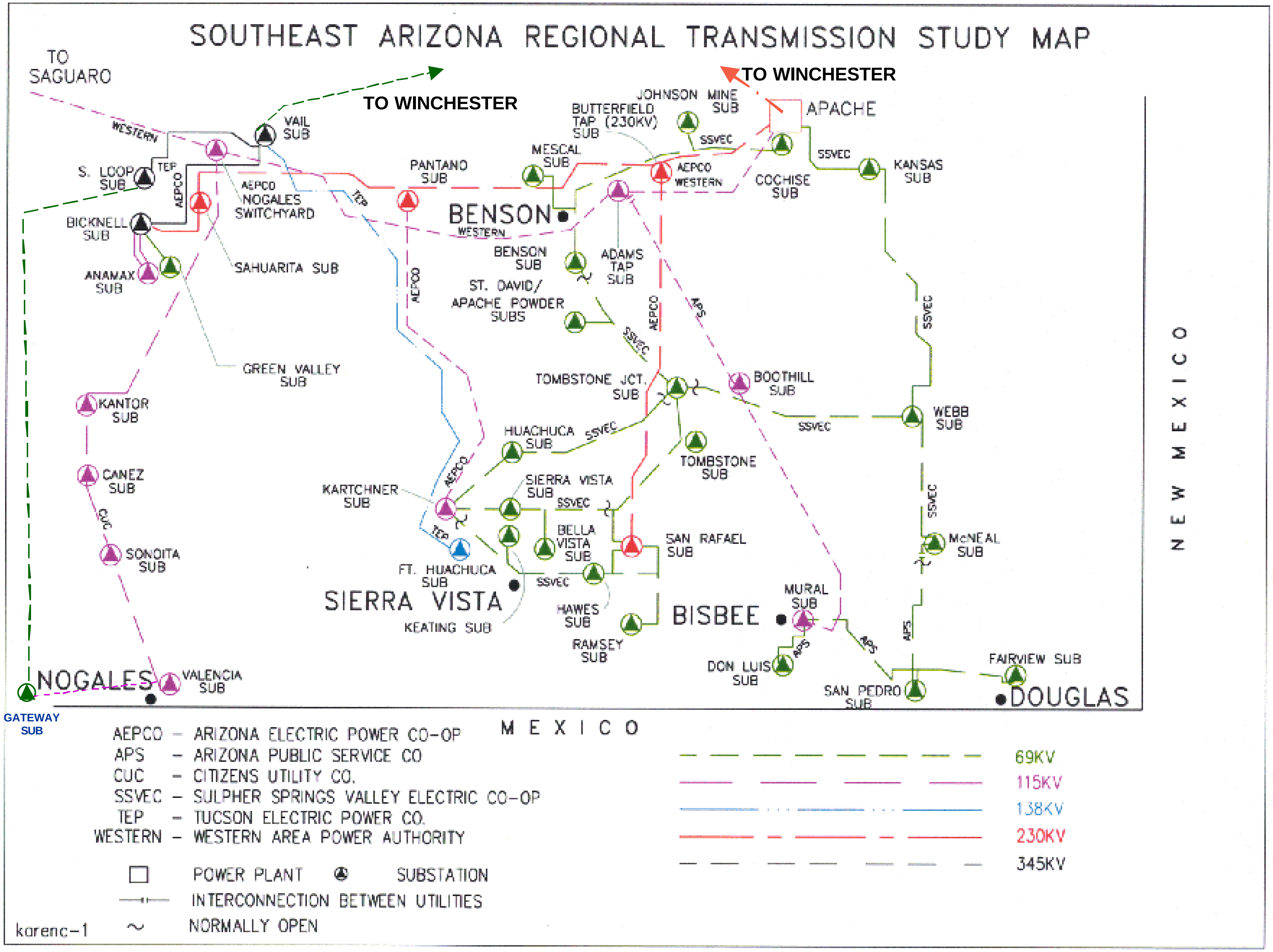


Figure 5.3



TEP Import Paths
Springerville
Westwing
TBD
TBD
TBD
Saguaro
2003
New 500 kV tie
TBD
345 kV
North Loop
Tortolita
Greenlee
Winchester
2004
TEP
Service
Jojoba
Pinal
West
2009
Vail
South
Irvington
Voltage
500 kV
345 kV
2003
Gateway
TBD – To Be Determined

Figure 5.4



SOUTHEAST ARIZONA REGIONAL TRANSMISSION STUDY MAP
TO SAGUARO
TO WINCHESTER
TO WINCHESTER
APACHE
JOHNSON MINE SUB
BUTTERFIELD TAP (230KV) SUB
VAIL SUB
S. LOOP SUB
BICKNELL SUB
ANAMAX SUB
AEPCO NOGALES SWITCHYARD
SAHUARITA SUB
GREEN VALLEY SUB
PANTANO SUB
MESCAL SUB
BENSON
BENSON SUB
ADAMS TAP SUB
ST. DAVID/ APACHE POWDER SUBS
COCHISE SUB
KANSAS SUB
TOMBSTONE JCT. SUB
BOOTHILL SUB
WEBB SUB
HUACHUCA SUB
TOMBSTONE SUB
SIERRA VISTA SUB
KARTCHNER SUB
BELLA VISTA SUB
SAN RAFAEL SUB
FT. HUACHUCA SUB
SIERRA VISTA
KEATING SUB
HAWES SUB
RAMSEY SUB
BISBEE
MURAL SUB
DON LUIS SUB
SAN PEDRO SUB
McNEAL SUB
FAIRVIEW SUB
DOUGLAS
KANTOR SUB
CANEZ SUB
SONOITA SUB
NOGALES
VALENCIA SUB
GATEWAY SUB
WESTERN
TEP
AEPCO
SSVEC
APS
CUC
N E W M E X I C O
M E X I C O
AEPCO – ARIZONA ELECTRIC POWER CO-OP
APS – ARIZONA PUBLIC SERVICE CO
CUC – CITIZENS UTILITY CO.
SSVEC – SULPHER SPRINGS VALLEY ELECTRIC CO-OP
TEP – TUCSON ELECTRIC POWER CO.
WESTERN – WESTERN AREA POWER AUTHORITY
POWER PLANT
SUBSTATION
INTERCONNECTION BETWEEN UTILITIES
NORMALLY OPEN
69KV
115KV
138KV
230KV
345KV
karenc-1

Figure 5.5
Northern Arizona 230 kV Transmission Plans
2002-2011

Winona/Flagstaff 230kV Interconnection

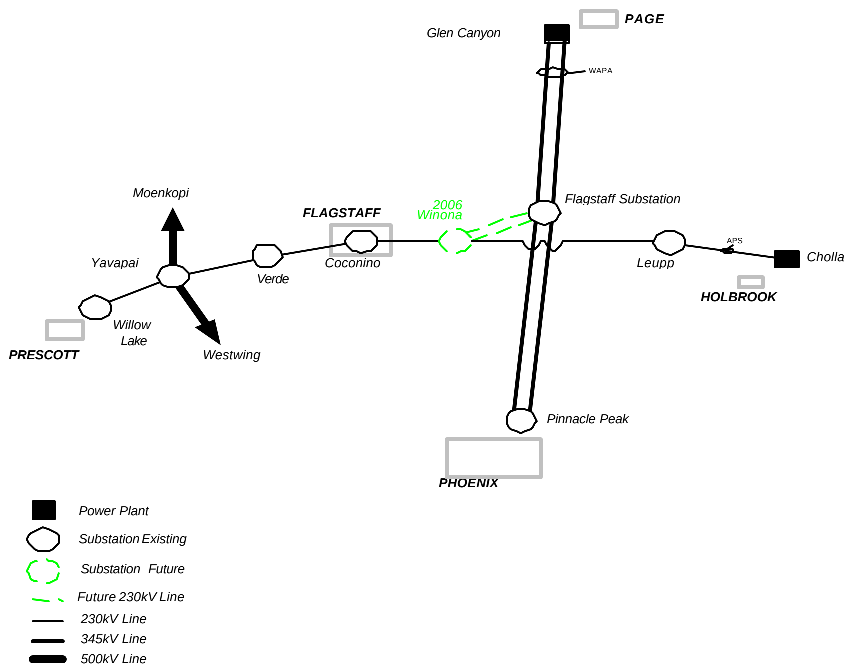


Figure 5.6
Citizens Transmission Plans
2002-2011

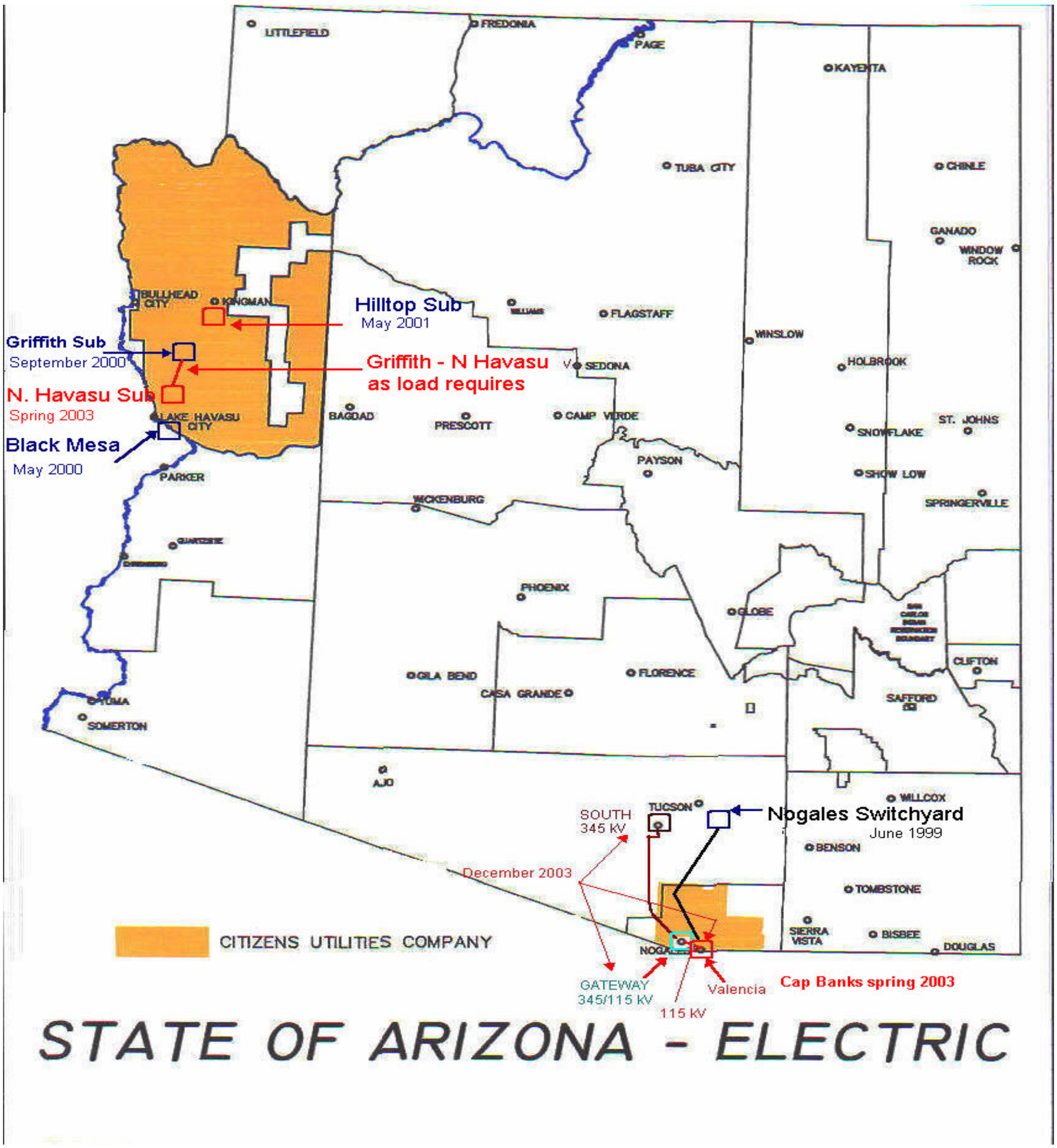
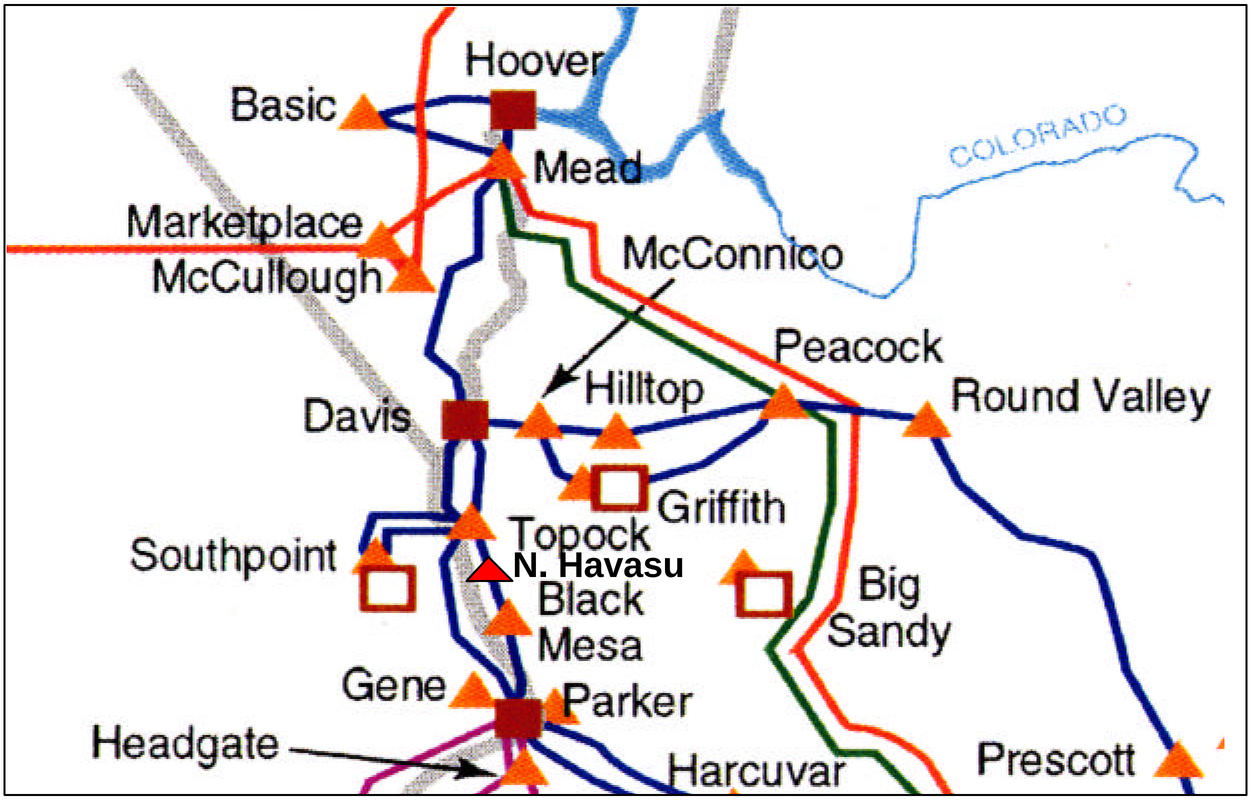


Figure 5.7
Mohave County Area



Utility Power Plant

Merchant Power Plant

Substation

Tables 5.1 through 5.3 compare the transmission plan filings between the first and second BTA. Based on the information presented by various utilities, the following tables summarize the following:

- Transmission projects filed for the first time
- Transmission projects with change in planned in-service date
- Transmission projects deleted from previous filed plan

Table 5.1
Transmission Projects Filed for the First Time

In-Service	Description	Voltage	Status
2002	Gila River –Jojoba #1 and # 2	500 kV	New
2003	Saguaro-Tortolita #2	500 kV	New
2003	South-Gateway #1 and #2 (Joint Project)	345 kV	New
2003	Gateway-Valencia	115 kV	New
2004	Loop-in of TEP Winchester switchyard (Joint Project)	345 kV	New
2004	Apache-Winchester	230 kV	New
2005	Westwing-Raceway	230 kV	New
2006	Rudd cut in of Jojoba-Kyrene	500 kV	New
2006	Silver King-Southeast Valley	500 kV	New
2006	Southeast Valley-Browning	500 kV	New
2006	Hassayampa-S.E. Valley	500 kV	New
2006	Hassayampa-Jojoba-Pinal West	230 kV	New
2006	Flagstaff-Winona	230 kV	New
2006	Pinal West-Southeast Valley	230 kV	New
2006	Pinal-Ice House	115 kV	New
2008	Palo Verde-Table Mesa	500 kV	New
2008	Table Mesa-Raceway	230 kV	New
2008	Fountain Hills Station	115/230 or 500 kV	New
2010	Irvington–East Loop (through 22nd Street) #2	138 kV	New
TBD	Gila Bend-Agua Caliente	500 kV	New
TBD	Agua Caliente-Yuma West	500 kV	New
TBD	Yuma West-Blythe	500 kV	New
TBD	Palo Verde-Saguaro	500 kV	New
TBD	Yuma West-Highline #1 and #2	230 kV	New
TBD	RS19-RS23	230 kV	New
TBD	Silver King-Knoll-New Hayden	230 kV	New

TBD: To Be Determined

Table 5.2
Transmission Projects with Change in Planned In-service Date
(In Chronological Order by New In-Service Date)

Description	Voltage	Prior In-Service	New In-Service
Santa Rosa-Gila Bend	230 kV	2006	2005
East Loop-Northeast through Snyder Phase 2	138 kV	2005	2005
Gila Bend-Yuma	230 kV	2004	2006
Rancho Vistoso-Catalina	138 kV	2005	2008
Browning-Southeast Valley #1 and #2	230 kV	2012	2010
Westwing-El Sol	230 kV	2008	2009
Browning-RS19, RS19	230 kV	2012	2006
Tortolita-South	345 kV	TBD	2009
Loop North Loop-DeMoss Petrie Station through Del Cerro (Sweetwater)	138 kV	2006	2009
Loop Vail-East Loop through Pantano and Los Reales	138 kV	2006	2009
Loop Green Valley-Cypress Sierrita through New Cypress Raw Water Substation	138 kV	2007	2009
Springerville-Greenlee #2	345 kV	TBD	TBD
Westwing-South #2	345 kV	TBD	TBD
Vail-East Loop (through Houghton Loop Station) #3	138 kV	TBD	TBD
Westwing-Pinnacle Peak	230 kV	2012	TBD
Pinnacle Peak-Brandow, Loop into Rodgers	230 kV	2012	TBD
Rogers-Corbell	230 kV		TBD
Rogers-Browning	230 kV		TBD
Silver King-Browning	230 kV	2012	TBD
Browning-Pierce	230 kV	2012	TBD
RS19-Pierce, Pierce	230 kV	2012	TBD
All SRP Projects	115 kV	2010	TBD
All SRP Projects	115 kV	2012	TBD

TBD: To Be Determined

Table 5.3
Projects Deleted from Previous Plan

2000 BTA In-Service Date	Description	Voltage	Status
2004	Pinnacle Peak-TS1	230 kV	Replaced with subtransmission facilities
2007	Pioneer-TS5	230 kV	Replaced with Raceway-Avery 230kV
2007	White Tanks-TS3-Buckeye	230 kV	White Tanks-TS3 replaced with Rudd-Lib So-Ts3 and Lib-Lib So- and advanced to 2005
2007	TS3-Buckeye	230 kV	Replaced White Tanks TS3-Buckeye
2008	Pinnacle Peak-Pioneer	230 kV	Replaced with Pinnacle Peak–Avery 230kV
2009	Westwing-Pioneer	230 kV	Replaced with Westwing-Pinnacle Peak, 2011
2003	Loop DeMoss-Petrie-Northwest line through new Fort Lowell-Mountain Substation	138 kV	Deleted

5.2 Technical Studies Supporting Filed Plans

A.R.S. 40-360.02 stipulates the following:

A. *Every person contemplating construction of any transmission line within the state during any ten -year period shall file a ten-year plan with the commission on or before January 31 of each year.*

B. *Every person contemplating construction of any plant within the state shall file a plan with the commission ninety days before filing an application for a certificate of environmental compatibility as provided in section 40-360.03.*

C. *Each plan filed pursuant to subsection A or B of this section shall set forth the following information with respect to the proposed facilities to the extent such information is available:*

1. *The size and proposed route of any transmission lines or location of each plant proposed to be constructed.*
2. *The purpose to be served by each proposed transmission line or plant.*
3. *The estimated date by which each transmission line or plant will be in operation.*

4. The average and maximum power output measured in megawatts of each plant to be installed.

5. The expected capacity factor for each proposed plant.

6. The type of fuel to be used for each proposed plant.

7. The plans for any new facilities shall include a power flow and stability analysis report showing the effect on the current Arizona electric transmission system. Transmission owners shall provide the technical reports, analysis or basis for projects that are included for serving customer load growth in their service territories.

Through the results of the power flow and stability analyses, the parties shall determine when and where new electrical facilities are needed to serve the customer load in a reliable and economical manner. In addition, the parties shall evaluate, through these study analyses, the needs of increasing the import capability to load constrained areas, and the needs of interconnection of generation to the transmission system to satisfy system adequacy.

All the utilities in Arizona provided detailed technical study reports in support of their ten-year plans, and included adequate details with regard to the contingencies considered, simulation tools employed for the analyses, and the power flow and stability analysis results.

5.3 Forecast of Transmission Siting Applications

The following Table 5.4 is a listing of the projects that will likely file an application for a Certificate of Environmental Compatibility (CEC) within the next two years. It represents a significant hearing workload for the Siting Committee.

Table 5.4
Transmission Projects That Require CEC Filing

In-Service	Description (CEC Filing Date)	CEC Filing Date	Voltage
2005	Westwing-Raceway	2002	230 kV
2005	Liberty South-TS3	2002	230 kV
2005	Liberty South-Liberty (Western)	2002	230 kV
2003	Saguaro-Tortolita #2	2002	500kV
2006	Trilby Wash-TS2-El Sol	2003	230 kV
2004	Apache-Winchester	2003	230 kV
2006	Hassayampa-SE Valley	TBD	500 kV

In-Service	Description (CEC Filing Date)	CEC Filing Date	Voltage
2006	Flagstaff-Winona	TBD	230 kV
2006	Gila Bend-Yuma	TBD	230 kV
2008	Fountain Hills Substation	TBD	115/230/345 kV
2006	Silver King-Southeast Valley	TBD	500 kV
2006	Southeast Valley-Browning	TBD	500 kV
2006	Browning-SE Valley #1 and #2	TBD	230 kV
2005	Loop-in Irvington Station to Vail through Robert Bills-Wilmot substation	TBD	138 kV
2008	Rancho Vistoso-Catalina	TBD	138 kV

6. Arizona EHV Transmission Projects and Studies

There is a need to perform transmission planning and expansion in the State of Arizona at a state and regional level given the location of load pockets, generation resources and merchant plant development. As explained in Section 3, coordination is required among the various transmission providers in developing transmission expansion plans that serve the needs of Arizona customers in an economical and reliable manner. In addition, coordination is required with the utilities in neighboring states to ensure adequate transmission interconnections for import and export of energy. This section describes the coordinated transmission planning activities among utilities in the state of Arizona, and among utilities in the southwest region.

6.1 Diné Power Authority's Navajo Transmission Project

The Navajo Transmission Project (NTP) is a 460- mile, 500 kV line with an expected capacity of 1,200 to 1,800 MW. It will interconnect Shiprock, Moenkopi and Market Place substations, and traverse three states. The project is being developed by the Diné Power Authority (DPA). The Navajo Nation has the right-of-way, which is 60% of the line from Shiprock to Moenkopi substation.

The ongoing activities on the project development are:

- Finalize combination and selection of NTP segments: Segment 1 from Shiprock to Cheat, segment 2 from Cheat to Moenkopi, and segment 3 from Moenkopi to Southern Nevada.
- Finalize combination of new/existing substations: Substations in Four Corners and Shiprock, and build a new one in Red Mesa East, with 230kV to 500 kV lines coming from the Page area.

DPA obtained a CEC for the non-reservation Segment 3 of the project from the ACC in October 2000. In its decision granting a CEC for the project, the Commission stipulated that construction of Segment 3 could not commence until Segment 1 from Shiprock to Red Mesa was operational at rated capacity.[21] DPA is also required to become a WECC member and file a copy of its

[21] Decision No. 63197, Condition 5, Docket No. L-00000U-00-0103.

Reliability Management Agreement with the Commission.[22] Copies of all interconnection studies performed for the project are also to be filed with the Commission.[23]

DPA identified the following benefits of the NTP:

- Improve the operational flexibility and reliability of the EHV system in the region
- Relieve the constraints on the transmission of electricity west of the Four Corners area
- Allow increased economical power transfers, sales, and purchases in the region
- Improve the economic conditions of the Navajo Nation
- Facilitate the development of Navajo Nation energy resources such as coal, oil, and gas for use in energy projects

6.2 Palo Verde System Constraints

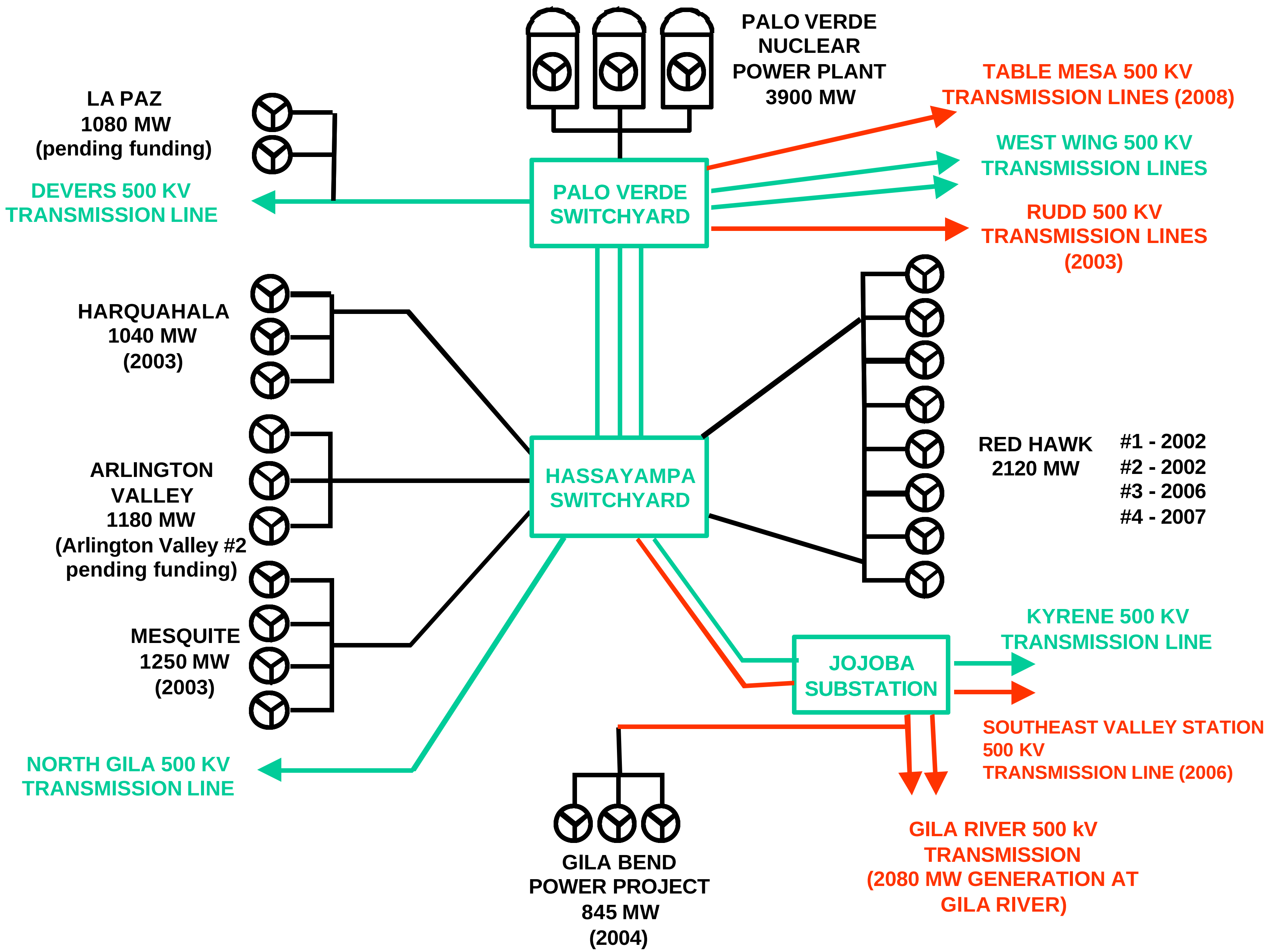
The Palo Verde Nuclear Generating Station is located approximately 35 miles southwest of the Phoenix Metropolitan area. It is comprised of three nuclear generating units with a net output of approximately 1,270 MW each. The Palo Verde Transmission System Facilities include the Palo Verde 500 kV Switchyard, the Arizona Nuclear Power Project (ANPP) Valley Transmission System (the Palo Verde-Westwing 500 kV #1 and #2 transmission lines, the Palo Verde-Kyrene 500 kV transmission line and the Kyrene 500 kV Switchyard), the Palo Verde-Devers 500 kV transmission line, and the Palo Verde-North Gila 500 kV transmission line, as illustrated in Figure 6.1.

The Palo Verde Nuclear Generating Plant and new generators interconnected into the Palo Verde Transmission System are required to operate within the requirements of the "Interchange Scheduling and Congestion Management Procedure". Revisions to this procedure will be made over time as studies incorporating the latest WECC criteria are performed, new generation is actually brought on-line, and transmission expansions are made. The detailed operating studies will identify revised capacities, ratings, restrictions and limitations under all assumed operating

[22] Ibid, Condition 6.

[23] Ibid, Condition 7.

Figure 6.1
PALO VERDE AND HASSAYAMPA 500 kV SWITCHYARDS



conditions. Staff would view any generation restrictions or limitations identified for single contingency outages (N-1) by the operating studies performed in accordance with the Palo Verde "Interchange Scheduling and Congestion Management Procedure" as not complying with CEC conditions placed by the Commission upon new interconnecting generators.

The generation at the Palo Verde hub with an approved CEC is not expanding as expected or within the time frames projected. The assessment of whether the generation capacity has outstripped the transmission capability must be evaluated with respect to actual generation and transmission expansion and timing of their occurrence. No curtailments or scheduling restrictions should be required to accommodate single contingency outages if the industry is to rely on the new units as being available for firm energy transactions.

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. The technical studies show that simply interconnecting to a market hub does not assure that the power from new plants can be delivered to the intended consumer market. It further determines that the existing Palo Verde transmission system falls considerably short of being able to accommodate all of the new power plants. According to Palo Verde Interconnection Studies, the existing Palo Verde transmission system can accommodate a maximum of 3,360 MW of additional power over and above the output of the Palo Verde nuclear units. Generating capacity of the power plants, with a Commission approved CEC and proposing to interconnect at Palo Verde or with the Palo Verde Transmission system, has a total output (9,595 MW) that far exceeds the limits of the existing system. Staff concludes that the existing Palo Verde transmission system is inadequate. As the new plants are constructed they must file a study report with the Commission prior to commercial operation that demonstrates the plant can deliver it full output to a market without causing a priori generation at the Palo Verde hub to be curtailed. Failure to do so will mean the plant has not fulfilled one of the conditions of its CEC

The Palo Verde Interconnection studies do verify that the Palo Verde system is very crucial to the reliable operation of the whole Western Interconnection. This is demonstrated by the voltage stability of the Pacific Northwest being a limiting factor in the outage consideration of some Palo

Verde system elements. This phenomenon persists even with the construction of the Palo Verde to Rudd 500 kV line in 2003 and upgrade of the Palo Verde to N. Gila and Palo Verde to Kyrene 500 kV lines. On this basis, Staff considers the transmission plans for Palo Verde to be inadequate for the interconnection of all new proposed power plants.

Staff began taking a more stringent position regarding the lack of adequate transmission out of the Palo Verde hub in more recent power plant and transmission line siting cases. Staff recommended a moratorium on all pending, or yet to be filed, CEC applications for generating units proposing to interconnect at the Palo Verde hub or with transmission lines emanating from the hub.[24] The moratorium was recommended to allow proper development and review of reliability and system security traits appropriate for large commercial hubs in Arizona and the Western Interconnection, and commensurate with risks present and prevalent in today's society. This need was underscored by the tragic and devastating terrorist attacks against the United States on September 11, 2001.

6.3 Palo Verde Hub Risk Assessment

During the Siting process for the Palo Verde/Southwest Valley, Staff raised concerns about the concentration of lines and generation out of the Palo Verde/Hassayampa site as the hub assumed greater commercial importance.

In the Commission decision authorizing construction of a new 500 kV transmission line from the Palo Verde hub to Southwest Valley (Rudd), APS and SRP are required 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 the 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".[25]

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[24] Staff Exhibit S-1, Docket No. L-00000P-01-0117, September 14, 2001.

[25] Condition No. 23, Decision No. 65573, Docket No. L-00000D-01-0115.

A study was initiated by APS and SRP to do a technical analysis in compliance with the aforementioned requirements. The study scope includes a comprehensive technical analysis reviewing a series of catastrophic events and the impact those events could have. Common mode failure events were simulated and various alternatives addressing reconfiguration of the system after such an outage were evaluated.

This unique study first identified causes of catastrophic events including sabotage, weather, natural disasters and equipment failures. Secondly, substation layout and transmission corridors were looked at with respect to these catastrophic events, to see how many facilities would be lost under these common mode events. Computer simulations were analyzed to determine the impact of such events on the system.[26] Preliminary simulation results showed that the system is stable even for these low probability events. However, all the simulations have not yet been completed. A report will be prepared after all the results, operating and planning solutions have been evaluated.

APS, SRP and Staff have undertaken this study effort in a discretionary manner. In light of the current national anti-terrorism climate it is prudent to err on the side of confidentiality. Once studies are concluded, it may be necessary for the study participants to devise a means of engaging the industry in needed changes without disclosing the details of the study to the public.

6.4 Central Arizona Transmission Studies

The Central Arizona Transmission System (CATS) study encompasses an area bounded by the Phoenix Metropolitan area to the north, the Tucson Metropolitan area to the south, the Palo Verde Generating Station and environs to the west, and New Mexico to the east as shown in Figure 6.2. The history and objectives of the CATS study group are described in Section 3.6.

The objectives of the CATS study were to develop and address the regional transmission needs of the participants. The study was organized into the following three phases.

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[26] SRP Ten-Year Plan, 2002-2011, Appendix 2, Preliminary Study for the Palo Verde Interconnection.

Phase I study analyzed individual transmission alternatives proposed by the CATS participants, with the analysis limited to a power flow analysis for (N-0) and (N-1) contingencies. Each alternative was compared to a benchmarked case to determine its performance. The alternatives that performed the best were carried forward into Phase II study.

To meet the original objectives set down by the study team, six transmission paths were determined to be of significant interest in Phase I.

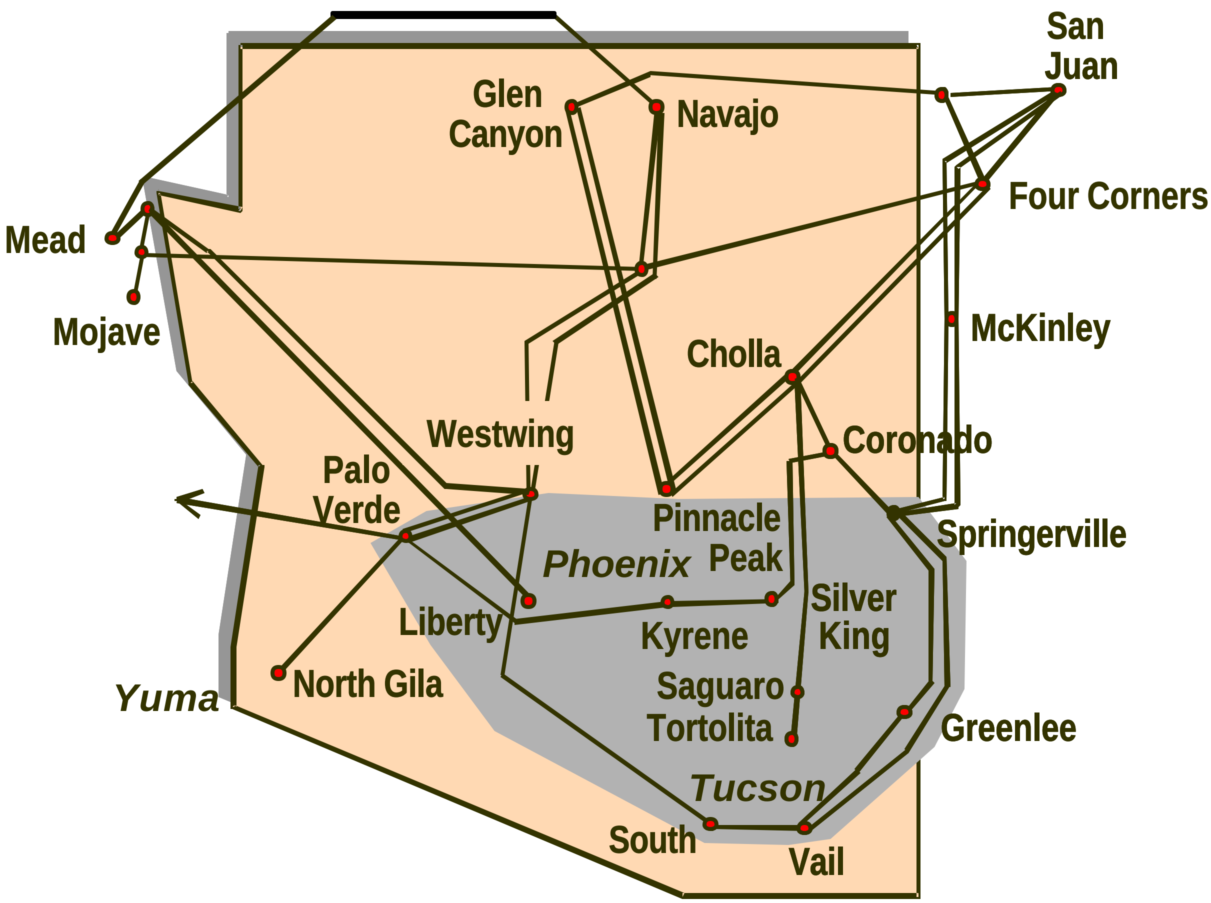
- Palo Verde to Saguaro 500kV line (four variations)
- Palo Verde to Southwest Phoenix Valley 500kV line (two variations)
- Use of Westwing to South 345kV line (two variations)
- 500kV line to the Southeast Phoenix Valley
- Loop-in of the Cholla to Saguaro 500kV line into Silver King (two variations)
- Saguaro to Tucson Area at 500kV, 345kV, or 230kV (four variations)

Power flow studies were performed to assess the system performance of each of the proposed transmission alternatives for each of the generation dispatch and load patterns studied. The study methodology increased generation output in a generation area, and correspondingly increased load in a load area. The system was determined to be constrained when a facility limit was reached for an N-1 contingency. Three major load centers were identified for this study: the Phoenix, Tucson and Southern Arizona load areas. The Phoenix load area consisted of load served by both Salt River Project, and Arizona Public Service with the valley load split 55% and 45% respectively. The Southern Arizona area consisted of load served by TEP and SWTC with the load split 80% and 20% respectively. Four scenarios were defined for study:

- Schedule new generation from the Palo Verde area (Group A. Generation) into the Phoenix area
- Schedule new generation from the Coolidge area (Group B. Generation) into the Phoenix area
- Schedule new generation from Tucson (Group C. Generation), Saguaro and Springerville (Group C. Generation) and Palo Verde (Group A. Generation) into the Tucson and Southwest Transmission Coop (SWTC) areas
- Schedule new generation from the Palo Verde area (Group A. Generation) to the Colorado/New Mexico area.

Figure 6.2

CATS Study Area



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The study group drew the following conclusions from Phase I study results:

- Building new transmission in the CATS area will increase transfers between Phoenix and Tucson
- While single alternatives can provide benefits to individual participants, more synergies are derived and more regional benefits can be achieved by combining alternatives
- SRP will derive more benefits from a new transmission alternative between Palo Verde and the Southeast valley (Southeast Station).
  - By improving its Phoenix load serving capability
  - By interfacing with the "build out of Browning" for local system expansion needs.
- Tucson will derive more benefits from a transmission alternative between Palo Verde-Saguaro-South or Palo Verde-Saguaro-Winchester
- SWTC will derive more benefits from a transmission alternative between Palo Verde-Saguaro-Winchester
- The system performance of the Palo Verde-Saguaro and the Gila Bend-Saguaro alternatives is nearly the same. However, the recent establishment of new national monuments in southeastern Arizona creates uncertainty about being able to build timely transmission for the Gila Bend –Saguaro alternative
- The availability of gas in the Saguaro/Southeast Valley area coupled with the proposed CATS transmission alternative to this area should enhance the siting of new generation in the Saguaro and Southeast Valley areas
- Developing generation in the Saguaro/Southeast Valley area will improve the efficiency of all the transmission alternatives studied, and increase the load serving capability to Phoenix and Tucson
- Strengthening the interconnection between the Cholla/Saguaro and/or the Coronado/Silver King transmission system to the east of the Phoenix system will enhance exports from Palo Verde to Phoenix
- Developing new interconnections to the transmission system east of Tucson enhances exports from Palo Verde to Tucson
- Opportunities to tie Winchester to the Southeast Valley may improve the transmission capability of the Springerville south system
- The alternatives chosen to advance to Phase II will need to incorporate consideration of TEP's Two–County flow requirements.

The **CATS Phase II** study included power flow analysis of the combination of alternatives found to be most desirable by Phase I study participants. The CATS Phase II base system is depicted in Figure 6.3. The following transmission alternatives to the base system were studied in Phase II:

- Palo Verde to Jojoba 500 kV
- Palo Verde to Gila Bend 500 kV
- Gila Bend to Watermelon 500 kV
- Watermelon to Pinal West 500 kV
- Jojoba to Pinal West 500 kV
- Pinal West to Southeast Station 500 kV
- Pinal West to Saguaro 500 kV
- Southeast Station Loop into Silver King/Browning 500 kV
- Southeast Saguaro to South 345 kV
- Winchester to South 345 kV

The Phase II study scope also included the alternative of replacing one of the 500 kV lines between Jojoba and Pinal West and Saguaro with two 345 kV circuits. The loop-in of the Cholla to Saguaro 500 kV line into Silver King was also studied. Two additional alternatives to the Cholla to Saguaro loop-in were also studied.

Several new transmission projects have emerged as a result of the CATS Phase II study effort. Each of the following four projects is depicted on Figure 6.4. The Palo Verde to Southeast Valley 500 kV line has become a formal project. It is being funded by multiple participants and is projected for service in 2006. Secondly, a Winchester Station and related 230 kV transmission project has been identified by Southwest Transmission Cooperative as a requirement for service to its member distribution cooperatives by 2004. The third project is for a 500 kV line between Hassayampa and Jojoba switchyards. Gila Bend Power Partners has filed an application for a CEC to complete construction of that line in 2004. The CATS Phase II study also resulted in the formation of a new HV subcommittee. Its purpose is to study and develop an underlying 69 kV to 230 kV transmission plan for service to northern Pinal County and interconnecting with the CATS EHV facilities.

Figure 6.3

CATS Phase II Scope

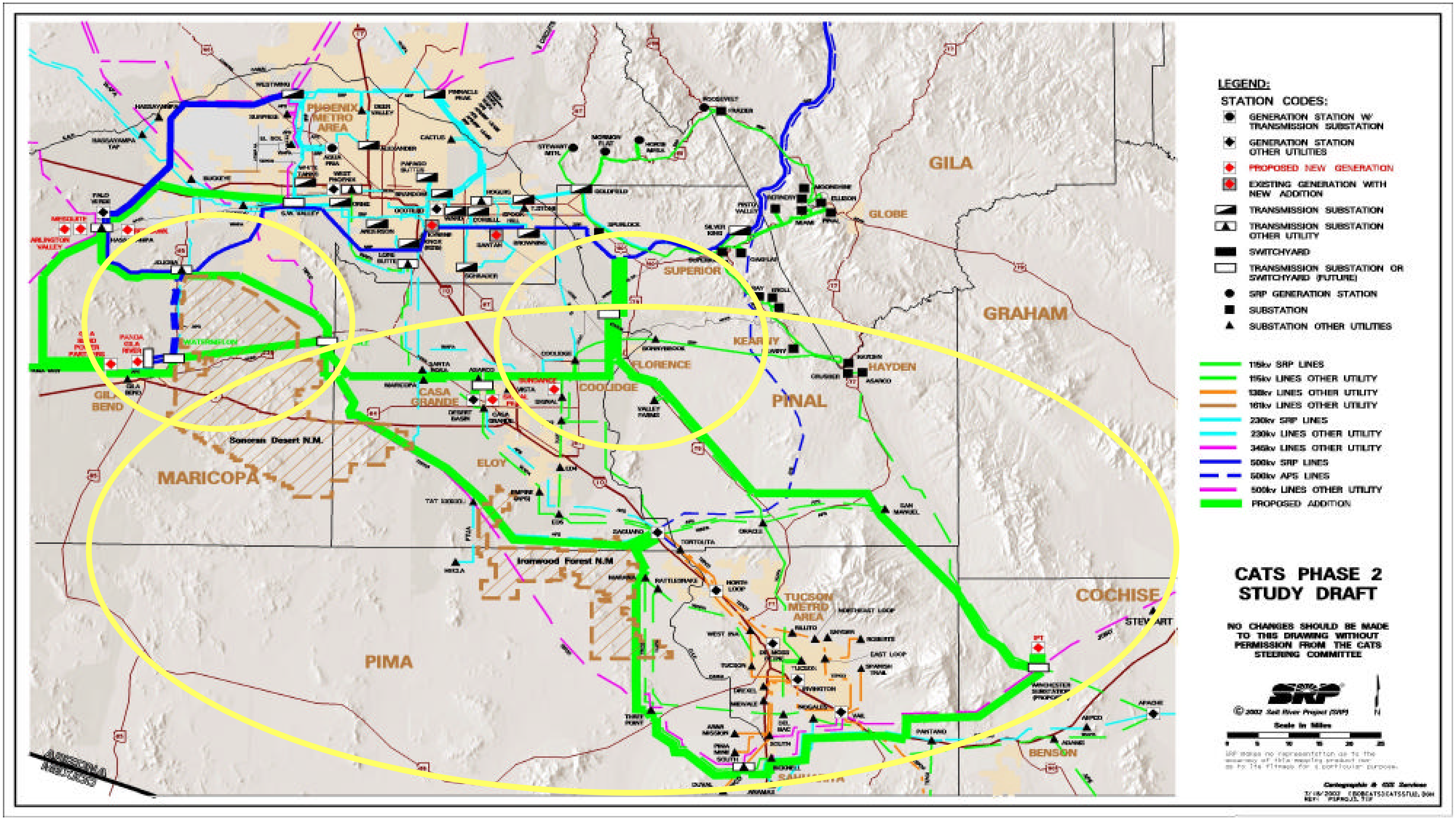
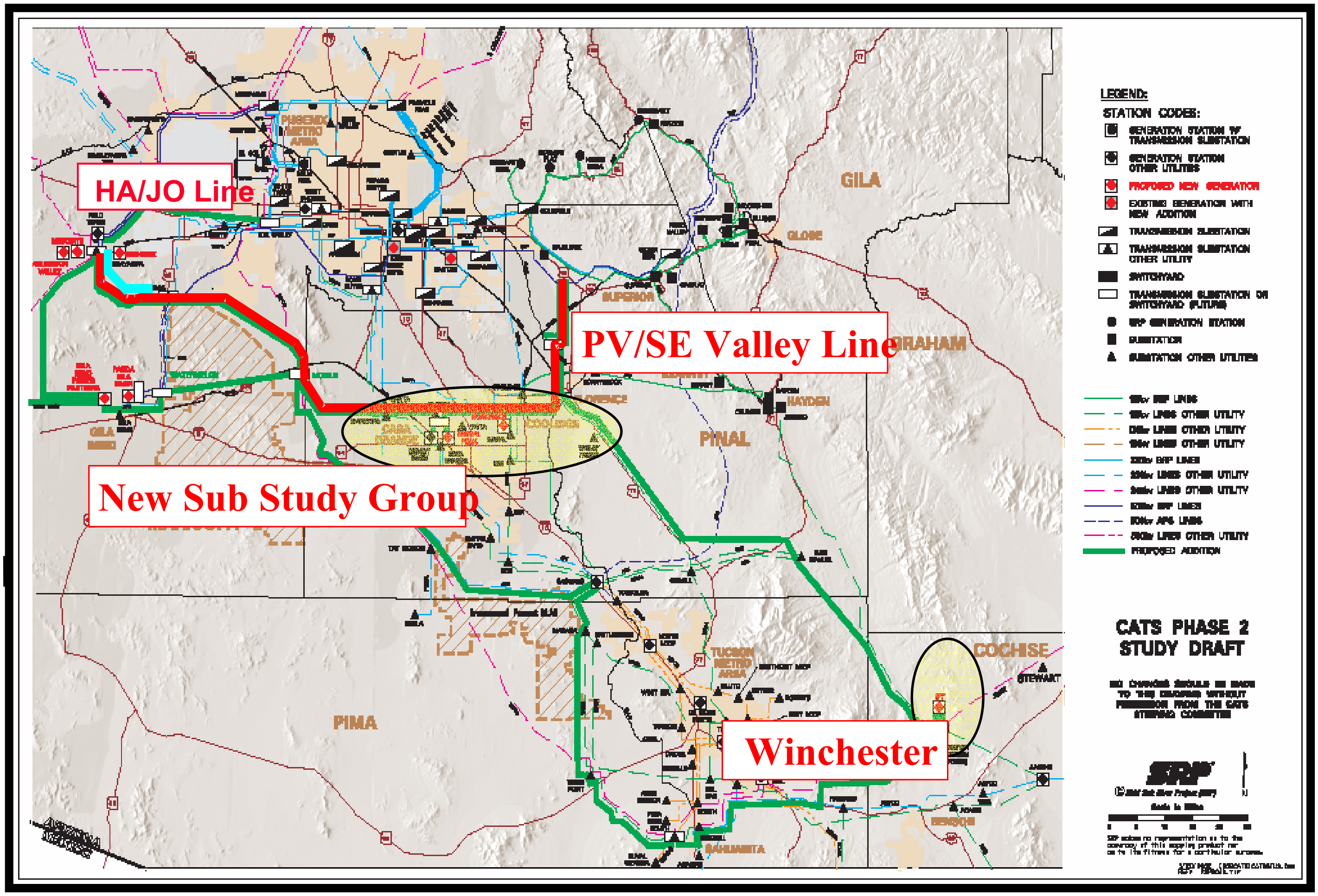


Figure 6.4

Making Progress



Based on the results of Phase II study, the following conclusions are reached:

- Both of the Palo Verde to Pinal West options, namely, two lines from Jojoba to Pinal West or one 500 kV from Jojoba and one 500 kV from Watermelon had similar performance.
- Looping Cholla to Saguaro 500 kV into Silver King was a better alternative than looping this line into Southeast Valley. There was little or no benefit from looping the Cholla to Saguaro 500 kV line into both Southeast Valley and Silver King.
- There are several good options to strengthen the ties to Saguaro. These options are:
  - A 500 kV line from Pinal West to Saguaro.
  - Two 345 kV lines for Pinal West to Saguaro.
  - A 500 kV line from Southeast Station to an intermediate switching station (initially named Carpas substation). From Carpas, a 500 kV line connects to Winchester and another 500 kV line connecting to Saguaro. This can be enhanced with the loop-in of the Cholla to Saguaro 500 kV line into Silver King.

    Each of the above options would require additional facilities to reinforce the remaining Southern Arizona system.
- The development of Winchester substation and a 500 kV line connection from the north reinforces the existing eastern EHV feed into Tucson, and the EHV feed into Southern Arizona from the east.
- The transfer capability from the Palo Verde Hub and from Central Arizona to the combined Tucson/Mexico area increased with the alternative of one 500 kV line and two 345 kV lines over the CATS base system of two 500 kV lines.
- Additional studies are needed to determine how these alternatives can be staged and integrated.

Based on the CATS Phase II study results and conclusions, the following were identified as **Phase III objectives**, which still need to be finalized by the CATS Steering Committee.[27]

- Develop a ten-year regional plan for central Arizona.
- Determine what CATS components will be needed within this ten-year time frame.
- Develop final CATS configuration recommendations along with identifying the desired timing, if possible, of each individual recommended section.

The ongoing Central Arizona HV study between Phoenix and Tucson, and a proposed Arizona - California interstate study project are also being considered by the CATS study group as CATS

[27] Report on the Phase II Study of the Central Arizona Transmission System (CATS), September 2002.

Phase III progresses. It is to be emphasized that CATS is an important and significant undertaking. Given its regional scope, the CATS reports were referred by numerous parties in support of their transmission plans filed in January 2002. Similarly, considerable national attention is being given to Arizona's novel and creative approach to planning its transmission system in an open and collaborative manner.

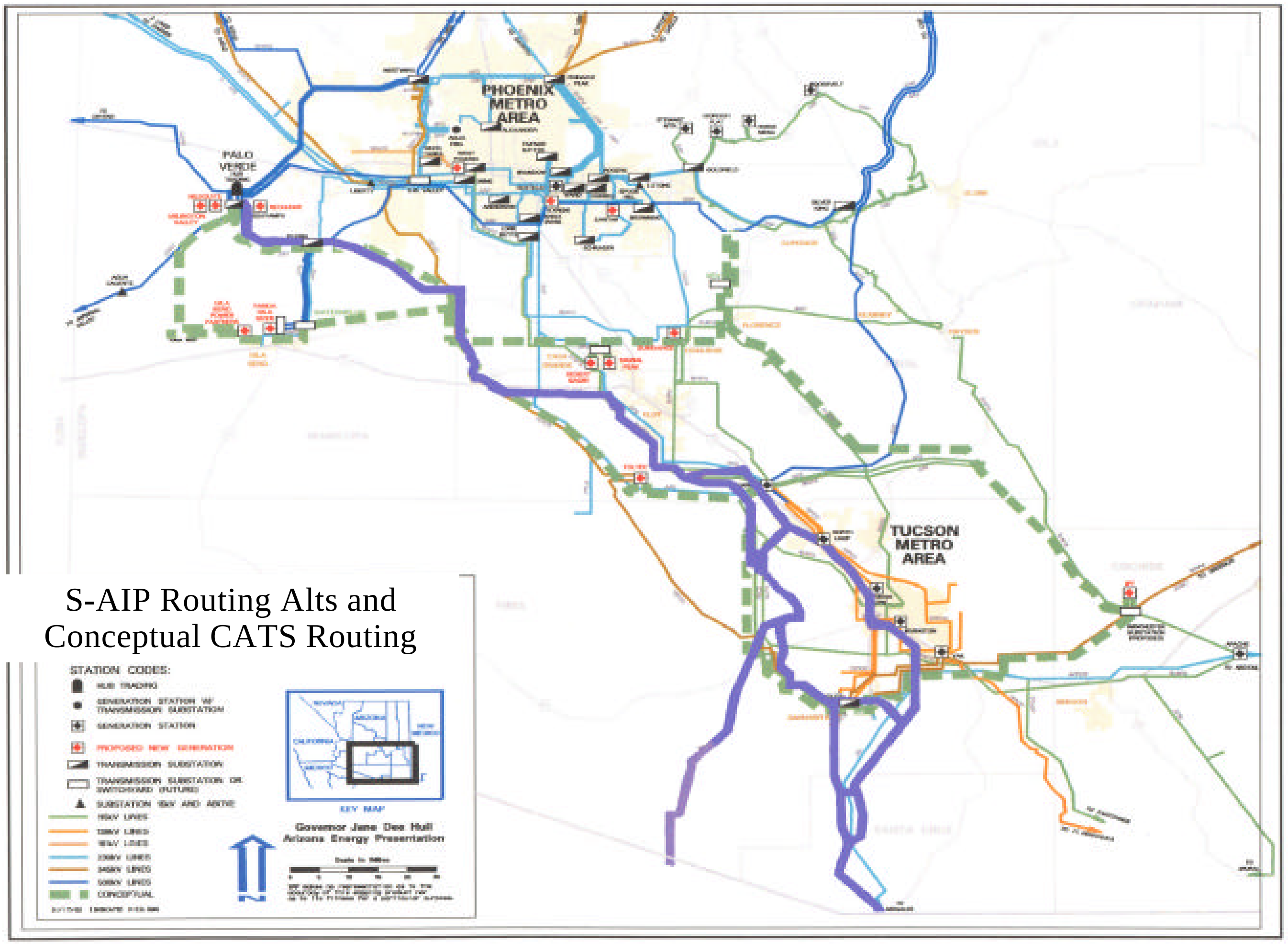
6.5 PNM Arizona-Sonora, Mexico Transmission Proposal

The Arizona-Sonora transmission interconnection is a project that Public Service Company of New Mexico (PNM) proposes to connect from Palo Verde to Mexico. The interconnection includes two 345 kV lines running south to the border of Arizona and Mexico, and 60 miles further into the State of Sonora, Mexico connecting to the Comision Federal de Electricidad (CFE) system, as shown in Figure 6.5. The transfer capability of the interconnection is expected to be between 800 MW and 1,000 MW. In order to safeguard against disturbances on either side of the border an AC/DC/AC converter station will be built on the border. PNM has also been participating in the CATS project. Through this process PNM has identified interconnection opportunities with its project that could improve import capability into the Tucson area by as much as 500 MW.

PNM applied for a Presidential Permit in December 1998, and has been working on the environmental studies. The lead agency for the Environmental Impact Statement (EIS) and Presidential Permit assessment is the U.S. Department of Energy. The Bureau of Land Management (BLM) and Forest Service are the other interested federal agencies involved in the process. Since February of 1999, there have been four sets of public scoping sessions held at 13 different locations in Arizona and New Mexico. The results so far have eliminated five transmission line corridors and now the study is focusing on the remaining five although, in some areas, the preferred corridor has been identified.

The draft EIS was expected to be available for review perhaps as early as September 2002, at which time an application for a CEC was to be made to the ACC. Neither activity has occurred at the writing of this report.

Figure 6.5
Arizona-Sonora, Mexico Transmission



6.6 Proposed Palo Verde/Gila Bend to California Transmission

Generation, existing and under construction, interconnecting to the Palo Verde hub is greater than the outlet capability of the transmission. The total nominal generation is around 13,500 MW (4,000 existing and 9,500 permitted), and the transmission outlet capability is 8,500 MW. Hence there is a potential that 5,000 MW of generation would be stranded with an (N-1) planning criteria condition. There is new generation in the Mexicali area that could effectively back off flows from Arizona to California. This would limit Arizona's export to California. There is also new generation proposed for the Las Vegas area which could load the transmission between Arizona and California. Then there is the interaction between transmission and generation, which will stress the existing transmission beyond its capability and reliability. These events could result in stranded generation within the respective generation areas. Increased system losses, wasted fuel, lost income, and higher energy delivery costs with lower reliability could result from the scenarios just described.

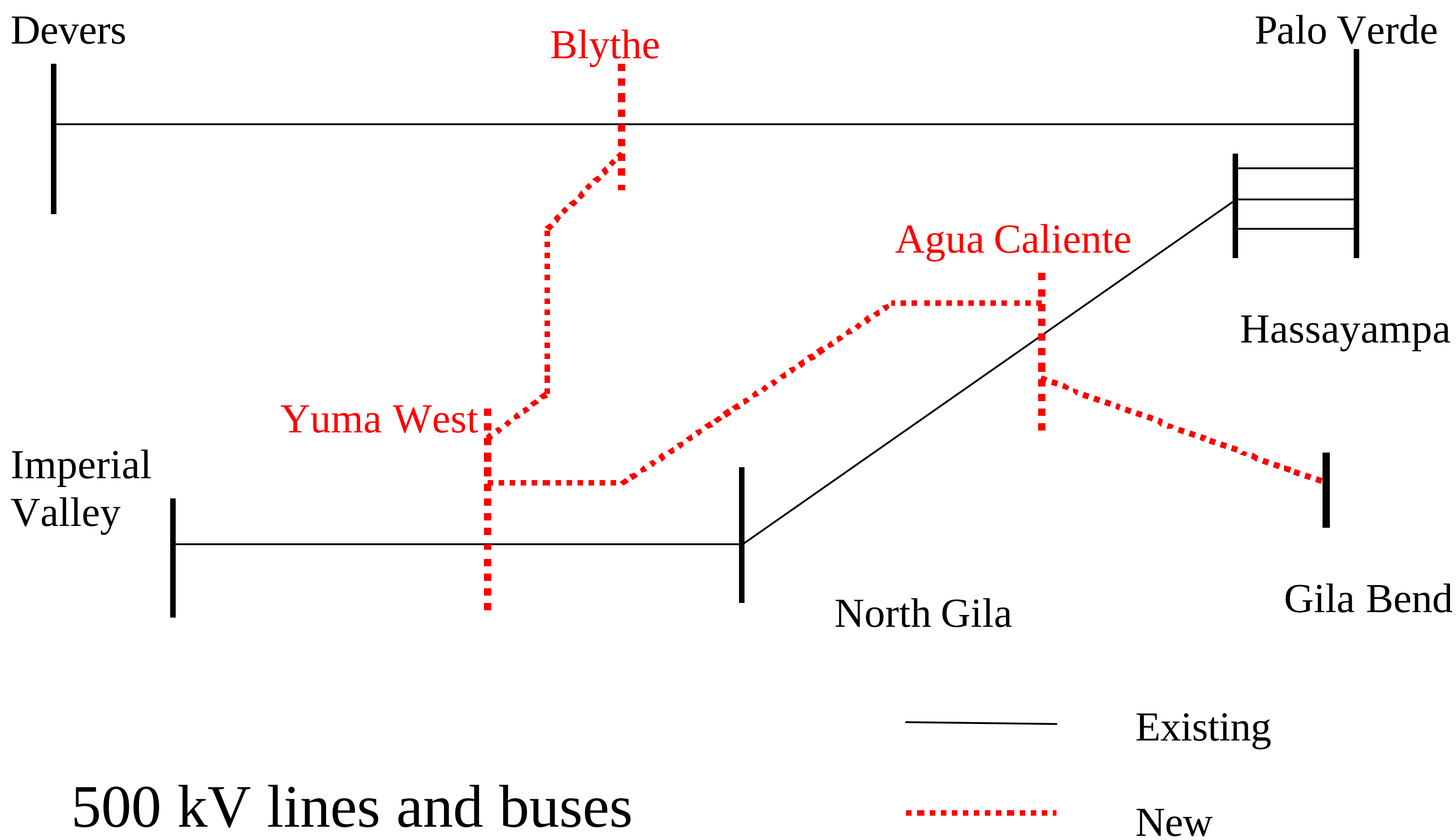
National Resources Group (NRG) has been active in study activities in Arizona and California and offered the following observations:

- Multiple regional study groups such as CATS and WATS are focused on regional areas, with little attention on wider multi-state transmission system.
- Generation companies developed power plant plans without detailed examination of area transmission constraints, including impacts of other area generation.
- New independent power producers have no particular interest in planning adequate outlet transmission for their projects.

The WATS and CATS study efforts have considered the following possible solutions to Palo Verde area stranded generation:

- Add a 500/345 kV phase shifter and a 345 kV line from Palo Verde area to Liberty and a third phase shifter at Perkins
- Upgrade existing PV-Southern California 500kV lines
- Add new transmission from PV area to Phoenix area
- Add new transmission from PV area to Southern California

Figure 6.6
NRG Proposes Adding Significant New Transmission West of Palo Verde Area



500 kV lines and buses

Sec
20(

The NRG proposes a 500/230 kV project that could add 1,400 MW of transfer capability from the PV/Gila Bend area to the Southern California area. The NRG proposed project consists of the following elements depicted in Figure 6.6.

- PV/GB area to Yuma West 500kV (100 Miles)
- Yuma West to Blythe 500kV (60 Miles)
- Yuma West to Highline 230kV double circuit (40 Miles)

There are certain transmission ownership issues that may inhibit projects such as that proposed by NRG. These include the following:

- IPPs are prohibited by federal law to own and operate transmission
- Low FERC rate of return discourages new merchant transmission construction and ownership by existing utilities and by independent transmission owners/operators
- Existing utilities do not have an incentive to build transmission if they are not serving their own load.

NRG has suggested two ways of overcoming such obstacles for transmission projects similar to what they have proposed. First, public/private transmission project developments could be formed. As an alternative, IPPs that are building generation in the Palo Verde area could form a consortium to fund Western to design, build and operate, and Western in return provides firm contractual rights to the use of new transmission capability. Either of these approaches gets around the ownership issue.

6.7 Power Up Corporation's Palo Verde to Devers II Proposal

The sponsor for the Devers II transmission project is Power Up Corporation, a new Gas and Electric Transmission Corporation. Power Up is in the initial stages of performing feasibility studies to determine siting and construction requirements for a second transmission line commencing at or near the Harquahala generating station, and traversing westward to the Devers Substation located near Palm Springs, California. This proposal is not being addressed by the CATS study group at the present time.

At the present time Power Up believes that it will co-venture the transmission line project with Southern California Edison. Power Up is reviewing the feasibility of building a gas pipeline along the same route, and stated that their preference is to build a HVDC transmission line. As an option, there is the notion that by expanding the project to reach the Los Angeles basin in Southern California this transmission line could replace a project being considered in California by Sempra.

Power Up has declared it intends to become active in the CATS and WATS planning study groups. They intend to file copies of initial feasibility and interconnection studies with the Corporation Commission in late 2002.

6.8 TEP/TECO-Panda Gila River: Jojoba-Pinal West Transmission Project

TEP and TECO-Panda Gila River (PGR) are jointly evaluating a transmission project to connect the Jojoba substation with TEP's Westwing to South transmission line. The proposed transmission project under evaluation would include a new 500 kV line from Jojoba to a new 345/500 kV substation, with the Westwing to South 345 kV line looped through the new 345/500 kV substation. This transmission project would improve voltage support in the Tucson area and improve system reliability by providing an additional source of power and by adding an additional path into Westwing. In addition, the project complements the long-term transmission plans in the region, specifically the proposed South East Valley 500 kV project (SEV). TEP and PGR estimate the line would add approximately 600 MW transfer capability into the Tucson area upon completion.

7. Local Area Transmission Import Constraints

7.1 Contemporary Challenges Serving Key Load Pockets

Local load pockets are geographic locations in an electric system where the load cannot be served solely by local transmission. During some portions of the year, there is a requirement for local generation located within a load pocket to serve that portion of the local load that cannot be served by local transmission. Such a resource requirement is often referred to as Reliability Must-Run (RMR) generation; that is, areas where loads do not get served totally by transmission, but by a combination of transmission and generation. That combination of facilities establishes what is referred to as the load serving capability of an area. One needs to look at both local generation and transmission capability when assessing the adequacy of the system to reliably serve the load in any load pocket.

The greatest system efficiency is achieved by placing generation as close to the load as practical. This is the benefit of small distributed generation being located at the customer's premises. The same basic benefit is derived from the operation of larger central power plants in the local area being served by the utility.

Investment in transmission and distribution infrastructure may be deferred by a utility if such local large-scale generation and distributed generation is reliable, cost competitive with remote power supplies, and is not environmentally restricted when such units can be operated. On the other hand, a utility must weigh the risks of such local units being unavailable at time of need due to planned or unplanned outages, unavailability or volatile fluctuation of prices of fuel for generation, or changing environmental requirements for generation. Similarly, the utility must consider reserve requirements and development of more cost effective, more environmentally friendly or more reliable resources located remote to the load pocket. Therefore, there needs to be a balance between dependence upon local generation and transmission import capability.

The Commission's electric restructuring docket established that local transmission import constraints limit the opportunities for utilities to take full advantage of a competitive wholesale market. Therefore, the Commission ordered APS and TEP to work with Staff to resolve RMR concerns and to publish the resultant plan in the 2004 BTA report. Consideration of the factors listed above is necessary to arrive at a determination of what is in the consumers' best interest.

The first Biennial Transmission Assessment identified three load pockets: Phoenix, Tucson, and Yuma. This assessment identifies two additional import constraint areas: Santa Cruz County and Mohave County. The issues and concerns in each of these five load pockets are discussed below. Figure 7.1 illustrates these five load pockets.

7.2 Reliability Must-Run Generation (RMR) Requirements

Commission retail electric competition rules, in place since September 29, 1999, require that at least 50% of the power supply for Standard Offer Service by an investor owned utility distribution company (UDC) be purchased through a competitive bid process.[28] The Commission's generic electric restructuring docket[29] established that existing Arizona transmission constraints will limit APS' and TEP's ability to deliver competitively procured power to less than the required 50% of Standard Offer Service load. Therefore this requirement has been stayed by the Commission pending its Track B proceedings determination of the proper competitive procurement levels. That same UDC retains the obligation to assure that adequate transmission import capability is available to meet the load requirements of all distribution customers within its service area.[30] 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.

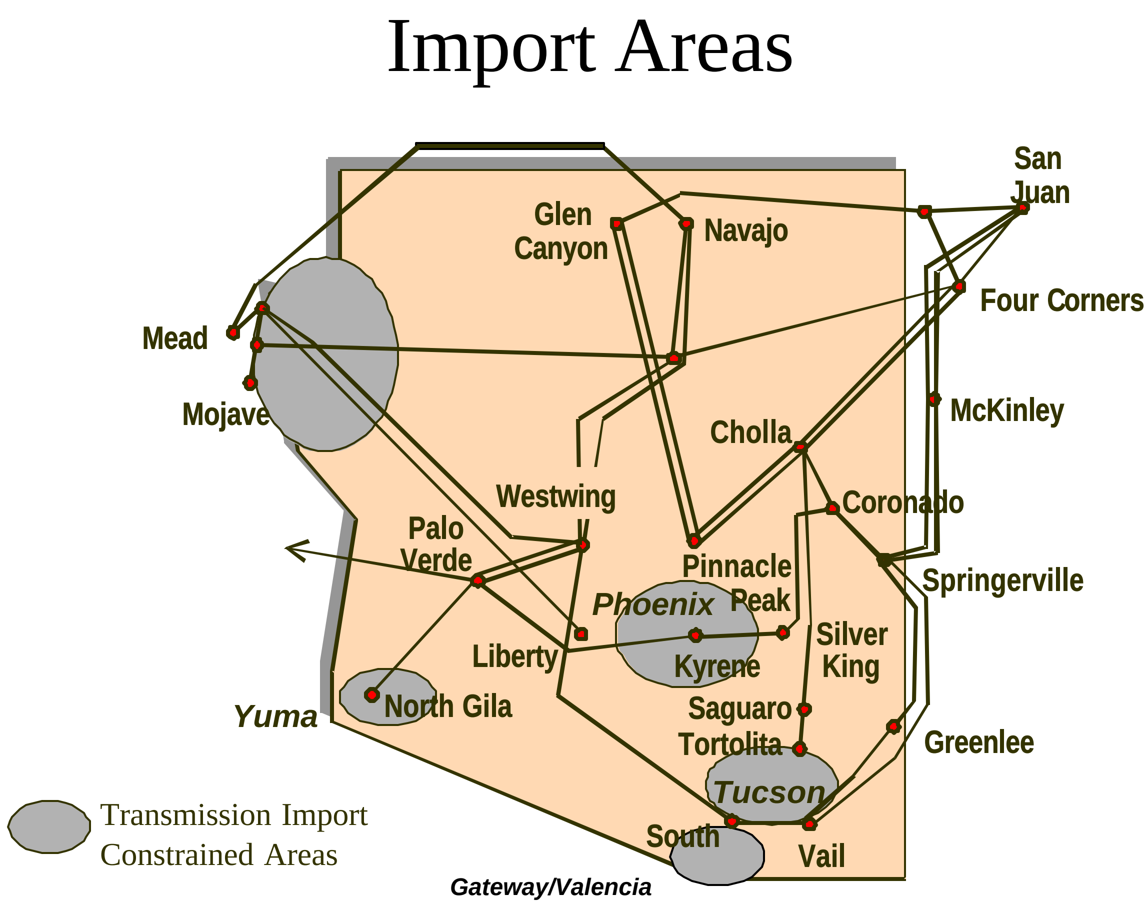
In Decision No. 65152, the Commission ordered APS and TEP to work with Staff to develop a 2002 study process to resolve RMR generation concerns and that such study plan results are to

[28] A.A.C. R14-2-1606.B.

[29] Direct Testimony of Jerry D. Smith and rebuttal testimony of Cary Deise, Docket No. E-00000A-02-0051.

[30] A.A.C. R14-2-1609.B.

Figure 7.1


Import Areas
San Juan
Glen Canyon
Navajo
Four Corners
Mead
Mojave
McKinley
Cholla
Westwing
Coronado
Palo Verde
Pinnacle Peak
Springerville
Phoenix
Silver King
Liberty
Kyrene
Yuma
North Gila
Saguaro
Tortolita
Greenlee
Tucson
Transmission Import Constrained Areas
South
Vail
Gateway/Valencia

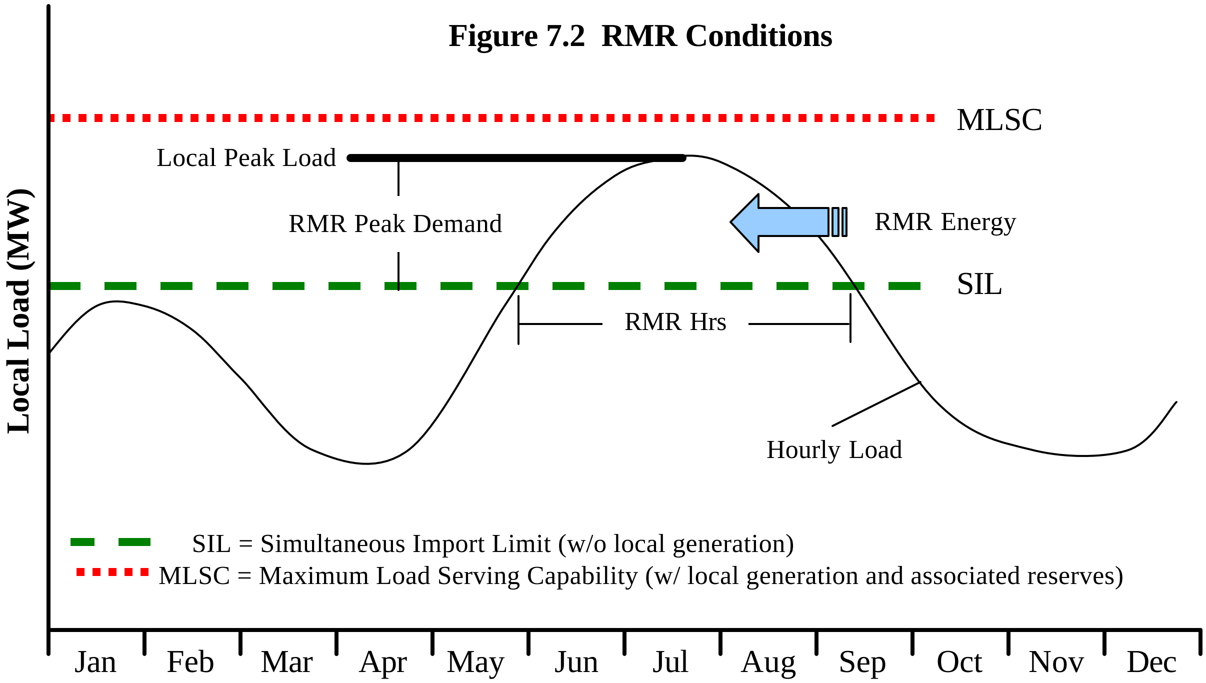
be included in the 2004 Biennial Transmission Assessment.[31] This includes studying and analyzing the merits of existing dependence on RMR generation instead of building transmission to resolve transmission import constraints and the merits of any future contemplated utilization of RMR generation to defer transmission projects. Until the 2004 Biennial Transmission Assessment is issued with RMR study plan results resolved, APS and TEP are to file annual RMR study reports with the Commission in concert with their January 31 annual ten-year plan for review prior to implementing any new RMR generation strategies.[32]

Staff recognizes that the transmission reliability constraints identified in Sections 7.3 through Section 7.7 of this report are not solely resolved by use of RMR generation. Over time, a combination of transmission enhancements and local generation solutions may be considered and utilized. Furthermore, APS and TEP are not the only utilities dependent on local generation for RMR purposes. However, Staff is of the opinion that all UDCs do have a responsibility to demonstrate the merits of continuing, beginning or increasing their dependence upon local generation as a remedy to transmission import constraints.

Staff proposes that any UDC that currently relies on local generation, or foresees a future time period when utilization of local generation may be required to assure reliable service for a local area, should perform and report the findings of an RMR study as a feature of their ten year plan filing with the Commission in January, 2003 and 2004. Figure 7.2, provided below, defines those conditions that warrant an RMR study. Any RMR study filed in January 2003 must, as a minimum, provide an RMR assessment through the 2005 summer peak. RMR studies reported in January 2004 should include an RMR assessment for each year of the ten-year plan that an RMR condition exists. The remainder of this section of the report describes what Staff believes such an RMR study should address.

[31] Decision No. 65152, Docket No. E-00000A-02-0051, et al., September 2002.

[32] Ibid, Finding of Fact 41.



The transmission system's simultaneous import limit (SIL) for each local constrained area is established for single contingency outage events (N-1) with no local generation in operation. An RMR condition exists during those periods of time 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 outage events that establish the local transmission import limitation. 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 (N-1) of transmission lines.

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 nor 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 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 is equivalent 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.

Staff consulted with transmission providers and UDCs impacted by the local transmission import constraints described in Sections 7.3 through 7.7. All parties committed to participate in a collaborative RMR study process when they are interconnected with an area impacted by a common transmission import constraint. When a single party is affected by an import constraint, they assume the sole responsibility for the associated RMR assessment. A generic RMR Study Plan and the scope of the associated RMR Study Report have been discussed and agreed upon by all parties. The RMR Study Plan and report should include the following six components as a minimum:

1. Define the annual SIL for each transmission import limited area. The combination of transmission import elements that make up the SIL are to be listed and the thermal rating of each individual element reported. Any planned changes in composition or rating of SIL transmission import elements are to be noted. The most critical outage is to be identified for each annual SIL reported and the nature of the constraint (thermal loading, stability limit, voltage limit or VAR margin) is to be described. In addition, all other

single contingency outage conditions that would result in a less restrictive SIL should be listed and the nature of the associated constraint also identified. When SIL is a thermal limitation then the thermal loading limit of each transmission element overloaded by the outage should also be reported. Identify and study any unique external system load and generation dispatch patterns that could impact local SIL or RMR conditions.

2. A listing of all local generation units and associated operational attributes should be provided. The maximum and minimum dispatch capacity and voltage regulation capability of each local unit should be documented. Similarly, any operational limitations or restrictions that apply to a local unit should be identified and causes noted. Causes of such operational restrictions may include but are not limited to the following: permitting, siting conditions, or planned outages for maintenance and repair.

3. Define annual RMR conditions for each year of the ten year plan being filed. The description of such RMR conditions should as a minimum include the following:

   - Magnitude of local load, demand and energy, expected to exceed the local SIL.
   - Annual hours for which local load is expected to exceed the local SIL.

4. Provide a local generation sensitivity analysis that determines the following:

   - The effectiveness of each local unit in mitigating the local RMR condition.
   - The location and dispatch level of local units that yields the lowest local generation output required to mitigate the local RMR condition.
   - The MLSC with all local generation at full output while maintaining the ability to withstand loss of the largest local unit(s). Loss of multiple units should be accommodated if interconnected to the system by a single common transformer or line or if loss of a common fuel supply could result in outage of multiple units.

5. Identify and study the effectiveness of alternative transmission solutions and new local generation supply in mitigating annual local RMR conditions. Existing local generation should be displaced by remote generation when considering transmission solutions to mitigate local RMR conditions. Planned remote generation additions with a Commission approved Certificate of Environmental Compatibility (CEC) and completed interconnection studies may be considered for this purpose. When existing local generation is insufficient to mitigate the annual RMR condition then the effectiveness of new local generation should be studied and compared with other solutions. In fact, the best solution may include a staged utilization of a combination of a number of these alternative solutions over time.

   Utilization of reactive devices such as high voltage (HV) 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 while maximizing the transmission and sub-transmission line capacity available to deliver real power measured in megawatts (MW). Advancement of planned transmission lines or construction of previously unplanned lines should be among the alternatives studied for thermal and stability constrained SIL conditions.

6. A comparative analysis of all alternative solutions, including utilization of local generation that individually or collectively 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 in step 4.
   - 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.

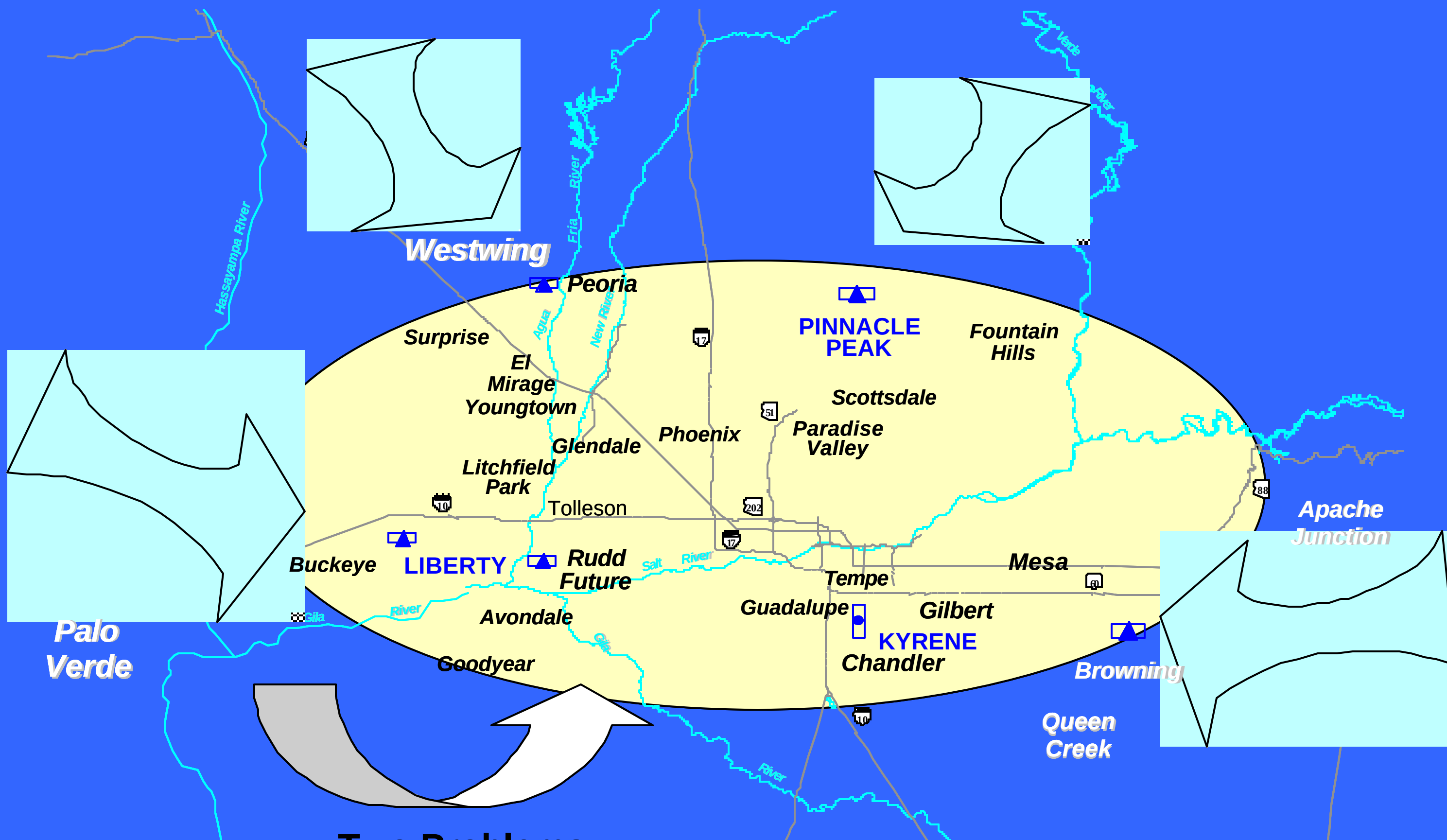
In concluding the RMR Study and RMR Report, Staff expects the UDCs to describe the course of action to be pursued and the rationale for the solutions chosen. Of particular interest to Staff is the degree to which the UDC's planned action is in the best interest of consumers and the public. Do the planned solutions to local area SIL constraints maintain the level of reliable service expected by consumers at a reasonable price? Furthermore, does the comparative analysis of alternative solutions support the solutions chosen to resolve transmission reliability constraints identified in Section 7.3 through Section 7.7 of this report?

7.3 Phoenix Area Import Assessment

The interconnected EHV and 230 kV transmission system serving the metropolitan Phoenix area is owned and operated by APS, SRP and Western, as illustrated in Figure 7.3. The Phoenix Valley is served by APS' and SRP's 69 kV subtransmission systems and 12 kV distribution systems, with 45% and 55% of the load being served by each utility respectively. A majority of this 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.

Challenge to Serve Customers

Figure 7.3



Two Problems:

1) Getting more energy into the grid from 5 delivery points
2) Delivering energy within the 230 kV grid

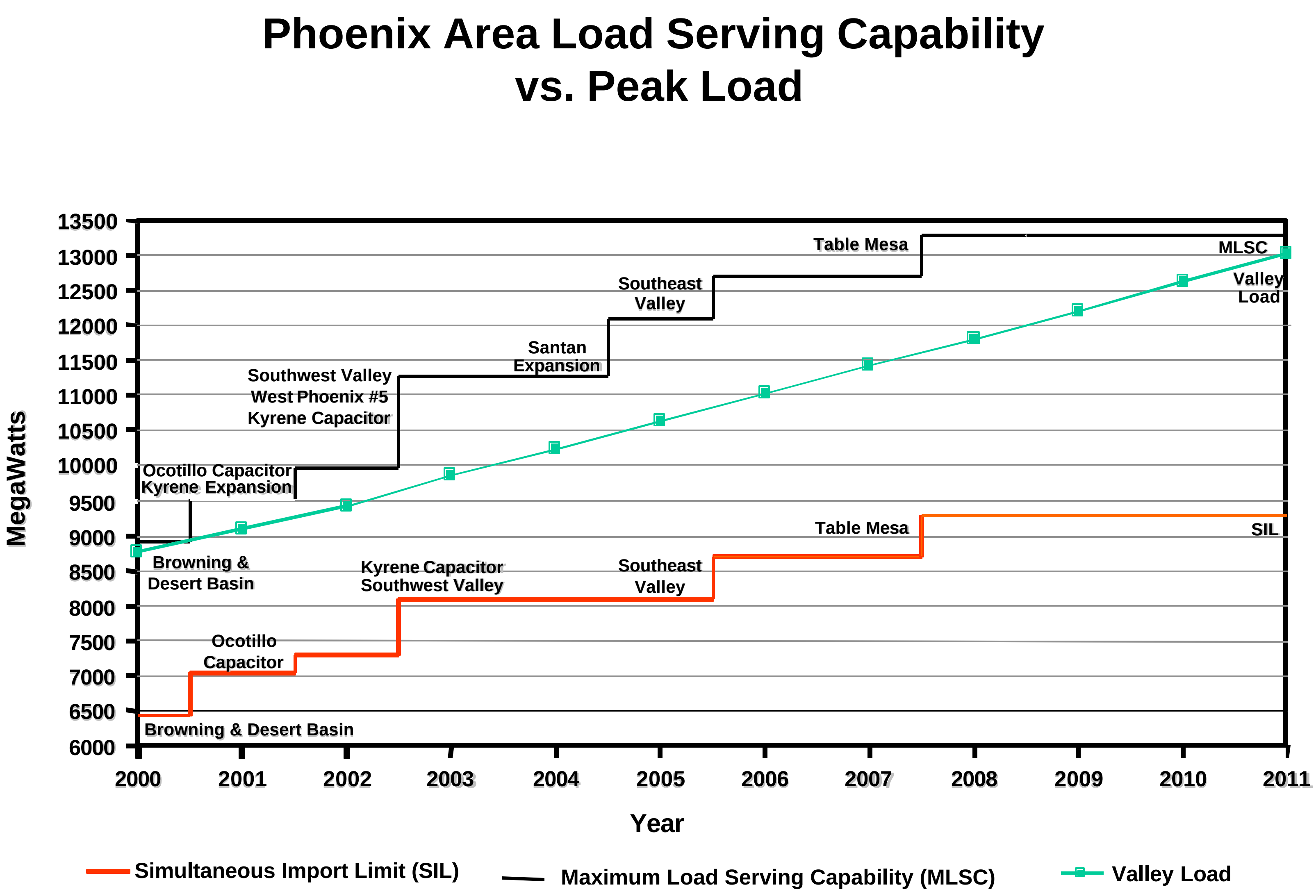
Planners consider that for summer 2003 there will be five transmission delivery points into the Phoenix metro area: Westwing Substation, Pinnacle Peak Substation, Kyrene Substation, Liberty Substation through Silver King, and the Rudd Substation (previously called Southwest Valley or Estrella) as shown in Figure 7.3. There are two concerns: getting sufficient energy to the delivery points, and transmitting the energy from the five delivery points internally to the 230 kV ring of transmission that encompasses the Phoenix area.

APS and SRP utilize a combined methodology to develop an annual operating plan that extends forward for several years. It is the most detailed for the current operating season and becomes progressively less detailed for each additional year into the future. The plan models and studies service to loads at voltage levels down to and including 69 kV. The measure of transmission import constraint for the Phoenix valley has changed over the past 2-3 years from solely a wire thermal constraint, to a system voltage limit, and now incorporates a MVAR margin requirement to assure stability of the interconnected system.

In 2001, a new WECC criterion with regard to voltage constraints, which states that the system must be planned for five percent Var Margin, was applied. The Zero Mvar margin operating points are derived first and the 5% Mvar load margin is calculated. This 5% Mvar margin line defines the safe operating region for the Phoenix Valley load center. This criterion became the most limiting for the Valley and it means that the system should have a five percent Mvar margin for (N-0) and (N-1) conditions.

The APS and SRP operating plan produces a nomogram constructed for use by their System Operators as illustrated in Figure 7.4. The cut-set for the nomogram analysis is drawn within the 230 kV ring around the Valley. The expected system operation will fall between the SIL and MLSC boundaries depending upon the load and the on-line local generation. The MLSC in Figure 7.4 includes all of the valley generation operating at maximum power levels and connecting transmission lines delivering maximum rated power.

Figure 7.4


Phoenix Area Load Serving Capability
vs. Peak Load
MegaWatts
13500
13000
12500
12000
11500
11000
10500
10000
9500
9000
8500
8000
7500
7000
6500
6000
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
Year
Table Mesa
MLSC
Southeast Valley
Valley Load
Santan Expansion
Southwest Valley
West Phoenix #5
Kyrene Capacitor
Ocotillo Capacitor
Kyrene Expansion
Table Mesa
SIL
Browning & Desert Basin
Kyrene Capacitor
Southwest Valley
Southeast Valley
Ocotillo Capacitor
Browning & Desert Basin
Simultaneous Import Limit (SIL)
Maximum Load Serving Capability (MLSC)
Valley Load

The nomogram depicts the effects of transmission line additions or upgrades on import capability and the voltage constraints while taking into account all the capacitor and transmission system additions that are shown in Figure 7.4. Through the (N-1) contingency analysis, APS and SRP found the most limiting contingency that drives the Mvar margin. It is a Palo Verde (Jojoba) to Kyrene 500 kV line outage for which the Kyrene 230 kV substation is the most limiting Mvar margin bus.

Figure 7.5 shows specific projects that are planned, which will add to the SIL and MLSC values. For example, in 2002 it is the Ocotillo 230 kV capacitors at the Ocotillo 230 kV substation that will increase SIL.

7.3.1 Staff Observation

In this section, Staff provides its observations of the meaning and application of Figure 7.4. Further Staff analysis will be deferred until the RMR studies defined in Section 7.2 are completed.

Figure 7.4 shows SIL has grown in the past two years by 800 MW. This SIL increase resulted from transmission enhancements that allow an additional 800 MW to be delivered into the Valley. From 2003 to 2008, SIL increases by another 2,000 MW. Over the same six-year period, Phoenix area load is also projected to grow by approximately 2,000 MW. This implies that the SIL of APS and SRP is increasing at the same rate that near-term load growth is occurring.

A second observation from Figure 7.4 is that the difference between the SIL and MLSC lines appears to be growing over time. The divergence of the SIL and MLSC is attributable to the new local generation being constructed at West Phoenix, Kyrene and Santan. It does not include Desert Basin or Sundance generation. The implication is that Valley load is becoming more dependent upon capacity and energy supplied by local generation.

Figure 7.5

Valley Transmission Projects

(showing changes to SIL and MLSC in MW)

	SIL	***MLSC***
2002	**Ocotillo Caps 200MW**	**Ocotillo Caps 200MW** **Kyrene #7 250MW**
2003	**Kyrene Caps 200MW** **Southwest Valley 600MW**	**Kyrene Caps 200MW** **Southwest Valley 600MW** **W. Phoenix 525MW**
2004		
2005		**Santan 825MW**
2006	**Southeast Valley 600MW**	**Southeast Valley 600MW**
2007		
2008	**Table Mesa 600MW**	**Table Mesa 600MW**
2009		
2010		

SIL – Simultaneous Import Limit

MLSC – Maximum Load Serving Capability

Another observation is that the MLSC reflects (N-1) transmission outages with local generation running at its maximum output. The utilities operate the local system so that they carry reserves locally to withstand the loss of the largest local unit during RMR conditions. This means that the MLSC curve should be lowered by that amount of local reserves. Looking at Figure 7.4, in 2011 there appears to be very little margin, and if the largest local unit (520 MW) happens to experience an outage, then conceivably load would have to be curtailed. Otherwise, for **some number of** hours, the Valley load may be above the wire carrying capability with all other local units operational at maximum capacity.

The issue that has not been addressed is if local units are modeled at their minimum dispatch level, what would be the transmission import capability -- would it exceed the total load requirement or would it be less than the load-serving requirement? Similarly, what combination of local units provides the largest Var Margin improvement when modeled at their minimum dispatch level? Could such improvements be accomplished by additional installation of reactive power devices such as capacitors, static or dynamic Var compensators, or new Flexible AC Transmission System (FACT) controllers? RMR studies discussed in Section 7.2 should be able to validate the effectiveness of the measures such as capacitor additions, new technology options and system additions taken by transmission providers to improve their local load serving capability.

7.4 Tucson Area Import Assessment

The Tucson area is located in a large valley surrounded by mountains and up until 1969 was served only by local generation. As the load grew, decisions were made to procure resources outside of the area, and bring the power into the area by transmission lines. Now the imported power is transmitted from the Westwing substation in the Northwest, from the Saguaro substation through Tortolita in the North, and from Four Corners power station through Springerville in the Northeast. Since transmission lines cannot economically be built in discrete blocks, TEP went through a period before the load grew to match the import capacity. Growth studies indicate that there is sufficient import capacity along with local generation to last until

2008 when some action would need to be taken, as illustrated in Figure 7.6. The transmission system in the TEP area is comprised of 345 kV and 138 kV.

A fairly immediate but small project is a parallel 500 kV line between Saguaro and Tortolita substations that will improve import capability by approximately 200 MW. Additional projects include participation, along with Southwest Transmission Coop, on the Winchester Substation which will be built between Vail and Greenlee Substation; a double circuit 345 kV line from South Substation to Nogales with an eventual connection in Mexico to CFE territory; and participation in the Palo Verde to Southeast Valley project.

The import power versus local generation relationship is such that, depending upon which generation is in service, the import capability can be increased anywhere from 190 MW to as much as 300 MW or slightly more.

Tucson's problem from an import constraint point of view is voltage support, that is supporting the voltage locally and running the local generation to alleviate that problem.

Figure 7.6 shows TEP's maximum transmission import capability for its Tucson service area is presently 1,538 MW and increases to 1,690 MW with the addition of a second Saguaro to Tortolita 500 kV tie in 2003. This transmission import capability relies upon local generation being operational at maximum dispatch levels. The MLSC of the TEP service area ranges from 2,178 MW in 2002 to 2,480 MW in 2010. The issue is whether to build additional transmission or to build more local generation beginning in 2008. TEP indicates that local peaking units have historically been most economical and hence, two local peaking units of 75 MW each are assumed for 2008 and 2010. The TEP/Panda Gila River 500 kV transmission project under evaluation would add additional import capability from Jojoba or Palo Verde to TEP's system.

Figure 7.7 shows transmission import capability dependency versus local generation in 2002. With no local generation, 950 MW of load can be served with import capability. This is the SIL for the Tucson service area. Looking at the 2001-2002 load duration curve depicted in Figure 7.8, this condition existed for 4,300 hours of the year. In 2003, TEP estimates that its must-run local generation energy will be approximately 180 Gigawatt hours. Approximately 80% of that

Figure 7.6

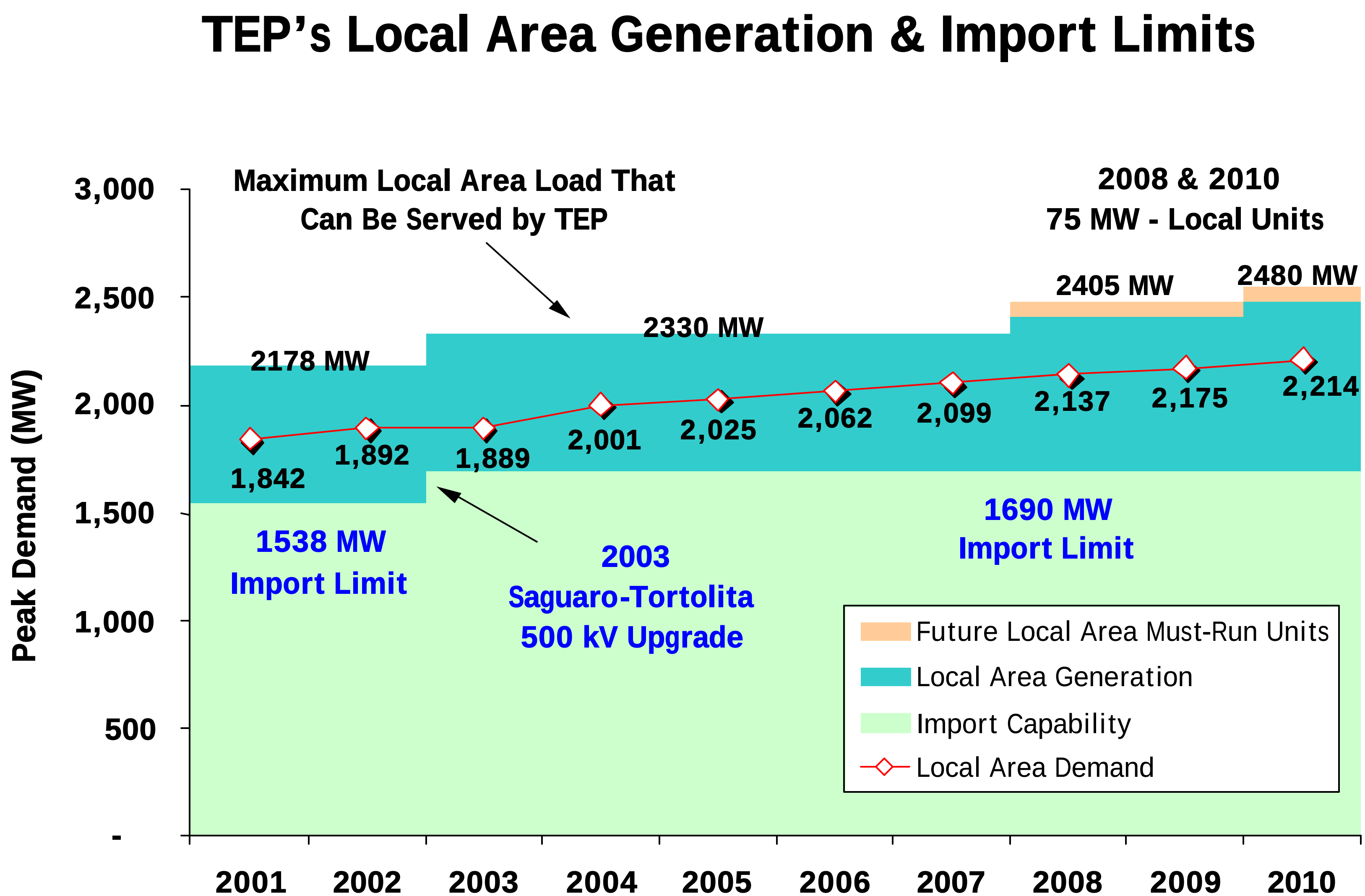

TEP's Local Area Generation & Import Limits
Maximum Local Area Load That Can Be Served by TEP
2008 & 2010
75 MW - Local Units
2178 MW
2330 MW
2405 MW
2480 MW
1,842
1,892
1,889
2,001
2,025
2,062
2,099
2,137
2,175
2,214
1538 MW
Import Limit
2003
Saguaro-Tortolita
500 kV Upgrade
1690 MW
Import Limit
Future Local Area Must-Run Units
Local Area Generation
Import Capability
Local Area Demand
Peak Demand (MW)
3,000
2,500
2,000
1,500
1,000
500
-
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010

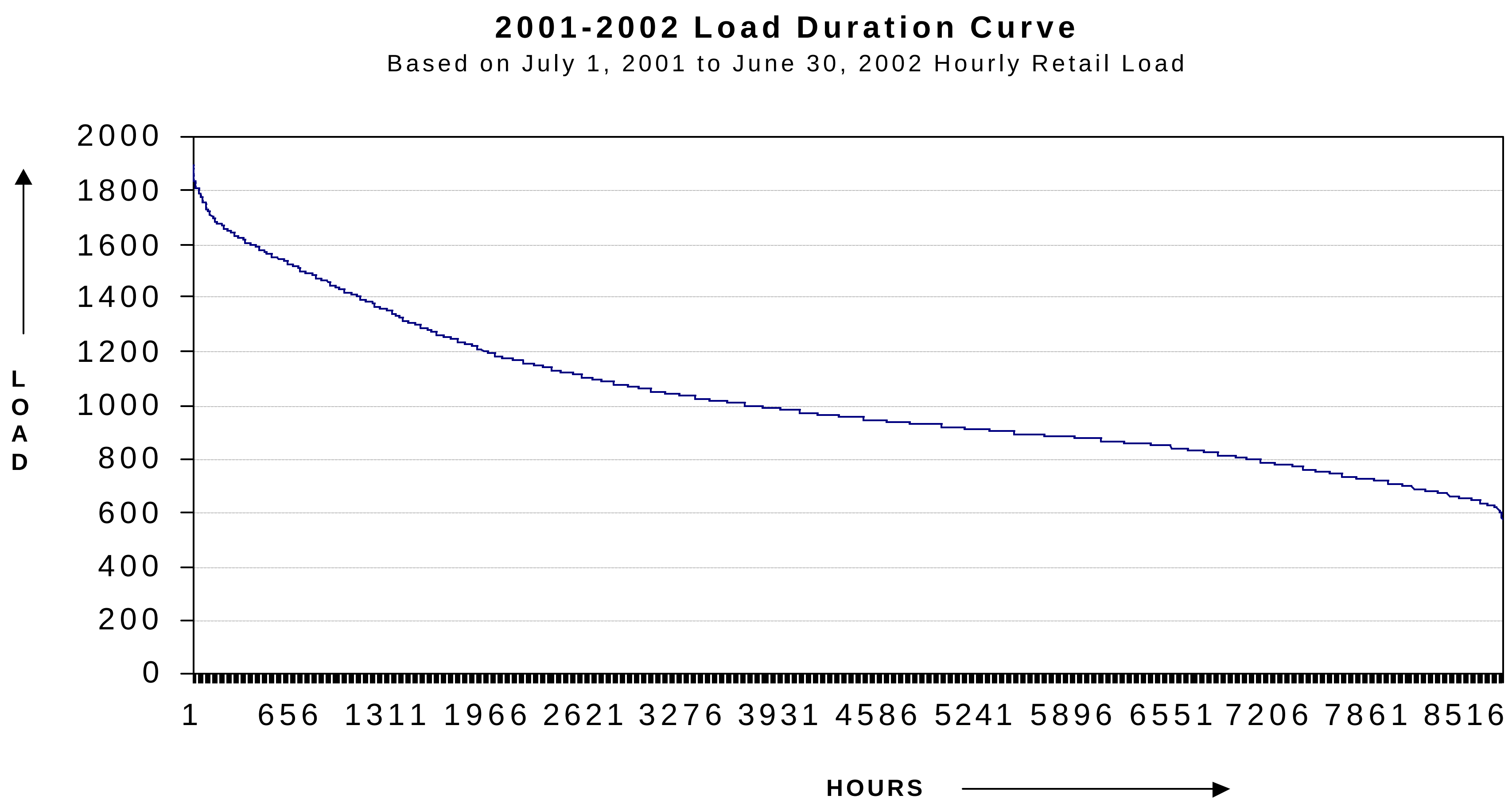
Figure 7.7

TEP's Existing System Local/Import

	UNITS ON LINE	Load w/min local	Local Gen.	IMPORT
Min MW on units:				
	No Local	950	0	950
	IRV 1,2	1250	11	1239
	IRV 1,2,3	1350	24	1326
	IRV 3,4	1450	13	1437
	IRV 1,3,4	1450	34	1416
	IRV 1,4	1450	11	1439
	IRV 1,2,4	1450	31	1419
	IRV 1,2,3,4	1450	45	1405
Max MW Local:		Max with Local		
	Turbines Only	1550	203	1347
	IRV 1,2+ CTs	1750	322	1428
	IRV 1,2,3+CTs	1900	453	1447
	IRV 3,4+CTs	1900	409	1491
	IRV 1,3,4+CTs	1950	438	1512
	IRV 1,4+CTs	1900	387	1513
	IRV 1,2,4+CTs	1950	431	1519
	IRV 1,2,3,4+CTs	2100	562	1538

Figure 7.8

Tucson Electric Power



RMR energy is expected to occur in the four summer months. The existing MLSC for Tucson is 2100 MW based upon a 562 MW of local generation and a maximum transmission import limit of 1538 MW. TEP estimates approximately 182 MW of additional transmission import capability will result from the addition of the second Saguaro to Tortolita 500 kV line in 2003.

TEP's import transmission capability is dependent upon which units get committed locally. For example, Figure 7.7 documents that with only 11 MW of local generation on-line at Irvington (units 1 and 2) the import capability increases from 950 MW to 1,239 MW. With Irvington units 1 and 4 on at a minimum dispatch of 11 MW, TEP can import 1439 MW via its transmission system. This implies Irvington unit 4 is more effective in regulating voltage than unit 2.

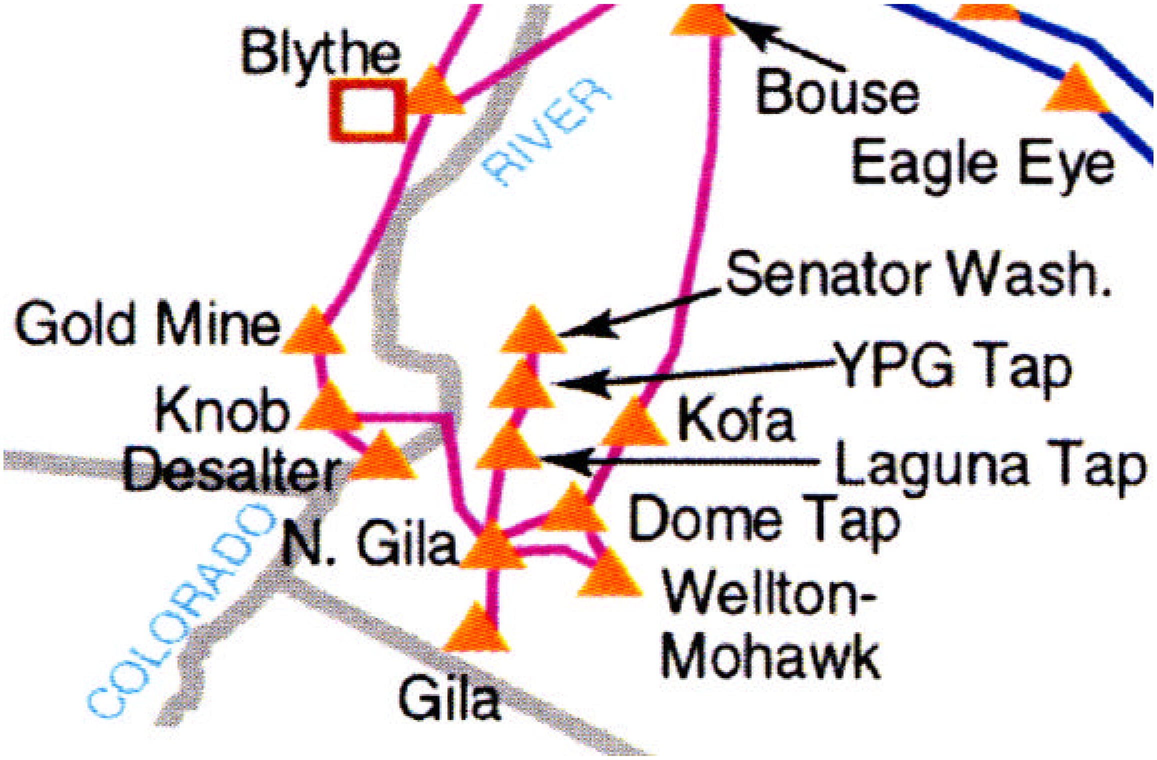
TEP indicates it complies with the WECC Mvar criteria. However, TEP does consider all other measures, including adding capacitors, before adding more local generation or transmission lines. TEP states this enables the most feasible and yet lowest cost solution to be chosen. Hence, in the Tucson area, the import constraint problem is managed by a combination of local generation and imports through transmission coming into the Tucson service area.

7.5 Yuma Area Import Assessment

Peak load in the Yuma area, as shown in Figure 7.9, is expected to grow from about 300 MW in 2002 to about 375 MW in 2006. This load is served by a combination of local generation and imported power. The local generation consists of two 19 MW and two 55 MW combustion turbines, three of which are capable of burning oil or gas, and the fourth is oil only. In addition, the local generation includes the Imperial Irrigation District's (IID's) Yucca 75 MW steam unit and the YCA 55 MW combustion turbine. Imported power is made up of 38 MW on Western's 161 kV Parker-Yuma line, 140 MW on the Palo Verde-North Gila 500 kV transmission Line (APS 11% share), plus potential short-term purchases from San Diego Gas and Electric Company (SDG&E, which owns the largest portion of the Palo Verde-North Gila 500 kV line)

Figure 7.9

Yuma County



Substation

Utility Power Plant

along with power purchases from CAISO. In 2002, APS was able to purchase 50 MW from SDG&E, which along with other resources discussed above, provides a total capability of 375 MW.

APS' Ten-Year Plan includes a 115-mile long, 230 kV line from Gila Bend to Yuma which is proposed to be in service by 2006, and which would add 150 MW of transfer capability to meet the area load serving needs (an application for a CEC for this line has not yet been filed). APS is also considering several other options and alternatives that include other transmission modifications/additions and local generation solutions (such as the Wellton-Mohawk generating facility which is discussed in Section 9.3.9 and which is planned to be on line in 2005). The transmission options include making modifications to the Palo Verde-North Gila line which will give APS about 40 MW <u>more</u> import capability by eliminating sag limitations, increasing series capacitor ratings, and reducing the induced voltage into the communications system used by a railroad. System upgrades at Blythe can also help to provide transfer capability from Blythe to the Yuma area. There are literally a handful of transmission and/or generation options that taken together can add to APS' ability to serve load in the Yuma area.

In summary, it appears that the measures contemplated by APS and others should be able to alleviate the import constraints in the Yuma load pocket. In evaluating the merits of the various solutions, APS has agreed to follow the RMR Study Plan in Section 7.2 of this report. In addition to a present worth analysis, the evaluation of alternatives is to consider a wide range of factors including environmental considerations. The purpose of the RMR Study Plan is to assure options that are in the public's best interest prevail.

7.6 Santa Cruz County Import Assessment

Citizens is a full requirements wholesale customer of APS. All of its Santa Cruz County power purchases are coming from Pinnacle West and delivered through one point of receipt on Western's Saguaro 115 kV bus. From there, Citizens' purchased power is delivered over a Parker-Davis transmission system, 115 kV line to Nogales Switchyard located on the southeast side of Tucson.

At the present time the load in Citizens' Santa Cruz County area is served by a single 115 kV line between Nogales Switchyard and Nogales that is owned and operated by Citizens. Citizens has generation located in the Nogales area (Valencia Power Plant) that it runs on an emergency basis. When the single 115 kV line is out of service, the local generation is used to pick up the Nogales load. During storm seasons, the local generation is started, but not brought on line until after a power outage occurs.

In order to improve the reliability of service in the Santa Cruz County area, Citizens has developed an agreement with Tucson to connect to Tucson's South substation by way of a double circuit 345 kV line that will terminate at a new substation, Gateway, located about 3 miles from the Valencia substation near Nogales, as shown in Figure 7.10. A short 115 kV line will be built to connect Gateway to the Valencia substation near Nogales. To improve voltage during transmission outages 115 kV capacitors will be installed at Valencia.

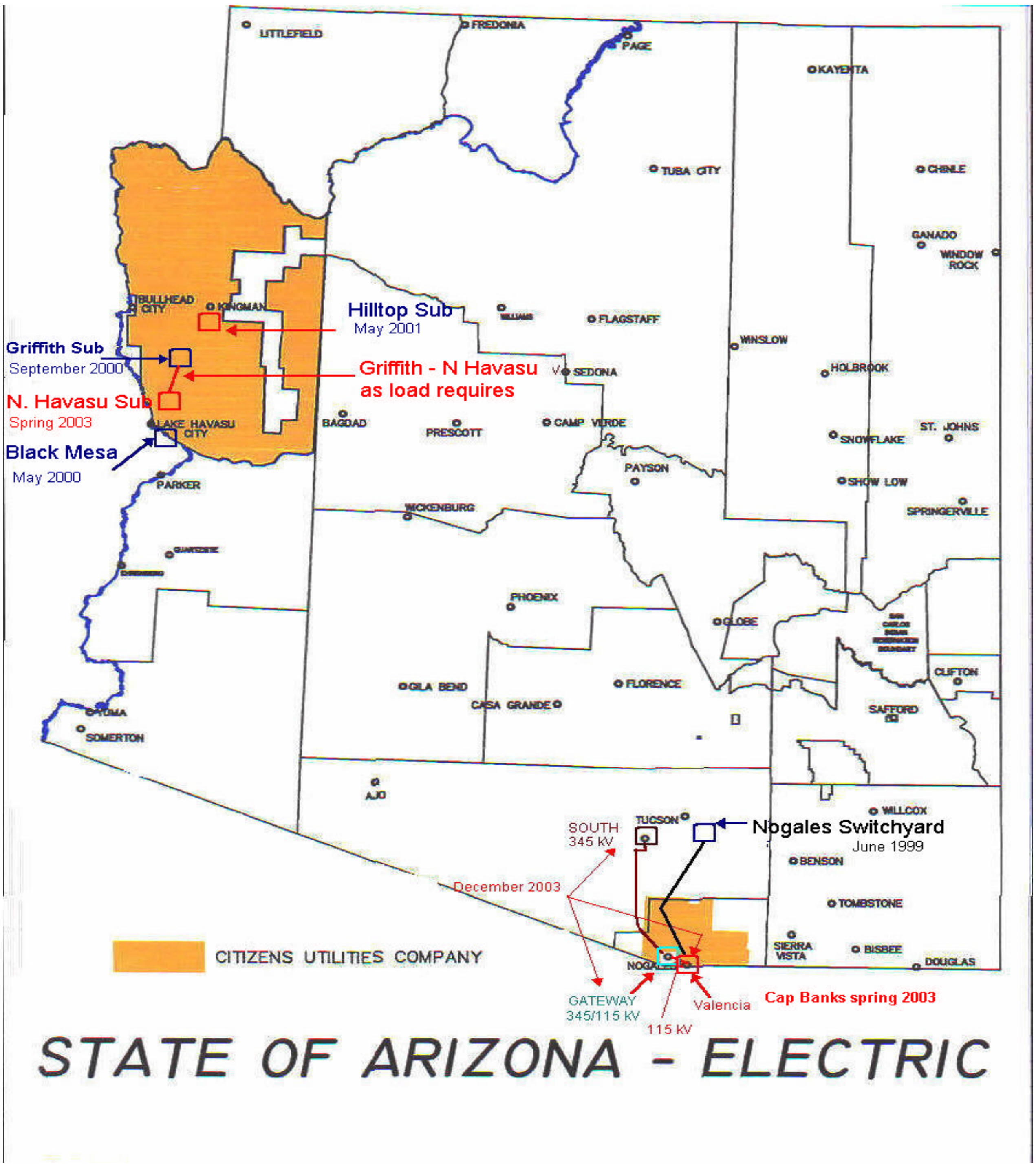
The 345 kV line will add 100 MW of firm import capacity to the Citizens service area. Service to Citizens over Western's Parker-Davis transmission system is presently limited by contract to 69 MW. Citizens will be working with Western and with SWTC that also have customers in Southeastern Arizona to see if some or all of the difference could be made up by improvement on Western's transmission lines.

7.6.1 Issues and Concerns

Under present operating conditions, with one radial 115 kV line serving the entire load, and with 50 MW peaking generation at Valencia, if the transmission line goes out of service, then load must be picked up by starting this generation. When thunderstorms are in the area, Citizens runs the Valencia turbines at full speed with no load to minimize the time required to pick up load in the event of a transmission outage. The small units are not capable of maintaining synchronism with the rest of the system during line outages. Therefore, when the turbines are actually used to

Figure 7.10

Santa Cruz County



carry load, Citizens separates the load carried on the Valencia generation from the remainder of the system until the problem on the transmission line is repaired. In this case, that part of the load is isolated on local generation.

The hours that the Santa Cruz County load would exceed the 115 kV line capacity is estimated to be very small. Citizens estimates the number of hours that the load would exceed 70 MW (peak load) is not greater than 9.

Citizens' transmission contract with Western on the Parker-Davis System is on a three-year rolling basis. Transmission capacity presently under contract from Western for delivery to Santa Cruz is 67.9 MW for the summer of 2003. The present capacity reservation requested for the third year out (2004) is 69.9 MW.

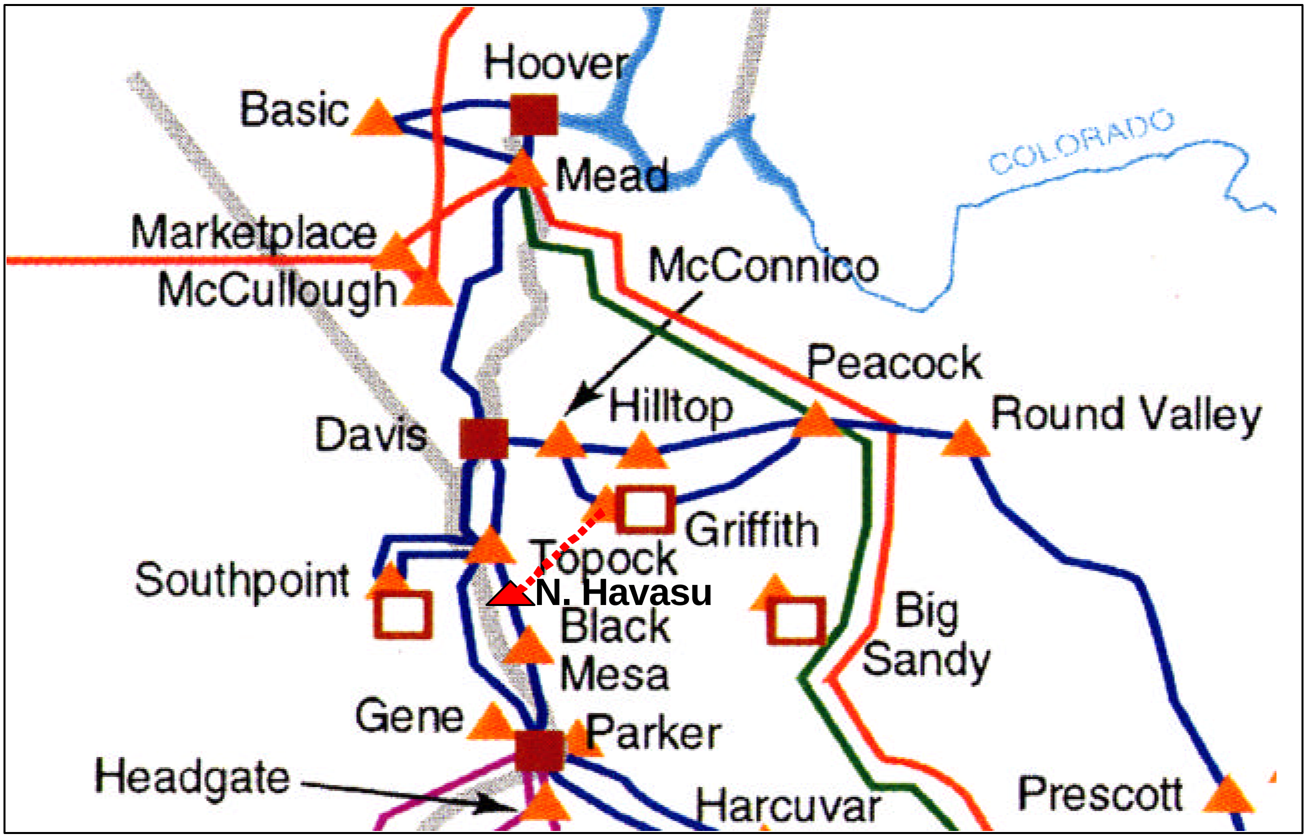
7.7 Mohave County Import Assessment

The transmission system depicted in Figure 7.11 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 inward transmission, and distribution is provided by Southwestern Transmission Cooperative, Citizens Communications Company, Aha MACV Power Service, City of Needles, and Arizona Public Service Company.

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. 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 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 7.11

Mohave County Area



Utility Power Plant

Merchant Power Plant

Substation

The load growth in the Lake Havasu City area had necessitated Citizens to build another substation, North Havasu, and propose an associated 230 kV transmission line, Griffith/North Havasu. The needs of other Western customers in the area, in addition to Citizens, caused Western to begin a study group to improve transmission in the area.

Near term, with maximum generation at Griffith (merchant plant) and Davis Dam, minimum generation at Parker Dam and South Point and the Havasu pump at full operation, there are problems relating to (N-1) conditions. Parker generation being brought up could alleviate the problem, but there is a concern about meeting downstream water needs forecasts and river operations restrictions. The merchant plants, Griffith and South Point, which operate within the area are in Western's Control Area. These plants could be expected to operate for redispatch if called upon to do so; however, provision must be made for payment for their action to reduce the constraints. The plants are being contacted to develop a means for redispatch and payment. If the plants are redispatched to cover Citizens' loads, they will be expected to fund the redispatch.

It is possible for the merchant plants to become their own Control Area, which could make the situation more complex. Another complication is that Citizens already has full requirements capacity and energy contracts for their load from another supplier. Such arrangements make it difficult for Citizens to arrange for local generation

There are some options being discussed by the transmission providers, and service utilities. A study has been initiated which will involve all stakeholders in the area. Western will chair the study. Participants are anticipated to be Central Arizona Water Conservation District (CAWCD), Citizens Communications Company, Southwest Transmission Cooperative, Mohave Electric Cooperative (MEC), Aha MACV Power Service, City of Needles, Calpine South Point, Griffith Energy, Arizona Public Service Company and Metropolitan Water District. While there does not seem to be an entity such as CATS that could perform such a study, the development of a plan by the interested parties should be able to examine the alternatives and possible solution.

Meanwhile, Citizens and others in the area continue with their 3-year rolling term contracts for transmission service with Western, and at the same time merchant plants such as Griffith, South

Point, Blythe Energy, Dome Valley Partners, Arizona Power Authority, CAWCD, MEC, Aha MACV, City of Needles, and Arizona Public Service continue to press Western for long-term transmission service.

There are a number of transmission alternatives that could increase import capability to the Mohave County area. All of the following and other identified alternatives will need to be examined.

a. Increase the capacity of the Mead Substation to Davis Dam line
b. Build the Griffith Substation to North Havasu line stout enough to serve Citizens and the other needs in the area
c. Build a second Mead Substation to Davis Substation line
d. Upgrade the Parker Davis Dam to Topock Substation line

Another alternative is how the local generation is factored into the deliverability of transmission. It is being considered separately partly because of FERC rules with respect to interconnection. It is also completely separated because these units are owned by Independent Power Producers which have purchased sufficient transmission to export their energy to various other areas of the state and out of state. There is generation sitting in the middle of a load area but it is not functioning to support the system to meet the load if not purchased to do so. Due to the sale of transmission into and out of the area for loads elsewhere and generation in the area not being purchased for the area loads, the area could be termed a transmission limited area. Also, based on system situations, increased load growth, and lack of transmission resources, these merchant plants could possibly be treated as reliability must run generation.

8. Local Area Transmission Plan Assessment

8.1 General

The load in local areas is growing and there is a need to address local transmission in certain local areas to meet the projected load growth. Although there are good EHV transmission overlays at the 345 kV and 500 kV levels, the existing underlying HV transmission system requires enhancements to serve the projected needs of customers. Hence, the HV transmission system serving local areas needs to be investigated further, and collaborative HV transmission plans need to be developed to ensure compatibility with the planned EHV system for the areas.

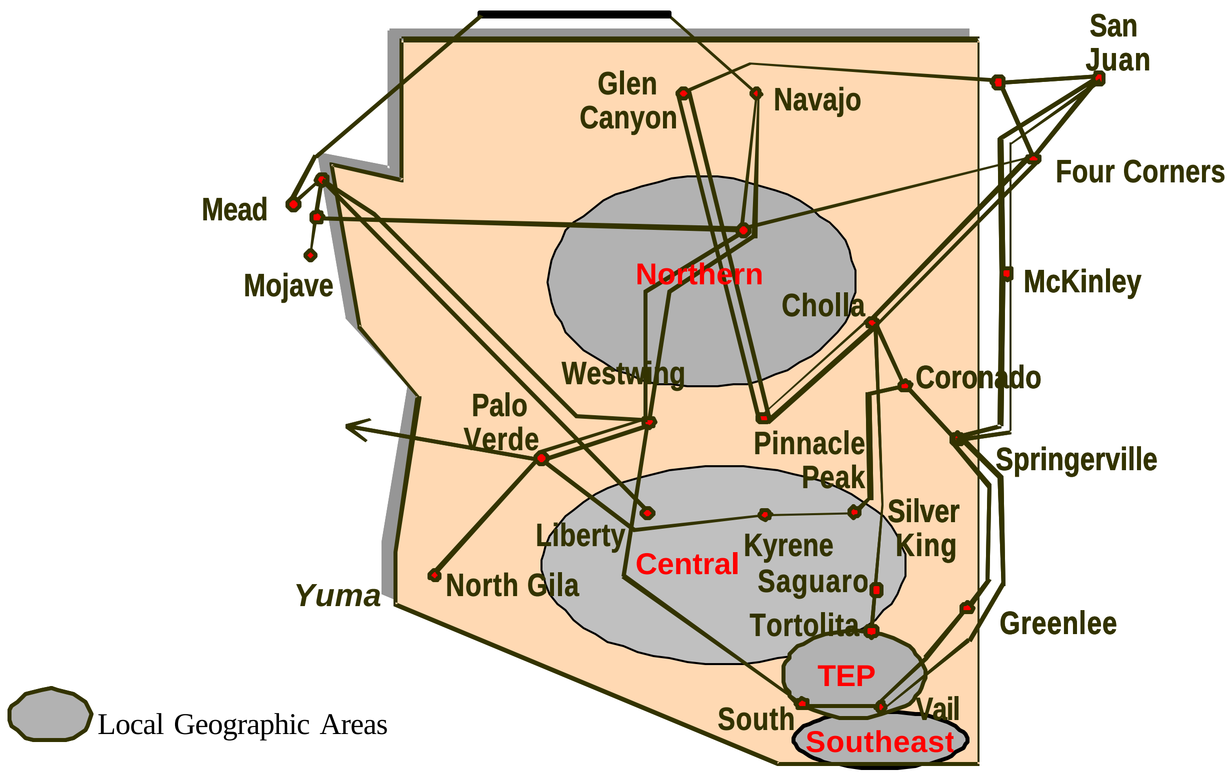
Transmission systems of Arizona utilities are also intertwined with Western's transmission system throughout the state. Western's transmission is built to meet the needs of its long-term preference customers, and participation with other utilities can materialize only through trust accounts where the upgrades have to be paid by the users. Hence, there is a need to plan local area transmission requirements in concert with Western's plans for transmission upgrades.

The HV transmission requirements in the following four local areas, shown in Figure 8.1, are discussed in the following Sections:

- Central Arizona
- Northern Arizona
- Tucson area
- Southeastern Arizona

Figure 8.1

Local Transmission Assessment



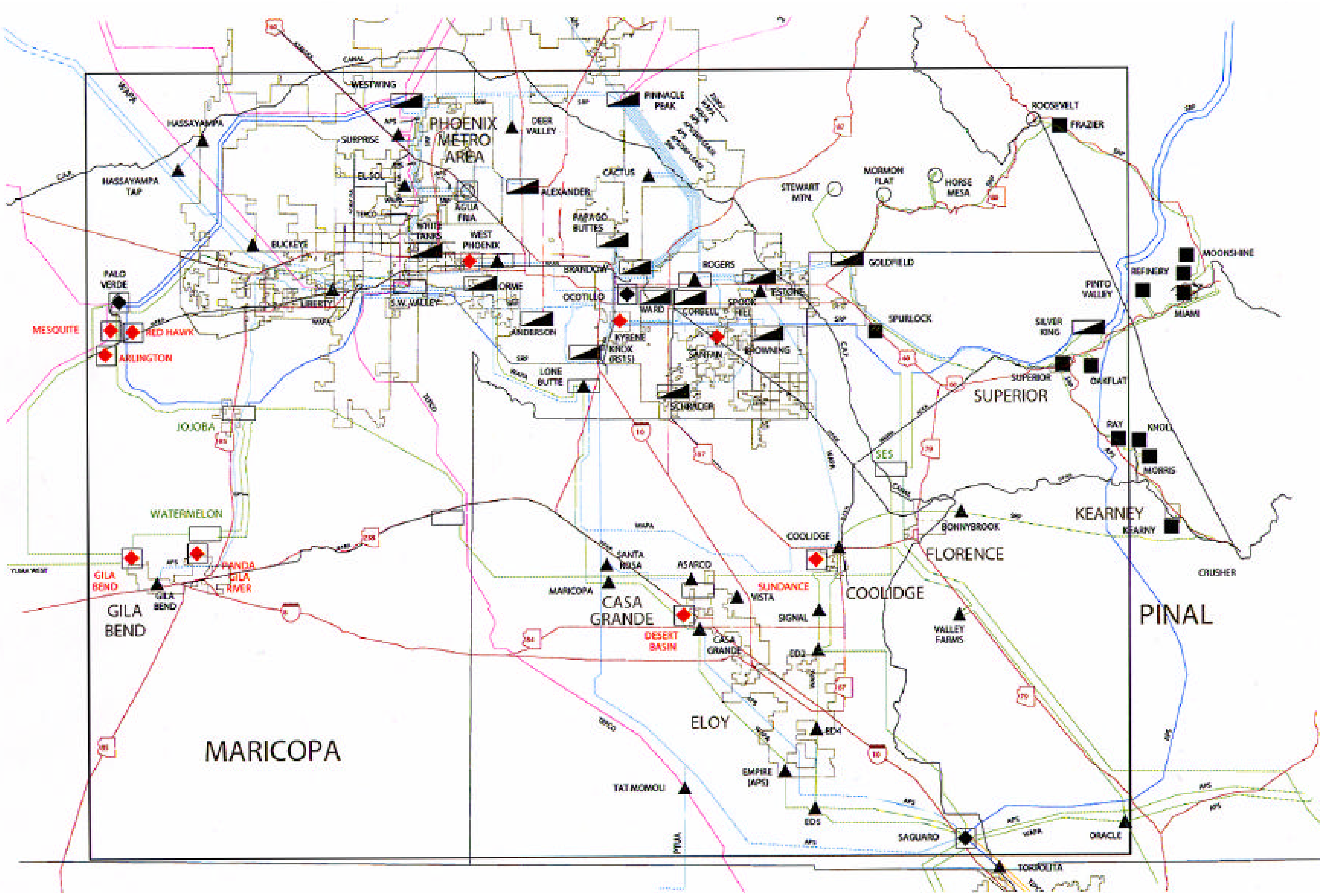
8.2 Central Arizona

For the purpose of this BTA, the high voltage (HV) transmission system serving customers in western Pinal County and Maricopa County south of the Gila River is referred to as Central Arizona. The CATS study has addressed the EHV (345 and 500 kV) transmission system overlay between Phoenix and Tucson, but did not look at the underlying 230/115 kV system that is serving customers in this geographic area. The existing HV transmission system in Central Arizona is adequate to serve customer load until approximately 2006. However, there are some transmission operational difficulties in the region and a study is required to look at how to overcome those difficulties with regard to line capacities.

The load growth occurring in the Central Arizona area may impact the HV transmission needed to serve the customers in that area after 2006 and to effectively interface with the EHV system facilities planned for the same local area. The Arizona Power Authority is chairing a CATS HV subcommittee that is looking into the underlying Central Arizona system. This is a big study effort that is just getting underway. The Central Arizona HV transmission facility needs for the 2006-2007 timeframe are to be studied and planned for development.

As shown in Figure 8.2, the initial system to be studied extends from Palo Verde to Southeast Valley. The region to be modeled includes the communities of Casa Grande, Coolidge, Gila Bend and Maricopa. Looping in the Sundance/Liberty 230 kV line out of Lone Butte, and also the Westwing/Liberty line into the Rudd substation (SW Valley) will be looked at as alternatives. In addition, the Santa Rosa to Gila Bend 230 kV line will also be looked at. The study is just getting started and the study results will be reported at a later date.

Figure 8.2
Central Arizona Map



8.3 Northern Arizona

The Northern Arizona area is defined for the purpose of this BTA as a geographical region that ranges from Prescott on the west to Holbrook on the east. Flagstaff is centrally located in the Northern Arizona area, as shown in Figure 8.3. The existing local transmission system in Northern Arizona is adequate to serve the load in the region through 2006.

APS has proposed and planned an APS/WAPA interconnection in the Flagstaff area to serve growth projected to occur after 2006. There is an existing Flagstaff substation on Western's 345 kV lines from Glen Canyon to Pinnacle Peak. The APS proposal would have APS add a 345/230 kV transformer at Western's Flagstaff substation. APS would then build a double circuit 230 kV line from Flagstaff substation to the APS Cholla-Coconino 230 kV line and terminate the lines at a new Winona 230 kV substation

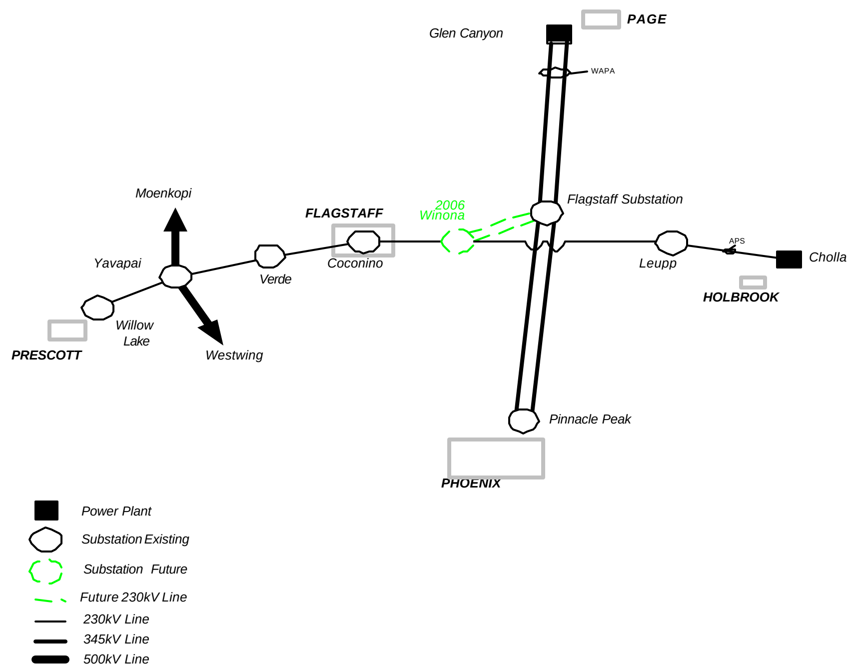
APS and Western have had preliminary discussions centered on a possible joint effort to resolve the local load issue. The planned APS/Western interconnection in the Flagstaff area should resolve any existing SIL for the foreseeable future. A process to study and resolve this proposed APS/WAPA interconnection at Flagstaff substation is yet to be defined.

8.4 Tucson Electric Power

TEP's 138 kV system is totally contained within the TEP service area. TEP set up a separate tariff rate for the 138 kV system. There are no constraints in the 138 kV system, since the system is designed and built to eliminate all local internal constraints. TEP continues to upgrade the 138 kV system by using SSAC conductor for increased current carrying capability. A 138 kV line at the southern edge of TEP's service area connects down to Green Valley, south of Tucson, which is a retirement community. That line is going to be continued to make a loop, with an in-service date of 2005. Hence the action items needed are reconductoring and upgrading existing 138 kV lines, and thus there are no internal constraints at the present time.

Figure 8.3
Northern Arizona Area

Winona/Flagstaff 230kV Interconnection



8.5 Southeastern Area

For the purpose of this BTA, Southeastern Arizona area is defined as a geographical region that ranges from Vail and Nogales on the west to Apache and Douglas on the east as shown in Figure 8.4. The local transmission issues in this region are discussed in the following subsections.

8.5.1 Southwest Transmission Cooperative

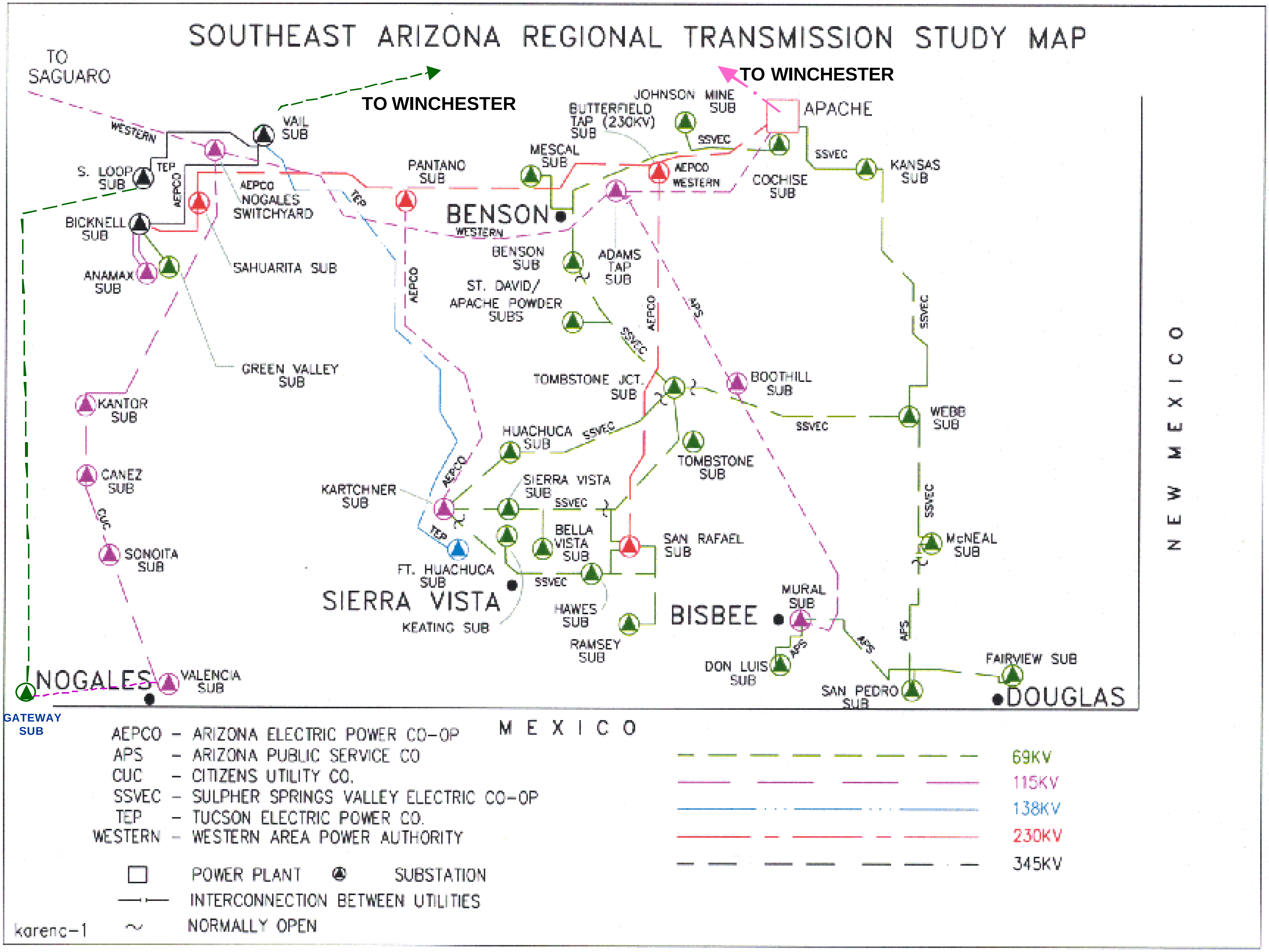
The Southwest Transmission Cooperative's (SWTC) existing backbone transmission system consists of two 230 kV lines that exit Apache Station going east and west. The 230 kV lines interconnect to TEP at Greenlee Substation to the east and Vail Substation to the west. SWTC also owns a 115 kV line that emanates from Apache Station and goes north to interconnect with Salt River Project (SRP) at Hayden Substation. Western owns a 115 kV line that also exits Apache Station and goes west, as shown in Figure 8.5.

On the current SWTC transmission system, the most severe single element outage is the loss of the Apache to Redtail 230 kV line. During this 230 kV line outage, the 345/230 kV transformer at Bicknell Substation and the remaining 230 kV line become heavily loaded.

To meet WECC's reliability criteria to be able to withstand any single element outage, (N-1), without uncontrolled loss of load, and to avoid cascading outages, (N-2), by shedding load and/or reducing generation, SWTC studied several alternatives.

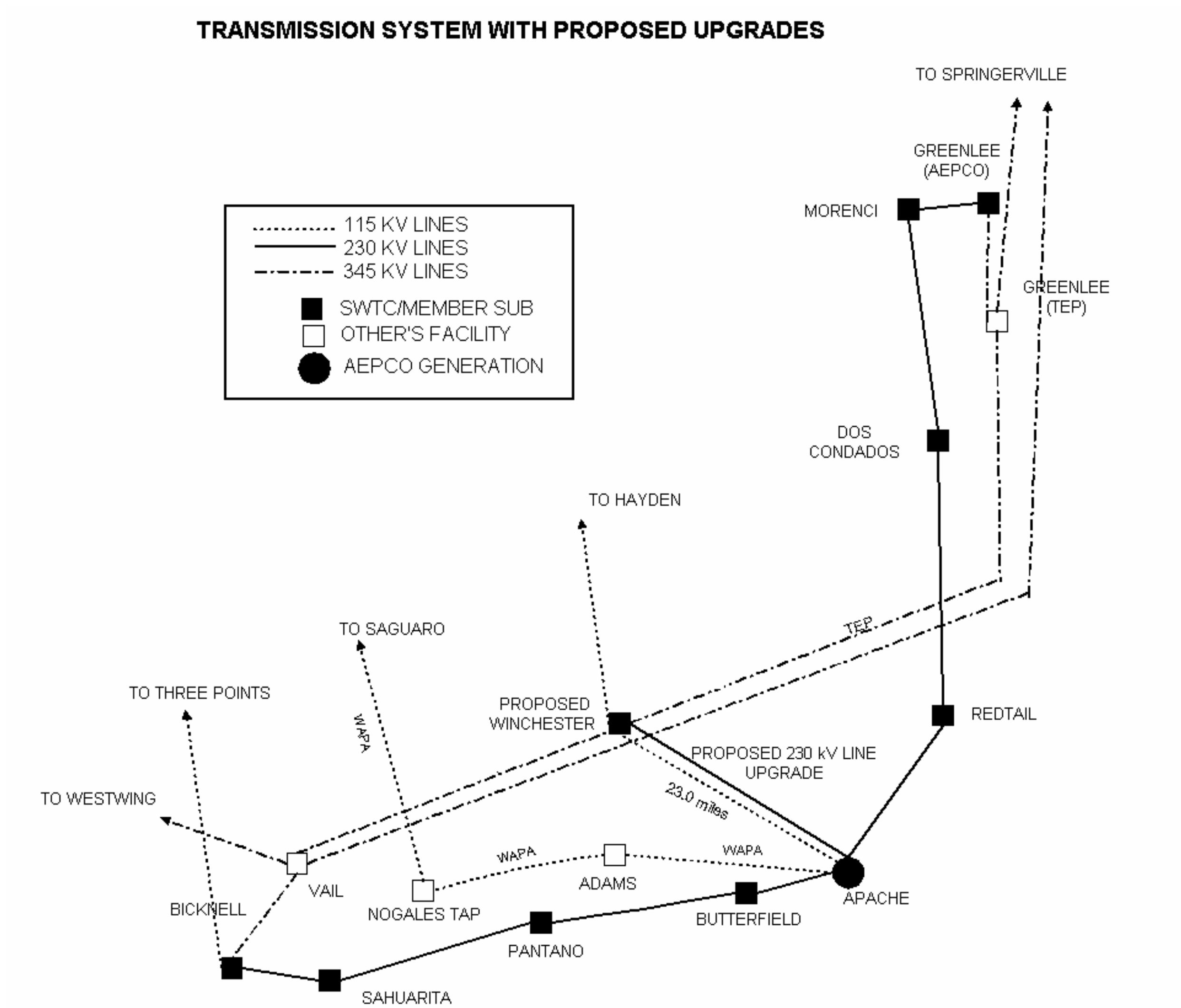
The Winchester Interconnection Project has been developed as part of the efforts by SWTC to enhance the reliability of the SWTC transmission system. It provides an additional 230 kV line that exits the existing Apache Station to a new interconnection point with TEP's 345 kV line from Greenlee to Vail. This project reduces the overload on system segments for (N-1) conditions, and decreases the need for Remedial Action Scheme (RAS) during multiple contingencies.

Figure 8.4



SOUTHEAST ARIZONA REGIONAL TRANSMISSION STUDY MAP
TO SAGUARO
TO WINCHESTER
TO WINCHESTER
VAIL SUB
S. LOOP SUB
BICKNELL SUB
ANAMAX SUB
AEPCO NOGALES SWITCHYARD
SAHUARITA SUB
GREEN VALLEY SUB
PANTANO SUB
MESCAL SUB
BUTTERFIELD TAP (230KV) SUB
JOHNSON MINE SUB
APACHE
AEPCO WESTERN
COCHISE SUB
KANSAS SUB
BENSON
BENSON SUB
ADAMS TAP SUB
ST. DAVID/ APACHE POWDER SUBS
TOMBSTONE JCT. SUB
BOOTHILL SUB
WEBB SUB
HUACHUCA SUB
TOMBSTONE SUB
KANTOR SUB
CANEZ SUB
SONOITA SUB
KARTCHNER SUB
SIERRA VISTA SUB
BELLA VISTA SUB
SAN RAFAEL SUB
McNEAL SUB
FT. HUACHUCA SUB
SIERRA VISTA
KEATING SUB
HAWES SUB
RAMSEY SUB
BISBEE
MURAL SUB
DON LUIS SUB
SAN PEDRO SUB
FAIRVIEW SUB
DOUGLAS
NOGALES
VALENCIA SUB
GATEWAY SUB
NEW MEXICO
MEXICO
WESTERN
TEP
AEPCO
SSVEC
APS
CUC
AEPCO – ARIZONA ELECTRIC POWER CO-OP
APS – ARIZONA PUBLIC SERVICE CO
CUC – CITIZENS UTILITY CO.
SSVEC – SULPHER SPRINGS VALLEY ELECTRIC CO-OP
TEP – TUCSON ELECTRIC POWER CO.
WESTERN – WESTERN AREA POWER AUTHORITY
POWER PLANT
SUBSTATION
INTERCONNECTION BETWEEN UTILITIES
NORMALLY OPEN
69KV
115KV
138KV
230KV
345KV
karenc-1

Figure 8.5


TRANSMISSION SYSTEM WITH PROPOSED UPGRADES
115 KV LINES
230 KV LINES
345 KV LINES
SWTC/MEMBER SUB
OTHER'S FACILITY
AEPCO GENERATION
TO SPRINGERVILLE
GREENLEE (AEPCO)
MORENCI
GREENLEE (TEP)
DOS CONDADOS
TO HAYDEN
TEP
TO SAGUARO
TO THREE POINTS
WAPA
PROPOSED WINCHESTER
REDTAIL
PROPOSED 230 kV LINE UPGRADE
23.0 miles
TO WESTWING
WAPA
WAPA
VAIL
ADAMS
APACHE
BICKNELL
NOGALES TAP
BUTTERFIELD
PANTANO
SAHUARITA

Joint projects with APS in the area are contemplated. Sulphur Springs Valley Electric Cooperative is planning a substation in the Palominas area that could help to serve the APS load in the area.

8.5.2 Citizens Utility

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 Citizens. Citizens 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.

Citizens has developed an agreement with Tucson to connect to Tucson's South substation by way of a 345 kV line that will terminate at a new substation, Gateway, located about 3 miles from the Valencia substation near Nogales, as shown in Figure 8.4.

The 345 kV line will add 100 MW of firm capacity to the area, which is currently limited by contract to approximately 69 MW. Citizens will be working with Western and with SWTC that also has customers in this area to see if some or the entire future shortfall could be made up.

Citizens has filed a report with the ACC relative to the improvements of the existing line from Nogales down to the Citizens service area, by adding capacitors to withstand the outage of the new line to Nogales.

The Western line that is delivering power into Citizens system becomes constrained as the Citizens load grows. When a second line into Nogales is completed, Citizens will have 100 MW of transmission capacity from South to Gateway. To improve its SIL, Citizens is adding 50 Mvar of capacitors on its existing transmission line.

9. Merchant Plant Update

9.1 Ten-Year Plans

A.R.S. 40-360.02 states that every organization contemplating construction of any transmission line within the state during any ten-year period shall file a ten-year plan with the Commission on or before January 31 of each year. This requirement applies to merchant plants as well as those that are planning interconnections with the Arizona transmission grid. The merchant plants shall demonstrate the impact of transmission interconnections on the transmission grid through power flow and stability analysis results.

A compilation of planned plant interconnections filed by merchant plant developers in January 2002 is included in Appendix C. This section of the report documents a review of the ten-year plans filed by merchant plants, and Staff's assessment of those plans.

9.1.1 Gila Bend Power Project

Gila Bend Power Partners (GBPP) plan to build a 500 kV and a 230 kV line as part of the project. The size of the GBPP plant is expected to be 833 MW.

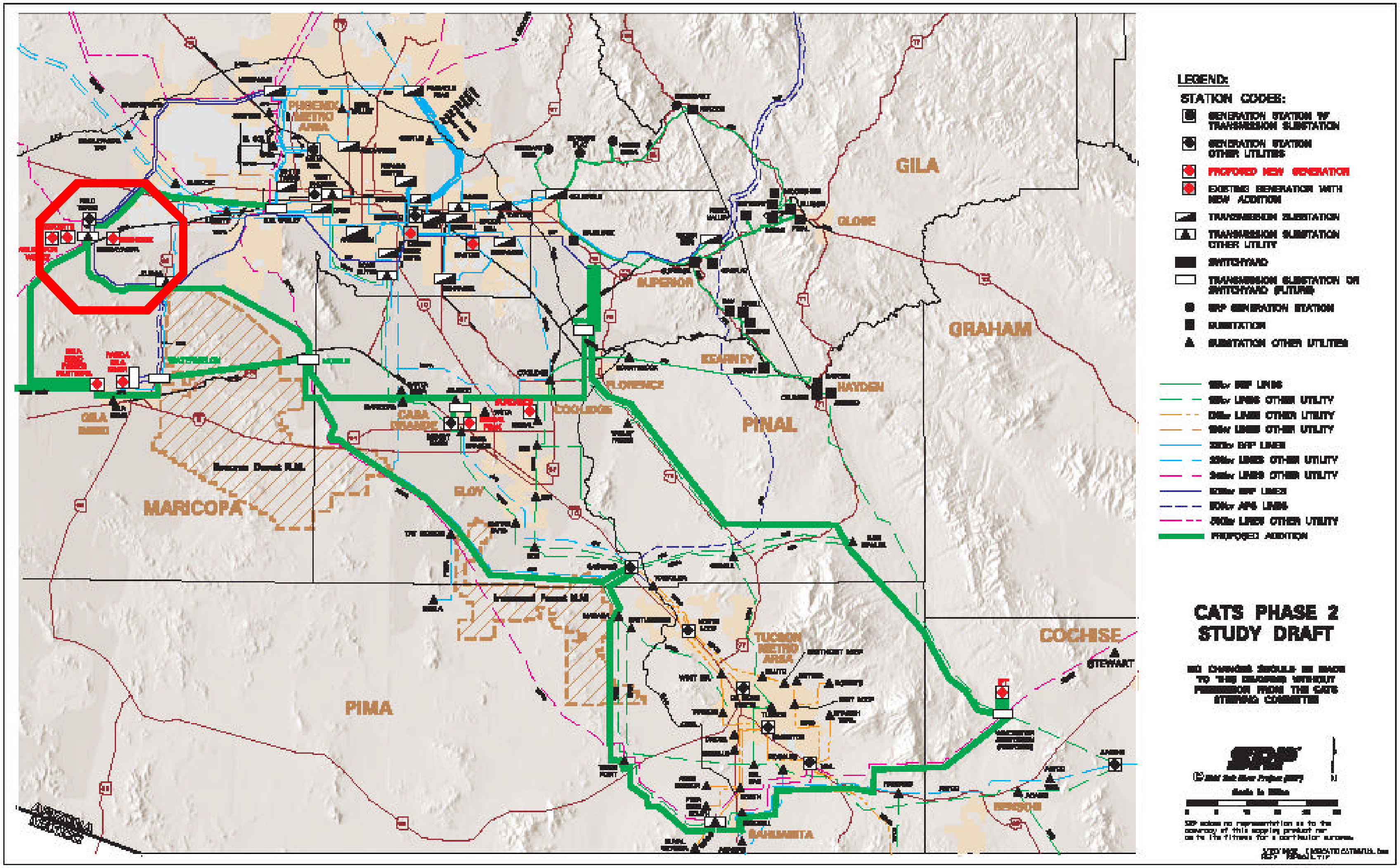
As shown in Figure 9.1, the 500 kV line will run from the GBPP site in the Northwest corner of Gila Bend and interconnect with the APS Gila River line at the Watermelon switchyard. The 230kV line will run from the GBPP to the APS Gila Bend substation at which point it will be interconnected with the APS Gila Bend to Liberty 230 kV line.

The 500 kV system impact study is completed and the 230 kV impact study is ongoing.

The 230 kV and 500 kV lines and the Watermelon switchyard are scheduled for completion in late 2003.

Figure 9.1

Central AZ: Long-Term Plan



The purpose of the system impact study was to assess the impact of the GBPP project on the Palo Verde transmission grid and the WECC EHV grid. The study was limited to power flow and stability analysis. The study results are included in the report.[25] For this analysis, two alternative configurations were evaluated: (a) GBPP project interconnection to the planned Jojoba-Gila River 500 kV double circuit line at Watermelon station (assumes a 500/230 kV transformer at Gila River substation to interconnect the existing Liberty-Gila Bend 230 kV line) and (b) same as (a), without the 500/230 kV transformer at Gila River 500 kV substation.

The study result of significance is that the maximum generation that can be scheduled out of Gila River vicinity to Arizona load centers is a function of the capability of Palo Verde transmission, which is based on the thermal limitation of either the Hassayampa–N. Gila 500 kV line or the Hassayampa-Kyrene 500 kV line.

The maximum GBPP generation that can be scheduled is 583 MW with Configuration (a), and 683 MW with Configuration (b). With these schedules, the GBPP interconnection will not have any adverse impact on the Palo Verde plant and its grid.

9.1.2 Gila River Project

The Gila River is a generating project owned by Panda Gila River LP (PGR). It will consist of four gas fired two-on-one combined cycle power blocks for a combined nominal rating of 2,080 MW. Operation of the first unit is scheduled to begin April 2003, with the last power block scheduled to be in service by August 2003.

The Gila River Project will have three interconnections: two with the 500 kV system and one with the 230 kV system. Gila River will interconnect with the Arizona Nuclear Power Project (ANPP) Transmission System Palo Verde-Kyrene line through two 21-mile long 500 kV transmission lines at the newly constructed Jojoba substation scheduled to be in service by November 1, 2002.[23] The third interconnection will be a 230 kV tie to the Liberty-Gila Bend line through a new 230 kV substation, as shown in Figure 9.2.

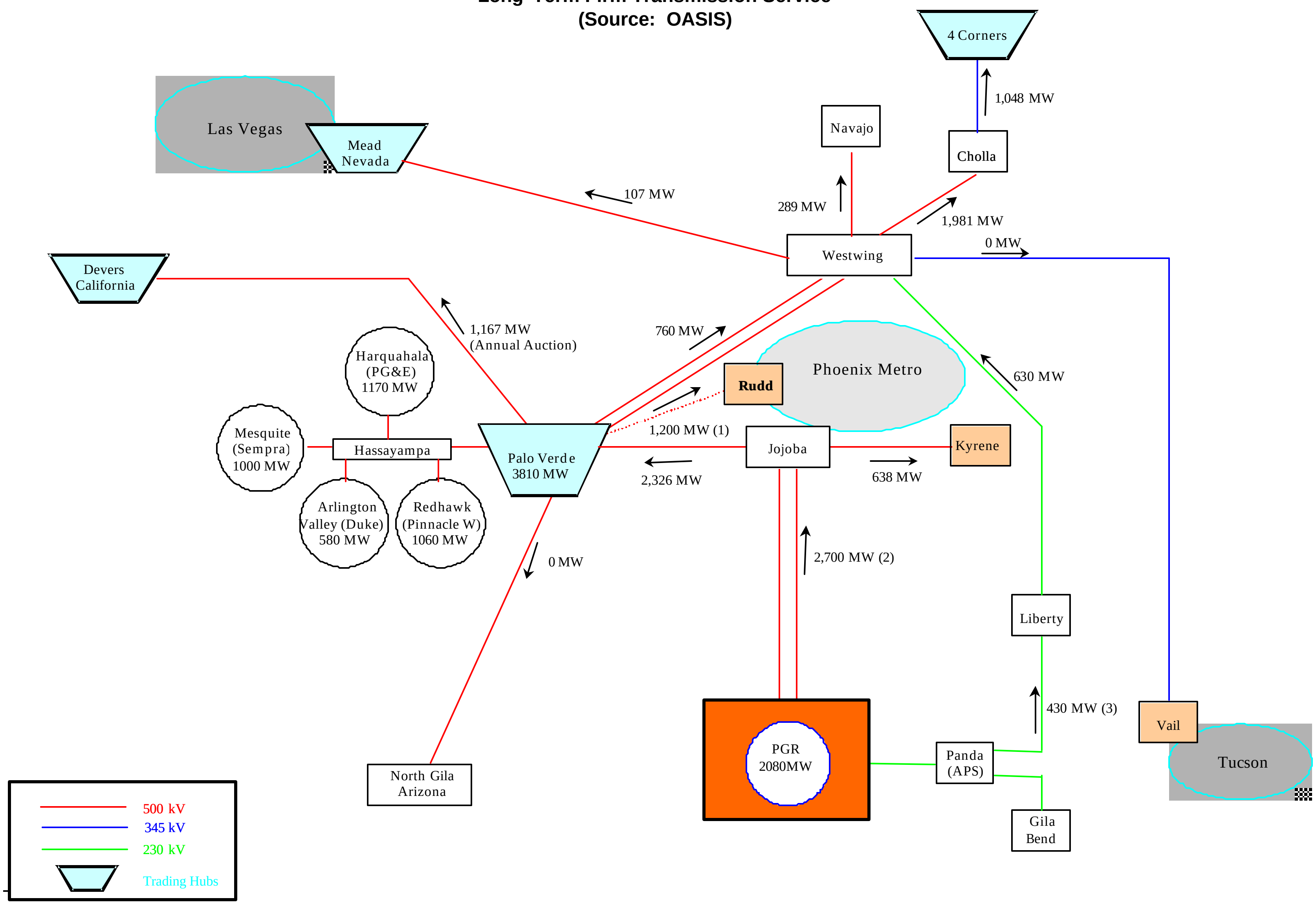
Gila River's interconnection at the Jojoba substation provides significant stability benefits over an interconnection at Palo Verde/Hassayampa.[37] With the Palo Verde to Jojoba 500 kV line segment out of service, PGR can reliably deliver at least 1,800 MW to Kyrene via the Jojoba to Kyrene 500 kV path and 240 MW to Liberty via the Panda to Liberty 230 kV path. For this outage, PGR is the only generator in the region that can directly deliver power at Kyrene, improving system reliability. With the Jojoba to Kyrene 500 kV line segment out of service, PGR can reliably deliver at least 1,600 MW to Palo Verde via the Jojoba to Palo Verde 500 kV path and 430 MW to Liberty via the Panda to Liberty 230 kV path. With the Liberty to Panda 230 kV line segment out of service, PGR can serve APS load at Gila Bend. With the two 500 kV lines from Palo Verde to Westwing out of service, PGR can reliably deliver at least 1,825 MW on the 500 kV system and 300 MW to Liberty via the Panda to Liberty 230 kV path.

The Gila River Project currently has 333 MW of firm transmission service to the Palo Verde hub from APS, APS has offered an additional 430 MW on the Gila River to Liberty 230 kV line. The Gila River Project has made transmission service requests from SRP for 1,100 MW on the Jojoba to Palo Verde line. Also, under consideration on the Jojoba to Palo Verde line is 196 MW from El Paso Electric.

The Gila River Project has been actively working with CATS developing additional interconnection options, including an interconnection with Tucson Electric Power's 345 kV Westwing to Vail line. TEP has filed an interconnection request with the Arizona Nuclear Power Project (ANPP) Valley Transmission System to interconnect, via a 500 kV transmission line, a new Pinal West 500/345 kV substation to the Jojoba substation. The Pinal West 500/345 kV substation would have TEP's Westwing to Vail 345 kV line looped through, providing a direct path from Jojoba to TEP's system. This interconnection request is being evaluated by SRP as the first phase of the Southeast Valley (SEV) project, which is currently in the siting and permitting process. In summary, to ensure access to the Palo Verde trading hub, the project has

Figure 9.2
Panda Gila River Project

Arizona Electrical Diagram and
Long-Term Firm Transmission Service
(Source: OASIS)



(1) Line under construction. The total expected line capacity will be 1,200, however, available firm transmission on this line not currently posted.
(2) PGR has firm transmission rights to Jojoba for the total output of plant.

Revised: July 18, 2002

secured 333 MW of firm transmission service from APS, requested 1,100 MW of service from SRP, and is considering 196 MW from El Paso Electric. In addition, PGR is evaluating a joint transmission project with TEP for up to 600 MW of service on the Westwing-Vail line. The combination of Gila River's interconnection to both 500 and 230 kV systems provides the project with ample transmission access to deliver the full output of the Gila River Project to market, and improves the overall reliability of the Arizona transmission system.

9.1.3 Sundance Energy Project

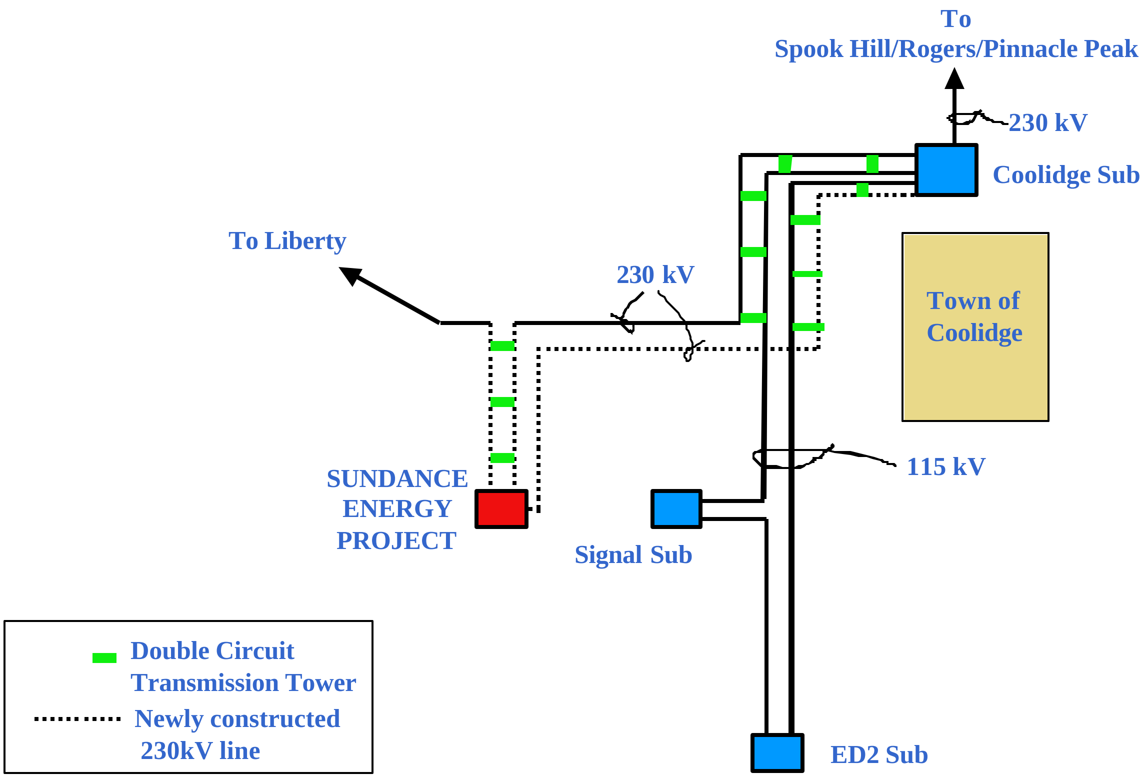
The Sundance Energy Project, with a total gross generation of 450 MW in stage I, has requested transmission service. This includes interconnection to Desert Southwest Region (DSW) system extending from the Coolidge area to greater Phoenix area, as shown in Figure 9.3.

The Stage I system impact study was conducted according to Western's Open Access Transmission Tariff (OATT), and looked at the transmission upgrades needed to mitigate any impacted DSW facilities, and the impact of the Project on the stable operation of the interconnected system.[38] The study results showed that there are no power flow and stability problems, and no equipment overload problems.

9.1.4 Ambos Nogales Generation Project

The plant capacity is estimated to be 500 MW, combined cycle natural gas fired facility, with a 230 kV double circuit line connected to CFE in Mexico (and not connected to the U.S. grid), and a 115 kV intertie with Citizens.[20]. The project claims that it will start construction by 2003, and be in operation by 2006, assuming CFE approval. However, this schedule seems unlikely, given that the project has not even filed an application with the Commission for a CEC. The project did not provide any power flow or stability analysis with it ten-year plan filed the Commission since it does not propose to connect to the U.S. grid, and since no capacity is proposed to be exported out of Citizen's service area.

Figure 9.3
Sundance Energy Project Transmission Interconnection



9.1.5 Allegheny Power Project

Allegheny Power project plans to interconnect a new generating plant with a capacity of 1,290 MW to SCE's Devers-Palo Verde 500 kV line. The proposed in-service date is 2004.

The system impact studies revealed that the existing facilities are inadequate to accommodate the Allegheny Power project.[36] The Allegheny–Devers and Palo Verde-North Gila 500 kV lines are loaded in excess of the ratings as limited by capacitors. The Allegheny power project will be required to schedule according to Southern California Interconnected Transmission (SCIT) nomogram and will have an adverse impact on the amount of East of River (EOR) and West of River (WOR) generation that can be scheduled for import.

A facilities study is required to determine the facilities and upgrades required to interconnect the proposed project.

9.2 Operational Experience of Plants On-Line

During the presentations several questions were asked of the panel members, which led to discussions. The discussion points and responses are captured here even if there was not a full conclusion arrived at:

- Did the plant owners believe they had performed adequate interconnection studies, either themselves, or in collaboration with the transmission providers, to determine the impact of their power plants on the integrated grid system, either current operation or future operation? The respondents believed that considerable study had been performed. In the cases of operating the plants there have not been any difficulties in operations due to transmission constraints except as noted by specific plants.
- What and who determines the commercial operation date? The date that the plant is operational has mainly to do with warranties, and provisional performance acceptance as described in the construction contracts.
- A further discussion developed about whether or not the merchant plants were to participate in supplying area reserves. It was not clear that the respondents fully understood the premise of the question, but most agreed that their plant was to help out the system in some way.

9.2.1 South Point

South Point is a generating station owned by Calpine Western Region. It consists of a two-on-one combined cycle gas fired plant producing 550 MW. The project came on line in May 2001, and up until December 31, 2001 had achieved 5580 hours of operation. In 2002 through June, the plant has experienced 380 hours of planned outage.

The plant is connected to Topock 230 kV substation, on the Parker-Davis System and ties directly to the Number 1 and Number 2 lines between Davis Dam and Parker Dam. Firm transmission exists for delivery to five points; Mead, Pinnacle Peak, McCullough, Marketplace and Liberty, with terms of 40 years. Transwestern supplies gas. In constructing the plant, upgrades were needed to the new 230 kV system between Davis and Parker. Twenty eight miles of new and 60 miles of reconductored 230 kV line were completed by Western on the Davis to Parker 230 kV line. South Point interconnects to the Davis to Parker 230 kV line at the Topock Substation.

The plant has not experienced any delivery constraints.

9.2.2 Griffith Energy

Griffith Energy is a generating project owned in equal parts by Duke Energy and PPL. It consists of a combined cycle 2X1 gas fired plant producing 600 MW. The project was declared commercial on January 17, 2002, and has run at an average of 40 percent capacity factor since going commercial, limited by market conditions.

The power project has firm transmission to Mead provided by Western, and is sited in Western's control area. In constructing the plant, two new substations, Griffith 230 kV Switchyard and Peacock 345/230 kV Substation, were built along with 28 miles of new and 60 miles of reconductored 230 kV line. Griffith Switchyard substation connects the plant to Western's Parker-Davis Transmission System and to the Pacific Northwest-Southwest Intertie System via Peacock 230/345 kV Substation.

Although the plant is located in Mohave County, a transmission constrained area, the plant output flows out, not in, and does not contribute to the constraint. However, under certain transmission line outage conditions the operational status of Griffith and South Point plants can limit the capability of the local transmission system to serve local load.

9.2.3 West Phoenix 4

West Phoenix 4 is owned and operated by Pinnacle West Energy Corporation. The 120 MW plant is a one-on-one combined cycle unit utilizing a stress demand steam turbine with supplemental duct firing. It went into service in June 2001, and has to date experienced an annual capacity factor of 60 percent, and an availability factor of 90 percent. The plant is fueled with gas from the El Paso pipeline.

The plant is constructed on the site of an existing power station that contains five other units. The site has infrastructure built in anticipation of West Phoenix 5. An initial interconnection study was performed and as a result some reconductoring of 69 kV lines was done to accommodate the plant. In the future some reconductoring and building of 230 kV lines is anticipated, including a line to White Tanks, as well as installing refrigeration on a Lincoln-Country Club 230 kV cable.

The plant serves Arizona load, and there has been no restricted operation due to transmission constraints.

9.2.4 Desert Basin

Desert Basin is a generating project owned by Reliant Energy. It consists of a combined cycle two-on-one gas fired plant producing a nominal 500 MW, and is supplied by the El Paso gas pipeline. The plant was declared commercial in October 2001, and has run at an average capacity factor of 65 percent, and an availability factor of 90 percent. The full output has been contracted to SRP.

Desert Basin has operated successfully with no reductions or curtailments due to transmission issues below the 510 MW of Firm Point to Point Transmission Service purchased from APS.

Like other power projects, the owner worked with the transmission provider to identify constraints. A System Impact Study was completed by APS for the plant prior to its being interconnected to the APS transmission system. The System Impact Study revealed that the plant would operate successfully maintaining system stability without corrective actions. Network upgrades were identified on the APS transmission system to allow the plant to deliver 510 MW of firm capacity to the point of delivery identified in the transmission service request made by Reliant Energy. These upgrades were completed by APS and a Transmission Service Agreement (TSA) was executed for the 510 MW of firm transmission service.

Subsequent to the execution of this TSA, changes occurred on the APS system and some facility/equipment ratings on the WAPA system were found to be incorrect. This resulted in some transmission system overloads being identified on the WAPA and APS system under certain contingency conditions. APS and WAPA agreed to upgrade the WAPA facilities to eliminate overloads on them and to develop operating procedures to deal with the APS facility overloads. This work was completed and operating procedures were developed earlier this summer. The current Operating Procedures for the APS transmission system in the vicinity of the Desert Basin plant allow the plant to deliver 510 MW of firm capacity under the TSA with all lines in service.

Under certain conditions with the loss of the Desert Basin to Santa Rosa 230 kV line, actions must be taken within 30 minutes to relieve overloads on some transmission facilities. These actions include a Remedial Action System (RAS) tripping scheme that may result in tripping one 50 MW Gas Turbine at Saguaro and further manual reduction in the output of Desert Basin and Saguaro of up to 50 MW.

It is also to be noted that the total output of the plant is 560 MW as per the approved CEC. That means that there might be a transmission adequacy problem if the balance of power from the plant were to be delivered to any entity other than SRP.

9.2.5 Kyrene

Kyrene is a generating project owned by Salt River Project. The new Kyrene plant is approximately 250 MW, one GE 7-FA turbine with a GE steam turbine and also HRSG. The initial synchronization was completed in April 2002, and was declared ready for commercial operation in Fall 2002.

This project uses effluent from the City of Tempe, and the plant is connected to the El Paso Natural Gas pipeline system. At Kyrene there is an existing 500 kV and 230 kV and 69 kV switchyards, and Kyrene is one of the backbone receiving stations on the SRP system.

9.2.6 Arlington Valley Energy: Facility I

Arlington Valley Energy Facility I (AVEFI) is a 570 MW gas-fired combined cycle facility owned by Duke Energy, and went into commercial operation in June 2002, six weeks ahead of schedule.

AVEFI is located south of Elliot Road between 387th and 391st avenues. There are no major technical issues or dependencies affecting the operation of the facility.

Gas is transported to AVEFI from the El Paso Gas transmission lines located southwest of the Facility.

Transmission interconnection was provided by Salt River Project, and a 2.5 mile 500 kV line was constructed to connect AVEFI to the Hassayampa switchyard. The transmission line is completed and is fully operational.

The project has been operating at full capacity and transactions have been successfully completed at the Palo Verde hub. The facility experienced no major start-up problems, and the underground water supply has been reliable and water wells have operated efficiently.

9.2.7 Saguaro CT 3

Saguaro CT 3 is owned and operated by Pinnacle West Energy Corporation. Saguaro CT 3 is a simple cycle unit GE 7-A, EA, has an 80 MW nominal output, located at the Saguaro site. The unit went into commercial operation in July 2002. It has been used as a peaking unit.

The data on unit performance is still being gathered, and there have been no operational problems with the unit. The existing cooling tower on-site was tapped into for cooling water since the cooling water requirements of the unit are small.

9.2.8 Redhawk 1 and 2

Redhawk units 1 and 2 are owned and operated by Pinnacle West Energy Corporation. There are two, two-by-one units, each with a nominal rating of 530 MW. These are GE combustion turbine units, Alstom steam turbines, and steam HRSGs. The gas for the units is supplied by El Paso Gas, and water is taken from the Palo Verde Reclamation Facility.

Redhawk site is located just south of Palo Verde. Redhawk has its own switchyard, built by Pinnacle West Energy Corporation, and it ties into the Hassayampa switchyard.

Redhawk units 1 and 2 went into commercial operation in August 2002. The output from Redhawk 1 and 2 is contracted with Pinnacle West Power Market and Trading, serves dedicated loads in the Valley, and the units have been delivering power to the transmission grid.

9.3 Project Status of Plants Scheduled for Future Years Operation

9.3.1 Mesquite

Mesquite is a generating project developed by Sempra Energy Resources. The plant will consist of two combined cycle gas fired units of a two-on-one configuration producing a total of 1,000 MW. The first power block is scheduled to be in service on June 1, 2003, and the second block in November of 2003. Engineering, purchasing, and construction are ahead of schedule at this point. El Paso Gas will furnish the gas through a pipeline connection that includes plants owned by Pinnacle West, Redhawk 1 & 2, and Duke, ARVL 1.

The transmission connection is to Hassayampa where the Mesquite shares a property boundary. The Hassayampa switchyard study included connection of the plant.

9.3.2 Santan

Santan is a generating project owned by Salt River Project. It will consist of a two-on-one combined cycle unit and a one-on-one combined cycle units for a total of 825 MW. Santan is an existing generating station, which currently has four combined cycle units with a combined output of approximating 400 MW, built in the mid 1970s. El Paso Gas supplies the station with fuel, and for this plant the cooling water supply will be a combination of effluent from the town of Gilbert and water from the Central Arizona Project (CAP). The gas pipeline capacity is limited so SRP is in the initial stage of developing a 40-mile pipeline extension from south of Coolidge.

A 230 kV and 69 kV substation exists at the station.

Anticipated commercial operation date is May 2005.

9.3.3 Harquahala

Harquahala is a generating station owned by PG&E National Energy Group. The station will consist of three one-on-one combined cycle power blocks. All of the units are expected to be in operation by summer 2003.

Harquahala was included in the Hassayampa interconnection study, and the developer states no transmission problems are expected. However, the actual plant rating has been increased to 1,092 MW nominal. The significance of the plant rating changes will be determined by Commission hearings and the impact of increased ratings on the transmission system out of Palo

Verde/Hassayampa switchyard will be determined by transmission studies to be filed by the plant prior to commercial operation on or before April 1, 2003.

9.3.4 Arlington Valley Facility II (AVEF II)

Arlington Valley Facility II is a 600 MW facility gas-fired combined cycle facility owned by Duke Energy. The facility has received the ACC Certificate of Environmental Compatibility (CEC) permit, and the County land use approvals. The final air permit is expected by end of 2002.

The transmission capacity is built into the currently operating radial line from AVEFI to Hassayampa, and the CEC requires a few other transmission upgrades within the facility. The land reclamation plan for AVEF I includes AVEF II.

9.3.5 Bowie Power Station

Bowie is a generating station that is owned by Southwestern Power Group, and will be located one and one-half miles north of the town of Bowie, AZ.[28]. The station will consist of two combined cycle 2X1 power blocks each producing 500 MW. The first power block is expected to be placed in service 4th quarter 2004, and the second block in service 4th quarter 2005. A Certificate of Environmental Compatibility (CEC) was awarded in February 2002. Additional permits that are being worked on include an aquifer protection permit for the cooling ponds, and a rezoning permit. There are four optional pipelines that can be connected to, but the most likely is the El Paso Natural Gas All America pipeline, that is anticipated to be in service at 800 psi in fall 2002, although a 404 permit will be required for that. All of the permits are expected to be in hand by fall 2002.

An interconnection study is being conducted by TEP with expected results early fall 2002, followed by a facility study which will lead to entering into an interconnection agreement by January 2003.[27]

9.3.6 Desert Energy

Desert Energy will be a gas fired combined cycle plant rated at 585 MW, and will be located near APS' Saguaro station.[21] The owners expect to be in Siting hearing by early 2003. This workshop is the first public announcement of the power station, and consequently many of the studies and applications are just starting to be filed. No interconnection study has yet been performed.

9.3.7 West Phoenix 5

West Phoenix 5 is a generating project owned by Pinnacle West Energy, and is located at the existing West Phoenix station. It consists of two combined cycle 2X1 gas fired power blocks each producing 530 MW. The project is on or slightly ahead of schedule, which would put it in service by June 2003.

In conjunction with the West Phoenix station expansion, upgrades were made to the switchyard and to the transmission line connections to accommodate the project. No transmission line constraints are anticipated.

9.3.8 Redhawk 3 & 4

Redhawk 3 & 4 will be an expansion of an existing power station owned by Pinnacle West Energy. It will consist of two power blocks, with a footprint similar to Redhawk 1 & 2. Each power block will produce 530 MW.

The plant has an approved CEC, and air quality permit is in hand. When Redhawk 1 and 2 were constructed some infrastructure was built in anticipation of Units 3 and 4.

The in-service date for these units will be either 2006 or 2007.

9.3.9 Wellton-Mohawk

The proposed Wellton-Mohawk Generating Facility is being developed by a partnership of private and quasi-governmental entities including Dome Valley Energy Partners, LLC., Yuma County Water Users Association and the Wellton-Mohawk Irrigation and Drainage District[20]. The Wellton-Mohawk Generating Facility will be a combined cycle generating station consisting of two 2x1 power blocks each producing 310 MW, and located in the Yuma load pocket. The Wellton-Mohawk Irrigation and Drainage District operates a distribution system with a load of about 35 MW. The Project intends to connect the power station at existing Ligurta substation, and take cooling water from the Wellton–Mohawk Irrigation and Drainage District canal. Western has conducted an interconnection study and concluded that the plant could alleviate the problems of constraints into the Yuma area. A facility study is currently underway. The first Siting hearings were conducted in August 2001. The air permit application is complete and submitted, with an expected date for permit issuance in early 2003. The Wellton-Mohawk Generating Facility has received gas supply and transportation proposals and is currently negotiating with a few gas suppliers to serve the plant. The project is developing an interconnection with APS. At this point the in-service date is 2005.

A section of new transmission line and about 40 miles of upgrades to Western's 161 kV transmission line would have to be constructed.

It is worth noting that the Wellton-Mohawk Project is unique in that it also intends to utilize the patented SEECOT™ Solar Thermal Technology to reduce gas consumption by converting solar energy into thermal energy for inlet air-cooling of the Combustion Turbine Generator (CTG). This would result in an approximate 12 percent increase in CTG electric output during times of peak solar radiation, as well as improved efficiency and/or a lower heat rate. Using this system, the Project will generate kilowatt-hours that qualify as renewable energy credits under Arizona's Environmental Portfolio Standard and that qualify as renewable energy purchases under similar programs in both Nevada and California.

10. Conclusions and Recommendations

10.1 Steps Taken by Industry in Response to First Biennial Transmission Assessment, 2000-2009

The electricity industry responded formally to the findings in the first Biennial Transmission Assessment in a variety of ways. A renewed emphasis was placed on regional transmission planning, transmission facilities are being developed to increase transmission capacity out of the Palo Verde hub, local transmission import constraints are being better defined, and major service concerns in southeastern Arizona are being addressed. A short summary of each topic is provided below.

10.1.1 Regional Transmission Planning Effort

Given the diverse location of load pockets, generation resources and Merchant Plant development, the Arizona utilities agreed that a regional transmission planning effort is needed to assess the EHV transmission needs and opportunities in the central Arizona area. Hence, the utilities agreed to form the Central Arizona Transmission System (CATS) study group in June 2000, in which all the Arizona transmission utilities, Staff and other interested parties are participants.

The CATS study group has made rapid strides since its formation, and has completed studies related to the identification of alternative EHV transmission facilities in the Central Arizona area. The CATS study has proceeded in several phases, and the group issued a Phase I final report in July 2001 and Phase II final report in September 2002. The group is in the process of initiating its Phase III efforts.

Based on the success of the CATS EHV study effort, other related ongoing transmission projects such as the High Voltage transmission study between Phoenix and Tucson and the proposed Arizona-California interstate study project are also being pursued by the CATS study participants. The PNM's Arizona–Sonora Mexico Transmission project team is already participating in the CATS study activities.

10.1.2 The Palo Verde Hub Assessment

The first BTA highlighted the inadequacy of the existing Palo Verde transmission system to deliver the total capacity from all the new merchant plants connecting to the PV Hub. Plans for new transmission lines emanating from the Palo Verde Hub have emerged from the CATS studies and recent power plant proposals. In addition, a detailed PV Hub Risk Assessment study was initiated by APS and SRP. As part of this study, catastrophic events like the (N-3) and (N-4) types of contingencies are being studied, and the Hub reconfiguration after such outages is being evaluated.

10.1.3 Import Constraint Zones

In response to the concerns raised by Staff in the first BTA on three transmission import constraint zones (Phoenix, Tucson, and Yuma), the Arizona utilities have become more rigorous in defining the limitations of import constrained load zones. Identification and evaluation of alternative solutions are beginning to emerge. Vertically integrated utilities have traditionally undertaken to balance between adding local generation and building new transmission infrastructure in order to alleviate the import constraints. Nevertheless, utilities now acknowledge there is a need to better document cost minimization.

10.1.4 Southeastern Arizona

With regard to Staff's concerns on the inadequacy of transmission in the Southeastern Arizona and the consequent risk of service interruptions, the transmission utilities in the region are coordinating their transmission planning efforts to improve the system adequacy. Citizens has responded to Staff's assessment with regard to the need for additional transmission serving the Santa Cruz County. A second transmission line to Nogales has received a CEC and is currently going through the federal EIS process. Similarly, Citizens has proposed 115 kV capacitors to remedy the effects of loss of that new line due to an outage.

10.1.5 Power Flow and Stability Analysis

All parties have effectively responded to the requirement that power flow and stability analysis reports supporting planned facilities be submitted with their ten-year plans. Staff finds those technical reports were both sufficient and of suitable quality.

10.2 Adequacy of Planned System Facilities

10.2.1 Transmission Import Constraint Zones

Transmission import constraint zones within the Arizona transmission grid are still an area of concern. While the import constraint issues in certain load pockets are being addressed, the measures taken in others are still inadequate. Since the first BTA, the load pockets in Santa Cruz County and Mohave County are also becoming import constrained due to the overload of facilities feeding into those areas.

The measures contemplated by APS in the Yuma area appear to offer a variety of solutions that could alleviate the import constraints. The proposed measures depend on a combination of local generation (existing and new such as the Wellton-Mohawk project), APS' share of the lines feeding into the Yuma area, and potential new facilities (such as the 230 kV transmission line from Gila Bend to Yuma). The ultimate solution would take into account the relative reliability, cost effectiveness and environmental impacts of these options consistent with the State of Arizona's future outlook.

TEP is taking measures to increase the import capability into Tucson area through joint transmission projects with APS, SRP, SWTC and Citizens, in addition to depending on local generation. However, TEP also addressed the concern related to local voltage support by running local generation. Thus, TEP's proposed solution seems to alleviate the import constraint problem, assuming the proposed transmission projects are completed in a timely manner.

The utilities serving the Valley area have proposed a combination of Valley Transmission projects to relieve the import constraints in the Phoenix area, in addition to depending on local generation. As the transmission constraint for the Valley has changed over time from a thermally limited transmission import capability to a system constrained by the Mvar margin limits, a complex set of measures has to be considered to assure system adequacy. From the analysis of the measures proposed by the Valley utilities, ACC Staff has several issues that remain unanswered with regard to their proposed solutions. The ACC Staff issues are related to Megavar margin improvement, effect of local generation outages, dispatch levels of local generation to provide the needed load serving capability, and installing reactive power devices locally to improve the voltage support, all of which need to be addressed in greater detail.

In the Santa Cruz County area, there is limited local generation, and until the proposed transmission projects near the Gateway substation are completed the import constraint problem will persist. The existing transmission capability is inadequate to serve the load in this area under contingency conditions.

In Mohave County, the transmission path into the County is owned by Western and its capacity is fully subscribed. There is adequate local generation. However, the Merchant plants in the area have no contractual agreements in place to run the generation to alleviate the local import constraints. Hence, the transmission system in the area is inadequate to relieve the import constraints.

10.2.2 Local Transmission System Inadequacies

The load in local areas is growing and there is not enough local transmission in some local areas to meet the projected load growth. There are planned local HV transmission enhancements at the 230/138/115 kV levels to adequately and reliably meet the growth in Northern and Central Arizona. Although there are good EHV transmission overlays at the 345 kV and 500 kV levels for Central Arizona through the CATS efforts, the existing and underlying HV transmission system requires enhancements to serve the projected needs of customers. Hence, the HV transmission system serving Central Arizona needs to be investigated further, and collaborative HV transmission plans need to be developed to ensure compatibility with the planned EHV system for the area.

Transmission systems of Arizona utilities are also intertwined with the Western transmission in the Western, Northern and Southern Arizona areas. Western transmission is built to meet the needs of its long-term preference customers, and participation with other utilities can materialize only through trust accounts where the upgrades have to be paid by the users. Concerns related to non-availability of Western's transmission capacity for Arizona utilities have been identified in several areas, namely, Kingman, Flagstaff, Yuma, and Santa Cruz County. This introduces a degree of uncertainty in transmission upgrades, and needs to be resolved to the benefit of Arizona consumers.

In the Northern Arizona area, there is not enough transmission to serve the projected loads after 2006, and no concrete proposals are in place to address this issue.

In the Southeastern Arizona region, transmission reinforcement measures taken by SWTC, TEP, and Citizens are adequate to serve the customer load, and reduce the need for Remedial Action Schemes (RAS) during multiple contingencies.

10.2.3 Palo Verde System Constraints

Palo Verde system constraints continue to be an area of concern, with inadequate transmission to accommodate the additional generation capacity at the hub. The current system and current interconnected units do not have any limitations and curtailment requirements and that is not necessarily reflective of what the future may offer. The Palo Verde interconnection studies have shown that at some point there will be a need for transmission upgrades or some curtailment or some congestion management requirements. Staff has taken the position that curtailment or scheduling restrictions as a congestion management practice preparing for single contingency outages is inappropriate. Given the commercial importance of the PV hub, the transmission adequacy issues have to be addressed, possibly in a framework similar to CATS, in order to take full advantage of the total generation capacity available at the hub.

10.3 Recommendations

- Continue with the "Guiding Principles for ACC Staff Determination of Electric System Adequacy and Reliability" to aid Staff in the determination of adequacy and reliability of power plant and transmission line projects.
- Continue with the stipulation of the requirement of two or more lines out of each plant's switchyard to meet (N-1) contingency criteria without relying on remedial actions such as generator tripping or load shedding.
- Utility distribution companies (UDCs) should ensure sufficient transmission import capacity to reliably serve all load in their respective service area without limiting access to more economical or less polluting remote generation.
- New power plants should ensure sufficient interconnection transmission capacity to reliably deliver its full output without use of remedial action schemes for single contingency (N-1) outages or displacing a priori generation at same interconnection.
- 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.
- Continue to encourage collaborative study activities between the transmission providers and merchant plant developers in order to maximize the benefits of generation additions and cost–effective transmission enhancements and interconnections; and to facilitate restructuring of the electric utility industry to reliably serve Arizona consumers at just and reasonable rates via a competitive wholesale market.

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 ACC Staff determination of electric system adequacy and reliability in the two areas of transmission and generation.

Transmission

A.R.S §40-360.02E obligates the Arizona Corporation Commission (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, ACC 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 Western Systems Coordinating Council (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. Reliance on remedial action such as generator unit tripping or load shedding for single contingency outages will not be considered an acceptable means of compliance with this rule.

[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.

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. ACC Staff will 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.

ACC 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.

ACC 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)

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This date: (2/8/00)

DRS/jds:ESAR.doc

Appendix D
List of Reference Documents

Reliability and Planning Criteria and Guidelines

[1] Jerry D. Smith, ACC, "Arizona's Best Engineering Practices", Staff pre-filed comments for the Gila Bend Power Plant Hearing, Docket No. E-00000V-00-0106, November 9, 2000.

[2] WECC Reliability Criteria found at http://www.wecc.biz

[3] WECC Reliability Criteria for Transmission System Planning, May 2001

[4] WECC Reliability Management System (RMS) Agreement found at http://www.wecc.biz

[5] WECC: NERC/WECC Planning Standards, revised August 7, 2002

[6] WECC: Minimum Operating Reliability Criteria, revised March 28, 2001

[7] NERC Planning Standards found at http://www.nerc.com

Ten-Year Plans

[8] SRP Ten-Year Plan, 2002-2011, Appendix 1, Report on the Phase 1 Study of the CATS, July 20, 2001

[9] APS Ten-Year Plan, 2002-2011, January 2002

[10] SRP 10-Year Plan, 2002-2011, January 2002

[11] Tucson Electric Power Company, Amendment to Ten-Year Plan, February 5, 2002

[12] Southwest Transmission Cooperative, Inc., Ten-Year Plan, 2002-2011, January 2002

[13] Citizens Communications Company, Arizona Electric Division, Ten-Year Plan, 2002-2011, January 30, 2002

[14] Western-Desert Southwest Region (DSW) Ten-Year Plan, February 26, 2002

[15] Public Service Company of New Mexico, Ten-Year Plan, 2002-2011, January 30, 2002

[16] El Paso Electric Company's 2002 Filing of Arizona Ten-Year Plan, 2002-2011, January 2002

[17] Texas-New Mexico Power Company, Ten-Year Plan, Electric Transmission Lines, 28th Report, January 18, 2002.

[18] NRG MexTrans, Inc. Ten-Year Plan, January 31, 2002

[19] Ten-Year Plan Filing of Allegheny Energy Supply Company, LLC, Letter of January 30, 2002

[20] Ambos Nogales Generating Station, LLC and Maestros Group, LLC, Ten Year Plan, January 31, 2002

[21] Desert Energy, LLC Ten-Year Plan, (E-00000D-02-0065), January 28, 2002

[22] Reliant Energy Signal Peak, LLC Ten-Year Plan, 2002-2011, January 31, 2002

[23] Panda Gila River, LP, Ten Year-Plan, Letter of January 31, 2002 from Fennemore Craig

[24] Duke Energy Arlington Valley, LLC Ten Year Plan, Docket No: L-00000P-01-0117, Letter of January 24, 2002

[25] Gila Bend Power Project, Ten-Year Plan, January 30, 2002

[26] Toltec Power Station, LLC, Ten-Year Plan, January 29, 2002

[27] Letter from Martinez & Curtis, P.C., on Wellton-Mohawk Ten-Year Plan, January 31, 2002

[28] Bowie Power Station, LLC, Ten-Year Plan, January 29, 2002

[29] Central Arizona Project (CAP), Letter from Central Arizona Water Conservation District, January 31, 2002

[30] Letter from Doug Fant of Power Up Corporation on Ten-Year Plan, January 28, 2002

[31] SRP Ten-Year Plan, 2002-2011, Appendix 2, Report on the Preliminary Study for the Palo Verde Interconnection

Power Plant Interconnection Studies

[32] Arizona Power Plants-Technical Summary, June 24, 2002

[33] Toltec Power Station, LLC Interconnection Power Flow Update, August 2001 (prepared by R. W. Beck)

[34] Bowie Power Station Interconnection Power Flow Study, July 2001 (prepared by R.W. Beck)

[35] System Impact Study for Sundance Energy Project, Stage One, by Desert Southwest Region, May 2001

[36] Allegheny Energy Supply Company Allegheny Power Project Interconnection Study System Impact Study, October 19, 2001 (prepared by SCE)

Transmission Studies

[37] Facilities Study for Gila River Project for APS (By RW Beck), March 2000

[38] System Impact Study for Sundance Energy Project, Stage One, by Desert Southwest Region, May 2001

[39] Santa Cruz District Transmission System Action Plan, June 2002, by Citizens Communications Company, Arizona Electric Division

[40] Gila Bend-Yuma West 500/230 kV Transmission Project, Draft Study Plan Prepared by NRG Energy, Inc., February 26, 2002

Electric Restructuring

[41] ACC Staff Report on the Generic Electric Restructuring, Docket No. E-00000A-02-0051, March 22, 2002

[42] Direct Testimony of Jerry Smith, March 29, 2002, in the matter of APS request for a partial variance of certain requirements of AAC R14-2-1606, Docket No. E-0135A-01-0822 Rebuttal Testimony of Cary Deise on behalf of APS, April 22, 2002, Docket No. E-0135A-01-0822, et al.

[43] Generic Proceedings Concerning Electric Restructuring, APS and TEP, July 23, 2002 (Docket Nos. E-00000A-02-0051, E-01345A-01-0822, E-00000A-01-0630, E-01933A-02-0069, E-01993A-98-0471)

[44] WestConnect RTO, Docket No. RTO2-000, filed with FERC

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[45] Federal Energy Regulatory Commission, Standard Market Design, July 31, 2002, Docket No. RM01-12-000

[46] U.S. DOE National Transmission Grid Study, May 2002

[47] Conceptual Plans for Electricity Transmission in the West, Report to the Western Governors' Association, August 2001

[48] Western Market Interface Committee (WMIC) RTO SEAMS Task Force Meeting, June 2002

Appendix E
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