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January 29, 2010

Arizona Corporation Commission
DOCKETED

JAN 29 2010

DOCKETED BY

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RE: ARIZONA PUBLIC SERVICE COMPANY TEN-YEAR PLAN
DOCKET NO. E-00000D-09-0020

In compliance with AR.S. §40-360.02, enclosed please find Arizona Public Service Company's ("APS") 2010-2019 Ten-Year Plan for major transmission facilities, which includes the internal planning criteria and system ratings as required by Arizona Corporation Commission ("ACC") Decision No. 63876 (July 25, 2001):

> IT IS FURTHER ORDERED that Transmission Owners are required to file, with their Ten-Year Plans, internal planning criteria and systems rating with limiting elements identified. (Decision No. 63876, p. 3).

The Ten-Year Plan as well as other APS reliability-related infrastructure investments are premised on a number of assumptions including future growth, resource mix, the regulatory treatment of such investments by the ACC and the Federal Energy Regulatory Commission ("FERC"), other state and federal policies affecting transmission, and, of course, APS's ability to finance large investments of this nature on commercially-reasonable terms.

The 2010-2019 Ten-Year Plan describes planned transmission lines of 115 kV or higher that APS may construct over the next 10 years. This Ten-Year Plan includes approximately 181 miles of new 500 kV transmission lines, 83 miles of new 230 kV transmission lines, 6 miles of new 115kV transmission lines, and 12 new bulk transformers. The APS investment needed to construct these projects is currently estimated to exceed $520 million. When completed, these projects are expected to add approximately 2,000 MW of additional Extra-High Voltage scheduling capability, as well as 3,658 MW of import capability into the Metropolitan Phoenix Area and 220 MW of import capability into Yuma. These new transmission projects, coupled with additional distribution and sub-transmission investments, will support reliable power delivery in APS's service area, Arizona, and in the western United States.

Additionally, included in this filing is the Company's Reliability Must-Run Analysis ("RMR"), which was first developed in the Commission's Second Biennial Transmission Assessment and is now conducted biennially in response to the Commission's Third Biennial Transmission Assessment in Decision No. 67457 (January 4, 2005):

> "Require that RMR studies continue to be performed and filed with ten year plans in even numbered years for inclusion in future BTA reports....." (Decision No. 67457, p. 4).

Biennial filing of the RMR was reaffirmed in the Commission's Fourth Biennial Transmission Assessment. The analysis covers a ten-year period and includes detailed analysis of the years 2013 and 2019 for the two major areas in APS's service territory where load cannot be served by imports over transmission lines – Phoenix and Yuma. The study shows that, with currently planned transmission projects, available reserves are projected to meet or exceed the required generation reserves through 2019 in the Phoenix area, and reserve needs in the Yuma area do not at present outweigh the cost of transmission improvements beyond those in APS's Ten Year Plan.

If you or your staff have any questions, please contact Erinn Andreasen at (602)250-3276.

Sincerely,

Leland R. Snook

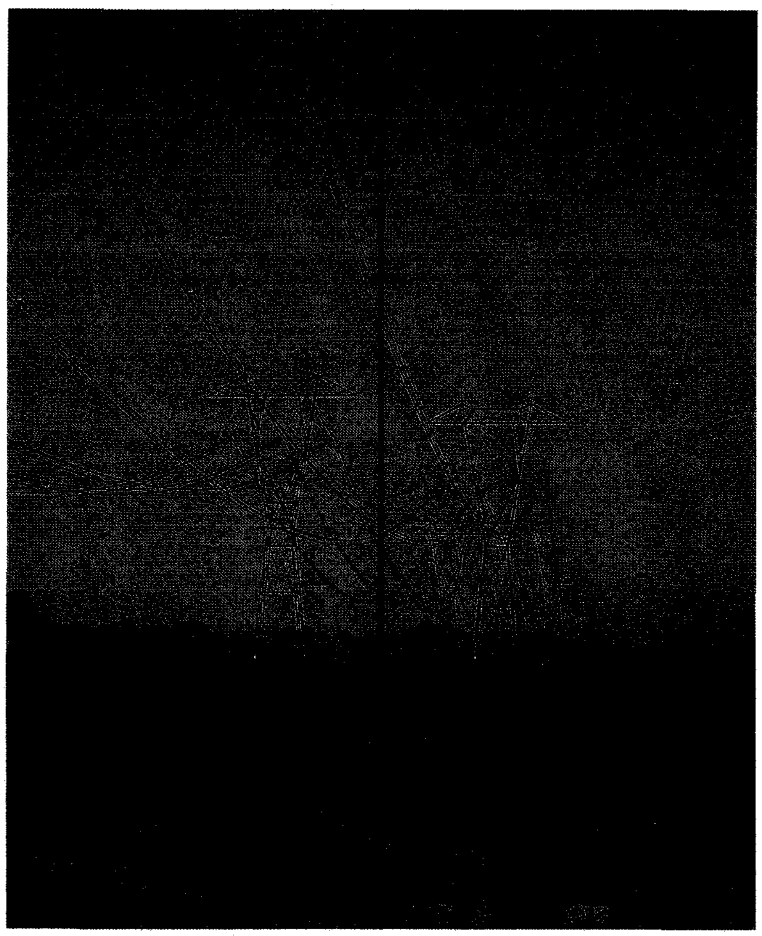
LS/sl

Attachments

cc: Ernest Johnson, Executive Director, Arizona Corporation Commission
Janice Alward, Chief Counsel, ACC Legal Division
Lyn Farmer, Chief Administrative Law Judge, ACC Hearing Division
Steve Olea, Director, ACC Utilities Division
John Foreman, Chair, Arizona Power Plant and Transmission Line Siting Committee
Brian Bozzo, Manager, ACC Compliance & Enforcement
Terri Ford, Chief, ACC Telecomm & Energy
Jodi Jerich, Director, RUCO

ARIZONA PUBLIC SERVICE COMPANY
2010–2019
TEN-YEAR PLAN

Prepared for the
Arizona Corporation Commission



January 2010

ARIZONA PUBLIC SERVICE COMPANY
2010 - 2019
TEN-YEAR PLAN

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* Projects are included in APS's response to Commission Decision No. 70635, Docket No. E-00000D-07-0376 regarding transmission for renewable energy projects. See additional information in the Ten-Year Plan related to development plans and in-service dates.

ARIZONA PUBLIC SERVICE COMPANY
2010–2019
TEN-YEAR PLAN

GENERAL INFORMATION

Pursuant to A.R.S. §40-360.02, Arizona Public Service Company ("APS") submits its 2010-2019 Ten-Year Plan. Additionally, pursuant to Arizona Corporation Commission ("Commission") Decision No. 63876 (July 25, 2001) concerning the first Biennial Transmission Assessment, APS is including with this filing its Transmission Planning Process and Guidelines and maps showing system ratings on APS's transmission system. The Transmission Planning Process and Guidelines outline generally APS's internal planning for its high voltage and extra-high voltage transmission system, including a discussion of APS's planning methodology, planning assumptions, and its guidelines for system performance. The system ratings maps show continuous and emergency system ratings on APS's extra-high voltage system, and on its Metro, Northern, and Southern 230kV systems. The Ten-Year Plan is conducted and filed annually with the Commission.

This 2010–2019 Ten-Year Plan describes planned transmission lines of 115kV or higher voltage that APS may construct or participate in over the next ten-year period. Pursuant to A.R.S. §40-360(10), underground facilities are not included. There are approximately 181 miles of 500kV transmission lines, 83 miles of 230kV transmission lines, 6 miles of 115kV transmission lines, and 12 bulk transformers contained in the projects in this Ten-Year Plan filing. The total investment for the APS projects and the anticipated APS portion of the participation projects as they are modeled in this filing is estimated to be approximately $520 million and the projects will add an expected 2,000 MW of additional extra high voltage ("EHV") scheduling capability. Also, over the next ten years the import capability into the Phoenix area will increase by 3,658 MW, while the import capability into the Yuma area will increase by 220 MW.[1,2] The following table shows a breakdown of the projects contained in this Ten-Year Plan.

Description	**Projects in Ten-Year Plan**
500kV transmission lines	181 miles
230kV transmission lines	83 miles
115kV transmission lines	6 miles
Bulk Transformers	12
Total Investment	$520 million
Extra High Voltage Scheduling Capability	+2,000 MW (+28 %)[a]
Total Phoenix Area Import	+3,658 MW (+26 %)[a]
Yuma Area Import	+220 MW (+39 %)[a]

[a] Based on 2009 values.

Some of the facilities reported in past Ten-Year plan filings that have been completed, canceled, or deferred beyond the upcoming ten-year period are not included in this report. The projects at the end of this Ten-Year Plan that have "to be determined" in-service dates are projects that have been identified but that are either still outside of the ten-year planning window or have in-service dates that have not yet been established. They have been included in this filing for informational purposes. A summary of changes from last year's plan is provided below, along with a list of projects that have been added to this year's Ten-Year Plan. Also, a section is included that briefly describes projects still in the feasibility planning phase.

For convenience of the reader, APS has included system maps showing the electrical connections and in-service dates for all overhead transmission projects planned by APS for Arizona, the Phoenix Metropolitan Area, and the Yuma area. Written descriptions of each proposed transmission project are provided on subsequent pages in the currently expected

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[1] Import capability increase is predicated on the Palo Verde to North Gila 500kV and North Gila to TS8 230kV projects. The Palo Verde to North Gila project was identified as one of APS's primary renewable transmission projects in response to Decision 70635 and will require approval for construction in the timeframe indicated.

[2] Import capability and scheduling capability are different numbers because "import" capability is an electrical ability to serve customers in a load pocket where "scheduling" capability is a contractual right to use the transmission line. Both are needed to reliably serve load.

chronological order of each project. The line routings shown on the system maps and the descriptions of each transmission line are intended to be general, showing electrical connections and not specific routings, and are subject to revision. Specific routing is recommended by the Arizona Power Plant and Transmission Line Siting Committee and ultimately approved by the Commission when issuing a Certificate of Environmental Compatibility and through subsequent right-of-way acquisition. Pursuant to A.R.S. §40-360.02(7), this filing also includes technical study results for the projects identified. The technical study results show project needs that are generally based on either security (contingency performance), adequacy (generator interconnection or increasing transfer capability), or both.

APS participates in numerous regional planning organizations and in the WestConnect organization. Through membership and participation in these organizations, the needs of multiple entities, and the region as a whole, can be identified and studied. This allows for potentially maximizing the effectiveness and use of new projects. Regional organizations of which APS is a member include the Western Electricity Coordinating Council ("WECC"), the Southwest Area Transmission Planning ("SWAT"), and WestConnect (which established a formal sub-regional transmission planning process during 2007). The plans included in this filing are the result of these coordinated planning efforts. APS provides an opportunity for other entities to participate in future planned projects. As a participant in the SWAT-Southeastern Arizona Transmission Study ("SATS") subcommittee, APS worked with other stakeholders in Cochise County to develop a transmission plan that will address the recommendations in the Fifth Biennial Transmission Assessment ("BTA") regarding providing continuity of service (Decision No. 70635 dated December 11, 2008).[3]

[3] Southwest Transmission Coop, Inc. ("SWTC"), on behalf of other participating utilities, will be submitting the Summary Report and Reference Filing of the Cochise County Technical Study Report as part of its Ten-Year Plan submittal.

As part of its planning process, APS is also evaluating the potential for renewable resource and associated transmission development. In response to the Fourth BTA order (Decision No. 69389 dated March 22, 2007), on August 6, 2008, the Joint Biennial Transmission Assessment Report on Renewables and Available Transmission Capability was submitted to the Commission on behalf of APS, Salt River Project, Tucson Electric Power, and Southwest Transmission Cooperative. That report described the collaborative efforts and analysis that was completed with the Southwest Area Transmission Sub-Regional Planning Group to address transmission for renewable resources, including an assessment of Available Transfer Capacity, a description of locations, and the transmission needed to bring renewable resources to load.

In addition, in response to the Fifth BTA order, and in collaboration with SWAT and its subgroups, other utilities, and stakeholders, APS developed plans to identify future renewable transmission projects and proposed funding mechanisms to construct the "top three" renewable transmission projects. APS submitted a report containing its prioritized renewable transmission projects to the Commission on October 30, 2009.[4] The projects selected are:

1. Delany – Palo Verde 500kV;
2. North Gila – Palo Verde 500kV #2;
3A. Palo Verde to Liberty;
3B. Gila Bend to Liberty; and
4. Delany – Blythe (Arizona Portion of Devers II).

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[4] Additionally, in APS's recent rate settlement (approved in Decision No. 71448 dated December 30, 2009) the Company agreed to "commence permitting, design, engineering, right of way acquisition, regulatory authorization…and line siting for one or more new transmission lines or upgrades" and "to construct such transmission line(s) or upgrade(s)" once APS obtains all required permitting and authorizations (*see* Exhibit A, §15.4 of Decision No. 71448). APS intends to pursue the Delany to Palo Verde 500 kV line to begin complying with this commitment, as described in the Company's 1/29/10 filing requesting approval of RTPs and their associated action plans.

Additionally, the specific development plans associated with the APS filing on October 30, 2009 will require Commission approval because they propose in-service dates and actions that may be beyond what is necessary for the reliable service of APS customers under a traditional analysis.[5] Absent Commission approval, in-service timeframes may differ from that indicated throughout this document.

APS believes that the projects identified in this 2010-2019 Ten-Year Plan, with their associated in-service dates, will ensure that APS's transmission system meets all applicable reliability criteria. Changes in regulatory requirements, regulatory approvals, or underlying assumptions such as load forecasts, generation or transmission expansions, economic issues, and other utilities' plans, may substantially impact this Ten-Year Plan and could result in changes to anticipated in-service dates or project scopes. Additionally, future federal and regional mandates may impact this Ten-Year Plan specifically and the transmission planning process in general. This Ten-Year Plan is tentative only and, pursuant to A.R.S. § 40-360.02(F), is subject to change without notice at the discretion of APS.

[5] *See* APS filing dated 1/29/10 requesting approval of RTPs and their associated action plans.

CHANGES FROM 2009-2018 TEN-YEAR PLAN

The following is a list of projects that were changed or removed from APS's January 2009 Ten-Year Plan, along with a brief description of why the change was made.

Morgan-Pinnacle Peak 500kV Line.

In the 2010-2019 Ten-Year Plan, the TS9 substation has been renamed and referred to as the Morgan substation.

In-Service Date Changes.

Project Name	Previous In-Service Date	New In-Service Date
Desert Basin – Pinal Central 230kV	2013	2014
Pinal Central – Sundance 230kV line	2013	2014

The in-service dates shown in this table are based on load projects, not potential interconnections. New generation interconnection may accelerate the in-service date.

NEW PROJECTS IN THE 2010-2019 TEN-YEAR PLAN

Mural – San Rafael 230kV.

This project is in response to the Fifth BTA order, which required the establishment of a long range system plan for Cochise County. This project is needed to serve the electrical energy need in the Cochise County area and is anticipated to be a joint participation 230kV circuit.

CONCEPTUAL PROJECTS IN THE FEASIBILITY PLANNING PHASE

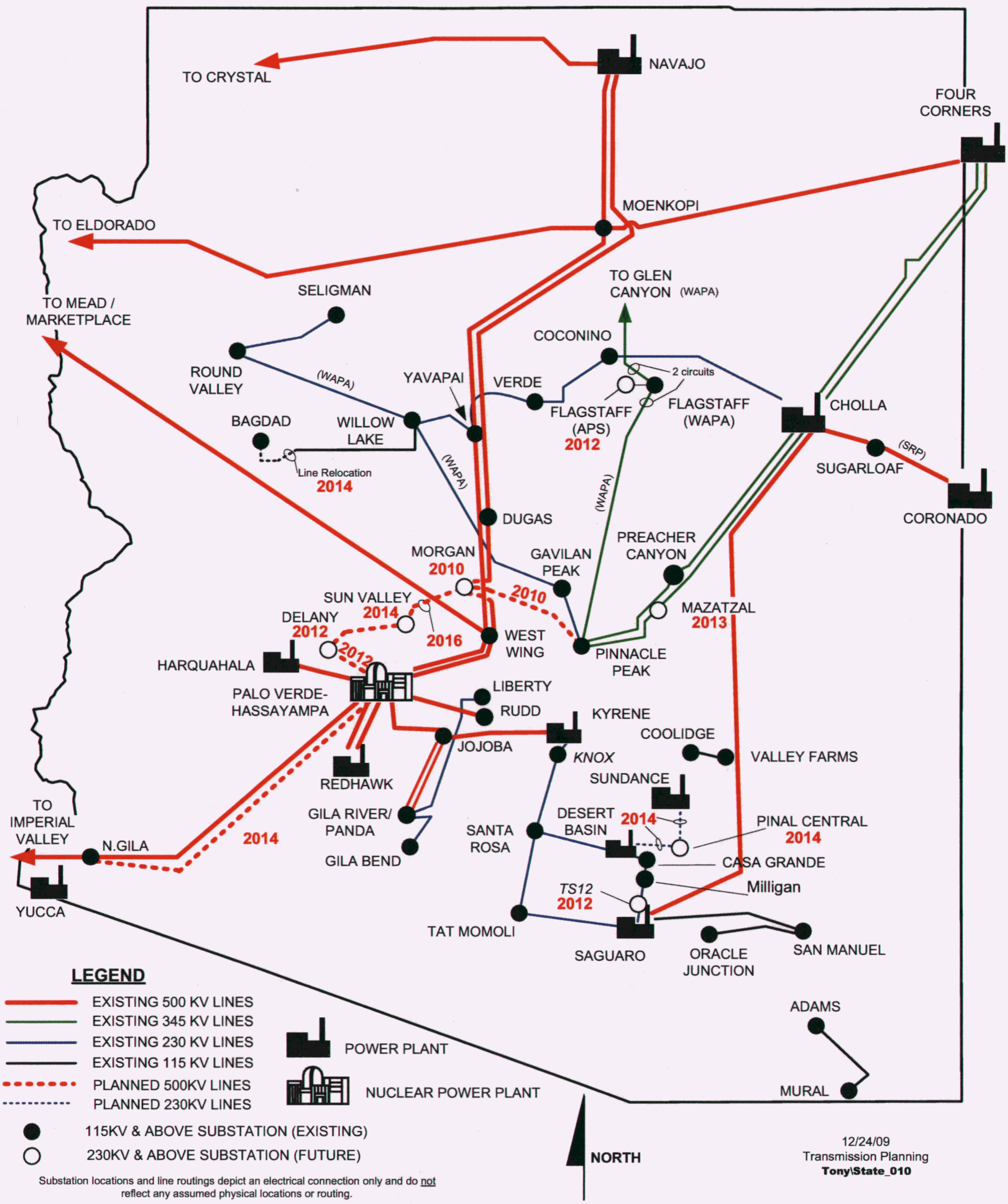
Palo Verde/Gila Bend Area To Valley Transmission Capacity.

Additional transmission capacity will be studied from the Palo Verde/Gila Bend areas to the Phoenix load center. This transmission capacity is a robust component of the overall APS transmission and resource need. The areas around and west of Palo Verde as well as the Gila Bend area contain some of the best solar resources in the country. APS expects that at least a portion of the future solar resources specified in the APS resource plan will be developed in relatively close proximity to these areas and will be supported by this transmission capacity. These areas also provide access to existing gas resources and, in the case of Palo Verde, potential new gas resources and market purchases. APS expects to need additional Palo Verde/Gila Bend transmission capacity, beyond what is shown in this plan, to deliver these resources to load and currently expects to require this additional capacity in the 2018-2019 timeframe absent a desire for advanced renewable resource development.

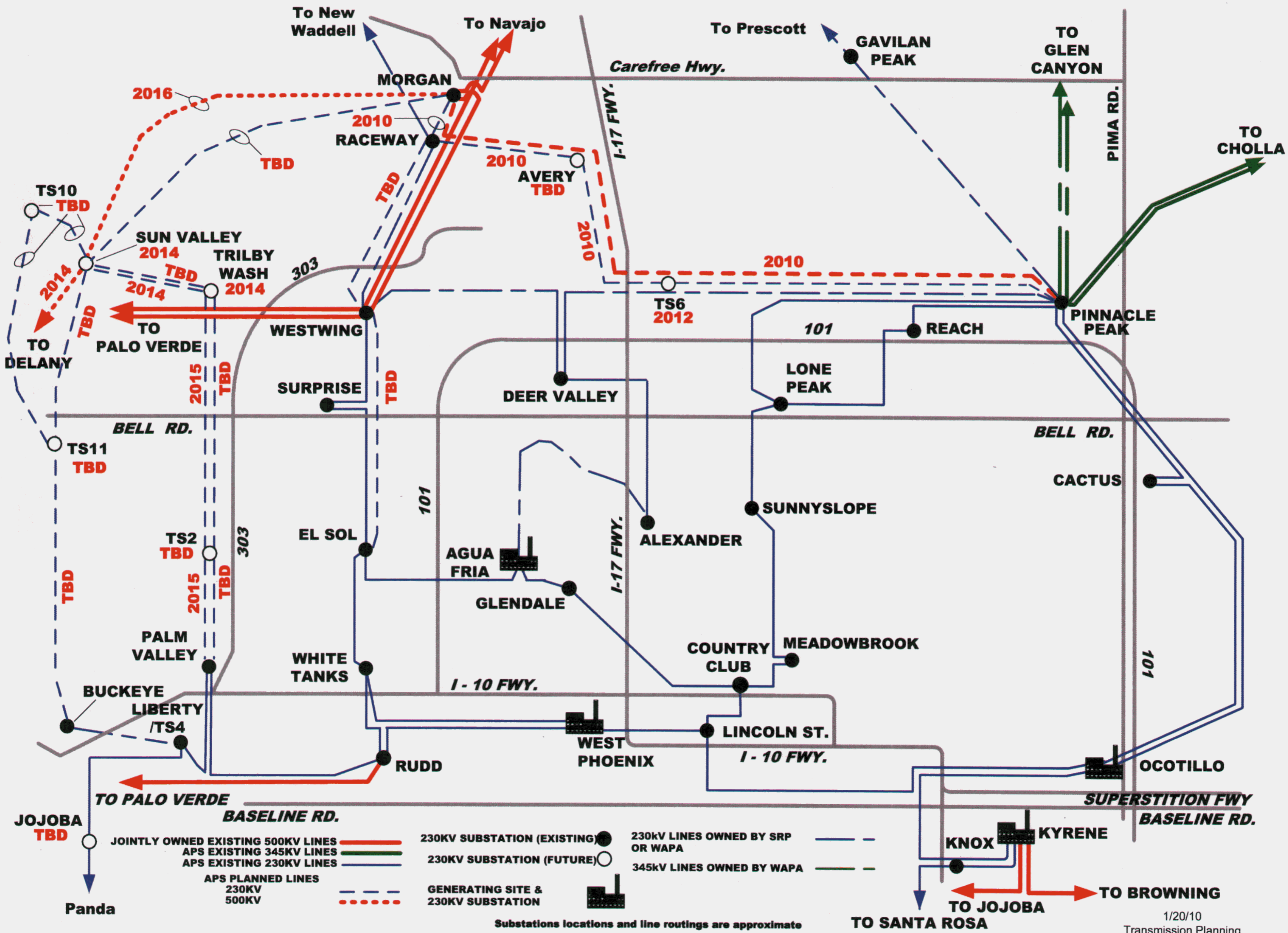
PLANNED TRANSMISSION MAPS

- Arizona EHV and Outer Divisions (*see page 9*)
- Phoenix Metropolitan Area (*see page 10*)
- Yuma Area (*see page 11*)

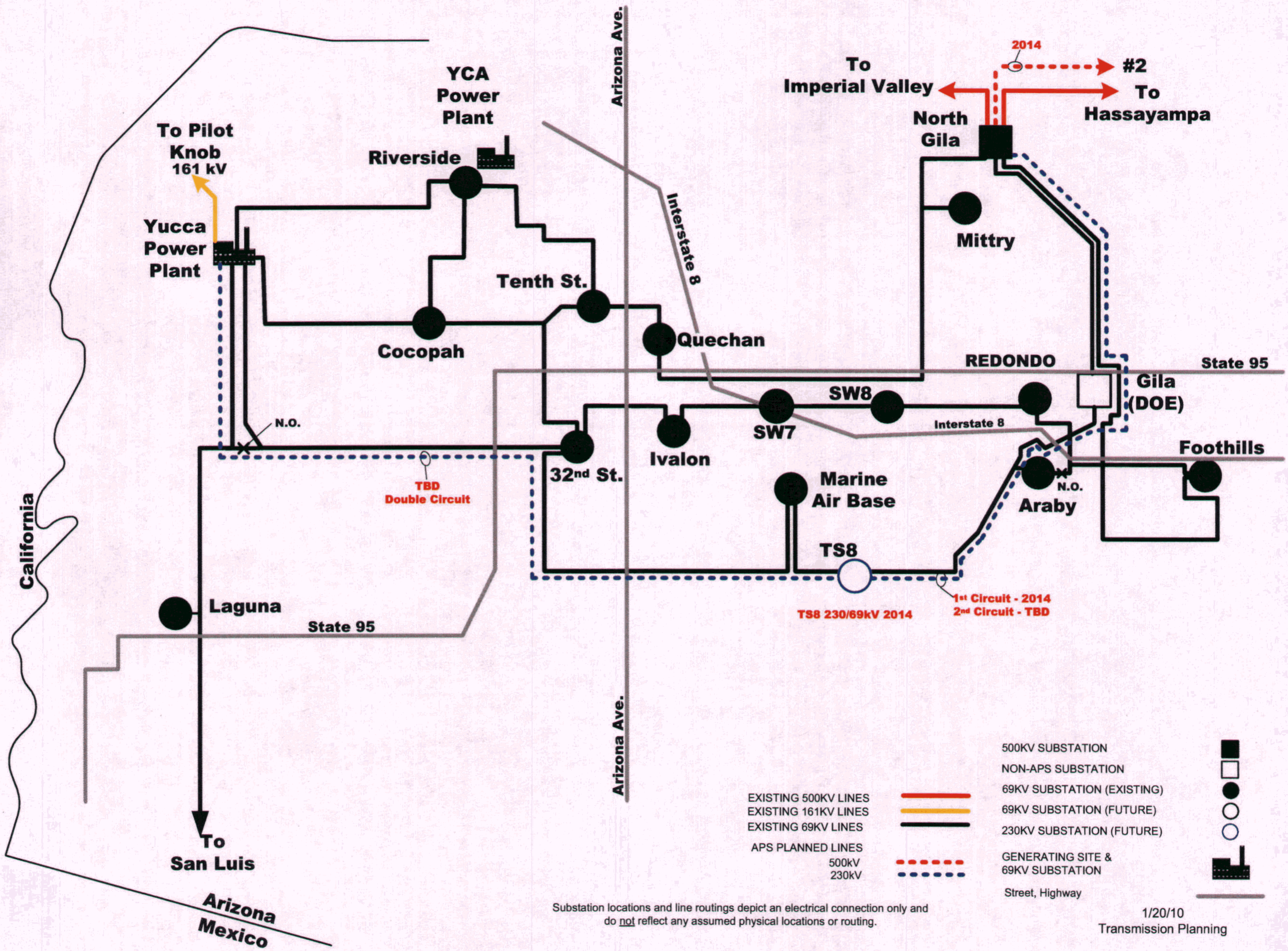
APS EHV & OUTER DIVISION 115/230 KV TRANSMISSION PLANS 2010 - 2019



PHOENIX METROPOLITAN AREA TRANSMISSION PLANS 2010-2019



Yuma Area Transmission Plans 2010- 2019



Substation locations and line routings depict an electrical connection only and do not reflect any assumed physical locations or routing.

1/20/10
Transmission Planning

Arizona Public Service Company
2010 – 2019
Ten-Year Plan
Planned Transmission Description

2010

Line Designation		Morgan – Pinnacle Peak 500kV Line (*2010*)
Project Sponsor		Arizona Public Service
Other Participants		SRP
Size		
(a)	Voltage Class	500kV AC
(b)	Facility Rating	To be determined
(c)	Point of Origin	Morgan substation to be in-service by 2010; Sec. 33, T6N, R1E
(d)	Intermediate Points of Interconnection	
(e)	Point of Termination	Pinnacle Peak substation; Sec. 4, T5N, R1E
(f)	Length	Approximately 1.2 miles
Routing		South from Morgan substation approximately 2 miles, generally paralleling the Navajo-Westwing 500kV lines, then turning east at approximately Dove Valley road to west side of Interstate 17, the line will continue 5 miles south to approximately the Happy Valley Road alignment where it turns east to the Pinnacle Peak substation, parallel to an existing 230kV transmission line corridor.
Purpose		This project is a result of joint planning through the SWAT forum. The project is needed to increase the import capability to the Phoenix Metropolitan area and the export/scheduling capability from the Palo Verde area to provide access to both solar and gas resources. The project also strengthens the transmission system on the east side of the Phoenix Metropolitan valley. The project is a joint participation project with APS as the project manager. The loop-in of the Navajo-Westwing 500kV line into the Morgan substation is the first phase of the project. Also, the line will be constructed as 500/230kV double-circuit capable, with the Morgan-Raceway-Avery-TS6-Pinnacle Peak 230kV line as the 230kV circuit.
Date		
(a)	Construction Start	2008
(b)	Estimated In Service	2010
Permitting / Siting Status		*Certificate of Environmental Compatibility issued on 2/13/07 (Case No. 131, Decision No. 69343, TS9-Pinnacle Peak 500/230kV Project).*

Arizona Public Service Company
2010 – 2019
Ten-Year Plan
Planned Transmission Description

2010

Line Designation	Morgan Raceway-Avery – TS6 – Pinnacle Peak 230kV Line (*2011*)
Project Sponsor	Arizona Public Service
Other Participants	None
Size	
(a) Voltage Class	230kVAC
(b) Facility Rating	3000 A
(c) Point of Origin	Morgan substation to be in-service in 2010; Sec. 33, T6N, R1E
(d) Intermediate Points of Interconnection	Raceway substation; Sec 4, T5N, R1E. Avery substation in-service TBD; Sec. 15, T5N, R2E TS6 substation to be in-service by 2014; Sec. 8, T4N, R3E
(e) Point of Termination	Pinnacle Peak substation; Sec. 10, T4N, R4E
(f) Length	Approximately 27 miles
Routing	The Morgan 500/230kV substation will be constructed adjacent to the Dugas – Westwing 500kV line corridor. The Morgan-Raceway 230kV circuit will be constructed south from the Morgan substation to the existing Raceway substation. The circuit continues south from Raceway Substation approximately 1 mile, parallel to existing Navajo-Westwing transmission lines, then east approximately 9 miles along the Dove Valley Road alignment to the location of the future Avery substation. From Avery Substation the line will continue east along Dove Valley Road to Interstate 17. At Interstate 17, the route will head south 5 miles to the to the Happy Valley Road alignment. The line will turn east, generally parallel to an existing 230kV transmission line corridor, for approximately 10 miles to the existing Pinnacle Peak substation.
Purpose	This project is needed to provide electric energy in the northern portions of the Phoenix Metropolitan area, as well as adjacent areas to the north. The in-service date for the TS6 substation is currently scheduled for 2012. The in-service date for the Avery substation is currently outside the ten year planning horizon. The in-service dates for the substations and the 2nd 500/230kV transformer at Morgan will be continuously evaluated in future planning studies.
Date	
(a) Construction Start	2008
(b) Estimated In Service	2010
Permitting / Siting Status	*Certificate of Environmental Compatibility issued on 2/13/07 (Case No. 131, Decision No. 69343, TS9-Pinnacle Peak 500/230kV Project).*

Arizona Public Service Company
2010 – 2019
Ten-Year Plan
Planned Transmission Description

2012

Line Designation	TS12 loop-in of Saguaro – Milligan 230kV Line (*2012*)
Project Sponsor	Arizona Public Service
Other Participants	None
Size	
(a) Voltage Class	230kVAC
(b) Facility Rating	188 MVA
(c) Point of Origin	Saguaro-Milligan 230kV line; approximately Sec. 17, T10S, R10E
(d) Intermediate Points of Interconnection	
(e) Point of Termination	TS12 substation to be in-service by 2012; Sec. 17, T10S, R10E
(f) Length	Less than 1 mile
Routing	The TS12 230/69kV substation will be constructed adjacent to the Saguaro-Casa Grande 230kV line, approximately 2 miles west of the Saguaro Generating Facility.
Purpose	This project is needed to provide electric energy in southern Pinal County as well as increase the reliability and continuity of service for these areas.
Date	
(a) Construction Start	2011
(b) Estimated In Service	2012
Permitting / Siting Status	*It is not anticipated that a Certificate of Environmental Compatibility will be needed for this project.*

Arizona Public Service Company
2010 – 2019
Ten-Year Plan
Planned Transmission Description

2012[6]

Line Designation	Delany – Palo Verde 500kV Line *(2012)*
Project Sponsor	Arizona Public Service
Other Participants	SRP, CAWCD
Size	
(a) Voltage Class	500kVAC
(b) Facility Rating	To be determined
(c) Point of Origin	Future Delany switching station; approximately Sec. 25, T2N, R8W
(d) Intermediate Points of Interconnection	
(e) Point of Termination	Palo Verde Switchyard
(f) Length	Approximately 15 miles
Routing	Generally leaving the Palo Verde Hub vicinity following the Palo Verde-Devers #1 and the Hassayampa-Harquahala 500kV lines to the Delany Switchyard site in Sec. 25, T2N, R8W.
Purpose	This project will increase the export/ scheduling capability from the Palo Verde area to provide access to both solar and gas resources. This is anticipated to be a joint participation project. APS will serve as the project manager. The initial plan of service for the project will be a 500kV line between the Palo Verde Switchyard and the Delany Switchyard.
Date	
(a) Construction Start	2011
(b) Estimated In Service	2012
Permitting / Siting Status	*Certificate of Environmental Compatibility issued 8/17/05 (Case No. 128, Decision No. 68063, Palo Verde Hub to TS5 500kV Transmission project). APS, as project manager, holds the CEC.*

[6] The in-service date of 2012 results from the Commission's directive in Decision No. 70635 and assumes Commission approval of the APS Renewable Transmission Action Plan ("RTAP") filed 1/29/10. Absent approval, the in-service date of this project would be in 2014, coincident with the Delany to Sun Valley 500kV project.

Arizona Public Service Company
2010 – 2019
Ten-Year Plan
Planned Transmission Description

2012

Line Designation	345/69kV Interconnection at Western's Flagstaff 345kV bus (*2012*)
Project Sponsor	Arizona Public Service
Other Participants	None
Size	
(a) Voltage Class	345kVAC
(b) Facility Rating	100 MVA
(c) Point of Origin	Western's Flagstaff 345kV substation; Sec. 24, T21N, R9E
(d) Intermediate Points of Interconnection	
(e) Point of Termination	A new Flagstaff 69kV substation to be in-service by 2012; Sec. 24, T21N, R9E
(f) Length	Less than 1 mile
Routing	A 345/69kV transformer will interconnect into Western's Flagstaff substation.
Purpose	This project is needed to provide the electrical source and support to the sub-transmission system in APS's northern service area. The project will provide increased reliability and continuity of service for the communities in northern Arizona.
Date	
(a) Construction Start	2011
(b) Estimated In Service	2012
Permitting / Siting Status	*It is not anticipated that a Certificate of Environmental Compatibility will be needed for this project.*

Arizona Public Service Company
2010 – 2019
Ten-Year Plan
Planned Transmission Description

2013

Line Designation	Mazatzal loop-in of Cholla – Pinnacle Peak 345kV Line (*2013*)
Project Sponsor	Arizona Public Service
Other Participants	None
Size	
(a) Voltage Class	345kVAC
(b) Facility Rating	100 MVA
(c) Point of Origin	Cholla-Pinnacle Peak or Preacher Canyon-Pinnacle Peak 345kV line; near Sec. 3, T8N, R10E
(d) Intermediate Points of Interconnection	
(e) Point of Termination	Mazatzal substation to be in-service by 2013; Sec. 3, T8N, R10E
(f) Length	Less than 1 mile
Routing	The Mazatzal 345/69kV substation will be constructed adjacent to the Cholla-Pinnacle Peak 345kV line corridor.
Purpose	This project is needed to provide the electric source and support to the sub-transmission system in the area of Payson and the surrounding communities. Additionally, improved reliability and continuity of service will result for the communities in the Payson area.
Date	
(a) Construction Start	2012
(b) Estimated In Service	2013
Permitting / Siting Status	*It is anticipated that an application for a Certificate of Environmental Compatibility will be filed in 2010.*

Arizona Public Service Company
2010 – 2019
Ten-Year Plan
Planned Transmission Description

2014

Line Designation	Bagdad 115kV Relocation Project (*2014*)
Project Sponsor	Arizona Public Service
Other Participants	None
Size	
(a) Voltage Class	115kV AC
(b) Facility Rating	430 A
(c) Point of Origin	Bagdad Capacitor switchyard; Sec. 10, T14N, R9W
(d) Intermediate Points of Interconnection	
(e) Point of Termination	Bagdad Mine substation; Sec. 31, T15N, R9W
(f) Length	Approximately 5.5 miles
Routing	Beginning at the existing APS capacitor switchyard and extending in a southwesterly direction for approximately 1.5 miles, then turning in a northwesterly direction approximately 4 miles to the existing Bagdad Mine substation. The project primarily crosses federal BLM lands, private lands (owned by the mine) and a short segment on Arizona State Trust Lands.
Purpose	Freeport McMoRan Inc. ("FMI") has future plans to expand the mine in the location of the existing 115kV transmission line. They have requested that APS move the line in a southerly direction beyond the limits of the planned expansion.
Date	
(a) Construction Start	2013
(b) Estimated In Service	2014
Permitting / Siting Status	*Certificate of Environmental Compatibility issued on 7/16/09. (Case No. 143, Decision No. 71217, Bagdad 115kV Relocation Project).*

Arizona Public Service Company
2010 – 2019
Ten-Year Plan
Planned Transmission Description

2014

Line Designation	Desert Basin – Pinal Central 230kV Line (*2014*)
Project Sponsor	Salt River Project
Other Participants	Arizona Public Service
Size	
(a) Voltage Class	230kVAC
(b) Facility Rating	To be determined
(c) Point of Origin	Desert Basin Power Plant Switchyard; Sec. 13, T6S, R5E
(d) Intermediate Points of Interconnection	
(e) Point of Termination	Pinal Central substation to be in-service by 2013; Sec. 30, T6S, R8E
(f) Length	Approximately 21 miles
Routing	From the Desert Basin Generation Station, in Casa Grande near Burris and Kortsen Roads, approximately 6 miles generally south and east to a point on the certificated SEV 500kV line near Cornman and Thornton Roads (vicinity of the proposed CATSHV03 Substation). Then the 230kV line will be attached to the 500kV structures for approximately 15 miles to the proposed Pinal Central Substation south of Coolidge, AZ.
Purpose	The project will improve the reliability of the 230kV system in the region by reducing the loading on existing lines in the area; increase local area system capacity and create one of the 230kV components of the CATS-HV proposed transmission system for the central Arizona area. APS participation in the project, along with the Sundance-Pinal Central 230kV line, will allow APS to increase the reliability and capability of delivering the output of the Sundance Generation Facility.
Date	
(a) Construction Start	2012
(b) Estimated In Service	2014
Permitting / Siting Status	*Authority for the portion of the 230kV line to be attached to the 500kV structures is provided for in the CEC granted in Case No. 126, awarded in 2005 (Commission Decision No. 68093 and No. 68291), and subsequently confirmed in Decision No. 69183, which approved SRP's compliance filing for Condition 23 of the CEC. SRP was granted a CEC for Case No. 132 in 2007 (Commission Decision No. 69647) for the approximately six mile portion of the project not previously permitted from Desert Basin Generating Station to the vicinity of Cornman and Thornton Roads south of Casa Grande.*

Arizona Public Service Company
2010 – 2019
Ten-Year Plan
Planned Transmission Description

2014

Line Designation		Pinal Central – Sundance 230kV Line (*2014*)
Project Sponsor		Arizona Public Service
Other Participants		ED-2
Size		
(a)	Voltage Class	230kVAC
(b)	Facility Rating	3000 A
(c)	Point of Origin	Sundance substation; Sec. 2, T6S, R7E
(d)	Intermediate Points of Interconnection	
(e)	Point of Termination	Pinal Central substation to be in-service by 2013; Sec. 30, T6S, R8E
(f)	Length	Approximately 6 miles
Routing		The project will originate at a new substation on the Sundance property, proceeding west and then south along Curry Road to the half-section between State Route 287 and Earley Road. The final west to east alignment connecting into the Pinal Central Substation will be located within an ACC-approved corridor and is subject to further design and right-of-way acquisition analysis.
Purpose		This project will serve increasing loads in Pinal County, and throughout the APS system, and will improve reliability and continuity of service for the communities in the area. Also, the project will increase the reliability of Sundance by providing a transmission line in a separate corridor than the existing lines that exit the plant. This project, in conjunction with the Desert Basin-Pinal Central 230kV project, will allow APS to reliably and economically deliver energy from Sundance over APS's transmission system. The project will be constructed as a 230kV double-circuit capable line, but initially operated as a single-circuit. The in-service date for the second circuit will be evaluated in future planning studies.
Date		
(a)	Construction Start	2013
(b)	Estimated In Service	2014
Permitting / Siting Status		*Certificate of Environmental Compatibility issued 4/29/08 (Case No. 136, Decision No. 70325, Sundance to Pinal South 230kV Transmission Line project). Note – the Pinal South substation is now referred to as Pinal Central.*

Arizona Public Service Company
2010 – 2019
Ten-Year Plan
Planned Transmission Description

2014

Line Designation	Delany – Sun Valley 500kV Line *(2014)*
Project Sponsor	Arizona Public Service
Other Participants	SRP, CAWCD
Size	
(a) Voltage Class	500kVAC
(b) Facility Rating	To be determined
(c) Point of Origin	Delany Substation
(d) Intermediate Points of Interconnection	
(e) Point of Termination	Sun Valley substation to be in-service by 2014; Sec. 29, T4N, R4W
(f) Length	Approximately 28 miles
Routing	Generally follows the Palo Verde-Devers #1 lines until crossing the CAP canal. Then easterly, generally following the north side of the CAP canal to the new Sun Valley substation.
Purpose	This project will serve projected need for electric energy in the area immediately north and west of the Phoenix Metropolitan area. It will increase the import capability to the Phoenix Metropolitan area as well as increase the export/ scheduling capability from the Palo Verde area to provide access to both solar and gas resources. The project will also increase the system reliability by providing a new transmission source to help serve the areas in the western portions of the Phoenix Metropolitan area. This is a joint participation project with APS as the project manager.
Date	
(a) Construction Start	2012
(b) Estimated In Service	2014
Permitting / Siting Status	*Certificate of Environmental Compatibility issued 8/17/05 (Case No. 128, Decision No. 68063, Palo Verde Hub to TS5 500kV Transmission project). APS, as project manager, holds the CEC.*

Arizona Public Service Company
2010 – 2019
Ten-Year Plan
Planned Transmission Description

<u>2014</u>

<u>Line Designation</u>	Sun Valley – Trilby Wash 230kV Line (*2014*)
<u>Project Sponsor</u>	Arizona Public Service
<u>Other Participants</u>	None
<u>Size</u>	
(a) Voltage Class	230kV AC
(b) Facility Rating	3000 A
(c) Point of Origin	Sun Valley substation to be in-service by 2014; Sec. 29, T4N, R4W
(d) Intermediate Points of Interconnection	
(e) Point of Termination	Trilby Wash substation to be in-service by 2014; Sec. 20, T4N, R2W
(f) Length	Approximately 15 miles
<u>Routing</u>	East from the Sun Valley substation along the CAP canal to approximately 243rd Ave., south to the existing 500kV transmission line corridor, and then east along the corridor to the Trilby Wash substation.
<u>Purpose</u>	This project is required to serve the need for electric energy in the western Phoenix Metropolitan area. Also, the project will provide more capability to import power into the Phoenix Metropolitan area along with improved reliability and continuity of service for communities in the area including El Mirage, Surprise, Youngtown, Buckeye, and unincorporated Maricopa county. The first circuit is scheduled to be in-service for the summer of 2014 and the in-service date for the second circuit will be evaluated in future planning studies.
<u>Date</u>	
(a) Construction Start	2013
(b) Estimated In Service	2014
<u>Permitting / Siting Status</u>	*Certificate of Environmental Compatibility issued 5/5/05 (Case No. 127, Decision No. 67828, West Valley North 230kV Transmission Line project).*

Arizona Public Service Company
2010 – 2019
Ten-Year Plan
Planned Transmission Description

2014[7]

Line Designation	Palo Verde Hub – North Gila 500kV #2 Line (*2014*)
Project Sponsor	Arizona Public Service
Other Participants	SRP, IID, WMIDD
Size	
(a) Voltage Class	500kV AC
(b) Facility Rating	To be determined
(c) Point of Origin	Hassayampa switchyard
(d) Intermediate Points of Interconnection	
(e) Point of Termination	North Gila substation; Sec. 11, T8S, R22W
(f) Length	Approximately 110 miles
Routing	This line will generally follow the route of the existing Hassayampa - North Gila 500kV #1 line.
Purpose	This project will increase the import capability for the Yuma area and export/scheduling capability from the Palo Verde area to provide access to both solar and gas resources. This is a joint participation project with APS as the project manager. This project will also allow the system to accommodate generation interconnection requests.
Date	
(a) Construction Start	2011
(b) Estimated In Service	2014
Permitting / Siting Status	*Certificate of Environmental Compatibility issued 1/23/08 (Case No. 135, Decision No. 70127, Palo Verde Hub to North Gila 500kV Transmission Line project).*

[7] The in-service date of 2014 assumes Commission approval of the APS RTAP, filed 1/29/10.

Arizona Public Service Company
2010 – 2019
Ten-Year Plan
Planned Transmission Description

2014[8]

Line Designation	North Gila – TS8 230kV Line (*2014*)
Project Sponsor	Arizona Public Service
Other Participants	None
Size	
(a) Voltage Class	230kV AC
(b) Facility Rating	3000 A
(c) Point of Origin	North Gila substation; Sec. 11, T8S, R22W
(d) Intermediate Points of Interconnection	
(e) Point of Termination	TS8 230kV substation to be in-service by 2014;TBD
(f) Length	To be determined
Routing	The routing for this line has not yet been determined.
Purpose	This project serves the need for electric energy, improved reliability, and continuity of service for the greater Yuma area. This project is expected to be double circuit capable with one circuit in service in 2014 and the second circuit in service at a date to be determined.
Date	
(a) Construction Start	2012
(b) Estimated In Service	2014
Permitting / Siting Status	*It is anticipated that an application for a Certificate of Environmental Compatibility will be filed in 2010.*

[8] This project is linked with the Palo Verde to North Gila 500kV project and will likely have the same in-service date.

Arizona Public Service Company
2010 – 2019
Ten-Year Plan
Planned Transmission Description

2015

Line Designation	Palm Valley – TS2 – Trilby Wash 230kV Line (*2015*)
Project Sponsor	Arizona Public Service
Other Participants	None
Size	
(a) Voltage Class	230kV AC
(b) Facility Rating	3000 A
(c) Point of Origin	Palm Valley substation; Sec. 24, T2N, R2W
(d) Intermediate Points of Interconnection	TS2 substation to be in-service by TBD; Sec. 25, T3N, R2W
(e) Point of Termination	Trilby Wash substation to be in-service by 2014; Sec. 20, T4N, R2W
(f) Length	Approximately 12 miles
Routing	North from the Palm Valley substation, generally following the Loop 303 to Cactus Road, west on Cactus Road to approximately 191st Avenue, and then north on 191st Avenue to the Trilby Wash substation.
Purpose	This project will serve the need for electric energy in the western Phoenix Metropolitan area and additional import capability into the greater Phoenix Metropolitan area. The proposed second 230kV source for Trilby Wash provides improved system reliability and continuity of service for communities in the area; such as El Mirage, Surprise, Youngtown, Goodyear, and Buckeye. The first circuit is scheduled to be in-service for the summer of 2015; the in-service date for the second circuit will be evaluated in future planning studies. The in-service date for the TS2 substation is currently outside of the ten year planning horizon and will be continuously evaluated in future planning studies.
Date	
(a) Construction Start	2014
(b) Estimated In Service	2015
Permitting / Siting Status	*The Palm Valley-TS2 230kV line portion was sited as part of the West Valley South 230kV Transmission Line project and a Certificate of Environmental Compatibility was issued 12/24/03 (Case No. 122, Decision No. 66646). The Trilby Wash-TS2 230kV line portion was sited as part of the West Valley North 230kV Transmission Line project and a Certificate of Environmental Compatibility was issued 5/5/05 (Case No. 127, Decision No. 67828).*

Arizona Public Service Company
2010 – 2019
Ten-Year Plan
Planned Transmission Description

2016

Line Designation	Morgan – Sun Valley 500kV Line *(2016)*
Project Sponsor	Arizona Public Service
Other Participants	SRP, CAWCD
Size	
(a) Voltage Class	500kV AC
(b) Facility Rating	To be determined
(c) Point of Origin	Sun Valley substation to be in-service in 2014; Sec. 29, T4N, R4W
(d) Intermediate Points of Interconnection	
(e) Point of Termination	Morgan substation to be in-service in 2010; Sec. 33, T6N, R1E
(f) Length	Approximately 40 miles
Routing	Generally the line will head north-northeast out of the Sun Valley substation and then east to the Morgan substation.
Purpose	This project is needed to serve the need for electric energy in the Phoenix Metropolitan area. It will increase the import capability to the Phoenix Metropolitan area, as well as increase the export/scheduling capability from the Palo Verde area, which includes both solar and gas resources. The project will also increase the reliability of the EHV system by completing a 500kV loop that connects the Palo Verde Transmission system, the Southern Navajo Transmission system, and the Southern Four Corners system. Additionally, the project will increase reliability by providing a second 500kV source for the Sun Valley substation and providing support for multiple Category C and D transmission contingencies. This project is anticipated to be 500/230kV double-circuit capable.
Date	
(a) Construction Start	2013
(b) Estimated In Service	2016
Permitting / Siting Status	*Certificate of Environmental Compatibility issued on 3/17/2009 (Case No. 138, Decision No. 70850, TS5-TS9 500/230kV Project) An application for right-of-way on the BLM portion of the project has been submitted and will require NEPA compliance prior to land acquisition and final engineering.*

Arizona Public Service Company
2010 – 2019
Ten-Year Plan
Planned Transmission Description

To Be Determined

Line Designation	Mural – San Rafael 230kV (*To Be Determined*)
Project Sponsor	Arizona Public Service
Other Participants	To be determined
Size	
(a) Voltage Class	230kV AC
(b) Facility Rating	To be determined
(c) Point of Origin	Mural substation
(d) Intermediate Points of Interconnection	
(e) Point of Termination	San Rafael substation
(f) Length	To Be Determined
Routing	The route for this project has not yet been determined. Generally the line will head west-northwest out of the Mural substation and then west to the San Rafael substation.
Purpose	This project was identified in the 2008 Biennial Transmission Assessment and is needed to serve the need for electric energy in the Cochise County area. It will increase the import capability to the Cochise County area, as well as increase the reliability of the local EHV system.
Date	
(a) Construction Start	To be determined
(b) Estimated In Service	To be determined
Permitting / Siting Status	*An application for a Certificate of Environmental Compatibility has not yet been filed.*

Arizona Public Service Company
2010 – 2019
Ten-Year Plan
Planned Transmission Description

To Be Determined

Line Designation	Jojoba loop-in of TS4-Panda 230kV Line (*To Be Determined*)
Project Sponsor	Arizona Public Service
Other Participants	None
Size	
(a) Voltage Class	230kV AC
(b) Facility Rating	188 MVA
(c) Point of Origin	TS4-Panda 230kV line; Sec. 25, T2S, R4W
(d) Intermediate Points of Interconnection	
(e) Point of Termination	Jojoba 230/69 substation with an in-service TBD; Sec. 25, T2S, R4W
(f) Length	Less than 1 mile
Routing	The Jojoba 230/69kV substation will be constructed adjacent to the TS4-Panda 230kV line.
Purpose	This project is needed to provide the electrical source and support to the sub-transmission system to serve the need for electric energy for the communities including Buckeye, Goodyear, and Gila Bend. The project will also increase the reliability and continuity of service for those areas.
Date	
(a) Construction Start	To be determined
(b) Estimated In Service	To be determined
Permitting / Siting Status	*Certificate of Environmental Compatibility issued 10/16/00 (Case No. 102, Decision No. 62960, Gila River Transmission Project) for the Gila River Transmission Project included the interconnection of the 230kV substation.*

Arizona Public Service Company
2010 – 2019
Ten-Year Plan
Planned Transmission Description

To Be Determined

Line Designation	TS8 – Yucca 230kV Line (*To Be Determined*)
Project Sponsor	Arizona Public Service
Other Participants	None
Size	
(a) Voltage Class	230kV AC
(b) Facility Rating	To be determined
(c) Point of Origin	Yucca substation; Sec. 36, T7S, R24W
(d) Intermediate Points of Interconnection	
(e) Point of Termination	TS8 substation will be in-service in 2014; to be determined
(f) Length	To be determined
Routing	The routing for this line has not yet been determined.
Purpose	This double circuit 230kV project is needed to serve the need for electric energy, improved reliability, and continuity of service for the greater Yuma area. This will project will also provide a second electrical source to the future TS8 substation. The ability to transmit electric energy generated by renewable resources in the region may be an additional benefit subject to study by APS in regional planning forums.
Date	
(a) Construction Start	To be determined
(b) Estimated In Service	To be determined
Permitting / Siting Status	*An application for a Certificate of Environmental Compatibility has not yet been filed.*

Arizona Public Service Company
2010 – 2019
Ten-Year Plan
Planned Transmission Description

To Be Determined

Line Designation	Sun Valley – TS10 –TS11 230kV Line (*To Be Determined*)
Project Sponsor	Arizona Public Service
Other Participants	None
Size	
(a) Voltage Class	230kV AC
(b) Facility Rating	To be determined
(c) Point of Origin	Sun Valley substation to be in-service by 2014; Sec. 29, T4N, R4W
(d) Intermediate Points of Interconnection	A future TS10 substation; location to be determined
(e) Point of Termination	A future TS11 substation; location to be determined
(f) Length	To be determined
Routing	The routing for this line has not yet been determined.
Purpose	This project will be needed to provide a transmission source to serve future load that emerges in the currently undeveloped areas northwest of the White Tank Mountains. This line is anticipated to be a 230kV line originating from the Sun Valley substation, with the future TS10 230/69kV substation to be interconnected into the 230kV line.
Date	
(a) Construction Start	To be determined
(b) Estimated In Service	To be determined
Permitting / Siting Status	*An application for a Certificate of Environmental Compatibility has not yet been filed.*

Arizona Public Service Company
2010 – 2019
Ten-Year Plan
Planned Transmission Description

To Be Determined

Line Designation	Buckeye – TS11 – Sun Valley 230kV Line (*To Be Determined*)
Project Sponsor	Arizona Public Service
Other Participants	None
Size	
(a) Voltage Class	230kV AC
(b) Facility Rating	To be determined
(c) Point of Origin	Sun Valley substation to be in-service by 2014; Sec. 29, T4N, R4W
(d) Intermediate Points of Interconnection	A future TS11 substation; location to be determined
(e) Point of Termination	Buckeye substation; Sec. 7, T1N, R3W
(f) Length	To be determined
Routing	The routing for this line has not yet been determined.
Purpose	This project is needed to serve the need for electric energy in the largely undeveloped areas west of the White Tank Mountains. This project will provide the first portion of the transmission infrastructure in this largely undeveloped area and provides a transmission connection between the northern and southern transmission sources that will serve the area. Improved reliability and continuity of service will result for this portion of Maricopa County. It is anticipated that this project will be constructed with double-circuit capability, but initially operated as a single circuit. The in-service date and location of the TS11 230/69kV substation will be determined in future planning studies based upon the development of the area.
Date	
(a) Construction Start	To be determined
(b) Estimated In Service	To be determined
Permitting / Siting Status	*An application for a Certificate of Environmental Compatibility has not yet been filed.*

Arizona Public Service Company
2010 – 2019
Ten-Year Plan
Planned Transmission Description

To Be Determined

Line Designation		Morgan – Sun Valley 230kV Line (*To Be Determined*)
Project Sponsor		Arizona Public Service
Other Participants		None
Size		
(a)	Voltage Class	230kV AC
(b)	Facility Rating	To be determined
(c)	Point of Origin	Sun Valley substation to be in-service by 2014; Sec. 29, T4N, R4W
(d)	Intermediate Points of Interconnection	To be determined
(e)	Point of Termination	Morgan substation to be in-service in 2010; Sec. 33, T6N, R1E
(f)	Length	Approximately 40 miles
Routing		This line is expected to be co-located with the Sun Valley to Morgan 500kV line, which generally heads north-northeast out of the Sun Valley substation and then east to the Morgan substation.
Purpose		This project will be needed to provide a transmission source to serve future load that emerges in the currently undeveloped areas south and west of Lake Pleasant. This line is anticipated to be the 230kV circuit on the Sun Valley-Morgan 500/230kV double-circuit line.
Date		
(a)	Construction Start	To be determined
(b)	Estimated In Service	To be determined
Permitting / Siting Status		*Certificate of Environmental Compatibility issued on 3/17/2009 (Case No. 138, Decision No. 70850, TS5-TS9 500/230kV Project).*

Arizona Public Service Company
2010 – 2019
Ten-Year Plan
Planned Transmission Description

To Be Determined

Line Designation	Raceway – Westwing 230kV Line (*To Be Determined*)
Project Sponsor	Arizona Public Service
Other Participants	None
Size	
(a) Voltage Class	230kV AC
(b) Facility Rating	To be determined
(c) Point of Origin	Westwing substation; Sec. 12, T4N, R1W
(d) Intermediate Points of Interconnection	
(e) Point of Termination	Raceway substation; Sec. 4, T5N, R1E
(f) Length	Approximately 7 miles
Routing	Northeast from Westwing substation paralleling existing transmission lines to the Raceway 230kV substation.
Purpose	This project will serve the need for electric energy in the far north and northwest parts of the Phoenix Metropolitan area and provide contingency support for multiple Westwing 500/230kV transformer outages. The in-service date will continue to be evaluated in future planning studies.
Date	
(a) Construction Start	To be determined
(b) Estimated In Service	To be determined
Permitting / Siting Status	*Certificate of Environmental Compatibility issued 6/18/03 (Case No. 120, Decision No. 64473, North Valley 230kV Transmission Line Project).*

Arizona Public Service Company
2010 – 2019
Ten-Year Plan
Planned Transmission Description

To Be Determined

Line Designation		El Sol – Westwing 230kV Line (*To Be Determined*)
Project Sponsor		Arizona Public Service
Other Participants		None
Size		
(a)	Voltage Class	230kV AC
(b)	Facility Rating	To be determined
(c)	Point of Origin	Westwing substation; Sec. 12, T4N, R1W
(d)	Intermediate Points of Interconnection	
(e)	Point of Termination	El Sol substation; Sec. 30, T3N, R1E
(f)	Length	Approximately 11 miles
Routing		Per certificate. Generally following the existing Westwing-Surprise-El Sol 230kV corridor.
Purpose		This project will increase system capacity to serve the Phoenix Metropolitan area, while maintaining system reliability and integrity for delivery of bulk power from Westwing south into the APS Phoenix Metropolitan area 230kV transmission system.
Date		
(a)	Construction Start	To be determined
(b)	Estimated In Service	To be determined
Permitting / Siting Status		*Certificate of Environmental Compatibility issued 7/26/73 (Case No. 9, Docket No. U-1345). Note that this Certificate authorizes two double-circuit lines. Construction of the first double-circuit line was completed in March 1975. Construction of the second line, planned to be built with double-circuit capability, but initially operated with a single circuit, is described above.*

Arizona Public Service Company
2010 – 2019
Ten-Year Plan
Planned Transmission Description

To Be Determined

Line Designation	Palo Verde – Saguaro 500kV Line (*To Be Determined*)
Project Sponsor	CATS Sub-Regional Planning Group Participants
Other Participants	To be determined
Size	
(a) Voltage Class	500kV AC
(b) Facility Rating	To be determined
(c) Point of Origin	Palo Verde switchyard; Sec. 34, T1N, R6W
(d) Intermediate Points of Interconnection	
(e) Point of Termination	Saguaro substation; Sec. 14, T10S, R10E
(f) Length	Approximately 130 miles
Routing	Generally south and east from the Palo Verde area to a point near Gillespie Dam, then generally easterly until the point at which the Palo Verde-Kyrene 500kV line diverges to the north and east. The corridor then continues generally south and east again, adjacent to a gas line corridor, until converging with the Tucson Electric Power Company's Westwing-South 345kV line. The corridor follows the 345kV line until a point due west of the Saguaro Generating Station. The corridor then follows a lower voltage line into the 500kV yard just south and east of the Saguaro Generating Station.
Purpose	This line is the result of the joint participation CATS study. The line will be needed to increase the adequacy of the existing EHV transmission system and permit increased power delivery throughout the state.
Date	
(a) Construction Start	To be determined
(b) Estimated In Service	To be determined
Permitting / Siting Status	*Certificate of Environmental Compatibility issued 1/23/1976 (Case No. 24, Decision No. 46802).*

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TRANSMISSION PLANNING PROCESS AND GUIDELINES

APS Transmission Planning

January 2010

TRANSMISSION PLANNING PROCESS AND GUIDELINES

I. INTRODUCTION AND PURPOSE

The Transmission Planning Process and Guidelines (Guidelines) are used by Arizona Public Service Company (APS) to assist in planning its Extra High Voltage (EHV) transmission system (345kV and 500kV) and High Voltage transmission system (230kV and 115kV). In addition to these Guidelines, APS follows the Western Electricity Coordinating Council's (WECC) regional planning reliability criteria for system disturbance and performance levels. These WECC Reliability Criteria are (1) WECC/NERC Reliability Criteria for Transmission System Planning and (2) Minimum Operating Reliability Criteria, which can be found in their entirety on the WECC website; (http://www.wecc.biz/documents/library/procedures/CriteriaMaster.pdf). These Guidelines are for internal use by APS and may be changed or modified. Thus, others should not use these Guidelines without consultation with APS.

II. PLANNING METHODOLOGY

A. General

APS uses a deterministic approach for transmission system planning. Under this approach, system performance should meet certain specific criteria under normal conditions (all lines in-service) and for any single contingency condition (any one element out-of-service). In general, an adequately planned transmission system will:

- Provide an acceptable level of service that is cost-effective for normal and single contingency operating conditions.
- Maintain service to all firm loads for any single contingency outage; except for radial loads.
- Not result in overloaded equipment or unacceptable voltage conditions for single contingency outages.
- Not result in cascading for single or double contingency outages.
- Provide for the proper balance between the transmission import capability and local generation requirements for an import limited load area.

Although APS uses a deterministic approach for transmission system planning, the WECC reliability planning criteria provides for exceptions based upon a probabilistic approach. APS uses these probabilistic criteria when/where appropriate in the transmission planning process. Historical system reliability performance is analyzed on a periodic basis and the results are used in the design of planned facilities.

These planning methodologies, assumptions, and guidelines are used as the basis for the development of future transmission facilities. Additionally, consideration of potential alternatives to transmission facilities (such as distributed generation or new technologies) is evaluated on a case-specific basis.

As new planning tools and/or information become available revisions or additions to these guidelines will be made as appropriate.

B. Transmission Planning Process

APS' transmission planning process consists of an assessment of the following needs:

- Provide adequate transmission to access designated network resources in-order to reliably and economically serve all network loads.
- Support APS' and other network customers' local transmission and sub-transmission systems.
- Provide for interconnection for new resources.
- Accommodate requests for long-term transmission access.

During this process, consideration is given to load growth patterns, other system changes affected by right-of-way, facilities siting constraints, routing of future transportation corridors, and joint planning with neighboring utilities, governmental entities, and other interested stakeholders (see APS OATT Attachment (E).

1. EHV Transmission Planning Process

APS' EHV transmission system, which consists of 500kV and 345kV, has primarily been developed to provide transmission to bring the output of large base-loaded generators to load centers, such as Phoenix. Need for new EHV facilities may result from any of the bullet items described above. APS' annual planning process includes an assessment of APS' transmission capability to ensure that designated network resources can be accessed to reliably and economically serve all network loads. In addition, biennial RMR studies are performed to ensure that proper balance between the transmission import capability and local generation requirements for an import limited load area are maintained.

2. 230kV Transmission Planning Process

APS' 230kV transmission system has primarily been developed to provide transmission to distribute power from the EHV bulk power substations and local generators to the distribution system and loads throughout the load areas.

Planning for the 230kV system assesses the need for new 230/69kV substations to support local sub-transmission and distribution system growth and the reliability performance of the existing 230kV system. This process takes into account the future land use plans that were developed by government agencies, Landis aerial photo maps, master plans that were provided by private developers, and APS' long-range forecasted load densities per square mile for residential, commercial, and industrial loads.

3. Transmission Facilities Required for Generation/Resource Additions

New transmission facilities may also be required in conjunction with generation resources due to (1) a "merchant" request by an Independent Power Producer (IPP) for generator interconnection to the APS system, (2) a "merchant" request for point-to-point transmission service from the generator (receipt point) to the designated delivery point, or (3) designation of new resources or re-designation of existing units to serve APS network load (including removal of an older units' native load designation). These studies/processes are performed pursuant to the APS Open Access Transmission Tariff (OATT).

C. Ten Year Transmission System Plans

Each year APS uses the planning process described in section B to update the Ten-Year Transmission System Plan. The APS Ten Year Transmission System Plan identifies all new transmission facilities, 115kV and above, and all facility replacements/upgrades required over the next ten years to reliably and economically serve the load.

D. Regional Coordinated Planning

1. Western Electricity Coordinating Council (WECC)

APS is a member of the Western Electricity Coordinating Council. The focus of the WECC is on promoting the reliability of the interconnected bulk electric system. The WECC provides the means for:

- Developing regional planning and operating criteria.
- Coordinating future plans.
- Compiling regional data banks for use by the member systems and the WECC in conducting technical studies.
- Assessing and coordinating operating procedures and solutions to regional problems.
- Establishing an open forum with interested non-project participants to review the plan of service for a project.
- Through the WECC Transmission Expansion Policy Committee, performing economic transmission congestion analysis.

APS works with WECC to adhere to these planning practices.

2. Sub-Regional Planning Groups

Southwest Area Transmission Planning (SWAT) and other sub-regional planning groups provide a forum for entities within a region, and any other interested parties, to determine and study the needs of the region as a whole. It also provides a forum for specific projects to be exposed to potential partners and allows for joint studies and participation from interested parties.

3. WestConnect

APS and the other WestConnect members executed the WestConnect Project Agreement for Subregional Transmission Planning in May of 2007. This agreement promotes coordination of regional transmission planning for the WestConnect planning area by formalizing a relationship among the WestConnect members and the WestConnect area sub-regional planning groups including SWAT. The agreement provides for resources and funding for the development of a ten year integrated regional transmission plan for the WestConnect planning area. The agreement also ensures that the WestConnect transmission planning process will be coordinated and integrated with other planning processes within the Western Interconnection and with the WECC planning process.

4. Joint Studies

In many instances, transmission projects can serve the needs of several utilities and/or IPPs. To this end, joint study efforts may be undertaken. Such joint study efforts endeavor to develop a plan that will meet the needs and desires of all individual companies involved.

E. Generation Schedules

For planning purposes, economic dispatches of network resources are determined for APS' system peak load in the following manner:

a. Determine base generation available and schedule these units at maximum output.
b. Determine resources purchased from other utilities, IPPs, or power marketing agencies.
c. Determine APS' spinning reserve requirements.
d. Schedule intermediate generation (oil/gas steam units) such that the spinning reserve requirements, in section (c) above, are met.
e. Determine the amount of peaking generation (combustion turbine units) required to supply the remaining system peak load.

Phoenix area network resources are dispatched based on economics and any existing import limitations. When possible, spinning reserve will be carried on higher cost Phoenix area network generating units.

Generation output schedules for interconnected utilities and IPPs are based upon consultation with the neighboring utilities and IPPs or as modeled in the latest data in WECC coordinated study cases.

F. Load Projections

APS substation load projections are based on the APS Corporate Load Forecast. Substation load projections for neighboring interconnected utilities or power agencies operating in the WECC area are based on the latest data in WECC coordinated study cases. Heavy summer loads are used for the Ten-Year Transmission System Plans.

G. Alternative Evaluations

1. General

In evaluating several alternative plans, comparisons of power flows, transient stability tests, and fault levels are made first. After the alternatives are found that meet the system performance criteria in each of these three areas comparisons may be made of the losses, transfer capability, impact on system operations, and reliability of each of the plans. Finally, the costs of facility additions (capital cost items), costs of losses, and relative costs of transfer capabilities are determined. A brief discussion of each of these considerations follows.

2. Power Flow Analyses

Power flows of base case (all lines in-service) and single contingency conditions are tested and should conform to the system performance criteria set forth in Section IV of these Guidelines. Double or multiple contingencies are examined, but in general, no facilities are planned for such conditions. Normal system voltages, voltage deviations, and voltage extreme limitations are based upon operating experience resulting in acceptable voltage levels to the consumer. Power flow limits are based upon the thermal ratings and/or sag limitations of conductors or equipment, as applicable.

3. Transient Stability Studies

Stability guidelines are established to maintain system stability for single contingency, three-phase fault conditions. Double or multiple contingencies are examined, but in general, no facilities are planned for such conditions.

4. Short Circuit Studies

Three-phase and single-phase-to-ground fault studies are performed to ensure the adequacy of system protection equipment to clear and isolate faults.

5. Reactive Power Margin Analyses

Reactive Power Margin analyses are performed when steady-state analyses indicate possible insufficient voltage stability margins. V-Q curve analyses are used to determine post-transient voltage stability.

6. Losses Analyses

A comparison of individual element and overall transmission system losses are made for each alternative plan being studied. The losses computed in the power flow program consist of the I^2R losses of lines and transformers and the core losses in transformers, where represented.

7. Transfer Capability Studies

In evaluating the relative merits of one or more EHV transmission plans, both simultaneous and non-simultaneous transfer capability studies are performed to determine the magnitude of transfer capabilities between areas or load centers.

8. Subsynchronous Resonance (SSR)

SSR phenomenon result from the use of series capacitors in the network where the tuned electrical network exchanges energy with a turbine generator at one or more of the natural frequencies of the mechanical system. SSR countermeasures are applied to prevent damage to machines as a result of transient current or sustained oscillations following a system disturbance. SSR studies are not used directly in the planning process. SSR countermeasures are determined after the transmission plans are finalized.

9. FACTS (Flexible AC Transmission System)

FACTS devices are a recent application of Power Electronics to the transmission system. These devices make it possible to use circuit reactance, voltage magnitude and phase angle as control parameters to redistribute power flows and regulate bus voltages, thereby improving power system operation. FACTS devices can provide series or shunt compensation. These devices can be used as a controllable voltage source in series or as a controllable current source in shunt mode to improve the power transmission system operations. FACTS will be evaluated as a means of power flow control and/or to provide damping to dynamic oscillations where a need is identified and it is economically justified.

10. Economic Evaluation

In general, an economic evaluation of alternative plans consists of a cumulative present worth or equivalent annual cost comparison of capital costs.

III. PLANNING ASSUMPTIONS

A. General

1. Loads

Loads used for the APS system originate from the latest APS Corporate Load Forecast. In most cases, the corrected power factor of APS loads is 99.5% at 69kV substations.

2. Generation and Other Resources

Generation dispatch is based on firm power and/or transmission wheeling contracts including network resources designations.

3. Normal Voltage Levels

a. Nominal EHV design voltages are 500kV, 345kV, 230kV, and 115kV.

b. Nominal EHV operating voltages are 535kV, 348kV, 239kV, and 119kV.

4. Sources of Databases

WECC Heavy Summer base cases are the sources of the databases. Loop flow (unscheduled flow), of a reasonable amount and direction, will be allowed for use in planning studies.

5. Voltage Control Devices

Devices which can control voltages are shunt capacitors, shunt reactors, tap-changing-under-load (TCUL) and fixed-tap transformers, static VAR compensators, and machine VAR capabilities. If future voltage control devices are necessary, these devices will be evaluated based upon economics and the equipment's ability to obtain an adequate voltage profile on the EHV and HV systems.

6. Phase Shifters

In general, where phase shifters are used, schedules are held across the phase shifter in base case power flows and the phase shifter tap remains fixed in the outage cases.

7. Conductor Sizes

Existing transmission voltages utilized by APS are 230kV, 345kV, and 500kV. It is presently planned that the 345kV transmission system will not be expanded, thus all future APS EHV lines will be 500kV or 230kV. Planned 500kV lines will initially be modeled using tri-bundled 1780 kCM ACSR conductor (Chukar). Preferred construction for 230kV lines consists of 2156 kCM ACSS conductor on steel poles.

8. 69kV System Modeling

230kV facility outages may result in problems to the underlying 69kV system due to the interconnection of those systems. For this reason, power flow cases include a detailed 69kV system representation. Solutions to any problems encountered on the 69kV system are coordinated with the subtransmission planning engineers.

9. Substation Transformers

a. 500kV and 345kV Substations

Bulk substation transformer banks may be made up of one three-phase or three single-phase transformers, depending upon bank size and economics. For larger banks where single-phase transformers are used, a fourth (spare) single-phase transformer will be used in a jack-bus arrangement to improve reliability and facilitate connection of the spare in the event of an outage of one of the single-phase transformers. TCUL will be considered in the high voltage windings, generally with a range of plus or minus 10%. High voltage ratings will be 500kV or 345kV class and low voltage windings will be 230kV, 115kV, or 69kV class.

b. 230kV Substations

For high-density load areas, both 230/69kV and 69/12.5kV transformers can be utilized. 230/69kV transformers will be rated at 113/150/188 MVA with a 65°C temperature rise, unless otherwise specified. 69/12.5kV transformers will be rated at 25/33/41 MVA with a 65°C temperature rise, unless otherwise specified.

With all elements in service, a transformer may be loaded up to its top Forced Oil Air (FOA) rating without sustaining any loss of service life. For a single contingency outage (loss of one transformer) the remaining transformer or transformers may be loaded up to 20% above their top FOA rating, unless heat test data indicate a different overload capability. The loss of service life sustained will depend on the transformer pre-loading and the outage duration. Tap setting adjustment capabilities on 230/69kV transformers will be ±5% from the nominal voltage setting (230/69kV) at 2½% increments.

10. Switchyard Arrangements

a. 500kV and 345kV Substations

Existing 345kV switchyard arrangements use breaker-and-one-half, main-and-transfer, or modified paired-element circuit breaker switching schemes. Because of the large amounts of power transferred via 500kV switchyards and the necessity of having adequate reliability, all 500kV circuit breaker arrangements are planned for an ultimate breaker-and-one-half scheme. If only three or four elements are initially required, the circuit breakers are connected in a ring bus arrangement, but physically positioned for a breaker-and-one-half scheme. The maximum desired number of elements to be connected in the ring bus arrangement is four. System elements such as generators, transformers, and lines will be arranged in breaker-and-one-half schemes such that a failure of a center breaker will not result in the loss of two lines routed in the same general direction and will minimize the impact of losing two elements.

b. 230kV Substations

Future 230/69kV substations should be capable of serving up to 452 MVA of load. 400 MVA has historically been the most common substation load level in the Phoenix Metropolitan area. Future, typical 230/69kV substations should accommodate up to four 230kV line terminations and up to three 230/69kV transformer bays. Based upon costs, as well as reliability and operating flexibility considerations, a breaker-and-one-half layout should be utilized for all future 230/69kV Metropolitan Phoenix Area substations, with provision for initial development to be a ring bus. Any two 230/69kV transformers are to be separated by two breakers, whenever feasible, so that a stuck breaker will not result in an outage of both transformers.

11. Series Capacitor Application

Series capacitors may be used on EHV lines to increase system stability, for increased transfer capability, and/or for control of power flow. The series capacitors may be lumped at one end of a line because of lower cost; however, the capacitors are generally divided into two banks, one at either end of a line, for improved voltage profile.

12. Shunt and Tertiary Reactor Application

Shunt and/or tertiary reactors may be installed to prevent open end line voltages from being excessive, in addition to voltage control. The open end line voltage must not be more than 0.05 per unit voltage greater than the sending end voltage. Tertiary reactors may also be used for voltage and VAR control as discussed above.

B. Power Flow Studies

1. System Stressing

Realistic generation capabilities and schedules should be used to stress the transmission system in order to maximize the transfer of resources during the maximum load condition.

2. Displacement

In cases where displacements (due to power flow opposite normal generation schedules) may have an appreciable effect on transmission line loading, a reasonable amount of displacement (Generation Units) may be removed in-order to stress a given transmission path.

C. Transient Stability Studies

1. Fault Simulation

When studying system disturbances caused by faults, two conditions will be simulated:

a. Three-phase-to-ground faults, and
b. Single-line-to-ground faults with a stuck circuit breaker in one phase with back-up delayed clearing.

2. Margin

a. Generation margin may be applied for the contingencies primarily affected by generation, or
b. Power flow margin may be applied for the contingencies primarily affected by power flow.

3. Unit Tripping

   Generator unit tripping may be allowed in-order to increase system stability performance.

4. Machine Reactance Representation

   For transient stability studies, the unsaturated transient reactance of machines with full representation will be used.

5. Fault Damping

   Fault damping will be applied to the generating units adjacent to faults. Fault damping will be determined from studies that account for the effect of generator amortisseur windings and the SSR filters.

6. Series Capacitor Switching

   Series capacitors, locations to be determined from short circuit studies, will be flashed and reinserted as appropriate.

D. Short Circuit Studies

Three-phase and single-phase-to-ground faults will be evaluated.

1. Generation Representation

   All generation will be represented.

2. Machine Reactance Representation

   The saturated subtransient reactance (X''_d) values will be used.

3. Line Representation

   The transmission line zero sequence impedance (X_0) is assumed to be equal to three times the positive sequence impedance (X_1).

4. Transformer Representation

   The transformer zero sequence impedance (X_0) is assumed to be equal to the positive sequence impedance (X_1). Bulk substation transformers are modeled as auto-transformers. The two-winding model is that of a grounded-wye transformer. The three-winding model is that of a wye-delta-wye with a solid ground.

E. Reactive Power Margin Studies

Using Q-V curve analyses, APS assesses the interconnected transmission system to ensure there are sufficient reactive resources located throughout the electric system to maintain post-transient voltage stability for system normal conditions and certain contingencies.

IV. SYSTEM PERFORMANCE

A. Power Flow Studies

1. Normal (Base Case Conditions)

a. Voltage Levels

1) General

(a) 500kV bus voltages will be maintained between 1.05 and 1.08 p.u. on a 500kV base.

(b) 345kV bus voltages will range between .99 and 1.04 p.u. on the 345kV system.

(c) 500kV and 345kV system voltages are used to maintain proper 230kV bus voltages.

(d) Voltage on the 230kV and 115kV system should be between 1.01 p.u. and 1.05 p.u.

(e) Tap settings for 230/69kV and 345/69kV transformers should be used to maintain low side (69kV) voltages of 1.03 to 1.04 p.u. Seasonal tap changes may be required.

2) Specific Buses

(a) APS Pinnacle Peak 230kV bus voltage should be between 1.025 p.u. and 1.035 p.u.

(b) APS Westwing 230kV bus voltage should be between 1.04 p.u. and 1.05 p.u.

(c) Saguaro 115kV bus voltage will be approximately 1.035 p.u.

(d) Voltage at the Prescott (DOE) 230kV bus should be approximately 1.02 p.u.

b. Facility Loading Limits

1) Transmission Lines

Transmission line loading cannot exceed 100% of the continuous rating, which is based upon established conductor temperature limit or sag limitation.

2) Underground Cable

Underground cable loading should not exceed 100% of the continuous rating with all elements in service. This rating is based on a cable temperature of 85°C with no loss of cable life.

3) Transformers

Transformers cannot exceed 100% of top FOA, 65°C rise, nameplate ratings.

4) Series Capacitors

Series Capacitors cannot exceed 100% of continuous rating.

c. Interchange of VARs

Interchange of VARs between companies at interconnections will be reduced to a minimum and maintained near zero.

d. Distribution of Flow

Schedules on a new project will be compared to simulated power flows to ensure a reasonable level of flowability.

2. Single Contingency Outages

a. Voltage Levels

Maximum voltage deviation on APS' major buses cannot exceed 5%. This deviation level yields a close approximation to the post-transient VAR margin requirements of WECC.

b. Facilities Loading Limits

1) Transmission Lines

Transmission line loading cannot exceed 100% of the lesser of the sag limit or the emergency rating (30-minute rating) which is based upon established conductor temperature limits.

2) Underground Cable

Underground cable loading should not exceed the emergency rating during a single-contingency outage. This rating is based on a cable temperature of 105°C for two hours of emergency operation with no loss of cable life.

3) Transformers

Transformers cannot exceed 120% of top FOA, 65°C rise, nameplate ratings.

4) Series Capacitors

Series Capacitors cannot exceed 100% of emergency rating.

c. Generator Units

Generator units used for controlling remote voltages will be modified to hold their base case terminal voltages.

d. Impact on Interconnected System

Single contingency outages will not cause overloads upon any neighboring transmission system.

B. Transient Stability Studies

Transient stability studies are primarily performed on the 500kV and 345kV systems.

1. Fault Simulation

Three-phase-to-ground faults and single-line-to-ground faults, simulating a stuck circuit breaker in one phase with back-up delayed clearing will be simulated. Fault clearing times of four cycles after fault inception (5 cycles for a 230kV fault) and a back-up clearing time of twelve cycles after fault inception is utilized. System elements are switched out at the appropriate clearing times, as applicable. Fault damping will be applied when applicable at fault inception.

2. Series Capacitor Switching

Series capacitors, at locations determined from short-circuit studies, will be flashed at fault inception and will be reinserted depending on their reinsertion types.

3. System Stability

The system will be considered stable if the following conditions are met:

a. All machines in the system remain synchronized as demonstrated by the relative rotor angles.

b. Positive system damping exists as demonstrated by the damping of relative rotor angles and the damping of voltage magnitude swings. For N-1 disturbances, voltages for the first swing after fault clearing should not drop below 75% of pre-fault value with maximum time duration of 20 cycles for voltage dip exceeding 20%.

4. Re-closing

Automatic re-closing of circuit breakers controlling EHV facilities is not utilized.

C. Short Circuit Studies

Fault current shall not exceed 100% of the applicable breaker fault current interruption capability for three-phase or single-line-to-ground faults.

D. Reactive Power Margin Studies

For system normal conditions or single contingency conditions, post-transient voltage stability is required with a path or load area modeled at a minimum of 105% of the path rating or maximum planned load limit for the area under study, whichever is applicable. For multiple contingencies, post-transient voltage stability is required with a path or load area modeled at a minimum of 102.5% of the path rating or maximum planned load limit for the area under study, whichever is applicable.

2009 SYSTEM RATING MAPS

PREPARED BY

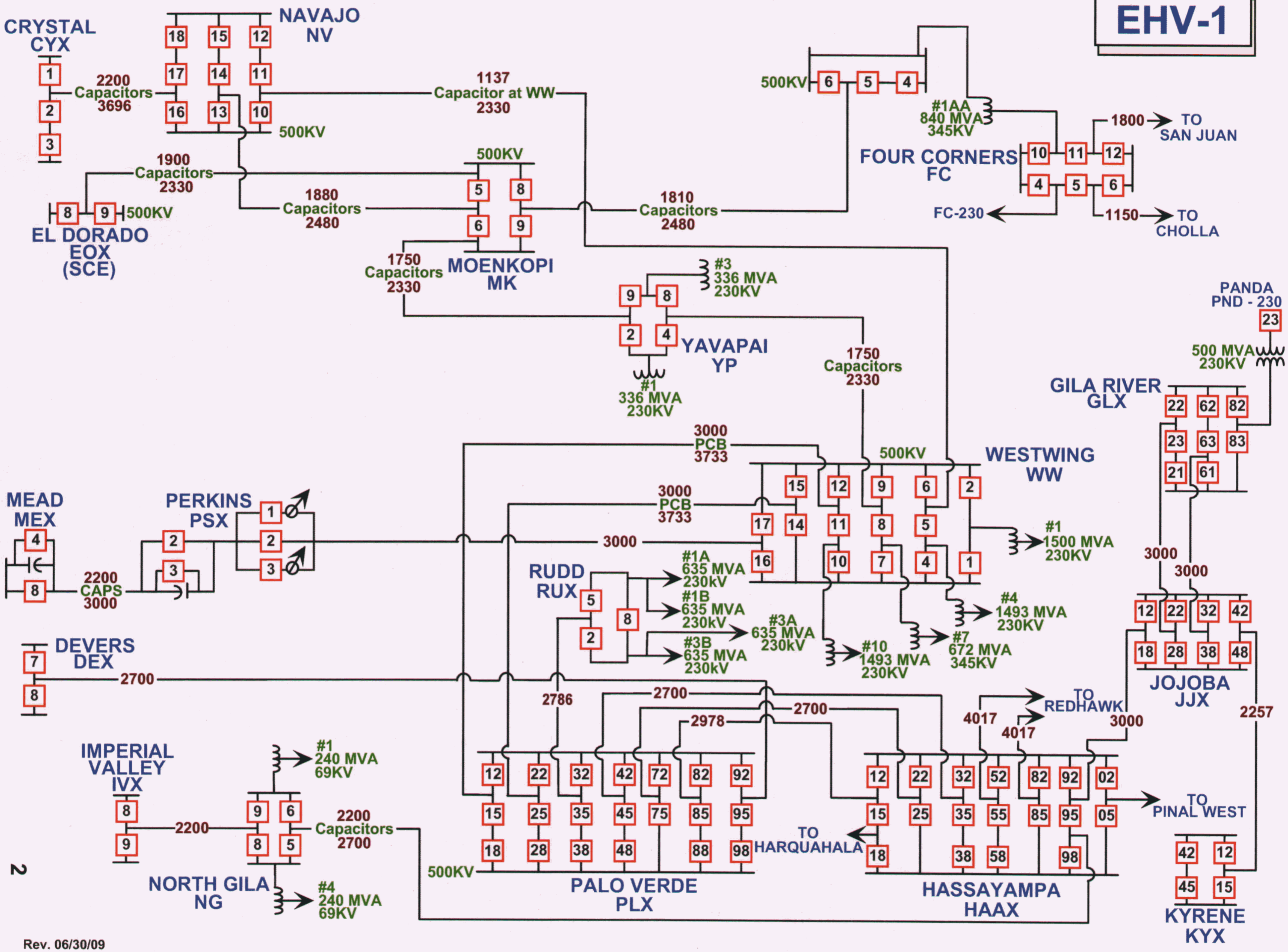
TRANSMISSION OPERATIONS
Aug 2009

TABLE OF CONTENTS

LEGEND
SYSTEM RATING MAPS

SYMBOL	DESCRIPTION
###	CURRENT LIMIT IN AMPS
—###—	LIMITING ELEMENT
###	CONDUCTOR LIMIT IN AMPS
	TRANSFORMER LIMITS ARE IN MVA
————	OVERHEAD TRANSMISSION LINE
– – – – – –	UNDERGROUND CABLE
M	MOTOR OPERATED SWITCH
V	VACCUM SWITCH
H	HYDRAULIC SWITCH
1 (boxed)	BREAKER NUMBER

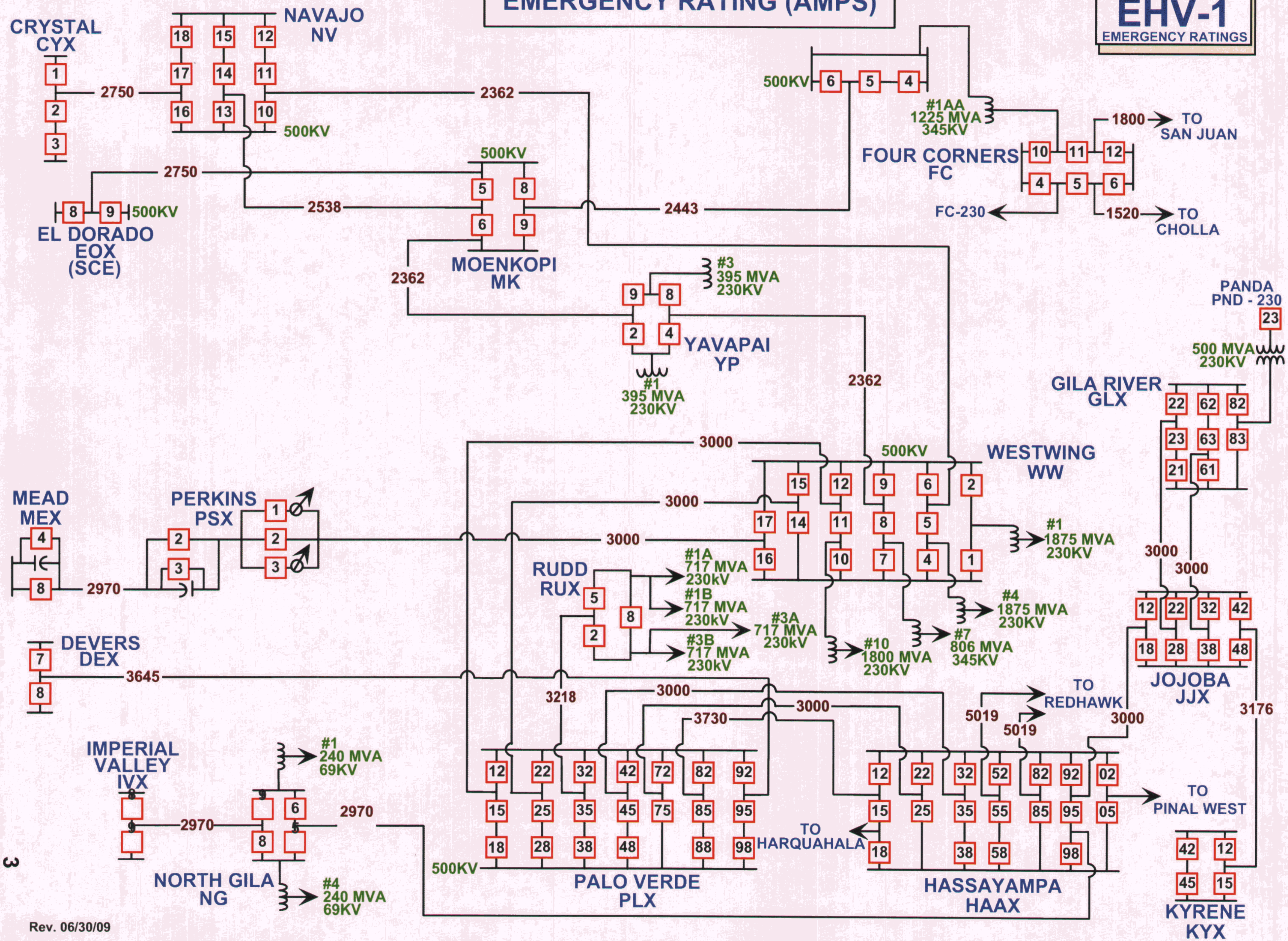
EHV-1



Rev. 06/30/09

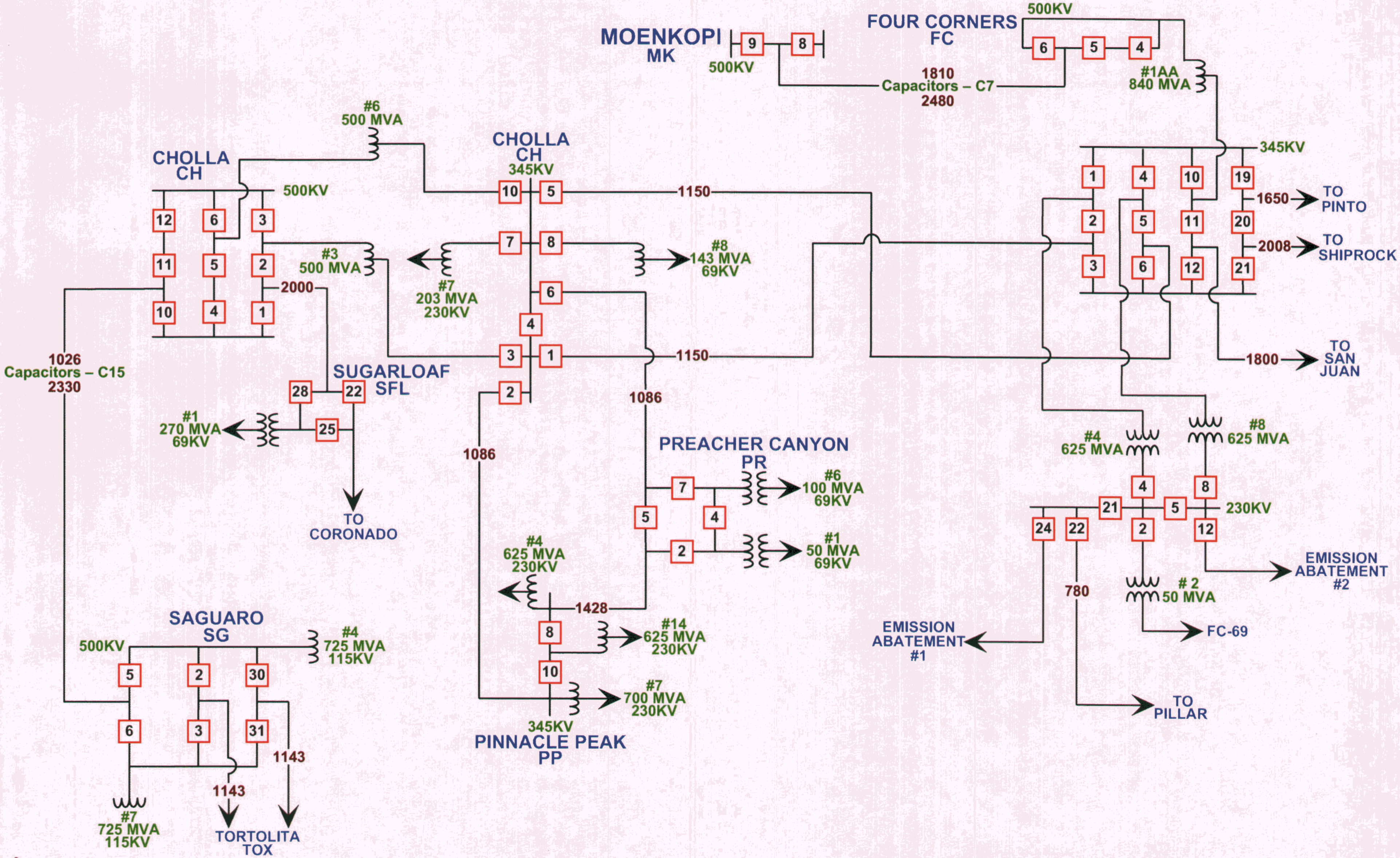
EMERGENCY RATING (AMPS)

EHV-1
EMERGENCY RATINGS



Rev. 06/30/09

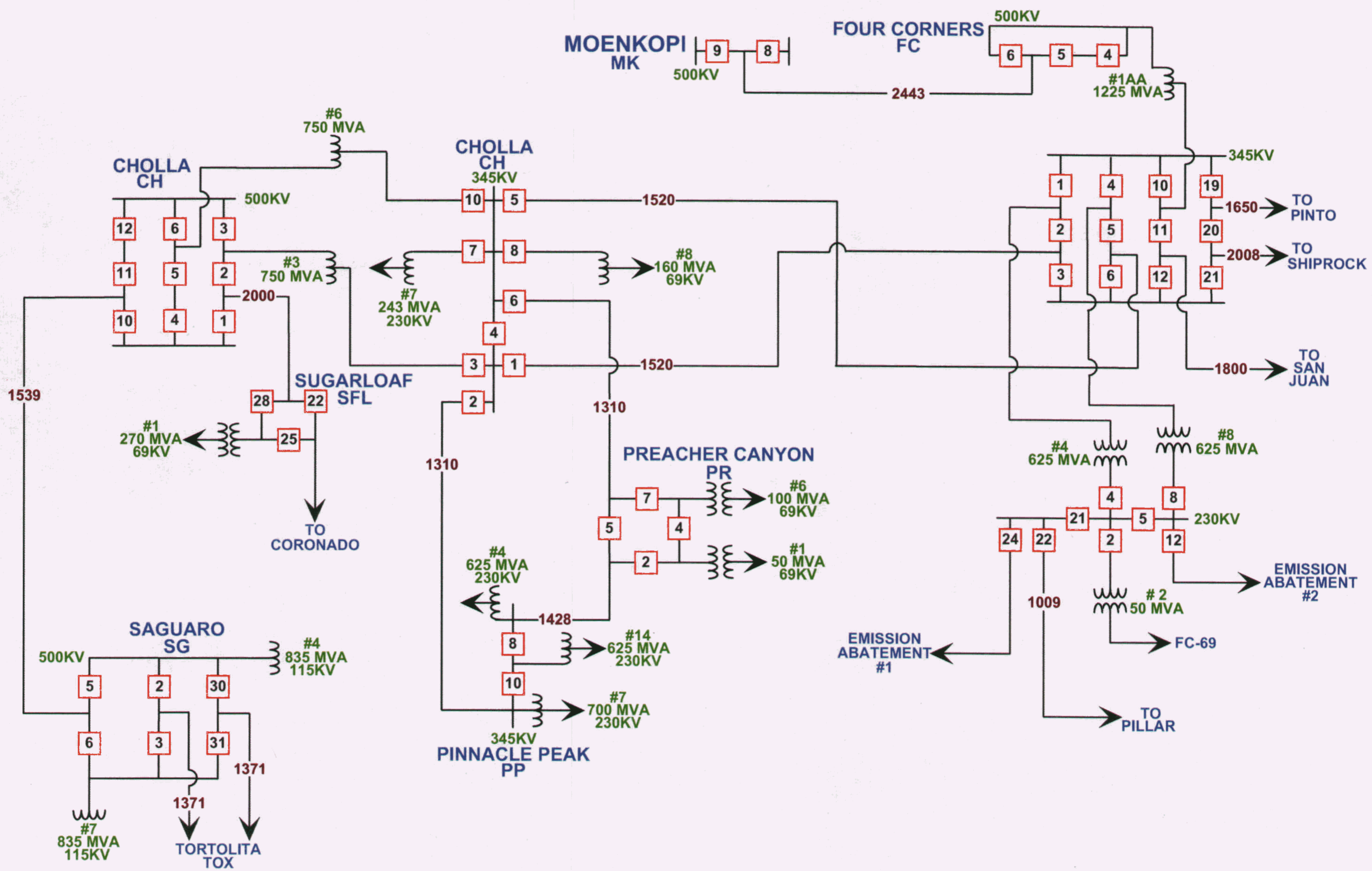
EHV-2



Rev. 07/9/09

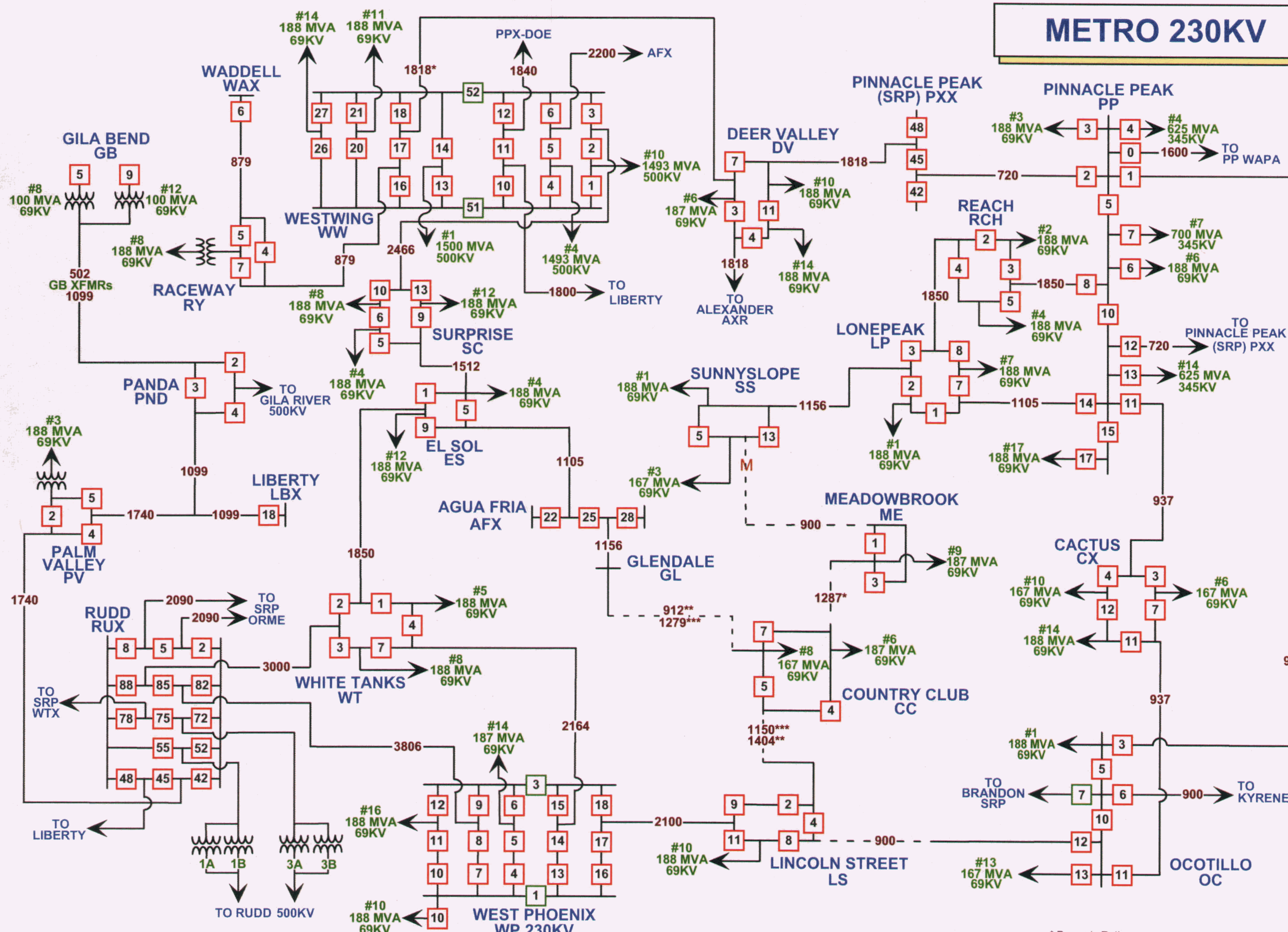
EHV-2
EMERGENCY RATINGS

EMERGENCY RATING (AMPS)



Rev. 07/9/09

METRO 230KV

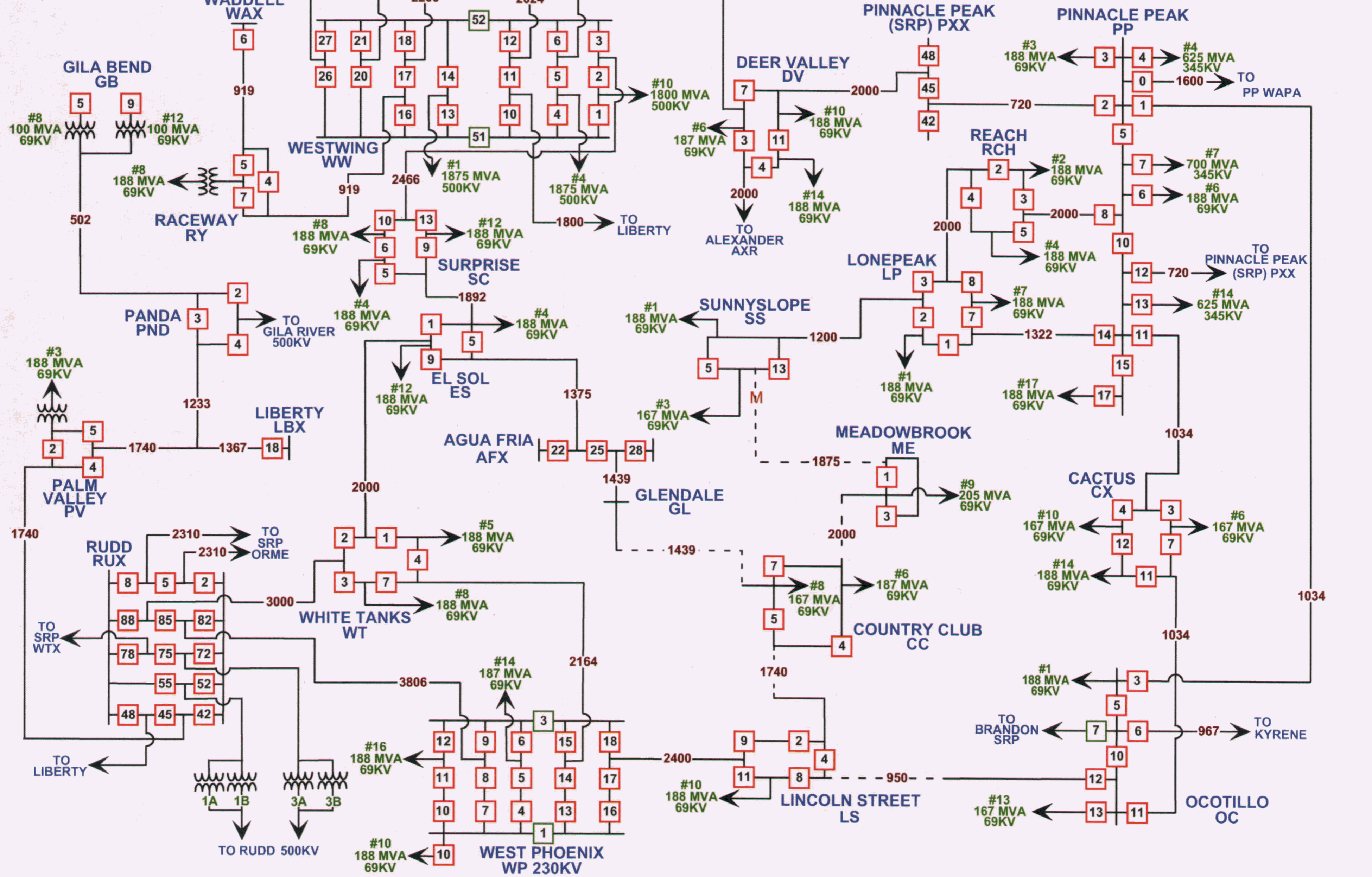


* Dynamic Rating
** No forced cooling on GT-CC, Cooling both ends LS-CC
*** Forced cooling on GT-CC, Cooling one end LS-CC

Rev. 07/9/09

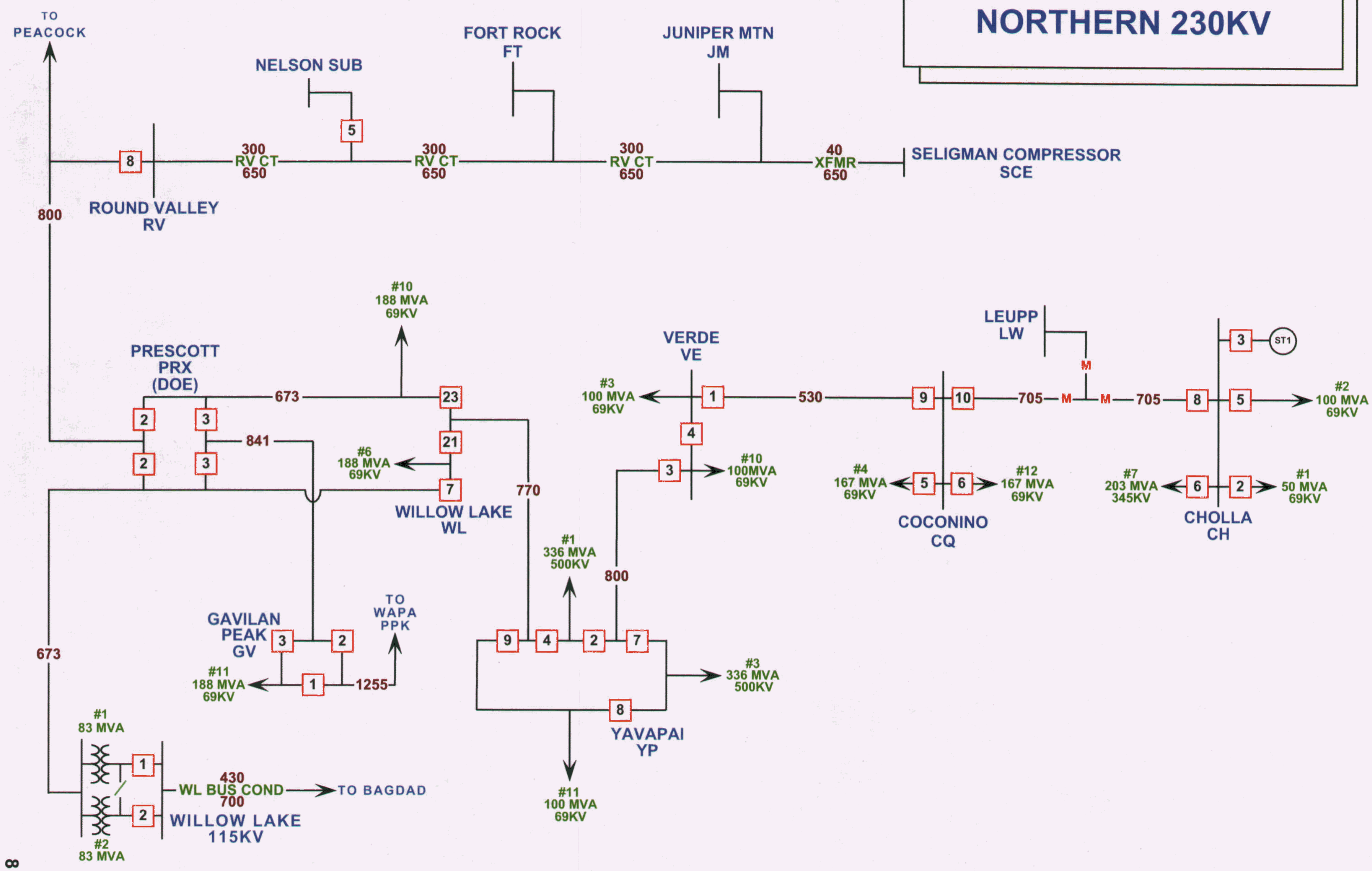
METRO 230KV

EMERGENCY RATINGS



Rev. 07/15/09

NORTHERN 230KV



Rev. 07/15/2009

NORTHERN 230KV

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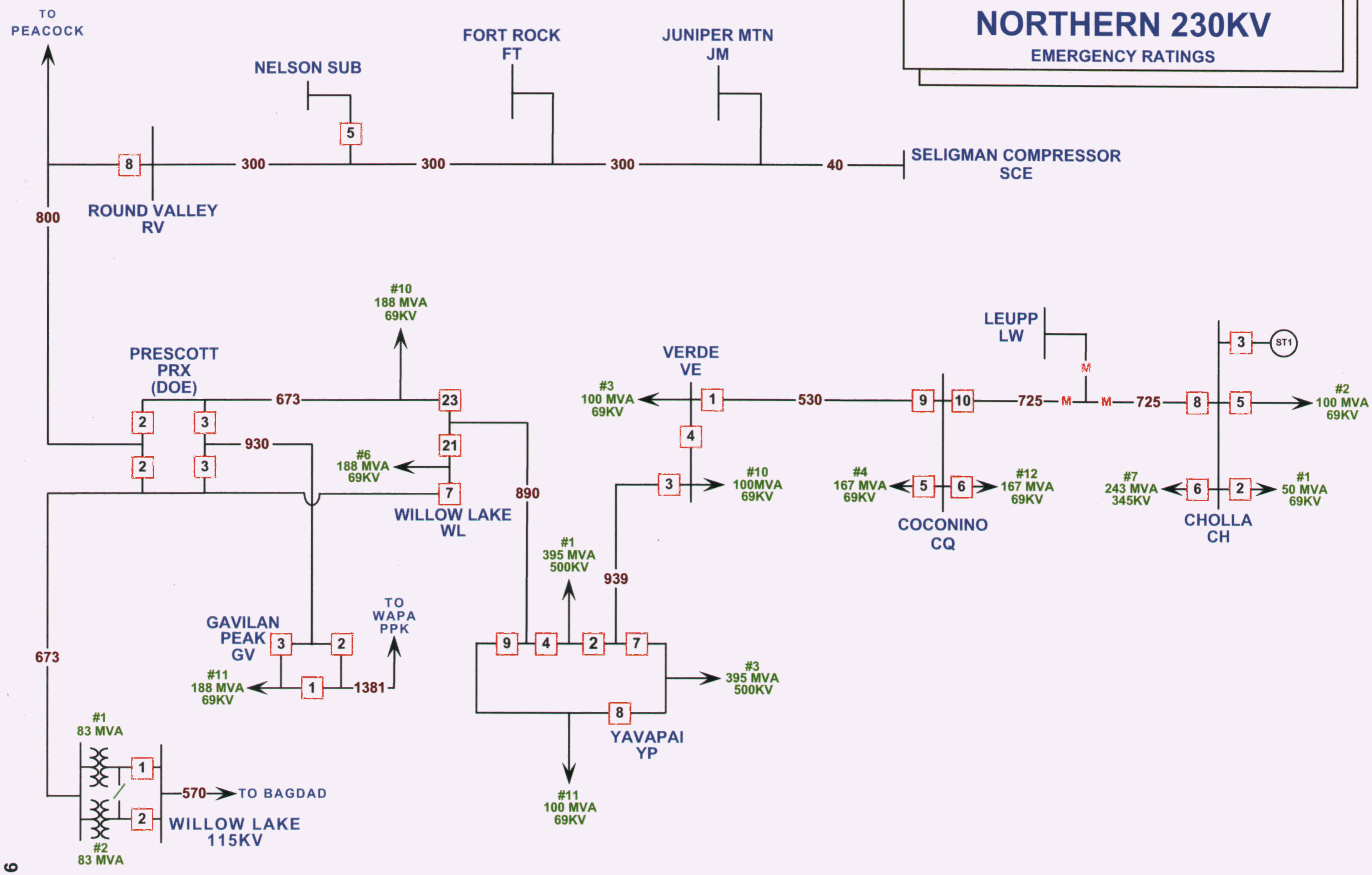

Rev. 07/16/2009

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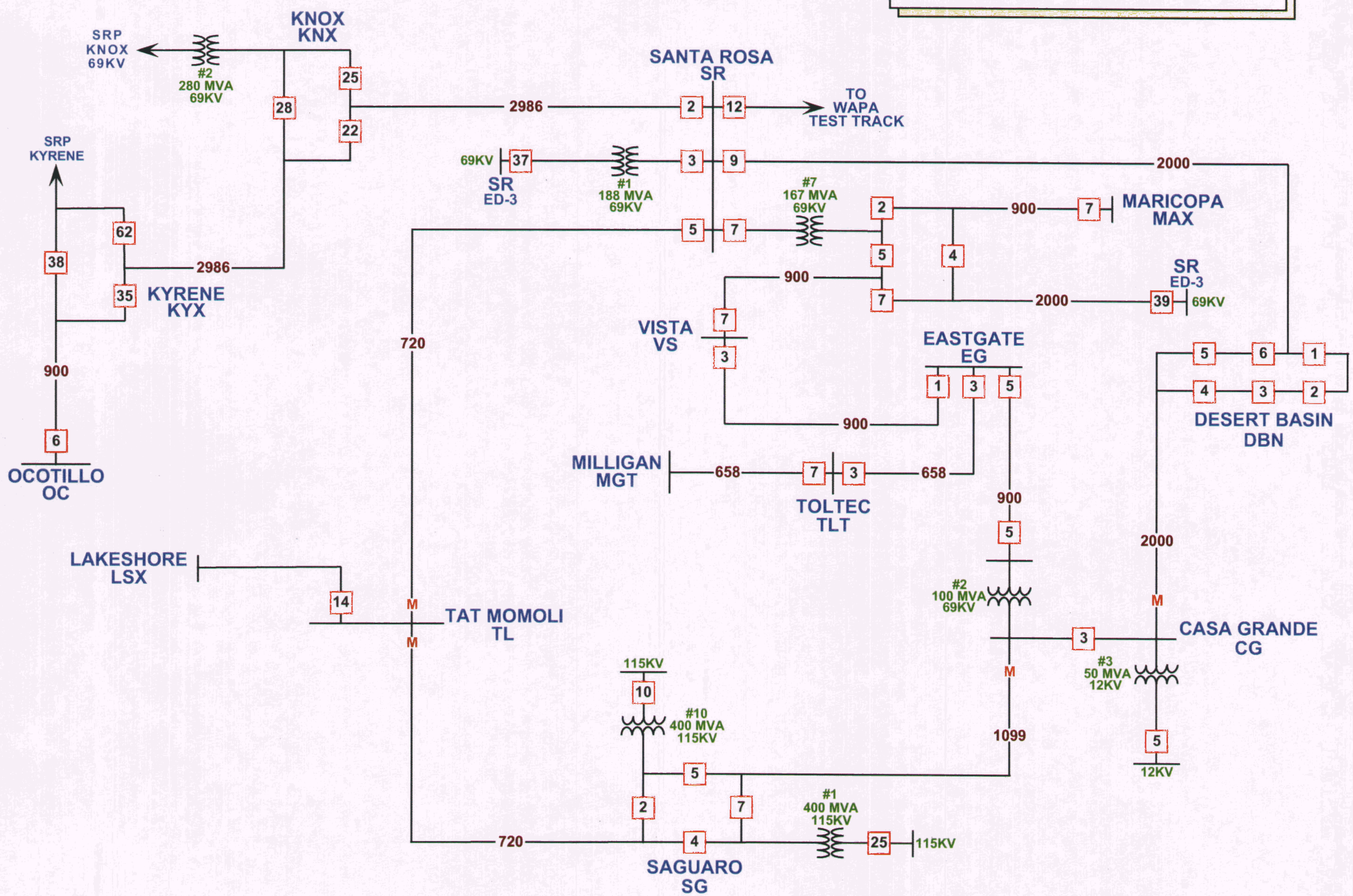

Rev. 07/16/09

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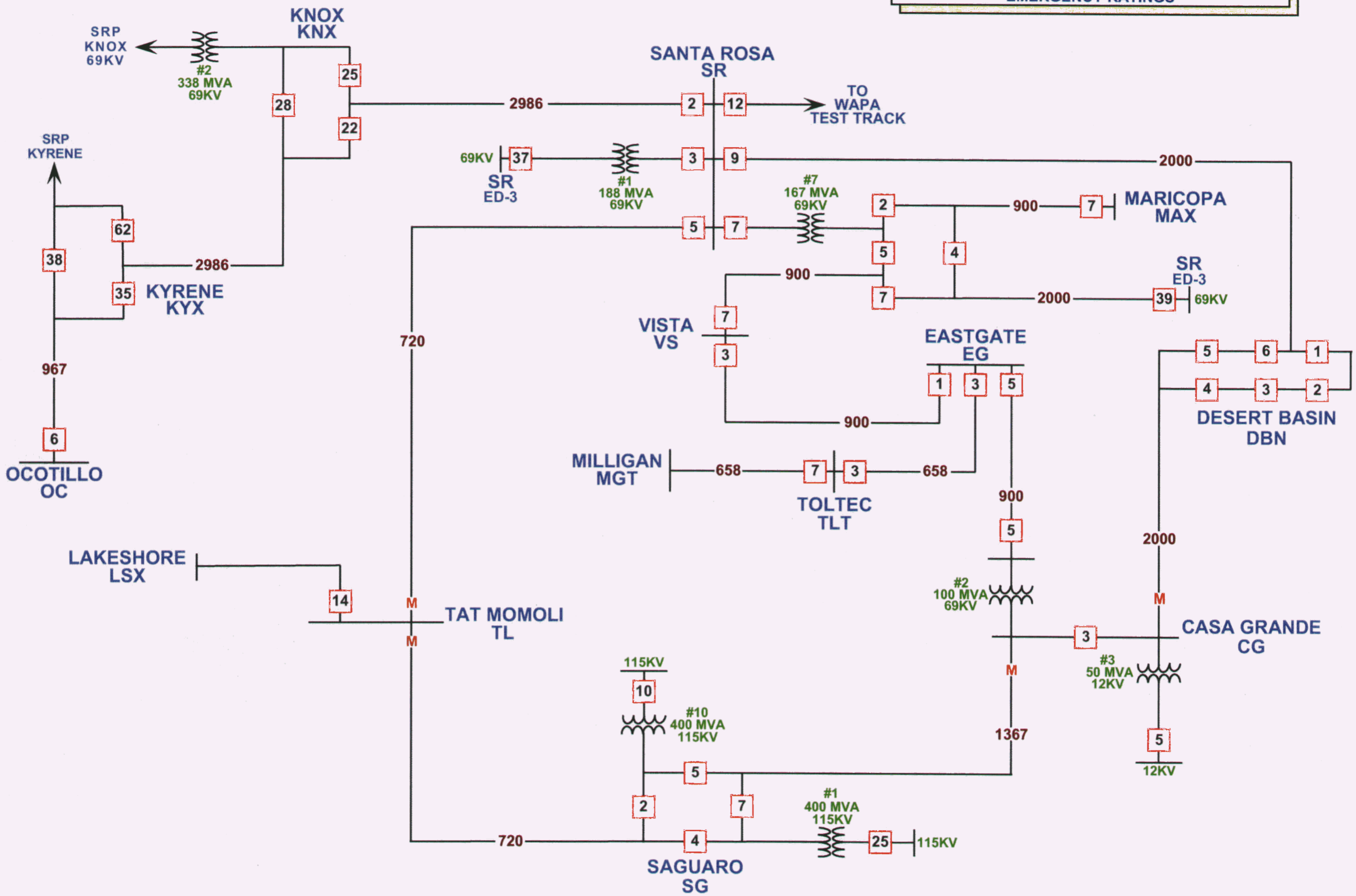

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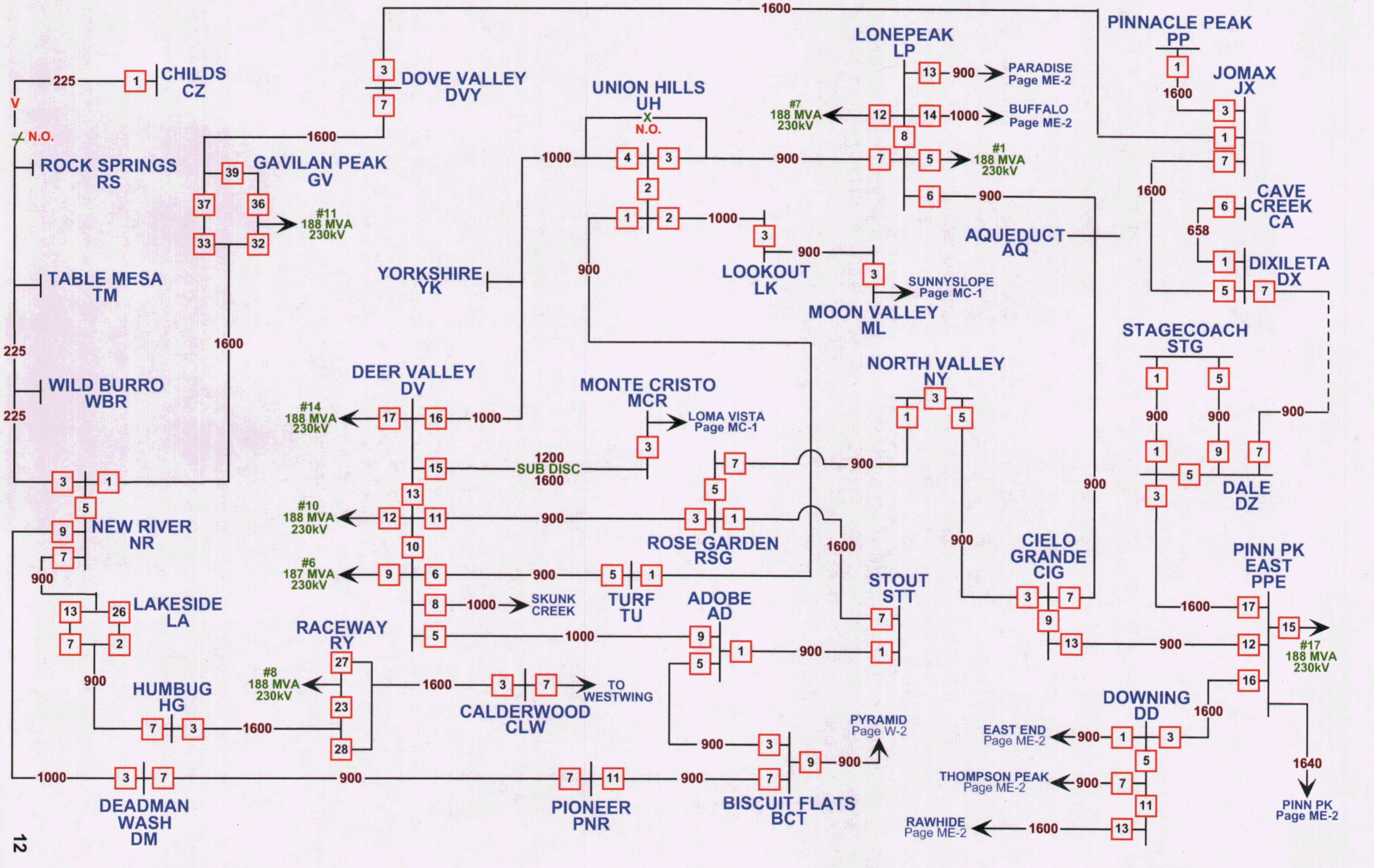

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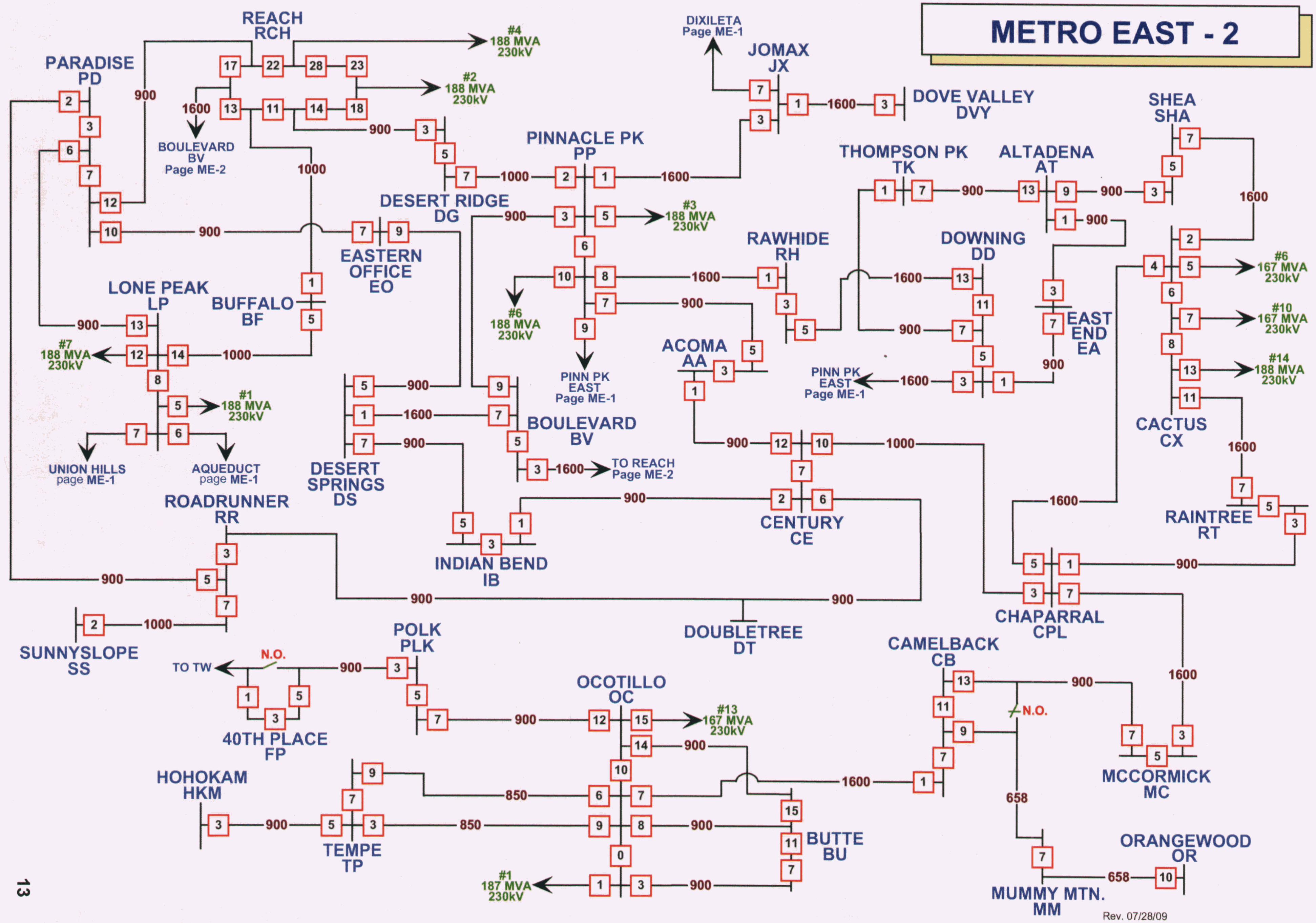

REACH RCH
PARADISE PD
BOULEVARD BV Page ME-2
#4 188 MVA 230kV
#2 188 MVA 230kV
DIXILETA Page ME-1
JOMAX JX
DOVE VALLEY DVY
PINNACLE PK PP
SHEA SHA
THOMPSON PK TK
ALTADENA AT
DESERT RIDGE DG
#3 188 MVA 230kV
EASTERN OFFICE EO
LONE PEAK LP
BUFFALO BF
RAWHIDE RH
DOWNING DD
#6 167 MVA 230kV
#6 188 MVA 230kV
EAST END EA
#10 167 MVA 230kV
#7 188 MVA 230kV
ACOMA AA
#14 188 MVA 230kV
PINN PK EAST Page ME-1
#1 188 MVA 230kV
BOULEVARD BV
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INDIAN BEND IB
CENTURY CE
RAINTREE RT
DOUBLETREE DT
CHAPARRAL CPL
SUNNYSLOPE SS
POLK PLK
CAMELBACK CB
TO TW
N.O.
OCOTILLO OC
#13 167 MVA 230kV
40TH PLACE FP
MCCORMICK MC
HOHOKAM HKM
TEMPE TP
BUTTE BU
ORANGEWOOD OR
#1 187 MVA 230kV
MUMMY MTN. MM
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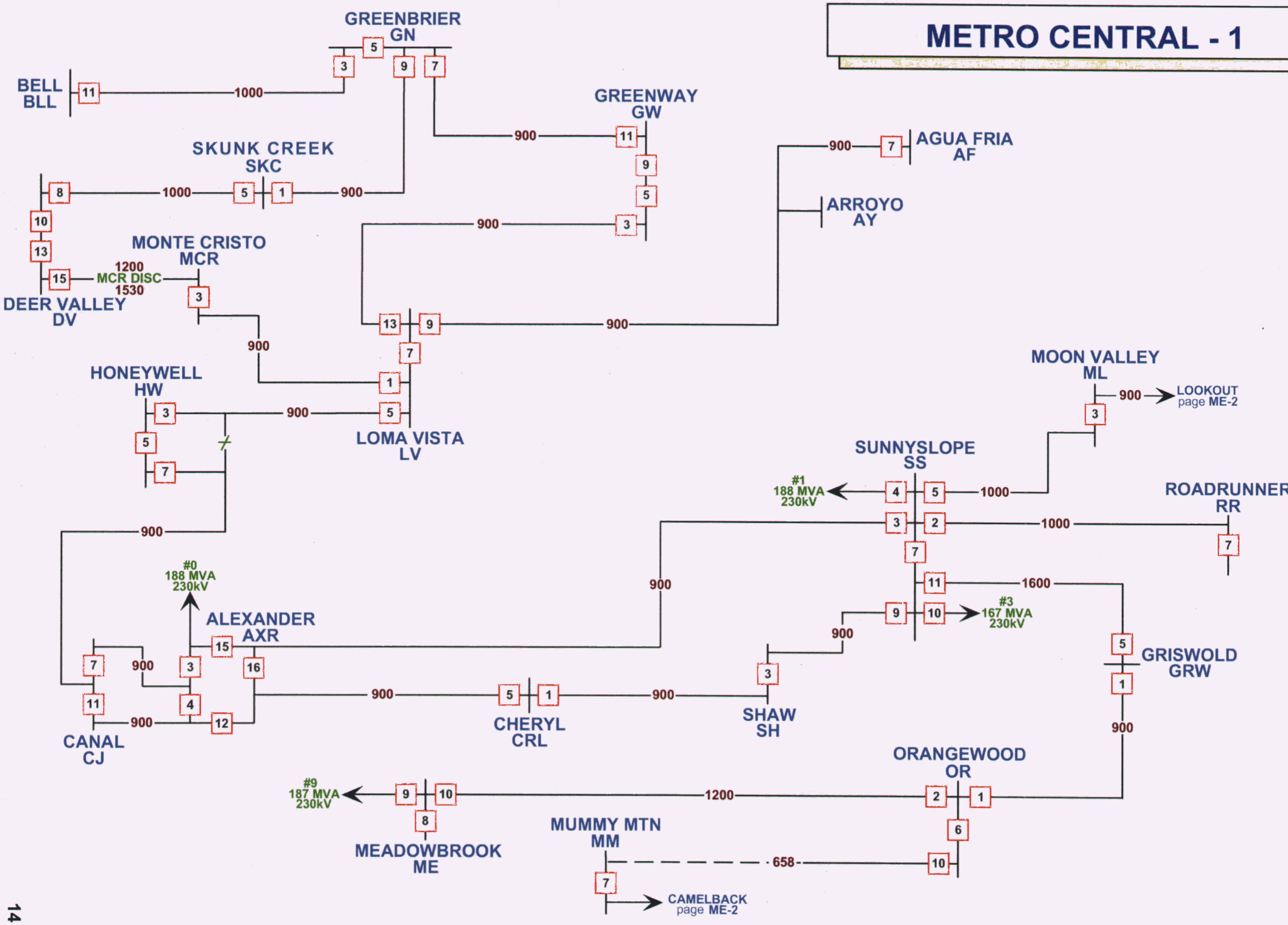
METRO CENTRAL - 1



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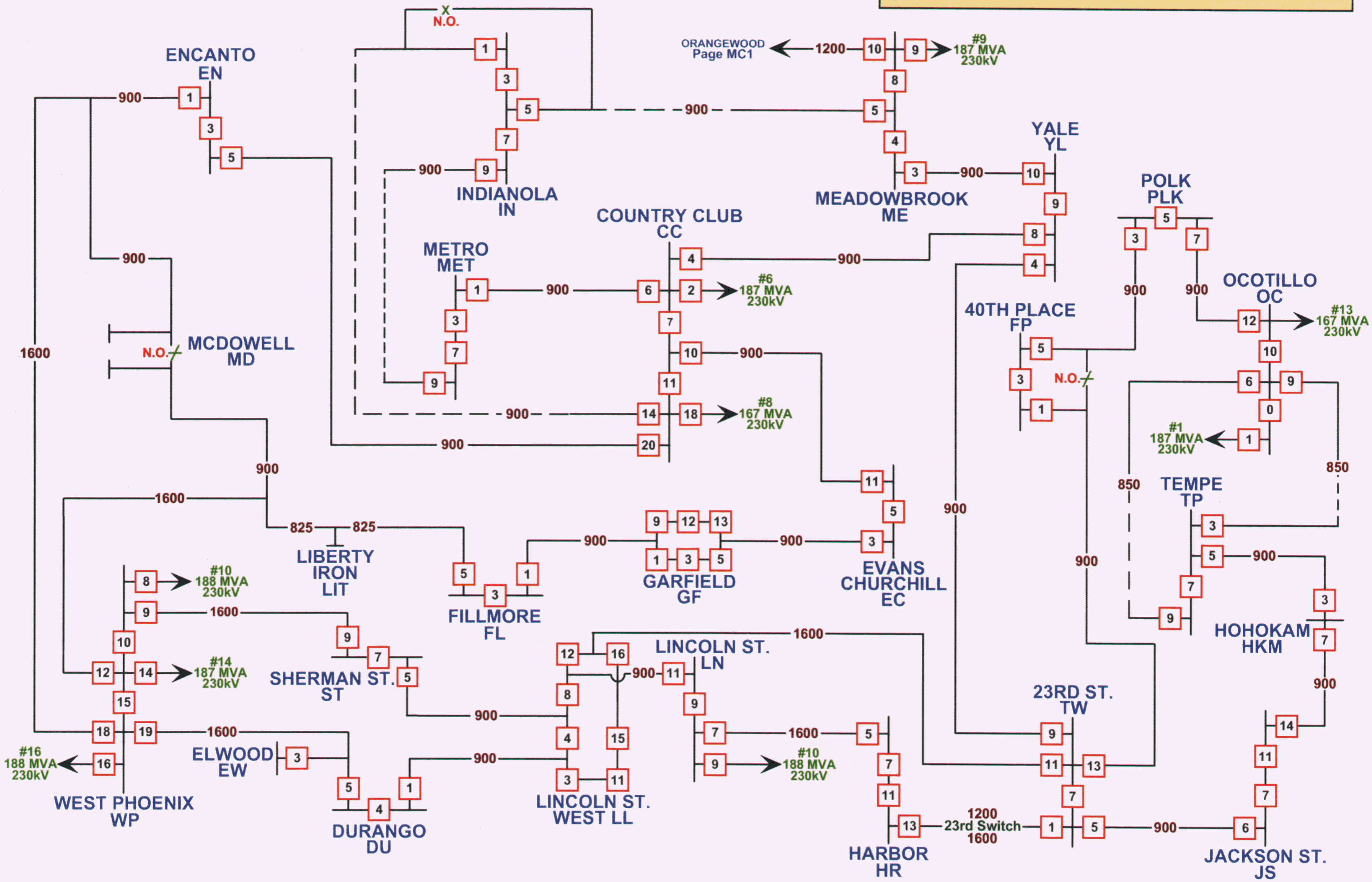

Rev. 08/11/09

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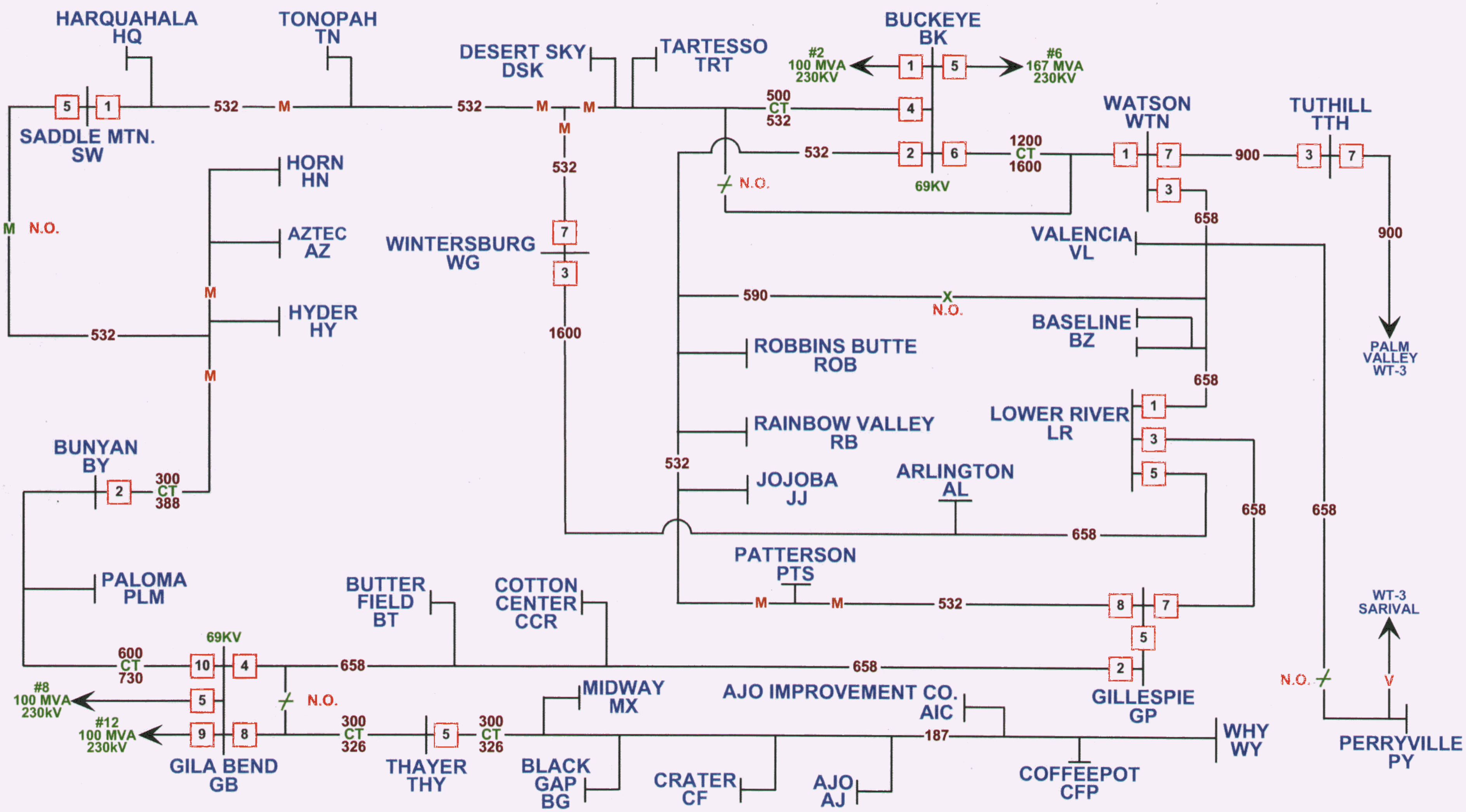

Rev. 07/31/09

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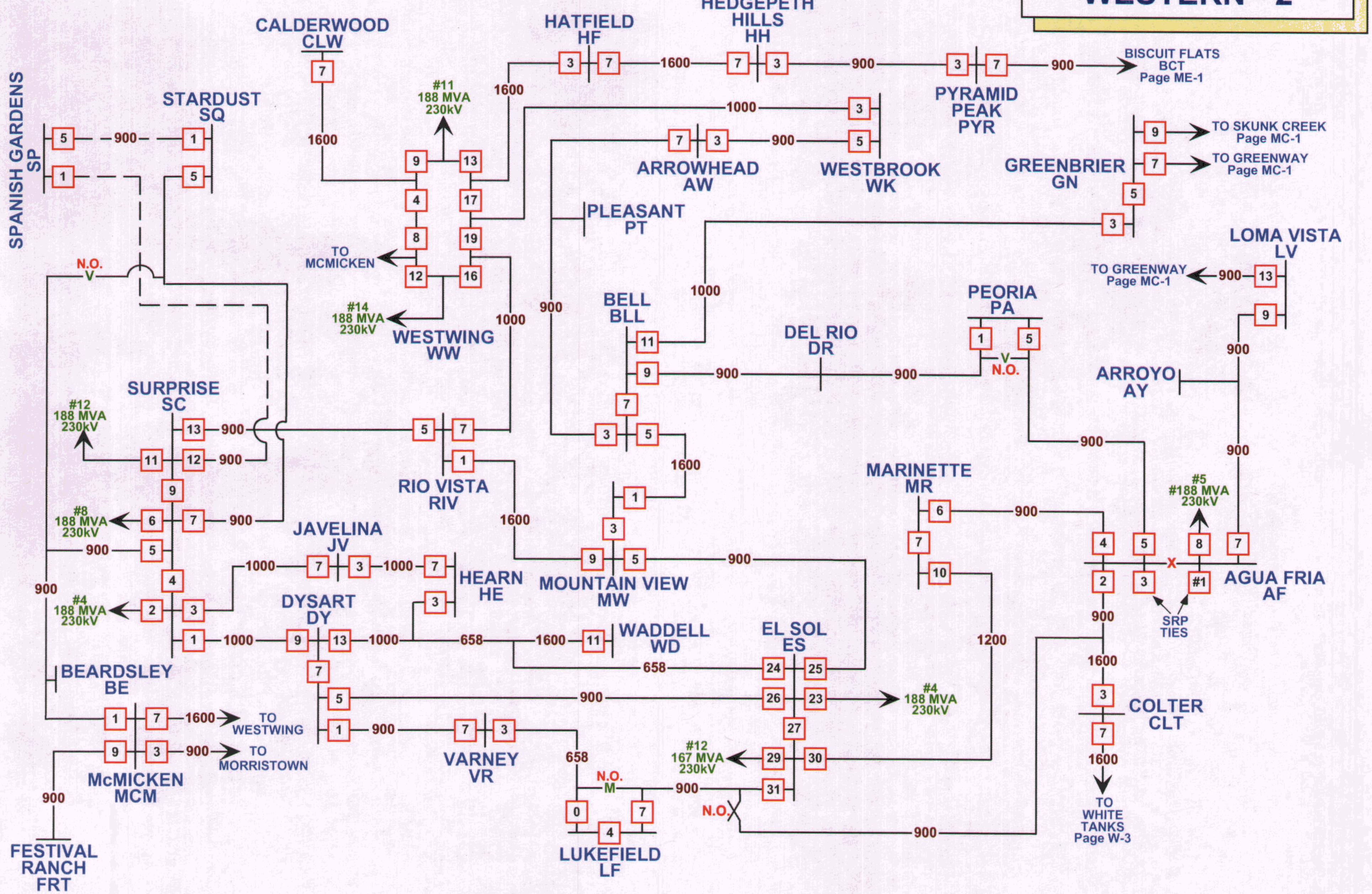

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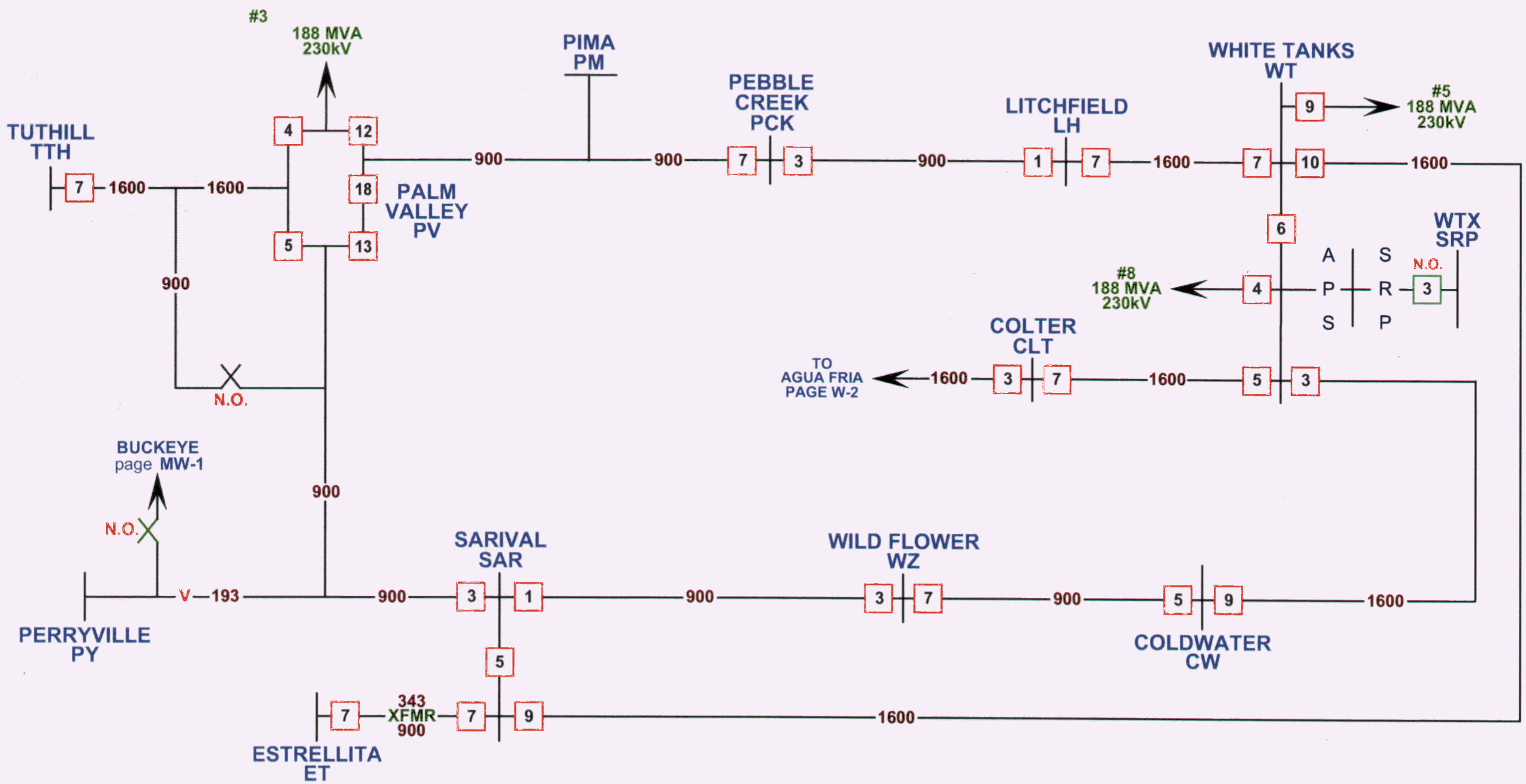
WESTERN - 3



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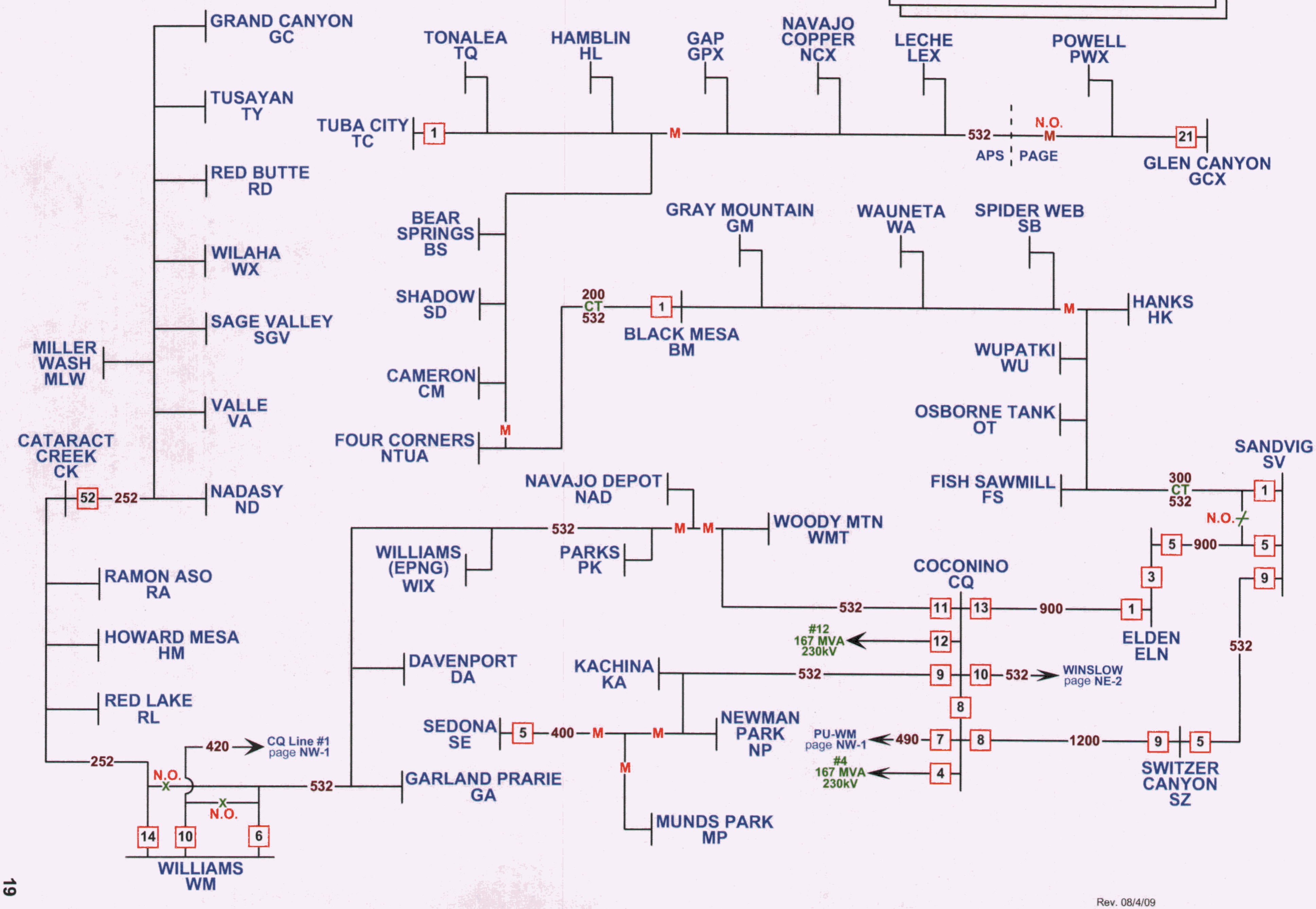
GRAND CANYON GC
TUSAYAN TY
RED BUTTE RD
WILAHA WX
SAGE VALLEY SGV
MILLER WASH MLW
VALLE VA
CATARACT CREEK CK
52
252
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HOWARD MESA HM
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N.O.
420
CQ Line #1 page NW-1
X N.O.
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10
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WILLIAMS WM
532
TUBA CITY TC
1
TONALEA TQ
HAMBLIN HL
M
GAP GPX
NAVAJO COPPER NCX
LECHE LEX
532
N.O. M
APS
PAGE
POWELL PWX
21
GLEN CANYON GCX
BEAR SPRINGS BS
SHADOW SD
CAMERON CM
FOUR CORNERS NTUA
M
200 CT 532
1
BLACK MESA BM
GRAY MOUNTAIN GM
WAUNETA WA
SPIDER WEB SB
M
HANKS HK
WUPATKI WU
OSBORNE TANK OT
FISH SAWMILL FS
300 CT 532
SANDVIG SV
1
N.O.
5
900
5
3
9
NAVAJO DEPOT NAD
M M
WOODY MTN WMT
532
WILLIAMS (EPNG) WIX
PARKS PK
COCONINO CQ
532
11
13
900
1
ELDEN ELN
#12 167 MVA 230kV
12
532
DAVENPORT DA
KACHINA KA
532
9
10
532
WINSLOW page NE-2
8
SEDONA SE
5
400
M
M
NEWMAN PARK NP
PU-WM page NW-1
490
7
8
1200
9
5
SWITZER CANYON SZ
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MUNDS PARK MP
Rev. 08/4/09

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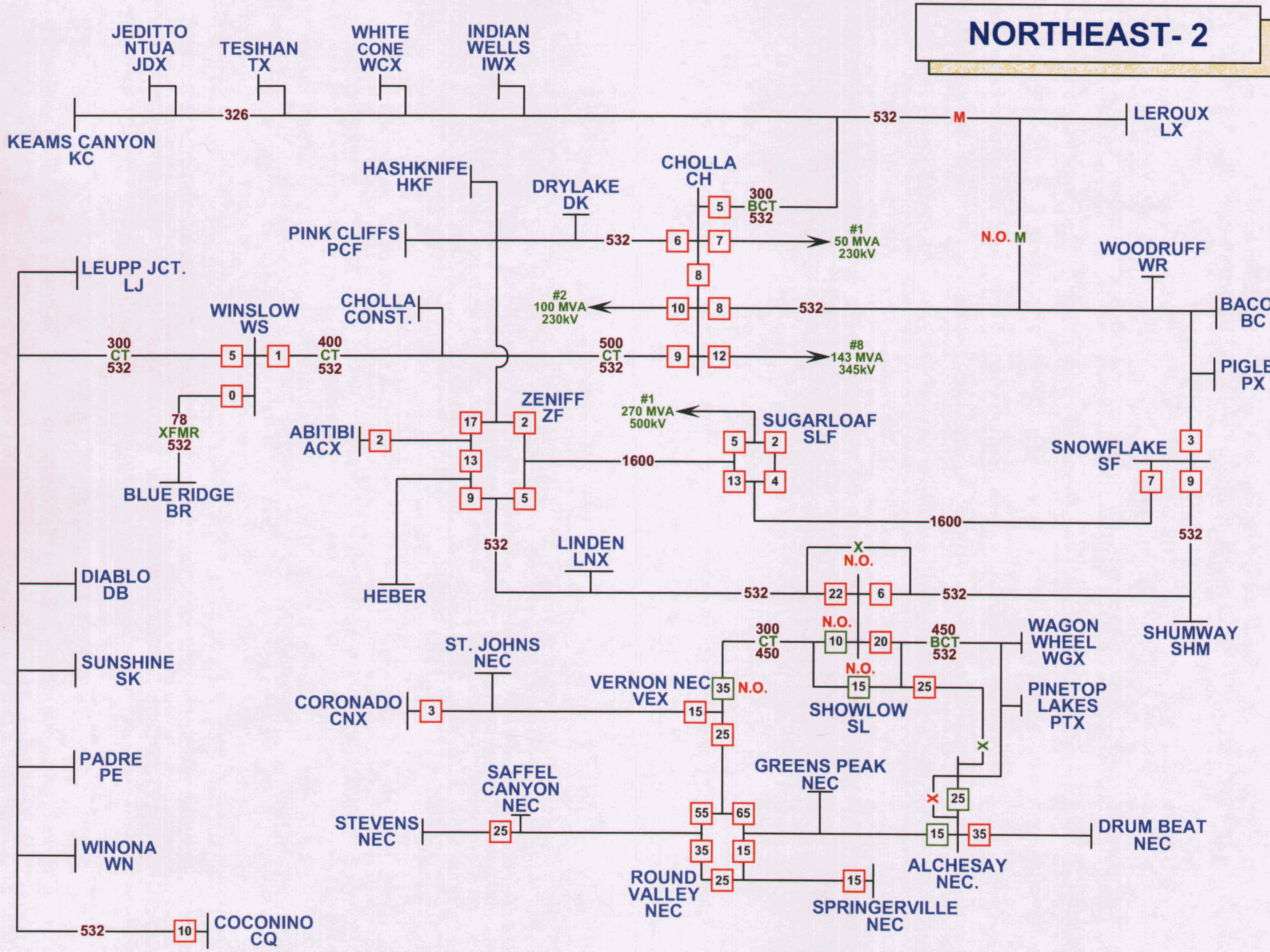

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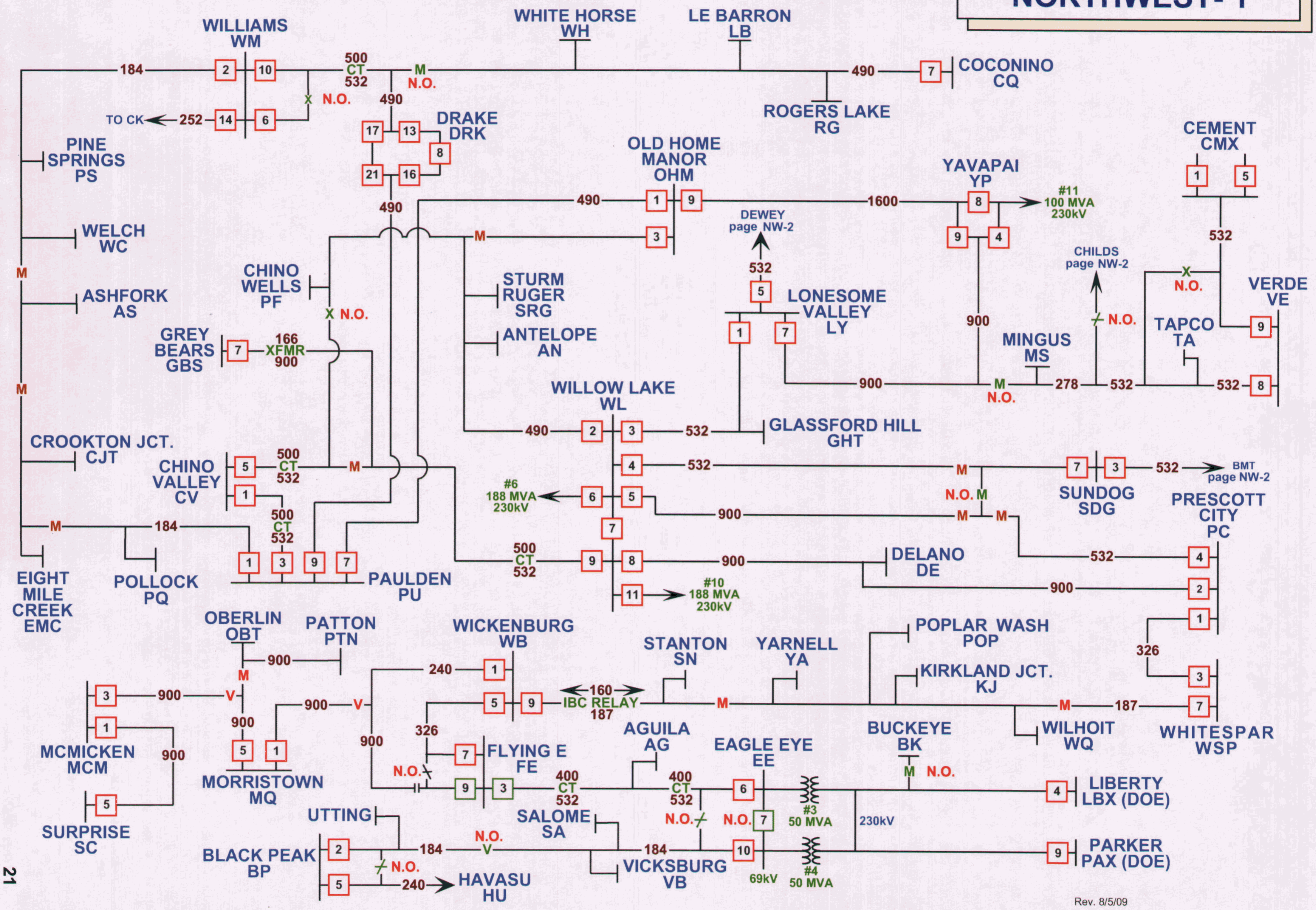

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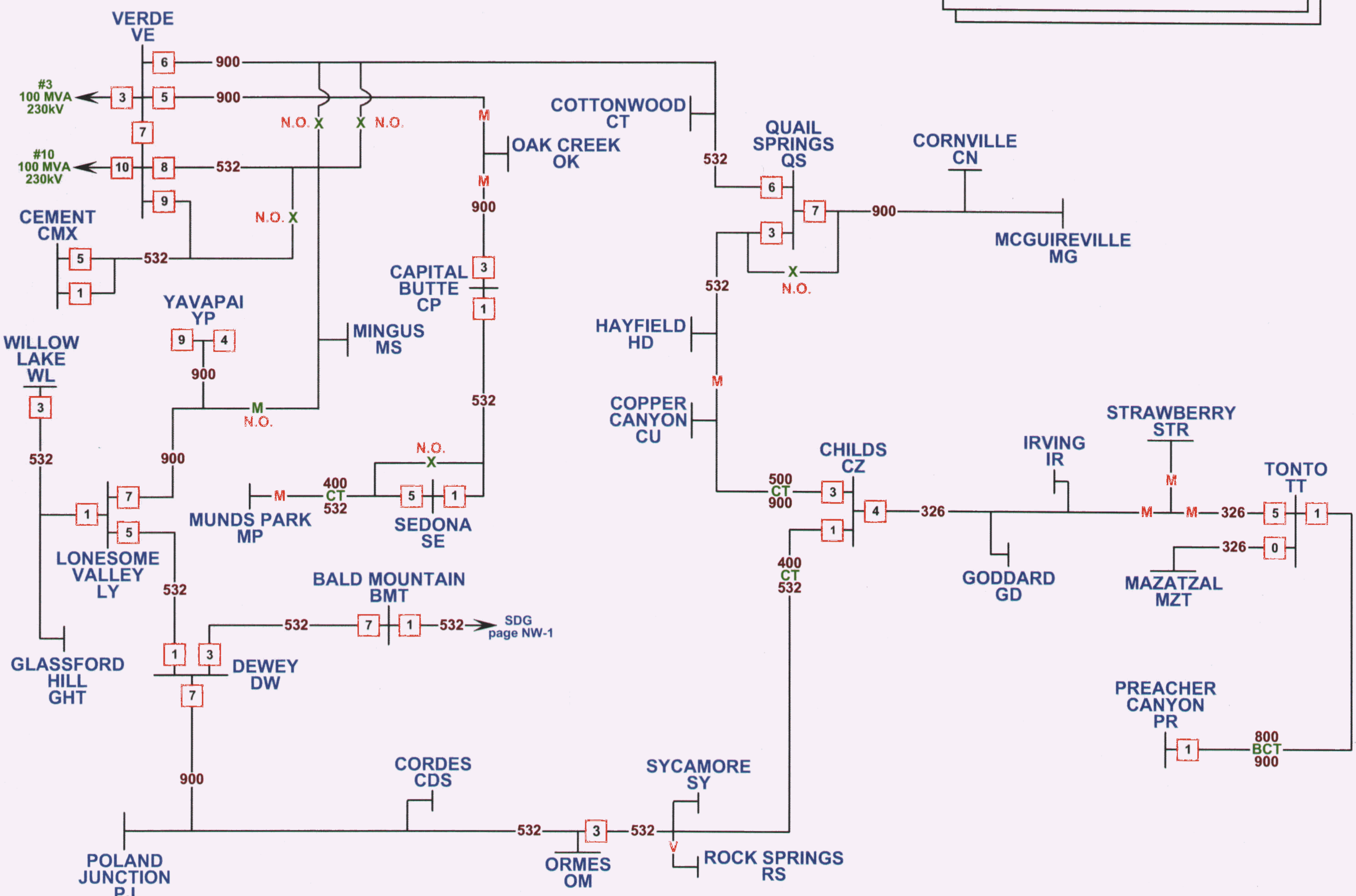

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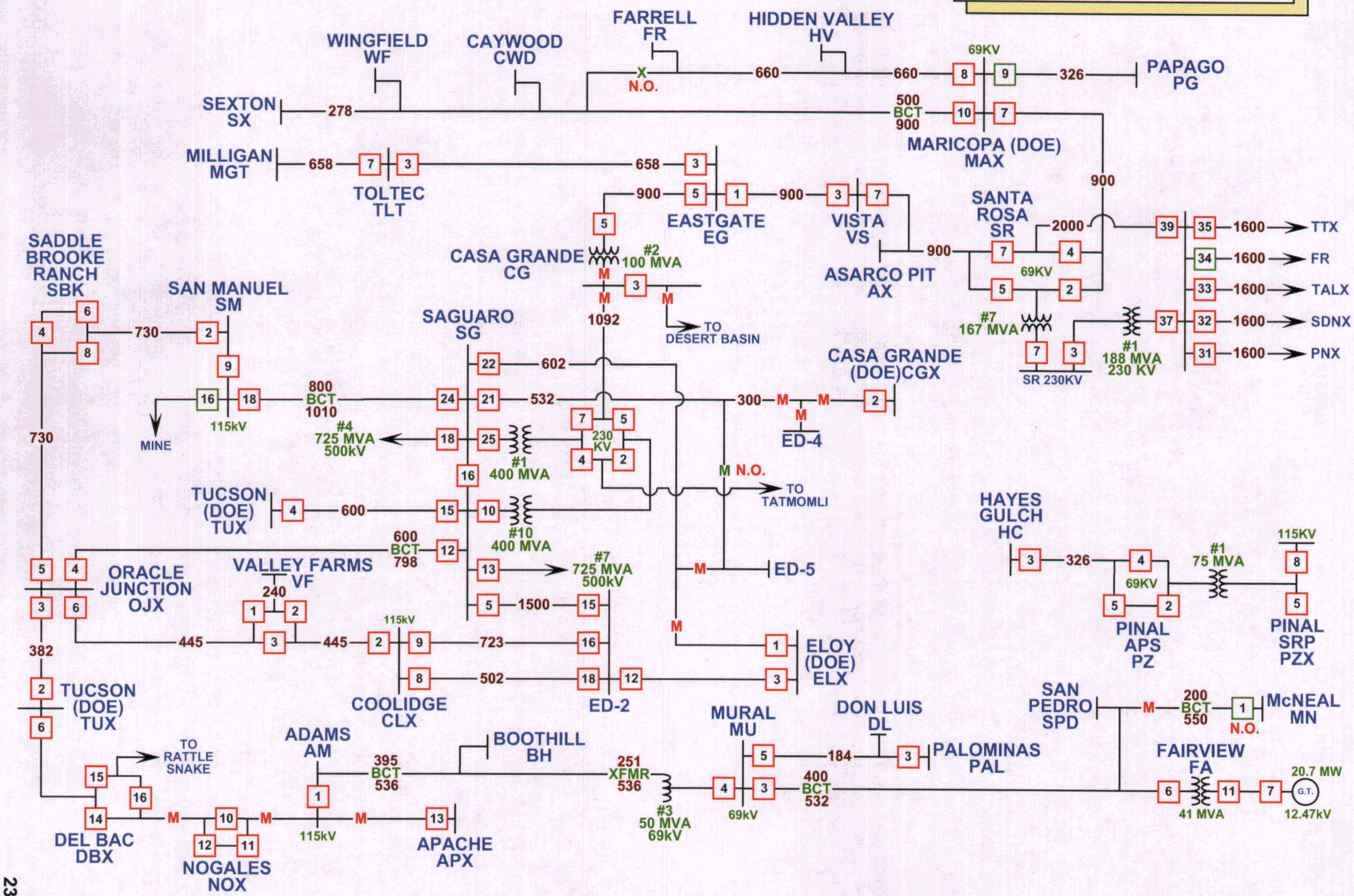

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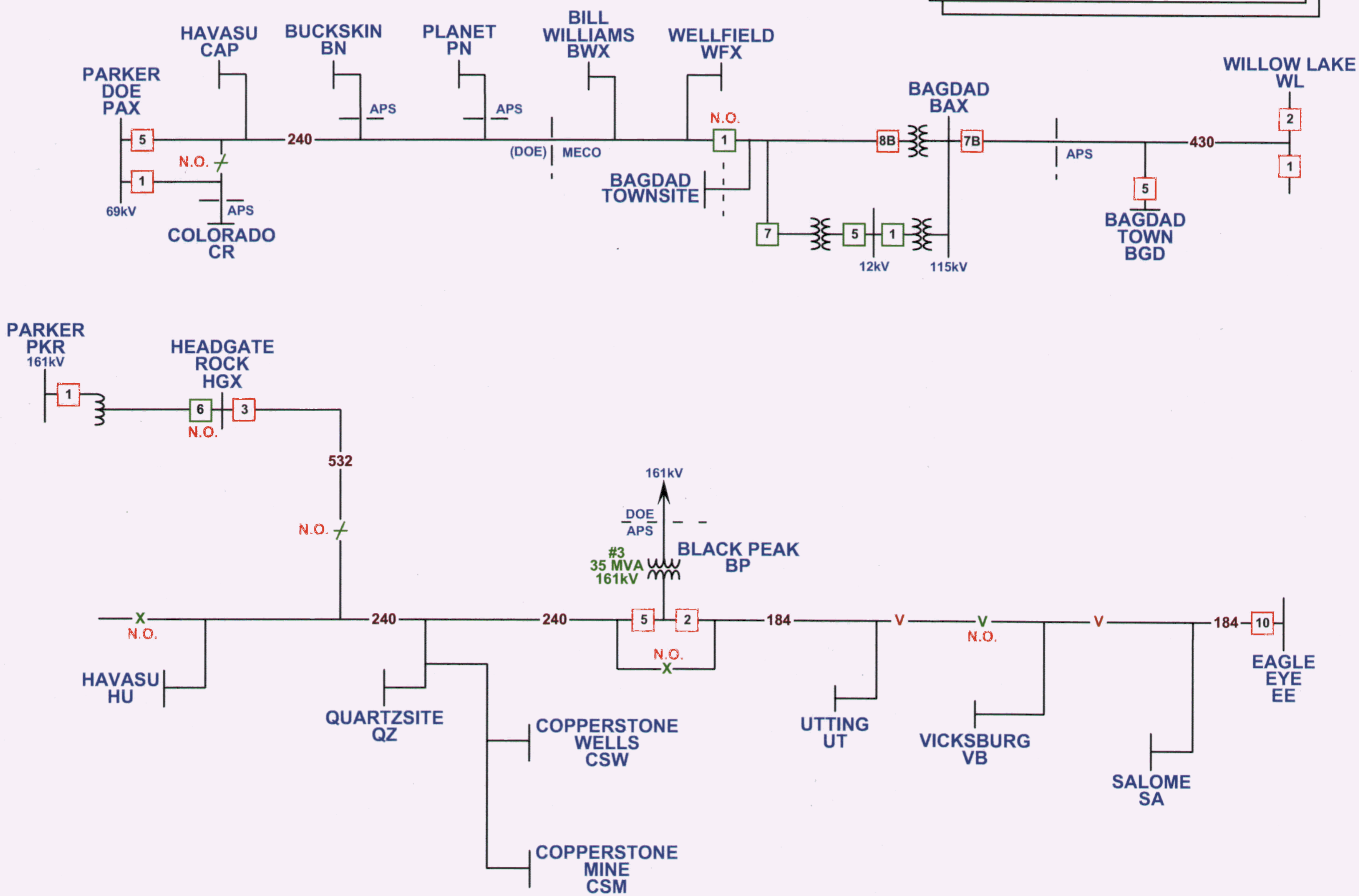

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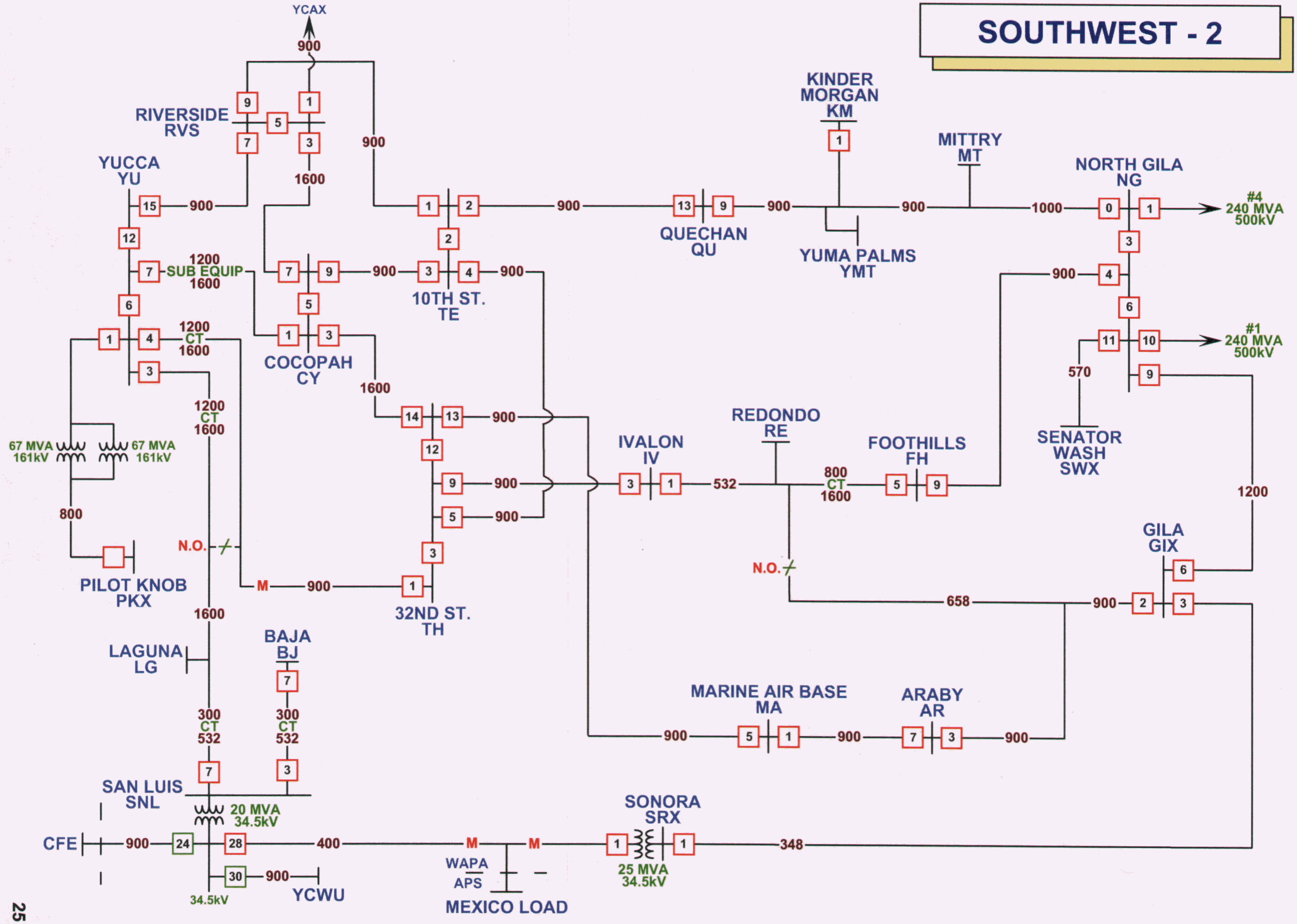

Rev. 8/10/09

ARIZONA PUBLIC SERVICE COMPANY

TEN-YEAR PLAN

2010 – 2019

TECHNICAL STUDY REPORT

FOR

THE ARIZONA CORPORATION COMMISSION

JANUARY 2010

Executive Summary

Pursuant to NERC Standard TPL-001 "System Performance Under Normal (No Contingency) Conditions (Category A)", Arizona Public Service (APS) performs annually a Category A analysis. The Category A analysis is performed for system conditions listed in Table I of the NERC/WECC Planning standards.

Results of the study indicate that, with the projects identified in APS's Ten-Year Transmission Plan, APS is fully compliant with NERC Standard TPL-001.

Pursuant to NERC Standard TPL-002 "System Performance Following Loss of a Single Bulk Electric System Element (Category B)", APS performs annually a Category B contingency analysis. In Table I of the NERC/WECC planning standards, there are a total of four different Category B events that are to be studied each year to meet NERC Standard TPL-002.

A comprehensive list of contingencies was developed for the Category B contingency analysis and performed for the system conditions listed in Table I of the NERC/WECC Planning standards based on engineering judgment. APS believes that the selection of contingencies for inclusion in these studies, which is based on Category B of Table 1 of the NERC/WECC Planning standards, is acceptable to WECC. If requested by WECC, APS will implement measures to correct any deficiencies that have been identified by WECC.

Results of the study indicate that, with the projects identified in APS's Ten-Year Transmission Plan, APS is fully compliant with NERC Standard TPL-002.

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ARIZONA PUBLIC SERVICE COMPANY
2009-2018
TEN-YEAR PLAN
TECHNICAL STUDY REPORT

I. Introduction

This technical study report is performed and filed annually with the Arizona Corporation Commission ("Commission") pursuant to ARS §40-360.02 and Commission Decision No. 63876 (July 25, 2001). This report summarizes the results of power flow analyses and stability analyses for the APS system.

Power flow analyses were conducted for every year within the ten year planning window (2010-2019) and performed for two scenarios: (i) assumption that all transmission system elements are in service and within continuous ratings (Category A); and (ii) assumption of an outage on a single element, with all remaining system elements remaining within emergency ratings (Category B). Voltage deviations for these scenarios must also be within established guidelines. These voltage deviation guidelines closely approximate post-transient VAR margin requirements of the Western Electricity Coordinating Council (WECC). More detail is provided in APS's Transmission Planning Process and Guidelines, which is also included in the annual APS Ten-Year Plan filing.

The stability analyses were performed to simulate electrical disturbances on the transmission system and evaluate the system response. The desired result is that all generators will remain on line, no additional lines will open, and the system oscillations will damp out.

Results of the power flow and stability analyses aid in determining when and where new electrical facilities are needed because of reliability or security reasons. Additionally, some facilities are planned to address adequacy concerns. These include the interconnection of generation to the transmission system or efforts to increase import capability and/or export/scheduling capability to load-constrained or other areas.

II. Base Case Development

Power flow cases were created for each year of the 2010-2019 study time frame. These cases were developed from the latest available WECC heavy summer power flow cases.

The 2009 Valley Operating case was chosen as the first seed case. This case was developed from a 2008 WECC Heavy Summer base case. The WECC case was then updated in a coordinated effort between APS and SRP to include the sub-transmission and distribution models and was the basis for the valley operating studies performed by APS and SRP for the 2009 summer operating season. This case was used as the seed case in the creation of the 2010, 2011, and 2012 power flow cases used for the power flow analyses performed for the 2010-2019 Ten-Year plan. Each intermediate case developed was updated with the forecasted loads and any system additions/upgrades that are planned in the respective year.

The second seed case chosen was the 2013 Heavy Summer power flow case that was developed through the CATS-EHV sub-committee of SWAT. A recent WECC 2012 heavy summer power flow case was used as the initial case to develop the WestConnect 2013 heavy summer power flow case. In a collaborative effort, the Arizona utilities used the jointly developed 2013 WestConnect case to develop a 2013 summer case that included the sub-transmission and distribution systems of the Arizona utilities. This seed case was used to develop the 2014, 2015, and 2016 power flow cases. Each intermediate case developed was updated with the forecasted loads and any system additions/upgrades that are planned in the respective year.

The final seed case chosen was the CATS 2019 heavy summer power flow case. The latest WECC 2018 heavy summer power flow case was used as the initial case to develop the CATS 2018 heavy summer power flow case. In a collaborative effort, the Arizona utilities used the jointly developed 2019 CATS case to develop a 2019 summer case that included the sub-transmission and distribution systems of the Arizona utilities. This seed case was used to develop the 2017 and 2018 power flow cases. The 2017 case was updated with the forecasted load for 2017 and removed any system additions/upgrades that were planned for 2018 and 2019. The 2018 case was updated with the forecasted load for 2018 and removed any system additions/upgrades that were planned for 2019.

These cases represent the latest transmission and sub-transmission plans, load projections, and resource plans of utilities and independent power producers. By utilizing WECC base cases, all loads, resources, firm power transfers, and planned projects within the WECC system are represented. By using jointly developed seed cases the most accurate Arizona system is represented.

III. Power Flow Analyses

Base case and single contingency conditions are evaluated to determine system needs and timing. Various iterations of possible solutions lead to the final plans for transmission additions. The contingency analysis involves simulations for every non-radial 115kV or above line that APS owns, partially owns, or operates. Transformer outages are also evaluated.

The APS system includes several reactive power resources that are used to maintain bus voltages within the limited defined by The Transmission Planning Process & Guidelines. These reactive power resources include shunt devices, series compensation, and tap changing transformers. The reactive power resources are adequate and meet the system performance.

APS does not have any existing or planned control devices. These devices exist outside the APS control area; however, they are not utilized or their operation is not necessary as a result of the contingencies in this study.

No planned outage of bulk electric equipment at APS occurs during the heavy summer peak time. Therefore it is not necessary to study planned outages since this Ten-Year Plan study focuses on the heavy summer peak time.

Results of the power flow studies are tabulated in a Security Needs Table and an Adequacy Needs Table, below. These tables identify eleven transmission projects that are included in this Ten-Year Plan filing. Some of the projects were classified as Adequacy Needs because of the uncertainty of generation location, project size, and transmission availability in the later years. As projects near the five-year planning time frame, they may be redefined as Security Needs projects. For the projects included in the Security Needs Table, selected maps of the power flow simulations are contained in Appendix B showing the pre-project scenario (outage and resulting violation) and the post-project scenario (outage and no criteria violations).

Table 1: Security Needs Table

Transmission Project	In Service Year	Critical Outage	Limiting Element	Map
Youngs Canyon (Flagstaff) 345/69kV interconnection	2012	230/69kV transformers at Coconino	Voltage deviations on the sub-transmission system in the area resulting in load shedding	B1-B2
TS6 230kV substation	2012	Adobe-Deer Valley 69kV line	Overloads Deer Valley-Rose Garden 69kV line	B3-B4
		Adobe-Stout 69kV line	Overloads Deer Valley-Rose Garden 69kV line	B5-B6
Mazatzal 345kV substation	2013	Owens-Preacher Canyon 69kV line	Voltage deviations on the sub-transmission system in the area resulting in load shedding	B7-B8

Table 2: Adequacy Needs Table

Transmission Project	In Service Year	System Benefits
Loop-in of Navajo-Westwing 500kV into Morgan 500kV substation (2010) and Morgan-Pinnacle Peak 500kV line (2010)	2010	Increases import capability for the Phoenix Metropolitan area and export/scheduling capability from the PV area to provide access to both solar and gas resources. Increases transmission system reliability and ability to deliver power from these resources. Provides additional voltage support to the Phoenix Metropolitan 230kV and sub-transmission system.
Loop-in of Saguaro-Casa Grande 230kV line into TS12 230kV substation	2012	Provides a transmission source to serve the new load developing in the local area that does not have any electrical facilities existing in the area.
Desert Basin-Pinal South 230kV line and Pinal South-Sundance 230kV line	2014	Increases the reliability of the Sundance generating facility and provides an APS transmission path for delivery of the full output of the Sundance generating facility. Provides another transmission path in the regional system, thereby increasing the system reliability and capacity in order to continue to serve the growing electrical demand in an economical and reliable manner.
Palo Verde vicinity to North Gila 500kV.	2014	Increases import capability for the Yuma area and export/scheduling capability from the PV area to provide access to both solar and gas resources. Increases transmission system reliability and ability to deliver power from these resources. Increases transmission system reliability.
North Gila-TS8 230kV line.	2014	Increase transmission system reliability and ability to distribute and deliver power within the Yuma area.
Delany-Sun Valley 500kV line & Sun Valley-Trilby Wash 230kV line	2014	Increases the import capability for the Phoenix Metropolitan area and export/scheduling capability from the PV area to provide access to both solar and gas resources. Increases the system reliability by providing a new transmission source to help serve the growing areas in the western portions of the Phoenix Metropolitan area.
Palm Valley-TS2-Trilby Wash 230kV line	2015	Provides a second 230kV source for Trilby Wash so that it is not served as a radial substation, thereby increasing the local system reliability. Also, connecting the Sun Valley-Trilby Wash 230kV line to Palm Valley also increases the reliability of the high voltage transmission system on the western side of the Phoenix Metropolitan area.
Sun Valley-Morgan 500kV line.	2016	Increases import capability for the Phoenix Metropolitan area and export/scheduling capability from the PV area which includes both solar and gas resources. Increases transmission system reliability and ability to deliver power from these resources. Provides a second 500kV source for the Sun Valley substation. Provides support for multiple Category C and D transmission contingencies.

IV. Stability Analyses

A stability simulation for simulated three-phase faults was performed for 2013 and 2019 for every non-radial 115kV, 230kV, 345kV or 500kV line that APS owns (totally or partially) or operates. It has been APS's experience that stability concerns do not manifest on the sub-transmission system, which is primarily designed to deliver power to load. Therefore, no simulations were performed at voltage levels less than 115kV, except at generator substation. Additionally, every new proposed generation plant will be required to perform stability evaluations prior to receiving permission to interconnect to the transmission system.

Existing and planned protection systems are utilized in the study, including any backup or redundant system, and represent fault clearing times, the operation of the protection system, and the resulting removal of the facility that would occur as a result of the simulated even. Each simulation modeled a 3-phase bus fault, appropriate series capacitor flashing and reinsertion, fault removal, and transmission line removal. System performance was evaluated by monitoring representative generator rotor angles, bus voltages and system frequency. Plots of these system parameters are included in Appendices C and D. The stability simulations performed to date indicate that no stability problems limit the transmission system.

V. Category A & B Contingency Study Results

A high level overview of the results for the Category A and Category B contingences is shown in Table 3. From this table, it is shown that each of the Category A and Category B contingencies meets the NERC/WECC Planning Standards.

Table 3: Overview of Category A & B Standard Results

		1-5 year Time Frame		6-10 year Time Frame	
	NERC Planning Standards Category A	Case Years Studied	Standards Met?	Case Years Studied	Standards Met?
1	All Facilities in Service	2010 through 2014	Yes	2015 through 2019	Yes
		1-5 year Time Frame		6-10 year Time Frame	
	NERC Planning Standards Category B	Case Years Studied	Standards Met?	Case Years Studied	Standards Met?
1	3-Phase Fault with Normal Clearing – Generator	2010 through 2014	Yes	2015 through 2019	Yes
2	3-Phase Fault with Normal Clearing – Transmission Circuit	2010 through 2014	Yes	2015 through 2019	Yes
3	3-Phase Fault with Normal Clearing – Transformer	2010 through 2014	Yes	2015 through 2019	Yes
4	Loss of an Element without a Fault	2010 through 2014	Yes	2015 through 2019	Yes

Table 3 is a high level summary that shows, with the projects listed in Tables 1 & 2, the APS system meets the criteria listed in NERC Standards TPL-001 and TPL-002. The transient stability plots are detailed in Appendices C & D. Due to the size of the power flow thermal and voltage steady state analysis the detailed results are not included. However, they are available upon request by WECC or any other authorized stakeholder.

APPENDIX A

Representative Contingency List

(2016 used as an example year)

2016 Single Contingency List (Category B)

Outage Number	Type	Contingency	Circuit #
line_1	Line	CHOLLA 500.0 to SAGUARO 500.0	Circuit 1
line_2	Line	FOURCORN 500.0 to MOENKOPI 500.0	Circuit 1
line_3	Line	NAVAJO 500.0 to MOENKOPI 500.0	Circuit 1
line_4	Line	CHOLLA 345.0 to PNPKAPS 345.0	Circuit 1
line_5	Line	CHOLLA 345.0 to PRECHCYN 345.0	Circuit 1
line_6	Line	FOURCORN 345.0 to CHOLLA 345.0	Circuit 1
line_7	Line	FOURCORN 345.0 to CHOLLA 345.0	Circuit 2
line_8	Line	BUCKEYE 230.0 to LIBERTY 230.0	Circuit 1
line_9	Line	CACTUS 230.0 to OCOTILLO 230.0	Circuit 1
line_10	Line	CACTUS 230.0 to PPAPS N 230.0	Circuit 1
line_11	Line	CTRYCLUB 230.0 to LINCSTRT 230.0	Circuit 1
line_12	Line	CTRYCLUB 230.0 to GRNDTRML 230.0	Circuit 1
line_13	Line	DEERVALY 230.0 to ALEXANDR 230.0	Circuit 1
line_14	Line	DEERVALY 230.0 to PINPKSRP 230.0	Circuit 1
line_15	Line	EL SOL 230.0 to AGUAFRIA 230.0	Circuit 1
line_16	Line	GLENDALE 230.0 to GRNDTRML 230.0	Circuit 1
line_17	Line	GLENDALE 230.0 to AGUAFRIA 230.0	Circuit 1
line_18	Line	LEUPP 230.0 to COCONINO 230.0	Circuit 1
line_19	Line	LINCSTRT 230.0 to OCOTILLO 230.0	Circuit 1
line_20	Line	LINCSTRT 230.0 to WPHXAPSN 230.0	Circuit 1
line_21	Line	LONEPEAK 230.0 to PPAPS E 230.0	Circuit 1
line_22	Line	LONEPEAK 230.0 to SUNYSLOP 230.0	Circuit 1
line_23	Line	MEADOWBK 230.0 to CTRYCLUB 230.0	Circuit 1
line_24	Line	MEADOWBK 230.0 to SUNYSLOP 230.0	Circuit 1
line_25	Line	REACH 230.0 to LONEPEAK 230.0	Circuit 1
line_26	Line	REACH 230.0 to PPAPS C 230.0	Circuit 1
line_27	Line	PPAPS N 230.0 to OCOTILLO 230.0	Circuit 1
line_28	Line	PPAPS N 230.0 to PINPKSRP 230.0	Circuit 1
line_29	Line	PPAPS N 230.0 to PINPKSRP 230.0	Circuit 2
line_30	Line	PPAPS W 230.0 to PINPK 230.0	Circuit 1
line_31	Line	SAGUARO 230.0 to TATMOMLI 230.0	Circuit 1
line_32	Line	SNTAROSA 230.0 to TATMOMLI 230.0	Circuit 1
line_33	Line	SNTAROSA 230.0 to TESTTRAK 230.0	Circuit 1
line_34	Line	SURPRISE 230.0 to EL SOL 230.0	Circuit 1
line_35	Line	SURPRISE 230.0 to WESTWNGW 230.0	Circuit 1
line_36	Line	WESTWNGW 230.0 to PINPK 230.0	Circuit 1
line_37	Line	WHTNKAPS 230.0 to EL SOL 230.0	Circuit 1
line_38	Line	WHTNKAPS 230.0 to RUDD 230.0	Circuit 1
line_39	Line	WPHXAPSS 230.0 to WPHXAPSN 230.0	Circuit 1
line_40	Line	PPAPS W 230.0 to PPAPS C 230.0	Circuit 1
line_41	Line	PPAPS C 230.0 to PPAPS E 230.0	Circuit 1
line_42	Line	PPAPS N 230.0 to PPAPS E 230.0	Circuit 1
line_43	Line	WPHXAPSS 230.0 to RUDD 230.0	Circuit 1
line_44	Line	YAVAPAI 230.0 to VERDE N 230.0	Circuit 1
line_45	Line	YAVAPAI 230.0 to WILOWLKE 230.0	Circuit 1
line_46	Line	KYR-NEW 230.0 to OCOTILLO 230.0	Circuit 1
line_47	Line	KYR-NEW 230.0 to KNOX 230.0	Circuit 1
line_48	Line	GILARIVR 230.0 to GILABEND 230.0	Circuit 1

line_49	Line	WPHXAPSN 230.0 to WHTNKAPS 230.0	Circuit 1
line_50	Line	FORTROCK 230.0 to ROUNDVLY 230.0	Circuit 1
line_51	Line	FORTROCK 230.0 to JUNIPRMT 230.0	Circuit 1
line_52	Line	WILOWLKW 230.0 to PRESCOTT 230.0	Circuit 1
line_53	Line	WILOWLKW 230.0 to WILOWLKE 230.0	Circuit 1
line_54	Line	JUNIPRMT 230.0 to SELIGMAN 230.0	Circuit 1
line_55	Line	CORONADO 500.0 to SILVERKG 500.0	Circuit 1
line_56	Line	PALOVRDE 500.0 to WESTWING 500.0	Circuit 1
line_57	Line	PALOVRDE 500.0 to WESTWING 500.0	Circuit 2
line_58	Line	PALOVRDE 500.0 to RUDD 500.0	Circuit 1
line_59	Line	PERK PS2 500.0 to PERKINPS 500.0	Circuit 1
line_60	Line	HASSYAMP 500.0 to REDHAWK 500.0	Circuit 1
line_61	Line	HASSYAMP 500.0 to REDHAWK 500.0	Circuit 2
line_62	Line	HASSYAMP 500.0 to PALOVRDE 500.0	Circuit 1
line_63	Line	HASSYAMP 500.0 to PALOVRDE 500.0	Circuit 2
line_64	Line	HASSYAMP 500.0 to PALOVRDE 500.0	Circuit 3
line_65	Line	HASSYAMP 500.0 to PINAL_W 500.0	Circuit 1
line_66	Line	HASSYAMP 500.0 to ARLINTON 500.0	Circuit 1
line_67	Line	HASSYAMP 500.0 to MESQUITE 500.0	Circuit 1
line_68	Line	AGUAFRIA 230.0 to WESTWNGW 230.0	Circuit 1
line_69	Line	AGUAFRIA 230.0 to ALEXANDR 230.0	Circuit 1
line_70	Line	AGUAFRIA 230.0 to WHITETNK 230.0	Circuit 1
line_71	Line	BRANDOW 230.0 to KYRENE 230.0	Circuit 1
line_72	Line	BRANDOW 230.0 to PAPAGOBT 230.0	Circuit 1
line_73	Line	BRANDOW 230.0 to WARD 230.0	Circuit 1
line_74	Line	BRANDOW 230.0 to WARD 230.0	Circuit 2
line_75	Line	CORBELL 230.0 to KYRENE 230.0	Circuit 1
line_76	Line	KYRENE 230.0 to KYR-NEW 230.0	Circuit 1
line_77	Line	KYRENE 230.0 to SCHRADER 230.0	Circuit 1
line_78	Line	ORME 230.0 to RUDD 230.0	Circuit 1
line_79	Line	PAPAGOBT 230.0 to PINPKSRP 230.0	Circuit 1
line_80	Line	ROGERS 230.0 to THUNDRST 230.0	Circuit 1
line_81	Line	ROGERS 230.0 to ROGSWAPA 230.0	Circuit 1
line_82	Line	ROGERS 230.0 to ROGSWAPA 230.0	Circuit 2
line_83	Line	SANTAN 230.0 to CORBELL 230.0	Circuit 1
line_84	Line	SANTAN 230.0 to THUNDRST 230.0	Circuit 1
line_85	Line	SCHRADER 230.0 to SANTAN 230.0	Circuit 1
line_86	Line	THUNDRST 230.0 to GOLDFELD 230.0	Circuit 1
line_87	Line	THUNDRST 230.0 to GOLDFELD 230.0	Circuit 2
line_88	Line	KNOX 230.0 to SNTAROSA 230.0	Circuit 1
line_89	Line	BROWNING 230.0 to SANTAN 230.0	Circuit 1
line_90	Line	RUDD 230.0 to WHITETNK 230.0	Circuit 1
line_91	Line	RUDD 230.0 to LIBERTY 230.0	Circuit 1
line_92	Line	COPPERVR 230.0 to FRISCO 230.0	Circuit 1
line_93	Line	APACHE 230.0 to BUTERFLD 230.0	Circuit 1
line_94	Line	APACHE 230.0 to RED TAIL 230.0	Circuit 1
line_95	Line	APACHE 230.0 to WINCHSTR 230.0	Circuit 1
line_96	Line	BUTERFLD 230.0 to SAN RAF 230.0	Circuit 1
line_97	Line	MORENCI 230.0 to GREEN-AE 230.0	Circuit 1
line_98	Line	RED TAIL 230.0 to DOSCONDO 230.0	Circuit 1

line_99	Line	SAHUARIT 230.0 to BICKNELL 230.0	Circuit 1
line_100	Line	MEAD N 230.0 to HVRA3A4 230.0	Circuit 1
line_101	Line	MEAD S 230.0 to MEAD N 230.0	Circuit 1
line_102	Line	DAVIS 230.0 to RIVIERA 230.0	Circuit 1
line_103	Line	DAVIS 230.0 to MEAD N 230.0	Circuit 1
line_104	Line	DAVIS 230.0 to TOPOCK 230.0	Circuit 2
line_105	Line	HOVRA5A6 230.0 to MEAD S 230.0	Circuit 1
line_106	Line	HOVRA7-9 230.0 to MEAD S 230.0	Circuit 1
line_107	Line	MEAD 500.0 to PERKINS 500.0	Circuit 1
line_108	Line	PARKER 230.0 to EAGLEYE 230.0	Circuit 1
line_109	Line	PARKER 230.0 to BLK MESA 230.0	Circuit 1
line_110	Line	PARKER 230.0 to HAVASU 230.0	Circuit 1
line_111	Line	PARKER 230.0 to HARCUVAR 230.0	Circuit 1
line_112	Line	COOLIDGE 230.0 to SUN ARIZ 230.0	Circuit 1
line_113	Line	COOLIDGE 230.0 to SUN ARIZ 230.0	Circuit 2
line_114	Line	LIBERTY 230.0 to WESTWNGW 230.0	Circuit 1
line_115	Line	LIBERTY 230.0 to LONE BUT 230.0	Circuit 1
line_116	Line	LIBERTY 230.0 to PHXWAPA 230.0	Circuit 1
line_117	Line	LIBERTY 345.0 to PEACOCK 345.0	Circuit 1
line_118	Line	LONE BUT 230.0 to TESTTRAK 230.0	Circuit 1
line_119	Line	LONE BUT 230.0 to SUN ARIZ 230.0	Circuit 1
line_120	Line	MCCONICO 230.0 to DAVIS 230.0	Circuit 1
line_121	Line	MCCONICO 230.0 to GRIFFITH 230.0	Circuit 1
line_122	Line	MCCONICO 230.0 to HARRIS 230.0	Circuit 1
line_123	Line	PHXWAPA 230.0 to LONE BUT 230.0	Circuit 1
line_124	Line	PINPK 230.0 to PINPKSRP 230.0	Circuit 1
line_125	Line	PINPK 230.0 to PINPKSRP 230.0	Circuit 2
line_126	Line	TESTTRAK 230.0 to CASAGRND 230.0	Circuit 1
line_127	Line	HILLTOP 230.0 to MCCONICO 230.0	Circuit 1
line_128	Line	N.HAVASU 230.0 to PARKER 230.0	Circuit 1
line_129	Line	N.HAVASU 230.0 to TOPOCK 230.0	Circuit 1
line_130	Line	HOVRN7N8 230.0 to MEAD S 230.0	Circuit 1
line_131	Line	HOVRN5N6 230.0 to MEAD S 230.0	Circuit 1
line_132	Line	HOVRN3N4 230.0 to MEAD S 230.0	Circuit 1
line_133	Line	HOVRN1N2 230.0 to MEAD S 230.0	Circuit 1
line_134	Line	HOVRA1A2 230.0 to MEAD S 230.0	Circuit 1
line_135	Line	HARCUVAR 230.0 to HARCU AZ 230.0	Circuit 1
line_136	Line	HARCUVAR 230.0 to HASSYTAP 230.0	Circuit 1
line_137	Line	SPKHILTP 230.0 to COOLIDGE 230.0	Circuit 1
line_138	Line	GRIFFITH 230.0 to PEACOCK 230.0	Circuit 1
line_139	Line	PEACOCK 230.0 to HILLTOP 230.0	Circuit 1
line_140	Line	PEACOCK 345.0 to MEAD 345.0	Circuit 1
line_141	Line	TOPOCK 230.0 to BLK MESA 230.0	Circuit 1
line_142	Line	TOPOCK 230.0 to SOPOINT 230.0	Circuit 1
line_143	Line	TOPOCK 230.0 to SOPOINT 230.0	Circuit 2
line_144	Line	HASSYTAP 230.0 to HASSY AZ 230.0	Circuit 1
line_145	Line	HASSYTAP 230.0 to LIBERTY 230.0	Circuit 1
line_146	Line	RNDVLYTP 230.0 to ROUNDVLY 230.0	Circuit 1
line_147	Line	RNDVLYTP 230.0 to PEACOCK 230.0	Circuit 1
line_148	Line	ROGSWAPA 230.0 to PINPK 230.0	Circuit 1

line_149	Line	ROGSWAPA 230.0 to PINPK 230.0	Circuit 2
line_150	Line	ROGSWAPA 230.0 to SPKHILTP 230.0	Circuit 1
line_151	Line	FLAGSTAF 345.0 to GLENCANY 345.0	Circuit 1
line_152	Line	FLAGSTAF 345.0 to GLENCANY 345.0	Circuit 2
line_153	Line	FLAGSTAF 345.0 to PINPKBRB 345.0	Circuit 1
line_154	Line	FLAGSTAF 345.0 to PINPKBRB 345.0	Circuit 2
line_155	Line	GLEN PS 230.0 to NAVAJO 230.0	Circuit 1
line_156	Line	KAYENTA 230.0 to SHIPROCK 230.0	Circuit 1
line_157	Line	KAYENTA 230.0 to LNGHOUSE 230.0	Circuit 1
line_158	Line	SHIPROCK 345.0 to FOURCORN 345.0	Circuit 1
line_159	Line	NAVAJO 230.0 to LNGHOUSE 230.0	Circuit 1
line_160	Line	TS4 230.0 to PLMVLY 230.0	Circuit 1
line_161	Line	RUDD 230.0 to PLMVLY 230.0	Circuit 1
line_162	Line	LIBERTY 230.0 to TS4 230.0	Circuit 1
line_163	Line	BUTERFLD 230.0 to SLOAN 0.0	Circuit 1
line_164	Line	DOSCONDO 230.0 to HACKBERY 230.0	Circuit 1
line_165	Line	HACKBERY 230.0 to MORENCI 230.0	Circuit 1
line_166	Line	ORME 230.0 to RUDD 230.0	Circuit 2
line_167	Line	ABEL 500.0 to BROWNING 500.0	Circuit 1
line_168	Line	DAVIS 230.0 to ZORB 230.0	Circuit 1
line_169	Line	ZORB 230.0 to TOPOCK 230.0	Circuit 1
line_170	Line	FOURCORN 500.0 to FCW 500.0	Circuit 1
line_171	Line	MOENKOPI 500.0 to RME 500.0	Circuit 1
line_172	Line	NAVAJO 500.0 to RME 500.0	Circuit 1
line_173	Line	DRPP 500.0 to FCW 500.0	Circuit 1
line_174	Line	DRPP 500.0 to FCW 500.0	Circuit 2
line_175	Line	RME 500.0 to FCW 500.0	Circuit 1
line_176	Line	NAVAJO 500.0 to DUGAS 500.0	Circuit 1
line_177	Line	MORGAN 500.0 to WESTWING 500.0	Circuit 1
line_178	Line	MORGAN 500.0 to PNPKAPS 500.0	Circuit 1
line_179	Line	SGRLF 500.0 to CHOLLA 500.0	Circuit 1
line_180	Line	DUGAS 500.0 to MORGAN 500.0	Circuit 1
line_181	Line	AVERY 230.0 to RACEWAY 230.0	Circuit 1
line_182	Line	AVERY 230.0 to TS6 230.0	Circuit 1
line_183	Line	TS6 230.0 to PPAPS W 230.0	Circuit 1
line_184	Line	SNVLY 230.0 to TRLBY 230.0	Circuit 1
line_185	Line	SNVLY 230.0 to TRLBY 230.0	Circuit 2
line_186	Line	CORONADO 500.0 to SGRLF 500.0	Circuit 1
line_187	Line	PD-MORNC 230.0 to FRISCO 230.0	Circuit 1
line_188	Line	CHOLLA 230.0 to LEUPP 230.0	Circuit 1
line_189	Line	SNVLY 230.0 to HASSY AZ 230.0	Circuit 1
line_190	Line	MEAD S 230.0 to EQUEST 230.0	Circuit 1
line_191	Line	MEAD N 230.0 to EQUEST 230.0	Circuit 2
line_192	Line	MEAD N 230.0 to NEWPORT 230.0	Circuit 1
line_193	Line	MEAD N 230.0 to EASTSIDE 230.0	Circuit 1
line_194	Line	MOENKOPI 500.0 to MARKETPL 500.0	Circuit 1
line_195	Line	NAVAJO 500.0 to CRYSTAL 500.0	Circuit 1
line_196	Line	FOURCORN 345.0 to RIOPUERC 345.0	Circuit 1
line_197	Line	FOURCORN 345.0 to SAN_JUAN 345.0	Circuit 1
line_198	Line	FOURCORN 345.0 to WESTMESA 345.0	Circuit 1

line_199	Line	FOURCORN 230.0 to PILLAR 230.0	Circuit 1
line_200	Line	HENDRSON 230.0 to MEAD N 230.0	Circuit 1
line_201	Line	H ALLEN 500.0 to MEAD 500.0	Circuit 1
line_202	Line	BC TAP 230.0 to MEAD N 230.0	Circuit 1
line_203	Line	DAVIS 230.0 to MCCULLGH 230.0	Circuit 1
line_204	Line	MEAD N 230.0 to DECATUR 230.0	Circuit 1
line_205	Line	MEAD S 230.0 to PAHRUMP 230.0	Circuit 1
line_206	Line	MEAD S 230.0 to GREENWAY 230.0	Circuit 1
line_207	Line	MEAD S 230.0 to MCCULLGH 230.0	Circuit 1
line_208	Line	MEAD S 230.0 to MCCULLGH 230.0	Circuit 2
line_209	Line	MEAD 500.0 to MARKETPL 500.0	Circuit 1
line_210	Line	PINTO PS 345.0 to FOURCORN 345.0	Circuit 1
line_211	Line	SIGURDPS 230.0 to GLENCANY 230.0	Circuit 1
line_212	Line	SHIPROCK 345.0 to SAN_JUAN 345.0	Circuit 1
line_213	Line	HASSYAMP 500.0 to N.GILA 500.0	Circuit 1
line_214	Line	MOENKOPI 500.0 to ELDORDO 500.0	Circuit 1
line_215	Line	PALOVRDE 500.0 to DEVERS 500.0	Circuit 1
line_216	Line	MEAD S 230.0 to ELDORDO 230.0	Circuit 1
line_217	Line	MEAD S 230.0 to ELDORDO 230.0	Circuit 2
line_218	Line	PARKER 230.0 to GENE 230.0	Circuit 1
line_219	Line	CAMINO 230.0 to MEAD S 230.0	Circuit E
line_220	Line	CAMINO 230.0 to MEAD S 230.0	Circuit W
line_221	Line	MEAD N 230.0 to ARDEN 230.0	Circuit 1
line_222	Line	MEAD S 230.0 to DIAMOND 230.0	Circuit 1
line_223	Line	MEAD S 230.0 to DIAMOND 230.0	Circuit 2
line_224	Line	HARQUAHA 500.0 to DEVERS 500.0	Circuit 1
line_225	Line	MEAD N 230.0 to SINATRA 230.0	Circuit 1
line_226	Line	EQUEST N 500.0 to MEAD 500.0	Circuit 1
line_227	Line	SNVLY 500.0 to MORGAN 500.0	Circuit 1
line_228	Line	DELANY 500.0 to SNVLY 500.0	Circuit 1
line_229	Line	PRECHCYN 345.0 to MAZATZAL 345.0	Circuit 1
line_230	Line	MAZATZAL 345.0 to PNPKAPS 345.0	Circuit 1
line_231	Line	JOJOBA 230.0 to GILARIVR 230.0	Circuit 1
line_232	Line	JOJOBA 230.0 to TS4 230.0	Circuit 1
line_233	Line	TRLBY 230.0 to TS2 230.0	Circuit 1
line_234	Line	TS2 230.0 to PLMVLY 230.0	Circuit 1
line_235	Line	MORENCI 230.0 to PD-MORNC 230.0	Circuit 1
line_236	Line	PANTANO 230.0 to NEWTUCSN 230.0	Circuit 1
line_237	Line	NEWTUCSN 230.0 to SAHUARIT 230.0	Circuit 1
line_238	Line	BOWIE 500.0 to PINAL_C 500.0	Circuit 1
line_239	Line	BOWIE 500.0 to ARROYO 500.0	Circuit 1
line_240	Line	MOENKOPI 500.0 to YAVAPAI 500.0	Circuit 1
line_241	Line	YAVAPAI 500.0 to WESTWING 500.0	Circuit 1
line_242	Line	DELANY 500.0 to HARQUAHA 500.0	Circuit 1
line_243	Line	DEERVALY 230.0 to WESTWNGE 230.0	Circuit 1
line_244	Line	WESTWNGW 230.0 to WESTWNGE 230.0	Circuit 1
line_245	Line	RACEWAY 230.0 to WESTWNGE 230.0	Circuit 1
line_246	Line	WESTWNGE 230.0 to EL SOL 230.0	Circuit 1
line_247	Line	HASSYAMP 500.0 to DELANY 500.0	Circuit 1
line_248	Line	PERKINS 500.0 to PERKINPS 500.0	Circuit 1

line_249	Line	PAPAGOBT 230.0 to KYR-NEW 230.0	Circuit 1
line_250	Line	PINAL_C 500.0 to TORTOLIT 500.0	Circuit 1
line_251	Line	SAGUARO 500.0 to TORTOLIT 500.0	Circuit 1
line_252	Line	SAGUARO 500.0 to TORTOLIT 500.0	Circuit 2
line_253	Line	BICKNELL 345.0 to VAIL 345.0	Circuit 1
line_254	Line	GREEN-AE 345.0 to GREENLEE 345.0	Circuit 1
line_255	Line	GREENLEE 345.0 to COPPERVR 345.0	Circuit 1
line_256	Line	GREENLEE 345.0 to WILLOW 345.0	Circuit 1
line_257	Line	GREENLEE 345.0 to WINCHSTR 345.0	Circuit 1
line_258	Line	HIDALGO 345.0 to GREENLEE 345.0	Circuit 1
line_259	Line	MCKINLEY 345.0 to SPRINGR 345.0	Circuit 1
line_260	Line	MCKINLEY 345.0 to SPRINGR 345.0	Circuit 2
line_261	Line	PINALWES 345.0 to SOUTH 345.0	Circuit 1
line_262	Line	SAN_JUAN 345.0 to MCKINLEY 345.0	Circuit 1
line_263	Line	SAN_JUAN 345.0 to MCKINLEY 345.0	Circuit 2
line_264	Line	SOUTH 345.0 to GATEWAY 345.0	Circuit 1
line_265	Line	SOUTH 345.0 to GATEWAY 345.0	Circuit 2
line_266	Line	SPRINGR 345.0 to CORONADO 345.0	Circuit 1
line_267	Line	SPRINGR 345.0 to GREENLEE 345.0	Circuit 1
line_268	Line	SPRINGR 345.0 to LUNA 345.0	Circuit 1
line_269	Line	SPRINGR 345.0 to VAIL2 345.0	Circuit 1
line_270	Line	TORTOLIT 345.0 to NLOOP345 345.0	Circuit 1
line_271	Line	VAIL 345.0 to SOUTH 345.0	Circuit 1
line_272	Line	WESTWING 345.0 to PINALWES 345.0	Circuit 1
line_273	Line	WESTWING 345.0 to SOUTH 345.0	Circuit 1
line_274	Line	WHTHILLS 345.0 to MEAD 345.0	Circuit 1
line_275	Line	WHTHILLS 345.0 to PEACOCK 345.0	Circuit 1
line_276	Line	WILLOW 345.0 to BOWIE 345.0	Circuit 1
line_277	Line	WILLOW 345.0 to BOWIE 345.0	Circuit 2
line_278	Line	WINCHSTR 345.0 to VAIL 345.0	Circuit 1
line_279	Line	WINCHSTR 345.0 to WILLOW 345.0	Circuit 1
line_280	Line	FRANCONI 230.0 to GRIFFITH 230.0	Circuit 1
line_281	Line	FRANCONI 230.0 to N.HAVASU 230.0	Circuit 1
line_282	Line	MCCONICO 230.0 to MERC230 230.0	Circuit 1
line_283	Line	WHTHILLS 230.0 to MERC230 230.0	Circuit 1
line_284	Line	RACEWAY 230.0 to RACEWYWA 230.0	Circuit 1
line_285	Line	PRSCOTWA 230.0 to PRESCOTT 230.0	Circuit 1
line_286	Line	PRSCOTWA 230.0 to RNDVLYTP 230.0	Circuit 1
line_287	Line	GAVLINWA 230.0 to GAVILNPK 230.0	Circuit 1
line_288	Line	GAVLINWA 230.0 to PINPK 230.0	Circuit 1
line_289	Line	GAVLINWA 230.0 to PRSCOTWA 230.0	Circuit 1
line_290	Line	N.WADDEL 230.0 to RACEWYWA 230.0	Circuit 1
line_291	Line	HASSYAMP 500.0 to N.GILA 500.0	Circuit 2
line_292	Line	ANDERSON 230.0 to KYR-NEW 230.0	Circuit 1
line_293	Line	SILVERKG 230.0 to GOLDFELD 230.0	Circuit 1
line_294	Line	ABEL 230.0 to DINOSAUR 230.0	Circuit 1
line_295	Line	RACEWYWA 230.0 to WESTWNGE 230.0	Circuit 1
line_296	Line	CASGRAPS 230.0 to MILLIGAN 230.0	Circuit 1
line_297	Line	TS12 230.0 to SAGUARO 230.0	Circuit 1
line_298	Line	MILLIGAN 230.0 to TS12 230.0	Circuit 1

line_299	Line	VERDE S 230.0 to VERDE N 230.0	Circuit 1
line_300	Line	VERDE S 230.0 to COCONINO 230.0	Circuit 1
line_301	Line	GILA 230.0 to NGL-E 230.0	Circuit 1
line_302	Line	GILA 230.0 to NGL-W 230.0	Circuit 1
line_303	Line	SLRC 230.0 to GILA 230.0	Circuit 2
line_304	Line	SLRC 230.0 to GILA 230.0	Circuit 1
line_305	Line	GLENDALE 230.0 to GLENDALW 230.0	Circuit 1
line_306	Line	GLENDALW 230.0 to AGUAFRIA 230.0	Circuit 1
line_307	Line	BUCKEYE2 230.0 to LIBERTY 230.0	Circuit 1
line_308	Line	EAGLEYE 230.0 to BUCKEYE2 230.0	Circuit 1
line_309	Line	BUCKEYE 230.0 to BUCKEYE2 230.0	Circuit 1
line_310	Line	CORONADO 500.0 to CHOLLA 500.0	Circuit 1
line_311	Line	PERKINPS 500.0 to WESTWING 500.0	Circuit 1
line_312	Line	BUCK230 230.0 to J.HINDS 230.0	Circuit 1
line_313	Line	PALOVRDE 500.0 to DELANY 500.0	Circuit 1
line_314	Line	HASSYAMP 500.0 to HARQUAHA 500.0	Circuit 1
line_315	Line	SNTAROSA 230.0 to DBG 230.0	Circuit 1
line_316	Line	DBG 230.0 to CASGRAPS 230.0	Circuit 1
line_317	Line	KYRENE 500.0 to BROWNING 500.0	Circuit 1
line_318	Line	PERKINPS 500.0 to PERK PS1 500.0	Circuit 1
line_319	Line	BROWNING 500.0 to SILVERKG 500.0	Circuit 1
line_320	Line	PINAL_C 500.0 to ABEL 500.0	Circuit 1
line_321	Line	PINAL_C 500.0 to SNTAROSA 500.0	Circuit 1
line_322	Line	PINAL_W 500.0 to SNTAROSA 500.0	Circuit 1
line_323	Line	JOJOBA 500.0 to GILARIVR 500.0	Circuit 1
line_324	Line	JOJOBA 500.0 to GILARIVR 500.0	Circuit 2
line_325	Line	JOJOBA 500.0 to KYRENE 500.0	Circuit 1
line_326	Line	HASSYAMP 500.0 to JOJOBA 500.0	Circuit 1
line_327	Line	ORME 230.0 to ANDERSON 230.0	Circuit 1
line_328	Line	ORME 230.0 to ANDERSON 230.0	Circuit 2
line_329	Line	PINPKSRP 230.0 to BRANDOW 230.0	Circuit 1
line_330	Line	PINPKSRP 230.0 to BRANDOW 230.0	Circuit 2
line_331	Line	SANTAN 230.0 to RS-24 230.0	Circuit 1
line_332	Line	SCHRADER 230.0 to RS-24 230.0	Circuit 1
line_333	Line	ABEL 230.0 to RS-24 230.0	Circuit 1
line_334	Line	ABEL 230.0 to RS-24 230.0	Circuit 2
line_335	Line	ABEL 230.0 to SANTAN 230.0	Circuit 1
line_336	Line	BROWNING 230.0 to DINOSAUR 230.0	Circuit 1
line_337	Line	BROWNING 230.0 to RANDOLPH 230.0	Circuit 1
line_338	Line	ABEL 230.0 to RANDOLPH 230.0	Circuit 1
line_339	Line	PINAL_C 230.0 to DBG 230.0	Circuit 1
line_340	Line	PINAL_C 230.0 to RANDOLPH 230.0	Circuit 1
line_341	Line	SUN ARIZ 230.0 to PINAL_C 230.0	Circuit 1
line_342	Line	N.GILA 230.0 to TS8 230.0	Circuit 1
tran_343	Tran	CHOLLA 500.00 to CHOLLA 345.0	Circuit 1
tran_344	Tran	CHOLLA 500.00 to CHOLLA 345.0	Circuit 2
tran_345	Tran	FOURCORN 500.00 to FOURCORN 345.0	Circuit 1
tran_346	Tran	WESTWING 500.00 to WESTWNGW 230.0	Circuit 1
tran_347	Tran	WESTWING 500.00 to WESTWNGW 230.0	Circuit 2
tran_348	Tran	GILARIVR 500.00 to GILARIVR 230.0	Circuit 1

tran_349	Tran	FOURCORN 345.00 to FOURCORN 230.0	Circuit 1
tran_350	Tran	FOURCORN 345.00 to FOURCORN 230.0	Circuit 2
tran_351	Tran	PNPKAPS 345.00 to PPAPS C 230.0	Circuit 1
tran_352	Tran	PNPKAPS 345.00 to PPAPS N 230.0	Circuit 2
tran_353	Tran	PNPKAPS 345.00 to PPAPS E 230.0	Circuit 3
tran_354	Tran	KYRENE 500.00 to KYRENE 230.0	Circuit 7
tran_355	Tran	PERKINS 500.00 to PERK PS1 500.0	Circuit 1
tran_356	Tran	PERKINS 500.00 to PERK PS2 500.0	Circuit 1
tran_357	Tran	SILVERKG 500.00 to SILVERKG 230.0	Circuit 1
tran_358	Tran	BROWNING 500.00 to BROWNING 230.0	Circuit 1
tran_359	Tran	BROWNING 500.00 to BROWNING 230.0	Circuit 2
tran_360	Tran	RUDD 500.00 to RUDD 230.0	Circuit 1
tran_361	Tran	RUDD 500.00 to RUDD 230.0	Circuit 2
tran_362	Tran	RUDD 500.00 to RUDD 230.0	Circuit 3
tran_363	Tran	MESQUITE 500.00 to MESQUITE 230.0	Circuit 1
tran_364	Tran	COPPERVR 345.00 to COPPERVR 230.0	Circuit 1
tran_365	Tran	BICKNELL 345.00 to BICKNELL 230.0	Circuit 1
tran_366	Tran	GREEN-AE 345.00 to GREEN-AE 230.0	Circuit 1
tran_367	Tran	MEAD 345.00 to MEAD N 230.0	Circuit 1
tran_368	Tran	MEAD 500.00 to MEAD N 230.0	Circuit 1
tran_369	Tran	LIBERTY 345.00 to LIBTYPHS 230.0	Circuit 1
tran_370	Tran	LIBTYPHS 230.00 to LIBERTY 230.0	Circuit 1
tran_371	Tran	PEACOCK 345.00 to PEACOCK 230.0	Circuit 1
tran_372	Tran	GLEN PS 230.00 to GLENCANY 230.0	Circuit 1
tran_373	Tran	GLENCANY 345.00 to GLENCANY 230.0	Circuit 1
tran_374	Tran	GLENCANY 345.00 to GLENCANY 230.0	Circuit 2
tran_375	Tran	PINPKBRB 345.00 to PINPK 230.0	Circuit 1
tran_376	Tran	PINPKBRB 345.00 to PINPK 230.0	Circuit 2
tran_377	Tran	PINPKBRB 345.00 to PINPK 230.0	Circuit 3
tran_378	Tran	SHIPROCK 345.00 to SHIPROCK 230.0	Circuit 1
tran_379	Tran	RUDD 500.00 to RUDD 230.0	Circuit 4
tran_380	Tran	SNVLY 500.00 to SNVLY 230.0	Circuit 1
tran_381	Tran	SNVLY 500.00 to SNVLY 230.0	Circuit 2
tran_382	Tran	MORGAN 500.00 to RACEWAY 230.0	Circuit 1
tran_383	Tran	MORGAN 500.00 to RACEWAY 230.0	Circuit 2
tran_384	Tran	PNPKAPS 500.00 to PPAPS N 230.0	Circuit 1
tran_385	Tran	PNPKAPS 500.00 to PPAPS E 230.0	Circuit 1
tran_386	Tran	MEAD 500.00 to MEAD N 230.0	Circuit 2
tran_387	Tran	CHOLLA 345.00 to CHOLLA 230.0	Circuit 1
tran_388	Tran	CHOLLA 345.00 to CHOLLA 230.0	Circuit 2
tran_389	Tran	MEAD S 230.00 to MEAD 287.0	Circuit 1
tran_390	Tran	SHIP PS 230.00 to SHIPROCK 230.0	Circuit 1
tran_391	Tran	ARROYO 500.00 to ARROYO 345.0	Circuit 1
tran_392	Tran	ARROYO 500.00 to ARROYO 345.0	Circuit 2
tran_393	Tran	WESTWING 500.00 to WESTWNGE 230.0	Circuit 1
tran_394	Tran	YAVAPAI 500.00 to YAVAPAI 230.0	Circuit 1
tran_395	Tran	YAVAPAI 500.00 to YAVAPAI 230.0	Circuit 2
tran_396	Tran	CORONADO 500.00 to CORONADO 345.0	Circuit 1
tran_397	Tran	CORONADO 500.00 to CORONADO 345.0	Circuit 2
tran_398	Tran	PINAL_W 500.00 to PINALWES 345.0	Circuit 1

tran_399	Tran	TORTOLIT 500.00 to TORTOLIT 345.0	Circuit 1
tran_400	Tran	WESTWING 500.00 to WESTWING 345.0	Circuit 1
tran_401	Tran	WHTHILLS 345.00 to WHTHILLS 230.0	Circuit 1
tran_402	Tran	WINCHSTR 345.00 to WINCHSTR 230.0	Circuit 1
tran_403	Tran	BOWIE 500.00 to BOWIE 345.0	Circuit 1
tran_404	Tran	BOWIE 500.00 to BOWIE 345.0	Circuit 2
tran_405	Tran	GREEN-AE 345.00 to GREEN-AE 230.0	Circuit 2
tran_406	Tran	NGL-E 230.00 to N.GILA 500.0	Circuit 1
tran_407	Tran	NGL-W 230.00 to N.GILA 500.0	Circuit 1
tran_408	Tran	ABEL 500.00 to ABEL 230.0	Circuit 1
tran_409	Tran	COPPERVR 345.00 to COPPERVR 230.0	Circuit 2
tran_410	Tran	KYRENE 500.00 to KYR-NEW 230.0	Circuit 6
tran_411	Tran	KYRENE 500.00 to KYRENE 230.0	Circuit 8
tran_412	Tran	ABEL 500.00 to ABEL 230.0	Circuit 2
tran_413	Tran	PINAL_C 500.00 to PINAL_C 230.0	Circuit 1
tran_414	Tran	PINAL_C 500.00 to PINAL_C 230.0	Circuit 2
tran_415	Tran	SNTAROSA 500.00 to SNTAROSA 230.0	Circuit 1
tran_416	Tran	N.GILA 500.00 to N.GILA 230.0	Circuit 1
tran_417	Tran	PNPKAPS 500.00 to PPAPS W 230.0	Circuit 1
gen_418	Gen	CORONAD1 22.0	Unit 1
gen_419	Gen	CORONAD2 22.0	Unit 1
gen_420	Gen	NAVAJO 1 26.0	Unit 1
gen_421	Gen	NAVAJO 2 26.0	Unit 1
gen_422	Gen	NAVAJO 3 26.0	Unit 1
gen_423	Gen	SANTAN 1 13.8	Unit 1
gen_424	Gen	ARL-CT1 18.0	Unit 1
gen_425	Gen	ARL-CT2 18.0	Unit 1
gen_426	Gen	ARL-ST1 18.0	Unit 1
gen_427	Gen	HGC-CT1 16.0	Unit 1
gen_428	Gen	HGC-ST1 13.8	Unit 1
gen_429	Gen	HGC-CT2 16.0	Unit 1
gen_430	Gen	HGC-ST2 13.8	Unit 1
gen_431	Gen	HGC-CT3 16.0	Unit 1
gen_432	Gen	HGC-ST3 13.8	Unit 1
gen_433	Gen	MES-CT1 18.0	Unit 1
gen_434	Gen	MES-CT2 18.0	Unit 1
gen_435	Gen	MES-ST1 18.0	Unit 1
gen_436	Gen	MES-CT3 18.0	Unit 1
gen_437	Gen	MES-CT4 18.0	Unit 1
gen_438	Gen	MES-ST2 18.0	Unit 1
gen_439	Gen	CHOLLA 13.8	Unit 1
gen_440	Gen	CHOLLA2 22.0	Unit 1
gen_441	Gen	CHOLLA3 22.0	Unit 1
gen_442	Gen	CHOLLA4 22.0	Unit 1
gen_443	Gen	FCNGEN 1 20.0	Unit 1
gen_444	Gen	FCNGEN 2 20.0	Unit 1
gen_445	Gen	FCNGEN 3 20.0	Unit 1
gen_446	Gen	FCNGN4CC 22.0	Unit 4
gen_447	Gen	FCNGN5CC 22.0	Unit 5
gen_448	Gen	OCOTGT2 13.8	Unit 1

gen_449	Gen	PALOVRD1 24.0	Unit 1
gen_450	Gen	PALOVRD2 24.0	Unit 1
gen_451	Gen	PALOVRD3 24.0	Unit 1
gen_452	Gen	SAGUARO1 15.5	Unit 1
gen_453	Gen	SAGUARO2 15.5	Unit 1
gen_454	Gen	WPHX CC1 13.8	Unit 1
gen_455	Gen	WPHX CC2 13.8	Unit 1
gen_456	Gen	WPHX CC3 13.8	Unit 1
gen_457	Gen	WPCC5CT1 15.0	Unit 1
gen_458	Gen	WPCC5CT2 15.0	Unit 1
gen_459	Gen	WPCC5ST1 16.5	Unit 1
gen_460	Gen	WPCC4CT1 13.8	Unit 1
gen_461	Gen	RED-CT1 18.0	Unit 1
gen_462	Gen	RED-CT2 18.0	Unit 1
gen_463	Gen	GIL-CT1 18.0	Unit 1
gen_464	Gen	GIL-CT2 18.0	Unit 1
gen_465	Gen	GIL-ST1 18.0	Unit 1
gen_466	Gen	GIL-CT3 18.0	Unit 1
gen_467	Gen	GIL-CT4 18.0	Unit 1
gen_468	Gen	GIL-ST2 18.0	Unit 1
gen_469	Gen	GIL-CT5 18.0	Unit 1
gen_470	Gen	GIL-CT6 18.0	Unit 1
gen_471	Gen	GIL-ST3 18.0	Unit 1
gen_472	Gen	GIL-CT7 18.0	Unit 1
gen_473	Gen	GIL-CT8 18.0	Unit 1
gen_474	Gen	GIL-ST4 18.0	Unit 1
gen_475	Gen	APACHST2 20.0	Unit 1
gen_476	Gen	APACHST3 20.0	Unit 1
gen_477	Gen	RED-CT3 18.0	Unit 1
gen_478	Gen	RED-CT4 18.0	Unit 1
gen_479	Gen	RED-ST1 18.0	Unit 1
gen_480	Gen	RED-ST2 18.0	Unit 1
gen_481	Gen	SANTN 5S 18.0	Unit 1
gen_482	Gen	SANTN 5A 18.0	Unit 1
gen_483	Gen	SANTN 6A 18.0	Unit 1
gen_484	Gen	SANTN 6S 13.8	Unit 1
gen_485	Gen	HOOVERA3 16.5	Unit 1
gen_486	Gen	HOOVERA4 16.5	Unit 1
gen_487	Gen	HOOVERA5 16.5	Unit 1
gen_488	Gen	HOOVERA6 16.5	Unit 1
gen_489	Gen	HOOVERA7 16.5	Unit 1
gen_490	Gen	HOVRA1A2 16.5	Unit A1
gen_491	Gen	HOVRA1A2 16.5	Unit A2
gen_492	Gen	HOVRN1N2 16.5	Unit N1
gen_493	Gen	HOVRN1N2 16.5	Unit N2
gen_494	Gen	HOVRN3N4 16.5	Unit N3
gen_495	Gen	HOVRN3N4 16.5	Unit N4
gen_496	Gen	HOVRN5N6 16.5	Unit N5
gen_497	Gen	HOVRN5N6 16.5	Unit N6
gen_498	Gen	HOVRN7N8 16.5	Unit N7

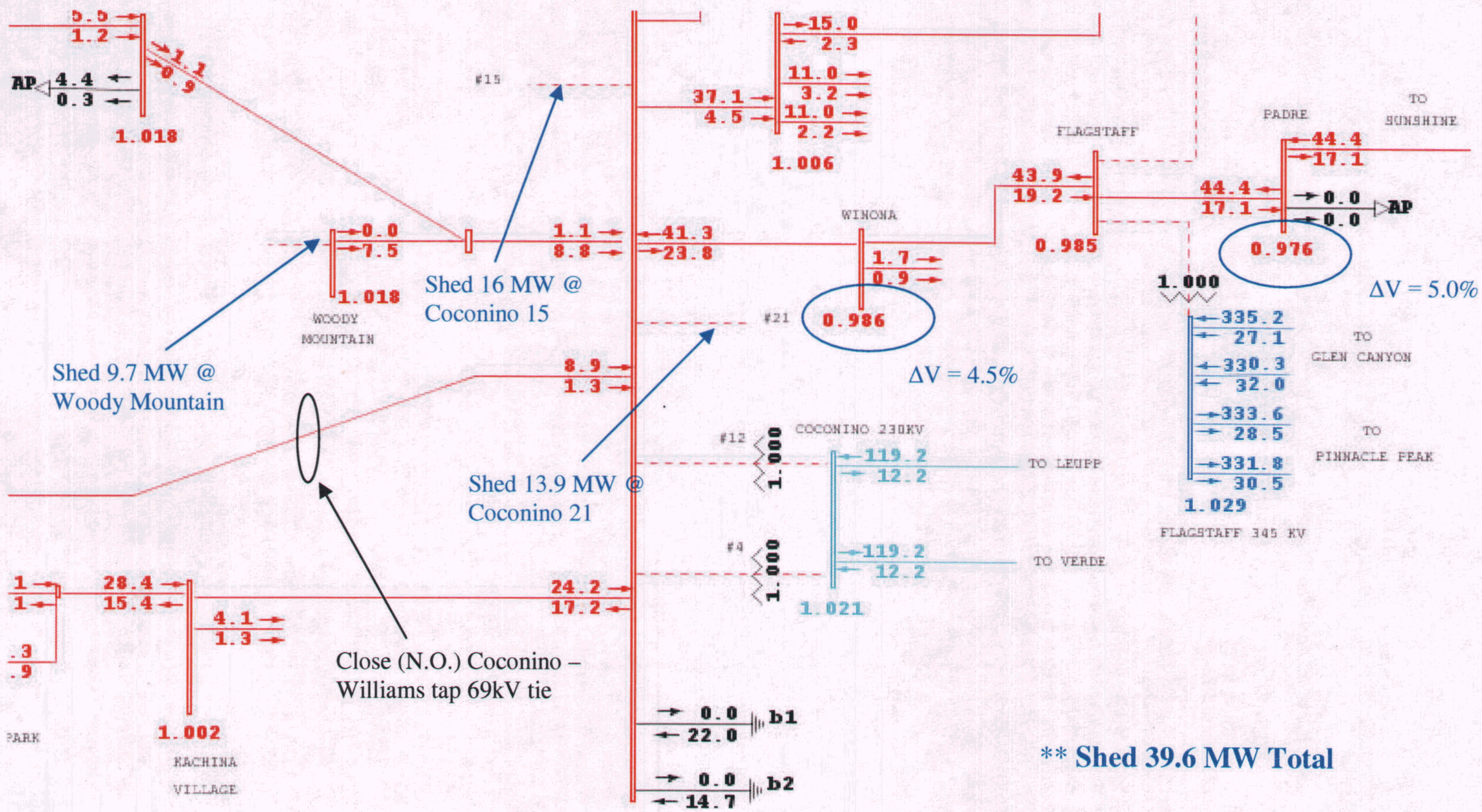
gen_499	Gen	HOVRN7N8 16.5	Unit N8
gen_500	Gen	GLENC1-2 13.8	Unit 1
gen_501	Gen	GLENC1-2 13.8	Unit 2
gen_502	Gen	GLENC3-4 13.8	Unit 3
gen_503	Gen	GLENC3-4 13.8	Unit 4
gen_504	Gen	GLENC5-6 13.8	Unit 5
gen_505	Gen	GLENC5-6 13.8	Unit 6
gen_506	Gen	GLENC7-8 13.8	Unit 7
gen_507	Gen	GLENC7-8 13.8	Unit 8
gen_508	Gen	SOPOINT1 16.0	Unit 1
gen_509	Gen	SOPOINT2 16.0	Unit 2
gen_510	Gen	SOPOINT3 16.0	Unit 3
gen_511	Gen	GRIFFTH1 18.0	Unit 1
gen_512	Gen	GRIFFTH2 18.0	Unit 2
gen_513	Gen	GRIFFTH3 18.0	Unit 3
gen_514	Gen	BLYENG1 16.0	Unit 1
gen_515	Gen	BLYENG2 16.0	Unit 1
gen_516	Gen	BLYENG3 16.0	Unit 1
gen_517	Gen	HAVASU12 13.2	Unit 1
gen_518	Gen	HAVASU12 13.2	Unit 2
gen_519	Gen	DBG-CT1 18.0	Unit 1
gen_520	Gen	DBG-CT2 18.0	Unit 1
gen_521	Gen	DBG-ST1 18.0	Unit 1
gen_522	Gen	DRPP G1 24.0	Unit 1
gen_523	Gen	DRPP G2 24.0	Unit 1
gen_524	Gen	BOWIE_G1 18.0	Unit 1
gen_525	Gen	BOWIE_G2 18.0	Unit 1
gen_526	Gen	BOWIE_G3 18.0	Unit 1
gen_527	Gen	BOWIE_G4 18.0	Unit 1
gen_528	Gen	BOWIE_S1 18.0	Unit 1
gen_529	Gen	BOWIE_S2 18.0	Unit 1
gen_530	Gen	DMPCCT#1 13.8	Unit 1
gen_531	Gen	SPR GEN1 19.0	Unit 1
gen_532	Gen	SPR GEN2 19.0	Unit 1
gen_533	Gen	SPR GEN3 21.0	Unit 1
gen_534	Gen	SPR GEN4 21.0	Unit 1
gen_535	Gen	SUNDTGE1 13.8	Unit 1
gen_536	Gen	SUNDTGE2 13.8	Unit 1
gen_537	Gen	SUNDTGE3 13.8	Unit 1
gen_538	Gen	SUNDTGE4 18.0	Unit 1
gen_539	Gen	OCOTGT1 13.8	Unit 1
gen_540	Gen	WPHX GT1 13.8	Unit 1
gen_541	Gen	WPHX ST4 12.5	Unit 1
gen_542	Gen	OCOTST2 13.8	Unit 1
gen_543	Gen	OCOTST1 13.8	Unit 1
gen_544	Gen	WPHX GT2 13.8	Unit 1
gen_545	Gen	WPHX ST6 12.5	Unit 1
gen_546	Gen	FAIRVW11 12.5	Unit 1
gen_547	Gen	CHILDS 2.3	Unit 1
gen_548	Gen	IRVING 2.3	Unit 1

gen_549	Gen	ABITIBI 13.8	Unit 1
gen_550	Gen	YUCCAGEN 13.8	Unit 1
gen_551	Gen	YUCCACT1 13.2	Unit 1
gen_552	Gen	YUCCACT2 13.2	Unit 1
gen_553	Gen	YUCCACT3 13.8	Unit 1
gen_554	Gen	YUCCACT4 13.8	Unit 1
gen_555	Gen	RVERSIDE 69.0	Unit 1
gen_556	Gen	YUCCACT5 13.8	Unit 1
gen_557	Gen	YUCCACT6 13.8	Unit 1
gen_558	Gen	SLRC-ST1 21.0	Unit 1
gen_559	Gen	SLRC-CT2 18.0	Unit 1
gen_560	Gen	SLRC-CT1 18.0	Unit 1
gen_561	Gen	SANTAN 2 13.8	Unit 1
gen_562	Gen	SANTN 5B 18.0	Unit 1
gen_563	Gen	SANTAN 4 13.8	Unit 1
gen_564	Gen	CROSSHYD 69.0	Unit 1
gen_565	Gen	AGUAFR 3 18.0	Unit 1
gen_566	Gen	AGUAFR 1 13.8	Unit 1
gen_567	Gen	AGUAFR 2 13.8	Unit 2
gen_568	Gen	ABEL G1 13.8	Unit 1
gen_569	Gen	ABEL G2 13.8	Unit 1
gen_570	Gen	ABEL G3 13.8	Unit 1
gen_571	Gen	ABEL G4 13.8	Unit 1
gen_572	Gen	ABEL G5 13.8	Unit 1
gen_573	Gen	ABEL G6 13.8	Unit 1
gen_574	Gen	ABEL G7 13.8	Unit 1
gen_575	Gen	ABEL G8 13.8	Unit 1
gen_576	Gen	ABEL G9 13.8	Unit 1
gen_577	Gen	KYREN 7S 13.8	Unit 1
gen_578	Gen	KYREN 7A 18.0	Unit 1
gen_579	Gen	SANTAN 3 13.8	Unit 1

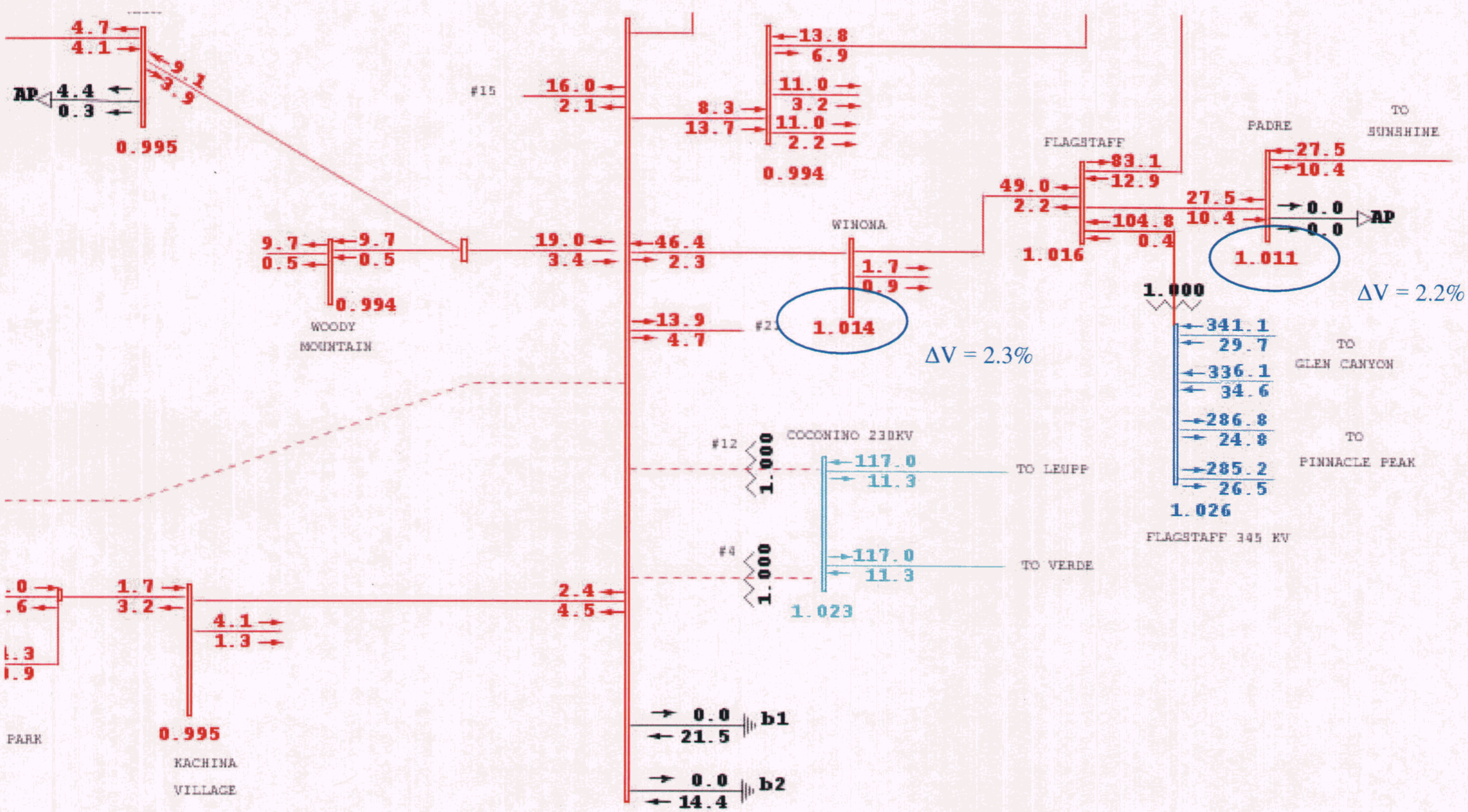
APPENDIX B

Power Flow Maps

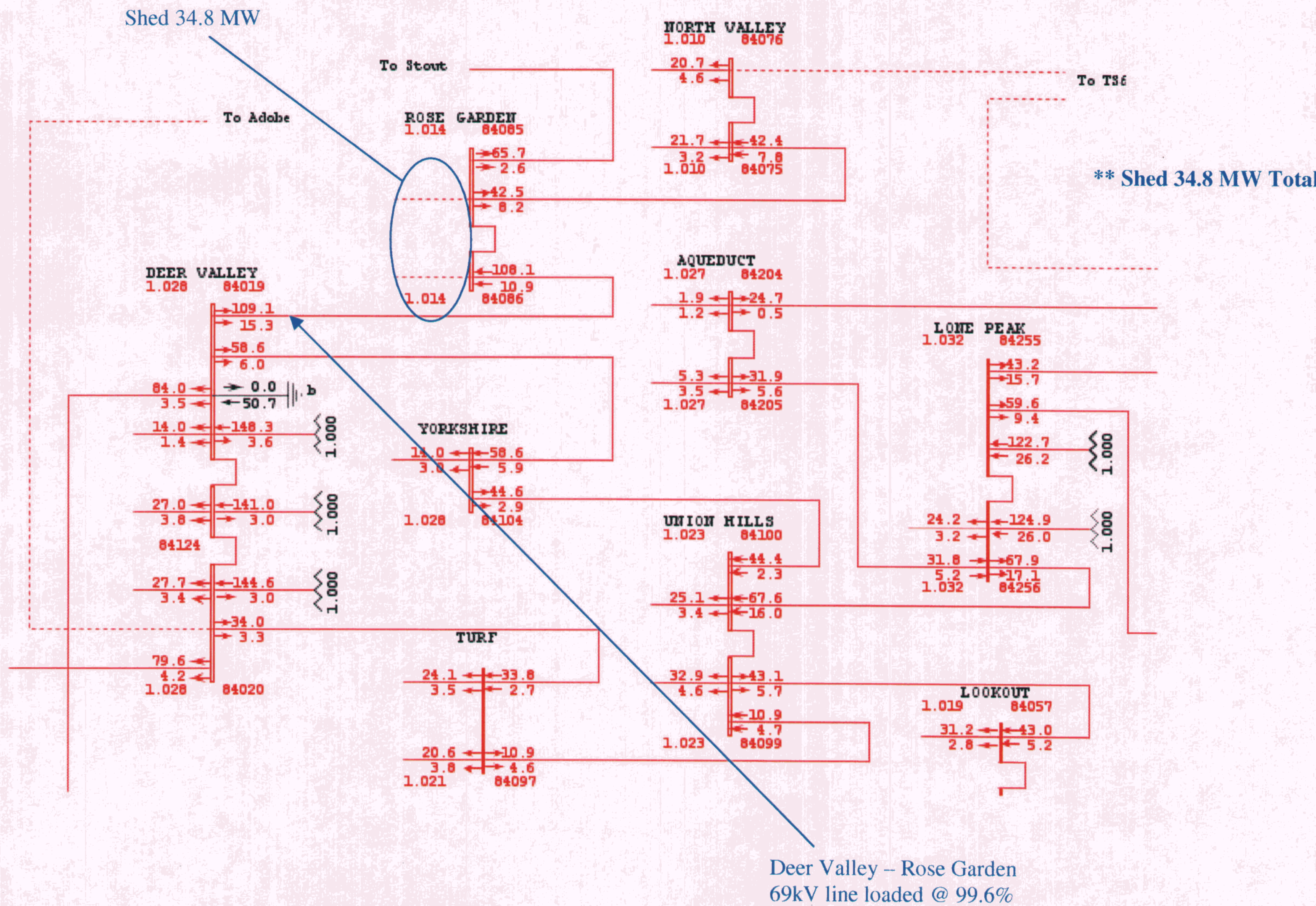
Coconino 230/69kV Substation Outage without Youngs Canyon (Flagstaff) 345/69kV Substation (2012)



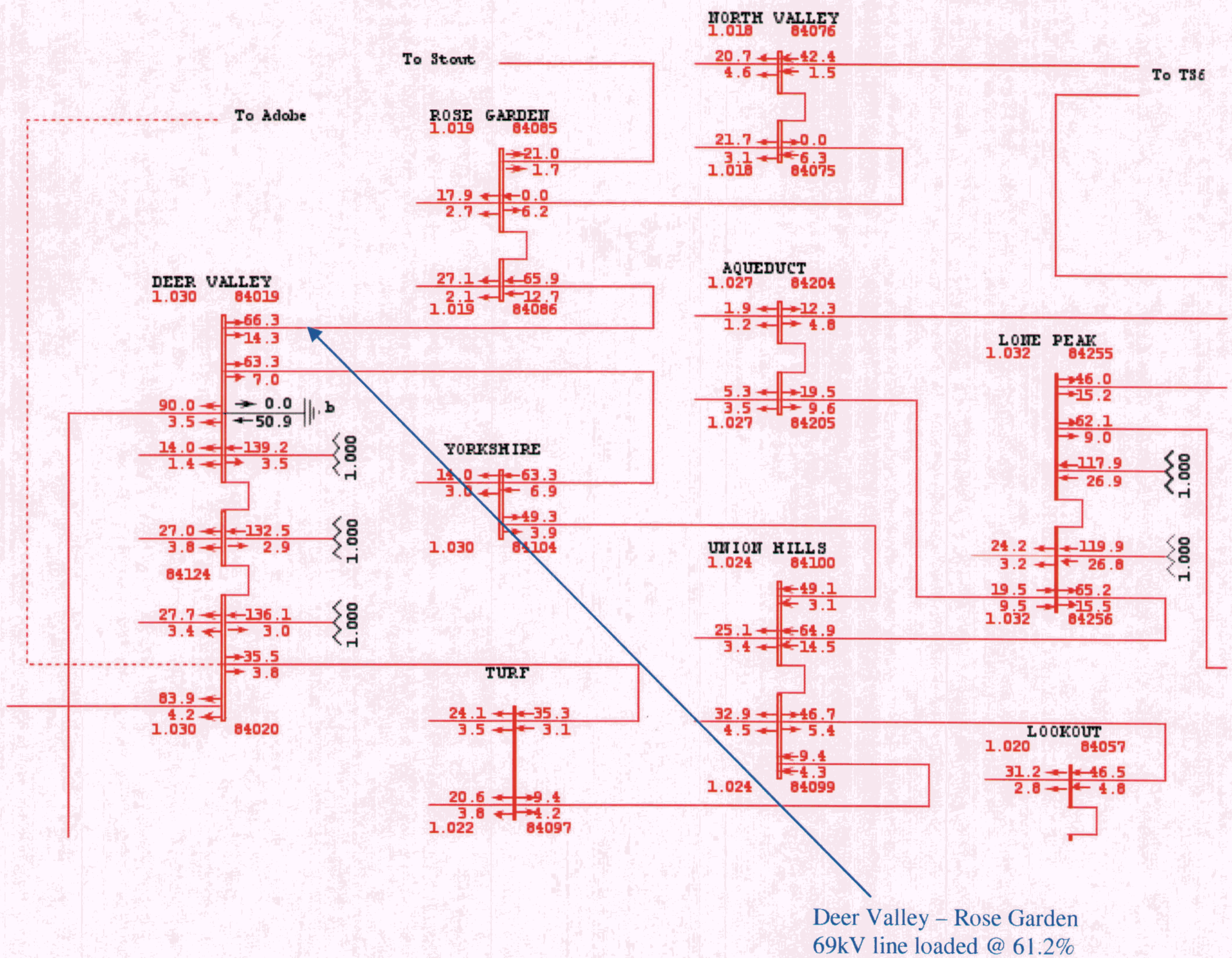
Coconino 230/69kV Substation Outage with Youngs Canyon (Flagstaff) 345/69kV Substation (2012)



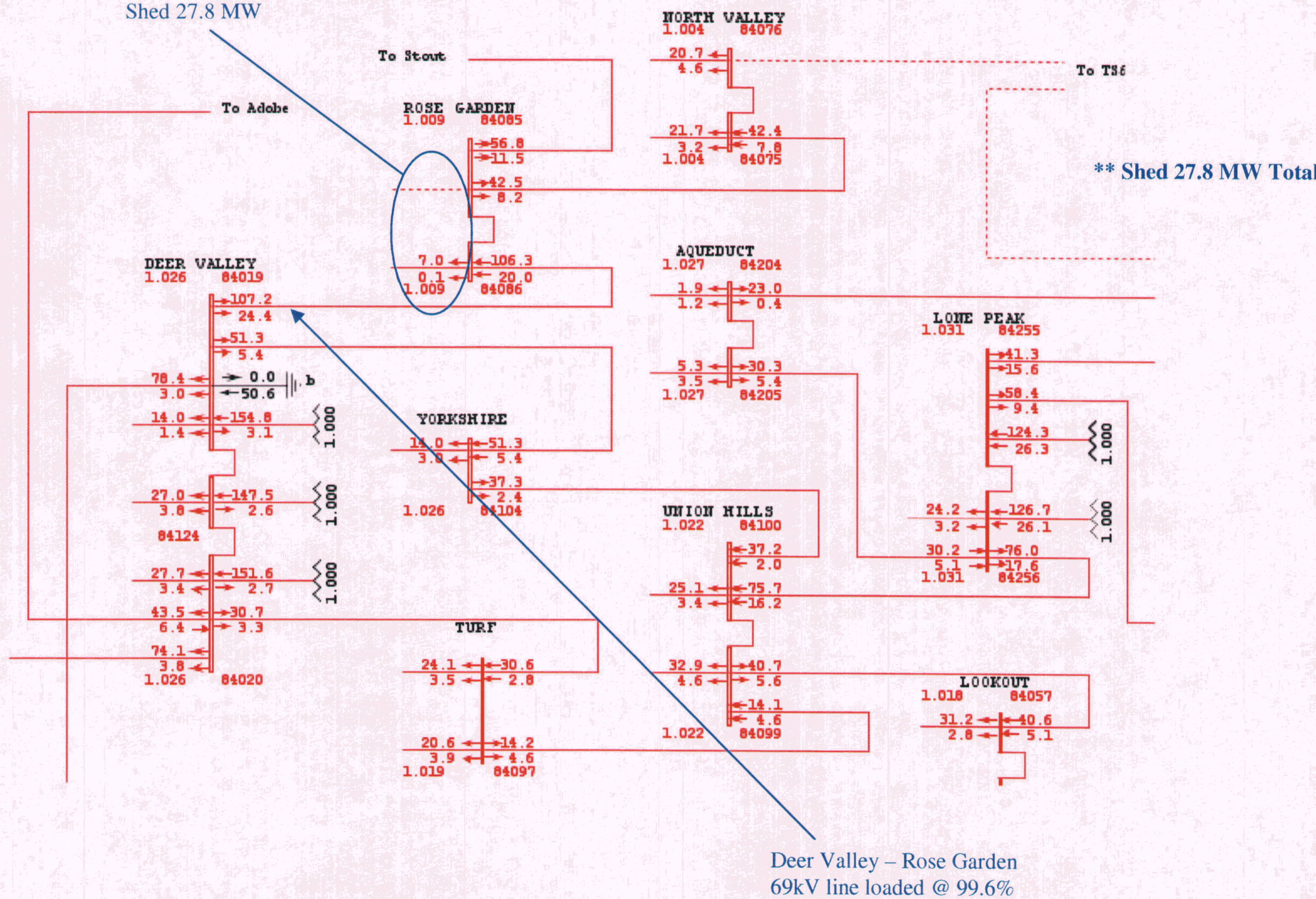
Adobe – Deer Valley 69kV Outage without TS6 230/69kV Substation (2012)



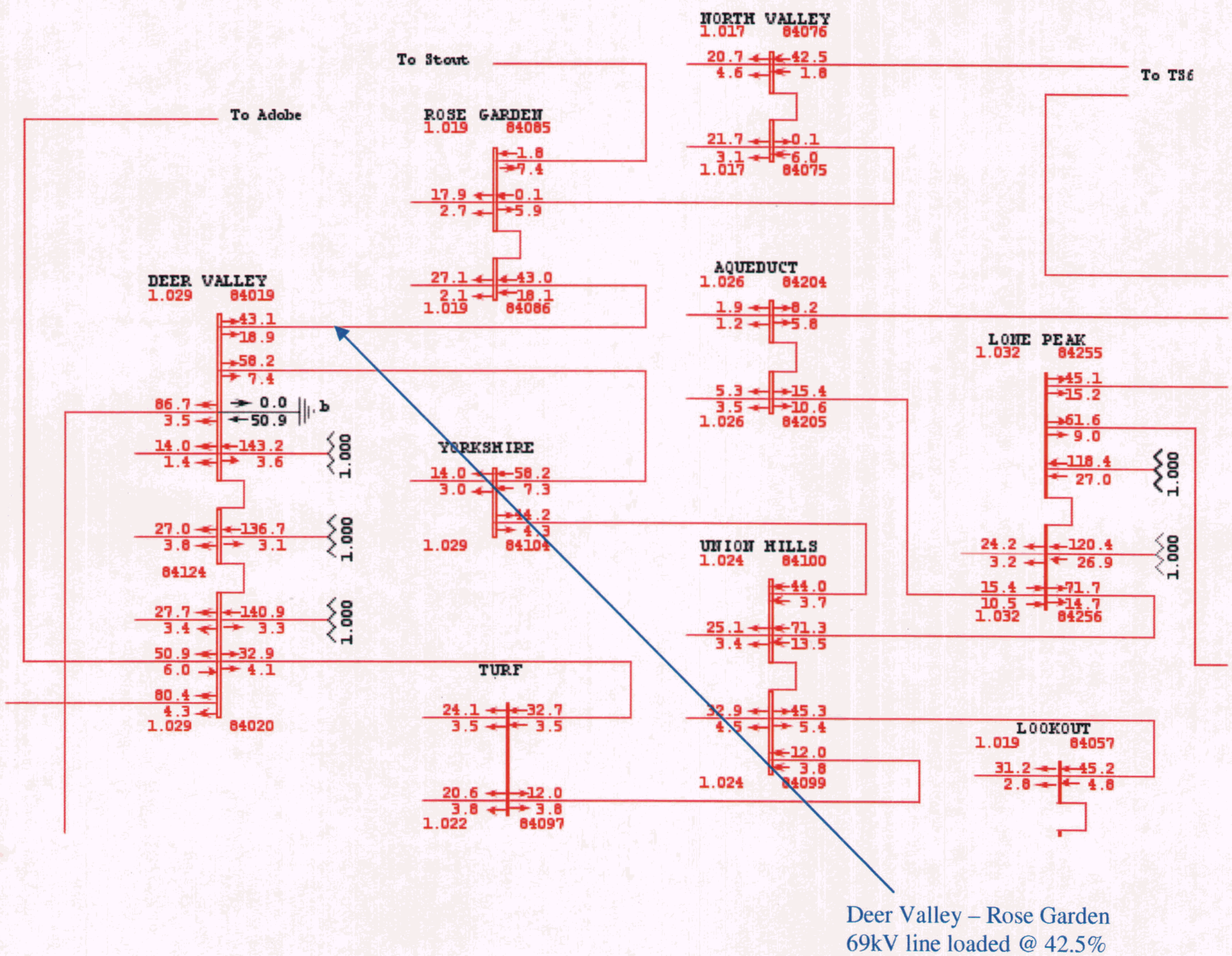
Adobe – Deer Valley 69kV Outage with TS6 230/69kV Substation (2012)



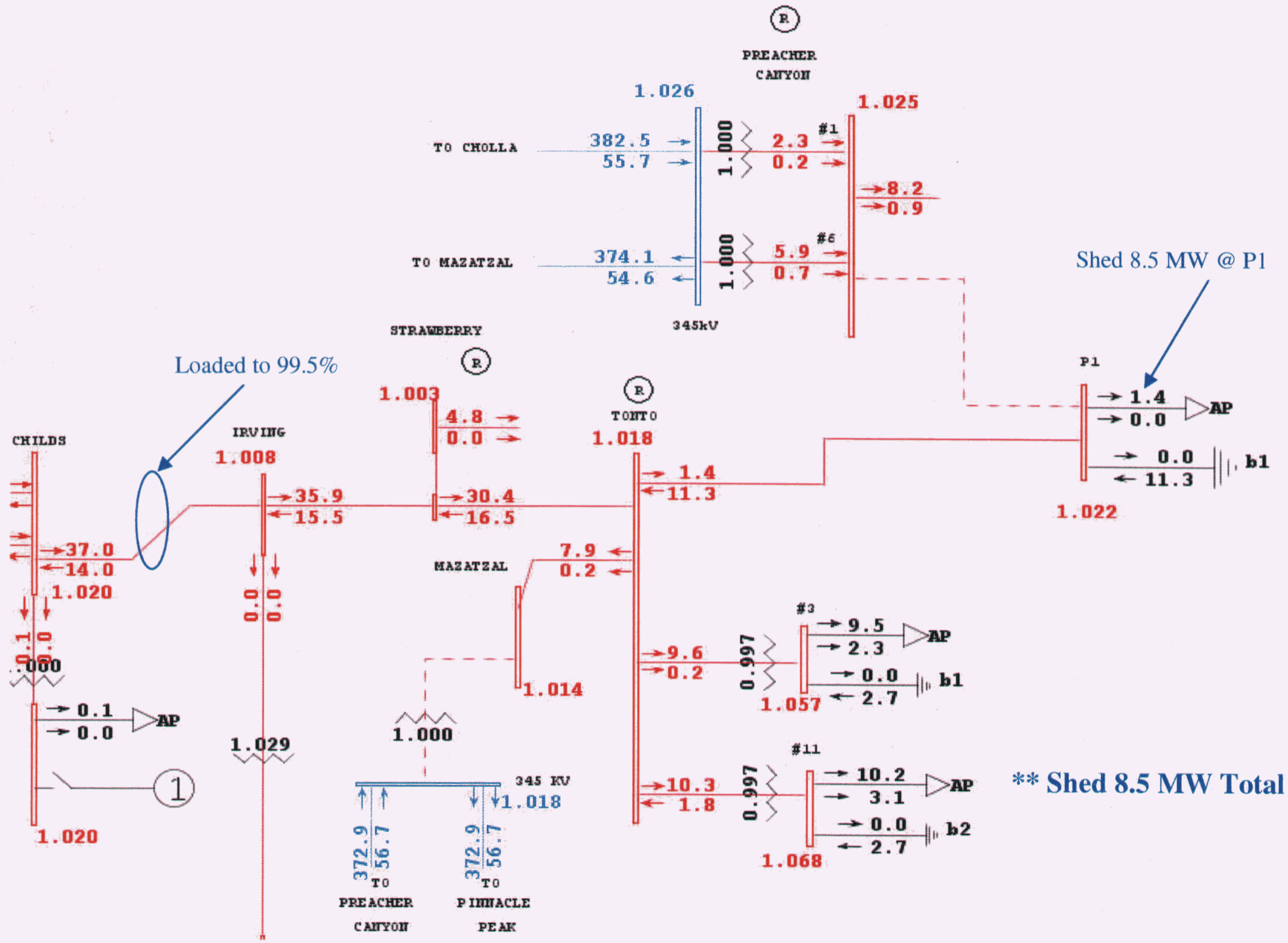
Adobe – Stout 69kV Outage without TS6 230/69kV Substation (2012)



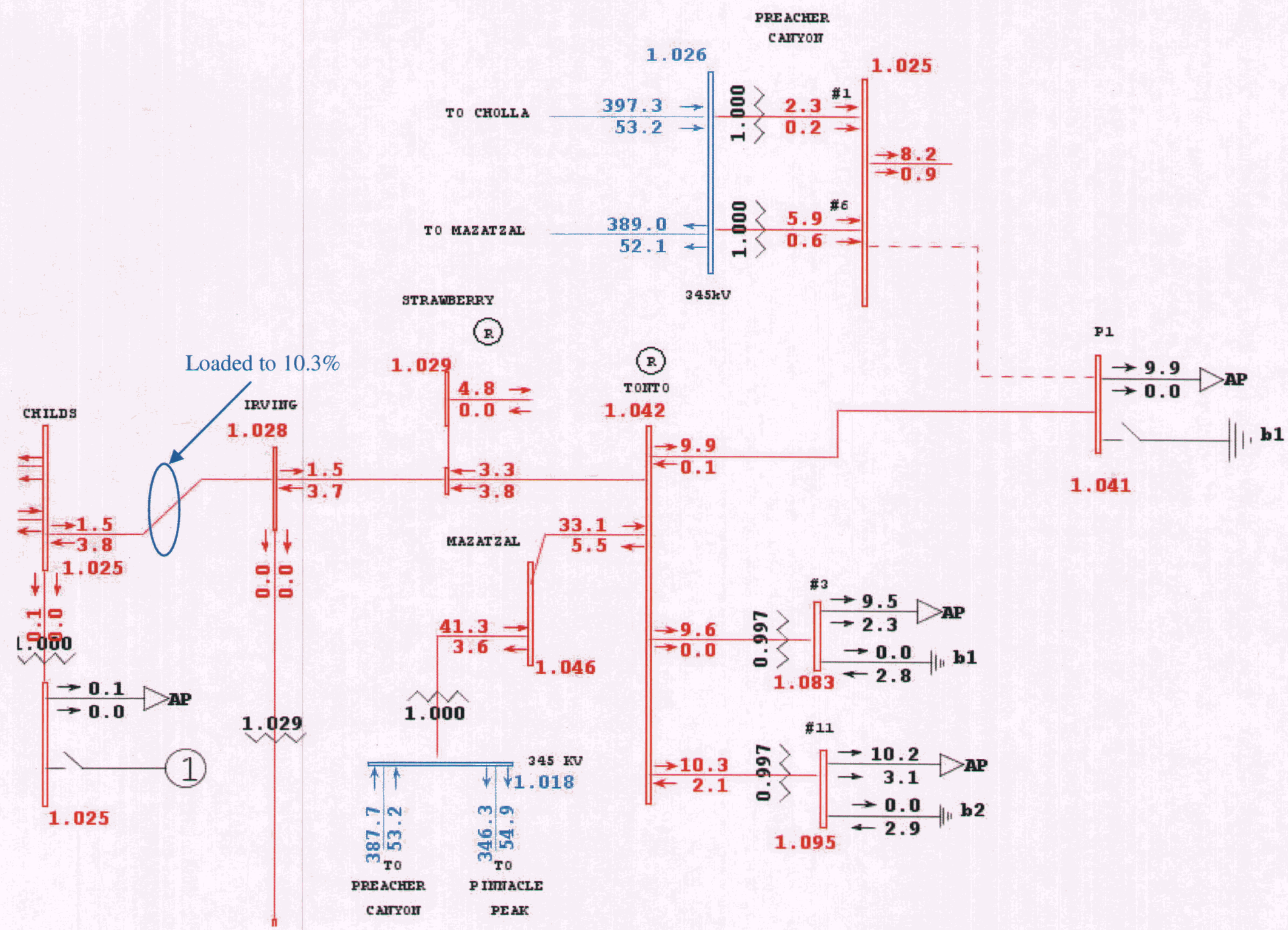
Adobe – Stout 69kV Outage with TS6 230/69kV Substation (2012)



Owens – Preacher Canyon 69kV outage without Mazatzal 345/69kV Substation (2013)



Owens – Preacher Canyon 69kV outage with Mazatzal 345/69kV Substation (2013)



APPENDIX C

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Stability Plots

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Plots provided upon request

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Generator Outages (Fault at Generator Terminals)

Plots provided upon request

Reliability Must-Run Analysis

2010-2019

January 30, 2010
APS Transmission Planning

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APS Reliability Must-Run Analysis 2010-2019

I. Executive Summary

This report documents the study methodology, results, and conclusions of Arizona Public Service Company's (APS) Reliability Must-Run (RMR) Analysis for the ten years from 2010 to 2019 (2010 RMR Analysis). This analysis was conducted in response to the Arizona Corporation Commission's (ACC) Second Biennial Transmission Assessment and Decision No. 65476 (December 19, 2002). The 2010 RMR Analysis covers a ten-year period and includes detailed analysis of the years 2013 and 2019.

If a city or load pocket must be served by local generating units at certain peak times, then those units are designated as "reliability must-run" or RMR units. There are two major areas where load cannot be served totally by power imported over transmission lines in the APS service territory – the Phoenix metropolitan area, which is served by a combination of APS and Salt River Project (SRP) facilities, and the APS service territory in the Yuma area.

Although ninety-nine percent of the Phoenix area energy requirements can be met by remote generation, local generation is critically important for the reliability of the local power system. The November 2003 U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada pointed out the importance of the reactive capability of voltage support from local generation. Local generation can provide critical support for transmission contingencies and other power system disturbances and can prevent customer outages including blackout conditions such as those experienced in the Northeast on August 14, 2003.

Comments during the workshop for the 2003 RMR analysis held in February 2003 indicated that electric power system industry participants desired to have a more participative role in the 2004 RMR analysis. To facilitate this participation, APS and the other Arizona transmission providers utilized the Central Arizona Transmission Study (CATS) forum to publicly develop the 2004 RMR study plan, after extensive discussion on study models and preliminary results. APS and the other Arizona transmission providers conducted a workshop on January 15, 2004 to present the study results for comment. This process led to the decision to study the Phoenix area as a combined APS and SRP network and a determination of the specific loads to include in the Phoenix area for the study years.

The ACC Third Biennial Transmission Assessment (BTA) determined that RMR studies must be performed on a biennial basis, with the next report being filed with the ten year plan in January 2006. The ACC Fourth BTA reaffirmed that RMR studies will continue to be performed on a biennial basis, with two representative years being studied and publicly available data being utilized. The Southwest Area Transmission (SWAT) planning group was utilized to facilitate the public discussions and input for this 2010 RMR Analysis. The years 2013 and 2019 were selected because the SWAT planning group was coordinating power flow base cases for these years.

As part of the ACC Fifth BTA, Per Decision No. 70635, under Section 5.2 Efficacy of Commission Ordered Studies, item 1c states:

> *The focus of the Yuma area RMR study is solely based on the import to the local APS 69kV system. There needs to be a system perspective of the RMR conditions for the entire Yuma County area in the future rather than limiting the RMR analysis solely to the APS 69kV system. This is particularly true given that the SIL and MLSC import limits to the APS system are restricted by the overloads on other transmission providers' systems. This is underscored by the fact that major system changes are being proposed for that area by other interconnected entities such as WAPA, WMIID, IID and parties seeking LGIA interconnections in the area.*

For the 2010 RMR study effort, APS formed an open forum under the guidance of the Colorado River Transmission (CRT) sub-regional study group and held several meetings to discuss the need to incorporate the plans of all entities in Yuma County. Within this open forum, WAPA, IID, WMIDD have all agreed that the cut plane for the Yuma RMR study is to remain as it was previously defined. Although APS performed the 2010 Yuma RMR study with a previously defined cut plane, the 2013 and 2019 base cases are modeled with existing and planned project facilities of all Yuma County area. APS also performed additional sensitivity studies to evaluate the impact of external generation and transmission projects to the Yuma Area. The sensitivity studies resulted in a minimal impact to the Yuma Area.

Unlike previous RMR studies, where the first year was used as a benchmark to compare the results to the RMR study preceding it, in this study, only a general comparison to the results in the previous RMR study can be made. This is due to the different years studied and in the assumption about which transmission projects would be in-service for the various years studied. However, the results of this study are similar to those from the previous RMR studies in that there is negligible impact of RMR in Phoenix. Also, in the previous RMR study, it was noted that the available Phoenix generation reserves, with the planned transmission projects, were projected to meet or exceed the required generation reserves through 2018. The 2010 RMR study also shows that, with the planned transmission projects, the available Phoenix generation reserves are projected to meet or exceed the required generation reserves through 2019.

The cost of using must-run units can be measured by the difference between generation costs with the transmission limit and costs without the limit. This report looks at and compares the cost of serving these two areas with and without the identified transmission constraints.

This report concludes that for the Phoenix metropolitan area, the cost of RMR is not significant and does not at present outweigh the cost of transmission improvements beyond those already included in the APS and SRP ten-year plans. For Yuma, the report shows that there is negligible RMR cost for 2013 and it would not be warranted to advance transmission improvements beyond those already included in the APS ten-year plan. Environmental effects for both areas with and without transmission constraints are also documented in this report. Because there is such a small RMR requirement for both areas in the two years studied, the environmental effects of RMR are minimal.

A. Study Overview

The existence of transmission import limited areas is not uncommon in the United States, and particularly in the West where load centers are generally separated by long distances. APS has transmission import-limited areas in Phoenix and Yuma. An import area is transmission limited when all load cannot be served solely by importing resources over local transmission lines, thus requiring some use of local generating units to reliably meet peak load.

The two transmission import-limited areas in APS' system were studied to determine:

- The system simultaneous import limit (SIL), which is the maximum amount of capacity that can be reliably imported into an area with no local generation;
- The maximum load serving capability (MLSC), which is the total load that can be served from imports and from local generation;
- The load serving capability and local generation reserves, at the peak forecasted load;
- Annual RMR conditions, including magnitude of load in excess of the import capability and number of hours the load exceeds the SIL; and
- Estimated economic and environmental impacts of the import limits.

The Phoenix area is a tight network of APS and SRP load, resources, and transmission facilities. Because the Phoenix system is highly integrated, the import limits must be determined for the combined area. This analysis was coordinated with SRP personnel, who had significant involvement in the study and were helpful in the overall analysis. The Western Area Power Administration (WAPA) also coordinated with APS and SRP in the study because their transmission facilities interface with the Phoenix network.

After the combined import limits for the Phoenix area were determined, RMR conditions were evaluated for the Phoenix area based on the Phoenix area import limits, the Phoenix area load, and Phoenix area local generation, which includes generation owned by APS and SRP.

The Yuma area, which has a forecast 2013 summer peak demand of approximately 446 MW, is served by an internal APS 69kV sub-transmission network containing the entire load in the import-limited area. There are external ties to WAPA and the Imperial Irrigation District (IID), as well as a bulk power interface at North Gila with 500kV ties east to the Palo Verde Hub and west to Imperial Valley in California. This analysis was coordinated with the WAPA Phoenix office to ensure accurate modeling.

B. Summary of Results

Results of the analysis for the two years of the study, 2013 and 2019, assumed that present plans for system improvements, in place when the study was conducted, are completed on schedule.

The following table summarizes the estimated RMR conditions and costs for the Phoenix area.

Table ES1
Phoenix Area RMR Conditions and Costs

Year	SIL[1] (MW)	Peak Demand (MW)	Import @ Peak (MW)	RMR[2] @ Peak (MW)	RMR[3] Hours	RMR Energy[4] (GWH)	RMR Energy (% of total)	RMR Cost[5] ($M)
2013	11,296	12,129	11,232	897	45	15	0.0	0
2019	11,693	14,621	12,459	2,162	497	317	0.5	0

Table Key:
[1]**SIL** – System Simultaneous Import Limit is the maximum amount of capacity that can be reliably imported into the area with no local generation operating.
[2]**RMR** @ Peak – The amount of local generation required to meet the area peak demand (Peak Demand minus Import Capability at peak load – See figures 3 and 4).
[3]**RMR Hours** – The number of hours that the area's demand exceeds the SIL, thus requiring the use of local generation to meet load, even if otherwise economically dispatched.
[4]**RMR Energy** – The annual energy required to be met by local generation (even if otherwise economically dispatched).
[5]**RMR Cost** – The difference in annual generation cost with and without the transmission limitation (this accounts for generation economically dispatched).

The following table summarizes the estimated RMR conditions and costs for the Yuma area.

Table ES2
Yuma Area RMR Conditions and Costs

Year	SIL[1] (MW)	Peak Demand (MW)	Import @ Peak (MW)	RMR[2] @ Peak (MW)	RMR[3] Hours	RMR Energy[4] (GWH)	RMR Energy (% of total)	RMR Cost[5] ($M)
2013	312	446	285	161	950	43	2.2	0
2019	473	562	477	85	171	4	0.2	0

Table Key:
[1]**SIL** – System Simultaneous Import Limit is the maximum amount of capacity that can be reliably imported into the area with no local generation operating.
[2]**RMR @ Peak** – The amount of local generation required to meet the area peak demand (Peak Demand minus Import Capability at peak load – See figures 7 and 8).
[3]**RMR Hours** – The number of hours that the area's demand exceeds the SIL, thus requiring the use of local generation to meet load, even if otherwise economically dispatched.
[4]**RMR Energy** – The annual energy required to be met by local generation (even if otherwise economically dispatched).
[5]**RMR Cost** – The difference in annual generation cost with and without the transmission limitation (this accounts for generation economically dispatched).

APS determined the reserve requirement for Phoenix based on Loss of Load Probability (LOLP) criteria of one day in ten years. Based on Phoenix area load, import capability and the availability of local generation, this criteria would result in not being able to meet Phoenix load one day in ten years. APS conducted the Metro Phoenix Reserve Margin Analysis in compliance with ACC Decision No. 70131 and Docket Nos. E-O1345A-05-08 16, E-O1345A-05-0826, E-O1345A-05-0827. The 1/10 criteria resulted in reserve requirements of 800 MW for the Phoenix area for the years studied.

The Simultaneous Import Limit (SIL) and Maximum Load Serving Capability (MLSC) are determined by performing power flow studies. The SIL and MLSC results are utilized to develop the Phoenix area Load Serving Capability (LSC) graphs, determining the amount of local Phoenix generation that is required to serve the projected peak demand, and determining the import capability at the projected peak demand. The Phoenix area projected reserves are calculated from the total local Phoenix generation less the amount of local generation required at peak demand. The following table shows the projected Phoenix area reserve capacity.

Table ES3
Phoenix Area Reserve Capacity

Year	Local Generation	Peak Demand (MW)	Import @ Peak (MW)	RMR @ Peak (MW)	Projected Reserves[1]	Required Reserves
2013	3,962	12,129	11,232	897	3,065	800
2019	3,962	14,621	12,459	2,162	1,800	800

Table Key:
[1]**Projected Reserves** – The amount of local generation minus the amount of RMR @ Peak.

APS determined the reserve requirement for Yuma based on Loss of Load Probability (LOLP) criteria of one day in ten years. Based on Yuma area load, import capability and the availability of local generation, this criteria would result in not being able to meet Yuma load one day in ten years. The 1/10 criteria translates to a reserve requirement of 97 MW during the time frame studied.

Similarly to the Phoenix area analysis, the Yuma area SIL and MLSC are determined and utilized to develop the Yuma area LSC graphs and calculating the projected reserves. The following table summarizes the Yuma area reserve capacity.

Table ES4
Yuma Area Reserve Capacity

Year	Local Generation	Peak Demand (MW)	Import @ Peak (MW)	RMR @ Peak (MW)	Projected Reserves[1]	Required Reserves
2013	313	446	285	161	152	97
2019	313	562	477	85	228	97

Table Key:
[1]**Projected Reserves** – The amount of local generation minus the amount of RMR @ Peak.

Local generating units are dispatched based on cost. Thus, most of the RMR hours shown above are dispatched in merit order. However, the presence of a transmission constraint may require local generation to be dispatched out of merit order or "out of the money." This report considered Phoenix area and Yuma area transmission limitations and generation resources in determining the overall RMR situation. The economic impact of RMR can be seen from the following tables.

Taking economic generation into account the Phoenix load area did not reach its transmission import limits. The following table shows, for the years of 2013 and 2019, Phoenix generation is not expected to run outside of economic dispatch.

Table ES5

Phoenix Area RMR Outside Economic Dispatch

Year	Hours outside economic dispatch	Energy outside economic dispatch (GWH)	RMR Cost ($M)
2013	0	0	0
2019	0	0	0

The following table summarizes the estimated total number of hours that APS local Yuma generation may run outside of economic dispatch, the amount of energy that is produced outside of economic dispatch and the associated cost in 2013. APS local Yuma generation is not expected to run outside of economic dispatch in 2019.

Table ES6
APS Yuma Area RMR Outside Economic Dispatch

Year	Hours outside economic dispatch	Energy outside economic dispatch (GWH)	RMR Cost ($M)
2013	22	1	0
2019	0	0	0

In addition to economic modeling, the emissions impact of RMR generation is also evaluated. The Phoenix load area did not have generation dispatched outside of economic dispatch, so there is no emissions impact to the Phoenix area. The following table summarizes the emissions impact of RMR generation for the Phoenix area.

Table ES7
Phoenix Area Air Emissions Impact of RMR

Pollutant	RMR Impact[1] (tons/year)	Phoenix Area Emissions RMR Impact (% of total emissions from all sources)
NO_x	0.00	0.00
CO	0.00	0.00
PM_{10}	0.00	0.00
VOC	0.00	0.00

[1]2013 and 2019 results

Similarly to the Phoenix area, the emissions impact in the Yuma area, due to RMR generation was determined. Removing the transmission constraints would reduce total Yuma area air emissions by a negligible amount in 2013. In 2019, since the Yuma area did not have generation dispatched outside of economic dispatch, there is no emissions impact. The following table summarizes the emissions impact of RMR generation for the Yuma area.

Table ES8
Yuma Area Air Emissions Impact of RMR

Pollutant	RMR Impact (tons/year)		Yuma Area Emissions RMR Impact (% of total emissions from all sources)	
	2013	2019	2013	2019
NO_x	0.13	0.00	N/A	N/A
CO	0.01	0.00	N/A	N/A
PM_{10}	0.04	0.00	0.00	0.00
VOC	0.01	0.00	N/A	N/A

C. Report Conclusions

Phoenix area Conclusions

1. Phoenix area existing and planned transmission and local generation are adequate to reliably serve Phoenix area peak load in 2013 and 2019. In addition, the projected local generation reserve margin exceeds the required reserve margin in both years.

2. During the summer, Phoenix area load is expected to exceed the available transmission import capability for approximately 45 hours in 2013 and 497 hours in 2019. These hours represent less than one percent of the annual energy requirements for the Phoenix area.

3. From a total Phoenix load, transmission, and resources viewpoint, local generation is not expected to be dispatched out of economic dispatch order in 2013 or 2019.

4. Because there is not expected to be an out of merit order cost of Phoenix area RMR generation, advancement of transmission projects to increase import capability are presently not cost justified.

5. The Phoenix load area did not reach its transmission import limits in 2013 and 2019, so there is no emission impact to the Phoenix area.

6. Since the Phoenix load area did not reach its transmission import limits in 2013 and 2019, there is no impact to local generation capacity factor and total yearly natural gas consumption by the Phoenix area generators.

Yuma Area Conclusions

7. Yuma area existing and planned transmission and local generation are adequate to reliably serve Yuma area peak load in 2013 and 2019. In addition, the projected local generation reserve margin exceeds the required reserve margin in both years.

8. The Yuma area load is expected to exceed the available transmission import capability for 950 hours in 2013 and 171 hours in 2019. These hours represent approximately 2% of the annual energy requirements for Yuma in 2013 and less than 1% in 2019.

9. From a total Yuma load, transmission, and resources viewpoint, the import constraint in 2013 could cause APS Yuma generation to be dispatched out of economic dispatch order for 22 hours. In 2019, the local generation is not expected to be dispatched out of economic dispatch order.

10. The estimated annual economic cost of Yuma area generation required to run out of economic dispatch order is negligible for 2013. There is not expected to be an out of

merit order cost of Yuma area RMR generation in 2019. Therefore, advancement of transmission projects to increase import capability is presently not cost justified.

11. Removing the transmission constraint would reduce total Yuma area air emissions by a negligible amount in 2013. The Yuma area did not reach its transmission import limits in 2019, so there is no emission impact.

12. Removing the import restriction into the Yuma area would have a negligible affect on the APS Yuma generation capacity factor in 2013. Since the Yuma area did not reach its transmission import limits in 2019, there is no impact to local generation capacity factor.

13. Removing the transmission constraint could reduce total yearly natural gas consumption by the Yuma area generators by 0.012 BCF and total system natural gas consumption by 0.006 BCF in 2013. Since the Yuma area did not reach its transmission import limits in 2019, there is no impact to total yearly natural gas consumption by the APS Yuma generators.

D. Report Organization

This report is organized in seven sections. Section I provides an executive summary of the report. Section II provides general background information of the study requirements, an overview of RMR, and describes the study methodology. Section III describes the Phoenix area, the nature of the import limit, the resulting import limits for 2013 and 2019, and the impact of various generators in and around the Phoenix area on the import limit. Section IV provides a similar discussion of the Yuma area. Section V describes the RMR conditions such as number of hours, maximum capacity, and annual energy for the Phoenix and Yuma areas. Section VI provides results of the economic analysis of the Phoenix and Yuma area RMR conditions performed utilizing a planning model (PROMOD) and emissions impact. Finally, Section VII lists the conclusions of the analysis.

II. Introduction

A. Background of Study Requirement

Like all large electric utilities, Arizona utilities have historically relied on both transmission, to deliver remote generation into its load centers, as well as local generation to reliably serve its customers. Due in part to environmental, economic, and fuel availability considerations, large base-load thermal generators have typically been located away from the load centers while smaller but less efficient intermediate and peaking units, with lower capacity factors, were located within the load centers. Although this local generation is relied on for a relatively small amount of energy, this local generation is critically important for the reliability of the local power system. The November 2003 U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada pointed out the importance of the reactive capability of voltage support from local generation. Local generation can provide critical support for transmission contingencies and other power system disturbances and can prevent customer outages including blackout conditions such as those experienced in the Northeast on August 14, 2003. Local generation also results in lower power system losses and lower capital expenses for transmission infrastructure.

In the past, vertically-integrated utilities, such as APS, managed the siting and construction of both generation and transmission resources needed to serve their customers. Electric systems were designed based on a detailed integrated resource planning process used to evaluate the appropriate balance of generation, transmission, and demand-side resources. Interconnections with neighboring systems were primarily intended to improve system reliability and lower the costs of reserves by allowing for sharing of capacity reserves by multiple systems. Each utility's system was primarily designed to accommodate that utility's resources and that utility's load.

The Commission's Second Biennial Transmission Assessment (BTA) required "any [Utility Distribution Company] 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, [to] perform and report the findings of an RMR study as a feature of their ten year plan filing with the Commission in January 2003 and 2004." The Assessment required that the RMR study filed in January 2003 evaluate RMR conditions through the 2005 summer peak. The January 2004 RMR study covers the 10-year period from 2004 to 2013. The Commission's Third BTA determined that RMR studies must be performed on a biennial basis, with the next report being filed with the ten year plan filed in January 2006. The Commission's Fourth BTA reaffirmed that RMR studies will continue to be performed on a biennial basis, with two representative years being studied and publicly available data being utilized.

B. Overview of RMR

Local "load pockets" are areas that do not have enough transmission import capability to serve all load in the area solely by importing remote generation over local transmission facilities. For these areas, during peak hours of the year, local generation is required to serve that portion of the load that cannot reliably be served by transmission imports. This local generation requirement is often referred to as Reliability Must-Run or RMR generation. In these areas, during peak conditions, load is served by a combination of importing remote generation over transmission lines and operating local generation.

The maximum load that can be served in a load pocket with all of the local generation operating – in other words, the maximum load that can be served by importing remote generation and local generation – is referred to as the system Maximum Load Serving Capability (MLSC). The MLSC is established through technical studies by ensuring that:

- With the local load at the MLSC and all local generation operating there are no transmission system normal operating (N-0) limit violations of thermal loading or voltages, and
- Under all single contingency outage events (N-1) there are no emergency operating limit violations of thermal loading or voltages, and no system instability.

The maximum load that can be served in a load pocket with no local generation operating — in other words, the maximum load that can be served solely by importing remote generation — is referred to as the system Simultaneous Import Limit (SIL). The SIL is established through technical studies by ensuring that:

- With the local load at the SIL and no local generation operating there are no transmission system normal operating (N-0) limit violations of thermal loading or voltages, and
- Under all single contingency outage events (N-1) there are no emergency operating limit violations of thermal loading or voltages, and no system instability.

C. Study Methodology

Import limit analysis was performed for the Phoenix and Yuma areas. The import limit area or load pocket is defined as that load which, when increased, would increase the severity of the limiting contingency. For example, load in Flagstaff has no impact on the severity of the limiting contingency for the Phoenix import limited area, and therefore Flagstaff is not included in the Phoenix load pocket. In contrast, downtown Phoenix load does impact the severity of the limiting contingency and therefore is included in the load pocket. All area contingencies known to result in system stress were evaluated to determine the critical contingency for the area. Import limits were determined by contingency conditions of thermal loading at the emergency rating of a facility, steady state voltages at the emergency voltage limit, and system instability including voltage instability.

Import limits were determined for the Phoenix and Yuma areas with no local generation operating, with maximum local generation operating, and sufficient points in between to determine curves which define import limits at all load levels. This methodology was applied to studies of the Phoenix area, which for 2013 is constrained by voltage instability and in 2019 is constrained by thermal loadings. For the Yuma studies, the limitations are primarily thermal constraints.

From each year's forecasted peak load and historical daily load cycles, the annual RMR conditions were determined, including magnitude of local load that is expected to exceed the SIL and the annual hours for which local load is expected to exceed the SIL.

Detailed hourly analysis of each area was performed to determine the impact of the transmission constraints on local generation capacity factor, power plant emissions, fuel consumption, and out of the money cost to serve load. This was accomplished through the use of Ventyx PROMOD IV, an industry standard production cost simulation model.

Additional transmission alternatives to mitigate the import limits of the Yuma area in 2013 were not studied due to the minimal amounts of RMR conditions that were identified in the study. The cost for any transmission alternative would significantly exceed the costs associated with any RMR conditions.

D. Determination of SIL and RMR Conditions

In this analysis, assessments of the SIL and RMR conditions for the Phoenix area and the Yuma area were performed for the years 2013 and 2019. The years 2013 and 2019 were selected because the SWAT planning group was coordinating power flow base cases for these years. To consider potential economic effects resulting from using local generation or arising from RMR conditions, an economic analysis was performed using the Ventyx PROMOD model. Much of the data used in the production cost model comes from publicly available WECC Transmission Expansion Planning Policy Committee (TEPPC) 2019 Base Case power plant data (dated October 21, 2009). Base case and contingency power flow, stability, and voltage stability analyses were performed to determine import limitations. The initial starting cases were based on WECC heavy summer full loop base cases in GE Power Flow format for the corresponding year. Those base cases model the entire Western Interconnection's transmission system and were reviewed and then updated to represent expected loads and system configuration for 2013 and 2019. Both cases were coordinated between APS, SRP, Tucson Electric Power Company (TEP), Southwest Transmission Cooperative (SWTC), and WAPA to capture the most accurate expected operating conditions for the Arizona transmission system.

III. Phoenix Load Pocket

A. Description of Phoenix Area

During summer 2013, the Phoenix area — which consists of both APS' and SRP's integrated network — will be served from the following major Extra High Voltage (EHV) substations: Westwing, Pinnacle Peak, Kyrene, Rudd, Browning, Silverking, Abel and Morgan. These EHV stations form the "cornerstones" of an extensive internal network of 230kV transmission lines that constitute the high voltage energy delivery system within the Phoenix load area. Between the summers of 2013 and 2019, the Sun Valley EHV substation is currently planned to begin serving the Phoenix.

Because the City of Mesa load is served by dedicated resources external to Phoenix, the RMR analysis is performed with this load excluded.

Energy flows into the EHV delivery points from the EHV transmission lines and then is stepped down to 230kV and transmitted into the load center via the 230kV transmission lines. These loads, with area losses, are measured by determining the flows from the EHV substations into the load area to include all of these load stations. The specific loads to be included in the Phoenix area load for each of the years was determined by sensitivity analysis performed in a previous RMR study effort which determined the impact of various loads on the severity of the critical contingencies. Figure 1 shows all of the loads included for the 2013 study. Figure 2 shows all of the loads included for the 2019 study.

Figure 1

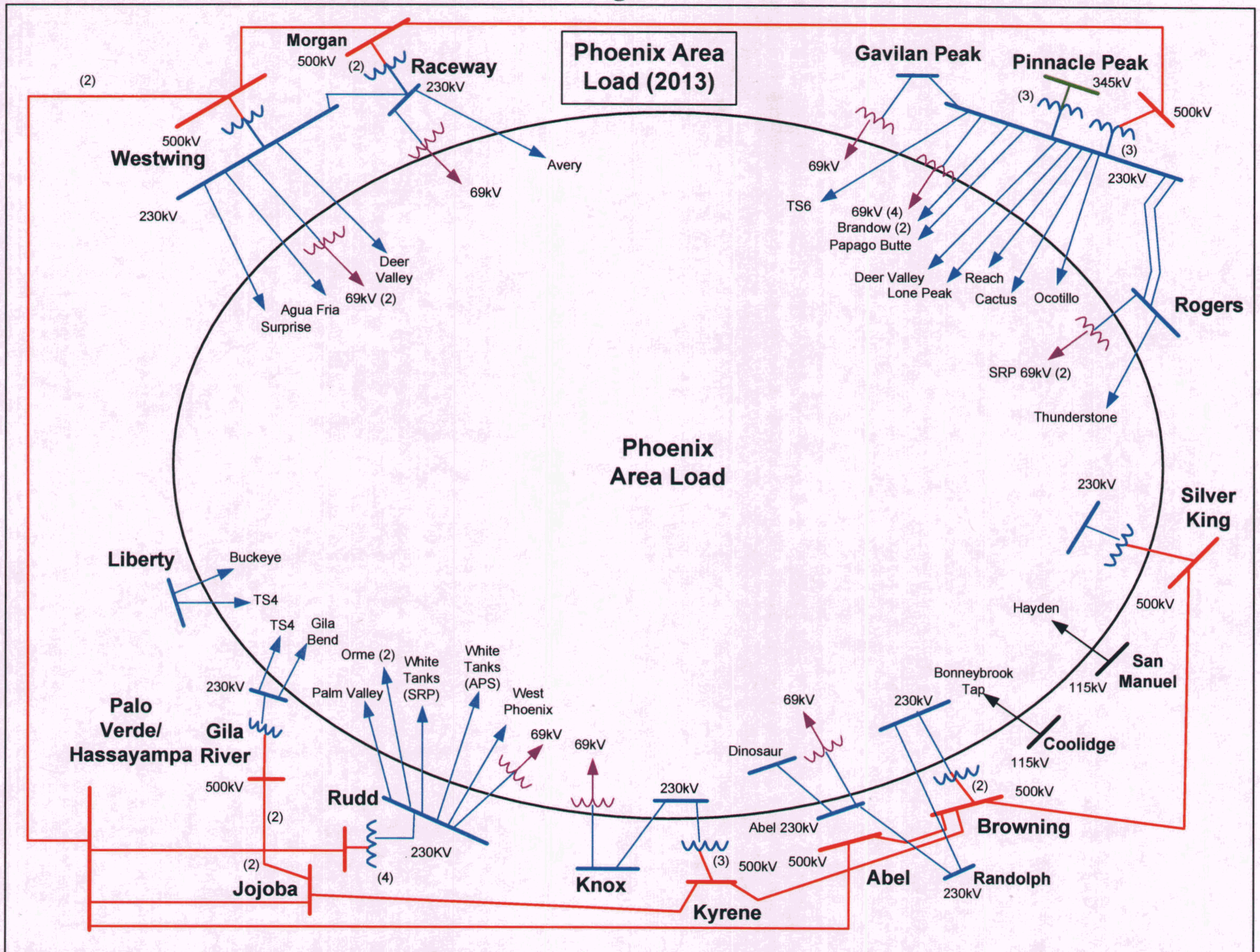
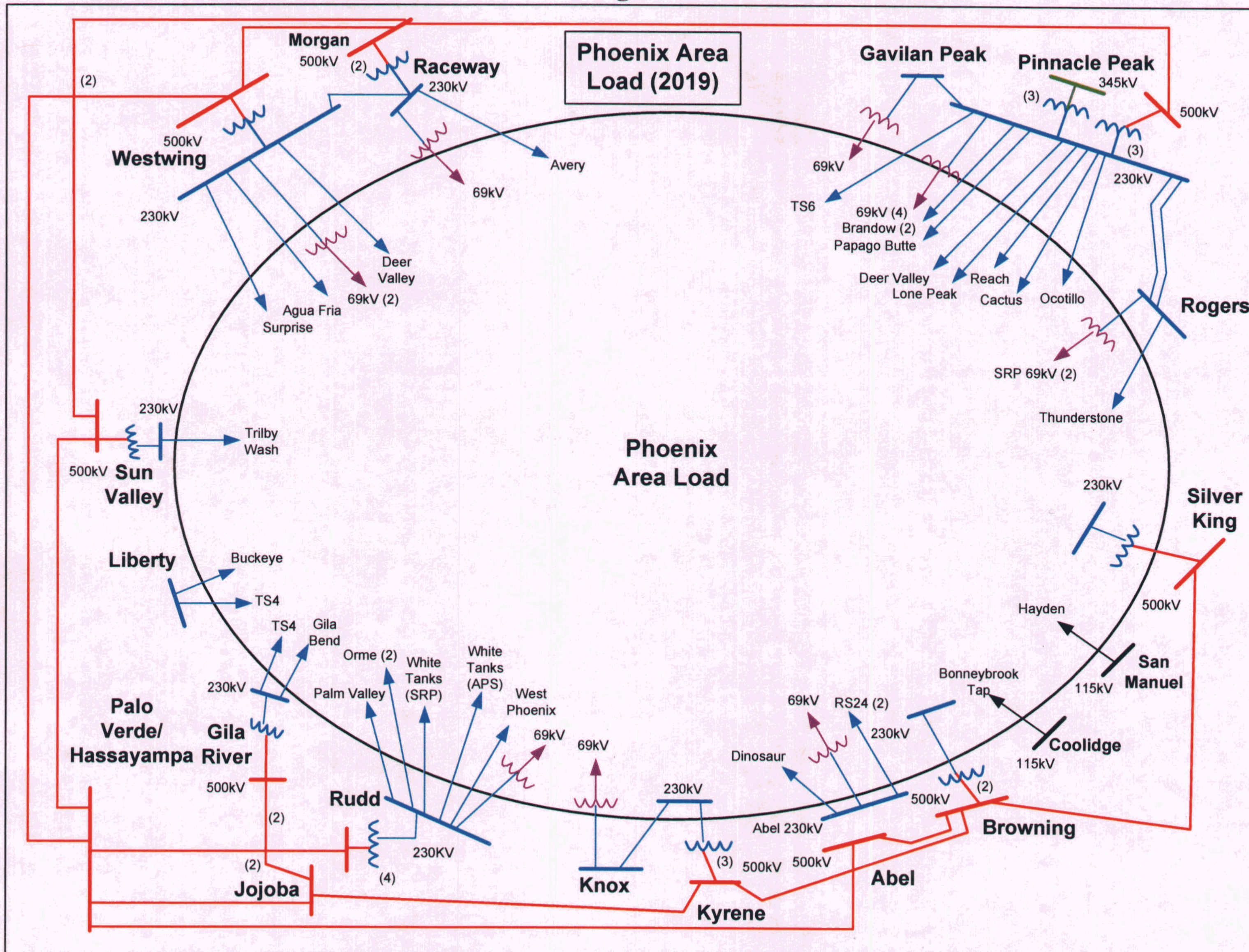

Phoenix Area Load (2013)
Phoenix Area Load
Morgan
500kV
(2)
Raceway
230kV
Westwing
500kV
230kV
Avery
69kV
Deer Valley
69kV (2)
Agua Fria
Surprise
Gavilan Peak
Pinnacle Peak
345kV
(3)
500kV
230kV
69kV
TS6
69kV (4)
Brandow (2)
Papago Butte
Deer Valley
Lone Peak
Reach
Cactus
Ocotillo
Rogers
SRP 69kV (2)
Thunderstone
Silver King
230kV
500kV
Hayden
San Manuel
115kV
Bonneybrook Tap
Coolidge
115kV
Browning
500kV
Randolph
230kV
Abel
500kV
Abel 230kV
Dinosaur
69kV
Kyrene
500kV
Knox
69kV
Liberty
Buckeye
TS4
Gila Bend
Palo Verde/ Hassayampa
Gila River
500kV
Jojoba
Rudd
230KV
(4)
Palm Valley
Orme (2)
White Tanks (SRP)
White Tanks (APS)
West Phoenix

Figure 2


Phoenix Area Load (2019)
Phoenix Area Load
Morgan
500kV
(2)
Raceway
230kV
Westwing
500kV
230kV
Avery
69kV
Deer Valley
69kV (2)
Agua Fria
Surprise
Gavilan Peak
Pinnacle Peak
345kV
(3)
500kV
230kV
69kV
TS6
69kV (4)
Brandow (2)
Papago Butte
Deer Valley
Lone Peak
Reach
Cactus
Ocotillo
Rogers
SRP 69kV (2)
Thunderstone
Sun Valley
Trilby Wash
Liberty
Buckeye
TS4
Silver King
Hayden
San Manuel
115kV
Bonneybrook Tap
Coolidge
Palo Verde/ Hassayampa
Gila River
Gila Bend
Orme (2)
Palm Valley
White Tanks (SRP)
White Tanks (APS)
West Phoenix
Rudd
230KV
(4)
Jojoba
Knox
Kyrene
Abel
Abel 230kV
Dinosaur
RS24 (2)
Browning

In performing the Phoenix area studies several planned projects were added to reflect transmission system upgrades, in the Phoenix area High Voltage (HV) system and the Arizona Extra-High Voltage (EHV) system, for the next ten years. They are listed below; under one of the two study years they will first appear:

Projects in service by 2013

- 500kV Morgan substation on the Dugas – Westwing 500kV circuit
- 500/230kV transformer at Morgan 500kV connected to Raceway 230kV
- Pinnacle Peak 500kV substation with three 500/230kV transformers and a 500kV line to the Morgan 500kV substation.
- Raceway – Pinnacle Peak 230kV circuit
- A fourth 230/69kV transformer at Pinnacle Peak substation
- A third 500/230kV transformer at Kyrene substation
- New generation at Randolph
- Dinosaur-Abel-Randolph 230kV circuit
- TS6 substation on the Raceway – Pinnacle Peak 230kV circuit
- 230/69kV transformer at TS6
- 230/69kV transformer at Rudd

Projects in service by 2019

- Delany 500-kV substation
- Delany – Palo Verde 500kV circuit
- Delany – Sun Valley 500kV circuit
- Sun Valley 500kV and 230kV substation with a 500/230kV transformer
- Sun Valley – Morgan 500kV circuit
- TS1 230kV substation with a 230/69kV transformer and Sun Valley-TS1 230kV line
- TS1-Palm Valley 230kV line
- Pinal West-Santa Rosa-Pinal Central-Abel-Browning 500kV line
- Santa Rosa 500/230kV substation
- Abel 500/230kV substation with two 500/230kV transformers
- TS2 230/69kV substation with a 230/69kV transformer and looped into the TS1-Palm Valley 230kV line
- Generation at Abel: 910 MW

B. Phoenix Area Critical Outages

1. 2013

The analysis determined that the critical single contingency for the Phoenix load area at all load and generation levels is the loss of the Palo Verde-to-Rudd 500kV transmission line.

The loss of this major 500kV line results in significantly higher flows on the remaining transmission lines and the underlying 230kV transmission system and causes a large increase in reactive power (Var) losses in the transmission network. The increase in Var consumption results in insufficient Vars for voltage support in the load area. Consequently, this condition creates low voltages in the system and makes the area deficient in reactive power.

2. <u>2019</u>

The analysis determined that the critical single contingency for the Phoenix load area at the SIL point is the loss of the Silverking 500/230kV transformer. The loss of this transformer results in a thermal overload of the Rogers – Thunderstone 230kV line. With local Phoenix area generation at high levels the critical element for the Phoenix load area is the continuous rating (N-0, no contingency) of the Cactus - Pinnacle Peak 230kV circuit. All single contingencies with generation at high levels do not result in any overloads. Thus, the system is constrained by these thermal overloads at the two ends of the nomogram.

A thermal overload occurs when more power flows through an element than the continuous or emergency rating of that element.

The voltage stability analysis was performed using Q-V analysis on the most reactive deficient buses in the Phoenix area. These buses were the Kyrene 500kV, Kyrene 230kV, Browning 230kV, Pinnacle Peak 230kV, Rudd 230kV, Liberty 230kV, Raceway 230kV, Westwing 230kV, Corbell 230kV, Brandow 230kV, and Ocotillo 230kV buses.

Q-V analysis is performed by adding reactive load at the critical bus until the voltage reaches a minimum value which indicates potential voltage instability. Voltage instability is characterized by a progressive fall in voltage magnitude at a particular location of the power system that may spread throughout the network causing a complete area voltage collapse and blackout. The import limit is determined as the lesser of 95% of the import with zero reactive margin or 100% of the import with a 5% voltage drop following the worst single-contingency per WECC planning criteria.

C. Phoenix Area – SIL and MLSC for 2013 and 2019

Analysis of the Phoenix area transmission network resulted in area import limits based on the limits discussed in the previous section (B. Phoenix Area Critical Outages). Operation of the Phoenix system within these limits ensures that the area does not experience voltage instability or thermal overloading of a system element. The Phoenix area SIL and MLSC for the years 2013 and 2019 are outlined in Table 1.

Table 1
2013 and 2019 Phoenix area Simultaneous Import Limit

Year	SIL (MW)	MLSC (MW)
2013	11,296	14,978
2019	11,693	17,058

The maximum Phoenix area load-serving capability for various generation levels is shown in Figures 3 and 4.

Figure 3

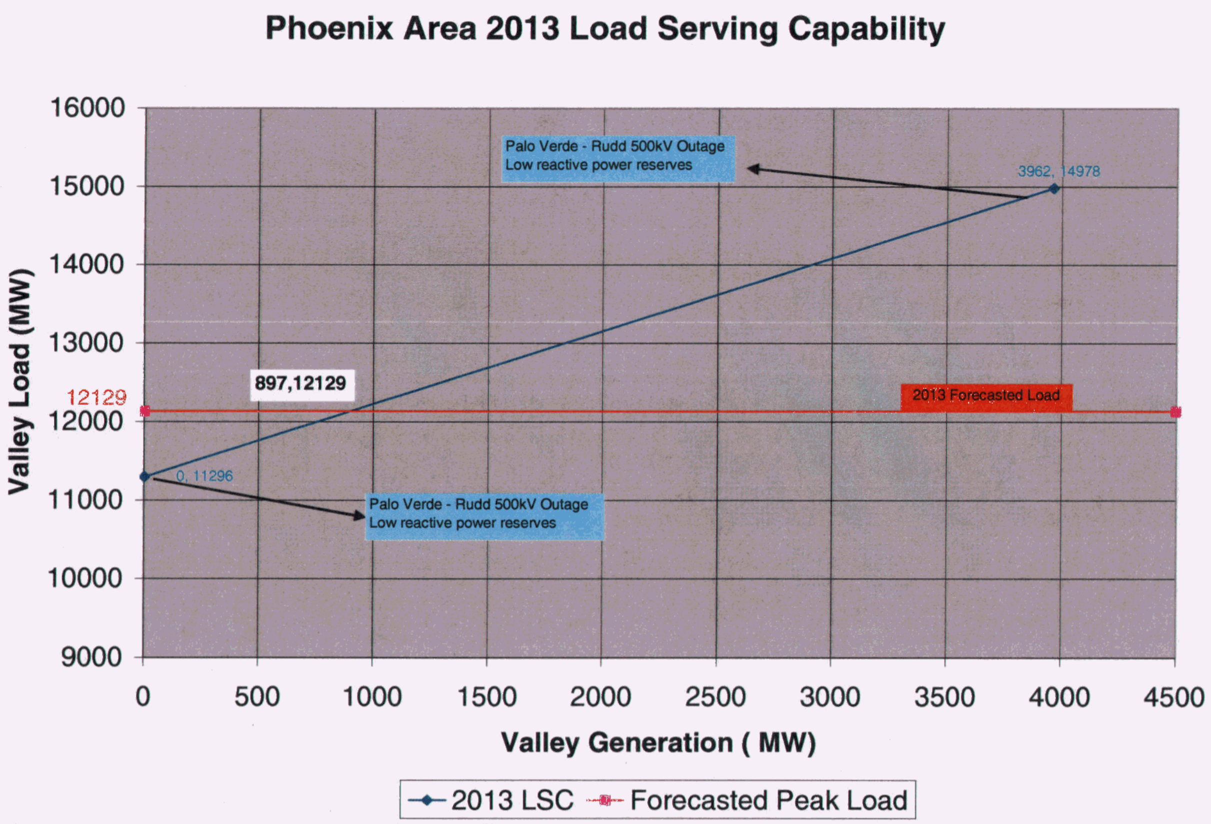
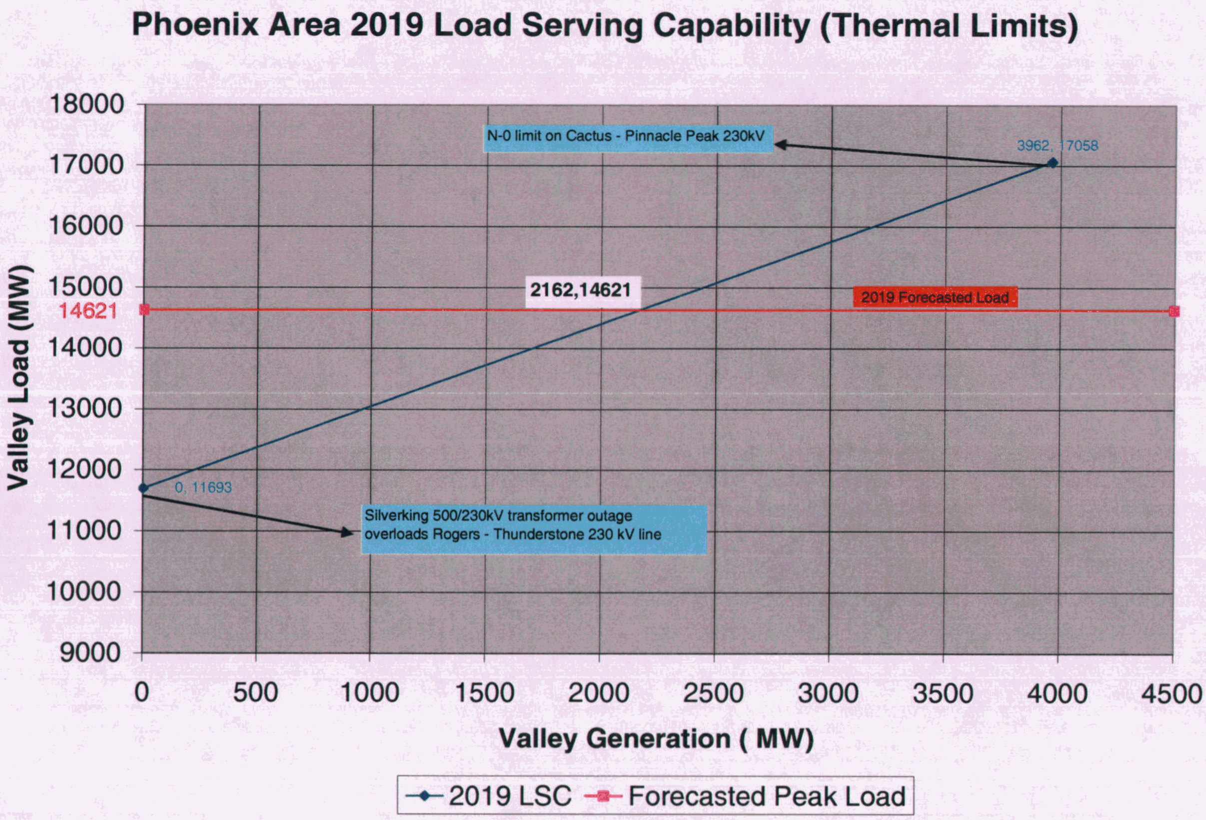


Figure 4



IV. Yuma Area

As part of the ACC Fifth BTA, Per Decision No. 70635, under Section 5.2 Efficacy of Commission Ordered Studies, item 1c states:

> *The focus of the Yuma area RMR study is solely based on the import to the local APS 69kV system. There needs to be a system perspective of the RMR conditions for the entire Yuma County area in the future rather than limiting the RMR analysis solely to the APS 69kV system. This is particularly true given that the SIL and MLSC import limits to the APS system are restricted by the overloads on other transmission providers' systems. This is underscored by the fact that major system changes are being proposed for that area by other interconnected entities such as WAPA, WMIDD, IID and parties seeking LGIA interconnections in the area.*

For the 2010 RMR study, APS approached the Colorado River Transmission (CRT) sub-regional study group to seek their guidance and create an open forum for Yuma County Stakeholders to address the ACC's recommendation. Several meetings were held throughout 2009 to discuss the need and interest of incorporating the entire Yuma County in the APS RMR study cut plane. APS provided the Yuma County Stakeholders (WAPA, IID, WMIDD) a one-line diagram that defined the present cut-plane to seek their interest and need for the 2010 Yuma RMR study effort. APS solicited Stakeholders to outline a new cut plane if they see a need or interest to expand it. All Stakeholders within Yuma County (APS, IID, WAPA, and WMIDD) have all agreed that the cut plane for the Yuma RMR study is to remain as it is presently defined.

APS' approach for the 2010 RMR study was to perform the Yuma RMR study with the cut-plane as previously defined. The 2013 and 2019 base cases are modeled with existing and planned project facilities for all of Yuma County as well as the entire WECC area. Although all Stakeholders have agreed not to redefine the cut-plane, APS performed three additional sensitivity studies to evaluate the impact of external generation and transmission projects to the Yuma Area. These sensitivities included modeling the Blythe generation off with North Branch (SLRC) on, SLRC generation off with Blythe on and adding 100MW of new generation at North Gila. The addition of the generic 100MW generation at North Gila is to evaluate any future generation interconnection to the area that may have an impact the RMR condition. The sensitivity studies resulted in a minimal impact to the Yuma Area.

A. Description of Yuma Area

Currently the Yuma area is served from three transmission sources:

- APS' North Gila 500/69kV substation, which is located east of Yuma. Two 69kV lines extend west and southwest from this substation into Yuma to serve Yuma area load. A third 69kV line interconnects into WAPA's Gila 161/69kV substation.
- WAPA's Gila 161/69kV substation, which is also located east of Yuma. From this substation, APS has one 69kV line into the Yuma load area and one 69kV tie to APS' North Gila substation.
- APS' Yucca 69kV station, which is located on the west side of Yuma near the Colorado River. APS' local generation is located at this station, along with four 69kV lines into the load area and an interconnection to IID's 161kV system through two 161/69kV transformers. The IID 75 MW steam-generating unit is also located at this substation.

Figure 5 shows the transmission system in 2013 and the metering points for the Yuma area load pocket. Listed below, under one of the two study years they will first appear, is a list of the planned projects that were added to reflect the system upgrades for the next ten years.

<u>Projects in service by 2013</u>

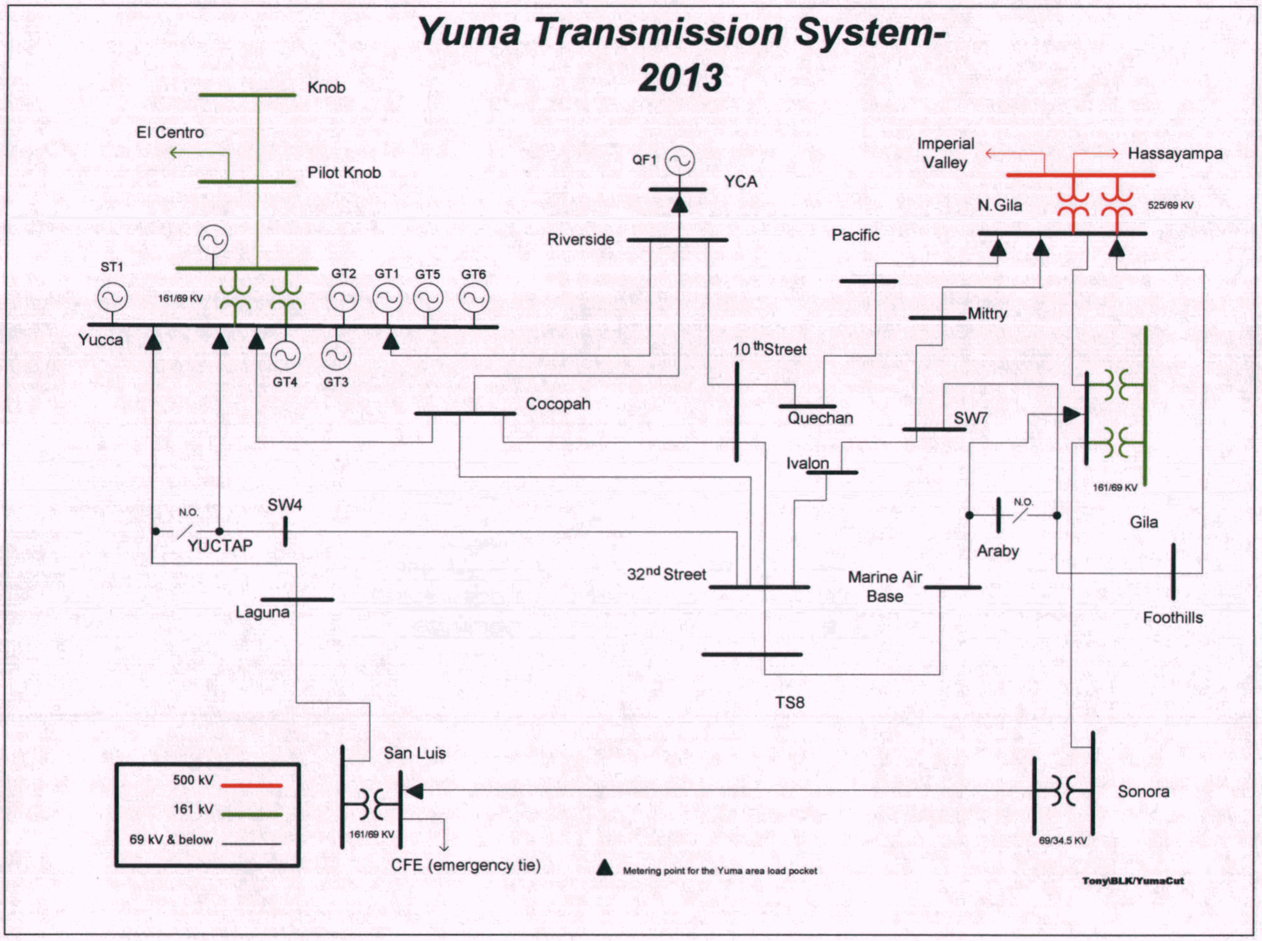
- TS8 69kV substation looped in and out of Marine Air Base-32nd Street 69kV line
- North Gila-Sanguinetti 69kV Line
- Reconductor Ivalon-Araby 69 kV line

<u>Projects in service by 2019</u>

- Construct a new North Gila-Hassayampa 500kV #2 line
- Construct a new North Gila 230kV bus with a 500/230kV transformer

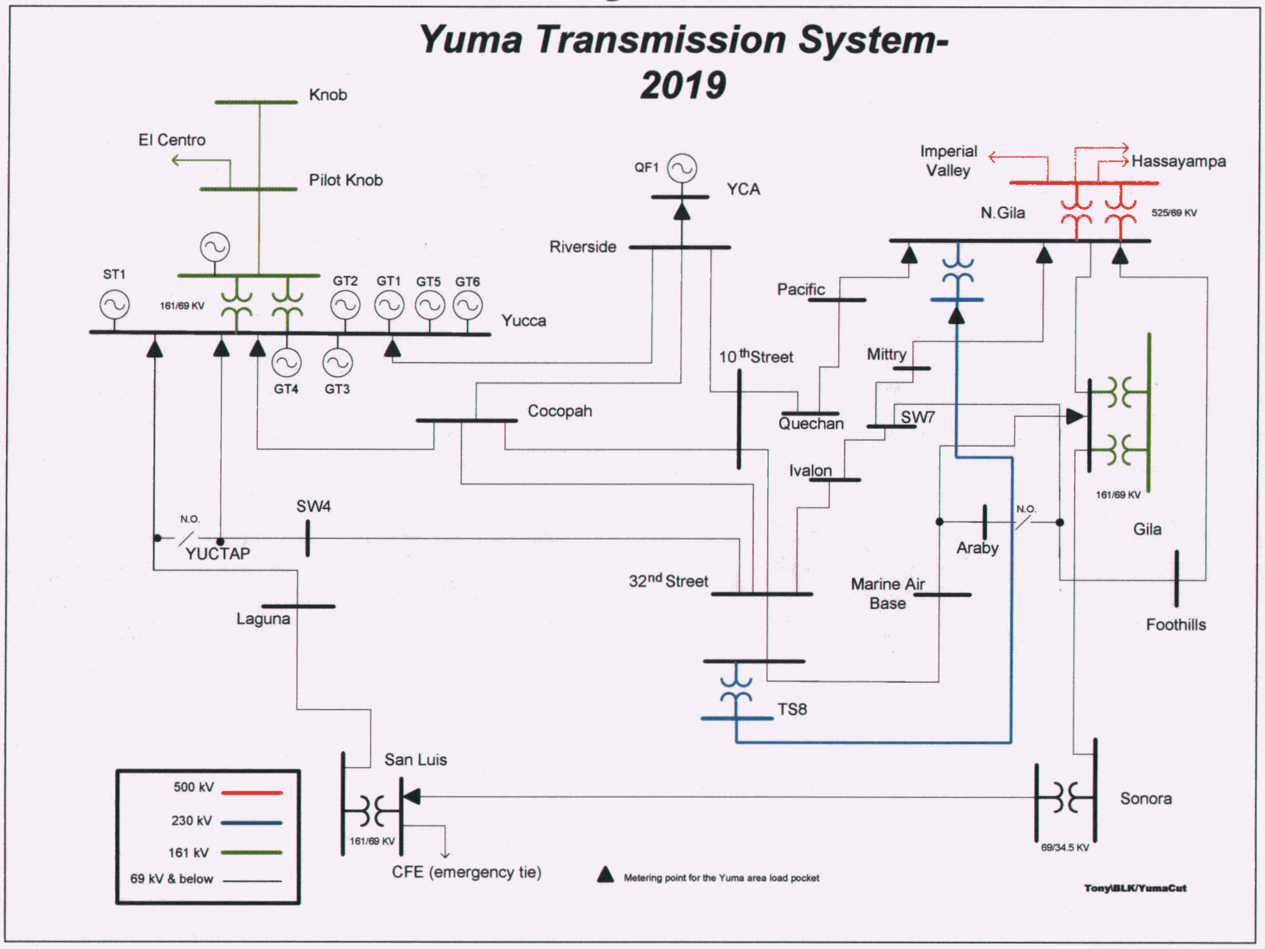
- Construct a new TS8 230kV substation with a 230/69kV transformer and a North Gila-TS8 230kV line
- Construct a new TS8-Baja-San Luis 69kV line
- Reconductor North Gila-Mittry and Mittry-Quechan 69kV lines
- Reconductor TS8-Marine Air Base 69kV line

Figure 5



New additions to the system in the Yuma area for 2019 were the additions of a 69kV line from TS8 to San Luis, a 230kV line from North Gila to the new TS8 230kV substation, and a second 500kV line from the Palo Verde area to North Gila. This can be seen in Figure 6.

Figure 6



B. Yuma Area Critical Outages

Several critical contingencies exist affecting the determination of the system import limit for the Yuma area during the 2013 and 2019 time frame. For the 2013 year, the primary critical outage is the existing Yucca-Cocopah 69kV line and the limiting element is a thermal overload on the Yucca Tap-SW4 69kV line. In 2019, the critical outage is the N.Gila-TS8 230 kV line and the limiting element is a thermal overload of the Gila 230/161 kV transformer.

C. Yuma Area – SIL and MLSC for 2013 and 2019

With planned system additions for the Yuma area, including the 97 MW of new generation, the SIL and MLSC for the Yuma area will increase enough to serve the rapidly growing load and maintain the desired generation reserves. For 2013 and 2019 the SIL will be 312MW and 473 MW, respectively. The MLSC for 2013 and 2019 will be 573 MW and 800 MW, respectively. Results of these studies are shown in Figures 7 and 8.

Figure 7

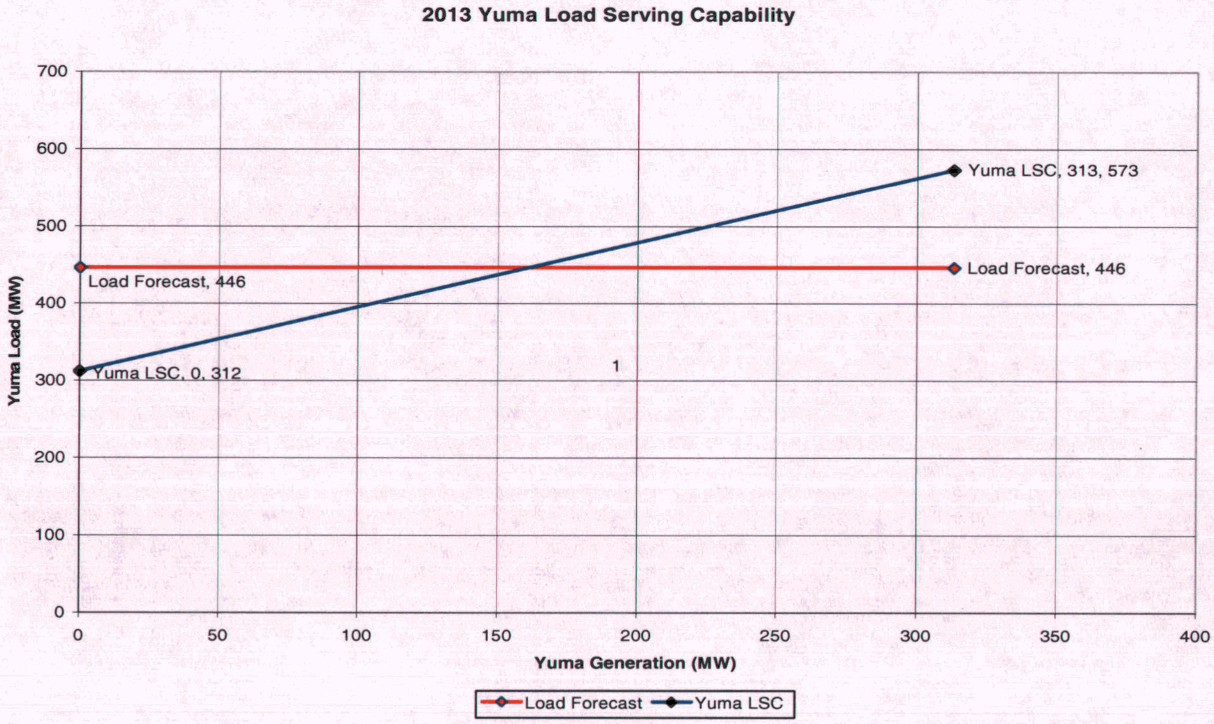
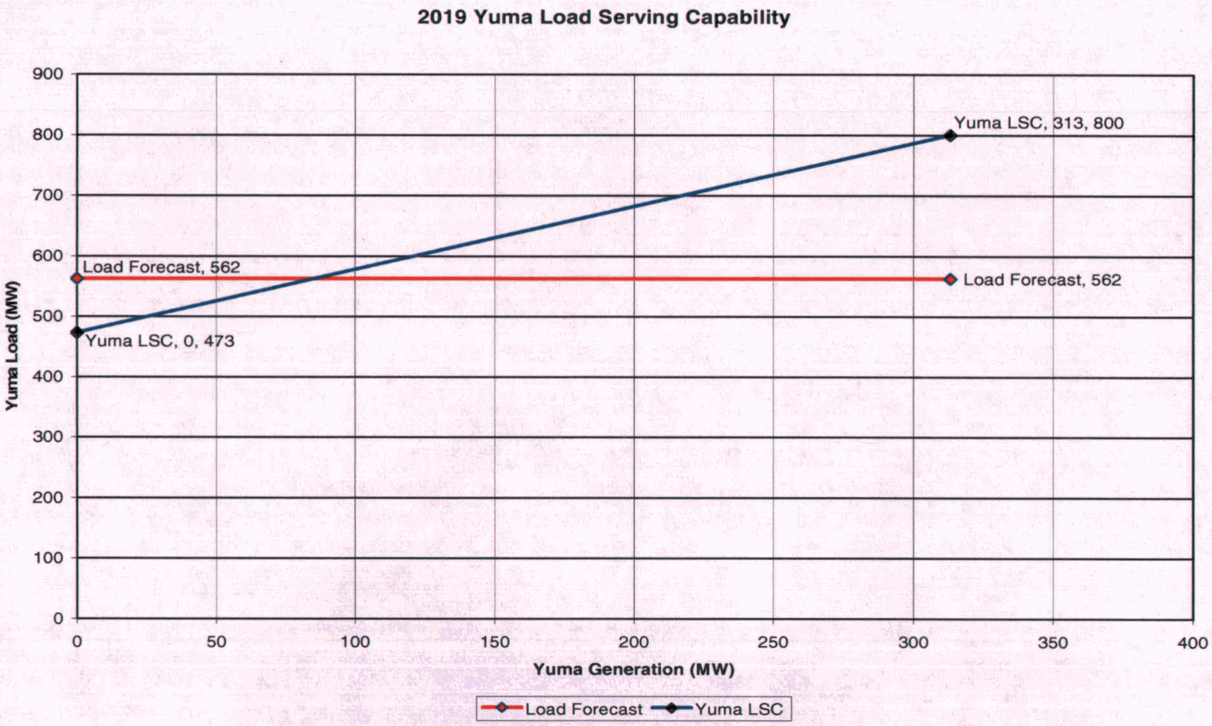


Figure 8



V. Analysis of RMR Conditions

A. Phoenix Area

1. Annual RMR Conditions

An RMR condition exists when the local load is greater than the SIL. In such cases, the RMR condition is the amount of generation that must be located inside of the constrained load area to meet the utility's peak load. RMR conditions for the Phoenix area are shown in Table 2 and are represented in the load-duration curves in Figures 9 and 10.

Table 2

Phoenix RMR Conditions
(MW)

	PHOENIX	
	2013	**2019**
Peak Load	12,129	14,621
Import Capability @ Peak	11,232	12,459
Must-Run Generation @ Peak	897	2,162
Hours Load Exceeds SIL	45	497
Energy - GWH	15	317
Energy Percent of Valley Load	0.0%	0.5%

Figure 9

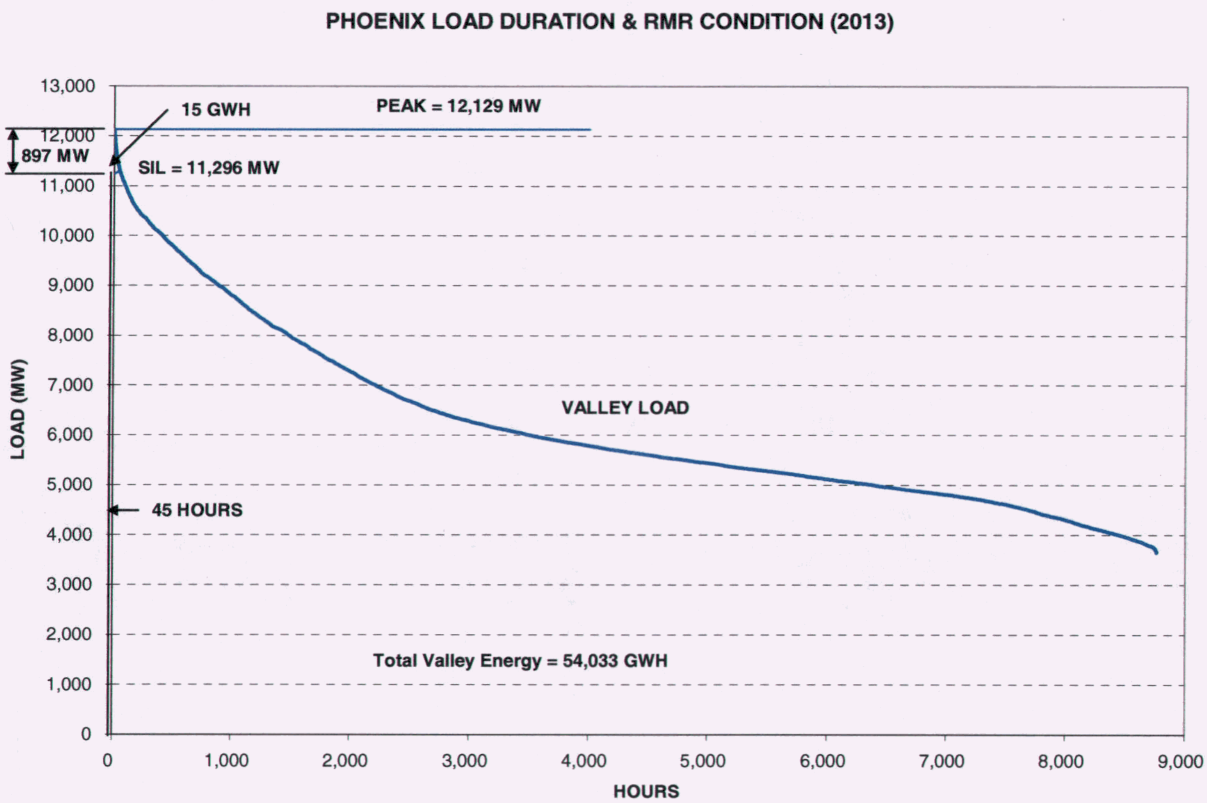

PHOENIX LOAD DURATION & RMR CONDITION (2013)
15 GWH
PEAK = 12,129 MW
897 MW
SIL = 11,296 MW
VALLEY LOAD
45 HOURS
Total Valley Energy = 54,033 GWH
LOAD (MW)
HOURS
13,000
12,000
11,000
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
0
1,000
2,000
3,000
4,000
5,000
6,000
7,000
8,000
9,000

Figure 10

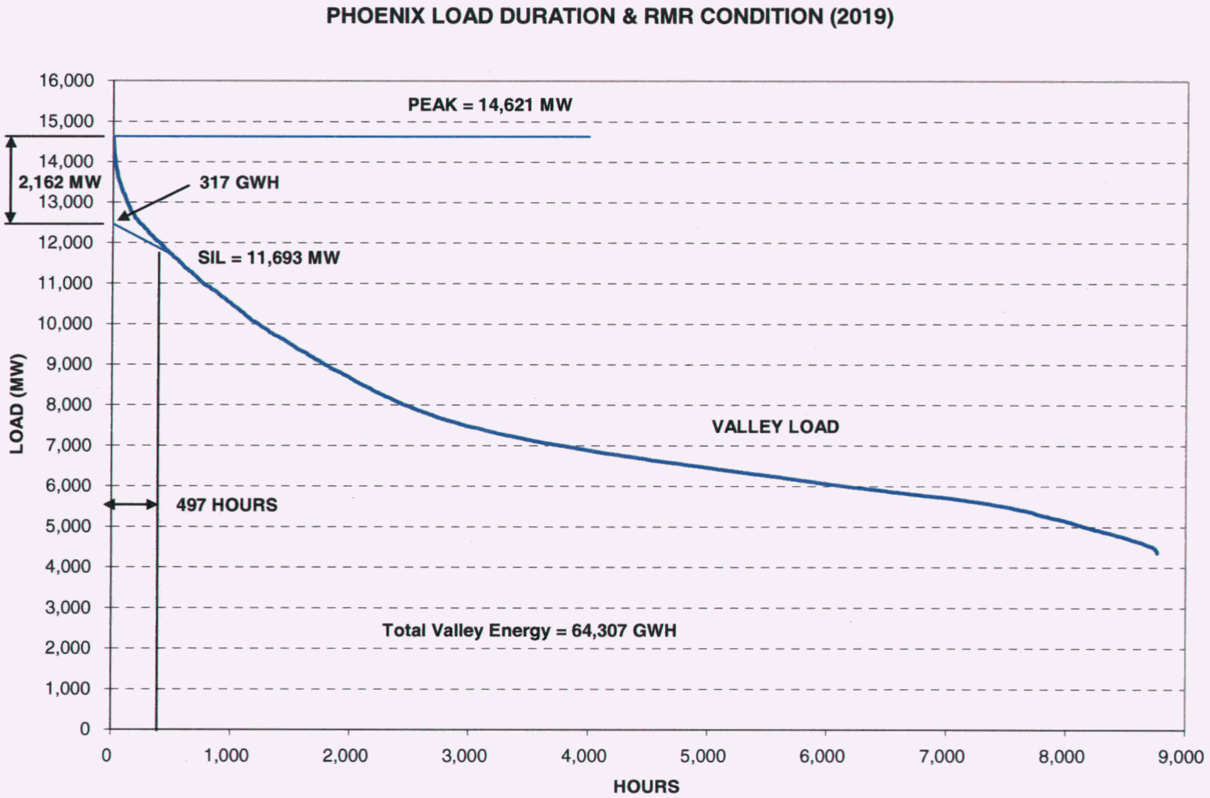


Table 2 shows that Phoenix is expected to require 897 MW of local generation resources over and above its import capability to meet peak load in 2013 and 2,162 MW in 2019. For Phoenix, generation is estimated to be in a must-run condition for 45 hours in 2013 and 497 hours in 2019. However, because RMR occurs only at peak, the amount of associated energy is less than one percent of the total Phoenix area energy requirements, as shown in Figures 9 and 10.

2. Phoenix Area Reserve Capacity

MLSC is the maximum load that can be served in the load pocket. It is the import capability plus the generation capability located inside the load pocket. Based on the load forecast and SIL presented in this analysis, along with existing local generation, the MLSCs for Phoenix were developed. The SIL and MLSC are utilized to develop the Phoenix Area Load Serving Capability graphs; Figures 3 and 4. The import capability and the amount of local generation required, at the forecasted peak load, are determined. The difference between the amount of local generation required at peak load and the total valley generation are the projected reserves for that year. The approach used shows how much generation or transmission may be needed to reliably meet load.

The generation and transmission assumptions are depicted in Table 3. As shown on this table, additional resources, beyond those projects in APS' Ten-Year Plan, are not required in years 2013 and 2019 to reliably serve the peak load and maintain the required reserves margin.

Table 3

Phoenix Area Reserve Capacity
(MW)

	PHOENIX	
	2013	**2019**
Peak Load	12,129	14,621
Import Capability @ Peak	11,232	12,459
Valley Generation	3,962	3,962
Valley Gen + Import	15,194	16,421
Reserves	3,065	1,800
Required Reserves	800	800

3. Area Load Forecast

The historical peak load and annual energy within the Phoenix area constraint is shown in Table 4 for 2005-2009, along with forecasted peak load for 2013 and 2019. This peak load represents load growth as well as the expanding boundaries of the Phoenix area, as discussed in Section III, part A and shown in Figures 1 and 2. The Phoenix load and energy for 2005-2007 has been revised from previous RMR studies to reflect inclusion of the Buckeye and Gila Bend areas. Forecasted peak load is based on the same assumptions embodied in APS' total system load forecast used for budgeting and planning. This peak load is the load measured within the defined Phoenix area constraint.

Table 4

Phoenix and Yuma Load and Energy Forecast
(MW / GWH)

	HISTORICAL					FORECAST	
	2005	**2006**	**2007**	**2008**	**2009**	**2013**	**2019**
PHOENIX							
LOAD	10,953	12,053	11,891	11,908	11,711	12,129	14,621
ENERGY	46,715	48,791	50,963	49,819	49,015	54,033	64,307
Load Factor	48.7%	46.2%	48.9%	47.6%	47.8%	50.9%	50.2%
APS YUMA							
LOAD	370	404	415	401	404	446	562
ENERGY	1,609	1,717	1,811	1,800	1,764	1,925	2,419
Load Factor	49.7%	48.5%	49.8%	51.1%	49.8%	49.3%	49.1%

Phoenix area APS load forecasts were developed through the use of a multiple regression model using historic hourly load data, weather, and number of customers. These historic relationships (correlations) were combined with the metro area customer forecast and normal Phoenix weather to produce the APS Phoenix area load. The SRP forecast, was then added to the APS forecast to obtain a total valley load forecast.

4. Generation

Currently, APS owns 1,318 MW and SRP owns 2,644 MW of generation electrically located inside the Phoenix area. Table 5 shows operational data associated with each unit.

Table 5

PHOENIX AREA GENERATION									
OWNER	**PLANT**	**TYPE**	**SUMMER CAPABILITY**	**MIN LOAD**	**MIN UP TIME**	**MIN DOWN TIME**	**FOR**	**EFOR**	**FUEL TYPE**
APS	Ocotillo 1	ST	110	20	8	8	4%	6%	NG
APS	Ocotillo 2	ST	110	20	8	8	4%	6%	NG
APS	Ocotillo GT1	GT	50	4	2	1	10%	12%	NG
APS	Ocotillo GT2	GT	50	4	2	1	10%	12%	NG
APS	West Phoenix GT1	GT	50	4	2	1	10%	12%	NG
APS	West Phoenix GT2	GT	50	4	2	1	10%	12%	NG
APS	West Phoenix CC1	CC	85	20	8	6	3.5%	7%	NG
APS	West Phoenix CC2	CC	85	20	8	6	3.5%	7%	NG
APS	West Phoenix CC3	CC	85	50	8	6	3.5%	7%	NG
APS	West Phoenix CC4	CC	110	77	8	3	5%	7%	NG
APS	West Phoenix CC5	CC	533	160	8	6	8%	10%	NG
SRP	Agua Fria 1	ST	113	15	8	8	4%	6%	NG
SRP	Agua Fria 2	ST	113	15	8	8	4%	6%	NG
SRP	Agua Fria 3	ST	181	22	8	8	4%	6%	NG
SRP	Agua Fria 4	GT	73	5	2	1	10%	12%	NG
SRP	Agua Fria 5	GT	73	5	2	1	10%	12%	NG
SRP	Agua Fria 6	GT	73	5	2	1	10%	12%	NG
SRP	Crosscut 1	HY	3	N/A	N/A	N/A	0%	0%	WAT
SRP	Horse Mesa 1	HY	10	N/A	N/A	N/A	0%	0%	WAT
SRP	Horse Mesa 2	HY	10	N/A	N/A	N/A	0%	0%	WAT
SRP	Horse Mesa 3	HY	10	N/A	N/A	N/A	0%	0%	WAT
SRP	Horse Mesa 4	HY	119	N/A	N/A	N/A	0%	0%	WAT
SRP	Kyrene 1	ST	34	10	8	8	4%	6%	NG
SRP	Kyrene 2	ST	72	12	8	8	4%	6%	NG
SRP	Kyrene GT4	GT	59	5	2	1	10%	12%	NG
SRP	Kyrene GT5	GT	53	7	2	1	10%	12%	NG
SRP	Kyrene GT6	GT	53	7	2	1	10%	12%	NG

SRP	Kyrene CC1	CC	250	161	8	6	8%	10%	NG
SRP	Mormon Flat 1	HY	11	N/A	N/A	N/A	0%	0%	WAT
SRP	Mormon Flat 2	HY	57	N/A	N/A	N/A	0%	0%	WAT
SRP	Roosevelt	HY	36	N/A	N/A	N/A	0%	0%	WAT
SRP	Santan 1	CC	92	21	8	6	3.5%	5%	NG
SRP	Santan 2	CC	92	21	8	6	3.5%	5%	NG
SRP	Santan 3	CC	92	21	8	6	3.5%	5%	NG
SRP	Santan 4	CC	92	21	8	6	3.5%	5%	NG
SRP	Santan 5	CC	582	150	8	6	8%	10%	NG
SRP	Santan 6	CC	277	156	8	6	8%	10%	NG
SRP	South Consolidated 1	HY	1	N/A	N/A	N/A	0%	0%	WAT
SRP	Stewart Mt	HY	13	N/A	N/A	N/A	0%	0%	WAT
PHOENIX	**TOTAL**		**3,962**						

APS owns West Phoenix CC 1-2-3-4-5, West Phoenix CT 1-2, Ocotillo ST 1-2, and Ocotillo CT 1-2. With the exception of West Phoenix CC 4-5, these units collectively have a 675 MW summer rating, have historically operated at capacity factors in the 3-30 percent range, and have operated at lower capacity factors (about 7%) over the last few years as new high-efficiency plants came on line in Arizona and the Southwest. West Phoenix CC 4 (110 MW), which went into service in June 2001, and West Phoenix CC 5 (533 MW), which came on-line in July 2003, improve reliability to the Phoenix area. These units have operated at capacity factors in the 10-50 percent range.

SRP owns the Agua Fria, Kyrene and Santan generating stations inside the Phoenix area, totaling 2,374 MW of generation. These units were built in the late 1950s to the mid-1970s, with three exceptions -- a new Kyrene CC unit went into service in 2002, a new Santan 5 unit went into service in 2005, and a new Santan 6 unit went into service in 2006. The generating capacity of Crosscut and South Consolidated hydroelectric plants, which are part of SRP's canal system, is 4 MW. SRP also operates four dams along the Salt River System that produce 266 MW of hydroelectric generation; Roosevelt, Horse Mesa, Mormon Flat, and Stewart Mountain.

5. Reserves

Reliability within a load pocket such as Phoenix must be evaluated differently than for an unconstrained system. For example, although a 15 percent reserve margin may be adequate for unconstrained total system loads, it may not provide adequate reliability to load pockets that may not have access to all reserves present in the WECC interconnected system. APS performs an analysis that considers the size, forced outage rate, and effective forced outage rate of each generating unit in the load pocket to determine the probability that enough generation will be available when needed. The reserve requirement for Phoenix is based on Loss of Load Probability (LOLP) criteria of one day in ten years. In other words, based on Phoenix area load, import capability and the availability of local generation, this criteria would result in not being able to meet Phoenix load one day in ten years. The 1/10 criteria results in a reserve requirement for Phoenix of 800 MW as documented in a report filed with the ACC on September 30, 2008 in compliance with ACC Decision No. 70131.

B. Yuma Area

1. Annual RMR Conditions

RMR conditions for the Yuma constrained area are shown in Table 6 and pictorially represented in a load-duration curve in Figures 11 and 12. Table 6 shows that APS requires 161 MW in 2013 and 85 MW in 2019 of generation over and above its transmission import capability to meet peak load in Yuma. These resources can be APS-owned generation or non-APS owned generation located within the constrained area. APS is in a must-run condition for 950 hours in 2013 and 171 hours in 2019 in Yuma. The amount of associated energy is 2 percent of Yuma's total energy requirement in 2013 and less than 1 percent in 2019.

Table 6

Yuma RMR Conditions (MW)	YUMA 2013	YUMA 2019
Peak Load	446	562
Import Capability @ Peak	285	477
Must-Run Generation @ Peak	161	85
Hours Load Exceeds SIL	950	171
Energy - GWH	43	4
Energy Percent of Yuma Load	2.2%	0.2%

Figure 11

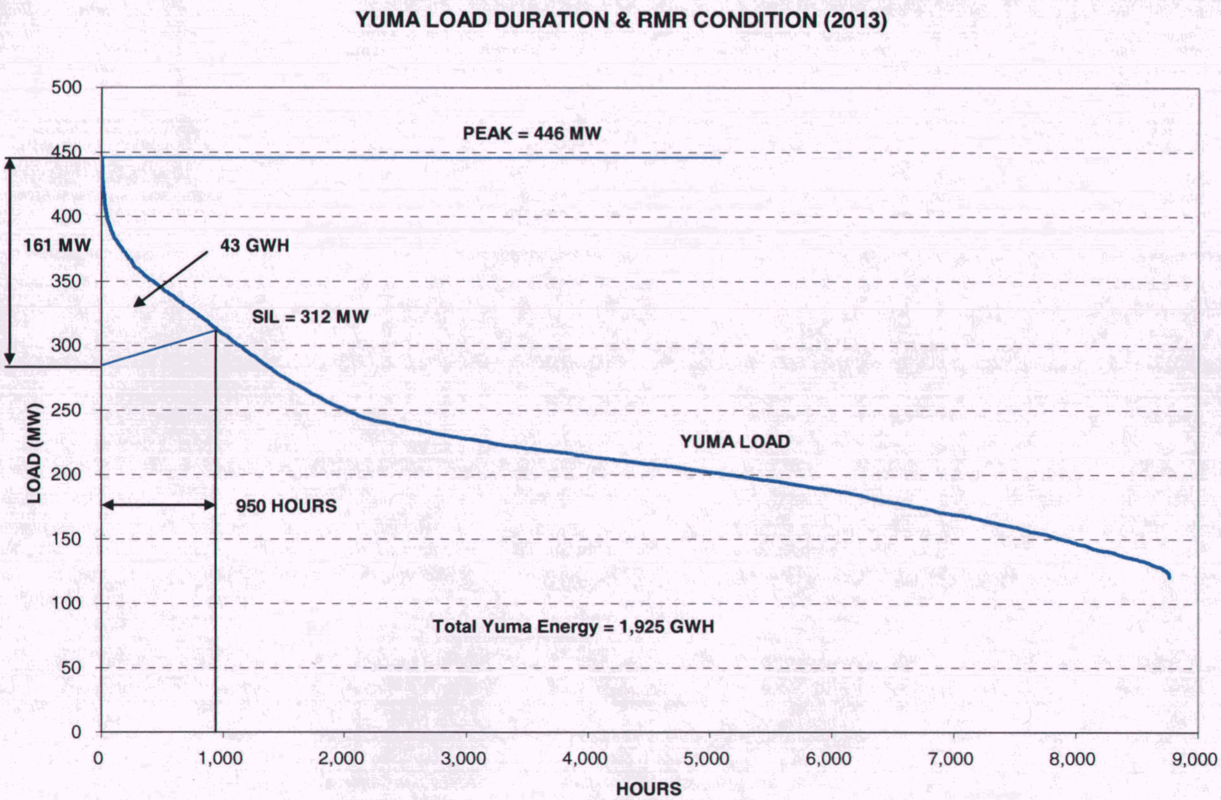
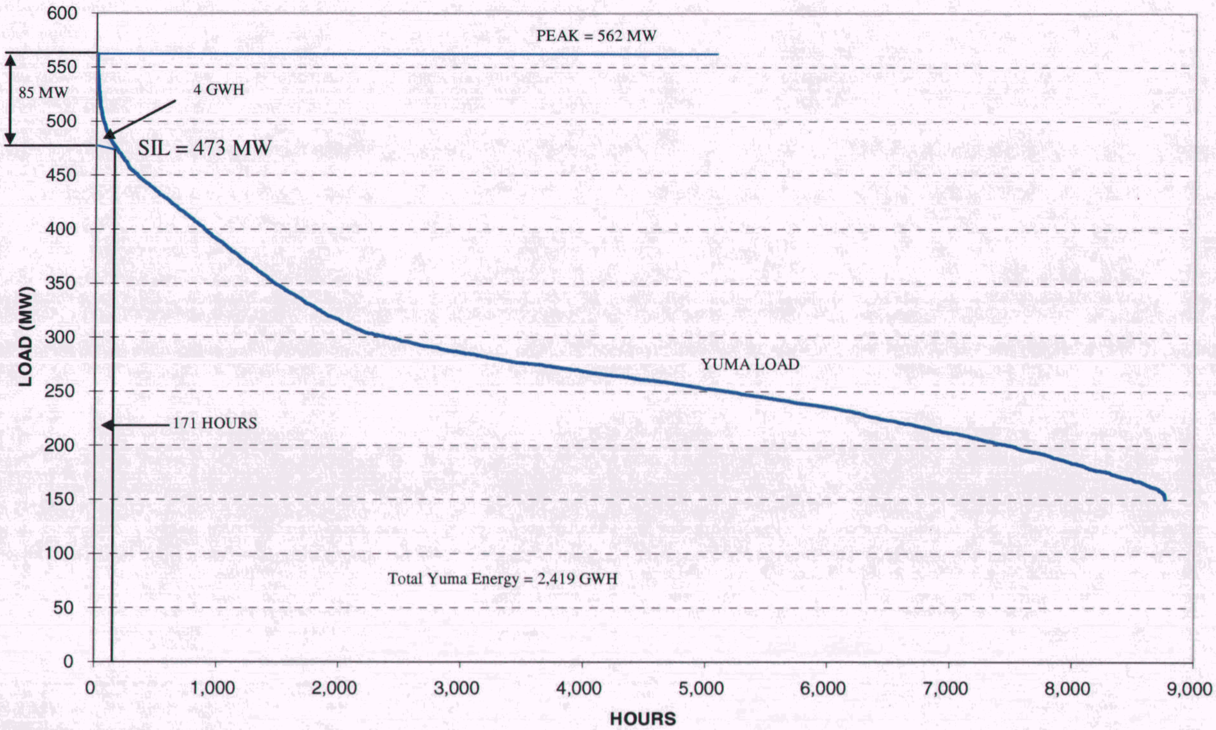


Figure 12

YUMA LOAD DURATION & RMR CONDITION (2019)



2. Yuma Area Reserve Capacity

The generation and transmission assumptions are depicted in Table 7. As shown on this table, additional resources, beyond those projects in APS' Ten-Year Plan, are not required in years 2013 and 2019. With a load forecast of between 446 MW to 562 MW, the local generation requirements can be met from either APS or non-APS owned generation (Yucca steam and YCA units) within the load pocket.

Table 7

Yuma Area Reserve Capacity (MW)	YUMA	
	2013	**2019**
Peak Load	446	562
Import Capability @ Peak	285	477
Local Generation	313	313
Local Gen + Import	598	790
Reserves	152	228
Required Reserves	97	97

3. Area Load Forecast

Table 4 shows APS' Yuma historical peak load for 2005-2009 and forecasted peak load for 2013 and 2019. Forecasted peak load is based on the same assumptions used in APS' total system load forecast used for budgeting and planning. This peak is the load measured just inside the Yuma area. Yuma load represents approximately 6 percent of APS' total system load. Yuma area APS load forecasts were developed through the use of a multiple regression model using historic hourly load data, weather, and number of customers. These historic relationships (correlations) were combined with the Yuma area customer forecast, and normal Yuma weather to produce the Yuma area load.

4. Generation

APS (Yucca CTs 1-6), IID (Yuma Axis 1) and YCA (Yuma Cogen 1,2) own generation within the Yuma load pocket. These plants have an aggregate summer capacity rating of 313 MW. Eight of the nine units run on natural gas while the other unit (Yucca CT 4) runs on oil. In June 2008, APS brought Yucca CTs 5 and 6 into commercial operation in order to enhance our ability to reliably serve Yuma load. These are high efficiency combustion turbines equipped with state of the art emission controls. IID's Yuma Axis 1 full load summer capability is 75MW. The unit is used to regulate IID's system, and therefore may not be operating at full load during Yuma peak load hours. Based on historical performance, it is assumed that Yuma Axis 1 contributes 25MW to Yuma reliability. Additional power plant data for this generation is provided in Table 8.

Although operated by APS, IID dispatches its steam plant to meet its load and spinning reserve needs. YCA is a cogeneration plant that has a contract with San Diego Gas & Electric

(SDG&E). Although APS has no dispatch rights to these units, whenever the units are running they provide internal generation in the Yuma area for purposes of using the import nomogram.

Table 8

YUMA AREA GENERATION

OPERATOR	PLANT	TYPE	SUMMER CAPABILITY	MIN LOAD	MIN UP TIME	MIN DOWN TIME	FOR	EFOR	FUEL TYPE
APS	Yucca GT1	GT	18	2	2	1	10%	10%	NG
APS	Yucca GT2	GT	18	2	2	1	10%	10%	NG
APS	Yucca GT3	GT	52	5	2	1	10%	10%	NG
APS	Yucca GT4	GT	51	5	2	1	10%	10%	FO2
APS	Yucca GT5	GT	48	20	1	1	2%	2%	NG
APS	Yucca GT6	GT	48	20	1	1	2%	2%	NG
APS	**SUBTOTAL**		**235**						
IID	Yuma Axis 1	ST	25[1]	18	8	8	4%	6%	NG
YCA	Yuma Cogen 1	CC	36	14	N/A	N/A	3.5%	7%	NG
YCA	Yuma Cogen 2	CC	17	7	N/A	N/A	3.5%	7%	NG
YCA	**SUBTOTAL**		**53**						
YUMA	**TOTAL**		**313**						

NOTE: 1) Based on historical summer performance

5. *Reserves*

The required reserve margin for Yuma was calculated to be 97 MW. The reserve requirement for Yuma is based on Loss of Load Probability (LOLP) criteria of one day in ten years. In other words, based on Yuma area load, import capability and the availability of local generation, this criteria would result in not being able to meet Yuma load one day in ten years. The 1/10 criteria translates to a reserve requirement of 97 MW during the time frame studied.

VI. ECONOMIC ANALYSIS OF RMR

A. Introduction

To consider potential economic effects resulting from using local generation or arising from RMR conditions, an economic analysis was performed using an economic dispatch model. For this economic analysis, the production cost of meeting Phoenix loads was determined with the existing transmission import limitations in place. Next, a second hypothetical case was built in which the transmission import limits were removed. Comparing the two cases shows the economic costs of the transmission constraint.

These two cases were simulated with PROMOD and their outputs were compared to determine the cost of transmission constraints. PROMOD is a detailed production cost model that includes generation and transmission of SRP and APS control areas. PROMOD dispatches all generators on an economic basis to meet the combined SRP and APS system loads, within constraints for individual system control area's reserve requirements and within transmission constraints.

The data used in the production cost model comes from 1) publicly available WECC Transmission Expansion Planning Policy Committee (TEPPC) 2019 Base Case power plant data (dated October 21, 2009), 2) the APS Resource Plan Filing, ACC Docket E-01345A-09-0037, and 3) updated forecasts of system load and fuel prices.

The following items were quantified based on the PROMOD simulations:

- Number of hours per year the Phoenix and Yuma area transmission system is expected to be constrained by the import limits;
- Phoenix and Yuma generation capacity factors;
- Cost to serve the APS and SRP systems, including fuel, variable O&M, and purchase power;
- Phoenix and Yuma generation emissions;
- Phoenix and Yuma natural gas consumption.

B. Phoenix

1. Phoenix Imports

Table 9 shows that under economic dispatch conditions for Phoenix area generation, Phoenix did not reach its transmission import limits in 2013 and 2019.

Table 9

IMPACT OF ELIMINATING PHOENIX IMPORT LIMITS						
	With Import Limits		**Without Import Limits**		**Difference (With minus Without)**	
	2013	**2019**	**2013**	**2019**	**2013**	**2019**
Hours Limiting	0	0	0	0	0	0
Phx Plant Generation (GWH)	3,873	7,748	3,873	7,748	0	0
Phx Plant Capacity Factor	11.0%	25.4%	11.0%	25.4%	0.0%	0.0%
Cost of Constraints ($M)					0	0

2. *Operation of Phoenix area Generating Units*

Historically, since 2001, the Phoenix area's combined-cycle power plant capacity factors have ranged from 24 to 51 percent, with an average of about 32 percent. Capacity factors for steam-fired plants ranged from 2 to 42 percent, averaging about 10 percent. Capacity factors for simple-cycle combustion turbines ranged from less than 1 percent to 25 percent, averaging about 4 percent. Historical capacity factors are shown in Table 10 by plant type for the period 2001 to 2009.

Capacity factors of these units in 2001 were higher than the historical average because the Western Interconnection and the Phoenix area both experienced high price volatility, high load growth, and few new generation resources had been added since the 1980s. With new higher-efficiency power plants coming on line, as well as the presence of the Palo Verde-Rudd 500 kV transmission line, the older Phoenix area units are expected to run at lower capacity factors. As noted above, however, these units remain critical to maintaining Phoenix area reliability.

Even if the Phoenix area transmission import limits were totally eliminated, these older units would still be needed to economically meet summer peak loads. Table 9 indicates that elimination of the constraints would have no impact on the capacity factors of all Phoenix area plants.

Table 10

PHOENIX AREA POWER PLANT HISTORICAL CAPACITY FACTOR (%)	2001	2002	2003	2004	2005	2006	2007	2008	2009
TOTAL PHOENIX									
STEAM	42.3	14.4	9.0	8.2	4.3	4.2	5.6	3.2	2.1
COMBINED CYCLE	50.5	27.7	25.1	23.7	28.8	31.5	34.3	35.2	30.0
COMBUSTION TURBINE	24.7	2.8	0.9	1.2	0.4	0.5	0.6	0.4	0.2
HYDROELECTRIC	21.8	10.1	15.6	14.4	18.7	17.5	15.9	14.1	22.6
TOTAL	38.0	16.5	15.7	14.9	18.6	20.9	22.8	22.7	20.0

3. Cost Impacts

An estimate of the cost of the transmission import constraints can be determined by comparing the system cost to serve Phoenix customers with and without constraints. Costs included in the analysis are fuel, variable O&M, and purchased power. The results of this analysis showed the Phoenix load area did not reach its transmission import limits in 2013 and 2019, and hence there was no cost impact due to the transmission import constraints. See Table 9.

4. Emissions Impact

In addition to economic modeling, the PROMOD analysis evaluated the change in plant air emissions that would result from removing the transmission constraint. The Phoenix load area did not reach its transmission import limits in 2013 and 2019, so there is no emission impact to the Phoenix area for the four criteria pollutants routinely tracked for power plants: NO_X, CO, VOC and PM_{10}.

Table 11
Phoenix Area Air Emissions Impact of RMR

Pollutant	RMR Impact[1] (tons/year)	Phoenix Area Emissions RMR Impact (% of total emissions from all sources)
NO_x	0.00	0.00
CO	0.00	0.00
PM_{10}	0.00	0.00
VOC	0.00	0.00

[1]2013 and 2019 results

Table 12 shows Phoenix area power plant emissions by type.

Table 12

PHOENIX POWER PLANT EMISSIONS (TONS)						
	With Import Limits		**Without Import Limits**		**Difference (With minus Without)**	
	2013	**2019**	**2013**	**2019**	**2013**	**2019**
NO_X	829	2,131	829	2,131	0	0
CO	108	251	108	251	0	0
PM_{10}	23	56	23	56	0	0
VOC	40	92	40	92	0	0

5. Natural Gas Impact

The PROMOD analysis was used to evaluate the change in natural gas consumption that would result from removing the transmission constraint. The Phoenix load area did not reach its transmission import limits in 2013 and 2019, so there is no natural gas consumption impact.

C. Yuma

1. Yuma Imports

Unlike the Phoenix area, the Yuma imports do reach their limits at various times throughout the summer. Table 13 shows that, for 2013, Yuma could be constrained for 22 hours in the year. The energy associated with these hours amounts to 1 GWH. During these hours, it would have been more economical to import cheaper power either generated on APS' own units outside the Yuma area or purchased from the wholesale market if the import limits were increased. As shown in Table 13, the APS Yuma load area did not reach its transmission import limits in 2019.

Table 13

IMPACT OF ELIMINATING YUMA IMPORT LIMITS						
	With Import Limits		Without Import Limits		Difference	
	2013	2019	2013	2019	2013	2019
Hours Limiting	22	0	0	0	22	0
APS Yuma Generation (GWH)	16	33	15	33	1	0
APS Yuma Plant Capacity Factor	1.9%	4.0%	1.9%	4.0%	0.0%	0.0%
Cost of Constraints ($M)					0	0

2. Operation of Yuma Units

Historically, the APS Yucca CTs have operated at capacity factors that range between 1 and 18 percent, averaging about 5%. Historical capacity factors are shown in Table 14 by unit for the period 2001 to 2009.

Table 14

YUMA POWER PLANTS HISTORICAL CAPACITY FACTOR (%)									
	2001	2002	2003	2004	2005	2006	2007	2008	2009
YUCCA									
CT1	23.4	4.0	2.6	2.8	1.7	1.8	2.0	0.6	0.3
CT2	21.8	4.6	2.3	3.6	1.2	1.3	1.5	0.7	0.4
CT3	22.0	14.4	6.8	9.2	6.5	4.1	2.0	1.1	0.5
CT4	11.9	0.3	0.4	0.5	0.0	0.3	0.2	0.2	0.2
CT5	-	-	-	-	-	-	-	4.8	7.5
CT6	-	-	-	-	-	-	-	4.3	7.0
Total Yucca	18.4	6.6	3.3	4.4	2.8	2.0	1.3	2.2	3.1

3. Cost Impacts

The PROMOD analysis indicates that the Yuma import limit will be constraining for 22 hours in 2013. The cost of this constraint in 2013 is negligible. The results of this analysis showed the Yuma area did not reach its transmission import limits in 2019, so there was no cost impact due to transmission import constraints. See Table 13.

4. Emission Impacts

The emission impact on the Yuma area due to a potential relieving of transmission constraints and "moving" generation outside of the Yuma area was determined by PROMOD similarly to the Phoenix analysis. Unlike Phoenix, however, Yuma County is a non-attainment area for PM_{10} only. Impacts on power plant emissions in Yuma were estimated by using average emission rates of normal operation of APS units along with the change in energy production. For comparison purposes, total PM_{10} emissions in Yuma County were measured by Arizona Department of Environmental Quality in 2006. To put the results into perspective, changes in Yuma area power plant emissions are shown as a percentage of total Yuma County PM_{10} emissions. The APS Yuma load area did not reach its transmission import limits in 2019, so there is no emission impact. Changes in emissions resulting from entirely eliminating the transmission import constraint into Yuma in 2013 are shown in Table 15.

Table 15
Yuma Area Air Emissions Impact of RMR

Pollutant	RMR Impact (tons/year)		Yuma Area Emissions RMR Impact (% of total emissions from all sources)	
	2013	2019	2013	2019
NO_x	0.13	0.00	N/A	N/A
CO	0.01	0.00	N/A	N/A
PM_{10}	0.04	0.00	0.00	0.00
VOC	0.01	0.00	N/A	N/A

Table 16 shows APS Yuma area power plant emissions by type.

Table 16

APS YUMA POWER PLANT EMISSIONS (TONS)						
	With Import Limits		Without Import Limits		Difference (With minus Without)	
	2013	2019	2013	2019	2013	2019
NOx	1.67	3.14	1.54	3.14	0.13	0.00
CO	0.13	0.24	0.12	0.24	0.01	0.00
PM_{10}	0.48	0.90	0.44	0.90	0.04	0.00
VOC	0.18	0.35	0.17	0.35	0.01	0.00

5. Natural Gas Impact

The PROMOD analysis was used to evaluate the change in natural gas consumption that would result from removing the transmission constraint. In 2013, by entirely eliminating the transmission import constraint into Yuma, the generation units within Yuma would reduce their consumption of natural gas by 0.012 BCF and total system natural gas consumption would drop by 0.006 BCF. The Yuma area did not reach its transmission import limits in 2019, so there would be no natural gas consumption impact.

VII. CONCLUSIONS

Phoenix area Conclusions

1. Phoenix area existing and planned transmission and local generation are adequate to reliably serve Phoenix area peak load in 2013 and 2019. In addition, the projected local generation reserve margin exceeds the required reserve margin in both years.

2. During the summer, Phoenix area load is expected to exceed the available transmission import capability for approximately 45 hours in 2013 and 497 hours in 2019. These hours represent less than one percent of the annual energy requirements for the Phoenix area.

3. From a total Phoenix load, transmission, and resources viewpoint, local generation is not expected to be dispatched out of economic dispatch order in 2013 or 2019.

4. Because there is not expected to be an out of merit order cost of Phoenix area RMR generation, advancement of transmission projects to increase import capability are presently not cost justified.

5. The Phoenix load area did not reach its transmission import limits in 2013 and 2019, so there is no emission impact to the Phoenix area.

6. Since the Phoenix load area did not reach its transmission import limits in 2013 and 2019, there is no impact to local generation capacity factor and total yearly natural gas consumption by the Phoenix area generators.

Yuma Area Conclusions

7. Yuma area existing and planned transmission and local generation are adequate to reliably serve Yuma area peak load in 2013 and 2019. In addition, the projected local generation reserve margin exceeds the required reserve margin in both years.

8. The Yuma area load is expected to exceed the available transmission import capability for 950 hours in 2013 and 171 hours in 2019. These hours represent approximately 2% of the annual energy requirements for Yuma in 2013 and less than 1% in 2019.

9. From a total Yuma load, transmission, and resources viewpoint, the import constraint in 2013 could cause APS Yuma generation to be dispatched out of economic dispatch order for 22 hours. In 2019, the local generation is not expected to be dispatched out of economic dispatch order.

10. The estimated annual economic cost of Yuma area generation required to run out of economic dispatch order is negligible for 2013. There is not expected to be an out of merit order cost of Yuma area RMR generation in 2019. Therefore, advancement of transmission projects to increase import capability is presently not cost justified.

11. Removing the transmission constraint would reduce total Yuma area air emissions by a negligible amount in 2013. The Yuma area did not reach its transmission import limits in 2019, so there is no emission impact.

12. Removing the import restriction into the Yuma area would have a negligible affect on the APS Yuma generation capacity factor in 2013. Since the Yuma area did not reach its transmission import limits in 2019, there is no impact to local generation capacity factor.

13. Removing the transmission constraint could reduce total yearly natural gas consumption by the Yuma area generators by 0.012 BCF and total system natural gas consumption by 0.006 BCF in 2013. Since the Yuma area did not reach its transmission import limits in 2019, there is no impact to total yearly natural gas consumption by the APS Yuma generators.