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Transcript Exhibit(s)

Docket#(s): L-00000A-06-0295-00130

Exhibit # : S-1 to S-42

EXHIBIT
S-1
admitted

BEFORE THE ARIZONA POWER PLANT AND

TRANSMISSION LINE SITING COMMITTEE

IN THE MATTER OF THE APPLICATION, OF SOUTHERN CALIFORNIA EDISON COMPANY AND ITS ASSIGNEES IN CONFORMANCE WITH THE REQUIREMENTS OF ARIZONA REVISED STATUTES SECTIONS 40-360.03 AND 40-360.06 FOR A CERTIFICATE OF ENVIRONMENTAL COMPATABILITY AUTHORIZING CONSTRUCTION OF A 500kV ALTERNATING CURRENT TRANSMISSION LINE AND RELATED FACILITIES IN MARICOPA AND LA PAZ COUNTIES IN ARIZONA ORIGINATING AT THE HARQUAHALA GENERATING STATION SWITCHYARD IN WESTERN MARICOPA COUNTY AND TERMINATING AT THE DEVERS SUBSTATION IN RIVERSIDE COUNTY, CALIFORNIA	)	DOCKET No. L-00000A-06-0295-00130 Case No. 130 **APPLICATION FOR ADMINISTRATIVE SUBPOENA**

The Arizona Power Plant and Transmission Line Siting Committee requests the issuance of subpoenas and subpoenas duces tecum to Mr. Rob Kondziolka and Mr. Robert Smith pursuant to Arizona Administrative Code § R14-3-210 for a joint appearance in connection with the transmission line siting in the above captioned proceeding.

DATED this ____ day of _____ , 2006.

By: _____
Laurie A. Woodall
Assistant Attorney General
Chairman, Arizona Power Plant and
Line Siting Committee

BEFORE THE ARIZONA POWER PLANT AND

TRANSMISSION LINE SITING COMMITTEE

IN THE MATTER OF THE APPLICATION, OF SOUTHERN CALIFORNIA EDISON COMPANY AND ITS ASSIGNEES IN CONFORMANCE WITH THE REQUIREMENTS OF ARIZONA REVISED STATUTES SECTIONS 40-360.03 AND 40-360.06 FOR A CERTIFICATE OF ENVIRONMENTAL COMPATABILITY AUTHORIZING CONSTRUCTION OF A 500kV ALTERNATING CURRENT TRANSMISSION LINE AND RELATED FACILITIES IN MARICOPA AND LA PAZ COUNTIES IN ARIZONA ORIGINATING AT THE HARQUAHALA GENERATING STATION SWITCHYARD IN WESTERN MARICOPA COUNTY AND TERMINATING AT THE DEVERS SUBSTATION IN RIVERSIDE COUNTY, CALIFORNIA	)	DOCKET No. L-00000A-06-0295-00130 Case No. 130 **SUBPOENA AND SUBPOENA DUCES TECUM**

TO: Mr. Rob Kondziolka

Pursuant to Arizona Revised Statute § 40-244, and Arizona Administrative Code § R14-3-210, you are hereby commanded to appear and give your testimony at the time and place specified below:

BEFORE WHOM APPEARANCE TO BE MADE: Arizona Power Plant and Transmission Line Siting Committee

DATE AND TIME OF APPEARANCE: The hearing is initially scheduled to begin on June 26, 2006 at 9:30 a.m. and continuing on June 27, 2006 at 9:30 a.m. Additional hearing days are expected. It is not expected that you will be required to appear on the initial hearing days. The date and time of your appearance is to be determined at a later date and you will be notified upon that determination.

PLACE OF APPEARANCE: The initial place of hearings is The Wigwam Resort 300 Wigwam Blvd., Litchfield Park, Arizona 85340. Continuation of the hearings will either be at the initial place or at a place to be determined. You will be notified of the place of appearance upon determination by the Committee.

YOU ARE COMMANDED to appear, provide testimony and presentation material concerning the above-captioned matter:

As provided in Exhibit A, as attached hereto.

YOU HAVE BEEN SUBPOENAED BY: Arizona Power Plant and Transmission Line Siting Committee

Disobedience of this subpoena constitutes contempt of the Arizona Corporation Commission and is so punishable, pursuant to A.R.S. § 40-424.

Given under the hand and seal of the Arizona Corporation Commission this ____ day of _____, 2006.

By: _____
Executive Director

BEFORE THE ARIZONA POWER PLANT AND

TRANSMISSION LINE SITING COMMITTEE

IN THE MATTER OF THE APPLICATION, OF SOUTHERN CALIFORNIA EDISON COMPANY AND ITS ASSIGNEES IN CONFORMANCE WITH THE REQUIREMENTS OF ARIZONA REVISED STATUTES SECTIONS 40-360.03 AND 40-360.06 FOR A CERTIFICATE OF ENVIRONMENTAL COMPATABILITY AUTHORIZING CONSTRUCTION OF A 500kV ALTERNATING CURRENT TRANSMISSION LINE AND RELATED FACILITIES IN MARICOPA AND LA PAZ COUNTIES IN ARIZONA ORIGINATING AT THE HARQUAHALA GENERATING STATION SWITCHYARD IN WESTERN MARICOPA COUNTY AND TERMINATING AT THE DEVERS SUBSTATION IN RIVERSIDE COUNTY, CALIFORNIA	)	DOCKET No. L-00000A-06-0295-00130 Case No. 130 **SUBPOENA AND SUBPOENA DUCES TECUM**

TO: Mr. Robert Smith

Pursuant to Arizona Revised Statute § 40-244, and Arizona Administrative Code § R14-3-210, you are hereby commanded to appear and give your testimony at the time and place specified below:

BEFORE WHOM APPEARANCE TO BE MADE: Arizona Power Plant and Transmission Line Siting Committee

DATE AND TIME OF APPEARANCE: The hearing is initially scheduled to begin on June 26, 2006 at 9:30 a.m. and continuing on June 27, 2006 at 9:30 a.m. Additional hearing days are expected. It is not expected that you will be required to appear on the initial hearing days. The date and time of your appearance is to be determined at a later date and you will be notified upon that determination.

PLACE OF APPEARANCE: The initial place of hearings is The Wigwam Resort 300 Wigwam Blvd., Litchfield Park, Arizona 85340. Continuation of the hearings will either be at the initial place or at a place to be determined. You will be notified of the place of appearance upon determination by the Committee.

YOU ARE COMMANDED to appear, provide testimony and presentation material concerning the above-captioned matter:

As provided in Exhibit A, as attached hereto.

YOU HAVE BEEN SUBPOENAED BY: Arizona Power Plant and Transmission Line Siting Committee

Disobedience of this subpoena constitutes contempt of the Arizona Corporation Commission and is so punishable, pursuant to A.R.S. § 40-424.

Given under the hand and seal of the Arizona Corporation Commission this ____ day of _____, 2006.

By: _____
Executive Director

EXHIBIT A

This subpoena is hereby served on Mr. Rob Kondziolka and Mr. Robert Smith for the purpose of summoning their appearance as expert witnesses during Arizona's transmission line siting hearings of the Palo Verde to Devers II 500 kV Project. You shall each appear before the Arizona Power Plant and Transmission Line Siting Committee ("Siting Committee") on the date(s) and time(s) established procedurally by the Siting Committee Chairman, Laurie Woodall, in Docket No. L-00000A-06-0295-00130. You are to be called as a Siting Committee witness in your respective areas of expertise: transmission planning. Your testimony is to be considered independent of any position taken by the applicant, Southern California Edison ("SCE"); any intervening party, including the Arizona Corporation Commission Staff ("Staff"); or your respective employers.

You are required to provide testimony in the form of a joint presentation addressing, at a minimum, the issues outlined in the section below entitled Topic of Inquiry. Your presentation material and any associated exhibits are to be filed in accordance with the procedures set forth for the subject proceeding by Chairman Woodall. You may supplement your testimony with any other subject matter you feel would be helpful to the Siting Committee and the Commission in their consideration of the Palo Verde to Devers II 500 kV Transmission Project. You will be subject to cross examination by the intervening parties. You may also be required to answer questions posed by members of the Siting Committee or the Arizona Corporation Commission ("Commission").

FOUNDATION AS INDUSTRY EXPERT WITNESS

Mr. Kondziolka and Mr. Robert Smith have each assumed key leadership roles as the electric industry has engaged in sub-regional and regional transmission studies of the Western Interconnection. Mr. Kondziolka is Chairman of the Western Congestion Assessment Task Force ("WCATF") and the Southwest Area Transmission ("SWAT") sub-regional planning forum. He also is vice chair of the Western Electricity Coordinating Council ("WECC") Planning and Coordination Committee ("PCC"). Mr. Smith is co-chairman of the Southwest Transmission Expansion Plan ("STEP") sub-regional planning forum.

Both Mr. Kondziolka and Mr. Smith have been participants in the Seam Steering Group – Western Interconnection ("SSG-WI") Planning Working Group that has performed economic transmission expansion planning studies for the West and the Western Governor's Association ("WGA"). They are also both members of the Transmission Expansion Planning Policy Committee ("TEPPC") of the WECC Board of Trustees. They have also managed and coordinated industry studies required to comply with Arizona Statutes A.R.S. §40-360 et. seq. regarding ten year plan filings with the Commission and the Commission's related Biennial Transmission Assessment. Those studies have included Reliability Must Run studies of local transmission constrained areas, extreme contingency studies, and Palo Verde Hub risk assessments. Their participation and leadership in these industry forums serves as the foundation for calling upon them as industry experts regarding transmission planning in the Western Interconnection, Desert Southwest and Arizona.

BOUNDS OF TESTIMONY

The technical studies performed in the aforementioned industry forums have considered alternative transmission projects needed to maintain regional and national system reliability standards established by WECC and North American Electric Reliability Council ("NERC"). Reliability serves as the justification of need for such projects. The same forums have performed studies to simulate transmission congestion and investigate the effectiveness of alternative proposed projects in mitigating such congestion. Economics serves as justification of need for such transmission projects. In some instances a project is justified for both reliability and economic reasons. Once need for a project has been established and moves forward for development, the project goes though a WECC process to establish its rating. These three areas of consideration frame the bounds of expert testimony being sought of Mr. Kondziolka and Mr. Smith.

TOPICS OF INQUIRY

Mr. Kondziolka and Mr. Smith have first hand knowledge of how the Palo Verde to Devers II 500 kV Project has been studied on a comparative basis with other projects in each of the following areas: reliability, general economic benefit and path rating. Therefore, they are requested to prepare testimony in the form of a presentation that addresses the following topics.

1. What is transmission congestion and what is the difference between physical congestion and fiscal congestion? Define transmission congestion as presently manifested in the Western Interconnection and in particular the Arizona / California transmission interface? How is transmission congestion between Arizona and California likely to change over time? In what general way(s) are retail consumers affected by transmission congestion?

2. What tools have been developed and used to model and study transmission congestion in the West? How has the electric industry used these tools to study and analyze the Western Interconnection? How well do such congestion studies correlate to congestion actually experienced historically? Can these tools be used to forecast future cost of electricity to consumers with any degree of accuracy?

3. What were the results of the congestion studies assembled by the WCATF for the U.S. Department of Energy ("DOE") congestion assessment of the Western Interconnection? What is the status of DOE's efforts to determine the appropriateness of establishing National Interest Electric Transmission Congestion Corridors ("NIETC") for which the Federal Energy Regulatory Commission ("FERC") will have backstop transmission siting authority? What is the status of DOE's Programmatic Environmental Impact Statement for energy corridors over federal lands in the West? What is the status of FERC's implementation of backstop authority under EPACT 2005?

4. What transmission and generation alternative solutions have been studied in the various study forums to resolve the congestion between Arizona and California? What project(s) or combination of projects has been determined to be effective in mitigating this congestion? How has the industry determined what economic transmission expansion

projects would be developed? What measures or criteria have been used in weighing the merits of alternative projects?

5. Have the regional and sub regional planning groups evaluated any other transmission projects that could address congestion issues between Arizona and California? If so, please discuss these projects. Contrast the potential congestion mitigation effects of those projects with the proposed Palo Verde to Devers II 500 kV Project?

LEWIS AND ROCA LLP LAWYERS

Thomas H. Campbell
40 North Central Avenue
Phoenix, Arizona 85004-4429

FILE COPY

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TCampbell@lrlaw.com
Admitted in: Arizona

Our File Number: 43431-00001

August 3, 2006

VIA HAND-DELIVERY

Jerry D. Smith
Utilities Division
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, Arizona 85007

Keith A. Layton
Legal Division
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, Arizona 85007

Re: Southern California Edison Company's Responses to Arizona Corporation Commission Staff's Seventh Set of Data Requests
Docket No: L-00000A-06-0295-00130

Dear Messrs Layton and Smith:

Enclosed are Southern California Edison Company's Responses to the Arizona Corporation Commission Staff's Seventh Set of Data Requests in the above-captioned proceeding.

Very truly yours,

LEWIS AND ROCA LLP

Thomas H. Campbell

RECEIVED
AUG 03 2006
LEGAL DIV.
ARIZ. CORPORATION COMMISSION

THC/jwp

Enclosures

cc: Michael Mackness

EXHIBIT
S-2
admitted

BEFORE THE ARIZONA POWER PLANT AND

TRANSMISSION LINE SITING COMMITTEE

IN THE MATTER OF THE APPLICATION OF SOUTHERN CALIFORNIA EDISON COMPANY AND ITS ASSIGNEES IN CONFORMANCE WITH THE REQUIREMENTS OF ARIZONA REVISED STATUTES SECTIONS 40-360.03 AND 40-360.06 FOR A CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY AUTHORIZING CONSTRUCTION OF A 500kV ALTERNATING CURRENT TRANSMISSION LINE AND RELATED FACILITIES IN MARICOPA AND LA PAZ COUNTIES IN ARIZONA ORIGINATING AT THE HARQUAHALA GENERATING STATION SWITCHYARD IN WESTERN MARICOPA COUNTY AND TERMINATING AT THE DEVERS SUBSTATION IN RIVERSIDE COUNTY, CALIFORNIA	)	Docket No. L-00000A-06-0295-00130 Case No. 130

SOUTHERN CALIFORNIA EDISON COMPANY'S OBJECTIONS AND RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S SEVENTH SET OF DATA REQUESTS

Southern California Edison Company ("SCE") submits the following objections and responses to the Arizona Corporation Commission Staff's ("Staff") Seventh Set of Data Requests in the above-referenced docket.

GENERAL OBJECTIONS TO ALL DATA REQUESTS

1. SCE objects to each and every Request to the extent it seeks information subject to the attorney-client privilege, work product doctrine or any other privilege recognized by the State of Arizona. In responding to these Requests, SCE does not waive, but preserves, all such privileges.

2. SCE objects to each and every Request to the extent it seeks information that is confidential, sensitive, competitive in nature or proprietary to it. In responding to these requests, SCE does not waive, but preserves, its claim that requests for customer and market information are confidential.

3. SCE objects to each and every Request to the extent that it is unreasonably burdensome, overly broad or not reasonably calculated to lead to the discovery of admissible evidence.

4. SCE objects to each and every one of Staff's definitions and/or instructions to the extent it purports to abrogate any of SCE's rights, or add to any of SCE's obligations under, the Arizona Rules of Civil Procedure or the Commission's Rules.

5. SCE objects to each and every Request to the extent it imposes any burden not expressly permitted under Commission's Rules or the Arizona Rules of Civil Procedure.

6. SCE objects to each and every Request to the extent that it calls for information already in the possession, custody and control of Staff.

7. SCE objects to each and every Request to the extent it seeks information outside of the Staff's possession, custody or control.

8. SCE expressly reserves the right to supplement or amend its objections and responses as necessary.

SCE incorporates the foregoing General Objections into each response as if fully set forth therein.

SPECIFIC DATA RESPONSES

JDS-7.1 The Department of Energy (DOE) has published its preliminary energy corridor maps for its EPAct 2005 Section 368 Programmatic Environmental Impact Study (PEIS) for comment. It depicts a new energy corridor traversing BLM lands in Arizona that appears to be aligned with the I-10 transportation corridor. The DLM is involved in both the PEIS and the EIR/EIS for the second Palo Verde to Devers Project. Nevertheless, the corridor conclusions of the two NEPA environmental processes appear to be contradictory.

a: Were the same BLM organizational units invovled in the PEIS and the DPV2 EIR/EIS efforts?

RESPONSE: Several members of the staff of the Phoenix and Yuma BLM Field Offices in Arizona, and the Palm Springs Field Office in California, are listed in Appendix 5 - Preparers and Reviewers of the DEIR/DEIS (Exhibit A-3, vol. 3). Participation and input from the Phoenix and Yuma Field Offices through the State office was requested by the Department of Energy (DOE) in preparation of the West-wide Energy Corridor Programmatic EIS. The BLM staff indicated that they were only "peripherally" involved and that information from the Phoenix and Yuma BLM Resource Management Plans indicating existing designated utility corridors was not included in the West-wide Potential Energy Corridor Map for Arizona, although the purpose of the mapping effort was to include designated utility corridors and/or rights-of-way.

b: Did SCE consider the I-10 corridor proposed by the PEIS in Arizona as a route for the DPV2 Project? If so, why was it eliminated as an alternative? Please provide an explanation if the PEIS I-10 corridor alignment was not considered by SCE.

RESPONSE: The I-10 corridor was previously considered and eliminated from consideration as an alternative route for the DPV2 Project for the reasons set forth below.

In previous studies for the DPV2 project, a route was considered within the I-10 corridor in Arizona as shown on the "Ongoing Work by Federal Agencies on Potential Energy Corridors (Preliminary Draft – Subject to Change), June 2006 Status Map (Potential Energy Corridors map)." The reasons why a route within the I-10 corridor was eliminated from further consideration was documented in the Final Supplemental EIS (BLM 1988), on page 1-6 (Exhibit B-1) as follows:

> "The Federal Land Policy and Management Act of 1976 (section 503) requires that existing utility corridors be used to the extent practicable. The eastern portion of the I-10 route does contain existing utilities. Although the western portion of this corridor does contain some facilities (pipelines), each project must be evaluated individually to determine if it is compatible… A 500kV transmission line was not considered suitable for this corridor because of very high visual impacts. In addition, there are overhead restrictions on link UC-10 because of resource concerns. For these reasons, no further consideration of this route as a viable alternative was deemed warranted…."

Since 1989, when the decision was made by the BLM to grant the right-of-way for the DPV2 transmission line, there have been minimal changes to the conditions within the DPV2 corridor or the I-10 corridor. There are no new overhead transmission lines and there are no significant changes to the existing environmental conditions within either the proposed corridor or

within the I-10 corridor since the right-of-way was granted.

In previous studies for the DPV2 project, SCE considered two subalternate routes that would include portions of up to approximately 15 to 20 miles of the new 500kV transmission line within the I-10 corridor. Subalternate 1 and Subalternate 4 were illustrated on Map 3-1 in the PEA (page 3-7, Exhibit B-2 to Exhibit A-1) and on Figure Ap.1-2 (page Ap.1-41 of the Draft EIR/EIS, v.3, Appendix 1). Several reasons for eliminating these subalternate routes from further consideration were documented in the PEA (Chapter 3, p.3-5 through 3-12) and also in the Draft EIR/EIS (Appendix 1, Section 4). Subalternates 1 and 4 would result in higher levels of visual impact and greater amounts of permanent ground disturbance than the proposed route parallel to DPV1.

A route located along I-10 would be inconsistent with the BLM Lower Gila South Resource Management Plan (RMP), which prohibits overhead transmission lines in the I-10 corridor. According to current planning efforts for the BLM's DRMP/DEIS, no new utility corridors would be designated for overhead transmission lines along I-10 within the Bradshaw-Harquahala planning area in the Phoenix Field Office. Within the Yuma Field Office area, I-10 passes through the Dome Rock Mountains across trust lands restored to the Colorado River Indian Tribe (CRIT) by Congress by the Boundary Correction Act on July 26, 2005; previously the Tribal Council would not allow a right-of-way for DPV2 across tribal lands.

Based on these factors as described above, SCE did not reconsider a route along the I-10 corridor in its current applications to construct and operate the DPV2 project.

c: Was consolidation of facilities in a common existing corridor and contiguous rights of way a priority in the BLM and SCE environmental assessment in the DPV2 EIR/EIS process?

RESPONSE: Priorities identified in the alternatives screening process were stated in the DEIR/EIS, and included "Legal Feasibility" and "Regulatory Feasibility" (Exhibit A-3, v. 1, Section C.2.1.3, page C-4). In the process of granting rights-of-way or permits, the BLM is guided by FLPMA to consolidate compatible uses in rights-of-way in common, stated as follows in Section 503:

> "In order to minimize adverse environmental impacts and the proliferation of separate rights-of-way, the utilization of rights-of-way in common shall be required to the extent practical, and each right-of-way or permit shall reserve to the Secretary concerned the right to grant additional rights-of-way or permits for compatible uses on or adjacent to rights-of-way granted pursuant to this Act."

d: The PEIS document claims the majority of preliminary energy corridors utilize existing corridors and/or rights of way. Does this imply that in the PEIS process the BLM views the I-10 corridor more appropriate for consolidation of energy infrastructure than the existing DPV and gas pipeline rights of way?

RESPONSE: No. The Potential Energy Corridors identified in the PEIS may not be suitable for overhead transmission lines, although they may include oil, gas, and hydrogen pipelines. The BLM views regarding the I-10 corridor have not yet been included in the West-wide PEIS process. As stated in 7.1(c) above, the purpose of the mapping effort was to include existing designated utility corridors and/or rights-of-way on BLM land, although it is unclear why the Potential Energy Corridors map excluded the existing BLM-designated utility corridors. The corridors are drawn only on BLM lands, and the extension of contiguous rights-of-way crossing private, state, municipal, and tribal lands may not be feasible. The jurisdictional data on the Potential Energy Corridors map does not recognize the CRIT boundary adjustment of 2005; the portion of the I-10 corridor that traverses the Dome Rock Mountains is shown incorrectly as BLM land instead of Tribal Trust land.

e: Were environmental field studies of the I-10 corridor proposed by the PEIS in Arizona performed during the EIR/EIS process for the DPV2 Project?

RESPONSE: No. Environmental field studies of the entire I-10 corridor (identified as a "Potential Energy Corridor", not the "corridor proposed by the PEIS") were not performed during the EIR/EIS process for the DPV2 Project. However, there were field studies performed by the "EIR/EIS team" in December 2005 for the Subalternate Routes 1 and 4, which include portions of the I-10 corridor, as noted in Appendix 1 of the DEIR/DEIR.

f: Are there any environmental considerations that would preclude consideration of the PEIS proposed corridor as a route for the DPV2 Project?

RESPONSE: Yes, there are environmental considerations that would preclude consideration of the PEIS potential energy ("proposed" I-10) corridor as a route for the DPV2 project. As stated in the response to JDS 7.1.b, the I-10 corridor was eliminated as a potential route for the DPV2 transmission line in the Final SEIS in 1988. Subsequent reviews in the current environmental study process have been conducted that confirm that an alternative route in the I-10 corridor would not be environmentally acceptable. Note that the potential energy corridors depicted on the June 2006 Status Map are subject to change; the proposed corridors will be officially established in August 2007, and must be designated in compliance with applicable laws and regulations. The Potential Energy Corridor identified along I-10 does not comply with BLM regulations. Regulations administered by the BLM Phoenix and Yuma Field Offices require that environmental studies be completed in compliance with NEPA in order to permit the construction of a new transmission line, even if it is located within a designated utility corridor. When the process is completed, the officially designated energy corridor for the PEIS could be the same as the proposed route for the DPV2 transmission line that is described in the DEIR/DEIS.

JDS-7.2 Staff previously provided comments in the PEIS[1] and EIR/EIS[2] process regarding siting facilities in corridors solely based upon environmental considerations. A copy of both documents is enclosed for your reference. Please cite all references in the most recent draft EIR/EIS that are responsive to reliability concerns raised by Staff in the two documents. In particular, cite any reference that:

a: Documents the justification of a regional need for the proposed action, compares the effectiveness of the various alternative solutions in meeting that regional need, and ascertains the cumulative effects of the proposed action and alternative solutions on the environment.

RESPONSE: Regional need: Section A.2 "Purpose and Need for the Proposed Project" (pp. A-7 – A-17)

Compares alternative solutions: Section C.4 "Alternatives Evaluated in the EIR/EIS" (pp. C-17 – C-65, Appendix 1)

Cumulative impacts: Section F "Cumulative Scenario and Impacts"

b: Identifies any currently prevailing environmental conditions that would preclude construction of a second line on separate structures through Copper Bottom Pass.

RESPONSE: Environmental conditions in Copper Bottom Pass are described in the Biological Resources (Section D.2.2.3), including the presence of migratory birds and bighorn sheep (p. D.2-56). This area was

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1 ACC Utilities Division, Director Ernest Johnson's November 28, 2005 letter to Ms. Julie Souder regarding PEIS scoping meeting comments filed in Federal Register Doc. 05-19375.

2 ACC Utilities Division, Staff EIR/EIS comments filed by Jerry Smith with CPUC, Aspen and BLM on March 10, 2006 regarding January 18, 2006 scoping meeting for DPV2.

also described in the PEA as subject to potentially significant impacts associated with low-density bighorn area at Copper Bottom Pass. The "Applicant Proposed Mitigation Measures" listed in Table D.2-6 (p. D.2-100) refer specifically to mitigation that would be implemented in Copper Bottom Pass, as follows:

APM B-5 Vegetation/ Wildlife

Copper Bottom Pass:

- Maintenance of low speed limit on right of way ROW to protect desert animals and reduce dust
- Continuous application of water to ROW roads to reduce dust
- Requirement that stopped vehicles stop engines if stationary for a determined period of time
- Requirement that operators of vehicles, if stopped for longer than a determined period of time, inspect under their vehicles to ensure that no animals have taken shelter from the sun; this requirement has been implemented before by requiring that vehicles with stopped engines have their keys placed under the vehicle thus forcing the operator to inspect
- Flagging of all disturbed areas if needed to clarify drive-able or walk-able areas
- Tight control of the Copper Bottom Pass area to ensure that only planned construction traffic is allowed in the area and that minimal trips are planned
- Restricted use of the area to periods outside of any animal breeding seasons

- Tight control on electrical workers for approved hours of access
- Ensure that all workers accessing this area have completed environmental awareness training for biological and cultural sensitivities; all trained workers would be equipped with stickers for their hardhats to provide for easy to spot inspection
- Removal of all construction debris from the area at the conclusion of the work

Although there are no environmental conditions that would "preclude" construction of a second line, it would be difficult to reduce the level of impacts to acceptable levels.

c: Ascertains whether the 241 feet height of double circuit structures in Copper Bottom Pass is solely the result of being designed for attaching two lines?

RESPONSE: We have not found any references in the draft EIR/EIS

d: Establishes whether there are terrain impediments to constructing a second line through Copper Bottom Pass in right of way contiguous to the existing line as is being proposed throughout the remainder of the DPV2 Project.

RESPONSE: Terrain impediments to construction were not discussed in the Draft EIR/EIS but they were identified by the BLM in its 1981 Decision requiring double circuit towers in Copper Bottom Pass.

e: Address whether there are environmentally acceptable alternative routes to the three mile long right of way through Copper Bottom Pass.

RESPONSE: No environmentally acceptable alternative routes were identified through either of these jurisdictions in the Draft EIR/EIS. Alternative routes to the north of the existing Copper Bottom Pass right-of-way would require acquisition of a new easement through the CRIT reservation. The "North of Blythe Alternative" was evaluated in the Draft EIR/EIS, as described in Section C.5.2.4 (pp. C-36 – C-39) and shown on Figure C-2a. This alternative route, also described as Subalternate 2 in the previous studies, would cross the Dome Rock Mountains north of I-10. This route was eliminated from further consideration because it would (1) require an amendment to the Lower Gila South RMP; (2) increase the length and intensity of short-term construction impacts and ground disturbance, affecting air quality , noise, transportation and traffic, and geologic resources related to soil erosion; (3) establish a new transmission corridor and require considerable upgrading and construction of new roads; (4) pass through bighorn sheep habitat, creating potentially significant impact to high-quality bighorn sheep habitat and nearby lambing areas in the North Plomosa Mountains; (5) impact agricultural land on the CRIT reservation; (6) create significant visual impacts to viewers from the La Posa Designated Camping Area, Highway 95, back-country recreationists accessing the Boyer Gap area, and the Colorado River crossing; (7) impact cultural resources on the CRIT reservation; (8) require two additional crossings of I-10.

While the draft EIR/EIS did not specifically assess routes south of Copper Bottom Pass, we note that such alternatives would require a new easement through the U.S. Department of Army - Yuma Proving Grounds.

JDS-7.3 Has either Aspen or EPG performed an assessment of environmental impacts of the proposed or alternative DPV2 routes traversing state or private lands in Arizona? If so, please describe what parties and individuals performed that assessment and cit all references to such an assessment in the EIR/EIS and the environmental material filed for the Arizona CEC application.

RESPONSE: Although major portions of the proposed and alternative routes cross federal lands in Arizona, all of the environmental studies of the proposed and alternative DPV2 routes that were performed by Aspen and EPG also included detailed study of the state and private lands contained within the corridors. The list of EPG individuals that performed the environmental assessment is included in Chapter 11 of the Proponent's Environmental Assessment (PEA), Exhibit B-2 to the CEC Application (Exhibit A-1). The list of the Aspen individuals that performed the environmental assessment is included in Appendix 5 - Preparers and Reviewers of the DEIR/DEIS the DEIR/DEIS (Exhibit A-3, v.3)

JDS-7.4 Has either Aspen or EPG done any environmental field reconnaissance in Arizona for the DPV2 Project? If so, please describe the purpose of such investigations, the parties and individuals that performed such field investigations and the dates of such activities. Cite documentation of all such activities in the EIR/EIS reports or environmental material filed for the Arizona CEC application. If neither Aspen nor EPG have done any field reconnaissance in Arizona for DPV2 please identify when such activity last occurred, who performed such field activities and the scope of such investigations.

RESPONSE: Both Aspen and EPG have performed field reconnaissance in Arizona for the DPV2 project. The results of field reconnaissance conducted by EPG were documented in Chapter 4 of the Proponent's Environmental Assessment (PEA), Exhibit B-2 to the CEC Application (Exhibit A-1). The following table includes the dates, purpose of the investigations, and individuals employed by EPG that performed the field reconnaissance.

Environmental Field Reconnaissance Conducted in Arizona by EPG for the Devers-Palo Verde No. 2 Project		
Dates	**Individuals**	**Purpose of Field Investigation**
2002		
April 30 – May 7, 2002	Kirsten Lake, Locana deSouza	Biological resources study
2003		
April 12-18, 2003	Locana deSouza	Biological resources study
May 13, 2003	Linwood Smith	Biological resources study
June 19, 2003	Locana deSouza, Michael Schroff	Biological resources study
October 1-3, 2003	Locana deSouza, Michael Schroff	Biological resources study
October 22-24, October 28-31, November 3-4, November 23-24, 2003	Sharon Bauer, Scott Wilcox, Glennda Luhnow, Kris Dobschuetz, Kelly Peoples, Jeff Roberson, Elizabeth Alter	Cultural resources survey
December 8-11, December 15-17, 2003	Glennda Luhnow, Elizabeth Alter, Yumi Yoshino, Scott Wilcox, Lisa Champagne, Torrey Cunningham	Cultural resources survey
May 12, 2003	Mickey Siegel, Paul	Visual resources and land use

Environmental Field Reconnaissance Conducted in Arizona by EPG for the Devers-Palo Verde No. 2 Project		
Dates	**Individuals**	**Purpose of Field Investigation**
	Trenter	update (helicopter)
May 13, 2003	Linwood Smith, Newton DeBardeleben	Biological resources and land use inventory (helicopter)
July 7-15, 2003	Michael Doyle	Visual resources and land use inventory
July 15, 2003	Sarah Homuth	Visual resources inventory
November 11, 2003	Newton DeBardeleben, Marc Schwartz	Visual resources and land use inventory
December 10, 2003	Mickey Siegel, Newton DeBardeleben	Visual resources and land use inventory
2004		
February 20, 2004	Mickey Siegel	Route overview
March 23, 2004	Linwood Smith, Mickey Siegel	Biological resources
April 12, 2004	Glennda Luhnow, Pamela Rainey	Cultural resources survey
May 4-7, 2004	Glennda Luhnow, Elizabeth Alter, Yumi Yoshino, Scott Wilcox, Lisa Champagne, Torrey Cunningham	Cultural resources survey

Environmental Field Reconnaissance Conducted in Arizona by EPG for the Devers-Palo Verde No. 2 Project		
Dates	**Individuals**	**Purpose of Field Investigation**
May 10-11, 2004	Glennda Luhnow, Elizabeth Alter, Yumi Yoshino, Scott Wilcox, Lisa Champagne, Torrey Cunningham	Cultural resources survey
January 22, 2004	Newton DeBardeleben, Mathew Millitello, Marc Schwartz	Visual resources and land use inventory
February 20, 2004	Mickey, Siegel, Joe Dickinson	Visual resources and land use inventory
March 23, 2004	Mickey Siegel	Land use and feature inventory
July 26, 2004	Randy Palmer, Marc Schwartz	Visual resources and land use inventory
2005		
November 1, 2005	Mickey Siegel	Visual resources and land use inventory
2006		
March 24, 2006	Kris Dobschuetz, Joe Dickinson	Cultural resources survey
April 11, 2006	Mickey Siegel	Environmental resource inventory
June 22, 2006	Randy Palmer	Visual resources and land use

Environmental Field Reconnaissance Conducted in Arizona by EPG for the Devers-Palo Verde No. 2 Project		
Dates	**Individuals**	**Purpose of Field Investigation**
		inventory
July 12, 2006	Marc Schwartz	Visual resources and land use inventory

The following are references to some of the field reconnaissance surveys performed in Arizona by members of the Aspen Environmental Group and subconsultants, as listed in the Draft EIR/EIS (Exhibit A-3):

October 2005 – Biological resources (p. D.2-2)

June 2005, September 2005, and February 2006 – Site visits/land use (p. D.4-13)

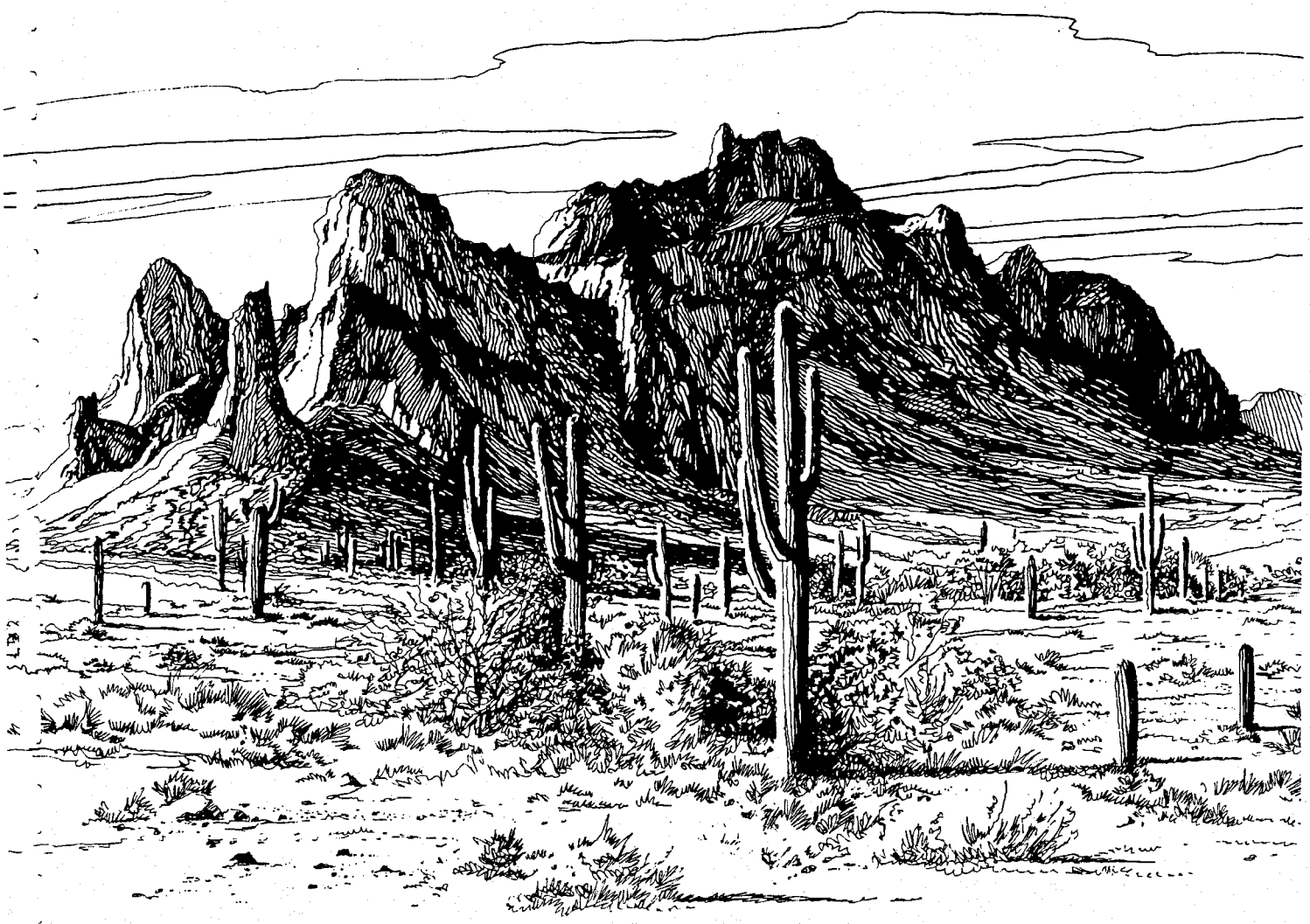
December 2005 – Cultural resources, Subalternate 1 (p. A.1-50)

LOWER GILA SOUTH

Resource Management Plan
Environmental Impact Statement
Phoenix District, Arizona

Final

EXHIBIT
S-3
admitted

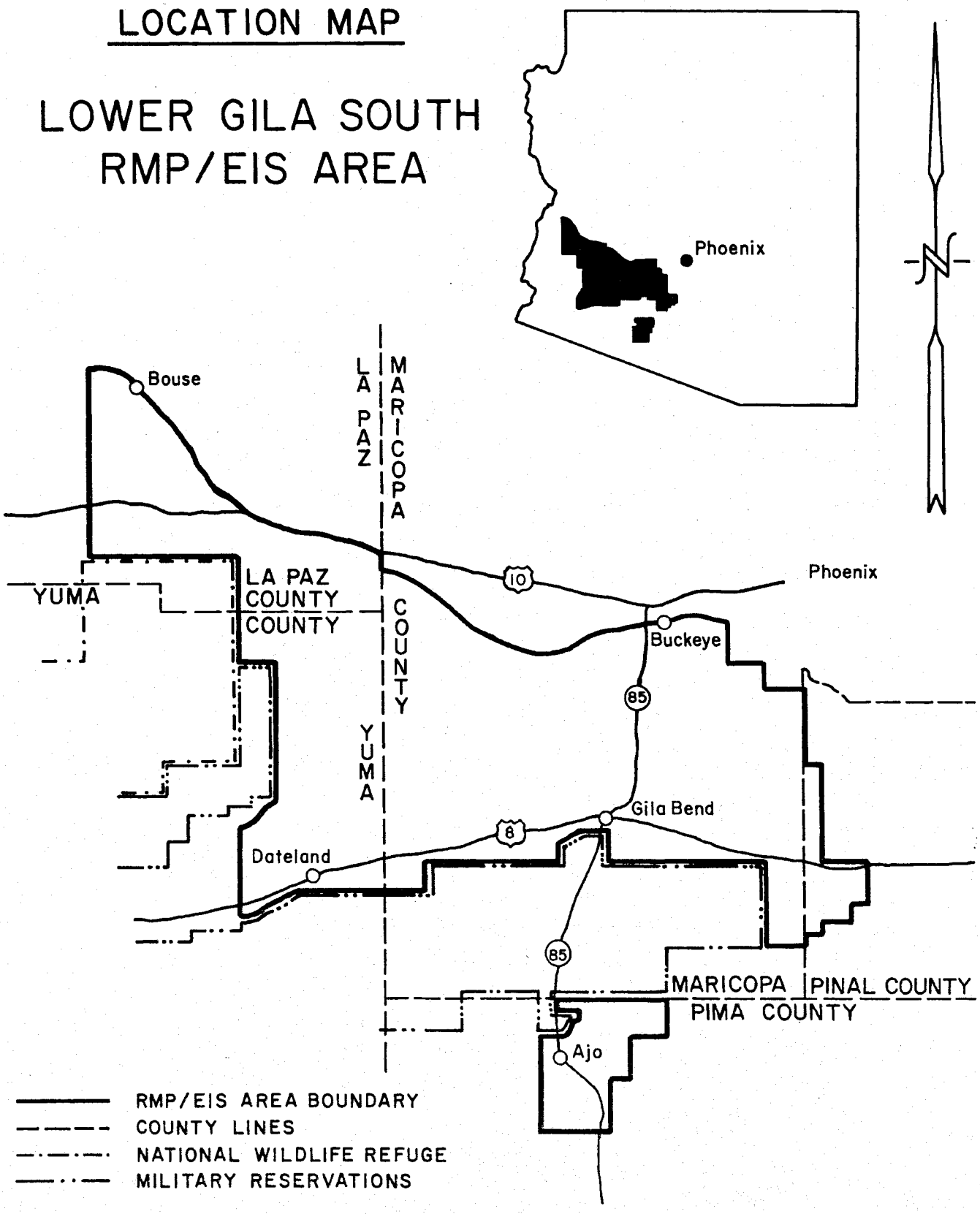


PHOENIX DISTRICT OFFICE
U.S. Department of the Interior
Bureau of Land Management
Arizona

S-3

LOCATION MAP

LOWER GILA SOUTH RMP/EIS AREA



IN REPLY REFER TO:

United States Department of the Interior

BUREAU OF LAND MANAGEMENT
Phoenix District Office
2015 West Deer Valley Road
Phoenix, Arizona 85027

August 1985

Enclosed for your review is the final environmental impact statement (FEIS) for the Lower Gila South Resource Management Plan (RMP). The draft environmental impact statement (DEIS) was published in February 1985, and the 90-day public comment period ended May 2, 1985. Changes based on public comments and new information have been incorporated into this FEIS and all portions of the draft, excluding the wilderness supplement, have been reprinted in order to portray those changes. This FEIS contains the proposed (preferred) resource management plan, which is a refinement of the proposed alternative in the draft. The proposed plan is the BLM's proposed action.

The RMP/EIS will not recommend whether WSAs are suitable or nonsuitable for inclusion in the National Wilderness Preservation System (NWPS). These recommendations will be reported in the final wilderness EIS for the Lower Gila South planning area through the Director of the Bureau of Land Management (BLM) to the Secretary of the Interior and to the President. Designation of an area as wilderness can only be made by Congress.

With the exception of wilderness recommendations, all parts of this proposed plan may be protested. A separate wilderness environmental impact statement is required and will be prepared. Non-wilderness related protests should be sent to the Director (202), Bureau of Land Management, U.S. Department of the Interior, 18th and C Streets NW, Washington D.C. 20240, within the 30-day protest period (ending date stamped on title page). Protest statements should contain the following information:

- The name, mailing address, telephone number and interest of the person filing the protest.
- A statement of the issue being protested.
- A copy of all documents addressing the issue or issues that were submitted during the planning process by the protesting party or an indication of the date the issue or issues were discussed for the record.
- A short concise statement explaining why the BLM State Director's decision is believed to be wrong.

At the end of the 30-day protest period, the proposed plan, excluding any portions under protest, shall become the final. Approval shall be withheld on any portion of the plan under protest until final action has been completed on such protest. The Final Resource Management Plan and record of decision will be published in late 1985.

Sincerely,

Marlyn V. Jones
District Manager

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Chapter 1

PURPOSE AND NEED

CHAPTER 1

PURPOSE AND NEED

INTRODUCTION

The *Resource Management Plan* (RMP) is designed to guide and control future management actions and the development of more detailed and limited scope activity plans for resources and uses. The activity plans that will be developed for the Lower Gila South Planning Area will be site specific and will involve input from other federal, state and local agencies and the interested public. Activity plans may be prepared for allotments, wildlife areas, recreation areas, designated wilderness areas, and for other resources such as cultural resources and threatened and endangered species.

Many comments received on the Lower Gila South RMP/EIS requested more detailed and site-specific data. This plan was not designed to address site-specific actions nor the impacts of those actions. The site-specific actions and impacts will be analyzed in the activity plans and associated environmental assessments.

The RMP will guide the development of the activity plans and the implementation of those and other actions in the planning area.

The *Lower Gila South Resource Management Plan/Environmental Impact Statement* (RMP/EIS) was prepared to provide a comprehensive framework for managing and allocating public land and resources in BLM's Lower Gila South RMP/EIS Area in southwestern Arizona.

The contents of this RMP/EIS are focused on resolving key issues that were developed through public input. The issue identification and public participation phases for this document began in November 1980 with mailouts and public meetings and continued through June 1983 when writing of this document began. (See *Chapter 5, Scoping and Public Participation*, for specific details.)

Several statutory or court-ordered requirements will be met when the decisions proposed in this plan are approved. As required under Section 603 of the *Federal Land Policy and Management Act of 1976* (FLPMA), this document analyzes preliminary wilderness suitability recommendations for 12 wilderness study areas (WSAs). The RMP/EIS will not recommend whether WSAs are suitable or nonsuitable for inclusion in the *National Wilderness Preservation System* (NWPS). These recommendations will be reported in the final wilderness EIS for the Lower Gila South planning area through the Director of the Bureau of Land Management (BLM) to the Secretary of the Interior and to the President. Designation of an area as wilderness can only be made by Congress.

On April 18, 1985 U.S. District Court Judge Lawrence Karlton, for the Eastern District of California, ruled in the Sierra vs. Watt that mineral estates are to be considered for wilderness. Certain mineral estate lands were deleted from wilderness review in 1982 and 1983. The above decision restores these lands to wilderness study. There were 14,374 acres of these lands within the WSAs studied in the draft EIS. This final EIS incorporates the 14,374 acres in the WSAs analyzed. Also, one WSA within the planning area was deleted from wilderness study in 1983, the Sierra Estrella, and will be studied in a state-wide wilderness EIS to begin in 1986 and to be completed in 1987. This RMP/EIS also analyzes alternatives for livestock grazing on public land, as required under a court-ordered agreement based on a 1973 lawsuit filed against BLM by the Natural Resource Defense Council (NRDC).

This document will address possible future management of the area for the next 10 or more years. When necessary, revisions will be made to the RMP to keep it current with resource management needs and policies.

SETTING

The Lower Gila South RMP/EIS area is in the Lower Gila Resource Area in southwestern Arizona. It includes portions of Maricopa, Pinal, Pima, Yuma, and La Paz Counties. BLM has management responsibilities on approximately 2,009,232 surface acres and 1,946,485 acres of subsurface minerals.

The primary economic uses of lands in the RMP/EIS area are agriculture, livestock grazing, mining, and recreation.

Except for approximately 63,000 acres along the Fred J. Weiler Green Belt (Gila River) most of the public lands in the area are in consolidated blocks. Population centers include Buckeye, Gila Bend, and Ajo. Phoenix is the major population center nearest to the RMP/EIS area.

PLANNING PROCESS OVERVIEW

BLM's planning process, as described in 43 CFR 1600, involves nine action steps and requires using an interdisciplinary team for the completion of each step. The

Lower Gila South RMP Action Steps listed below are described in detail in Appendix 1.

1. Inventory Data and Information Collection
2. Identification of Issues
3. Development of Planning Criteria
4. Analysis of Management Situation
5. Formulation of Alternatives
6. Estimation of Effects of Alternatives
7. Selection of the Preferred Alternative
8. Selection of the Resource Management Plan
9. Monitoring and Evaluation

The Lower Gila South RMP/EIS is designed to resolve three of the five public issues and BLM management concerns. The Fred J. Weiler Green Belt issue will be resolved through a management plan developed in cooperation with the U.S. Fish and Wildlife Service, Arizona Game and Fish Department, and BLM. The wilderness recommendations will be made in the final wilderness EIS for the Lower Gila South area.

The five planning issues (rangeland management, wilderness, land tenure, utility corridors, and the Fred J. Weiler Green Belt) were identified based on input from public land users, assigned BLM interdisciplinary team specialists, and city, county, state, and other federal government agencies. These issues were then reviewed by BLM managers. Responses to the issue identification step were obtained through public meetings and brochure mailings to help identify the five major issues of concern. The issues have been examined and alternative ways to resolve the issues have been developed.

ISSUES ANALYZED

These specific issues resulted from public input at scoping meetings, from brochure mailings, from BLM resource specialists, and input from other government agencies. The following is a brief description of the issues analyzed in Chapter 4.

Issue 1: Rangeland Management

The Lower Gila South RMP/EIS area has 48 grazing allotments on public land. Present rangeland management actions need to be reviewed in order to balance resource use opportunities and to aid in stabilizing the livestock industry through management actions. Rangeland developments, level of management, and results of monitoring studies are needed to improve trends in rangeland condition and/or maintain good rangeland conditions. Resolution of these issues should satisfy the requirement of the court-ordered agreement between BLM and the Natural Resource Defense Council (NRDC).

Issue 2: Wilderness

The *Federal Land Policy and Management Act* (FLPMA) of October 21, 1976, directed BLM to inventory, study, and then report to Congress (through the Secretary of the Interior and the President) the public lands suitable for inclusion into the National Wilderness Preservation System (NWPS).

As required by Section 603(a) of FLPMA, this resource management plan analyzes for wilderness suitability 12 wilderness study areas (WSAs) in the Lower Gila South RMP/EIS area (Table 1-1 and Map 1-1). For these WSAs, the RMP will make only preliminary recommendations as to whether they are suitable or nonsuitable for inclusion in the NWPS. Needed resolutions include:

- Which WSAs or portions of WSAs should be recommended to Congress as suitable for inclusion in the NWPS?
- Which WSAs or portions of WSAs should be recommended to Congress as nonsuitable for wilderness designation?
- How will areas not designated wilderness be managed?
- What are the environmental impacts of nondesignation on wilderness values?
- What identified or potential mineral and energy resource values could be forgone or adversely affected by wilderness designation?
- What other resource uses or values could be forgone or adversely affected by wilderness designation?
- What resources will benefit from wilderness designation?
- What are the local social and economic impacts of designation?

TABLE 1-1
WILDERNESS STUDY AREAS--LOWER GILA SOUTH RMP/EIS
Bureau of Land Management, Phoenix District, Arizona

WSAs	Unit Numbers	Acreage
New Water Mountains	AZ-020-125	40,600
Little Horn Mountains West	AZ-020-126A	13,800
Little Horn Mountains	AZ-020-127	91,930
Eagletail Mountains	AZ-020-128	119,700
East Clanton Hills	AZ-020-129	36,600
Face Mountain	AZ-020-136	27,575
Signal Mountain	AZ-020-138	20,920
Woolsey Peak	AZ-020-142/144	73,930
North Maricopa Mountains	AZ-020-157	75,483
South Maricopa Mountains	AZ-020-163	72,004
Butterfield Stage Memorial	AZ-020-164	9,566
Table Top Mountains	AZ-020-172	39,823
TOTAL		621,931

SOURCE: Phoenix District files

A separate final wilderness legislative EIS and wilderness study report will be prepared as a result of the RMP/EIS planning effort. These documents will be forwarded to Washington, D.C. for review by the BLM

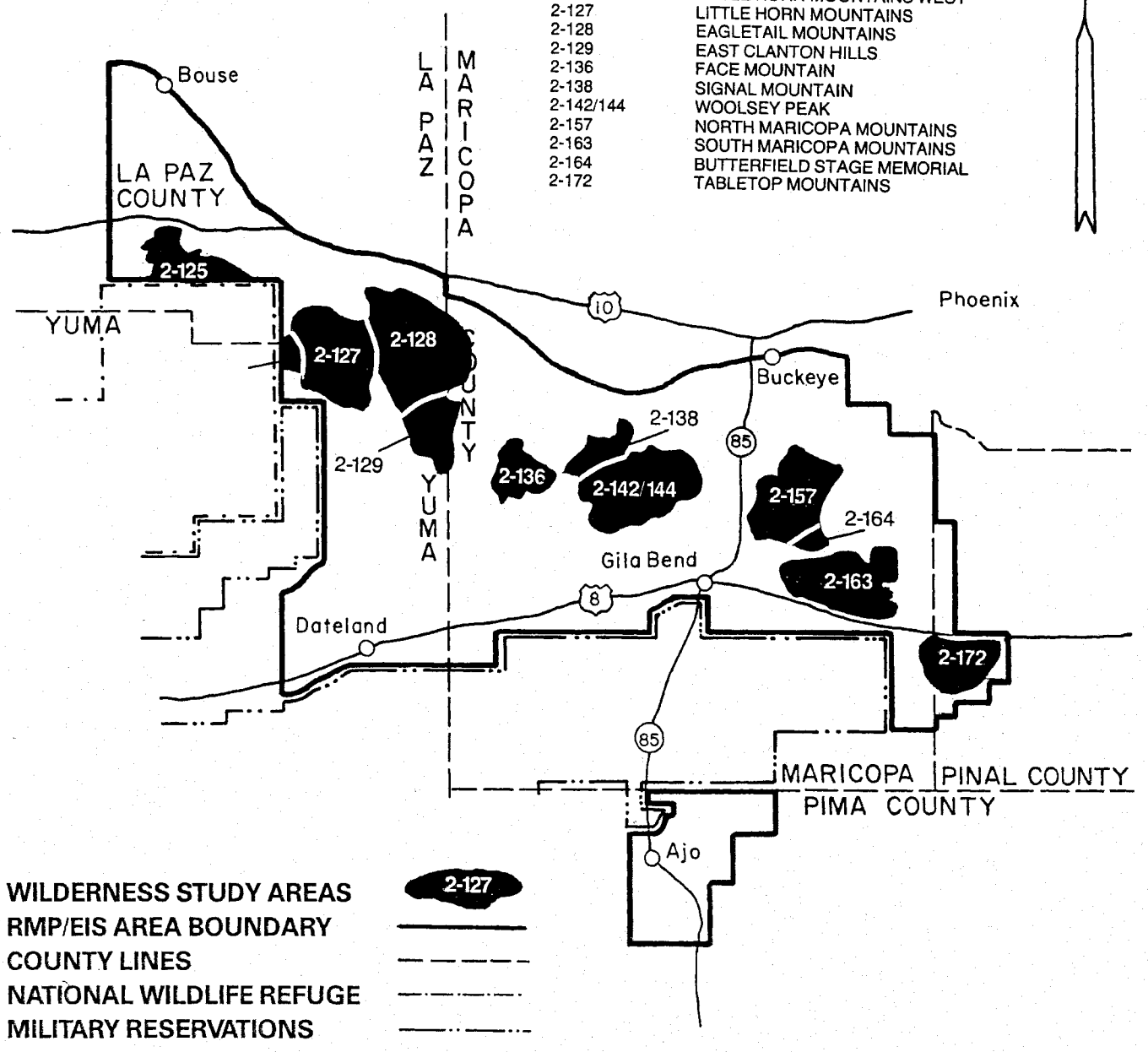
MAP 1-1

LOCATION MAP

LOWER GILA SOUTH RMP/EIS AREA

LEGEND

UNIT NUMBER	WILDERNESS STUDY AREA
2-125	NEW WATER MOUNTAINS
2-126A	LITTLE HORN MOUNTAINS WEST
2-127	LITTLE HORN MOUNTAINS
2-128	EAGLETAIL MOUNTAINS
2-129	EAST CLANTON HILLS
2-136	FACE MOUNTAIN
2-138	SIGNAL MOUNTAIN
2-142/144	WOOLSEY PEAK
2-157	NORTH MARICOPA MOUNTAINS
2-163	SOUTH MARICOPA MOUNTAINS
2-164	BUTTERFIELD STAGE MEMORIAL
2-172	TABLETOP MOUNTAINS



WILDERNESS STUDY AREAS 2-127
RMP/EIS AREA BOUNDARY
COUNTY LINES
NATIONAL WILDLIFE REFUGE
MILITARY RESERVATIONS

Director and the Secretary of the Interior before the recommendations in this plan are submitted to the President and Congress.

FLPMA requires the Secretary of the Interior to report his recommendations to the President by October 21, 1991, and the President has until October 21, 1993, to send his recommendations to Congress. Only Congress can designate a WSA as wilderness, but Congress has set no time limit for acting on the President's recommendations.

The analysis of WSAs described in this RMP/EIS result from the application of BLM's *Wilderness Study Policy* (Federal Register, 47:23, February 3, 1982) during the preparation of the Lower Gila South Management Situation Analysis (MSA). The Wilderness Study Policy directed BLM to apply certain criteria and quality standards to each WSA to ensure that wilderness suitability recommendations are (1) based on full consideration of all multiple resource values of public lands, (2) consistent with established national policy, and (3) that all interested and affected members of the public and state and local governments are made aware of the study and given adequate opportunity to comment and otherwise be involved in the study process.

Issue 3: Land Tenure Adjustment

Special attention is needed for identified areas where land ownership patterns pose a problem for proper management of the federal lands. Some land ownership adjustments such as exchanges, sales, state selections, and acquisitions would be beneficial to the management of wilderness, crucial wildlife habitat, and other resources. Special attention would be given to administrative costs, location, manageability, and resource values of all areas selected for land ownership adjustments.

Needed resolutions include (1) which lands should be retained in federal ownership, (2) which lands should be disposed of through either exchange or sale, (3) which private, state, or federal land exchanges would be used to consolidate ownership to benefit wilderness, wildlife, and cultural resources, and (4) where nonfederal surface or subsurface acreage should be acquired to benefit specific BLM programs?

Split Estate. The split estate issue is one not confined to the Lower Gila South RMP/EIS Area, but is a statewide problem. Therefore, it is important to identify those areas where the split estate occurs in order to help facilitate the statewide program.

Disposal of those federal minerals that underlie either state or private lands may be accomplished by exchanges or sales in accordance with Section 209 of the *Federal Land Policy and Management Act*. Acquisition of the state or private mineral estates that underlie federal surface would be accomplished by exchange.

Issue 4: Utility Corridors

Private and public utility companies and other agencies need to know where utility corridors would be designated so they can develop their plans based on known, approved corridors dedicated primarily for the use and construction of their structural facilities. Other public land users also need to know where future powerlines and pipelines will be located. If WSA boundaries are not adjusted to allow for utility corridor expansion, there could be conflicts between five utility corridors and eight WSA boundaries. This RMP/EIS identifies 10 existing utility rights-of-way that should be designated to serve as utility corridors and recommends that each of these corridors be one-mile-wide. The proposed corridors are (1) El Paso Natural Gas, (2) Palo Verde-Devers, (3) San Diego Gas and Electric Interconnect, (4) Palo Verde-Kyrene, (5) Liberty-Gila Bend, (6) Gila Bend-Ajo, (7) Santa Rosa-Gila Bend, (8) Tucson Electric Power, (9) Interstate 8, and (10) Interstate 10 (Map 1-2).

The Interstate 10 corridor, because of resource concerns, will have a restriction regarding overhead lines. Due to the close proximity of important bighorn sheep waters and lambing grounds north of the Interstate and because of terrain features north of the Interstate, overhead transmission lines will not be allowed north of I-10 between townships 16 W. and 18 W.

Currently there are two communication sites in the RMP/EIS area, Oatman Mountain west of Gila Bend and Guadalupe Mountain east of Quartzsite, both of which have room for expansion. Other potential sites would be studied on a case-by-case basis, and a communication site plan would be developed before construction could begin.

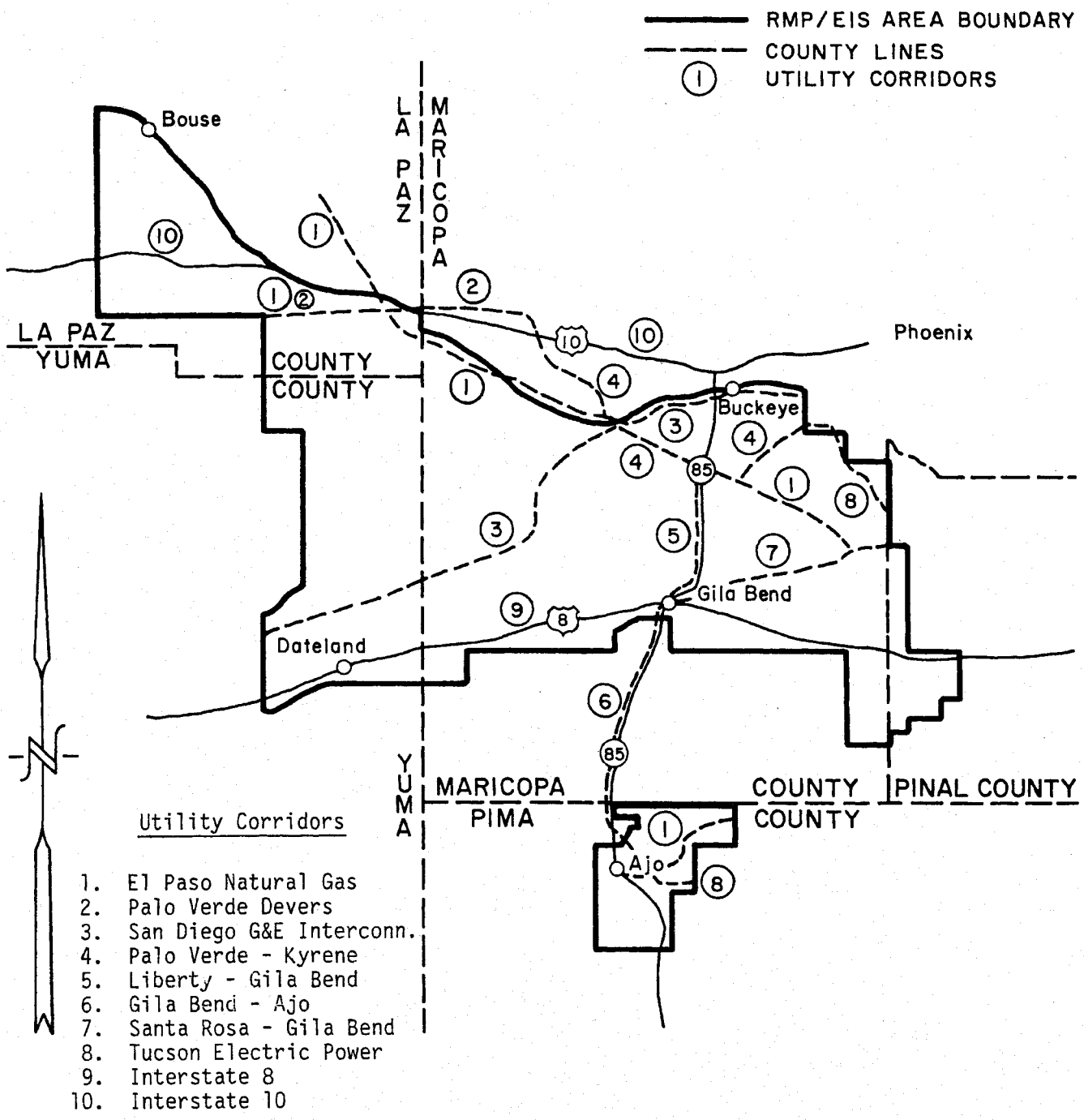
Issue 5: Fred J. Weiler Green Belt (Will Not Be Analyzed In This RMP/EIS)

Approximately 63,000 acres of public land are within the Fred J. Weiler Green Belt, which extends along the Gila River from the Sierra Estrella Park on the eastern edge of the RMP/EIS area boundary to 12 miles west of Dateland, Arizona. Following is a brief history of land use in this area.

Within the area now known as the Green Belt, Public Land Order 1015 withdrew 6,896 acres of land in 1954 to the U.S. Fish and Wildlife Service (FWS). At this time, the FWS entered into a cooperative management agreement with the Arizona Game and Fish Department for these withdrawn lands. These lands were segregated from all forms of appropriation under the public land laws, including the mining laws but not the mineral leasing laws.

In 1970 approximately 63,000 acres were studied and it was determined that they would be retained under the Classification for Multiple Use Act of 1964. A classification for multiple use was placed on the subject lands segregating the 63,000 acres (Fred J. Weiler Green Belt)

MAP 1-2



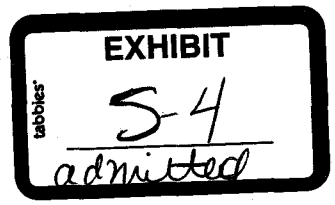
LOWER GILA SOUTH RMP/EIS AREA

from appropriation under the public land and mining laws. Mineral leasing, however, was not excluded. The multiple use classification was established to allow for the management of wildlife habitat, flood and erosion control, and recreational values.

Currently there is no management plan for the Fred J. Weiler Green Belt. BLM will develop a management plan for the Green Belt in cooperation with the Arizona Game and Fish Department and the U.S. Fish and Wildlife Service. The issues which need to be resolved are (1) how should the area be managed, (2) are the present boundaries adequate, (3) are there lands that should be deleted from the area, (4) are there lands that should be added to the area, and (5) what uses should be allowed and what uses restricted or prohibited?

An environmental assessment will be developed and made available to the public. This issue will not be discussed or analyzed in Chapters 2 and 4 of this document.

H. R. 794



One Hundred Ninth Congress of the United States of America

AT THE FIRST SESSION

Begun and held at the City of Washington on Tuesday, the fourth day of January, two thousand and five

An Act

To correct the south boundary of the Colorado River Indian Reservation in Arizona, and for other purposes.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

SECTION 1. SHORT TITLE, FINDINGS, PURPOSES.

(a) SHORT TITLE.—This Act may be cited as the "Colorado River Indian Reservation Boundary Correction Act".

(b) FINDINGS.—Congress finds the following:

(1) The Act of March 3, 1865, created the Colorado River Indian Reservation (hereinafter "Reservation") along the Colorado River in Arizona and California for the "Indians of said river and its tributaries".

(2) In 1873 and 1874, President Grant issued Executive Orders to expand the Reservation southward and to secure its southern boundary at a clearly recognizable geographic location in order to forestall non-Indian encroachment and conflicts with the Indians of the Reservation.

(3) In 1875, Mr. Chandler Robbins surveyed the Reservation (hereinafter "the Robbins Survey") and delineated its new southern boundary, which included approximately 16,000 additional acres (hereinafter "the La Paz lands"), as part of the Reservation.

(4) On May 15, 1876, President Grant issued an Executive Order that established the Reservation's boundaries as those delineated by the Robbins Survey.

(5) In 1907, as a result of increasingly frequent trespasses by miners and cattle and at the request of the Bureau of Indian Affairs, the General Land Office of the United States provided for a resurvey of the southern and southeastern areas of the Reservation.

(6) In 1914, the General Land Office accepted and approved a resurvey of the Reservation conducted by Mr. Guy Harrington in 1912 (hereinafter the "Harrington Resurvey") which confirmed the boundaries that were delineated by the Robbins Survey and established by Executive Order in 1876.

(7) On November 19, 1915, the Secretary of the Interior reversed the decision of the General Land Office to accept the Harrington Resurvey, and upon his recommendation on November 22, 1915, President Wilson issued Executive Order No. 2273 ". . . to correct the error in location said southern boundary line . . ."—and thus effectively excluded the La Paz lands from the Reservation.

S-4

(8) Historical evidence compiled by the Department of the Interior supports the conclusion that the reason given by the Secretary in recommending that the President issue the 1915 Executive Order—"to correct an error in locating the southern boundary"—was itself in error and that the La Paz lands should not have been excluded from the Reservation.

(9) The La Paz lands continue to hold cultural and historical significance, as well as economic development potential, for the Colorado River Indian tribes, who have consistently sought to have such lands restored to their Reservation.

(c) PURPOSES.—The purposes of this Act are:

(1) To correct the south boundary of the Reservation by reestablishing such boundary as it was delineated by the Robbins Survey and affirmed by the Harrington Resurvey.

(2) To restore the La Paz lands to the Reservation, subject to valid existing rights under Federal law and to provide for continued reasonable public access for recreational purposes.

(3) To provide for the Secretary of the Interior to review and ensure that the corrected Reservation boundary is resurveyed and marked in conformance with the public system of surveys extended over such lands.

SEC. 2. BOUNDARY CORRECTION, RESTORATION, DESCRIPTION.

(a) BOUNDARY.—The boundaries of the Colorado River Indian Reservation are hereby declared to include those boundaries as were delineated by the Robbins Survey, affirmed by the Harrington Survey, and described as follows: The approximately 15,375 acres of Federal land described as "Lands Identified for Transfer to Colorado River Indian Tribes" on the map prepared by the Bureau of Land Management entitled "Colorado River Indian Reservation Boundary Correction Act, and dated January 4, 2005", (hereinafter referred to as the "Map").

(b) MAP.—The Map shall be available for review at the Bureau of Land Management.

(c) RESTORATION.—Subject to valid existing rights under Federal law, all right, title, and interest of the United States to those lands within the boundaries declared in subsection (a) that were excluded from the Colorado River Indian Reservation pursuant to Executive Order No. 2273 (November 22, 1915) are hereby restored to the Reservation and shall be held in trust by the United States on behalf of the Colorado River Indian Tribes.

(d) EXCLUSION.—Excluded from the lands restored to trust status on behalf of the Colorado River Indian Tribes that are described in subsection (a) are 2 parcels of Arizona State Lands identified on the Map as "State Lands" and totaling 320 acres and 520 acres.

SEC. 3. RESURVEY AND MARKING.

The Secretary of the Interior shall ensure that the boundary for the restored lands described in section 2(a) is surveyed and clearly marked in conformance with the public system of surveys extended over such lands.

SEC. 4. WATER RIGHTS.

The restored lands described in section 2(a) and shown on the Map shall have no Federal reserve water rights to surface water or ground water from any source.

SEC. 5. PUBLIC ACCESS.

Continued access to the restored lands described in section (2)(a) for hunting and other existing recreational purposes shall remain available to the public under reasonable rules and regulations promulgated by the Colorado River Indian Tribes.

SEC. 6. ECONOMIC ACTIVITY.

(a) IN GENERAL.—The restored lands described in section (2)(a) shall be subject to all rights-of-way, easements, leases, and mining claims existing on the date of the enactment of this Act. The United States reserves the right to continue all Reclamation projects, including the right to access and remove mineral materials for Colorado River maintenance on the restored lands described in section (2)(a).

(b) ADDITIONAL RIGHTS-OF-WAY.—Notwithstanding any other provision of law, the Secretary, in consultation with the Tribe, shall grant additional rights-of-way, expansions, or renewals of existing rights-of-way for roads, utilities, and other accommodations to adjoining landowners or existing right-of-way holders, or their successors and assigns, if—

(1) the proposed right-of-way is necessary to the needs of the applicant;

(2) the proposed right-of-way acquisition will not cause significant and substantial harm to the Colorado River Indian Tribes; and

(3) the proposed right-of-way complies with the procedures in part 169 of title 25, Code of Federal Regulations consistent with this subsection and other generally applicable Federal laws unrelated to the acquisition of interests on trust lands, except that section 169.3 of those regulations shall not be applicable to expansions or renewals of existing rights-of-way for roads and utilities.

(c) FEES.—The fees charged for the renewal of any valid lease, easement, or right-of-way subject to this section shall not be greater than the current Federal rate for such a lease, easement, or right-of-way at the time of renewal if the holder has been in substantial compliance with all terms of the lease, easement, or right-of-way.

SEC. 7. GAMING.

Land taken into trust under this Act shall neither be considered to have been taken into trust for gaming nor be used for gaming

(as that term is used in the Indian Gaming Regulatory Act (25 U.S.C. 2701 et seq.)).

Speaker of the House of Representatives.

Vice President of the United States and President of the Senate.

EXHIBIT
S-5
admitted

Lake Havasu Field Office
Draft Resource Management Plan
and
Draft Environmental Impact Statement

Prepared by

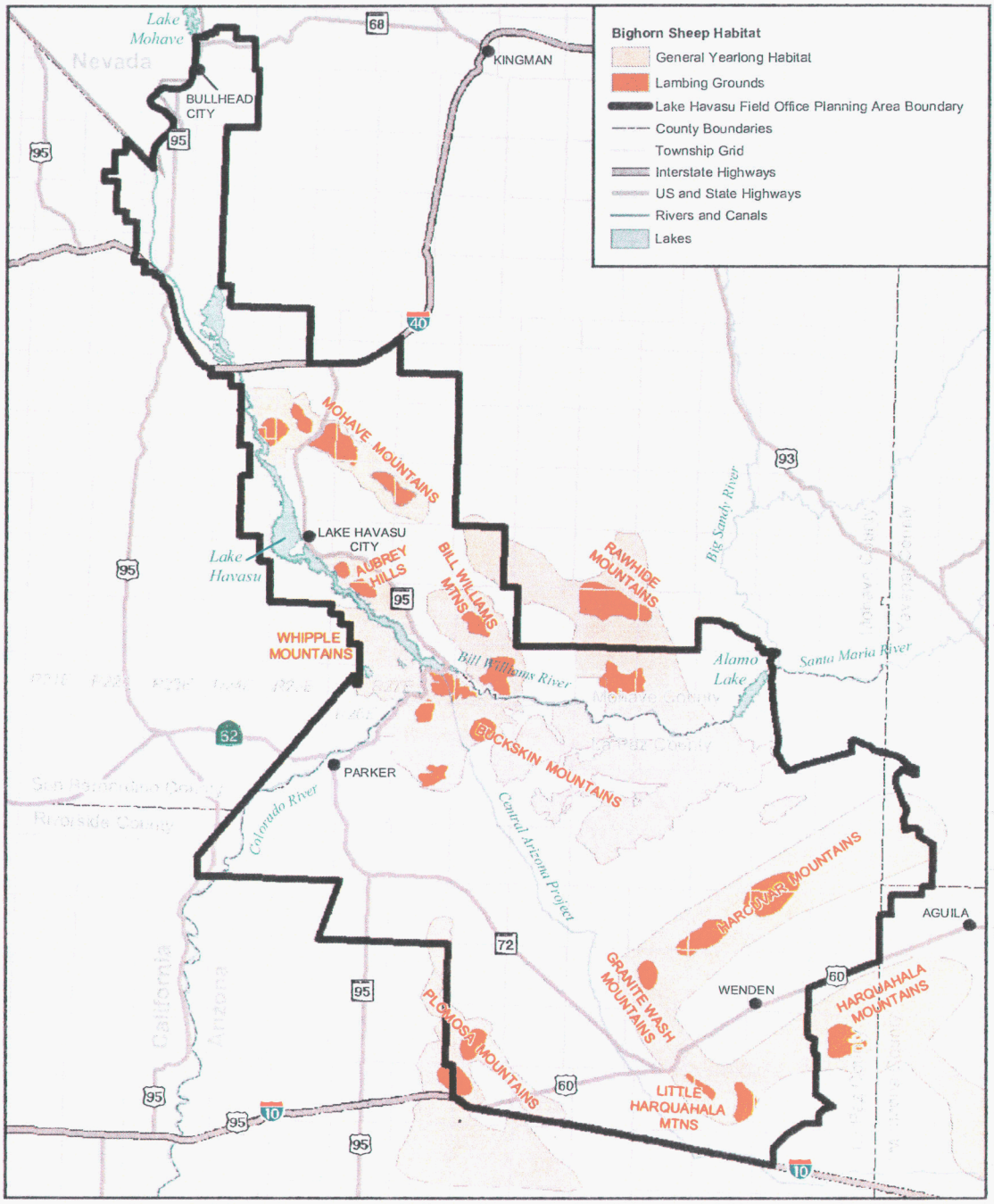
U.S. Department of the Interior
Bureau of Land Management
Lake Havasu Field Office
Arizona

September 2005

Elaine Y. Zielinski
State Director, Arizona

#5

Map 2-43 Bighorn Sheep Habitat



DRAFT

LAKE HAVASU FIELD OFFICE RESOURCE MANAGEMENT PLAN

N 0 5 10 20 Miles

0 5 10 20 Kilometers

The Bureau of Land Management makes no warranties, implied or expressed, with respect to information shown on this map.

UNITED STATES DEPARTMENT OF THE INTERIOR
Bureau of Land Management

August 2005

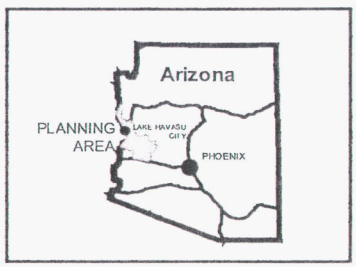


Table 2-11. ROW Corridors Designations Summary (See Maps 2-11, 2-12, 2-13, and 2-14)

Preferred Alternative	ROW Corridor/Location	Width in Miles	Alternative 1	Alternative 2	Alternative 3	Alternative 4
Alternative 4	California Desert Conservation Area "F" (CA) (UC-1)	1	Identified	Rerouted and designated		Dropped
Alternatives 3 and 4	Western Utility Group (WUG 1) (new)	1	N/A	N/A	Designated	
Alternatives 2, 3, and 4	Interstate 40 (UC-3)	1–2	Identified	Rerouted and designated		
	Davis-Parker "A" (UC-2A)	1				
	Parker-Blaisdell "B"-(UC-6B)	1				
	Parker-Liberty (UC-5)	1–2				
	Central Arizona Project (CAP) (LGN-2)	1	Designated	Rerouted and designated		
	Bouse-Salome [Adjust] (LGN-1)	1		Rerouted, adjust and designated		
	El Paso Natural Gas (LGN-11)	2	Identified	Rerouted and designated		
	San Juan Crossover (UC-4)	1		Designated		
Alternatives 1 thru 4	Interstate 10 (UC-7)	1	Designated			
	Bouse-Harcuvar (LGN-3)	1				
	Little Harquahala (LGN-4)	1				
	Wenden-Wickenburg (LGN-5)	1				
Alternatives 2, 3, and 4	State Route 60 (UC-8) (new)	1	N/A	Designated		
Alternatives 3 and 4	Western Utility Group (WUG 2) (new)	1	N/A	N/A	Designated	

tabbies EXHIBIT S-6 admitted

S-6

EXHIBIT
S-7
admitted

PRELIMINARY DRAFT MAP OF POTENTIAL ENERGY CORRIDORS ON FEDERAL LANDS

The U.S. Departments of Energy, Interior, Agriculture, and Defense (the Agencies) are preparing a draft Programmatic Environmental Impact Statement (PEIS) pursuant to the National Environmental Policy Act to identify the impacts associated with designating energy corridors on federal lands in 11 Western States. Energy corridors may contain oil, gas, and hydrogen pipelines and electricity transmission facilities. The Agencies are preparing the PEIS at the direction of Congress, as set forth in Section 368 of the Energy Policy Act of 2005. On the basis of the information and analyses developed in the PEIS, the Agencies will designate energy corridors by amending their respective land use plans.

Public scoping meetings were held in October and November 2005, and the comments received during scoping have helped the Agencies to identify preliminary energy corridors on federal lands that the Agencies propose to analyze in the draft PEIS. The Agencies are presenting this preliminary energy corridor map to inform the public of their progress and to obtain public comment on the proposed corridor locations. The Agencies encourage your views, criticism, and suggestions about these preliminary energy corridor locations.

The potential energy corridor locations depicted on this map represent ongoing work by the Agencies. **Therefore, the corridor locations shown in this map are subject to change until they are officially established in August 2007.** All officially designated corridors will be in compliance with applicable laws and regulations. The majority of the preliminary energy corridors utilize existing corridors and/or rights-of-way, however; there are a small number of potential new corridor locations.

Comments on the preliminary energy corridor map may be submitted electronically through the public comment form on the West-wide Energy Corridor Programmatic EIS Information Center Web Site at http://corridoreis.anl.gov. Written comments can also be mailed or faxed and should be addressed to:

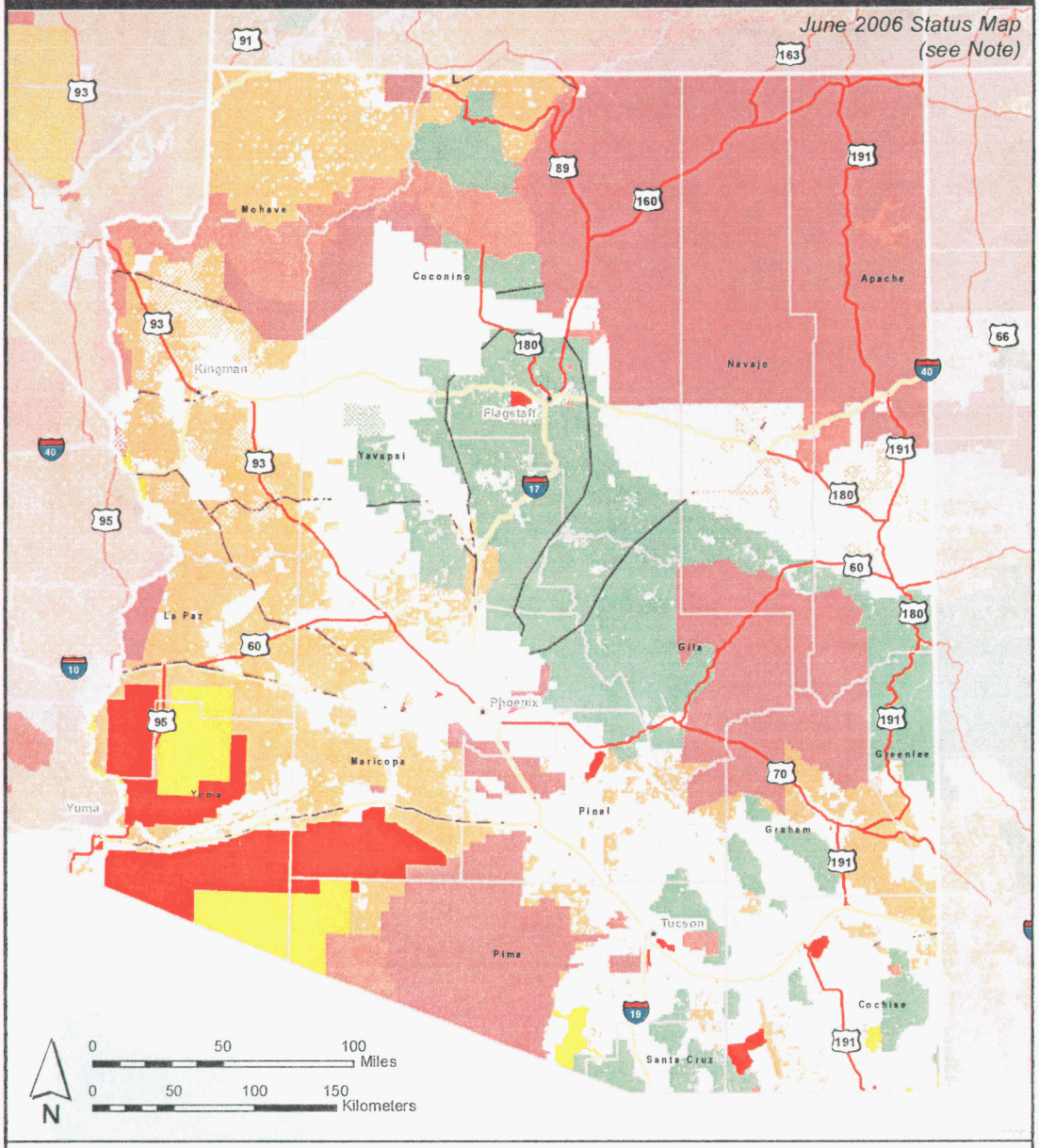
Office of Electricity Delivery and Energy Reliability
Room 8H-033
U.S. Department of Energy
1000 Independence Avenue, S.W.
Washington, DC 20585
Fax: (202) 586-1472

The Agencies request that all comments on the preliminary energy corridor map be provided no later than July 10, 2006. The Agencies will review and consider all comments that are received by the deadline in preparation of the draft PEIS. The opportunity for comment provided here is in addition to the opportunity the public will have to comment on the draft PEIS.

More information about the preliminary draft energy corridor map and the West-wide Energy Corridor PEIS is available on the West-wide Energy Corridor Programmatic EIS Information Center Web site at http://corridoreis.anl.gov.

S-7

Ongoing Work by Federal Agencies on Potential Energy Corridors (Preliminary Draft - Subject to Change) Arizona



Note:

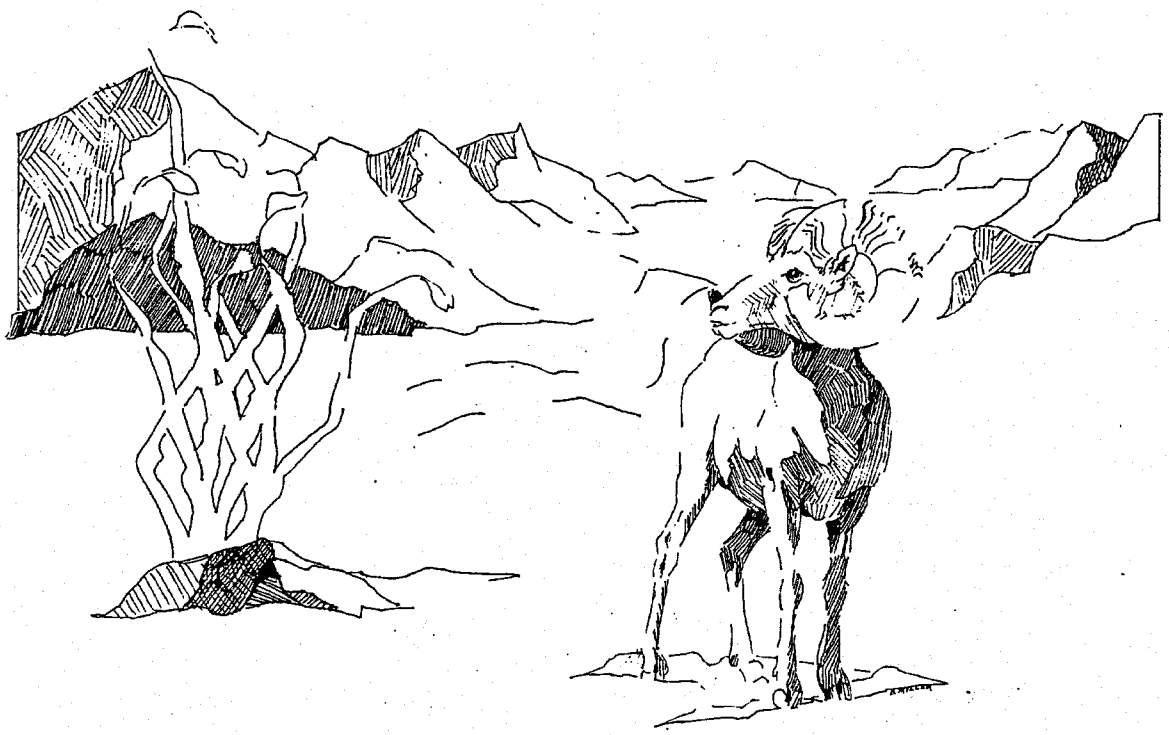
The potential energy corridors depicted on this map represent ongoing work by the Agencies to establish energy corridors in 11 Western states as required by the Energy Policy Act of 2005. The corridors are subject to change until they are officially established in August 2007. All officially designated corridors will be in compliance with applicable laws and regulations. The majority of the preliminary energy corridors utilize existing corridors and/or rights-of-way, but there are a small number of potential new corridor locations. Based upon the information and analyses developed in the West-wide Energy Corridor Programmatic EIS, the Agencies will designate energy corridors by amending their respective land use plans. Corridors are shown on this map with widths of 3,500 feet, the default width currently under consideration. Interstate and U.S. Route lines not to scale.

- Potential Energy Corridor (see Note)
- Interstate (see Note)
- U.S. Route (see Note)
- County Boundary
- Bureau of Land Management
- U.S. Forest Service
- U.S. Department of Defense
- National Park Service
- U.S. Fish and Wildlife Service
- Tribal Land

EXHIBIT
S-8a
admitted

FINAL

YUMA DISTRICT
RESOURCE MANAGEMENT PLAN

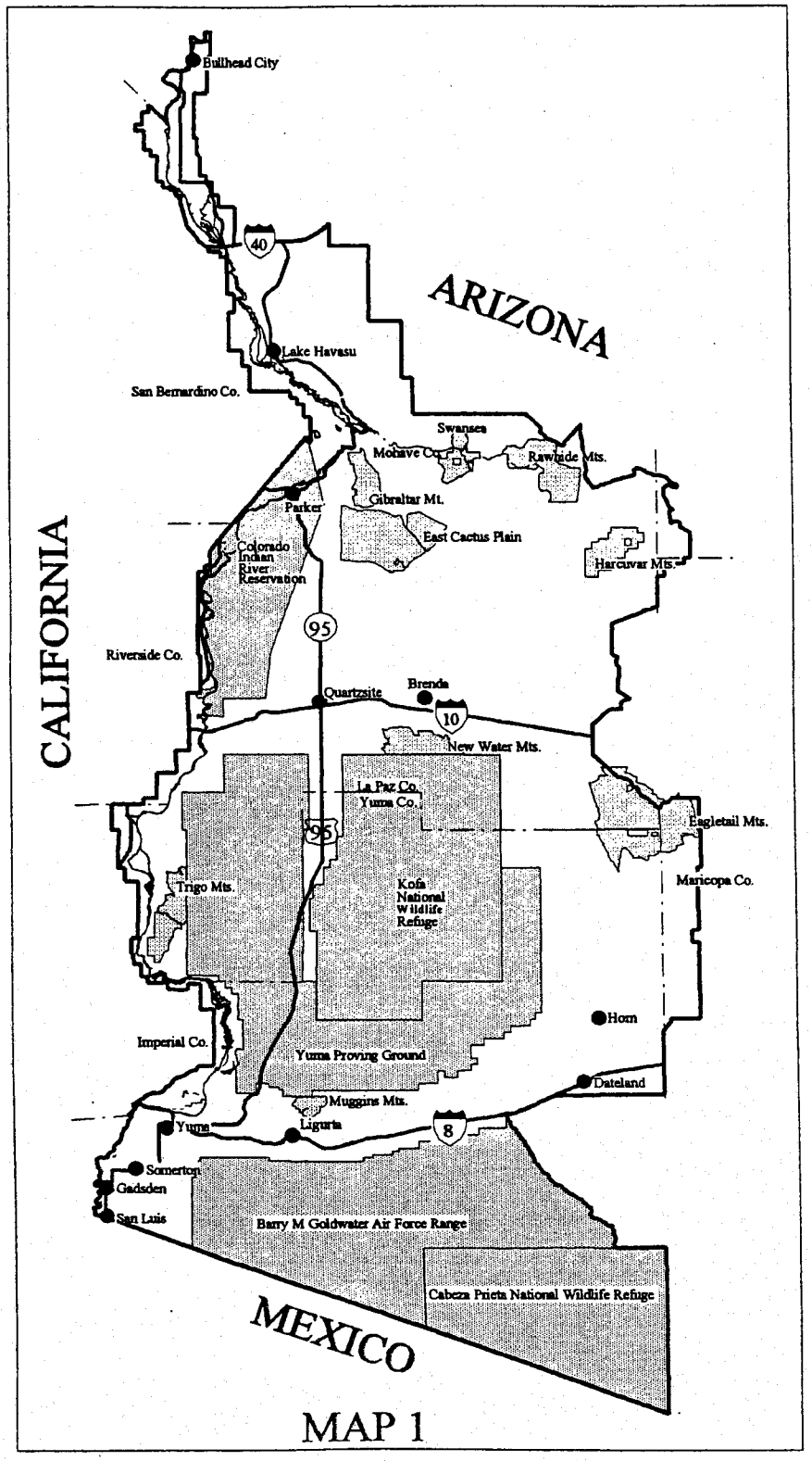


and Environmental Impact Statement

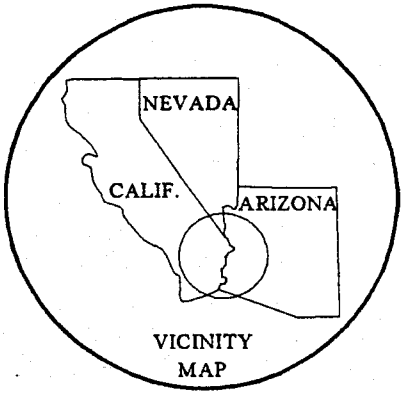
U.S. Department of the Interior
Bureau of Land Management
Arizona

S-8a

BUREAU OF LAND MANAGEMENT
YUMA DISTRICT



MAP 1



VICINITY MAP

COUNTY LINE

WILDERNESS AREA

N

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT
YUMA DISTRICT OFFICE
APRIL 1995

Under the *Preferred Alternative*, agricultural permits and leases for the **1,670** acres in the floodplain would be replaced with agricultural leases issued under BLM's land use authorizations program as outlined in federal regulations and BLM Manual 2920. The issuance of these leases, however, would be contingent on legal water rights being secured under state water law and in accordance with the Colorado River Adjudication of 1964. At the present time, only two agricultural users on **142** acres do not have a legal water source.

The **2,535** acres of agricultural lands outside the levee would be retained in federal ownership and leased for agricultural use. The ultimate disposition of these lands will be determined following further analysis, including delineation of the 100-year floodplain.

Agricultural lands that are not leased would revert to uses that would benefit other programs carried out by BLM such as development for recreational use or return to natural condition for use as wildlife habitat.

TABLE 2-5: PROPOSED UTILITY CORRIDOR DESIGNATIONS, BY ALTERNATIVE
Bureau of Land Management, Yuma District

ID No.	Name	Corridor Length by Alternative (Miles) Preferred	A	B[a]	C	D	E
1A.	CDCA "F"	16	---	---	16	16	---
1B.	CDCA "F"[b]	---	---	---	---	---	16
2A.	Davis-Parker "A"	33	---	---	---	33	33
2B.	Davis-Parker "B"	---	---	---	31	---	---
3.	Interstate 40[c]	20	---	---	20	20	20
4.	San Juan	6	---	---	6	6	6
5.	Parker-Liberty[b]	29	---	---	29	29	29
6A.	Parker-Blaisdell	---	79	---	107	107	107
6B.	Parker-Blaisdell[b]	110	---	---	---	---	---
7.	Interstate 10	22	22	---	8	8	8
8.	Palo Verde-Devers	23	---	---	23	23	23
9.	Interconnection	48	---	---	48	48	48
10.	R-O-W 3	---	38	---	---	---	---
11.	Interstate 8	---	58	---	---	---	---
12.	R-O-W 6	---	22	---	---	---	---
Total Length		307	219	0	288	290	290

[a]No corridors designated under Alternative B. All public lands subject to application for location of transmission facilities.
[b]Corridor width constrained to less than one mile in some places.
[c]Two-mile-wide corridor. All other corridors one mile wide.

ISSUE 5: Rights-of-Way for Utility Corridors and Communication Sites

Under the *Preferred Alternative*, new utility and communications facilities would be located in designated corridors and sites, unless an evaluation of the project shows that location outside of a designated area is the only practicable alternative. However, locating facilities outside of designated corridors and sites would be prohibited in special management areas and would be avoided insofar as possible in priority wildlife habitat areas. Map 8 shows the routes and locations of corridors and sites designated in this alternative.

Utility Corridors

Nine existing and proposed rights-of-way (**307** total miles) would be designated as utility corridors to accommodate recent and future development needs. The length and width of each corridor is shown in Table 2-5. **These designated corridors would apply to BLM-administered lands only.**

Portions of four corridors would be constrained or routed to protect natural values and to promote consistency with other government agencies. These are:

1) The Parker-Liberty corridor would narrow to a 330-foot width along the two-mile portion passing through bighorn sheep lambing grounds in the Buckskin Mountains.
2) The eastern boundary of the one-mile-wide CDCA "F" corridor would be formed by the Ft. Mohave Indian Reservation for five miles as it passes by the reservation.
3) The Davis-Parker "A" corridor would be designated up to the state lands surrounding Lake Havasu City. This corridor would be designated rather than Davis-Parker "B" in order to avoid Crossman Peak Natural Scenic Area.
4) **The Parker-Blaisdell corridor would shift two miles to the northwest of its original centerline for seven miles and narrow to less than a one-mile width in places in order to avoid recreational developments along the Parker Strip segment of the Colorado River (see Map 8). This segment of the corridor would be constrained by an existing transmission line to the northwest and the Parker Dam Highway to the southeast.**

   Along the Cactus Plain, the Parker-Blaisdell corridor would shift one to two miles east of the existing powerline and narrow to a one-half-mile width for 10 miles in order to avoid lands identified for transfer to Arizona (see Map 8). It would also narrow to less than a one-mile width as it passes Black Peak in order to avoid the construction of transmission facilities on the peak itself.

In addition, the entire 22-mile length of the Interstate 10 corridor is designated in the *Preferred Alternative* in order to supplement the Palo Verde-Devers corridor (PV-D) which has nearly reached its carrying capacity due to topographic constraints.

Three corridors identified in the 1975 MFPs — Interstate 8 and ROWs 3 and 6 (see Map 8) — would not be designated in the *Preferred Alternative* for the following reasons:

1) Neither ROW 3 or 6 has existing lines.
2) Public input discouraged the location of facilities along ROW 3 and Interstate 8.
3) Few public lands are involved in any of these potential corridors.

IN REPLY REFER TO:

United States Department of the Interior

1601 (YDO)

BUREAU OF LAND MANAGEMENT
YUMA DISTRICT OFFICE
3150 Windsor Avenue
P.O. Box 5680
Yuma, Arizona 85365

August, 1985

Dear Reader:

Enclosed for your review is the final environmental impact statement for the Yuma District Resource Management Plan (RMP-EIS). The draft Environmental Impact Statement (DEIS) was published in January 1985, and the 90-day public comment period ended April 19. Changes based on public comments and new information have been incorporated into this final RMP-EIS and all portions of the draft, excluding the wilderness appendix, have been reprinted in order to portray those changes. This final RMP-EIS includes the preferred alternative which is the BLM's proposed action.

This final RMP-EIS does not make any recommendations concerning the suitability of wilderness study areas (WSAs) for designation as wilderness. Wilderness recommendations will be reported in a separate EIS covering Yuma District WSAs and a number of other BLM-administered WSAs in Arizona.

All parts of this proposed plan may be protested. Protests should be sent to the Director (202), Bureau of Land Management, U.S. Department of the Interior, 18th and C Streets NW, Washington D.C. 20240, within the 30-day protest period. Protest statements should contain the following information:

-The name, mailing address, telephone number and interest of the person filing the protest.

-A statement of the issue or issues being protested.

-A statement of the part or parts of the plan being protested.

-A copy of all documents addressing the issue or issues that were submitted during the planning process by the protesting party and/or an indication of the date the issue or issues were discussed for the record.

-A short, concise statement explaining why the BLM State Director's decision is believed to be wrong.

At the end of the 30-day protest period, the proposed plan, excluding any portions under protest, will become final. Approval will be withheld on any portion of the plan under protest until final action has been completed on such protest. Any significant change to the proposed plan made as a result of a protest will be available for public review and comment prior to final plan approval and implementation. The final Resource Management Plan will be published with the record of decision in late 1985.

Sincerely,

J. Darwin Snell

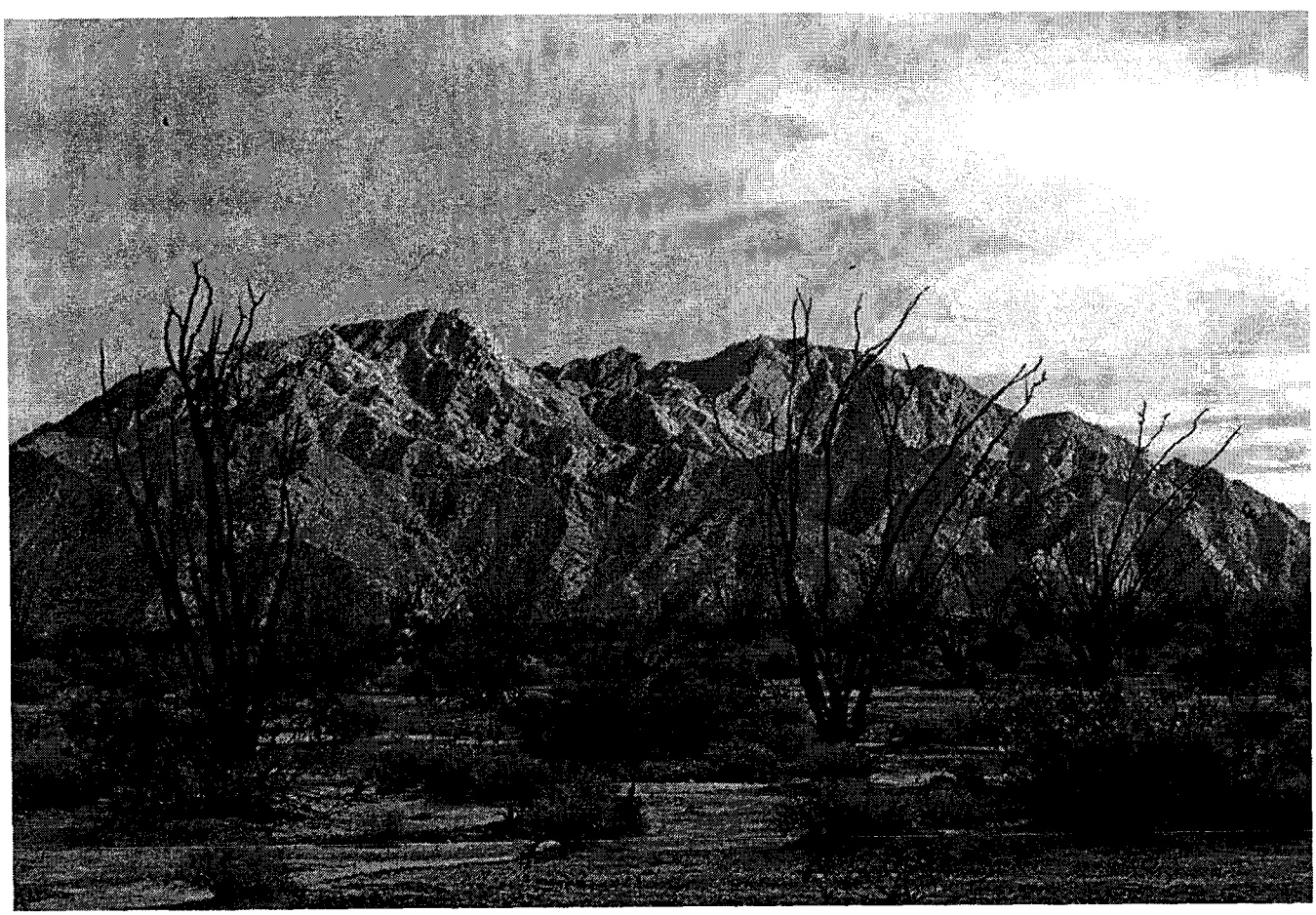
J. Darwin Snell
District Manager

EXHIBIT
S-8b

Preliminary Range of Alternatives

Yuma Field Office
Resource Management Plan Revision

July 2005



S-8b

Range of Alternatives

Alternative A (No Action): describes the continuation of the present management of the Yuma Field Office planning area. Alternative A provides an opportunity to compare the current management with various strategies suggested to be analyzed for future management (Alternatives B, C, and D). Alternative A will serve as a baseline for most resources and land use allocations.

Alternative B (Consumer): generally places an emphasis on appropriate human use and influences and the widest array of uses. It identifies areas most appropriate for various public uses and emphasizes those uses, including recreation, mineral, and energy development. It includes the greatest number of miles of open roads and trails. It places a greater emphasis on developed and motorized recreation opportunities and less on remote settings and primitive recreation.

Alternative C (Mixed Use): provides visitors with opportunities to experience natural and cultural resource values of the YFO planning area. It allows visitation and development within the planning area while ensuring resource protection is not compromised. It is generally managed with decisions that have a greater balance of multiple uses. It proposes a combination of natural processes and active management techniques for resource and use management and it provides access through transportation network.

Alternative D (Environmental Protection): generally places emphasis on preservation of the planning area's natural and cultural resources through limited public use and discontinuation of grazing use. It focuses on natural processes and other unobtrusive methods for natural resource use and management. It proposes the fewest miles of open roads and trails, increased opportunities for dispersed, non-motorized recreation; and fewer motorized and developed recreation opportunities.

Lands and Realty

Disposals

The Federal Land Policy and Management Act (FLPMA) states that "the public lands be retained in Federal ownership, unless as a result of the land use planning procedure provided for in this Act, it is determined that disposal of a particular parcel will serve the national interest."

- Alternative A: A total of 4,614 acres identified for disposal in the 1992 Amendment to the RMP remain available for disposal. These acres would be carried forward in all alternatives.
- Alternative B: Includes pending lands actions and a public proposal from the Town of Quartzsite (36,741.95 acres).
- Alternative C: Includes pending lands actions with the exception of the Town of Quartzsite public proposal.
- Alternative D: The parcels identified for disposal in Alternative A and the existing Recreation & Public Purpose (R&PP) lands actions.

Withdrawals

Areas of Critical Environmental Concern (ACECs) are proposed for withdrawal from location and entry under the general mining laws and the public land laws under all alternatives. ACECs would also be withdrawn for consideration under the mineral leasing laws and from disposal for mineral materials under the Materials Act as amended.

- Currently 164,075 acres of wilderness areas are withdrawn from mineral entry.
- The land use plan would use the least restrictive tool for withdrawal of designated or proposed ACECs.

Acquisition

Lands may be acquired by BLM through purchase, exchange, donation, or eminent domain. Lands to be acquired must either:

- facilitate access to public lands and resources;
- maintain or enhance public uses and values;
- facilitate implementation of this RMP; or
- provide for a more manageable land ownership pattern.

Utility Corridors

- Yuma Field Office (YFO) is proposing 10 utility corridors common to all alternatives.
- These proposed corridors were coordinated with the Western Utility Group Corridor Study.
- YFO would reclassify one utility corridor through the Palo Verde Wilderness in California as a right-of-way. There would be a new corridor established around the perimeter of the wilderness for future use.
- All designated major utility corridors would be one mile in width.
- YFO utility corridors would match adjoining corridors in California and Arizona.

Communication Sites

- YFO has 10 existing communication sites. The range of alternatives is from 9 to 12 communication sites. The Kofa and Airway Beacon communication sites would be retired. A new Qwest site and Laguna Mountains (high power) site would be proposed.

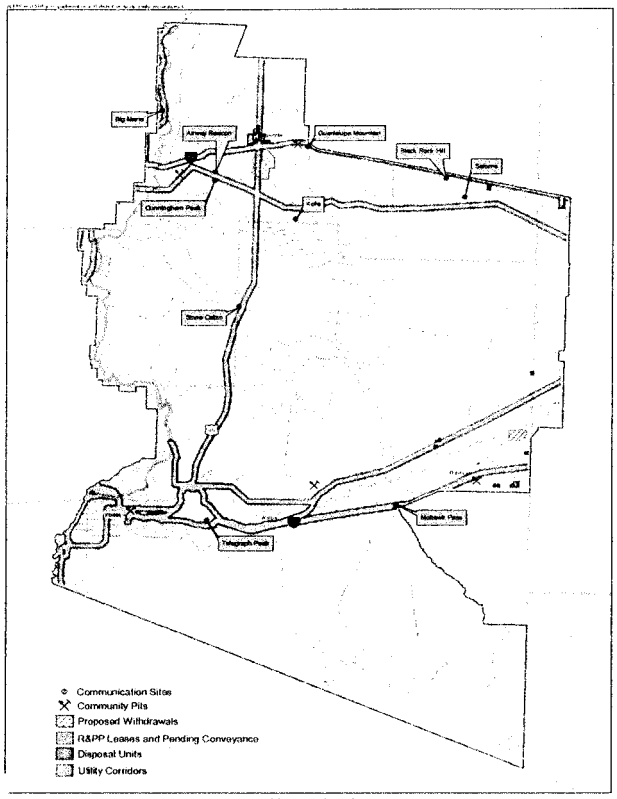
Renewable Energy

- Consider future applications for renewable energy only under moderate to high potential areas for wind, solar, geothermal, and biomass development.

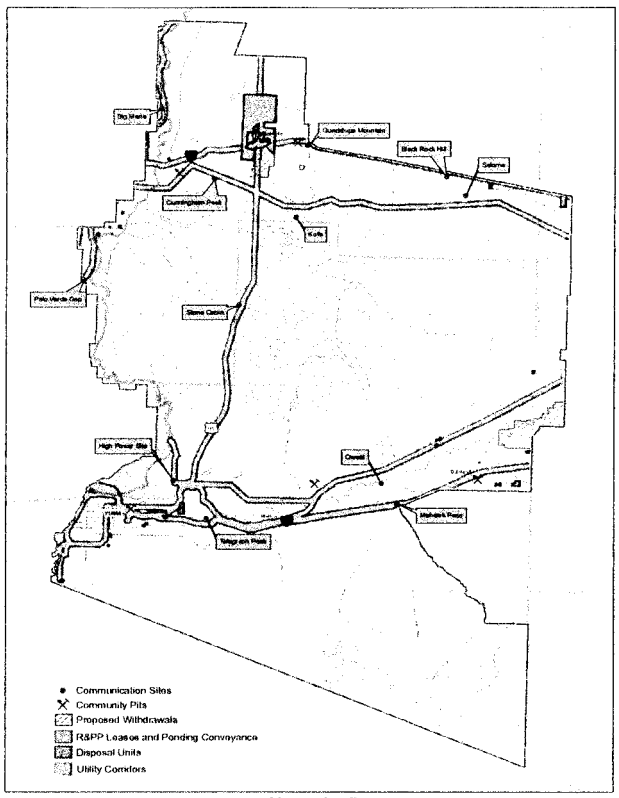
Lands and Realty Allocations by Alternative

	Lands Actions by Alternatives			
	A	B	C	D
Disposal (acres)	4,614	45,276	11,094	5,102
Utility Corridors (number)	10	10	10	10
Communication Sites (number)	10	12	11	9
• High Power Site	0	1	1	0

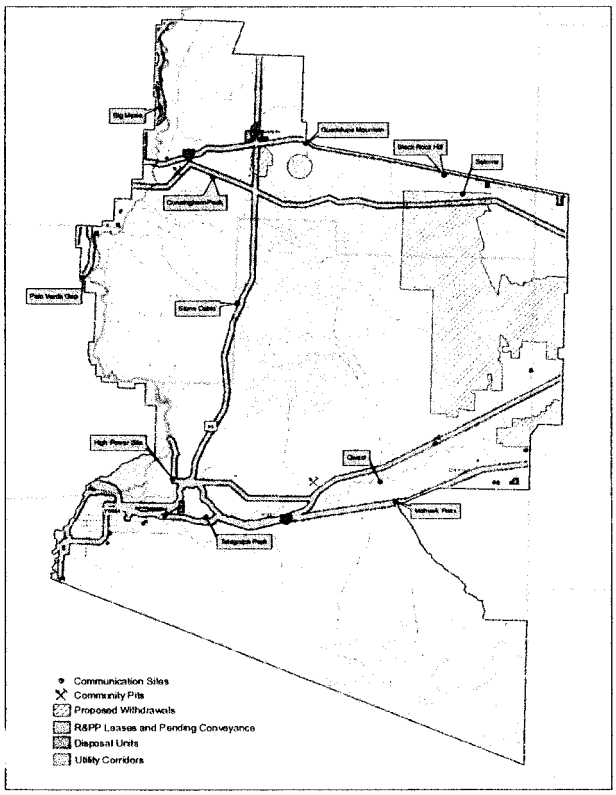
Lands and Realty/Minerals



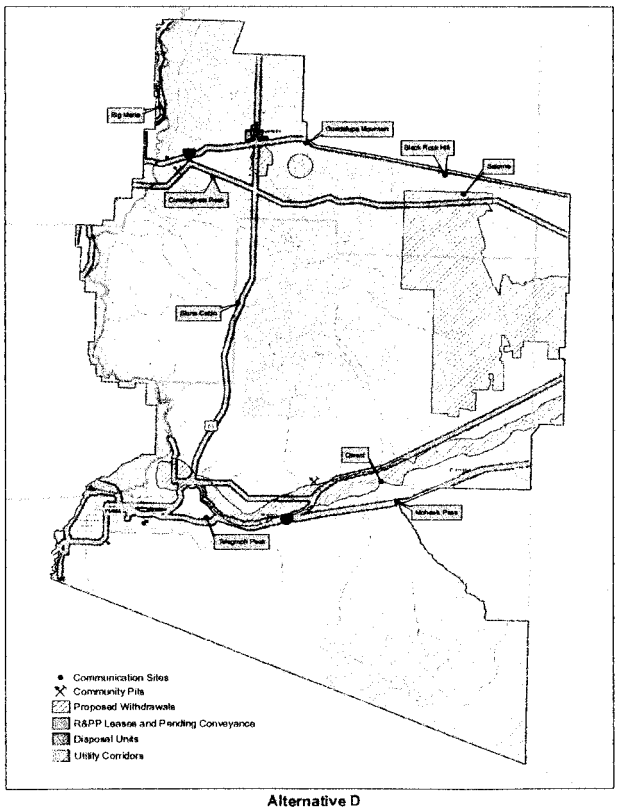
Alternative A



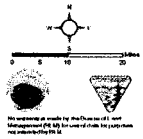
Alternative B



Alternative C



Alternative D



Yuma Field Office Boundary
County Boundary
Wilderness Areas
Interstate
Primary Paved
Secondary Paved
Trails
BLM
BOR
County Lands
PWS
Indian Lands
Military
Private-Other
State
State Wildlife Area
USFS

Lands and Realty/Minerals
Alternatives Analysis
Yuma RMP Planning Area, Arizona
FIGURE X

latimes.com

http://www.latimes.com/business/la-fi-edison15aug15,1,63202.story?coll=la-headlines-business
From the Los Angeles Times

EXHIBIT
S-9
admitted

Edison Issues Bid for More Electricity

From Reuters

August 15, 2006

Southern California Edison on Monday issued a formal bid seeking as much as 1,500 megawatts of new electricity generation in a move to encourage power-plant construction in the West, the company said.

The unit of Edison International said it wanted to purchase power under contracts of as long as 10 years in duration.

"Supply forecasts by state agencies show Southern California will need approximately 1,500 megawatts of new generating capacity between now and 2011," Edison Senior Vice President Pedro Pizarro said in a statement.

Power supplies could become tight as early as next summer if extreme conditions develop, Pizarro said. Southern California Edison has more 4.7 million customers in Central, coastal and Southern California.

Last month, California broke numerous records for power consumption during a weeklong heat wave. On July 24, Californians used 50,270 megawatts in the peak hour, up 11% from the 2005 record, according to the state grid operator.

On July 20, the California Public Utilities Commission approved a plan that allowed the costs of new generation contracts to be allocated to all customers within a utility's service territory.

A megawatt is enough to serve about 750 typical California homes.

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PARTNERS: ktla

S-89

EXHIBIT
S-10
admitted

News.bytes News.bytes Extra, issue 238

Power tower collapses

Southern California Edison (SCE), a major supplier of energy to millions of Californians, notified BLM over the past weekend that there was a catastrophic failure of one of the 500 Kv transmission line towers on the Palo Verde Devers 1 transmission line in eastern Riverside County. The tower was apparently brought down Saturday by a severe wind or weather event. The tower is just within the boundary of the Alligator Rock Area of Critical Environmental Concern and is also in desert tortoise habitat. The entire tower collapsed, completely severing and shutting down the energy transmission along the Interstate 10 utility corridor into Southern

S-10

California.

BLM's Desert District and Palm Springs Field Office are working together to ensure the emergency onsite work does not impact sensitive resources. All protective protocols are being carefully adhered to by SCE in cooperation with BLM. Power outages to Southern California were avoided due to re-routing, but onsite work to temporarily restore energy routing through the area and to re-construct the tower permanently are both underway.

- Information provided by Rolla Queen, BLM California Desert District archeologist. Photo by Tom Taylor, Manager, Natural and Cultural Resources, Environment, Health & Safety Division, Southern California Edison.

7/5/06

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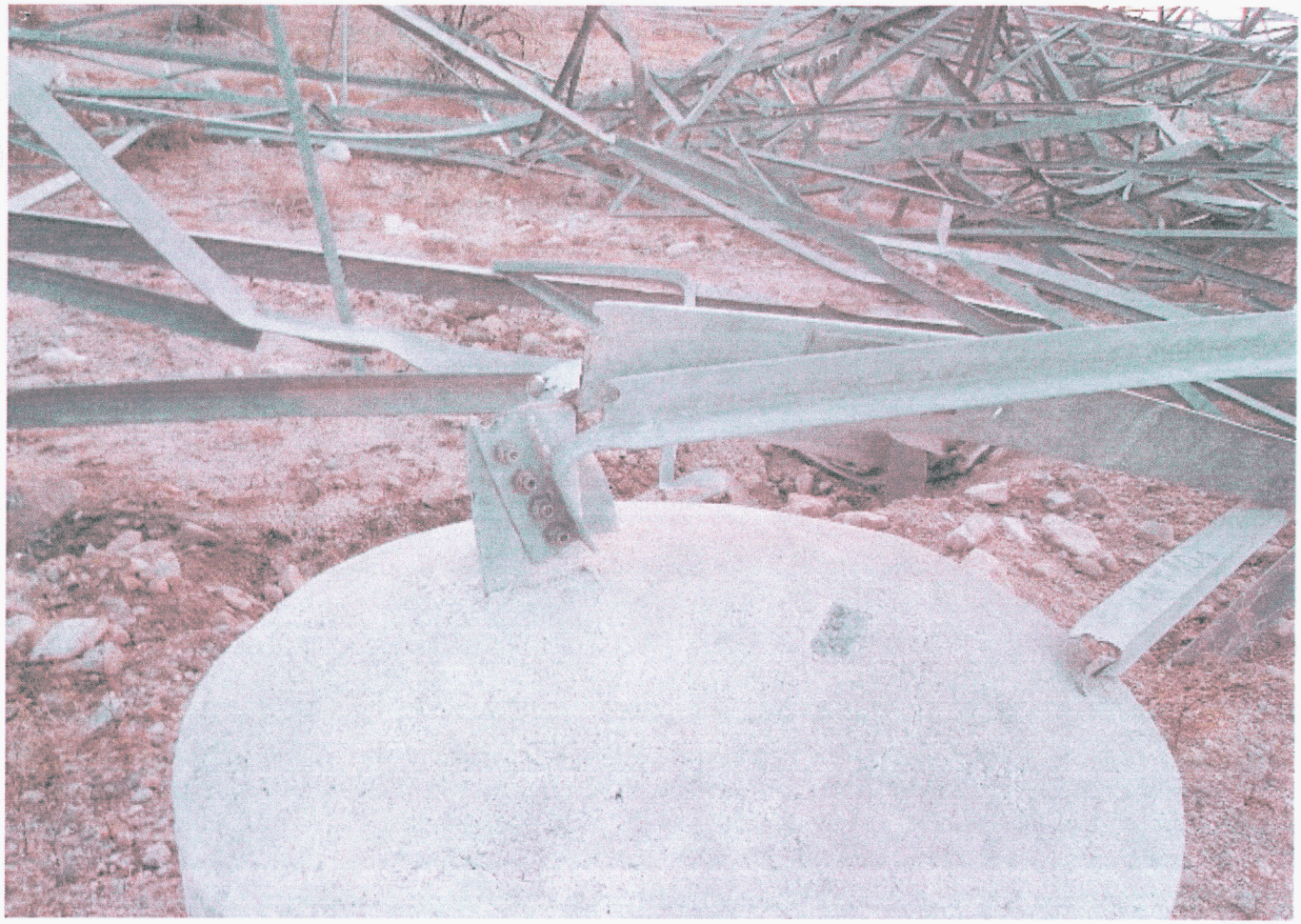
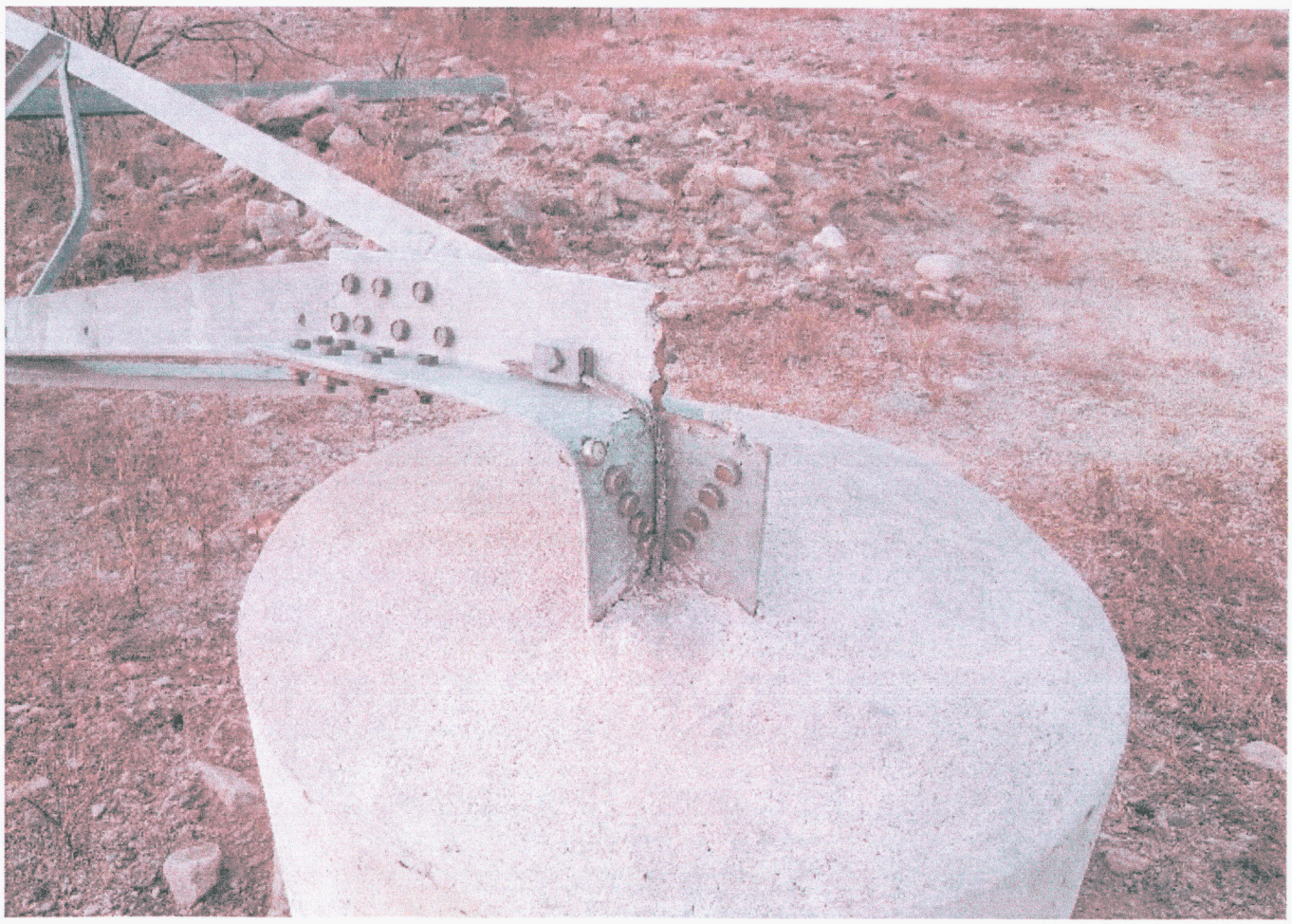




DANGER

EXHIBIT
S-11
Admitted

JDS-6.3 Please explain how the CAISO Market Redesign & Technology Upgrade (MRTU) initiative will impact the operational and commercial uses of the proposed 2nd Palo Verde to Devers 500 kV line and scheduling of capacity and energy produced at any power plants interconnected to the same line. What system elements of the DPV2 Project will CAISO have operational control of and to what elements will their tariffs apply? Does this include the Harquahala power plant?

RESPONSE: SCE does not expect that the CAISO's MRTU initiative will significantly affect the operational and commercial uses of the proposed DPV2 facility when compared to today's market design. Given DPV2's proposed operating date in 2009 and MRTU's proposed operating date of November 2007, SCE anticipates that MRTU will have been running for many months before DPV2 is operating. Other than the use of revised templates and new interface systems between the CAISO and market participants, the submission of schedules for power plants connected to DPV2 is not expected to change from today's practices on existing transmission facilities due to the MRTU initiative. One expected difference between today's market and that under the MRTU proposal is that there will not be a physical scheduling priority associated with the type of transmission rights offered under MRTU (Congestion Revenue Rights). Such a priority exists today with Firm Transmission Rights.

SCE's proposed project envisions a 500 kV transmission path from Devers Substation to the Harquahala 500 kV Switchyard, and from Harquahala 500 kV Switchyard to Hassayampa Substation. Under that proposal, the Devers-

Harquahala 500 kV line, the Harquahala 500 kV Switchyard and power plant, and the Harquahala-Hassayampa 500 kV line would be part of the CAISO Control Area and subject to the CAISO Tariff. Note that the CAISO would not have "operational control" of the Harquahala power plant. SCE and APS have been engaged in negotiations for a potential arrangement in which SCE and APS would jointly own the facilities between the Harquahala Junction Switchyard and the Hassayampa substation. Under this alternative arrangement, the Devers-Harquahala Junction 500 kV line would likely be incorporated into the CAISO control area and subject to the CAISO Tariff. However, the Harquahala Junction Switchyard, the Harquahala switchyard and power plant, and the Harquahala-Hassayampa 500 kV line would likely fall within the footprint of APS's control area. However, these arrangements being negotiated between SCE and APS have not been finalized.

JDS-6.4 Please provide a copy of the CAISO electronic presentation material given to CRT on September 1, 2004 per your response to JDS-4.7.

RESPONSE: A copy of the CAISO electronic presentation material for the CRT on September 1, 2004 is attached.

JDS-6.5 Will CAISO's MRTU initiative result in any modifications, deletions or additions to the material presented to CRT on September 1, 2004? If so, please elaborate.

RESPONSE: Insofar as SCE is aware, the CAISO's presentation is consistent with the CAISO's MRTU initiative. See, for example, the discussion at slides 11 through 13 concerning Firm Transmission Rights and Congestion Revenue Rights.

JDS-6.6 SCE has acknowledged several agreements already exist regarding the existing DPV line, the proposed second DPV line and the Harquahala Generating Station. Were there any regulatory approvals for any of the existing agreements? If so, who had jurisdictional authority and what was the assigned case or docket number or decision number? Was CAISO approval required for any of the same existing agreements? If yes, then identify the agreement(s)?

RESPONSE: Regulatory approvals were not required for the existing agreements between SCE and the Harquahala Generating Company. No jurisdictional service was provided by SCE to Harquahala Generating Company pursuant to the option or license agreements. If SCE were to exercise the option and thereafter provide transmission service, through the CAISO, to the generating station, SCE would file the appropriate agreement with the Federal Energy Regulatory Commission. CAISO approval was not required for the option or license agreements because the facilities that are the subject of the agreements were not transmission additions or upgrades to the CAISO controlled grid.

JDS-6.7 Will regulatory approval be required for any interconnection alternative of the DPV2 Project or any proposed interconnection agreement for the DPV2 project? If so, then who has jurisdiction and under what statutory authorization?

RESPONSE: Regulatory approvals will be required for interconnection with the DPV2 project. FERC has jurisdiction over interconnection agreements under Sections 201, 202, 210, and 212 of the Federal Power Act. If SCE must construct certain facilities to carry out the interconnection, the CPUC has jurisdiction under California Public Utilities Code Sections 1001, 1003.5, and 1004 et seq., and the California Environmental Quality Act to review the public convenience and necessity of the facilities. If the interconnection were to require the construction of a transmission line in Arizona, the Arizona Corporation Commission would review the environmental compatibility under Arizona Revised Statutes Sections 40-360.03 et seq.

JDS-6.8 If interconnections occur in the future along the length of the new DPV2 line, will regulatory approval be required? If so, then who has jurisdiction and under what current statutory authorization? Will CAISO approval be required for such future interconnections? Will CAISO tariffs and operational control apply to such interconnections?

RESPONSE: Future interconnections with the new DPV2 line will require regulatory approvals. See response to JDS 6.7, above. CAISO approval will be required for future interconnections. The CAISO would have operational control of the interconnection and transmission service would be provided in accordance with the CAISO Tariff.

JDS-6.9 SCE failed to provide, an unredacted copy of the Supplemental Direct Testimony filed with CPUC on June 1, 2006 and the associated Appendix A material referenced in Section II of that testimony as requested by Staff in JDS-4.2. Instead, you provided a table dated 6-15-06 with preliminary cost estimates for the various alternatives. That table did provide an estimate of the variety of alternative costs including the newly announced change in plan of service with a Devers–Valley 500 kV line in lieu of the rebuild of the existing four 230 kV lines west of Devers. But you failed to include estimates for the Harquahala Junction Switchyard Alternative.

Staff is aware that SCE filed a Phase II Supplemental Direct Testimony with the CPUC on July 7, 2006 that was unredacted and included all of the requested cost data for the project including the Harquahala Junction Alternative (Alternative 3). Exhibit B of that Supplemental Direct Testimony was dated 7-7-06 and filed at the CPUC two days after filing a response to Staff data request JDS-4.2.

a. Please explain why your response to Staff's data requests failed to include cost estimates for the Harquahala Junction Switchyard Alternative. Doesn't your failure to provide Staff with timely cost infraction and waiting to provide that information until after it is filed at CPUC contradict the procedural goals outlined in the Western Governors' Interstate Transmission Line Siting Protocol?

b. Do the cost estimates being provided in both regulatory forums reflect total project cost or only those costs SCE believes it will be obligated to fund if joint participation facilities are involved?

RESPONSE: a. The responses provided to the ACC staff on July 5, 2006 were prepared primarily during the last few days of June and finalized on July 5. When SCE provided the response to JDS 4.2 on July 5, 2006, it was developing the new cost estimates and preparing the Supplemental Direct Testimony dated July 7, 2006, for the CPUC proceedings. On July 5, SCE provided cost estimates based on completed work, not work in progress. The new estimates were not completed until shortly before they were served on parties to the CPUC proceedings. SCE's actions in the first week of July were consistent with its good-faith attempt to provide full responses to the ACC Staff and SCE regrets any misunderstanding that may have resulted.

b. The cost estimates SCE has provided in both forums are a forecast of SCE's costs, assuming the Los Angeles Department of Water and Power does not participate in funding the project. The estimates are subject to further refinement and may also change due to additional negotiations with other parties.

JDS-6.10 The SCE reply to JDS-4.3 was largely "non-responsive." Other than having established prior contractual rights with Harquahala Generating Company no evidence is offered that substantiates that the Harquahala Switchyard Alternative is superior to the Harquahala Junction Switchyard. Getting an agreement with parties for the Harquahala Junction Switchyard Alternative and CAISO approval does not necessarily mean it is a superior alternative. Does SCE care to amend and supplement its response to this question? Please identify the author of all responses to this data request.

RESPONSE: Without contractual arrangements, an alternative cannot be constructed. It was on this basis that SCE answered JDS 4.3 as to why SCE concluded that interconnection at the Harquahala Generating Station Switchyard was the preferred option. SCE supplements its response to JDS 4.3 by noting that it now has an agreement in principle by staff employees at both APS and SCE for the Harquahala Junction Switchyard. That agreement has not received final approval by members of management with signature authority at SCE, nor presumably at APS. SCE anticipates that such approval will be obtained when additional details are resolved. SCE will soon submit the Harquahala Junction Switchyard alternative to the CAISO for its approval. Michael Mackness prepared this response.

JDS-6.11 The SCE reply to JDS-4.4 was also largely "non-responsive." Would a Harquahala Junction Switchyard interconnection fulfill the three CAISO prerequisites for approval?

a. Does a jointly developed Harquahala Junction Switchyard with a five-mile shorter length of line from Devers reduce the cost of the DPV2 Project? Please cite supporting evidence previously filed with the CPUC or in this ACC Docket.

b. Does the Harquahala Junction Switchyard Alternative create additional congestion or reliability concerns? If so, please explain. In fact doesn't this alternative mitigate reliability and commercial transmission pancaking issues raised by ACC Staff? Provide and cite technical study results supportive of your response.

c. Doesn't SCE's testimony filed before the CPUC already state that it believes the ACC favors a Harquahala Junction Switchyard interconnection over that of a Palo Verde Switchyard termination or Harquahala Generator Switchyard interconnection?

If the answer to each of the above questions is yes, then doesn't the Harquahala Junction Alternative comply with the CAISO's prerequisite conditions?

RESPONSE: a. The cost of the Harquahala Junction Switchyard alternative is less than those of SCE's originally-proposed project. See Table II-1 of the prepared supplemental direct testimony in the CPUC proceedings.

b. The Harquahala Junction Switchyard Alternative does not create additional congestion or reliability concerns. SCE is in the process of obtaining the

CAISO's concurrence with this conclusion. Although such analysis would resolve reliability concerns, it does not resolve "commercial transmission pancaking issues." The attached PDF labeled DPV2_Path49RatingReport_aprvd.pdf contains the sensitivity with TS5 indicating no negative impact on achieving the 1,200 MW rating increase.

c. SCE's prepared supplemental direct testimony provided in the CPUC proceedings stated that "the ACC and ACC staff appear to disfavor the Palo Verde Alternative…." Therefore, in the supplemental direct testimony, SCE requested that the CPUC approve "Alternate 3," the Harquahala Junction Alternative and Devers-Valley No. 2.

It is SCE's position that the Harquahala Junction Switchyard alternative complies with the CAISO's conditions. SCE is in the process of obtaining the ISO's concurrence with that conclusion.

JDS-6.12 The SCE response to JDS-4.5 implies an approval from CAISO must be obtained prior to parties reaching an agreement for interconnection at an ACC approved Harquahala Junction Switchyard. Please explain why SCE cannot reach an agreement for an interconnection at a proposed switchyard in Arizona without CAISO approval. Was CAISO approval a prerequisite requirement for the existing SCE options agreement with Harquahala Generating Company? If so, please cite action taken by CAISO regarding the current SCE agreement with Harquahala Generating Company.

RESPONSE: SCE sought CAISO approval of the DPV2 project prior to applying for a certificate of public convenience and necessity from the CPUC. The Harquahala Junction Switchyard would modify certain aspects of the DPV2 project that the CAISO previously approved. Thus, SCE will seek the CAISO's approval of the Harquahala Junction Switchyard alternative. CAISO approval of the existing agreements with the Harquahala Generating Company were not required as explained in SCE's response to JDS 6.6, above.

CALIFORNIA ISO

California Independent
System Operator

California ISO Wheeling and Congestion Charges

Jeff Miller
California ISO

September 1, 2004

Overview

- Wheeling Charges
  - Losses – Based on TMM or GMM
  - Core Reliability Requirement
- Congestion Charges
  - Firm Transmission Rights - Today
  - Congestion Revenue Rights - Future

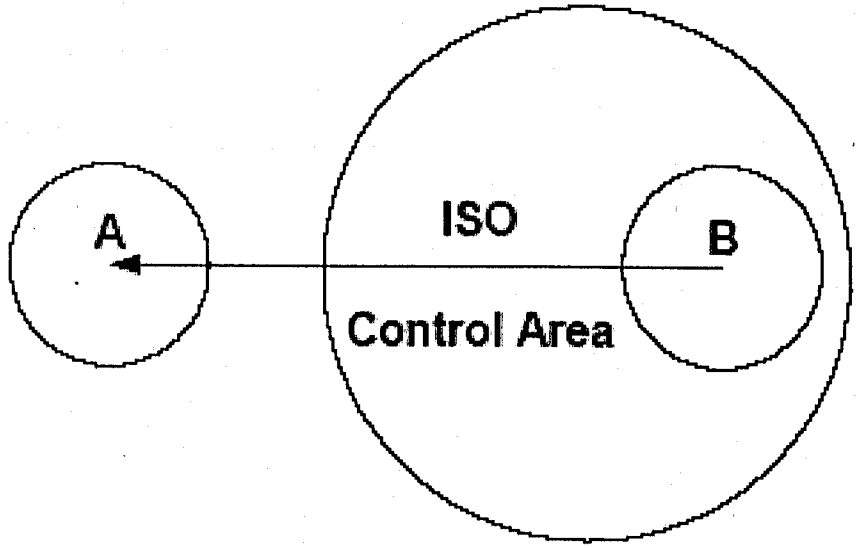
Wheeling Charges

- Charge assessed to SCs with schedules exiting/leaving the ISO Controlled Grid
- Based on gross exports, not net
- Based on actual flows (not always what you scheduled-may be curtailed)
- If exit point is below 200 kV, a Low Voltage Wheeling Access Charge is also incurred

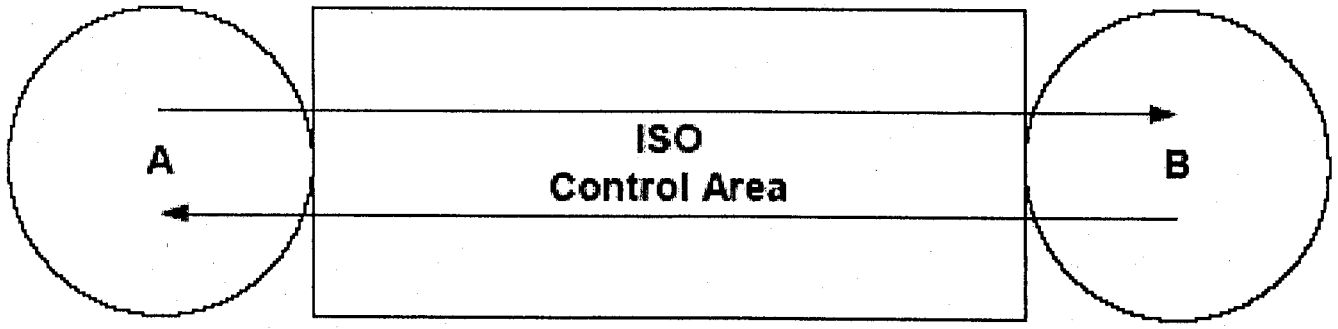
Wheeling Charges

- Wheeling Charges are Assessed on Energy Leaving the ISO Controlled Grid
  - Wheeling Out
  - Wheeling through
  - Wheeling to Non-PTO Load

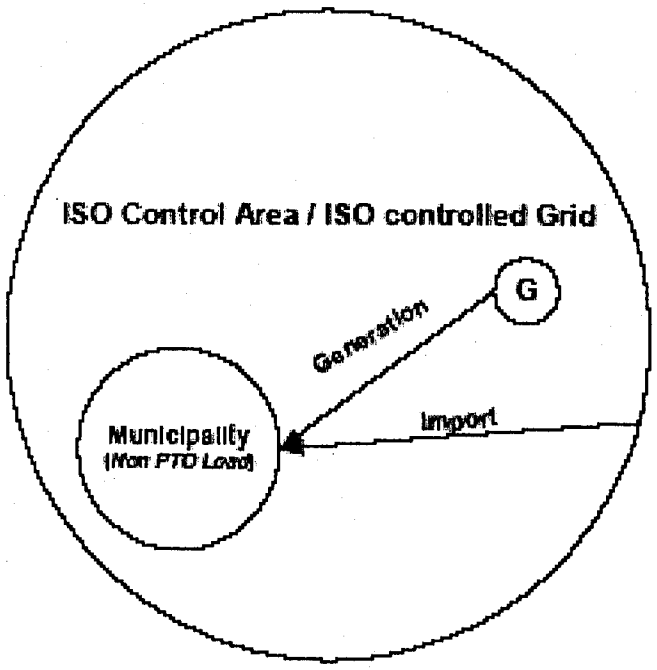
Wheeling Out



Wheeling Through



Wheeling to Non-PTO Load



Non-PTO Load

High Voltage vs. Low Voltage

High Voltage Wheeling Access Charges (HVAC)

- 200 kV and above
- ISO Grid wide rate (transition over 10 years- began Jan '01)
- Revenues spread to all TAC Areas/PTOs

Low Voltage Wheeling Access Charge (LVAC)

- Below 200 kV
- Utility specific rate
- Revenues flow back to specific utility

Example Charges

(for explanatory proposes only)

- Example base charge
  - Palo Verde to PG&E load - $0/MWh
  - Palo Verde to COB - $2.40/MWh
  - Devers to COB - $2.40/MWh
- Additional charges:
  - Losses – ISO delivers full schedule and bills for cost of making up losses
  - Core reliability requirement – Varies based on coincident demand of SC
  - Transaction charge - $1.49 per schedule
  - Congestion – Only if path is congested

Losses

- Meter Multipliers
  - Apply to generators and tie lines
  - Varies by location
  - Varies each hour
  - Posted on Oasis
- Generator Meter Multiplier Examples
  - South Bay – 0.9696
  - Big Creek – 1.0085
- Example Tie Meter Multiplier
  - Palo Verde - 0.95670
  - Malin – 0.98720

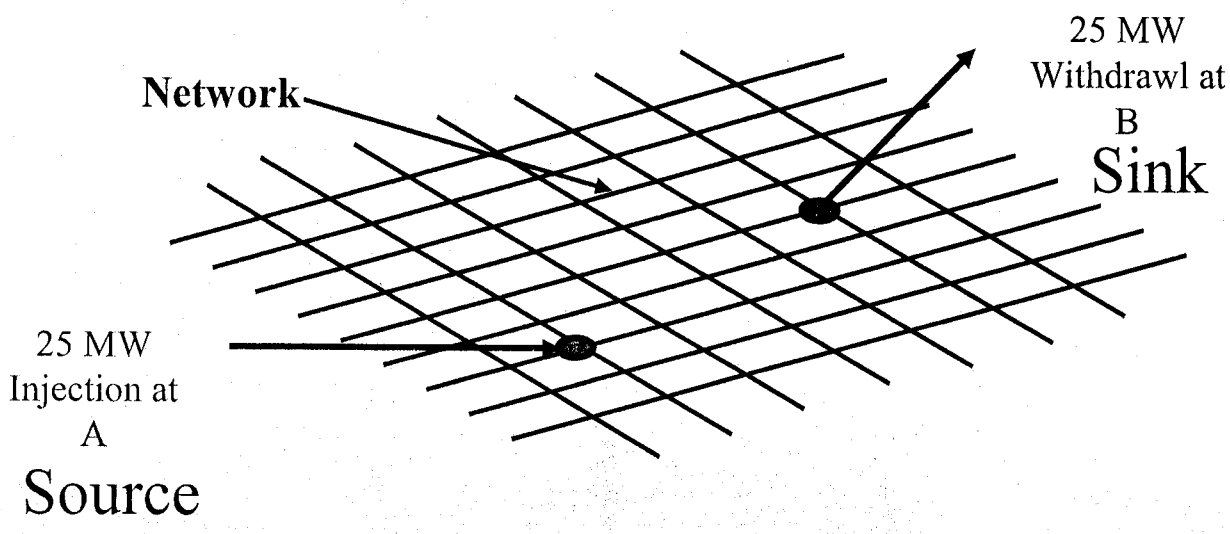
Congestion Charges

- ISO systems determine the cost of congestion for each hour
- Congestion costs may be hedged through the purchase of FTRs
- In the future, FTRs will transition to CRRs (with the implementation of nodal pricing)

Congestion Revenue Rights

- Point to Point Right (Source to Sink)
- CRR Holder is Obligated to Receive (or Pay) the difference in LMP Between Sink and Source
  - (LMP at Node A-LMP at Node B)xMW

Example



S-12

EXHIBIT
S-12
admitted

Non-Spinning Reserve	MW	Hourly	$/MW
Replacement Reserve	MW	Hourly	$/MW
Black Start	MW	Annual	$/MW

7 SYSTEM OPERATIONS UNDER NORMAL AND EMERGENCY OPERATING CONDITIONS.

7.1 ISO Control Center Operations.

7.1.1 ISO Control Center.

7.1.1.1 Establish ISO Control Center.

The ISO shall establish a WECC approved Control Area and control center to direct the operation of all facilities forming part of the ISO Controlled Grid, Reliability Must-Run Units and Generating Units providing Ancillary Services.

7.1.2 Establish Back-up Control Facility.

The ISO shall establish back-up control facilities remote from the ISO Control Center sufficient to enable the ISO to continue to direct the operation of the ISO Controlled Grid, Reliability Must-Run Units, System Resources and Generating Units providing Ancillary Services in the event of the ISO Control Center becoming inoperable.

7.1.3 ISO Control Center Authorities.

The ISO shall have full authority, subject to Section 4.2, to direct the operation of the facilities referred to in Section 7.1.2 including (without limitation), to:

(a) direct the physical operation by the Participating TOs of transmission facilities under the Operational Control of the ISO, including (without limitation) circuit breakers, switches, voltage control equipment, protective relays, metering, and Load Shedding equipment;

(b) commit and dispatch Reliability Must-Run Units, except that the ISO shall only commit Reliability Must-Run Generation for Ancillary Services capacity according to Section 30.6.1 of the Tariff;

(c) order a change in operating status of auxiliary equipment required to control voltage or frequency;

(d) take any action it considers to be necessary consistent with Good Utility Practice to protect against uncontrolled losses of Load or Generation and/or equipment damage resulting from unforeseen occurrences;

(e) control the output of Generating Units, Interconnection schedules, and System Resources that are selected to provide Ancillary Services or Imbalance Energy;

(f) Dispatch Curtailable Demand which has been scheduled to provide Non-Spinning Reserve or Replacement Reserve;

(g) procure Supplemental Energy; and

(h) require the operation of resources which are at the ISO's disposal in a System Emergency, as described in Section 7.4

The ISO will exercise its authority under this Section 7.1.3 by issuing Dispatch Instructions to the relevant Participants using the relevant communications method described in Section 34.3.6.

7.1.4 Primary ISO Control Center.

The Primary ISO Control Center shall have Operational Control over:

(a) all transmission lines greater than 230kV and associated station equipment on the ISO Controlled Grid;

(b) all Interconnections; and

(c) all 230 kV and lower voltage transmission lines and associated station equipment identified in the ISO Register as that portion of the ISO Controlled Grid located in the PG&E PTO Service Territory.

7.1.5 Backup ISO Control Center.

The Backup ISO Control Center shall have Operational Control over all 230 kV and lower voltage transmission lines and associated station equipment identified in the ISO Register as that portion of the ISO Controlled Grid located in the SCE and SDGE PTO Service Territories.

7.2 Operating Reliability Criteria.

7.2.1 Reliability Coordinator.

The ISO shall be the WECC reliability coordinator for the ISO Controlled Grid. As Reliability Coordinator, the ISO, in conjunction with the other WECC Reliability Coordinators, will be responsible for the stable and reliable operation of the Western Interconnection in accordance with the WECC Regional Security Plan.

7.2.1.1 Reliability Coordinator.

As Reliability Coordinator, the ISO may direct activities as appropriate to curtail Schedules, Dispatch Generation or impose transfer limitations as necessary to relieve grid Congestion, mitigate potential overloads or eliminate operation outside of existing Nomogram criteria.

7.2.1.2 Authority of WECC Reliability Coordinators.

(a) The Reliability Coordinator has the final authority to direct operations before, during and after problems or disturbances that have regional impacts. The WECC Security Monitoring plans include collaboration with sub-regional Reliability Coordinators and Control Area operators to determine actions for anticipated problems. If there is insufficient time, or mutual concurrence is not reached, the Reliability Coordinator is authorized to direct actions and the control area operators must comply.

(b) In the event of any situation occurring which is outside those problems already identified in the list of known problems, the Reliability Coordinator shall have the responsibility and authority to implement whatever measures are necessary to maintain System Reliability. Those actions include but are not

limited to; interchange curtailment, generation Dispatch adjustment (real power, reactive power and voltage), transmission configuration adjustments, special protection activation, load curtailment and any other action deemed necessary to maintain System Reliability.

(c) The Reliability Coordinator shall also have the responsibility and authority to take action in its sub-region for problems in another sub-region that it may help resolve. This must be accomplished at the request of and in coordination with the Reliability Coordinators of the other sub-regions.

7.2.2 [Not used]

7.2.2.1 The ISO shall exercise Operational Control over the ISO Controlled Grid to meet planning and Operating Reserve criteria no less stringent than those established by WECC and NERC as those standards may be modified from time to time, and Local Reliability Criteria that are in existence on the ISO Operations Date and have been submitted to the ISO by each Participating TO pursuant to Section 2.2.1(v) of the TCA. All Market Participants and the ISO shall comply with the ISO Reliability Criteria, standards, and procedures.

7.2.2.2 The ISO Governing Board may establish planning guidelines more stringent than those established by NERC and WECC as needed for the secure and reliable operation of the ISO Controlled Grid. The ISO may revise the Local Reliability Criteria subject to and in accordance with section 5 of the TCA.

7.2.2.3 Standards to be Observed.

The ISO shall exercise Operational Control over the ISO Controlled Grid in compliance with all Applicable Reliability Criteria.

7.2.2.3.1 Applicable Reliability Criteria.

Applicable Reliability Criteria are defined as the standards established by NERC, WECC and Local Reliability Criteria and include the requirements of the Nuclear Regulatory Commission (NRC).

7.2.2.3.2 WECC Criteria (Standards).

(a) Western Interconnection.

The WECC set of standards for the Western Interconnection, which are based on the NERC standards.

The WECC further defines procedures and policies applicable to the Western Interconnection. WECC guidelines include:

(i) Part 1 – Reliability Criteria for Transmission System Planning

(ii) Part 2 – Power Supply Design Criteria

(iii) Part 3 – Minimum Operating Reliability Criteria (MORC)

(iv) Part 4 – Definitions

(b) Operating Procedures.

The WECC Operating Procedures submitted to WECC by individual utilities and the ISO to address specific operating problems in their respective grids that could affect operations of the interconnected grid.

(c) Dispatcher's Handbook.

The WECC Dispatcher's Handbook supplied by WECC to all utilities and Control Areas as a reference for dispatchers to use during normal and emergency operations of the grid.

7.2.2.3.3 NERC Policies and Standards.

(a) National Standards

The NERC national level standards for all utilities to follow to allow for safe and reliable operation of electric systems.

(b) Operating Manual

The NERC Operating Manual supplied by NERC to all utilities and Control Areas as a reference for dispatchers to use during normal and emergency operations of the grid.

7.2.3 General Standard of Care. When the ISO is exercising Operational Control of the ISO Controlled Grid, the ISO and Market Participants shall comply with Good Utility Practice.

7.2.4 Routine Operation of the ISO Controlled Grid. The ISO shall operate the ISO Controlled Grid in accordance with the standards described in Section 7.2.2.3 and within the limit of all applicable Nomograms and established operating limits and procedures.

7.2.4.1 ISO Controlled Facilities.

7.2.4.1.1 General.

The ISO shall have Operational Control of all transmission lines and associated station equipment that have been transferred to the ISO Controlled Grid from the PTOs as listed in the ISO Register.

7.2.4.2 Clearing Equipment for Work.

The clearance procedures of the ISO and the relevant UDC and PTO must be adhered to by all parties, to ensure the safety of all personnel working on ISO Controlled Grid transmission lines and equipment. In accordance with Section 9.3, no work shall start on any equipment or line which is under the Operational Control of the ISO unless final approval has first been obtained from the appropriate ISO Control Center. Prior to starting the switching to return any line or equipment to service the ISO shall confirm that all formal requests to work on the cleared line or equipment have been released.

7.2.4.3 Equipment De-energized for Work.

In some circumstances, System Reliability requirements may require a recall capability that can only be achieved by allowing work to proceed with the line or equipment de-energized only (i.e. not cleared and grounded). Any personnel working on such de-energized lines and equipment must take all precautions as if the line or equipment were energized. Prior to energizing any such lines or equipment deenergized for work, the ISO shall confirm that all formal requests to work on the de-energized line or equipment have been released.

7.2.4.4 Hot-Line Work.

The ISO has full authority to approve requests by PTOs to work on energized equipment under the Operational Control of the ISO, and no such work shall be commenced until the ISO has given its approval.

7.2.4.5 Intertie Switching.

The ISO and the appropriate single point of contact for the relevant PTO and the adjacent Control Area shall coordinate during the de-energizing or energizing of any Interconnection.

7.2.4.6 Operating Voltage Control Equipment.

7.2.4.6.1 Operating Voltage Control Equipment Under ISO Control.

The ISO will direct each PTO's single point of contact in the operation of voltage control equipment that is under the ISO's Operational Control.

7.2.4.6.2 Operating Voltage Control Equipment Under UDC Control.

Each UDC must operate voltage control equipment under UDC control in accordance with existing UDC voltage control guidelines.

7.2.4.6.3 Special ISO Voltage Control Requirements.

The ISO may request a PTO via its single point of contact or a UDC via its single point of contact to operate under special voltage control requirements from time to time due to special system conditions.

7.3 Normal System Operations.

7.3.1 Actions for Maintaining Reliability of ISO Controlled Grid.

The ISO plans to obtain the control over Generating Units that it needs to control the ISO Controlled Grid and maintain reliability by purchasing Ancillary Services from the market auction for these services. When the ISO responds to events or circumstances, it shall first use the generation control it is able to obtain from the Ancillary Services bids it has received to respond to the operating event and maintain reliability. Only when the ISO has used the Ancillary Services that are available to it under such Ancillary Services bids which prove to be effective in responding to the problem and the ISO is still in need of additional control over Generating Units, shall the ISO assume supervisory control over other Generating Units. It is expected that at this point, the operational circumstances will be so severe that a real-time system problem or emergency condition could be in existence or imminent.

Each Participating Generator shall take, at the direction of the ISO, such actions affecting such Generator as the ISO determines to be necessary to maintain the reliability of the ISO Controlled Grid. Such actions shall include (but are not limited to):

(a) compliance with the ISO's Dispatch instructions including instructions to deliver Ancillary Services in real time pursuant to the Final Day-Ahead Schedules and Final Hour-Ahead Schedules;

(b) compliance with the system operation requirements set out in Section 7 of this ISO Tariff;

(c) notification to the ISO of the persons to whom an instruction of the ISO should be directed on a 24-hour basis, including their telephone and facsimile numbers; and

(d) the provision of communications, telemetry and direct control requirements, including the establishment of a direct communication link from the control room of the Generator to the ISO in a manner that ensures that the ISO will have the ability, consistent with this ISO Tariff and the ISO Protocols, to direct the operations of the Generator as necessary to maintain the reliability of the ISO Controlled Grid, except that a Participating Generator will be exempt from ISO requirements imposed in accordance with this subsection (d) with regard to any Generating Unit with a rated capacity of less than 10 MW, unless that Generating Unit is certified by the ISO to participate in the ISO's Ancillary Services and/or to submit Supplemental Energy bids.

7.4 Management of System Emergencies.

7.4.1 Declaration of System Emergencies.

The ISO shall, when it considers that conditions giving rise to a System Emergency exist, declare the existence of such System Emergency. A declaration by the ISO of a System Emergency shall be binding on all Market Participants until the ISO announces that the System Emergency no longer exists.

7.4.2 Emergency Procedures.

In the event of a System Emergency, the ISO shall take such action as it considers necessary to preserve or restore stable operation of the ISO Controlled Grid. The ISO shall act in accordance with Good Utility Practice to preserve or restore reliable, safe and efficient service as quickly as reasonably practicable.

The ISO shall keep system operators in adjacent Control Areas informed as to the nature and extent of the System Emergency in accordance with WECC procedures and, where practicable, shall additionally keep the Market Participants within the Control Area informed.

7.4.2.1 In the event of a System Emergency, UDCs shall comply with all directions from the ISO concerning the management and alleviation of the System Emergency and shall comply with all procedures concerning System Emergencies set out in this Tariff and the ISO Protocols, and each MSS Operator shall comply with all directions from the ISO concerning the avoidance, management and alleviation of the System Emergency and shall comply with all procedures concerning System Emergencies set forth in the ISO Tariff.

7.4.2.2 During a System Emergency, the ISO and UDCs shall communicate through their respective control centers and in accordance with procedures established in individual UDC operating agreements, and the ISO and the MSS Operator shall communicate through their respective control centers and in accordance with procedures established in the agreement through which the MSS Operator undertakes to the ISO to comply with the provisions of the ISO Tariff.

7.4.2.3 System Emergencies.

7.4.2.4 All Generating Units, System Units and System Resources that are owned or controlled by a Participating Generator are (without limitation to the ISO's other rights under this ISO Tariff) subject to control by the ISO during a System Emergency and in circumstances in which the ISO considers that a System Emergency is imminent or threatened. The ISO shall, subject to Section 7.4.4.1, have the authority to instruct a Participating Generator to bring its Generating Unit on-line, off-line, or increase or curtail the output of the Generating Unit and to alter scheduled deliveries of Energy and Ancillary Services into or out of the ISO Controlled Grid, if such an instruction is reasonably necessary to prevent an imminent or threatened System Emergency or to retain Operational Control over the ISO Controlled Grid during an actual System Emergency. The ISO shall have the authority to instruct an RMR Unit whose owner has selected Condition 2 of its RMR Contract to start-up and change its output if the ISO has reasonably used all other available and effective resources to prevent a threatened System Emergency

without declaring that a System Emergency exists. It the ISO so instructs a Condition 2 RMR Unit, it shall compensate that unit in accordance with Section 11.2.4.2 and allocate the costs in accordance with Section 11.2.4.2.1.1.

7.4.3.1 Notifications by ISO of System Conditions.

The ISO will provide the following notifications to Participants to communicate unusual system conditions or emergencies.

7.4.3.2 System Alert.

ISO will give a system Alert Notice when the operating requirements of the ISO Controlled Grid are marginal because of Demand exceeding forecast, loss of major Generation or loss of transmission capacity that has curtailed imports into the ISO Control Area, or if the Hour-Ahead Market is short on scheduled Energy and Ancillary Services for the ISO Control Area.

7.4.3.3 System Warning.

The ISO will give a system warning notice when the operating requirements for the ISO Controlled Grid are not being met in the Hour-Ahead Market, or the quantity of Regulation, Spinning Reserve, Non-Spinning Reserve, Replacement Reserve and Supplemental Energy available to the ISO is not acceptable for the Applicable Reliability Criteria. This system warning notice will notify Participants that the ISO will, acting in accordance with Good Utility Practice, take such steps as it considers necessary to ensure compliance with Applicable Reliability Criteria, including the negotiation of Generation through processes other than competitive bids.

7.4.3.4 System Emergency.

When, in the judgment of the ISO, the System Reliability of the ISO Controlled Grid is in danger of instability, voltage collapse or under-frequency caused by transmission or Generation trouble in the ISO Control Area, or events outside of the ISO Control Area that could result in a cascade of events throughout the WECC grid, the ISO will declare a System Emergency. This declaration may include a notice to suspend the Day-Ahead, Hour-Ahead and Real Time Markets, authorize full use of Black Start

Generation, initiate full control of manual Load Shedding, authorize the curtailment of Curtailable Demand (even though not scheduled as an Ancillary Service). The ISO will reduce the System Emergency declaration to a lower alert status when it is satisfied, after conferring with Reliability Coordinators within the WECC that the major contributing factors have been corrected, all involuntarily interrupted Demand is back in service (except interrupted Curtailable Demand selected as an Ancillary Service). This reduction in alert status will reinstate the competitive markets if they have been suspended.

7.4.4 Intervention in Market Operations.

The ISO may intervene in the operation of the Day-Ahead Market, the Hour-Ahead Market or the Real Time Market and set the Administrative Price, if the ISO determines that such intervention is necessary in order to contain or correct a System Emergency as follows.

7.4.4.1 The ISO will not intervene in the operation of the Day-Ahead Market unless there has been a total or major collapse of the ISO Controlled Grid and the ISO is in the process of restoring it. The ISO shall, where reasonably practicable, utilize Ancillary Services which it has the contractual right to instruct and which are capable of contributing to containing or correcting the actual, imminent or threatened System Emergency prior to issuing instructions to a Participating Generator under Section 7.4.2.4.

7.4.4.2 Before any such intervention the ISO must (in the following order): (a) dispatch all scheduled Generation and all other Generation offered or available to it regardless of price (including all Adjustment Bids, Supplemental Energy bids, Ancillary Services and reserves); (b) dispatch all interruptible Loads made available by UDCs to the ISO in accordance with the relevant agreements with UDCs; (c) dispatch or curtail all price-responsive Demand that has been bid into any of the markets and exercise its rights under all load curtailment contracts available to it; (d) exercise Load Shedding to curtail Demand on an involuntary basis to the extent that the ISO considers necessary.

7.4.4.3 The Administrative Price in relation to each of the markets for Imbalance Energy and Ancillary Services shall be set at the applicable Market Clearing Price in the Settlement Period

immediately preceding the Settlement Period in which the intervention took place. When Administrative Prices are imposed, Inter-Zonal Congestion will be managed in accordance with Section 27.1.1.6(c).

7.4.4.4 The intervention will cease as soon as the ISO has restored all Demand that was curtailed on an involuntary basis under Section 7.4.4.2(d).

7.4.5 Emergency Guidelines.

The ISO shall issue protocols for all Market Participants to follow during a System Emergency. These guidelines shall be consistent with the specific obligations of Scheduling Coordinators and Market Participants referenced in Sections 7.4.10, 7.4.11, 7.4.2, 7.4.2.4 and 7.4.4.1 of this tariff. All Participants shall respond to ISO Dispatch Instructions with an immediate response during System Emergencies.

7.4.6 The ISO shall in accordance with Section 7.4.5 hereof implement the Electrical Emergency Plan in consultation with the UDCs, the MSS Operator, or other entities, at the ISO's discretion, when Energy reserve margins are forecast to be at the levels specified in the plan.

7.4.6.1 Each UDC and MSS Operator will notify its End-Use Customers connected to the UDC's or the MSS's Distribution System of any voluntary curtailments notified to the UDC or to the MSS Operator by the ISO pursuant to the provisions of the EEP.

7.4.7 Periodic Tests of Emergency Procedures.

The ISO shall develop and administer periodic unannounced tests of System Emergency procedures. Such tests shall be designed to ensure that the ISO Market Participants are capable of promptly and efficiently responding to imminent or actual System Emergencies.

7.4.8 Prioritization Schedule for Shedding and Restoring Load.

Prior to the ISO Operations Date, and annually thereafter, the ISO shall, in consultation with Market Participants and subject to the provisions of Section 3, develop a prioritization schedule for Load Shedding should a System Emergency require such action. The prioritization schedule shall also establish a sequence for the restoration of Load in the event that multiple Scheduling Coordinators or Market Participants are affected by service interruptions and Load must be restored in blocks. For Load

shed in accordance with Section 7.4.11.4.2, the prioritization schedule will only include those UDCs or MSS Operators that have Scheduling Coordinators that are scheduling insufficient resources to meet the Load in the UDC or MSS Service Area. For Load shed in accordance with Section 7.4.11.4.3, the prioritization schedule will include all UDCs and MSS Operators.

7.4.9 Under Frequency Load Shedding (UFLS).

7.4.9.1 Each UDC's agreement with the ISO and each agreement through which the MSS Operator undertakes to the ISO to comply with the provisions of the ISO Tariff shall describe the UFLS program for that UDC or for that MSS. The ISO and UDC or the ISO and the MSS shall review the UFLS program periodically to ensure compliance with Applicable Reliability Criteria.

7.4.9.2 The ISO shall perform periodic audits of each UDC's UFLS system and of each MSS's UFLS system to verify that the system is properly configured for each UDC or MSS.

7.4.9. The ISO will use its reasonable endeavors to ensure that UFLS is coordinated among the UDCs and MSSs so that no UDC bears a disproportionate share of the ISO's UFLS program.

7.4.9.4 In compiling its UFLS program, the ISO, at its discretion, may also coordinate with other entities, review and audit their UFLS programs and systems as described in Section Sections 7.4.9.1 to 7.4.9.3.

7.4.10 Further Obligations Relating to System Emergencies.

The ISO and Participating TOs shall comply with their obligations in Section 9 of the TCA.

7.4.11 Use of Load Curtailment Programs.

7.4.11.1 Use of UDC's Existing Load Curtailment Programs.

As an additional resource for managing System Emergencies, the ISO will, subject to Section 3, notify the UDCs when the conditions to implement their Load curtailment programs have been met in accordance with their terms. The UDCs will exercise their best efforts, including seeking any necessary regulatory approvals, to enable the ISO to rely on their curtailment rights at specified levels of Operating Reserve. Each UDC shall by not later than October 1 of each year advise the ISO of the capabilities of its Load

curtailment programs for the forthcoming year, and the conditions under which those capabilities may be exercised and shall give the ISO as much notice as reasonably practicable of any change to such programs.

7.4.11.2 Load Curtailment.

A Scheduling Coordinator may specify that Loads will be reduced at specified Market Clearing Prices or offer the right to exercise Load curtailment to the ISO as an Ancillary Service or utilize Load curtailment itself (by way of self-provision of Ancillary Services) as Non-Spinning Reserve or Replacement Reserve. The ISO, at its discretion, may require direct control over such Curtailable Demand to assume response capability for managing System Emergencies. However, non-firm Loads shall not be eligible to provide Curtailable Demand if they are receiving incentives for interruption under existing programs approved by a Local Regulatory Authority, unless: a) participation in the ISO's Ancillary Services markets is specifically authorized by such Local Regulatory Authority, and b) there exist no contingencies on the availability, nor any unmitigated incentives encouraging prior curtailment, of such interruptible Load for Dispatch as Curtailable Demand as a result of the operation of such existing program. The ISO may establish standards for automatic communication of curtailment instructions to implement Load curtailment as a condition for accepting any offered Load curtailment as an Ancillary Service.

7.4.11.3 The ISO shall have the authority to direct a UDC or an MSS Operator to disconnect Load from the ISO Controlled Grid if necessary to avoid an anticipated System Emergency or to regain operational control over the ISO Controlled Grid during an actual System Emergency. The ISO shall direct the UDCs or the MSS Operator to shed Load in accordance with the prioritization schedule developed pursuant to Section 7.4.8. When ISO Controlled Grid conditions permit restoration of Load, the ISO shall restore Load according to the prioritization schedule developed pursuant to Section 7.4.8 hereof. The MSS Operator shall restore Load internal to the MSS.

7.4.11.4 Load Shedding.

7.4.11.4.1 A portion of the ISO forecast of Control Area Load for each Trading Day will be allocated to each UDC or MSS Service Area. The ISO will aggregate each Scheduling Coordinator's

Day-Ahead Schedules to Load in each UDC or MSS Service Area and will compare those aggregated Load Schedules to the ISO's Control Area Load forecast of metered Demand for that UDC or MSS Service Area to determine if the Load in the UDC or MSS Service Area has a resource deficiency based on the Day-Ahead Schedules.

7.4.11.4.2 If the ISO forecasts in advance of the Hour-Ahead Market that Load curtailment will be necessary due to a resource deficiency, the ISO will identify any UDC or MSS Service Area that is resource deficient. The ISO will provide notice to all Scheduling Coordinators if one or more UDC or MSS is deficient. If Load curtailment is required to manage a System Emergency associated with insufficient Hour-Ahead Schedules of resources, the ISO will determine the amount and location of Load to be curtailed and will allocate a portion of that required Load curtailment to each UDC or MSS Operator whose Service Area has been identified, based on Hour-Ahead Schedules, as being resource-deficient based on the ratio of its resource deficiency to the total Control Area resource deficiency. Each UDC or MSS Operator shall be responsible for notifying its customers and Generators connected to its system of curtailments and service interruptions.

7.4.11.4.3 If a Load curtailment is required to manage System Emergencies, in any circumstances other than those described in Section 7.4.11.4.2, the ISO will determine the amount and location of Load to be reduced and to the extent practicable, will allocate a portion to each UDC based on the ratio of its Demand (at the time of the Control Area annual peak for the previous year) to total Control Area annual peak Demand for the previous year taking into account system considerations and the UDC's curtailment rights under their tariffs. Each UDC or MSS Operator shall be responsible for notifying its customers and Generators connected to its system of curtailments and service interruption.

7.4.12 Curtailment under Emergency and Non-Emergency Conditions.

7.4.12.1 Emergency Conditions.

To the extent practicable, the ISO shall allocate necessary curtailments of Existing Rights or Non-Converted Rights under emergency conditions in accordance with the instructions submitted by the Responsible PTO pursuant to Section 16.2.4A.1. If circumstances prevent the ISO's compliance with

such instructions, the ISO shall allocate such curtailments in a non-discriminatory manner consistent with Good Utility Practice.

7.4.12.2 Non-Emergency Conditions.

Unless otherwise specified by the Responsible PTO in the instructions that it submits to the ISO under Section 16.2.4A.1, the ISO will allocate any necessary curtailments under non-emergency conditions, pro rata, among holders of Existing Rights, at particular Scheduling Points and/or on particular contract paths, in the order of: (1) non-firm, (2) each priority of conditional firm, and (3) each priority of firm rights. Priorities for firm and conditional firm transmission service are indicated using contract usage templates, as described in Section 30.2.7.

7.4.13 System Emergency Reports and Sanctions.

7.4.13.1 Review of Major Outages.

The ISO with the cooperation of any affected UDC shall jointly perform a review following a major Outage that affects at least ten (10) percent of the Load served by the Distribution System of a UDC or any Outage that results in major damage to the ISO Controlled Grid or to the health and safety of personnel. The review shall address the cause of the Outage, the response time and effectiveness of emergency management efforts, and whether the operation, maintenance or scheduling practices of the ISO, any Participating TOs, Eligible Customers, UDCs or Participating Generators enhanced or undermined the ability of the ISO to maintain or restore service efficiently and in a timely manner.

7.4.13.2 Provide Information to Review Outages.

Participating TOs, Participating Generators, Eligible Customers, Scheduling Coordinators and UDCs shall promptly provide information requested by the ISO to review Outages pursuant to Section 7.4.13.1 and to prepare Outage reports. The ISO shall seek the views of any affected Participating TOs, Participating Generators, Eligible Customers, Scheduling Coordinator or UDCs and allow such affected Participating TOs, Participating Generators, Eligible Customers, Scheduling Coordinators or UDCs to comment on any issues arising during the preparation of a report. All findings and reports arising from the ISO's review shall be shared with Participating TOs, Participating Generators, Eligible Customers and UDCs.

7.4.13.3 Imposing Sanctions.

If the ISO finds that the operation and maintenance practices of any Participating TOs, Participating Generators, Eligible Customers, or UDCs prolonged the response time or contributed to the Outage, the ISO may impose sanctions on the responsible Participating TOs, Participating Generators, Eligible Customers, or UDCs provided that no sanction shall be imposed in respect of actions taken in compliance with the ISO's instructions or pursuant to a Remedial Action Scheme. The ISO shall develop and file with FERC a schedule of such sanctions. Any dispute concerning whether sanctions should be imposed under this Section shall be resolved through the ISO ADR Procedures. The schedule of sanctions filed with FERC (including categories and levels of sanctions) shall not be subject to the ISO ADR Procedures. The ISO shall publish on the ISO Home Page details of all instances in which a sanction has been imposed.

7.4.14 ISO Facilities and Equipment.

7.4.14.1 ISO Facility and Equipment Outages.

The ISO has installed redundant control centers, communication systems and computer systems. Most, but not necessarily all, equipment problems or failures should be transparent to Participants. This Section 7.4.14.1 addresses some situations when Participants could be affected, but it is impossible to identify and plan for every type of equipment problem or failure. Real time situations will be handled by the real time ISO dispatchers. The ISO control room in Folsom is the Primary ISO Control Center and the ISO control room in Alhambra is the Backup ISO Control Center.

7.4.14.2 WEnet Unavailable.

7.4.14.2.1 Unavailable Critical Functions of WEnet.

During a total disruption of the WEnet several critical functions of the ISO will not be available including:

(a) the Scheduling Infrastructure (SI) computer will not be able to communicate with Scheduling Coordinators to receive any type of updated Schedule information;

(b) the SI computer will not be able to communicate Congestion Management information and Schedule changes to the Scheduling Coordinators; and

(c) the ISO will not be able to communicate general information, including emergency information, to any Participants.

7.4.14.2.2 Communications during WEnet Unavailability.

During any period of WEnet unavailability, the ISO shall:

(a) make all reasonable efforts to keep Participants aware of current ISO Controlled Grid status using voice communications;

(b) use the most recent set of Balanced Schedules for each Scheduling Coordinator for the current and all future Settlement Periods and/or Trading Days until the WEnet is restored; and

(c) attempt to take critical Schedule changes from Scheduling Coordinators via voice communications as time and manpower allows.

7.4.14.2.3 Primary ISO Control Center – Loss of all Voice Communications.

In the event of loss of all voice communication at the Primary ISO Control Center, the Primary ISO Control Center will use alternate communications to notify the Backup ISO Control Center of the loss of voice communications. The Backup ISO Control Center will post information on the situation on the WEnet. Additional voice notifications will be made as time permits. Once voice communications have been restored to the Primary ISO Control Center, the ISO will post this information on the WEnet.

7.4.14.2.4 Primary ISO Control Center – Control Center Completely Unavailable.

In the event that the Primary ISO Control Center becomes completely unavailable, the Primary ISO Control Center will use alternate communications to notify the Backup ISO Control Center that the Primary ISO Control Center is unavailable. The Backup ISO Control Center will post information on the situation on the WEnet. Additional voice notifications will be made as time permits.

The Backup ISO Control Center will post confirmation on the WEnet that all computer systems are functioning normally (if such is the case) and take complete control of the ISO Controlled Grid. The Backup ISO Control Center will notify the TOC by direct voice communication of the situation.

Once the Primary ISO Control Center is again available, all functions will be transferred back, and the Primary ISO Control Center will notify all Participants via the WEnet.

7.4.14.2.5 Primary ISO Control Center - ISO Energy Management System (EMS) Unavailable.

Should an outage occur to the redundant EMS computer systems in the Primary ISO Control Center, an auto transfer should occur to transfer EMS operation to the redundant EMS back up computers at the Backup ISO Control Center. Due to the severity of a total ISO EMS computer outage, the Primary ISO Control Center will post information on the WEnet that the Primary ISO Control Center EMS computer is unavailable and that EMS control has been transferred to the Backup ISO Control Center.

When the Primary ISO Control Center EMS computer is restored, the Backup ISO Control Center will initiate a transfer back of the EMS system to the Primary ISO Control Center. The Primary ISO Control Center will post information on the restored EMS computer system status on the WEnet.

7.4.14.2.6 Backup ISO Control Center – Loss of all Voice Communications.

In the event of a loss of all voice communications at the Backup ISO Control Center, the Backup ISO Control Center will use alternate communications to notify the Primary ISO Control Center of the loss of voice communications. The Primary ISO Control Center will post information on the situation via the WEnet. Additional voice notifications will be made as time permits.

Once voice communications have been restored to the Backup ISO Control Center, the Primary ISO Control Center will post this information on the WEnet.

7.4.14.2.7 Backup ISO Control Center – Control Center Completely Unavailable.

In the event that the Backup ISO Control Center becomes completely unavailable, the Backup ISO Control Center will use alternate communications to notify the Primary ISO Control Center that the

Backup ISO Control Center is unavailable. The Primary ISO Control Center will post information on the situation on the WEnet. Additional voice notifications will be made as time permits.

The Primary ISO Control Center will post confirmation on the WEnet that all computer systems are functioning normally (if such is the case) and take complete control of the ISO Controlled Grid. The Primary ISO Control Center will notify the SCE GCC by direct voice communications of the situation.

Once the Backup ISO Control Center is again available all functions will be transferred back, and the Backup ISO Control Center will notify all Participants via the WEnet.

7.4.14.2.8 Use of IOUs' Energy Control Center Computers.

The ISO and the IOUs will comply with the procedures for the utilization by the ISO of the IOUs' Energy control center computers when developed. The ISO will post such procedures on the WEnet when agreed.

7.5 Management of Overgeneration Conditions.

The ISO's management of Overgeneration relates only to real time. In the event that Overgeneration conditions occur during real time, the ISO will direct the Scheduling Coordinators to take the steps described in this Section 7.5 of the ISO Tariff and Scheduling Coordinators shall implement ISO directions without delay. Overgeneration in real time will be mitigated by the ISO as follows; provided that the ISO Operator will have the discretion, if necessary to avoid a System Emergency, to eliminate one or more of the following steps.

7.5.1 Commencing one hour prior to the start of the Settlement Period, the ISO will, based on available Adjustment Bids, Supplemental Energy bids and Ancillary Service Energy bids, issue Dispatch instructions to Scheduling Coordinators to reduce Generation and imports for the next operating hour.

7.5.2 To the extent that there are insufficient decremental Energy bids available for the operating hour to fully mitigate the Overgeneration condition, the ISO will notify Scheduling Coordinators of the projected amount of Overgeneration to be mitigated in that hour.

7.5.3 In addition to the action taken under 7.5.2, the ISO will, if it considers it necessary to maintain the reliable operation of the ISO Control Area, offer Energy for sale on behalf of Scheduling Coordinators to adjacent Control Area operators at the estimated BEEP Interval Ex Post Price or, if the ISO considers it necessary, at a price established by the ISO on behalf of Scheduling Coordinators, to be paid to adjacent Control Area operators.

7.5.4 To the extent that the steps described in Sections 7.5.1 through 7.5.3 fail to mitigate Overgeneration, the ISO will instruct Scheduling Coordinators to reduce either Generation, or imports, or both. The amount of the reduction for each Scheduling Coordinator will be calculated pro rata based on the product of the total required reduction in Generation and imports (or increase in exports) and the ratio of its Demand to the total Demand in the ISO Control Area.

7.5.5 To the extent that the above steps fail to fully mitigate the Overgeneration, the ISO will issue mandatory Dispatch instructions for specific reductions in Generating Unit output and external imports and all relevant Scheduling Coordinators shall be obligated to comply with such Dispatch instructions.

7.5.6 Any costs incurred by the ISO in implementing Section 7.5.3 shall be reimbursed to the ISO by Scheduling Coordinators based upon the extent to which they supplied Energy, in metered amounts, greater than the Generation and imports scheduled in their Final Schedules and consumed Energy, in metered amounts, less than the Demand scheduled in their Final Schedules, as a proportion of the total amount of such excess or shortfall among all Scheduling Coordinators.

8. ANCILLARY SERVICES.

8.1 Scope.

The ISO shall be responsible for ensuring that there are sufficient Ancillary Services available to maintain the reliability of the ISO Controlled Grid consistent with WECC and NERC criteria. The ISO's Ancillary Services requirements may be self-provided by Scheduling Coordinators. Those Ancillary Services which the ISO requires to be available but which are not being self-provided will be competitively procured by the ISO from Scheduling Coordinators in the Day-Ahead Market, Hour-Ahead Market and in real time or

ability to make changes, or cause such changes to be made, to interchange schedules during any interval of a Settlement Period at the discretion of the ISO).

8.4.7.3.3 Scheduling Coordinators may bid or self-provide external imports of Regulation from System Resources located outside the ISO Control Area, where technically feasible and consistent with WECC criteria by dynamic scheduling; provided that the operator of the Control Area in which the System Resources are located has entered into an agreement with the ISO for interconnected Control Area operations; and provided that such Scheduling Coordinator and the operator of the Control Area in which the resources are located have been certified by the ISO as to their ability to dynamically adjust interchange schedules based on control signals issued by the ISO anytime during a Settlement Period at the discretion of the ISO. Such certification shall include a demonstration of their ability to support the dynamic interchange of Regulation service based on ISO control signals received on dedicated communications links (either directly or through EMS computers) for ISO computer control and telemetry to provide this function in accordance with ISO standards and procedures posted on the ISO Home Page.

8.4.7.3.4 Scheduling Coordinators may utilize transmission service under Existing Contracts to self-provide Regulation (consistent with this ISO Tariff), from resources located outside the ISO Control Area, where technically feasible, consistent with WECC standards.

8.4.7.3.5 Scheduling Coordinators' bidding or self-provision of Ancillary Services according to this Section 8.4.7.3 shall be consistent with the ISO Protocols.

8.4.7.3.6 Due to the design of the ISO's scheduling system, any specific resource can bid to supply a specific Ancillary Service or can self-provide such Ancillary Service but cannot do both in the same Settlement Period.

8.5 The Bidding Process.

The ISO shall operate a competitive Day-Ahead and Hour-Ahead Market to procure Ancillary Services. It shall purchase Ancillary Services capacity at least cost to End-Use Customers consistent with maintaining System Reliability. Any Scheduling Coordinator representing Generating Units, System Units, Loads or external imports of System Resources may bid into the ISO's Ancillary Services market provided that it is

in possession of a current certificate for the Generating Units, System Units, external imports of System Resources or Loads concerned.

8.5.1 Provision of System Information to Scheduling Coordinators.

By 6:00 p.m. two days prior to the Trading Day, the ISO shall make available to Scheduling Coordinators general system information including those items of information set forth in Section 6.9.1. This information shall be provided at the same time as the ISO provides general system information to all Scheduling Coordinators wishing to schedule power on the ISO Controlled Grid.

8.5.2 Time Frame for Submitting And Evaluating Bids.

8.5.2.1 Day-Ahead Auction.

Bids for the ISO's Day-Ahead Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve service market must be received by 10:00 am on the day prior to the Trading Day. The bids shall include information for each of the twenty-four (24) Settlement Periods of the Trading Day. Failure to provide the information within the stated time frame shall result in the bids being declared invalid by the ISO.

8.5.2.2 Hour-Ahead Auction. The ISO will require Scheduling Coordinators to honor their Day-Ahead Ancillary Services schedules and/or bids when submitting their Hour-Ahead Ancillary Services schedules and/or bids. Bids for the ISO's Hour-Ahead Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve service market for each Settlement Period must be received at least two hours prior to the commencement of that Settlement Period. The bids shall include information for only the relevant Settlement Period. Failure to provide the information within the stated time frame shall result in the bids being declared invalid by the ISO. Scheduling Coordinators wishing to buy back in the Hour-Ahead Market Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity sold to the ISO in the Day-Ahead Market pursuant to Section 8.7 must do so by submitting a revised bid in the Hour-Ahead Market for the Ancillary Service and resource concerned.

8.5.3 Information to Be Submitted By Bidders.

8.5.3.1 Information for Use in Day-Ahead Market and Hour-Ahead Market.

Bids shall be submitted by Scheduling Coordinators acting on behalf of Participating Generators, and owners or operators of Loads. Bids must be in the format specified by the ISO and include the bid information for each service described in Sections 8.5.6 to 8.5.10 and such other information as the ISO may determine it requires to evaluate bids as published from time to time in this ISO Tariff or ISO Protocols. The ISO will verify and respond to submitted bid data in accordance with Appendix E and the ISO Protocols. Bidders may submit new bids on a daily basis (or hourly basis for the Hour-Ahead Market).

8.5.3.2 Information for Use in Real-Time Dispatch of Ancillary Services.

Scheduling Coordinators with Ancillary Services awards must submit a single Energy Bid curve in the Real Time Market to correspond to any awarded capacity for the relevant resources Scheduling Coordinators must submit Energy Bids for resources providing Spinning, Non-Spinning, or Replacement Reserves.

8.5.4 Bid Evaluation Rules.

Bid evaluation shall be based on the following principles:

(a) the ISO shall not differentiate between bidders other than through price and capability to provide the service, and the required locational mix of services;

(b) to minimize the costs to users of the ISO Controlled Grid, the ISO shall select the bidders with lowest bids for capacity which meet its technical requirements, including location and operating capability;

(c) for the Day-Ahead Market, the Day-Ahead bids shall be evaluated independently for each of the 24 Settlement Periods of the following Trading Day;

(d) for the Hour-Ahead Market, the ISO shall evaluate bids in the two hours preceding the hour of operation;

(e) the ISO will procure sufficient Ancillary Services in the Day-Ahead Market to meet its forecasted requirements, as known at the close of the Day-Ahead Market, except that the ISO may elect to procure a portion of such requirements in the Hour-Ahead Markets if the ISO first provides notice to Scheduling Coordinators of such action, including the approximate hourly megawatt amounts of each Ancillary Service that it intends to procure in the Hour-Ahead Markets;

(f) the ISO will (to the extent available) procure sufficient Ancillary Services to meet its requirements; and

(g) the ISO will evaluate and price only those Ancillary Services bids received.

8.5.5 Evaluation of Ancillary Services Bids.

When Scheduling Coordinators bid into the Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve markets, they may bid the same capacity into as many of these markets as desired at the same time by providing the appropriate bid information to the ISO. The ISO shall evaluate bids in the markets for Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve sequentially and separately in the following order: Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve. Any capacity accepted by the ISO in one of these markets shall not be passed on to another market, except that capacity accepted in the Regulation market that represents the downward range of movement accepted by the ISO may be passed on to another market; any losing bids in one market may be passed onto another market, if the Scheduling Coordinator so indicates to the ISO. A Scheduling Coordinator may specify capacity bid into only the markets it desires. A Scheduling Coordinator shall also have the ability to specify different capacity prices and different Energy prices for the Spinning Reserve, Non-Spinning Reserve, Replacement Reserve and Regulation markets. The bid information, bid evaluation and price determination rules set forth below shall be used in the Day-Ahead, Hour-Ahead and real-time procurement of Regulation, Spinning Reserve, Non- Spinning Reserve, and Replacement Reserve.

A Scheduling Coordinator providing one or more Regulation, Spinning Reserve, Non-Spinning Reserve, and Replacement Reserve services may not change the identification of the Generating Units or

Loads offered in the Day-Ahead Market, the Hour-Ahead Market or in real time for such services unless specifically approved by the ISO (except with respect to System Units, if any, in which case Scheduling Coordinators are required to identify and disclose the resource specific information for all Generating Units and Curtailable Demands constituting the System Unit scheduled or bid into the ISO's Day-Ahead Market and Hour-Ahead Market as required in SP 3.3.2(e) in Appendix Y).

8.5.5.1 Ancillary Service Bid Evaluation and Pricing Terminology.

Unless otherwise specifically described herein, the following terminology will apply:

$CapRes_{ijt}$	=	the Ancillary Service reserve reservation bid price (in $/MW).
$Cap_{ijt}max$	=	the maximum amount of reserve that can be scheduled by the ISO with respect to a Scheduling Coordinator's bid of that resource to supply Ancillary Services (in MW).
Cap_{ij}	=	that portion of an Ancillary Services bid (in MW), identified in the ISO's evaluation process, that may be used to meet the ISO's Requirement for a particular Ancillary Service ($Cap_{ijt} < Cap_{ijt}max$)
Requirement	=	the total amount of reserve that must be scheduled for a particular Ancillary Service required by the ISO in a Settlement Period (in MW).
i, j, t	=	Generating Unit i, Scheduling Coordinator j, Settlement Period t.

8.5.6 The Regulation Auction.

Bid Information. Each Scheduling Coordinator j desiring to participate in the ISO's Regulation auction will submit the following information for each relevant Generating Unit or System Unit i for each Settlement Period t of the relevant Trading Day:

(a) bidder name/Identification Code and Scheduling Coordinator's ID code;

(b) resource identification (name and Location Code);

(c) the date for which the bid applies;

(d) maximum operating level (MW);

(e) minimum operating level (MW);

(f) ramp rate (MW/Min) $Ramp_{ijt}$;

(g) the upward and downward range of generating capacity over which Generating Unit or System Unit i from Scheduling Coordinator j is willing to provide Regulation for Settlement Period t ($Cap_{ijt}max$ (MW) where $Cap_{ijt}max \leq$ Period $_{minutes}$ * $Ramp_{ijt.}$ Period $_{minutes}$ is established by the ISO, by giving Scheduling Coordinators twenty-four (24) hours advance notice, within a range from a minimum of 10 minutes to a maximum of 30 minutes. Bidders shall offer upward and downward range for Regulation service;

(h) the bid price of the capacity reservation, stated separately for Regulation Up and Regulation Down ($CapRes_{ijt}$ ($/MW));

(i) type of schedule: Regulation Ancillary Service (ANC_SRVC) or Revised Regulation Ancillary Service (REVISED_ANC_SRVC);

(j) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(k) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule; and

(l) upward and downward range of Generating Unit or System Unit capacity over which the Generating Unit or System Unit is offering to provide Regulation.

Each Scheduling Coordinator desiring to participate in the ISO's Regulation auction will submit the following information for each relevant external import for each Settlement Period of the relevant Trading Day:

(a) bidder name/Identification Code and Scheduling Coordinator's ID code;

(b) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(c) Scheduling Point (the name);

(d) interchange ID code(the name of the selling entity, buying entity and a numeric identifier);

(e) external Control Area ID;

(f) Schedule ID (NERC ID number) and complete WECC tag;

(g) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule;

(h) the contract reference number, if applicable,

(i) maximum operating level (MW);

(j) minimum operating level (MW);

(k) ramp rate (MW/Min) $Ramp_{ijt}$;

(l) the upward and downward range of generating capacity over which System Resource i from Scheduling Coordinator j is willing to provide Regulation for Settlement Period t ($Cap_{ijt}max$ (MW)) where $Cap_{ijt}max \leq$ Period $_{minutes}$ * $Ramp_{ijt}$. Period $_{minutes}$ is established by the ISO, by giving Scheduling Coordinators twenty-four (24) hours advance notice, within a range from a minimum of 10 minutes to a maximum of 30 minutes. Bidders shall offer upward and downward range for Regulation service;

(m) the bid price of the capacity reservation, stated separately for Regulation Up and Regulation Down ($CapRes_{ijt}$ ($/MW)); and

(n) type of schedule: (Regulation Ancillary Service).

Bid Evaluation. Based on the quantity and location of the system requirements, the ISO shall select Generating Units, System Units, and System Resources with the bids, which minimize the sum of the total bids of the Generating Units, System Units, and System Resources selected for Regulation Up or Regulation Down, subject to two constraints:

(a) the sum of the selected bid capacities must be greater than or equal to the required Regulation capacity; and

(b) each Generating Unit's, System Unit's, or System Resource's bid capacity must be less than or equal to that Generating Unit's, System Unit's, or System Resource's ramp rate times Period $_{minutes}$ where Period $_{minute}$ is established by the ISO, by giving Scheduling Coordinators twenty-four (24) hours advance notice, within a range from a minimum of 10 minutes to a maximum of 30 minutes.

The total bid for each Generating Unit, System Unit, or System Resource is calculated by multiplying the capacity reservation bid price by the bid capacity.

Thus, subject to any locational requirements, the ISO will accept winning Regulation bids in accordance with the following criteria:

$$\underset{i,j}{Min} \sum TotalBidijt$$

Subject to

$$\sum_{i,j} Cap_{ijt} \geq Requirement_t \text{ and } Cap_{ijt} \leq Cap_{ijtmax}$$

Where

$TotalBid_{ijt} = CapRes_{ijt} * Cap_{ijt}$

$Requirement_t$ = Amount of upward and downward movement capacity required

Price Determination. The price payable to Scheduling Coordinators for Regulation Capacity made available for upward and downward movement in accordance with the ISO's Final Day-Ahead Schedules shall, for each Generating Unit, System Unit, and System Resource concerned, be the Zonal Market Clearing Price as follows:

$PAGC_x = MCP_{xt}$

Where:

The Zonal Market Clearing Price (MCP_{xt}) is the highest priced winning Regulation capacity bid in Zone X based on the capacity reservation bid price, i.e.

MCP_{xt} = *Max* ($CapRes_{ijt}$) *in Zone x for Settlement Period t*

In the absence of Inter-Zonal Congestion, the Zonal Market Clearing Prices will be equal.

The ISO's auction does not compensate the Scheduling Coordinator for the minimum Energy output of Generating Units, System Units, or System Resources bidding to provide Regulation. Therefore, disposition of any minimum Energy associated with Regulation selected in the ISO's Ancillary Services markets is the responsibility of the Scheduling Coordinator selling the Regulation.

The price payable to Scheduling Coordinators for Regulation capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 8.7 shall be the bid price of the Regulation Capacity reserved ($CapRes_{ijt}$ ($/MW)).

8.5.7 The Spinning Reserve Auction.

Bid Information. If the bid is for the provision of Spinning Reserve from a Generating Unit or System Unit, each Scheduling Coordinator j must submit the following information for each Generating Unit or System Unit i for each Settlement Period t of the following Trading Day:

(a) bidder name/Identification Code;

(b) resource identification (name and Location Code);

(c) the date for which the bid applies;

(d) maximum operating level (MW);

(e) minimum operating level (MW);

(f) ramp rate (MW/min);

(g) MW additional capability synchronized to the system, immediately responsive to system frequency, and available within 10 minutes ($Cap_{ijt}max$) for Generating Unit i, or System Unit I, from Scheduling Coordinator j, for Settlement Period t;

(h) bid price of capacity reserved ($CapRes_{ijt}$ ($/MW));

(i) an indication whether the capacity reserved would be available to supply Imbalance Energy only in the event of the occurrence of an unplanned Outage, a Contingency or an imminent or actual System Emergency;

(j) type of schedule: Spinning Reserve Ancillary Service (ANC_SRVC) or Revised Spinning Reserve Ancillary Service (REVISED_ANC_SRVC);

(k) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(l) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule; and

(m) Spinning Reserve capacity (MW).

If the bid is for the provision of Spinning Reserve from an external import of a System Resource, each Scheduling Coordinator j must submit the following information for each external import of a System Resource i for each Settlement Period t of the following Trading Day:

(a) bidder name/Identification Code;

(b) the date for which the bid applies;

(c) ramp rate if applicable (MW/Min);

(d) MW additional capability synchronized to the system, immediately responsive to system frequency and available at the point of interchange with the ISO Control Area, within 10 minutes ($Cap_{ijt}max$) of the ISO calling for the external import of System Resource i, from Scheduling Coordinator j, for Settlement Period t;

(e) bid price of capacity reserved ($CapRes_{ijt}$ ($/MW));

(f) an indication whether the capacity reserved would be available to supply Imbalance Energy only in the event of the occurrence of an unplanned Outage, a Contingency or an imminent or actual System Emergency; and, for a dynamic import of a System Resource, the following additional information:

(g) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(h) Scheduling Point (the name);

(i) interchange ID code(the name of the selling entity, buying entity and a numeric identifier);

(j) external Control Area ID;

(k) Schedule ID (NERC ID number) and complete WECC tag;

(l) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule;

(m) the contract reference number, if applicable;

(n) type of schedule: Spinning Reserve Ancillary Service (ANC_SRVC) or Revised Spinning Reserve Ancillary Service (REVISED_ANC_SRVC);

(o) export flag, a "YES" indicates an external export and a "NO" indicates an external import; and

(p) Spinning Reserve capacity (MW).

Bid Evaluation. Based on the quantity and location of the system requirements, the ISO shall select the Generating Units, System Units and external imports of System Resources with the bids which minimize the sum of the total bids of the Generating Units, System Units and external imports of System Resources selected subject to two constraints:

(a) the sum of the selected bid capacities must be greater than or equal to the required Spinning Reserve capacity; and

(b) each Generating Unit's, System Unit's or external import's bid capacity must be less than or equal to that Generating Unit's, System Unit's or external import's ramp rate times 10 minutes.

The total bid for each Generating Unit, System Unit or external import of a System Resource is calculated by multiplying the capacity reservation bid price by the bid capacity. Thus, subject to any locational requirements, the ISO will select the winning Spinning Reserve bids in accordance with the following criteria:

$$Min \sum_{i,j} Totalbid_{ijt}$$

Subject to

$$\sum_{i,j} Cap_{ijt} \geq Requirement_t$$

and $Cap_{ijt} \leq Cap_{ijt}max$

Where

$TotalBid_{ijt} = Cap_{ijt} * CapRes_{ijt}$

$Requirement_t$ = the amount of Spinning Reserve capacity required

Price Determination. The price payable to Scheduling Coordinators for Spinning Reserve Capacity made available in accordance with the ISO's Final Day-Ahead Schedules shall, for each Generating Unit or external import of a System Resource concerned be the Zonal Market Clearing Price for Spinning Reserve calculated as follows:

$Psp_{xt} = MCP_{xt}$

Where the Zonal Market Clearing Price (MCP_{xt}) for Spinning Reserve is the highest priced winning Spinning Reserve capacity bid in Zone X based on the capacity reservation bid price, i.e.:

$MCP_{xt} = Max(CapRes_{ijt})$ in Zone x for Settlement Period t

In the absence of Inter-Zonal Congestion, the Zonal Market Clearing Prices will be equal.

The ISO's auction does not compensate a Scheduling Coordinator for the minimum Energy output of Generating Units, System Units or System Resources bidding to provide Spinning Reserve.

Therefore, any minimum Energy output associated with Spinning Reserve selected in the ISO's auction is the responsibility of the Scheduling Coordinator selling the Spinning Reserve.

The price payable to Scheduling Coordinators for Spinning Reserve Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 8.7 shall be the bid price of the Spinning Reserve capacity reserved ($CapRes_{ijt}$($/MW)).

8.5.8 The Non-Spinning Reserve Auction.

Bid information. If the bid is for the provision of Non-Spinning Reserve from a Generating Unit or System Unit, each Scheduling Coordinator j must submit the following information for each Generating Unit or System Unit i for each Settlement Period t of the following Trading Day:

(a) bidder name/Identification Code;

(b) Generating Unit or System Unit identification (name and Location Code);

(c) the date for which the bid applies;

(d) maximum operating level (MW);

(e) minimum operating level (MW);

(f) ramp rate (MW/Min);

(g) the MW capability available within 10 minutes ($Cap_{ijt}max$);

(h) the bid price of the capacity reserved ($CapRes_{ijt}$($/MW));

(i) time to synchronization following notification (min);

(j) an indication whether the capacity reserved would be available to supply Imbalance Energy only in the event of the occurrence of an unplanned Outage, a Contingency or an imminent or actual System Emergency;

(k) type of schedule: Non-Spinning Reserve Ancillary Service (ANC_SRVC) or Revised Non-Spinning Reserve Ancillary Service (REVISED_ANC_SRVC);

(l) type of market (Day-Ahead or Hour-Ahead) and Trading Day; and

(m) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule.

If the bid is for the provision of Non-Spinning Reserve from an external import of a System Resource, each Scheduling Coordinator j must submit the following information for each external import of a System Resource i for each Settlement Period t of the following Trading Day:

(a) bidder name/Identification Code;

(b) the date for which the bid applies;

(c) ramp rate if applicable (MW/Min);

(d) the MW capability available at the point of interchange with the ISO Control Area, within 10 minutes ($Cap_{ijt}max$) of the ISO calling for the external import of System Resource I, from Scheduling Coordinator j, for Settlement Period t;

(e) the bid price of the capacity reserved ($CapRes_{ijt}$($/MW));

(f) an indication whether the capacity reserved would be available to supply Imbalance Energy only in the event of the occurrence of an unplanned Outage, a Contingency or an imminent or actual System Emergency; and, for a dynamic import of a System Resource, the following additional information:

(g) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(h) Scheduling Point (the name);

(i) interchange ID code (the name of the selling entity, buying entity and a numeric identifier);

(j) external Control Area ID;

(k) Schedule ID (NERC ID number) and complete WECC tag;

(l) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule;

(m) the contract reference number, if applicable;

(n) type of schedule: Non-Spinning Reserve Ancillary Service (ANC_SRVC) or Revised Non-Spinning Reserve Ancillary Service (REVISED_ANC_SRVC);

(o) export flag, a "YES" indicates an external export and a "NO" indicates an external import; and

(p) Non-Spinning Reserve capacity (MW).

If the bid is for the provision of Non-Spinning Reserve from a Load located within the ISO Control Area, each Scheduling Coordinator j must submit the following information for each Load i for each Settlement Period t of the following Trading Day:

(a) bidder name/Identification Code;

(b) Load identification name and Location Code;

(c) the date for which the bid applies;

(d) Demand reduction available within 10 minutes ($Cap_{ijt}max$);

(e) to interruption following notification (min);

(f) maximum allowable curtailment duration (hr);

(g) the bid price of the capacity reserved ($CapRes_{ijt}$($/MW));

(h) an indication whether the capacity reserved would be available for Demand reduction only in the event of the occurrence of an unplanned Outage, a Contingency or an imminent or actual System Emergency;

(i) type of schedule: Non-Spinning Reserve Ancillary Service (ANC_SRVC) or Revised Non-Spinning Reserve Ancillary Service (REVISED_ANC_SRVC);

(j) type of market (Day-Ahead and Hour-Ahead) and Trading Day; and

(k) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule.

Bid Evaluation. Based on the quantity and location of the system requirements, the ISO shall select the Generating Units, System Units, Loads or external imports of System Resources with the bids which minimize the sum of the total bids of the Generating Units, System Units, Loads or external imports of System Resources selected subject to two constraints:

(a) the sum of the selected bid capacities must be greater than or equal to the required Non-Spinning Reserve capacity; and

(b) each Generating Unit's, System Unit's, Load's or external import's bid capacity must be less than or equal to that Generating Unit's, System Unit's, Load's or external import's ramp rate (or time to interruption in the case of a Load offering Demand reduction) times the difference between 10 minutes and the time to synchronize in the case of a Generating Unit or System Unit or to interruption in the case of a Load. The total bid for each Generating Unit, System Unit, Load or external import of a System Resource is calculated by multiplying the capacity reservation bid by the bid capacity.

Thus subject to any locational requirements, the ISO will accept the winning Non-Spinning Reserve bids in accordance with the following criteria:

$$Min \sum_{i,j} Totalbid_{ijt}$$

Subject to

$$\sum_{i,j} Cap_{ijt} \geq Requirement_t$$

$$Cap_{ijt} \leq Cap_{ijt}max$$

Where

$TotalBid_{ijt} = Cap_{ijt} * CapRes_{ijt}$

$Requirement_t$ = the amount of Non-Spinning Reserve capacity required

Price Determination. The price payable to Scheduling Coordinators for Non-Spinning Reserve Capacity made available in accordance with the ISO's Final Day-Ahead Schedules shall for each

Generating Unit, System Unit, Load or external import of a System Resource concerned be the Zonal Market Clearing Price for Non-Spinning Reserve calculated as follows:

$Pnonsp_{xt} = MCP_{xt}$

Where the Zonal Market Clearing Price (MCP_{xt}) for Non-Spinning Reserve is the highest priced winning Non-Spinning Reserve bid in Zone X based on the capacity reservation bid price, i.e.:

$MCP_{xt} = Max(CapRes_{ijt})$ in Zone x for Settlement Period t.

In the absence of Inter-Zonal Congestion, the Zonal Market Clearing Prices will be equal.

The price payable to Scheduling Coordinators for Non-Spinning Reserve Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 8.7 shall be the bid price of the Non-Spinning Capacity reserved ($CapRes_{ijt}(\$/MW)$).

8.5.8A The Replacement Reserve Auction.

Bid Information. If the bid is for the provision of Replacement Reserve from a Generating Unit or System Unit each Scheduling Coordinator j must submit the following information for each Generating Unit or System Unit i for each Settlement Period t of the following Trading Day:

(a) bidder name/Identification Code;

(b) Generating Unit or System Unit identification (name and Location Code);

(c) the date for which the bid applies;

(d) maximum operating level (MW);

(e) minimum operating level (MW);

(f) ramp rate (MW/Min);

(g) the MW capacity available within 60 minutes ($Cap_{ijt}max$);

(h) the bid price of the capacity reserved ($CapRes_{ijt}(\$/MW)$);

(i) time to synchronize following notification (min).

(j) type of schedule: Replacement Reserve Ancillary Service (ANC_SRVC) or Revised Replacement Reserve Ancillary Service (REVISED_ANC_SRVC);

(k) type of market (Day-Ahead or Hour-Ahead) and Trading Day; and

(l) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule.

If the bid is for the provision of Replacement Reserve from an external import of a System Resource, each Scheduling Coordinator j must submit the following information for each external import of a System Resource i for each Settlement Period t of the following Trading Day:

(a) bidder name/Identification Code;

(b) the date for which the bid applies;

(c) ramp rate applicable (MW/Min);

(d) the MW capability available at the point of interchange with the ISO Control Area, within 60 minutes ($Cap_{ijt}max$) of the ISO calling for the external import of System Resource i, from Scheduling Coordinator j, for Settlement Period t;

(e) bid price of capacity reserved ($CapRes_{ijt}$;($/MW)); and, for a dynamic import of a System Resource, the following additional information:

(h) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(i) Scheduling Point (the name);

(j) interchange ID code (the name of the selling entity, buying entity and a numeric identifier);

(k) external Control Area ID;

(l) Schedule ID (NERC ID number) and complete WECC tag;

(m) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule;

(n) the contract reference number, if applicable;

(o) type of schedule: Replacement Reserve Ancillary Service (ANC_SRVC) or Revised Replacement Reserve Ancillary Service (REVISED_ANC_SRVC);

(p) time to synchronize following notification (less than sixty (60) minutes mandatory); and

(q) Replacement Reserve capacity (MW).

If the bid is for the provision of Replacement Reserve from a Load located within the ISO Control Area, each Scheduling Coordinator j must submit the following information for each Load i for each Settlement Period t of the following Trading Day:

(a) bidder name/Identification Code;

(b) Load identification (name and Location Code);

(c) the date for which the bid applies;

(d) the Demand reduction available within 60 minutes (Cap_{ijt} (MW));

(e) time to interruption following notification (min);

(f) maximum allowable curtailment duration (hr);

(g) the bid price of the capacity reserved ($CapRes_{ijt}$ ($/MW));

(h) type of schedule: Replacement Reserve Ancillary Service (ANC_SRVC) or Revised Replacement Reserve Ancillary Service (REVISED_ANC_SRVC);

(i) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(j) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule; and

(k) Curtailable Demand reduction rate (MW/minute).

Bid Evaluation. Based on the quantity and location of the system requirements, the ISO shall select the Generating Units, System Units, Loads or external imports of System Resources with the bids which minimize the sum of the total bids of the Generating Units, System Units, Loads or external imports of System Resources selected subject to two constraints:

(a) the sum of the selected bid capacities must be greater than or equal to the required Replacement Reserve capacity; and

(b) each Generating Unit's, System Unit's, Load's or external import's bid capacity must be less than or equal to that Generating Unit's, System Unit's, Load's or external import's ramp rate (or time to interruption in the case of a Load offering Demand reduction) times the difference between 60 minutes and the time to synchronize in the case of Generating Unit or System Unit, or to interruption in the case of Load.

The total bid for each Generating Unit, System Unit, Load or external import of System Resource is calculated by multiplying the capacity reservation bid price by the bid capacity.

Thus, subject to any locational requirements, the ISO will select the winning Replacement Reserve bids in accordance with the following criteria:

$$Min \sum_{i,j} Totalbid_{ijt}$$

Subject to

$$\sum_{i,j} Cap_{ijt} \geq Requirement_t$$

$$Cap_{ijt} \leq Cap_{ijt}max$$

Where

$TotalBid_{ijt} = Cap_{ijt} * CapRes_{ijt}$

$Requirement_t$ = the amount of Replacement Reserve capacity required

Price Determination. The price payable to Scheduling Coordinators for Replacement Reserve Capacity made available in accordance with the ISO's Final Day-Ahead Schedules shall, for each Generating Unit, System Unit, Load or external import of a System Resource concerned, be the Zonal Market Clearing Price for Replacement Reserve calculated as follows:

$PRepRes_{xt} = MCP_{xt}$

Where the Zonal Market Clearing Price (MCP_{xt}) for Replacement Reserve is the highest priced winning Replacement Reserve bid in Zone X based on the capacity reservation bid price, i.e.:

$MCP_{xt} = Max(CapRes_{ijt})$ in Zone x for Settlement Period t.

In the absence of Inter-Zonal Congestion, the Zonal Market Clearing Prices will be equal.

The price payable to Scheduling Coordinators for Replacement Reserve Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services schedules issued in accordance with Section 8.7 shall be the bid price of the Replacement Reserve capacity reserved ($CapRes_{ijt}(\$/MW)$).

8.5.9 Voltage Support.

As of the ISO Operations Date, the ISO will contract for Voltage Support service with the owners of Reliability Must-Run Units. Payments for public utilities under the FPA shall be capped at the FERC authorized cost-based rates unless and until FERC authorizes different pricing. The ISO shall pay owners of Reliability Must-Run Units for long-term Voltage Support through their Scheduling Coordinators.

In addition, any Participating Generator who is producing Energy shall, upon the ISO's specific request, provide reactive energy output outside the Participating Generator's Voltage Support obligation defined in Section 8.2.3.4.

The ISO shall select Participating Generator's Generating Units which have been certified for Voltage Support to provide this additional Voltage Support. Subject to any locational requirements, the ISO shall select the least costly Generating Units from a computerized merit order stack to back down to produce additional Voltage Support in each location where Voltage Support is needed.

The ISO shall pay to the Scheduling Coordinator for that Participating Generator the opportunity cost of reducing Energy output to enable reactive energy production. This opportunity cost shall be:

Max{0, Zonal Settlement Interval Ex Post Price - Generating Unit bid price } x reduction in Energy output (MW).

If necessary, the ISO shall develop a regulatory cost-based determination of marginal operating cost to be used in place of the Generating Unit bid price.

8.5.10 Black Start Capability and Energy Output.

As of the ISO Operations Date, the ISO will contract for Black Start capability and Energy with owners of Reliability Must-Run Units and Black Start Generators. Public utilities under the FPA will be paid rates capped at the FERC authorized cost base rates unless and until FERC authorizes different pricing.

The ISO shall pay owners of Reliability Must-Run Units for Black Start Energy output through their Scheduling Coordinators. The ISO shall pay Black Start Generators for Black Start Energy output directly.

8.6 Obligations for and Self-Provision of Ancillary Services.

8.6.1 Ancillary Service Obligations.

Each Scheduling Coordinator shall be assigned a share of the total Regulation, Spinning Reserve, Non-Spinning and Replacement Reserve requirements by the ISO. Any references in this Tariff to the Ancillary Service "Regulation" shall be read as referring to "Regulation Up" or "Regulation Down". The share assigned to each Scheduling Coordinator is described in Section 8.6 and in Section 8.12 as that Scheduling Coordinator's obligation. Each Scheduling Coordinator's Regulation obligation in each Zone shall be pro rata based upon the same proportion as the Scheduling Coordinator's metered hourly Demand (excluding exports) bears to the total metered Demand (excluding exports) served in each hour in that Zone. Each Scheduling Coordinator's Operating Reserve obligation in each Zone shall be pro rata based upon the same proportion as the ratio of the product of its percentage obligation based on metered output and the sum of its metered Demand and firm exports bears to the total of such products for all Scheduling Coordinators in the Zone. The Scheduling Coordinator's percentage obligation based on metered output shall be calculated as the sum of 5% of its real-time Demand (except the Demand covered by firm purchases from outside the ISO Control Area) met by Generation from hydroelectric resources plus 7% of its Demand (except the Demand covered by firm purchases from outside the ISO Control Area) met by Generation from non-hydroelectric resources in that Zone, plus 100% of any Interruptible Imports and on-demand obligations which it schedules. Each Scheduling Coordinator's

13 DISPUTE RESOLUTION.

13.1 Applicability.

13.1.1 General Applicability.

Except as limited below or otherwise as limited by law (including the rights of any party to file a complaint with FERC under the relevant provisions of the FPA), the ISO ADR Procedures shall apply to all disputes between parties which arise under the ISO Documents except where the decision of the ISO is stated in the provisions of this ISO Tariff to be final. The ISO ADR Procedures shall not apply to:

13.1.1.1 Disputes arising under contracts which pre-date the ISO Operations Date, except as the disputing parties may otherwise agree;

13.1.1.2 Disputes as to whether rates and charges set forth in this ISO Tariff are just and reasonable under the FPA.

13.1.2 Disputes Involving Government Agencies.

13.1.2.1 If a party to a dispute is a government agency the procedures herein which provide for the resolution of claims and arbitration of disputes are subject to any limitations imposed on the agency by law, including but not limited to the authority of the agency to effect a remedy. If the governmental agency is a federal entity, the procedures herein shall not apply to disputes involving issues arising under the United States Constitution.

13.1.3 Injunctive and Declaratory Relief.

Where the court having jurisdiction so determines, use of the ISO ADR Procedures shall not be a condition precedent to a court action for injunctive relief nor shall the provisions of California Code of Civil Procedures sections 1281 et seq. apply to such court actions.

13.2 Negotiation and Mediation.

13.2.1 Negotiation.

The ISO and Market Participants (party or parties) shall make good-faith efforts to negotiate and resolve any dispute between them arising under ISO Documents prior to invoking the ISO ADR Procedures outlined herein. Each party shall designate an individual with authority to negotiate the matter in dispute to participate in such negotiations.

13.2.2 Statement of Claim.

In the event a dispute is not resolved through such good-faith negotiations, any one of the parties may submit a statement of claim, in writing, to each other disputing party, the ISO ADR Committee, and the ISO Governing Board, which submission shall commence the ISO ADR Procedures. The statement of claim shall set forth in reasonable detail (i) each claim, (ii) the relief sought, including the proposed award, if applicable, (iii) a summary of the grounds for such relief and the basis for each claim, (iv) the parties to the dispute, and (v) the individuals having knowledge of each claim. The other parties to the dispute shall similarly submit their respective statements of claim within fourteen (14) days of the date of the initial statement of claim or such longer period as the chair of the ISO ADR Committee may permit following an application by the responding party. If any responding party wishes to submit a counterclaim in response to the statement of claim, it shall be included in such party's responsive statement of claim. A summary of the statements of claim shall be published by the ISO in the ISO newsletter or WEnet, and any other method adopted by the ISO ADR Committee. No Market Participant shall be considered as having received notice of a claim decided or relief granted by a decision made under these procedures unless the summary of the statements of claim published by the ISO includes such claim or relief.

13.2.3 Selection of Mediator.

After submission of the statements of claim, the parties may request mediation, if at least 75% of the disputing parties so agree, except that where a dispute involves three parties, at least two of the parties must agree to mediation. If the parties agree to mediate, the chair of the ISO ADR Committee shall distribute to the parties by facsimile or other electronic means a list containing the names of at least

seven prospective mediators with mediation experience, or with technical or business experience in the electric power industry, or both, as he or she shall deem appropriate to the dispute. The parties shall either agree upon a mediator from the list provided or from any alternative source, or alternate in striking names from the list with the last name on the list becoming the mediator. The first party to strike off a name from the list shall be determined by lot. The parties shall have seven days from the date of receipt of the ISO ADR Committee chair's list of prospective mediators to complete the mediator selection process and appoint the mediator, unless the time is extended by mutual agreement. The mediator shall comply with the requirements of Section 13.3.2.

13.2.4 Mediation.

The mediator and representatives of the disputing parties, with authority to settle the dispute, shall within fourteen (14) days after the mediator's date of appointment schedule a date to mediate the dispute. Matters discussed during the mediation shall be confidential and shall not be referred to in any subsequent proceeding. With the consent of all disputing parties, a resolution may include referring the dispute directly to a technical body (such as a WECC technical advisory panel) for resolution or an advisory opinion, or referring the dispute directly to FERC. The ISO shall publish notice of the referral of the dispute in the ISO newsletter or WEnet, and any other method adopted by the ISO ADR Committee.

13.2.5 Demand for Arbitration.

If the disputing parties have not succeeded in negotiating a resolution of the dispute within thirty (30) days of the initial statement of claim or, if within that period the parties agreed to mediate, within thirty (30) days of the parties first meeting with the mediator, such parties shall be deemed to be at impasse and any such disputing party may then commence the arbitration process, unless the parties by mutual agreement agree to extend the time. A party seeking arbitration shall provide notice of its demand for arbitration to the other disputing parties, the ISO ADR Committee and the ISO Governing Board, which shall publish notice of such demand in the ISO newsletter or electronic bulletin board, and any other method adopted by the ISO ADR Committee.

13.3 Arbitration.

13.3.1 Selection of Arbitrator.

13.3.1.1 Disputes Under $1,000,000.

Where the total amount of claims and counterclaims in controversy is less than $1,000,000 (exclusive of costs and interest), the disputing parties shall select an arbitrator from a list containing the names of at least 10 qualified individuals supplied by the ISO ADR Committee, or if the ISO is a party to the dispute, the names of at least ten (10) qualified individuals supplied by the American Arbitration Association within 14 days following submission of the demand for arbitration. If the parties cannot agree upon an arbitrator within the stated time, they shall take turns striking names from the list of proposed arbitrators. The first party to strike-off a name shall be determined by lot. This process shall be repeated until one name remains on the list, and that individual shall be the designated arbitrator.

13.3.1.2 Disputes of $1,000,000 or Over.

Where the total amount of claims and counterclaims in controversy is $1,000,000 or more (exclusive of interest and costs), the disputing parties may agree on any person to serve as a single arbitrator, or shall endeavor in good faith to agree on a single arbitrator from a list of ten (10) qualified individuals provided by the ISO ADR Committee, or if the ISO is a party to the dispute, the names of at least ten (10) qualified individuals supplied by the American Arbitration Association within fourteen (14) days following submission of the demand for arbitration. If the parties are unable to agree on a single arbitrator within the stated time, the party or parties demanding arbitration, and the party or parties responding to the demand for arbitration, shall each designate an arbitrator. Each designation shall be from the ISO ADR Committee list of arbitrators no later than the tenth (10th) day thereafter. The two arbitrators so chosen shall then choose a third arbitrator.

13.3.2 Disclosures Required of Arbitrators.

The designated arbitrator(s) shall be required to disclose to the parties any circumstances which might preclude him or her from rendering an objective and impartial determination. Each designated arbitrator shall disclose:

13.3.2.1 Any direct financial or personal interest in the outcome of the arbitration;

13.3.2.2 Any information required to be disclosed by California Code of Civil Procedure Section 1281.9.; and

13.3.2.3 Any existing or past financial, business, professional, or personal interest that are likely to affect impartiality or might reasonably create an appearance of partiality or bias. The designated arbitrator shall disclose any such relationships that he or she personally has with any party or its counsel, or with any individual whom they have been told will be a witness. They should also disclose any such relationship involving members of their families or their current employers, partners, or business associates. All designated arbitrators shall make a reasonable effort to inform themselves of any interests or relationships described above. The obligation to disclose interests, relationships, or circumstances that might preclude an arbitrator from rendering an objective and impartial determination is a continuing duty that requires the arbitrator to disclose, at any stage of the arbitration, any such interests, relationships, or circumstances that arise, or are recalled or discovered. If, as a result of the continuing disclosure duty, an arbitrator makes a disclosure which is likely to affect his or her partiality, or might reasonably create an appearance of partiality or bias or if a party independently discovers the existence of such circumstances, a party wishing to object to the continuing use of the arbitrator must provide written notice of its objection to the other parties within ten (10) days of receipt of the arbitrator's disclosure or the date of a party's discovery of the circumstances giving rise to that party's objection. Failure to provide such notice shall be deemed a waiver of such objection. If a party timely provides a notice of objection to the continuing use of the arbitrator the parties shall attempt to agree whether the arbitrator should be dismissed and replaced in the manner described in Section 13.3.1. If within ten (10) days of a party's objection notice the parties have not agreed how to proceed the matter shall be referred to the ISO ADR Committee for resolution.

13.3.3 Arbitration Procedures.

The ISO ADR Committee shall compile and make available to the arbitrator and the parties standard procedures for the arbitration of disputes, which procedures (i) shall include provision, upon good cause

shown, for intervention or other participation in the proceeding by any party whose interests may be affected by its outcome, (ii) shall conform to the requirements specified herein, and (iii) may be modified or adopted for use in a particular proceeding as the arbitrator deems appropriate, in accordance with Section 13.3.4. The procedures adopted by the ISO ADR Committee shall be based on the latest edition of the American Arbitration Association Commercial Arbitration Rules, to the extent such rules are not inconsistent with this Section 13. Except as provided herein, all parties shall be bound by such procedures.

13.3.4 Modification of Arbitration Procedures.

In determining whether to modify the standard procedures for use in the pending matter, the arbitrator shall consider (i) the complexity of the dispute, (ii) the extent to which facts are disputed, (iii) the extent to which the credibility of witnesses is relevant to a resolution, (iv) the amount in controversy, and (v) any representations made by the parties. Alternatively, the parties may, by mutual agreement, modify the standard procedures. In the event of a disagreement between the arbitrator and the agreement of the parties regarding arbitration procedures to be utilized, the parties' agreement shall prevail.

13.3.5 Remedies.

13.3.5.1 Arbitrator's Discretion.

The arbitrator shall have the discretion to grant the relief sought by a party, or determine such other remedy as is appropriate, unless the parties agree to conduct the arbitration "baseball" style. Unless otherwise expressly limited herein, the arbitrator shall have the authority to award any remedy or relief available from FERC, or any other court of competent jurisdiction. Where any ISO Document leaves any matter to be agreed between the parties at some future time and provides that in default of agreement the matter shall be referred to the ISO ADR Procedures, the arbitrator shall have authority to decide upon the terms of the agreement which, in the arbitrator's opinion, it is reasonable that the parties should reach, having regard to the other terms of the ISO Document concerned and the arbitrator's opinion as to what is fair and reasonable in all the circumstances.

13.3.5.2 "Baseball" Arbitration.

If the parties agree to conduct the arbitration "baseball" style, the parties shall submit to the arbitrator and exchange with each other their last best offers in the form of the award they consider the arbitrator should make, not less than seven (7) days in advance of the date fixed for the hearing, or such other date as the arbitrator may decide. If a party fails to submit its last best offer in accordance with this Section, that party shall be deemed to have accepted the offer proposed by the other party. The arbitrator shall be limited to awarding only one of the proposed offers, and may not determine an alternative or compromise remedy.

13.3.6 Summary Disposition.

The procedures for arbitration of a dispute shall provide a means for summary disposition of a demand for arbitration, or a response to a demand for arbitration, that in the reasoned opinion of the arbitrator does not have a good faith basis in either law or fact. If the arbitrator determines that a demand for arbitration or response to a demand for arbitration does not have a good faith basis in either law or fact, the arbitrator shall have discretion to award the costs of the time, expenses, and other charges of the arbitrator to the prevailing party. A determination made under this Section is subject to appeal pursuant to Section 13.4.

13.3.7 Discovery Procedures.

The procedures for the arbitration of a dispute shall include adequate provision for the discovery of relevant facts, including the taking of testimony under oath, production of documents and other things, the presentation of evidence, the taking of samples, conducting of tests, and inspection of land and tangible items. The nature and extent of such discovery shall be determined as provided herein and shall take into account (i) the complexity of the dispute, (ii) the extent to which facts are disputed, (iii) the extent to which the credibility of witnesses is relevant to a resolution, and (iv) the amount in controversy. The forms and methods for taking such discovery shall be as described in the Federal Rules of Civil Procedure, except as modified pursuant to Section 13.3.4.

13.3.8 Evidentiary Hearing.

The arbitration procedures shall provide for an evidentiary hearing, with provision for the cross-examination of witnesses, unless all parties consent to the resolution of the matter on the basis of a written record. The forms and methods for taking evidence shall be determined by the arbitrator(s) and modified pursuant to Section 13.3.4. The arbitrator may require such written or other submissions from the parties as he or she may deem appropriate, including submission of direct and rebuttal testimony of witnesses in written form. The arbitrator may exclude any evidence that is irrelevant, immaterial, unduly repetitious or prejudicial, or privileged. The arbitrator shall compile a complete evidentiary record of the arbitration which shall be available to the parties on its completion upon request.

13.3.9 Confidentiality.

Subject to the other provisions of this ISO Tariff, any party may claim that information contained in a document otherwise subject to discovery is "Confidential" if such information would be so characterized under the Federal Rules of Evidence. The party making such claim shall provide to the arbitrator in writing the basis for its assertion. If the claim of confidentiality is confirmed by the arbitrator, he or she shall establish requirements for the protection of such documents or other information designated as "Confidential" as may be reasonable and necessary to protect the confidentiality and commercial value of such information. Any party disclosing information in violation of these provisions or requirements established by the arbitrator, unless such disclosure is required by federal or state law or by a court order, shall thereby waive any right to introduce or otherwise use such information in any judicial, regulatory, or other legal or dispute resolution proceeding, including the proceeding in which the information was obtained.

13.3.10 Timetable.

Promptly after the appointment of the arbitrator, the arbitrator shall set a date for the issuance of the arbitration decision, which shall be no later than six months (or such date as the parties and the arbitrator may agree) from the date of the appointment of the arbitrator, with other dates, including the dates for an evidentiary hearing or other final submissions of evidence, set in light of this date. The date for the

evidentiary hearing or other final submission of evidence shall not be changed, absent extraordinary circumstances. The arbitrator shall have the power to impose sanctions, including dismissal of the proceeding, for dilatory tactics or undue delay in completing the arbitration proceedings.

13.3.11 Decision.

13.3.11.1 Except as provided below with respect to "baseball" style arbitration, the arbitrator shall issue a written decision granting the relief requested by one of the parties, or such other remedy as is appropriate, if any, and shall include findings of fact and law. The arbitration decision shall be based on (i) the evidence in the record, (ii) the terms of the relevant ISO Documents, (iii) applicable United States federal law, including the FPA and any applicable FERC regulations and decisions, and international treaties or agreements as applicable, and (iv) applicable state law. Additionally, the arbitrator may consider relevant decisions in previous arbitration proceedings. A summary of the disputed matter and the arbitrator's decision shall be published in an ISO newsletter or electronic bulletin board and any other method adopted by the ISO ADR Committee, and maintained by the ISO ADR Committee.

13.3.11.2 In arbitration conducted "baseball" style, the arbitrator shall issue a written decision adopting one of the awards proposed by the parties, and shall include findings of fact and law. The arbitration decision shall be based on (i) the evidence in the record, (ii) the terms of the relevant ISO Documents, (iii) applicable United States federal law, including the FPA and any applicable FERC regulations and decisions, and international treaties or agreements as applicable, and (iv) applicable state law. If the arbitrator concludes that no proposed award is consistent with the factors enumerated in (i) through (iv) above, or addresses all of the issues in dispute, the arbitrator shall specify how each proposed award is deficient and direct that the parties submit new proposed awards that cure the identified deficiencies. A summary of the disputed matter and the arbitrator's decision shall be published in an ISO newsletter or electronic bulletin board, and any other method adopted by the ISO ADR Committee. An award shall not be deemed to be precedential.

13.3.11.3 Where a panel of arbitrators is appointed pursuant to Section 13.3.1.2, a majority of the arbitrators must agree on the decision.

13.3.12 Compliance.

Unless the arbitrator's decision is appealed under Section 13.4, the disputing parties shall, upon receipt of the decision, immediately take whatever action is required to comply with the award to the extent the award does not require regulatory action. An award that is not appealed shall be deemed to have the same force and effect as an order entered by the FERC or any court of competent jurisdiction.

13.3.13 Enforcement.

Following the expiration of the time for appeal of an award pursuant to Section 13.4.3, any party may apply to FERC or any court of competent jurisdiction for entry and enforcement of judgment based on the award.

13.3.14 Costs.

The costs of the time, expenses, and other charges of the arbitrator shall be borne by the parties to the dispute, with each side on an arbitrated issue bearing its pro-rata share of such costs, and each party to an arbitration proceeding bearing its own costs and fees. If the arbitrator determines that a demand for arbitration or response to a demand for arbitration was made in bad faith, the arbitrator shall have discretion to award the costs of the time, expenses, and other charges of the arbitrator to the prevailing party. Notwithstanding the above, at the discretion of the arbitrator, the winning party in any dispute which has resulted in the enforcement of an important right affecting the public interest shall not be required to pay any of the costs of the arbitrator and may recover such of its own reasonable attorney fees, expert witness fees and other reasonable costs from the losing party to the dispute if (a) a significant benefit, whether pecuniary or non-pecuniary, has been conferred on the general public, (b) the necessity and financial burden of private enforcement are such as to make the award appropriate, and (c) such fees should not, in the interest of justice, be paid out of the recovery.

13.4 Appeal of Award.

13.4.1 Basis for Appeal.

A party may apply to the FERC or any court of competent jurisdiction to hear an appeal of an arbitration award only upon the grounds that the award is contrary to or beyond the scope of the relevant ISO

Documents, United States federal law, including, without limitation, the FPA, and any FERC regulations and decisions, or state law. Appeals shall, unless otherwise ordered by FERC or the court of competent jurisdiction, conform to the procedural limitations set forth in this Section 13.4.

13.4.2 Appellate Record.

The parties intend that FERC or the court of competent jurisdiction should afford substantial deference to the factual findings of the arbitrator. No party shall seek to expand the record before the FERC or court of competent jurisdiction beyond that assembled by the arbitrator, except (i) by making reference to legal authority which did not exist at the time of the arbitrator's decision, or (ii) if such party contends the decision was based upon or affected by fraud, collusion, corruption, misconduct or misrepresentation.

13.4.3 Procedures for Appeals.

13.4.3.1 If a party to an arbitration desires to appeal an award, it shall provide a notice of appeal to the ISO Governing Board, all parties and the arbitrator within 14 days following the date of the award. The appealing party must likewise provide notice to the ISO ADR Committee, which shall publish notice of the appeal in an ISO newsletter or on WEnet, and any other method adopted by the ISO ADR Committee.

Within ten (10) days of the filing of the notice of appeal, the appealing party must file an appropriate application, petition or motion with the FERC to trigger review under the FPA or with a court of competent jurisdiction. Such filing shall state that the subject matter has been the subject of an arbitration pursuant to the relevant ISO Document.

13.4.3.2 Within 30 days of filing the notice of appeal (or such period as FERC or the court of competent jurisdiction may specify) the appellant shall file the complete evidentiary record of the arbitration and a copy of the award with FERC or with the court of competent jurisdiction. The appellant shall serve copies of a description of all materials included in the submitted evidentiary record.

13.4.4 Award Implementation.

Implementation of the award shall be deemed stayed pending an appeal unless and until, at the request of a party, the FERC or the court of competent jurisdiction to which an appeal has been filed, issues an

order dissolving, shortening, or extending such stay. However, a summary of each appeal shall be published in an ISO newsletter or electronic bulletin board, and any other method adopted by the ISO ADR Committee.

13.4.5 Judicial Review of FERC Orders.

FERC orders resulting from appeals shall be subject to judicial review pursuant to the FPA.

13.5 Allocation of Awards Payable by or to the ISO.

13.5.1 Allocation of an Award.

If the ISO must pay an award to a party pursuant to good faith negotiations or the ISO ADR Procedures, the ISO will recover the amount of the award from Market Participants and Scheduling Coordinators. If the ISO receives an award from a party pursuant to good faith negotiations or the ISO ADR Procedures, the ISO will flow back the amount of the award to Market Participants and Scheduling Coordinators.

13.5.2 Timing of Adjustments.

Upon determination that an award is payable by or to the ISO pursuant to good faith negotiations or the ISO ADR Procedures, the ISO shall calculate the amounts payable to and receivable from the party, Market Participants, and Scheduling Coordinators, as soon as reasonably practical, and shall show any required adjustments as a debit or a credit in a subsequent Preliminary Settlement Statement or, in the case of an amount payable by the ISO to a party, as soon as the ISO and that party may agree.

13.5.3 Method of Allocation.

13.5.3.1 Allocation to Market Participants.

The ISO will use best efforts to determine which Market Participant(s) is or are responsible for and/or benefit from payment of an award by or to the ISO and to allocate receipt of or payment for the award equitably to such Market Participant(s). In undertaking the allocation, the ISO shall consider the extent of a Market Participant's participation in affected markets and the ISO Tariff in effect on the applicable Trading Day(s), and may consider any other relevant factor, including but not limited to, applicable contracts.

13.5.3.2 Residual Amounts.

Any awards for which the ISO is unable to identify Market Participants in accordance with 13.5.3.1 and any award amounts that the ISO is unable to collect that are not covered by Section 11.16.1 will be allocated to all Scheduling Coordinators through Neutrality Adjustments.

14 FORCE MAJURE INDEMNIFICATION AND LIMITATIONS ON LIABILITY.

14.1 Uncontrollable Forces.

14.1.1 An Uncontrollable Force means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm, flood, earthquake, explosion, any curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities or any other cause beyond the reasonable control of the ISO or Market Participant which could not be avoided through the exercise of Good Utility Practice. Neither the ISO nor a Market Participant will be considered in default of any obligation under this ISO Tariff if prevented from fulfilling that obligation due to the occurrence of an Uncontrollable Force.

14.1.2 In the event of the occurrence of an Uncontrollable Force, which prevents the ISO or a Market Participant from performing any of its obligations under this ISO Tariff, the affected entity shall (i) if it is the ISO, immediately notify the Market Participants in writing of the occurrence of such Uncontrollable Force and, if it is a Market Participant, immediately notify the ISO in writing of the occurrence of such Uncontrollable Force, (ii) not be entitled to suspend performance of its obligations under this ISO Tariff in any greater scope or for any longer duration than is required by the Uncontrollable Force, (iii) use its best efforts to mitigate the effects of such Uncontrollable Force, remedy its inability to perform and resume full performance of its obligations hereunder, (iv) in the case of the ISO, keep the Market Participants apprised of such efforts, and in the case of the Market Participants, keep the ISO apprised of such efforts, in each case on a continual basis and (v) provide written notice of the resumption of its performance of its obligations hereunder.

Notwithstanding any of the foregoing, the settlement of any strike, lockout or labor dispute constituting an Uncontrollable Force shall be within the sole discretion of the entity involved in such strike, lockout or

weighted average of the Dispatch Interval Ex Post Prices in each Zone, where the weights are the system total Instructed Imbalance Energy, except Regulation Energy, for the Dispatch Interval.If the ISO declares a System Emergency, e.g. during times of supply scarcity, and involuntary Load Shedding occurs during the real-time Dispatch, the ISO shall set the Hourly Ex Post Price at the Administrative Price.

34.9.2.5 Price for Uninstructed Deviations for Participating Intermittent Resources.

Deviations associated with each Participating Intermittent Resource in a Scheduling Coordinator's Zonal portfolio shall be settled as provided in Section 11.2.4.5.1 at the monthly weighted average Dispatch Interval Ex Post Price, where the weights are the quantities of Instructed Imbalance Energy associated with each Dispatch Interval Ex Post Price.

35 [Not Used]

36 FIRM TRANSMISSION RIGHTS.

36.1 General.

36.1.1 Commencing in 2000, on the effective date established by the ISO Governing Board, the ISO shall make FTRs available in the amounts determined in accordance with Section 36.3, with the rights and other characteristics described in Sections 36.2, 36.6, 36.7 and 36.8, and through the processes described in Section 36.4. Proceeds of the ISO's auction of FTRs shall be distributed as described in Section 36.5. The owners of FTRs shall be entitled to share in Usage Charge revenues associated with Inter-Zonal Congestion in accordance with Section 36.6, and to scheduling priority in the event of Congestion in the Day-Ahead Market, as described in Section 36.7. For the purpose of Section 36, the term "Zone" shall be construed to mean both "Zone" and "Scheduling Point."

36.2 Characteristics of Firm Transmission Rights.

36.2.1 Each FTR shall be defined by a transmission path from an originating Zone to a contiguous receiving Zone. Each FTR shall entitle the FTR Holder to a share of Usage Charges attributable to Inter-Zonal Congestion for transfers on that path from the designated originating Zone to the designated receiving Zone in accordance with Section 36.6. An FTR is a right in one direction only. An FTR Holder shall not be entitled to share in (i) Usage Charges attributable to Inter-Zonal Congestion

from the designated receiving Zone to the designated originating Zone; or (ii) Usage Charges payable in accordance with Section 27.1.2.1.5.1 to a Scheduling Coordinator that counter-schedules from the designated originating Zone to the designated receiving Zone.

36.2.2 The ISO Governing Board shall, from time to time, approve the amount of FTRs to be auctioned for each FTR Market and the ISO shall publish this information on the ISO Home Page at least thirty (30) days prior to the auction. The ISO may issue FTRs in one or more auctions in any year so long as the total FTRs for any interface do not exceed the maximum amount permitted in Section 36.3.

36.2.2.1 Should the ISO create additional Zones or otherwise change the ISO's defined Inter-Zonal Interface, and if such changes would affect outstanding FTRs, such changes will not take effect prior to the expiration date of any such outstanding FTRs. The ISO shall also publish an announcement of any such pending changes on the ISO Home Page and WEnet at least thirty (30) days prior to the applicable FTR auction.

36.2.2.2 Any additional FTRs auctioned as a result of changes in the ISO's defined Inter-Zonal Interfaces shall not affect the rights associated with existing FTRs.

36.2.3 Each FTR shall be issued in the denomination of 1 MW. The annual release of FTRs shall start with the hour beginning at 12:00 a.m., on April 1 and end with the hour beginning at 11:00 p.m., on March 31 of the following year. An FTR shall not afford the FTR Holder any right to share in Usage Charges attributable to Inter-Zonal Congestion occurring in any hour before or after the term of the FTR.

36.2.4 The portion of the Usage Charges to which the FTR Holder is entitled shall be determined in accordance with Section 36.6.

36.2.5 FTR Holders shall be entitled to priority in the scheduling of Energy in the Day-Ahead Market as specified in Section 36.7.

36.2.6 Any entity, with the exception of the ISO, shall be eligible to acquire FTRs by participating in the ISO's auction of FTRs, as described in Section 36.4, or by purchasing FTRs in secondary markets. To participate in the ISO's auction of FTRs, an entity must either be a certified Scheduling Coordinator or have met financial requirements equivalent to the financial certification criteria required of all Scheduling

Coordinators. An entity may not acquire FTRs with a total value that exceeds the financial security proved by that entity to the ISO. In addition, an FTR Bidder must have, or have access to, the necessary technical equipment to participate in the electronic auction.

36.2.7 All entities which acquire FTRs by participating in the ISO's auction of FTRs, as described in Section 36.4, directly from the ISO pursuant to Section 36.4.3, or by purchasing FTRs in secondary markets, must register as an FTR Holder with the ISO. To complete this registration, the FTR Holder must notify the ISO, through the form specified for that purpose by the ISO, of all Affiliates of the FTR Holder that are themselves FTR Holders or Market Participants. The requirement that an FTR Holder notify the ISO of all Affiliates that are FTR Holders or Market Participants is continuing for as long as the FTR Holder owns FTRs, and FTR Holders must provide the ISO with supplemental notification concerning FTR Holders and/or Market Participants that become affiliated with the FTR Holder or Affiliates that subsequently become FTR Holders or Market Participants in order to satisfy this requirement.

36.3 Maximum Number of Firm Transmission Rights.

36.3.1 On each Inter-Zonal Interface and direction combination for which FTRs are issued, the ISO shall issue a number of FTRs that is less than or equal to the difference between:

(i) The WECC approved path rating of the interface in the direction from the originating Zone to the receiving Zone or, if the interface has not received a WECC approved rating, a rating determined by a methodology that is consistent with the WECC's rating methodology; and

(ii) The portion of the transfer capability of the interface available for transmission scheduling under Existing Contracts as Existing Rights.

and ensures the ISO's ability to honor all of its FTRs simultaneously under normal operating conditions.

36.4 Issuance of Firm Transmission Rights by the ISO.

36.4.1 The ISO shall make FTRs available by conducting an annual primary auction of FTRs, commencing approximately two months before the beginning of the term of the FTRs; provided; however

that for the initial FTR release, the primary auction shall be as determined by the ISO Governing Board. The auction of FTRs shall be a simultaneous multi-round, clearing price auction conducted separately and independently, as set forth in Section 36.4.2, for each FTR Market. In addition, if the ISO Governing Board decides to make available, between annual auctions, FTRs in addition to those that were purchased in the last annual auction, the ISO may conduct additional auctions of such FTRs in accordance with Section 36.4.2. The term of such FTRs shall only be for the remaining duration of the FTR term defined for the primary auction applicable to the year during which they were issued.

36.4.2 The ISO shall conduct the auction of FTRs through the following procedures:

36.4.2.1 At least thirty (30) days prior to the scheduled start of the auction, the ISO shall post on the ISO Home Page the following information:

(i) the number of FTRs to be issued for each FTR Market;

(ii) the starting bid price at which FTRs will be made available in each FTR Market in the first round of the auction, which price will be set in each FTR Market at a level equal to the greater of (a) $100 per MW-year; (b) twenty (20) percent of the ratio of the net Usage Charges collected by the ISO with respect to that FTR Market in the most recent twelve-month period for which data are available to the total MW-years of Energy scheduled over the Inter-Zonal Interface in the relevant direction during that period; or (c) twenty (20) percent of the ration of the net Grid Operation Charges (for new Inter-Zonal Interfaces that previously were transmission paths within a Zone) collected by the ISO in the most recent twelve-month period for which data are available to the total MW-years of Energy scheduled over the transmission paths in the relevant direction during that period, provided that, if data are available for only a portion of the twelve-month period, such data shall be used on annualized basis;

(iii) the formula through which the ISO will determine how much to adjust the price of FTRs in each FTR Market for subsequent rounds of the auction, including the initial coefficients to be used in the formula and the range over which the

coefficients may be adjusted in accordance with Section 36.4.2.3;

(iv) the date and time prior to the commencement of the auction by which each entity desiring to bid on FTRs must have satisfied the necessary financial requirements as outlined in Section 36.2.6;

(v) the specifications for the technical equipment necessary to participate in the auction, which will be conducted electronically, the date and time by which bids must be submitted in the first round of the auction, which shall be the same for all FTR Markets, and the form and format in which bids must be submitted; and

(vi) a schedule for the conduct of subsequent rounds of the auction, including the interval between rounds of the auction and the anticipated duration of the auction.

36.4.2.2 On or before the date specified in Section 36.4.2.1(v), any entity desiring to obtain FTRs in the ISO's auction must submit, via equipment satisfying the technical requirements specified in accordance with Section 36.4.2.1(v), a bid for each FTR Market in which the entity desires to participate, specifying the number of FTRs the entity is willing to purchase at the price specified in Section 36.4.2.1(ii). All individual bids will remain confidential throughout all rounds of the auction in each FTR Market. Once submitted to the ISO, a bid for FTRs in any round of an auction may not be cancelled or rescinded by the FTR Bidder. The ISO shall announce simultaneously to all FTR Bidders the total quantity of FTRs for which valid bids are submitted for each FTR Market.

36.4.2.3 In each round of the auction following the first round, the ISO will increase the price at which FTRs are made available in each FTR Market in accordance with the formula posted in accordance with Section 36.4.2.1(iii), or in accordance with any adjustment to the coefficients in that formula that is announced by the ISO to the FTR Bidders at least one round in advance of the round for which the adjustment is made. Price increases need not be uniform for all FTR Markets. In the case of an FTR Market in which the demand for FTRs in the preceding round is less than or equal to the quantity of FTRs being made available, the price shall not increase and the auction for that FTR Market shall close. After each round of the auction, the ISO shall announce simultaneously to all FTR Bidders the total quantity of

FTRs for which valid bids were submitted in each FTR Market, whether the auction for each FTR Market is closed, and, the revised prices for the following round of the auctions that remain open. Within the timeframe set by the ISO in accordance with Section 36.4.2.1(vi), each FTR Bidder may submit bids for the quantity of FTRs it desires to purchase in each FTR Market at the revised price, provided that an FTR Bidder may not bid for a number of FTRs in an FTR Market that exceeds the total number of FTRs in that FTR Market for which that entity submitted bids in the preceding round of the auction. The ISO shall conduct subsequent rounds of the auction in each FTR Market until the demand for FTRs in the FTR Market is less than or equal to the quantity of FTRs being made available, at which point the auction shall be closed in that FTR Market.

36.4.2.4 Subject to Section 36.4.2.5, each successful FTR Bidder shall receive a number of FTRs in each FTR Market equal to the number of FTRs for which it bid in the last round of the auction for that FTR Market.

36.4.2.5 For any FTR Market in which, when the auction has closed, the number of FTRs being made available exceeds the demand for FTRs in that FTR Market in the last round of the auction, each FTR Bidder shall be awarded a number of FTRs determined in accordance with the following formula, provided that, if the number of FTRs that would be awarded under the formula to an FTR Bidder that did not submit a bid in the last round of the auction is less than five percent (5%) of the initial bid submitted by that FTR Bidder for the FTR Market, that FTR Bidder shall have the option of declining the award of FTRs resulting from the formula:

$$N = B + [(R / TR) * D]$$

where

N = The total number of FTRs awarded to an FTR Bidder for an FTR Market, which shall be in whole MWs and shall not exceed the number of FTRs for which that FTR Bidder bid in the round preceding the final round of the auction;

B = The number of FTRs for which an FTR Bidder bid in the final round of the auction for the FTR Market in accordance with Section 36.4.2.4 (or zero, if the FTR Bidder did not bid in

that round);

R = The difference between the number of FTRs for which the FTR Bidder bid in the round preceding the final round of the auction and B, but not less than zero;

TR = The total of the demand reductions (R) for all FTR Bidders that submitted bids in the last round of the auction (treating the failure by an FTR Bidder to submit a bid as a bid of zero); and

D = The difference between the total demand for FTRs in the final round of the auction and the quantity of FTRs being made available for the FTR Market.

36.4.2.6 The price of FTRs in an FTR Market shall be the last price at which the demand for FTRs in the FTR Market exceeded or equaled the quantity of FTRs being made available pursuant to Section 36.4.2.1(i), except that, if the demand for FTRs in an FTR Market in the first round of the auction was less than the quantity of FTRs being made available for that FTR Market, the price of FTRs in that FTR Market shall be the first round price and each FTR Bidder in that FTR Market will receive a number of FTRs equal to the quantity of bids they submitted in the first round. Any remaining FTRs in that FTR Market will not be awarded in that auction.

36.4.2.7 Each FTR Bidder shall pay the ISO an amount equal to the sum, for all FTR Markets, of the products of the FTR price in each FTR Market (determined in accordance with Section 36.4.2.6) and the total quantity of FTRs awarded to that FTR Bidder in that FTR Market (determined in accordance with Section 36.4.2.4 or Section 36.4.2.5, as applicable). FTR Bidders shall pay the amount determined in accordance with the foregoing sentence within ten (10) Business Days of receiving an invoice from the ISO by making payment to the ISO Clearing Account in accordance with Section 11.10. If the FTR Bidder fails to make timely payment of the full amount due, the ISO may enforce any guarantee, letter of credit or other credit support provided by the defaulting FTR Bidder in accordance with Section 36.2.6 and, if the ISO is required to institute proceedings to collect any unpaid amount, the defaulting FTR Bidder shall pay Interest on the unpaid amount for the period from the Payment Date until the date on which payment is remitted to the ISO Clearing Account.

36.4.2.8 The ISO shall post on the ISO Home Page the prices at which FTRs are sold in each FTR Market through the primary auction.

36.4.3 For the ten-year transition period described in Section 4 of Schedule 3 to Appendix F, a New Participating TO that has an obligation to serve Load shall receive FTRs for Inter-Zonal Interfaces to which the transmission facilities and Converted Rights for Inter-Zonal Interfaces that the New Participating TO turns over to the ISO's Operational Control give it transmission rights, provided such transmission facilities are Existing High Voltage Facilities. The amount of FTRs will be determined when the Transmission Control Agreement is executed and shall be commensurate with the transmission capacity the New Participating TO is turning over to ISO Operational Control. The ISO will submit to FERC in the transmittal letter for the amendment to the Transmission Control Agreement regarding each New Participating TO the amount of FTRs allocated to such New Participating TO. The amount of FTRs that has been determined will not be effective until after FERC issues an order concerning the amendment required by this section. No additional FTRs will be issued to New Participating TOs for building High Voltage Transmission Facilities after they become Participating TOs. FTRs issued in accordance with this section shall entitle the FTR Holder to receive Usage Charge revenues and to priority in the scheduling of Energy in the Day-Ahead Market in accordance with the provisions of the ISO Tariff. FTRs associated with Converted Rights shall terminate on the earlier of termination of the Existing Contract or the end of the ten-year transition period.

36.5 Distribution of Auction Revenues Received by the ISO for Firm Transmission Rights.

36.5.1 For each Inter-Zonal Interface and direction for which an FTR is defined, the total proceeds received by the ISO through the auction described in Section 36.4 shall be allocated and paid by the ISO to the Participating TO that is entitled in accordance with Section 27.1.2.1.6 to receive Usage Charge revenues with respect to the corresponding Inter-Zonal Interface. Each Participating TO shall credit its FTR auction proceeds against its high voltage TRBA if the FTR is for a High Voltage Transmission Facility or against its low voltage TRBA if the FTR is a for a Low Voltage Transmission Facility.

36.5.2 In the event the transmission facilities or rights making up an Inter-Zonal Interface with respect to which FTRs are defined are owned by more than one Participating TO, the proceeds of the auction of such FTRs shall be allocated to those Participating TOs who auction FTRs in proportion to the FTRs associated with their Inter-Zonal Interface as of the date of the FTR auction compared to all FTRs auctioned for such Inter-Zonal Interface.

36.5.3 In the event the transmission facilities or rights making up an Inter-Zonal Interface with respect to which FTRs are defined have been upgraded resulting in increased transmission capacity on the Inter-Zonal Interface, and the costs of construction and operation were paid for by a Project Sponsor pursuant to Section 24.7.1 and were not included in the ISO's transmission Access Charge or a reimbursement or direct payment from a Participating TO, the proceeds of the auction of such FTRs shall be allocated to the Project Sponsors according to the allocated shares determined as set forth in Section 24.7.3(d).

36.6 Distribution of Usage Charges to FTR Holders.

36.6.1 The FTR Holder shall be entitled to receive from the ISO a portion of the total Congestion revenues related to Inter-Zonal Congestion calculated by the ISO in the Day-Ahead Market and collected by the ISO with respect to the Inter-Zonal Interface and direction combination for which the FTR was defined. This portion equals the Usage Charge calculated by the ISO in the Day-Ahead Market for the transfer of 1 MW from the originating Zone to the receiving Zone during each hour in which Usage Charges apply, multiplied by the number of FTRs owned by that FTR Holder, subject to adjustment in accordance with Section 36.6.3.

36.6.2 In addition, an FTR Holder shall be entitled to receive a portion of the additional net Usage Charges related to Inter-Zonal Congestion calculated by the ISO in the Hour-Ahead Market and collected by the ISO with respect to the Inter-Zonal Interface and direction combination for which the FTR was defined. The FTR Holder shall receive a portion of the net Usage Charges in the Hour-Ahead Market proportionate to the share of the Usage Charges it received in the Day-Ahead Market in accordance with Section 36.6.1.

36.6.3 When the Day-Ahead scheduling capability of an Inter-Zonal Interface and direction is less than its scheduling capacity, determined in accordance with Section 36.3, prior to the Day-Ahead Market, the entitlements of FTR Holders associated with that FTR Market to Usage Charge revenues shall not be reduced until and unless the entitlements of Participating TOs associated with that FTR Market to Usage Charge revenues in accordance with Section 27.1.2.1.6 have been reduced to zero. In that event, the financial entitlements associated with the corresponding FTRs shall be multiplied by a factor equal to the amount of scheduling capability available to holders of the remaining FTRs divided by the number of such FTRs. When the Day-Ahead scheduling capability of an Inter-Zonal Interface and direction is greater than its scheduling capacity, determined in accordance with Section 36.3, prior to the Day-Ahead Market, the entitlements of FTR Holders associated with that FTR Market to Usage Charge revenues shall not be increased.

36.6.4 When the Congestion Usage Charges calculated and collected by the ISO from the Hour-Ahead Market with respect to transfers across an Inter-Zonal Interface in a particular direction result in a net obligation to the ISO, in the circumstances described in Section 27.1.2.1.7, the provisions of this Section 9.6 shall continue to apply, and FTR Holders shall be required to pay the ISO these amounts.

36.6.5 The ISO will calculate the Congestion Usage Charge revenues to be credited or debited to the account of each FTR Holder on an hourly basis. Such calculation will identify the Inter-Zonal Interface and direction to which each credit or debit applies.

36.7 Scheduling Priority of FTR Holders.

36.7.1 FTRs will not affect the ISO's dispatch and operation of the ISO Controlled Grid except that each FTR Holder will have a priority, as described in this Section 36.7, for the scheduling of Energy in the Day-Ahead Market when an Inter-Zonal Interface experiences Inter-Zonal Congestion in the direction for which its FTR is defined. Any FTRs not used in Preferred Schedules in the Day-Ahead Market for any hour have no scheduling priority for that hour in the Trading Day. FTR Holders shall have no scheduling priority in the Hour-Ahead Market or in real-time operations.

36.7.2 When Inter-Zonal Congestion is experienced or projected to be experienced in the Day-Ahead Market, the ISO shall first attempt to relieve the Inter-Zonal Congestion using Adjustment Bids

submitted by Scheduling Coordinators in accordance with Section 27.1.1.4.

36.7.2.1 If the ISO is unable to relieve the Day-Ahead Inter-Zonal Congestion using Adjustment Bids, then the ISO will allocate Day-Ahead inter-zonal transmission capacity first to Schedules of Market Participants that are using Existing Contract rights that have higher scheduling priority than Converted Rights capacity and second to Market Participants who hold FTRs and have indicated to the ISO that they wish to exercise their scheduling priority option. The ISO will allocate any remaining transmission capacity to remaining Market Participants' Schedules pro rata.

36.7.3 When the scheduling capability of an Inter-Zonal Interface is less than or greater than its normal scheduling capability prior to the Day-Ahead Market, as described in Section 36.6.3, the priority scheduling rights of FTR Holders, as described in Section 36.7.2, shall remain constant (in MWs) to the extent that the total scheduling rights of FTR Holders do not exceed the total Interface scheduling capability of the associated Inter-Zonal Interface after adjustments have been made for transmission capacity allocated to Existing Contract rights that have higher scheduling priority than Converted Rights. If the total Interface scheduling capability, adjusted for transmission capacity allocated to Existing Contract rights that have higher scheduling priority than Converted Rights, is less than the total of all scheduling capability represented by FTR Holders who have chosen to exercise the FTR scheduling priority option, scheduling capability shall be allocated to FTR Holders pro rata.

36.7.4 The scheduling priority of FTR Holders:

(i) Shall not apply in the Hour-Ahead Market or in real-time dispatch and operation of the ISO Controlled Grid;

(ii) Shall not apply to any transfer of Energy other than a transfer across the Inter-Zonal Interface in the direction for which the FTR was defined during the hour or hours during which the circumstances described in Section 36.7.2.1 apply; and

(iii) Shall not be transferable, except in connection with a transfer of the FTR that is registered with the ISO, as described in Section 36.8.

36.8 Assignment of Firm Transmission Rights.

36.8.1 An FTR may be assigned, sold, or otherwise transferred by the FTR Holder to any entity eligible to be an FTR Holder in full MW increments, either for the entire term of the FTR or for any portion of that term providing, however, that any such transfer shall be in full hour increments that correspond to the FTR issued to the FTR Holder. All FTRs that are so assigned, sold, or otherwise transferred by the FTR Holder are subject to the terms and conditions for FTRs approved by FERC and set forth in the ISO Tariff. Both the FTR Holder of record and the entity to which the FTRs have been transferred shall register the transfer of the FTR with the ISO by notifying the ISO through the form specified for that purpose by the ISO, and within the number of Business Days following the transfer published by the ISO on the ISO Home Page and WEnet but no later than such time as the ISO shall specify before the deadline applicable to scheduling Energy in the Day-Ahead Market, of (i) the identity of the FTR Holder of record; (ii) the identity of the entity to which the FTRs have been transferred; (iii) the quantity and identification numbers of the FTRs being transferred; (iv) the portion of the term of the FTR for which they are transferred; (v) the price at which the FTRs are being transferred; and (vi) whether the transfer of FTRs is subject to any conditions. The entity to which the FTRs have been transferred must also notify the ISO of all entities with which the transferee is affiliated that are FTR Holders or Market Participants as defined in the ISO Tariff, pursuant to Section 36.2.7. After the ISO receives such notices, the transferee shall be considered the FTR Holder of record with respect to the portion of the term of the FTR that is transferred. In order to use the Scheduling Priority of an FTR, pursuant to Section 36.7, an FTR must be registered with the ISO.

36.8.2 The ISO shall publish on the ISO Home Page such information concerning the concentration of ownership of FTRs in each FTR Market as determined by the ISO Governing Board from time to time.

36.8.3 To facilitate the operation of secondary markets in FTRs, the ISO shall post on WEnet and the ISO Home Page: (i) the identity of entities that hold FTRs that have been registered with the ISO, together with the quantity of FTRs held by such entities in each FTR Market and the path rating of the interface; and (ii) the name and a contact telephone number or telecopy number of any entity that

operates a secondary market in FTRs and that requests the ISO to post such information. The ISO shall also post the prices at which FTRs are transferred through secondary market transactions and shall indicate whether such transfers are conditional.

37 ENFORCEMENT PROTOCOL.

37.1 Objectives, Definitions, and Scope.

37.1.1 Purpose.

This Section sets forth the guiding principles for participation in the markets administered by the California Independent System Operator. The specified Rules of Conduct are intended to provide fair notice to Market Participants of the conduct expected of them, to provide an environment in which all parties may participate on a fair and equal basis, to redress instances of gaming and other instances of anticompetitive behavior, and thereby to foster confidence of Market Participants, ratepayers and the general public in the proper functioning of the ISO markets.

37.1.2 Objectives.

The objectives of this ISO Tariff are to:

(a) Provide clear Rules of Conduct specifying the behavior expected of Market Participants; and

(b) Establish in advance the Sanctions and other potential consequences for violation of the specified Rules of Conduct.

37.1.3 Application of Other Remedies.

The activities and remedies authorized under this Section 37 are in addition to any other actions or relief that may be available to the ISO elsewhere in the ISO Tariff or under law, regulation or order. Nothing in this Section 37 limits or should be construed to limit the right of the ISO to take action or seek relief otherwise available to it, and such action or relief may be pursued in lieu of or in addition to the action or relief specified in this Section 37.

22.10 ISO Grid Operations Committee; Changes To ISO Protocols.

22.10.1 ISO Grid Operations Committee.

The ISO Grid Operations Committee shall coordinate activities relating to the ISO Controlled Grid and shall consider suggestions for changes to the ISO Protocols in accordance with the procedures set out in Article IV, Section 4 of the ISO's bylaws.

22.11 ISO Protocol Amendment Process.

The ISO Governing Board shall establish an ISO Protocol amendment process in order to ensure that all affected parties have an opportunity to participate. Under that process, the ISO shall file for acceptance at the FERC any amendment to an ISO Protocol that is on file with the FERC.

22.13 Scheduling Responsibilities and Obligations.

Nothing in this ISO Tariff is intended to permit or require the violation of Federal or California law concerning hydro-generation and Dispatch, including but not limited to fish release requirements, minimum and maximum dam reservoir levels for flood control purposes, and in-stream flow levels. In carrying out its functions, the ISO will comply with and will have the necessary authority to give instructions to Participating TOs and Market Participants to enable it to comply with requirements of environmental legislation and environmental agencies having authority over the ISO in relation to Environmental Dispatch and will expect that submitted Schedules will support compliance with the requirements of environmental legislation and environmental agencies having authority over Generators in relation to Environmental Dispatch. In contracting for Ancillary Services and Imbalance Energy the ISO will not act as principal but as agent for and on behalf of the relevant Scheduling Coordinators.

ARTICLE II – TRANSMISSION SERVICE

23 CATEGORIES OF TRANSMISSION CAPACITY.

References to new firm uses shall mean any use of ISO transmission service, except for uses associated with Existing Rights. Prior to the start of the Day-Ahead scheduling process, for each Inter-Zonal Interface, the ISO will allocate the forecasted total transfer capability of the Interface to four categories.

This allocation will represent the ISO's best estimates at the time, and is not intended to affect any rights provided under Existing Contracts, except as provided in Section 16.2.4.3. The ISO's forecast of total transfer capability for each Inter-Zonal Interface will depend on prevailing conditions for the relevant Trading Day, including, but not limited to, the effects of parallel path (unscheduled) flows and/or other limiting operational conditions. This information will be posted on WEnet by the ISO in accordance with Appendix Y. In accordance with Section 16.2.4D of the ISO Tariff, the four categories are as follows:

(a) transmission capacity that must be reserved for firm Existing Rights;

(b) transmission capacity that may be allocated for use as ISO transmission service (i.e., "new firm uses");

(c) transmission capacity that may be allocated by the ISO for conditional firm Existing Rights; and

(d) transmission capacity that may remain for any other uses, such as non-firm Existing Rights for which the Responsible PTO has no discretion over whether or not to provide such non-firm service.

24 TRANSMISSION EXPANSION.

A Participating TO shall be obligated to construct all transmission additions and upgrades that are determined to be needed in accordance with the requirements of this Section 24 and which: (1) are additions or upgrades to transmission facilities that are located within its PTO Service Territory, unless it does not own the facility being upgraded or added and neither terminus of such facility is located within its PTO Service Territory; or (2) are additions to existing transmission facilities or upgrades to existing transmission facilities that it owns, that are part of the ISO Controlled Grid, and that are located outside of its PTO Service Territory, unless the joint-ownership arrangement, if any, does not permit. A Participating TO's obligation to construct such transmission additions and upgrades shall be subject to: (1) its ability, after making a good faith effort, to obtain all necessary approvals and property rights under applicable federal, state, and local laws and (2) the presence of a cost recovery mechanism with cost responsibility assigned in accordance with Section 24.7. The obligations of the Participating TO to construct such transmission additions or upgrades will not alter the rights of any entity to construct and expand transmission facilities as those rights would exist in the absence of the TO's obligations under this ISO

Tariff or as those rights may be conferred by the ISO or may arise or exist pursuant to this ISO Tariff.

24.1 Determination of Need.

A Participating TO or any other Market Participant may propose a transmission system addition or upgrade. The ISO will determine that a transmission addition or upgrade is needed where it will promote economic efficiency or maintain System Reliability as set forth below.

24.1.1 Economically Driven Projects.

The Participating TO and Market Participants shall provide the necessary assistance and information to the ISO, as part of the coordinated planning process, to enable the ISO to determine that a project is needed to promote economic efficiency, including, at the ISO's discretion, studies comporting with ISO guidelines that demonstrate whether the project will promote economic efficiency or the information the ISO requires to carry out its own studies for economically driven projects. The ISO shall treat market sensitive information provided to the ISO in accordance with this Section by Participating TOs, Project Sponsors and applicable Market Participants confidentially in accordance with Section 20 provided that such information is clearly marked "Confidential" at the time it is provided to the ISO. The determination that a transmission addition or upgrade is needed to promote economic efficiency shall be made in any of the following ways:

24.1.1.1 If the Participating TO or any party questions the economic need for the project (except where the Project Sponsor commits to pay the full cost of construction) the proposal will be submitted to the ISO ADR Procedures for resolution.

24.1.1.2 Where a Project Sponsor other than the Participating TO commits to pay the full cost of construction of a transmission addition or upgrade and its operation, and demonstrates to the ISO financial capability to pay those costs, such commitment and demonstration shall be sufficient to demonstrate need to the ISO. To ensure that the Project Sponsor is financially able to pay the costs of the project to be constructed by the Participating TO, the Participating TO may require (1) a demonstration of creditworthiness (e.g. an appropriate credit rating), or (2) sufficient security in the form of an unconditional and irrevocable letter of credit or other similar security sufficient to meet its

responsibilities and obligations for the full costs of the transmission addition or upgrade.

24.1.1.3 Where a Project Sponsor asserts that a transmission addition or upgrade is economically beneficial, but that Project Sponsor is unwilling to commit to pay the full cost of the addition or upgrade; where (1) the proposed transmission addition or upgrade was submitted to the Participating TO but was not included in the transmission expansion plan of that Participating TO in accordance with Section 24.2 or (2) the operation date of the planned expansion is not acceptable to the ISO or the Project Sponsor or (3) the Participating TO unreasonably delays implementing or subsequently decides not to proceed with the project, the Project Sponsor may submit its proposal to the ISO ADR Procedure for determination of need. A determination of need shall be made as follows:

24.1.1.3.1 The Project Sponsor shall include in its proposal: (1) a showing that the economic benefits of the proposed transmission addition or upgrade are expected to exceed its costs (giving consideration to any reasonable alternatives to the construction of transmission additions or upgrades) using an economic analysis that comports with ISO guidelines, and (2) a statement of the proposed pricing methodology for the transmission upgrades or additions that the Project Sponsor elects in accordance with Section 24.7 of the ISO Tariff.

24.1.1.3.2 If neither any Market Participant nor the ISO disputes the Project Sponsor's showing, then the proposal is determined to be needed.

24.1.1.3.3 If any Market Participant or the ISO disputes the Project Sponsor's showing, the disputing Market Participant, the ISO, or the Project Sponsor may submit to resolution through the ISO ADR Procedure the issue of whether the transmission addition or upgrade is needed on the ground that its economic benefits exceed its costs. If a Market Participant fails to raise through the ISO ADR Procedure a dispute as to whether a proposed transmission addition or upgrade is needed, then the Market Participant shall be deemed to have waived its right to raise such dispute at a later date. The determination under the ISO ADR Procedure as to whether the transmission addition or upgrade is needed, including any determination by FERC or on appeal of a FERC determination in accordance with that process, shall be final.

24.1.2 Reliability Driven Projects.

The ISO in coordination with the Participating TO, will identify the need for any transmission additions or upgrades required to ensure System Reliability consistent with all Applicable Reliability Criteria. In making this determination, the ISO, in coordination with the Participating TO and other Market Participants, shall consider lower cost alternatives to the construction of transmission additions or upgrades, such as acceleration or expansion of existing projects, demand-side management, remedial action schemes, constrained-on Generation, interruptible Loads or reactive support. The Participating TO, in cooperation with the ISO, shall perform the necessary studies to determine the facilities needed to meet all Applicable Reliability Criteria. The Participating TO shall provide the ISO and other Market Participants with all information relating to a proposed transmission addition or upgrade that they may reasonably request (other than information available to them through the WECC or any other applicable regional organization) and shall, through the WECC or any other applicable regional organization coordinated planning processes, develop the scope of and assumptions for such studies that are acceptable to the ISO and those other Market Participants. The ISO shall be free to propose any transmission upgrades or additions it deems necessary to ensure System Reliability consistent with Applicable Reliability Criteria, and, subject to appropriate appeals, the Participating TO shall be obligated to construct such lines. After the ISO Operations Date, the ISO, in consultation with Participating TOs and any affected UDCs and MSSs, will work to develop a consistent set of Reliability Criteria for the ISO Controlled Grid which the Participating TOs will use in their transmission planning and expansion studies or decisions.

24.2 Transmission Planning and Coordination.

The ISO shall actively participate with each Participating TO and the other Market Participants in the ISO Controlled Grid planning process in accordance with the terms of this ISO Tariff and the Transmission Control Agreement.

24.2.1 Each Participating TO with a PTO Service Territory shall develop annually a transmission expansion plan covering the next five years plus a ten-year case for the Loads that are geographically embedded within its PTO Service Territory and are within the ISO Control Area, even if such Loads are

served by another Participating TO. Such Participating TO shall coordinate with the ISO and other Market Participants in the development of such plan. The Participating TO shall be responsible for ensuring that its transmission expansion plan meets all Applicable Reliability Criteria.

24.2.2 The ISO shall review the Participating TOs' transmission expansion plans for the PTO Service Territory, whether or not such plans are subject to Section 24.2.1, to ensure that each Participating TO's expansion plans meet the Applicable Reliability Criteria. The Participating TO will provide the necessary assistance and information as part of the coordinated planning process to the ISO to enable it to carry out its own studies for these purposes. If the ISO finds that the Participating TO's plan or projects do not meet the Applicable Reliability Criteria, the ISO will provide comments and the Participating TO will reassess its plans, as appropriate. The ISO may also propose new projects or suggest project changes (*e.g.*, timing, project size) for consideration by the Participating TO. Changes or additions made by the ISO and accepted by the TO will be included in the Participating TO's expansion plan. Changes or additions not accepted in the coordinated planning process will be resolved through the ISO ADR Procedure.

24.2.3 The Participating TO will act as a Project Sponsor for Participating TO proposed economic or reliability projects that are included in its expansion plan. The Participating TO shall provide to the ISO any information that the ISO requires to enable the ISO to comply with WECC and any other applicable regional coordination requirements pursuant to Section 24.6.

24.2.4 The ISO will be a member of the WECC and other applicable regional organizations and participate in WECC's operation and planning committees, and in other applicable regional coordinated planning processes. Neither the ISO nor any Participating TO nor any Market Participant shall take any position before the WECC or a regional organization that is inconsistent with a binding decision reached through the ISO ADR Procedure.

24.3 Studies to Determine Facilities to be Constructed.

Where a Participating TO is obligated to construct or expand facilities in accordance with this ISO Tariff or where the ISO or any Market Participant requests that a Facility Study be carried out, the Participating TO (in coordination with the ISO or the relevant Market Participants as the case may require), shall perform

the necessary study or studies to determine the appropriate facilities to be constructed in accordance with the terms set forth in the TO Tariff. The scope of and assumptions for any studies requested by a Project Sponsor of a transmission addition or upgrade on economic grounds must be acceptable to the Project Sponsors and the ISO. Any dispute relating to a Facility Study Agreement (including any dispute over the scope of the study or its assumptions) shall be resolved through the ISO ADR Procedures.

24.4 Operational Review.

The ISO will perform an operational review of all facilities that are to be connected to, or made part of, the ISO Controlled Grid to ensure that the facilities being proposed provide for acceptable operating flexibility and meet all its requirements for proper integration with the ISO Controlled Grid. If the ISO finds that such facilities do not provide for acceptable operating flexibility or do not adequately integrate with the ISO Controlled Grid, the Participating TO will reassess its determination of the facilities required to be constructed.

24.5 State and Local Approval and Property Rights.

24.5.1 The Participating TO shall be obligated to make a good faith effort to obtain all approvals and property rights under applicable federal, state and local laws that are necessary to complete the construction of transmission additions or upgrades required to be constructed in accordance with this ISO Tariff. This obligation includes the Participating TO's use of eminent domain authority, where provided by state law.

24.5.2 If the Participating TO cannot secure any such necessary approvals or property rights and consequently is unable to construct a transmission addition or upgrade, it shall promptly notify the ISO and the Project Sponsor and shall comply with its obligations under the TO Tariff to convene a technical meeting to evaluate alternative proposals. The ISO shall take such action as it reasonably considers appropriate, in coordination with the Participating TO, the Project Sponsor (if any) and other affected Market Participants, to facilitate the development and evaluation of alternative proposals including, where possible, conferring on a third party the right to build the transmission addition or upgrade.

24.5.3 Where it is possible for a third party to obtain all approvals and property rights under applicable federal, state and local laws that are necessary to complete the construction of transmission additions or upgrades required to be constructed in accordance with this ISO Tariff (including the use of eminent domain authority, where provided by state law) the ISO may confer on a third party the right to build the transmission addition or upgrade which shall enter into the Transmission Control Agreement in relation to such transmission addition or upgrade.

24.6 WECC and Regional Coordination.

The Project Sponsor will have responsibility for completing any applicable WECC requirements and other applicable regional coordination and rating study requirements to ensure that a proposed transmission addition or upgrade meets regional planning requirements. The Project Sponsor may request the Participating TO to perform this coordination on behalf of the Project Sponsor at the Project Sponsor's expense.

24.7 Cost Responsibility for Transmission Additions or Upgrades.

Cost responsibility for transmission additions or upgrades constructed pursuant to this Section 24 (including the responsibility for any costs incurred under Section 24.6) shall be determined as follows:

24.7.1 Where a Project Sponsor commits to pay the full cost of a transmission addition or upgrade as set forth in Section 24.1.1.2, the full costs shall be borne by the Project Sponsor.

24.7.2 Where the need for a transmission addition or upgrade is determined by the ISO or as a result of the ISO ADR Procedure as set forth in Section 24.1.1.3, the cost of the transmission addition or upgrade shall be borne by the Participating TO that will be the owner of the transmission addition or upgrade and shall be reflected in its Transmission Revenue Requirement.

24.7.3 Provided that the ISO has Operational Control of the transmission upgrade or addition, a Project Sponsor that does not recover the investment cost under a FERC-approved rate through the Access Charge or a reimbursement or direct payment from a Participating TO shall be entitled to receive:

(a) its share, as determined in subsection (d) below, of the Wheeling revenues calculated in accordance with Section 26.1.4.3 that are attributable to the transmission addition or upgrade,

which shall be determined by using the capacity increase, if any, of a Scheduling Point, to the extent such increase results from the addition or upgrade, as the rating increase for purposes of subsection (d) below;

(b) its share, as determined in subsection (d) below, of the proceeds of the FTR auction for FTRs defined on the Inter-Zonal Interface of which the transmission addition or upgrade forms a part as set forth in Section 36.5.3, provided that the Project Sponsor does not receive FTRs from the ISO in accordance with Section 36.4.3 of the ISO Tariff; and

(c) its share, as determined in subsection (d) below, of the Congestion revenues provided as calculated pursuant to Section 27.1.2.1.6 on the Inter-Zonal Interface of which the transmission addition or upgrade forms a part.

(d) The Project Sponsor's share of Wheeling, Congestion and FTR auction revenues for the upgraded transmission facility shall be the number that is determined by dividing the number that is determined by subtracting the rating of the transmission facility before the upgrade or addition from the new rating for the upgraded or additional transmission facility by the new rating for the upgraded or additional transmission facility. The Participating TO's share of Wheeling, Congestion and FTR auction revenues for the upgraded or additional transmission facility shall be the number that is determined by subtracting the Project Sponsor's share from one hundred percent (100%). Such allocated shares shall become effective on the date the new rating takes effect. The full amount of capacity added to the system will be as determined through the regional reliability council process of the Western Electricity Coordinating Council or its successor.

24.7.4 Once a New Participating TO has executed the Transmission Control Agreement and it has become effective, the cost for New High Voltage Facilities for all Participating TOs shall be included in the ISO Grid-wide component of the High Voltage Access Charge in accordance with Schedule 3 of Appendix F, unless and with respect to Western Path 15 only, cost recovery is provided in Section 24.7.3. The Participating TO who is supporting the cost of the New High Voltage Facility shall include such costs in its High Voltage Transmission Revenue Requirement, regardless of which TAC Area the facility is

geographically located.

24.8 Ownership of and Charges for Expansion Facilities.

24.8.1 All transmission additions and upgrades constructed in accordance with this Section 24 shall form part of the ISO Controlled Grid and shall be operated and maintained by a Participating TO in accordance with the Transmission Control Agreement.

24.8.2 Each Participating TO that owns or operates transmission additions and upgrades constructed in accordance with this Section 24 shall provide access to them and charge for their use in accordance with this ISO Tariff and its TO Tariff.

24.9 Expansion by "Local Furnishing" Participating TOs

Notwithstanding any other provision of this ISO Tariff, a Local Furnishing Participating TO shall not be obligated to construct or expand facilities, (including interconnection facilities as described in Section 8 of the TO Tariff) unless the ISO or Project Sponsor has tendered an application under FPA Section 211 that requests FERC to issue an order directing the Local Furnishing TO to construct such facilities pursuant to Section 24 of the ISO Tariff. The Local Furnishing TO shall, within 10 days of receiving a copy of the Section 211 application, waive its right to a request for service under FPA Section 213(a) and to the issuance of a proposed order under FPA Section 212(c). Upon receipt of a final order from FERC that is no longer subject to rehearing or appeal, such Local Furnishing TO shall construct such facilities in accordance with this Section 24.

25 INTERCONNECTION OF GENERATING UNITS AND GENERATING FACILITIES TO THE ISO CONTROLLED GRID.

25.1 Applicability.

This Section 25 and the Standard Large Generator Interconnection Procedures (LGIP) or ISO Tariff Appendix W, as applicable, shall apply to:

(a) each new Generating Unit that seeks to interconnect to the ISO Controlled Grid;

(b) each existing Generating Unit connected to the ISO Controlled Grid that will be modified with a

resulting increase in the total capability of the power plant;

(c) each existing Generating Unit connected to the ISO Controlled Grid that will be modified without increasing the total capability of the power plant but has changed the electrical characteristics of the power plant such that its re-energization may violate Applicable Reliability Criteria; and

(d) each existing qualifying facility Generating Unit connected to the ISO Controlled Grid whose total Generation was previously sold to a Participating TO or on-site customer but whose Generation, or any portion thereof, will now be sold in the wholesale market, subject to Section 25.1.2 below.

25.1.1 The owner of a Generating Unit described in Section 25.1 (a), (b), or (c), or its designee, shall be an Interconnection Customer required to submit an Interconnection Request and comply with the LGIP or ISO Tariff Appendix W, as applicable.

25.1.2 If the owner of a qualifying facility described in Section 25.1(d), or its designee, represents that the total capability and electrical characteristics of the qualifying facility will be substantially unchanged, then that entity must submit an affidavit to the ISO and the applicable Participating TO representing that the total capability and electrical characteristics of the qualifying facility will remain substantially unchanged. If there is any change to the total capability and electrical characteristics of the qualifying facility, however, the affidavit shall include supporting information describing any such changes. The ISO and the applicable Participating TO shall have the right to verify whether or not the total capability or electrical characteristics of the qualifying facility have changed or will change.

25.1.2.1 If the ISO and the applicable Participating TO confirm that the electrical characteristics are substantially unchanged, then that request will not be placed into the interconnection queue. However, the owner of the qualifying facility, or its designee, will be required to execute either a Standard Large Generator Interconnection Agreement in accordance with Section 11 of the LGIP or an interconnection agreement in accordance with ISO Tariff Appendix W, as applicable.

25.1.2.2 If the ISO and the applicable Participating TO cannot confirm that the total capability and electrical characteristics are and will be substantially unchanged, then the owner of the qualifying facility,

or its designee, shall be an Interconnection Customer required to submit an Interconnection Request and comply with either the LGIP or ISO Tariff Appendix W, as applicable.

25.2 Interconnections to the Distribution System.

Any proposed interconnection by the owner of a planned Generating Unit, or its designee, to connect that Generating Unit to a Distribution System of a Participating TO will be processed, as applicable, pursuant to the Wholesale Distribution Access Tariff or CPUC Rule 21, or other Local Regulatory Authority requirements, if applicable, of the Participating TO; provided, however, that the owner of the planned Generating Unit, or its designee, shall be required to mitigate any adverse impact on reliability of the ISO Controlled Grid consistent with the Standard Large Generator Interconnection Procedures. In addition, each Participating TO will provide to the ISO a copy of the system impact study used to determine the impact of a planned Generating Unit on the Distribution System and the ISO Controlled Grid pursuant to a request to interconnect under the applicable Wholesale Distribution Access Tariff or CPUC Rule 21, or other Local Regulatory Authority requirements, if applicable.

25.3 Maintenance of Encumbrances.

No new Generating Unit shall adversely affect the ability of the applicable Participating TO to honor its Encumbrances existing as of the time an Interconnection Customer submits its Interconnection Request to the ISO. The applicable Participating TO, in consultation with the ISO, shall identify any such adverse effect on its Encumbrances in the Interconnection System Impact Study performed under Section 7 of the LGIP or under Section 5.1 of ISO Tariff Appendix W, as applicable. To the extent the applicable Participating TO determines that the connection of the new Generating Unit will have an adverse effect on Encumbrances, the Interconnection Customer shall mitigate such adverse effect.

26 TRANSMISSION RATES AND CHARGES.

26.1 Access Charges.

All Market Participants withdrawing Energy from the ISO Controlled Grid shall pay Access Charges in accordance with this Section 26.1 and Appendix F, Schedule 3, except as provided in SPP 4.1. Prior to

the transition date determined under Section 4 of Schedule 3 to Appendix F, the Access Charge for each

Participating TO shall be

determined in accordance with the principles set forth in this Section 26.1 and in Section 5 of the TO Tariff. The Access Charge shall comprise two components, which together shall be designed to recover each Participating TO's Transmission Revenue Requirement. The first component shall be the annual authorized revenue requirement associated with the transmission facilities and Entitlements turned over to the Operational Control of the ISO by a Participating TO approved by FERC. The second component shall be based on the Transmission Revenue Balancing Account (TRBA), which shall be designed to flow through to the Participating TO's Transmission Revenue Credits calculated in accordance with Section 5 of the TO Tariff and other credits identified in Sections 6 and 8 of Schedule 3 in Appendix F of the ISO Tariff.

Commencing on the transition date determined under Section 4 of Schedule 3 to Appendix F, the Access Charges shall be paid by any UDC or MSS Operator that is serving Gross Load in a PTO Service Territory, and shall consist, where applicable, of a High Voltage Access Charge, a Transition Charge and a Low Voltage Access Charge. High Voltage Access Charges and Low Voltage Access Charges shall each comprise two components, which together shall be designed to recover each Participating TO's High Voltage Transmission Revenue Requirement and Low Voltage Transmission Revenue Requirement, as applicable. The first component shall be based on the annual authorized Transmission Revenue Requirement associated with the high voltage or low voltage, as applicable, transmission facilities and Entitlements turned over to the ISO Operational Control by a Participating TO. The second component shall be the Transmission Revenue Balancing Account (TRBA), which shall be designed to flow through the Participating TO's Transmission Revenue Credits associated with the high voltage or low voltage, as applicable, transmission facilities and Entitlements and calculated in accordance with Section 5 of the TO Tariff and other credits identified in Section 6 and 8 of Schedule 3 of Appendix F of the ISO Tariff. Each Participating TO shall provide in its TO Tariff filing with FERC an appendix to such filing that states the Participating TO's High Voltage Transmission Revenue Requirement, its Low Voltage Transmission Revenue Requirement (if applicable) and its Gross Load used in developing the rate. The allocation of each Participating TO's Transmission Revenue Requirement between the High Voltage Transmission Revenue Requirement and the Low Voltage Transmission Revenue Requirement shall be undertaken in accordance with Section 11 of Schedule 3 of Appendix F. To the extent necessary, each Participating TO

shall make conforming changes to its TO Tariff.

The applicable High Voltage Access Charge and the Transition Charge shall be paid to the ISO by each UDC and MSS Operator based on its Gross Load connected to a High Voltage Transmission Facility in a PTO Service Territory, either directly or through intervening distribution facilities, but not through a Low Voltage Transmission Facility. The applicable High Voltage Access Charge, the Transition Charge and the Low Voltage Access Charge for the applicable Participating TO shall be paid by each UDC and MSS Operator based on its Gross Load in the PTO Service Territory. The applicable High Voltage Access Charge and Transition Charge shall be assessed by the ISO as a charge for transmission service under this ISO Tariff, shall be determined in accordance with Schedule 3 of Appendix F, and shall include all applicable components of the High Voltage Access Charge and Transition Charge set forth therein.

The Low Voltage Access Charge for each Participating TO is set forth in that Participating TO's TO Tariff. Each Participating TO shall charge for and collect the Low Voltage Access Charge, as provided in its TO Tariff. If a Participating TO is using the Low Voltage Transmission Facilities of another Participating TO, such Participating TO shall also be assessed the Low Voltage Access Charge of the other Participating TO by such other Participating TO. The ISO shall provide to the applicable Participating TO a statement of the amount of Energy delivered to each UDC and MSS Operator serving Gross Load that utilizes the Low Voltage Transmission Facilities of that Participating TO on a monthly basis. If a UDC or MSS Operator that is serving Gross Load in a PTO Service Territory has Existing Rights to use another Participating TO's Low Voltage Transmission Facilities, such entity shall not be charged the Low Voltage Access Charge for delivery of Energy to Gross Load for deliveries using the Existing Rights. Each Participating TO shall recover Standby Transmission Revenues directly from the Standby Service Customers of that Participating TO through its applicable retail rates.

26.1.1 Publicly Owned Electric Utilities Access Charge.

Local Publicly Owned Electric Utilities whose transmission facilities are under ISO Operational Control shall file with the FERC their proposed High Voltage Transmission Revenue Requirements, and any proposed changes thereto, under procedures determined by the FERC to be applicable to such filings and shall give notice to the ISO and to all Scheduling Coordinators of any such filing. A prospective New

Participating TO that is a Local Publicly Owned Electric Utility shall submit its first proposed High Voltage Transmission Revenue Requirement to the FERC and the ISO at the time the Local Publicly Owned Electric Utility submits its application to become a New Participating TO in accordance with the Transmission Control Agreement. Federal power marketing agencies whose transmission facilities are under ISO Operational Control shall develop their High Voltage Transmission Revenue Requirement pursuant to applicable federal laws and regulations.

The procedures for public participation in a federal power marketing agency's ratemaking process are posted on the federal power marketing agency's website. Each federal power marketing agency shall

also post on its website the Federal Register Notices and FERC orders for rate making processes that impact the federal power marketing agency's High Voltage Transmission Revenue Requirement. At the time the federal power marketing agency submits its application to become a New Participating TO in accordance with the Transmission Control Agreement, it shall submit its first proposed High Voltage Transmission Revenue Requirement to the FERC and the ISO.

26.1.2 High Voltage Access Charge and Transition Charge Settlement.

UDCs and MSS Operators serving Gross Load in a PTO Service Territory shall be charged on a monthly basis, in arrears, the applicable High Voltage Access Charge and Transition Charge. The High Voltage Access Charge and Transition Charge for a billing period is calculated by the ISO as the product of the applicable High Voltage Access Charge or Transition Charge, as applicable, and Gross Load connected to the facilities of the UDC and MSS Operator in the PTO Service Territory. The High Voltage Access Charge and Transition Charge are determined in accordance with Schedule 3 of Appendix F of the ISO Tariff. These rates may be adjusted from time to time in accordance with Schedule 3 to Appendix F. During the 10-year transition period described in Section 4 of Schedule 3 of Appendix F of the ISO Tariff, a UDC or MSS Operator that is also a Participating TO shall pay, or receive payment of, if applicable, the difference between (i) the High Voltage Access Charge and the Transition Charge applicable to its transactions as a UDC or MSS Operator; and (ii) the disbursement of High Voltage Access Charge revenues to which it is entitled pursuant to Section 26.1.3.

26.1.3 Disbursement of High Voltage Access Charge and Transition Charge Revenues.

The ISO shall collect and pay, on a monthly basis, to Participating TOs all High Voltage Access Charge and Transition Charge revenues at the same time as other ISO charges and payments are settled. High Voltage Access Charge revenues received with respect to the High Voltage Access Charge and the Transition Charge shall be distributed to Participating TOs in accordance with Appendix F, Schedule 3, Section 10.

26.1.4 Wheeling.

Any Scheduling Coordinator or other such entity scheduling a Wheeling transaction shall pay to the ISO the product of (i) the applicable Wheeling Access Charge, and (ii) the total hourly schedules of Wheeling in kilowatt-hours for each month at each Scheduling Point associated with that transaction, except as provided in SPP 4.1. Schedules that include Wheeling transactions shall be subject to the Congestion Management procedures and protocols in accordance with Sections 27.1.1 and 27.1.2.

26.1.4.1 Wheeling Access Charge.

The Wheeling Access Charge shall be determined by the TAC Area and transmission ownership or Entitlement, less all Encumbrances, associated with the Scheduling Point at which the Energy exits the ISO Controlled Grid. The Wheeling Access Charge for Scheduling Points contained within a single TAC Area, that are not joint facilities, shall be equal to the High Voltage Access Charge for the applicable TAC Area in accordance with Section 3 of Appendix F plus the applicable Low Voltage Access Charge if the Scheduling Point is on a Low Voltage Transmission Facility. Wheeling Access Charges shall not apply for Wheeling under a bundled non-economy Energy coordination agreement of a Participating TO executed prior to July 9, 1996.

26.1.4.2 Wheeling Over Joint Facilities.

To the extent that more than one Participating TO owns or has Entitlement to transmission capacity, less all Encumbrances, exiting the ISO Controlled Grid at a Scheduling Point, the Scheduling Coordinator shall pay the ISO each month a rate for Wheeling at that Scheduling Point which reflects an average of the Wheeling Access Charge applicable to those Participating TOs, weighted by the relative share of such ownership or Entitlement to transmission capacity, less all Encumbrances, at such Scheduling Point. If the Scheduling Point is located at High Voltage Transmission Facilities, the Wheeling Access Charge will consist of a High Voltage Wheeling Access Charge component. Additionally, if the Scheduling Point is located at Low Voltage Transmission Facilities, the applicable Low Voltage Wheeling Access Charge component will be added to the Wheeling Access Charge. The methodology for developing the weighted average rate for Wheeling at each Scheduling Point is set forth in Appendix H.

26.1.4.3 Disbursement of Wheeling Revenues.

The ISO shall collect and pay to Participating TOs and other entities as provided in Section 24.7.3 all Wheeling revenues at the same time as other ISO charges and payments are settled. The ISO shall provide to the applicable Participating TO and other entities as provided in Section 24.7.3 a statement of the aggregate amount of Energy delivered to each Scheduling Coordinator using such Participating TO's Scheduling Point to allow for calculation of Wheeling revenue and auditing of disbursements. Wheeling revenues shall be disbursed by the ISO based on the following:

26.1.4.3.1 Scheduling Point with All Participating TOs in the Same TAC Area.

With respect to revenues received for the payment of High Voltage Wheeling Access Charges for Wheeling to a Scheduling Point at which all of the facilities and Entitlements, less all Encumbrances, are owned by Participating TOs in the same TAC Area, Wheeling revenues shall be disbursed to each such Participating TO based on the ratio of each Participating TO's High Voltage Transmission Revenue Requirement to the sum of all such Participating TO's High Voltage Transmission Revenue Requirements. If the Scheduling Point is located at a Low Voltage Facility, revenues received with respect to Low Voltage Wheeling Access Charges for Wheeling to that Scheduling Point shall be disbursed to the Participating TOs that own facilities and Entitlements making up the Scheduling Point in proportion to their Low Voltage Transmission Revenue Requirements. Additionally, if a Participating TO has a transmission upgrade or addition that was funded by a Project Sponsor, the Wheeling revenue allocated to such Participating TO shall be disbursed as provided in Section 24.7.3.

26.1.4.3.2 Scheduling Point without All Participating TOs in the Same TAC Area.

With respect to revenues received for the payment of Wheeling Access Charges for Wheeling to a Scheduling Point at which the facilities and Entitlements, less all Encumbrances, are owned by Participating TOs in different TAC Areas, Wheeling revenues shall be disbursed to such Participating TOs as follows. First, the revenues shall be allocated between such TAC Areas in proportion to the ownership and Entitlements of transmission capacity, less all Encumbrances, at the Scheduling Point of the Participating TOs in each such TAC Area. Second, the revenues thus allocated to each TAC Area shall be disbursed among the Participating TOs in the TAC Area in accordance with Section 26.1.4.3.1.

26.1.4.4 Information Required from Scheduling Coordinators.

Scheduling Coordinators that schedule Wheeling Out or Wheeling Through transactions to a Bulk Supply Point, or other point of interconnection between the ISO Controlled Grid and the transmission system of a Non-Participating TO, that are located within the ISO Control Area, shall provide the ISO, within 5 days from the end of the calendar month to which the relevant Trading Day relates, details of such transactions scheduled by them (other than transactions scheduled pursuant to Existing Contracts) sorted by Bulk Supply Point or point of interconnection for each Settlement Period (including kWh scheduled). The ISO shall use such information, which may be subject to review by the ISO, to settle Wheeling Access Charges and payments. The ISO shall publish a list of the Bulk Supply Points or interconnection points to which this Section 26.1.4.4 applies together with details of the electronic form and procedure to be used by Scheduling Coordinators to submit the required information on the ISO "Home Page".

26.1.5 Unbundled Retail Transmission Rates.

The Access Charge for unbundled retail transmission service provided to End-Users by a FERC-jurisdictional electric utility Participating TO shall be determined by the FERC and submitted to the ISO for information only. For a Local Publicly Owned Electric Utility, retail transmission service rates shall be determined by the Local Regulatory Authority and submitted to the ISO for information only.

26.2 Tracking Account.

If the Access Charge rate methodology implemented pursuant to Section 26.1 results in Access Charge rates for any Participating TO which are different from those in effect prior to the ISO Operations Date, an amount equal to the difference between the new rates and the prior rates for the remainder of the period, if any, during which a cost recovery plan established pursuant to Section 368 of the California Public Utilities Code (as added by AB 1890) is in effect for such Participating TO shall be recorded in a tracking account. The balance of that tracking account will be recovered from customers and paid to the appropriate Participating TO after termination of the cost recovery plan set forth in Section 368 of California Public Utilities Code (as added by AB 1890). The recovery and payments shall be based on an amortization period not exceeding three years in the case of electric corporations regulated by the CPUC or five years for Local Publicly Owned Electric Utilities.

26.3 Addition of New Facilities After ISO Implementation.

The costs of transmission facilities placed in service after the ISO Operations Date shall be recovered consistent with the cost recovery determinations made pursuant to Section 24.7.

26.4 Effect on Tax-Exempt Status.

Nothing in this Section shall compel any Participating TO to violate any restrictions applicable to facilities financed with tax-exempt bonds or contractual restrictions and covenants regarding the use of transmission facilities.

26.5 Transition Mechanism.

During the ten-year transition period described in Section 4 of Schedule 3 to Appendix F, the Original Participating TOs collectively shall pay to the ISO each year an amount equal to, annually, for all New Participating TOs, the amount, if any, by which the New Participating TO's cost of Existing High Voltage Facilities associated with Gross Loads in the PTO Service Territory of the New Participating TO is increased by the implementation of the High Voltage Access Charge described in Schedule 3 to Appendix F. Responsibility for such payments shall be allocated to Original Participating TOs in accordance with Schedule 3 to Appendix F. Amounts payable by Original Participating TOs under this section shall be recoverable as part of the Transition Charge calculated in accordance with Schedule 3 of Appendix F. Amounts received by the ISO under this section shall be disbursed to New Participating TOs with Existing High Voltage Facilities based on the ratio of each New Participating TO's net increase in costs in the categories described in the first sentence of this section, to the sum of the net increases in such costs for all New Participating TOs with Existing High Voltage Facilities.

EXHIBIT
S-13
admitted

4 ROLES AND RESPONSIBILITIES.

4.1 [Not Used]

4.2 Market Participant Responsibilities.

4.2.1 Comply with Operating Orders Issued.

With respect to this Section 4.2, all Market Participants, including Scheduling Coordinators, Utility Distribution Companies, Participating Transmission Owners, Participating Generators, Control Area Operators (to the extent the agreement between the Control Area Operator and the ISO so provides), and Metered Subsystem Operators within the ISO Control Area and all System Resources shall comply fully and promptly with the ISO's Dispatch Instructions and operating orders, unless such operation would impair public health or safety. A Market Participant is not required to comply with an ISO operating order if it is physically impossible for the Market Participant to perform in compliance with that operating order. Shedding Load for a System Emergency does not constitute impairment to public health or safety. The Market Participant shall immediately notify the ISO of its inability to perform in compliance with the operating order. The ISO will honor the terms of Existing Contracts, provided that in a System Emergency and circumstances in which the ISO considers that a System Emergency is imminent or threatened, holders of Existing Rights must follow ISO operating orders even if those operating orders directly conflict with the terms of Existing Contracts. For this purpose ISO operating orders to shed Load shall not be considered as an impairment to public health or safety. This section does not prohibit a Scheduling Coordinator from modifying its Schedule or re-purchasing Energy in the Hour-Ahead Market.

4.2.2 Implementation of Instructions.

All Market Participants shall respond to ISO instructions with no more delay than specified in the response times set out in the ISO Tariff and Protocols.

4.3 Relationship Between ISO and Participating Tos.

4.3.1 Nature of Relationship.

Each Participating TO shall enter into a Transmission Control Agreement with the ISO. In addition to converting Existing Rights in accordance with Section 16.2.1A, and except as provided in Section 4.3.1.3, New Participating TOs will be required to turn over Operational Control of all facilities and Entitlements that: (1) satisfy the FERC's functional criteria for determining transmission facilities that should be placed under ISO Operational Control; (2) satisfy the criteria adopted by the ISO Governing Board identifying transmission facilities for which the ISO should assume Operational Control; and (3) are the subject of mutual agreement between the ISO and the Participating TOs. The ISO shall notify Market Participants when an application has been received from a potential Participating TO and shall notify Market Participants that a New Participating TO has executed the Transmission Control Agreement and the date on which the ISO will have Operational Control of the transmission facilities.

4.3.1.1 In any year, a Participating TO applicant must declare its intent in writing to the ISO to become a New Participating TO by January 1 or July 1, and provide the ISO with an application within 15 days of such notice of intent. Applicable agreements will be negotiated and filed with the Federal Energy Regulatory Commission as soon as possible for the New Participating TO, such that the Agreements can be effective the following July 1 or January 1.

4.3.1.2 With respect to its submission of Schedules to the ISO, a New Participating TO shall become a Scheduling Coordinator or obtain the services of a Scheduling Coordinator that has been certified in accordance with Section 4.5.1.1, which Scheduling Coordinator shall not be the entity's Responsible Participating TO in accordance with the Responsible Participating Transmission Owner Agreement, unless mutually agreed, and shall operate in accordance with the ISO Tariff and applicable agreements.

The New Participating TO shall assume responsibility for paying all Scheduling Coordinators charges regardless of whether the New Participating TO elects to become a Scheduling Coordinator or obtains the services of a Scheduling Coordinator.

4.3.1.3 Western Path 15 shall be required to turn over to ISO Operational Control only its rights and interests in the Path 15 Upgrade and shall not be required to turn over to ISO Operational Control Central Valley Project transmission facilities, Pacific AC Intertie transmission facilities, California-Oregon Transmission Project facilities, or any other new transmission facilities or Entitlements not related to the Path 15 Upgrade. For purposes of the ISO Tariff, Western Path 15 shall be treated with respect to revenue recovery as a Project Sponsor in accordance with Section 24.7.

4.3.1.4 The capacity provided to the ISO under the Transmission Exchange Agreement originally accepted by FERC in Docket No. ER04-688 is deemed to be ISO Controlled Grid facilities and is subject to all terms and conditions of the ISO Tariff.

4.3.1.5 Each Participating TO must provide its Local Reliability Criteria to the ISO, as required by the TCA.

4.4 Relationship Between ISO And UDCs.

4.4.1 General Nature of Relationship Between ISO and UDCs.

4.4.1.1 The ISO shall not be obliged to accept Schedules, Adjustment Bids or bids for Ancillary Services which would require Energy to be transmitted to or from the Distribution System of a UDC directly connected to the ISO Controlled Grid unless the relevant UDC has entered into a UDC Operating Agreement. The UDC Operating Agreement shall require UDCs to comply with the applicable provisions of this Section 4.4 and any other expressly applicable Sections of this ISO Tariff and the ISO Protocols as these may be amended from time to time.

4.4.1.2 The ISO shall operate the ISO Controlled Grid, and each UDC shall operate its Distribution System at all times in accordance with Good Utility Practice and in a manner which ensures safe and reliable operation. The ISO shall, in respect of its obligations set forth in this Section 4.4, have the right by agreement to delegate certain operational responsibilities to the relevant Participating TO or UDC pursuant to this Section 4.4. All information made available to UDCs by the ISO shall also be made available to Scheduling Coordinators. All information pertaining to the physical state or operation, maintenance and failure of the UDC Distribution System affecting the operation of the ISO Controlled Grid

4.4.7 Coordination of Expansion or Modifications to UDC Facilities.

Each UDC and the Participating TO with which it is interconnected shall coordinate in the planning and implementation of any expansion or modifications of a UDC's or Participating TO's system that will affect their transmission interconnection, the ISO Controlled Grid or the transmission services to be required by the UDC. The Participating TO shall be responsible for coordinating with the ISO.

4.4.8 Information Sharing.

4.4.8.1 System Planning Studies.

The ISO, Participating TOs and UDCs shall share information such as projected Load growth and system expansions necessary to conduct necessary System Planning Studies to the extent that these may impact the operation of the ISO Controlled Grid.

4.4.8.2 System Surveys and Inspections.

The ISO and each UDC shall cooperate with each other in performing system surveys and inspections to the extent these relate to the operation of the ISO Controlled Grid.

4.4.8.3 Reports.

4.4.8.3.1 The ISO shall make available to the UDCs any public annual reviews or reports regarding performance standards, measurements and incentives relating to the ISO Controlled Grid and shall also make available, upon reasonable notice, any such reports that the ISO receives from the Participating TOs. Each UDC shall make available to the ISO any public annual reviews or reports regarding performance standards, measurements and incentives relating to the UDC's distribution system to the extent these relate to the operation of the ISO Controlled Grid.

4.4.8.3.2 The ISO and UDCs shall develop an operating procedure to record requests received for Maintenance Outages by the ISO and the completion of the requested maintenance and turnaround times.

4.4.8.3.3 The UDCs shall maintain records that substantiate all maintenance performed on UDC facilities which are under the Operational Control of the ISO. These records shall be made available to the ISO upon receipt of reasonable notice.

EXHIBIT
S-14
admin notice

Before the

POWER PLANT AND TRANSMISSION LINE

SITING COMMITTEE OF ARIZONA

In the Matter of the Application of SOUTHERN CALIFORNIA EDISON COMPANY, in conformance with the requirements of Arizona Revised Statutes Section 40-360, et seq., for a Certificate of Environmental Compatibility for the Arizona portion of one 500 kv transmission line between the Palo Verde Nuclear Generating Station (under construction) near Wintersburg, Arizona, and the Devers substation (existing) near Palm Springs, California.	)	CASE NO. 34 DECISION NO. 49226

CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY

Pursuant to notice given as provided by law, the Power Plant and Transmission Line Siting Committee ("Committee") held public hearings at Rooms N-9 and N-10, Phoenix Civic Plaza, 225 East Adams, Phoenix, Arizona, on March 2-3, 1978 regarding the Application, as amended, of Southern California Edison Company (the "Applicant"), in conformance with the requirements of Arizona Revised Statutes §40-360, et seq., for a Certificate of Environmental Compatibility authorizing one 500 kv transmission line between the Palo Verde Nuclear Generating Station near Wintersburg, Arizona and the Devers substation near Palm Springs, California.

The following members of the Committee, constituting the majority thereof, were present at the hearings held

March 2-3, 1978 and participated in the vote at the conclusion thereof in the manner hereinafter set forth:

Arlo B. Lee
Orme Lewis, Jr.
Arthur Lee
Dave Wood
William Fish, designee for Andrew L. Bettwy
John Carr, designee for Robert Jantzen
Ken Rotta, designee for Ernest Garfield
Clint Johnson, designee for Brent Brown
Don Gilbert
Wally Vegors, designee for Mike Ramnes
Clyde S. Roberts
Thomas P. Prose, designee for Bruce E. Babbitt
Martin Wurbs, designee for Wesley Steiner

The following members of the Committee were present at only portions of the hearing or did not attend the hearing and did not participate in the vote at the conclusion thereof:

James Ayres, designee for Raymond H. Thompson
Bruce Scott
James Betts
Clifford C. Tabor
Frank Aleshire

The Applicant was represented by attorneys Steven M. Wheeler of Snell & Wilmer and Tom P. Gilfoy, Senior Counsel of the Applicant. Intervenor, Harquahala Valley Association and Harquahala Valley Environmental Association, having duly served its written notice of intent to become a party as provided by law, was represented by attorney James H. Green, Jr. Intervenor, Tonopah Valley Association, having duly served its written notice of intent to become a party as provided by law, was represented by Frank Haze Burch of Burch, Cracchiolo, Levie, Guyer & Weyl, P.A.

Numerous persons made limited appearances and submitted written statements with respect to the Application.

These statements were incorporated in the record pursuant to the Rules of Practice and Procedure of the Committee as set forth in General Order U-51 of the Arizona Corporation Commission (A.C.R.R. R14-3-202).

Evidence in support of the Application, as amended, was submitted by Applicant's witnesses who were cross-examined by members of the Committee and the Intervenors.

Evidence in opposition to certain portions of the Application, as amended, was submitted by Intervenor witnesses who were cross-examined by members of the Committee and the Applicant.

At the conclusion of the March 3, 1978 hearing, the Committee, upon motion duly made and seconded and approved by a majority vote of the members present, which vote constituted a majority of the members of the entire Committee, granted Applicant the following Certificate of Environmental Compatibility:

> Applicant Southern California Edison Company is hereby granted a Certificate of Environmental Compatibility for the construction of the Arizona portion of one 500 kv transmission line from the Palo Verde Nuclear Generating Station near Wintersburg, Arizona to the Applicant's Devers Substation, near Palm Springs, California within the routing corridors shown on the maps attached hereto as Exhibit A (sheets A-1 through A-11) and generally described as follows:
>
> The routing corridor for the 500 kv transmission line begins at the main switchyard near the center of the Palo Verde Nuclear Generating Station site, located west of

Phoenix in the vicinity of Wintersburg, Arizona. It departs in a generally westerly direction and proceeds approximately ten miles west to Point AAA near the El Paso Natural Gas Company ("El Paso") pipeline right-of-way on the east side of the Harquahala Valley. The corridor turns southwesterly crossing the pipeline and proceeds for approximately 13 miles to Point 9 (as shown on Exhibit A), approximately one mile south of the southern tip of the Eagletail Mountains. The corridor then continues southwesterly for approximately one mile to the Arlington-Clanton Well Road. The corridor generally parallels this road approximately 12 miles to the vicinity of Clanton Well east of the Clanton Hills in the Nottbusch Valley.

Just north of Clanton Well, the corridor turns abruptly to the northwest and proceeds through the Nottbusch Valley west of Cemetery Ridge parallel with an unimproved dirt road for approximately 15 miles to a major angle point (Point 13) located approximately 3 miles south of the northwestern end of the Eagletail Mountains. At this point, the corridor then turns a major angle to the northwest and proceeds approximately 5 miles to Point NNN and the El Paso pipeline right-of-way approximately 10 miles east of the Kofa Game Range. The corridor then continues westerly along the El Paso pipeline right-of-way through the Kofa Game Range to an angle point (Point RRR) approximately one mile east of the western boundary of the Kofa Game Range.

The corridor leaves the game range and proceeds approximately 6 miles across the LaPosa Plain to the east boundary of the Yuma Proving Ground. At the Proving Ground boundary, the corridor continues westerly for approximately 2.5 miles to a pass in the Dome Rock Mountains, approximately 1.5 miles north of Weaver Pass. The corridor then proceeds across the Dome

Rock Mountains westerly for approximately 4 miles to an angle point on the east side of Ehrenberg Wash. The corridor then proceeds in a northwesterly direction for approximately 3 miles across Ehrenberg Wash to a point where the corridor turns back westerly and proceeds approximately 7 miles to Point YYY on the east side of the Colorado River north of Weaver Wash.

At this point, the corridor proceeds 1.5 miles to the Colorado River and enters California approximately 5 miles south of the City of Blythe.

The Applicant is also granted the following alternate route corridor:

From Point RRR, approximately one mile east of the western boundary of the Kofa Game Range, the corridor proceeds northwesterly along the El Paso pipeline to Point E. At Point E, the corridor parallels the El Paso pipeline northwesterly across the eastern slopes of the Dome Rock Mountains through Copper Bottom Pass. At Point KK the corridor then leaves the pipeline in a southwesterly direction and descends the western slope of the Dome Rock Mountains and proceeds approximately 9 miles to a crossing of the Colorado River where it enters California, approximately 5 miles south of the City of Blythe and 1.5 miles west of Point YYY.

The 500 kv line is to be located within a 2 mile corridor, the centerline of which shall be the lines designated on the maps comprising Exhibit A as the "Approved Route" and the "Approved Alternate Route" except as follows:

1. Between Point 9 and Point AAA, the line shown on the attached Exhibit A (sheets A-9 and A-10) which is designated the "Subalternate Route" shall serve as the northern boundary of a 2 mile corridor. The Applicant shall locate its line

within the southern-most one-half mile of that corridor except that Applicant shall locate its line between the two buttes in that area located primarily in Sections 13 and 24, Township 1S, Range 9W, and Sections 19, 20, 29 and 30, Township 1S, Range 8W Gila and Salt River Base and Meridian.

2. For the areas shown on sheets A-9 and A-10 of Exhibit A East of Point AAA and West of Point 9, the Applicant shall locate its transmission line between the two lines designated on sheets A-9 and A-10 as "Corridor Boundaries".

The Applicant shall be entitled to use any of the routings described above and designated on Exhibit A hereto and in the event of any discrepancy between the general description above and the specific routing corridors shown on Exhibit A, Exhibit A shall control.

This Certificate of Environmental Compatibility is granted subject to the following conditions:

1. The Applicant shall comply with all applicable nuclear radiation standards, air and water pollution control standards and regulations, and with all applicable ordinances, master plans and regulations of the State of Arizona, and the Counties of Maricopa and Yuma.

2. The Applicant shall cooperate with the Arizona State Game and Fish Department in an attempt to restrict public access to all new roads of the Applicant necessary for the

construction, operation and maintenance of the 500 kv line through the Dome Rock Mountains.

GRANTED THIS 15th day of June, 1978.

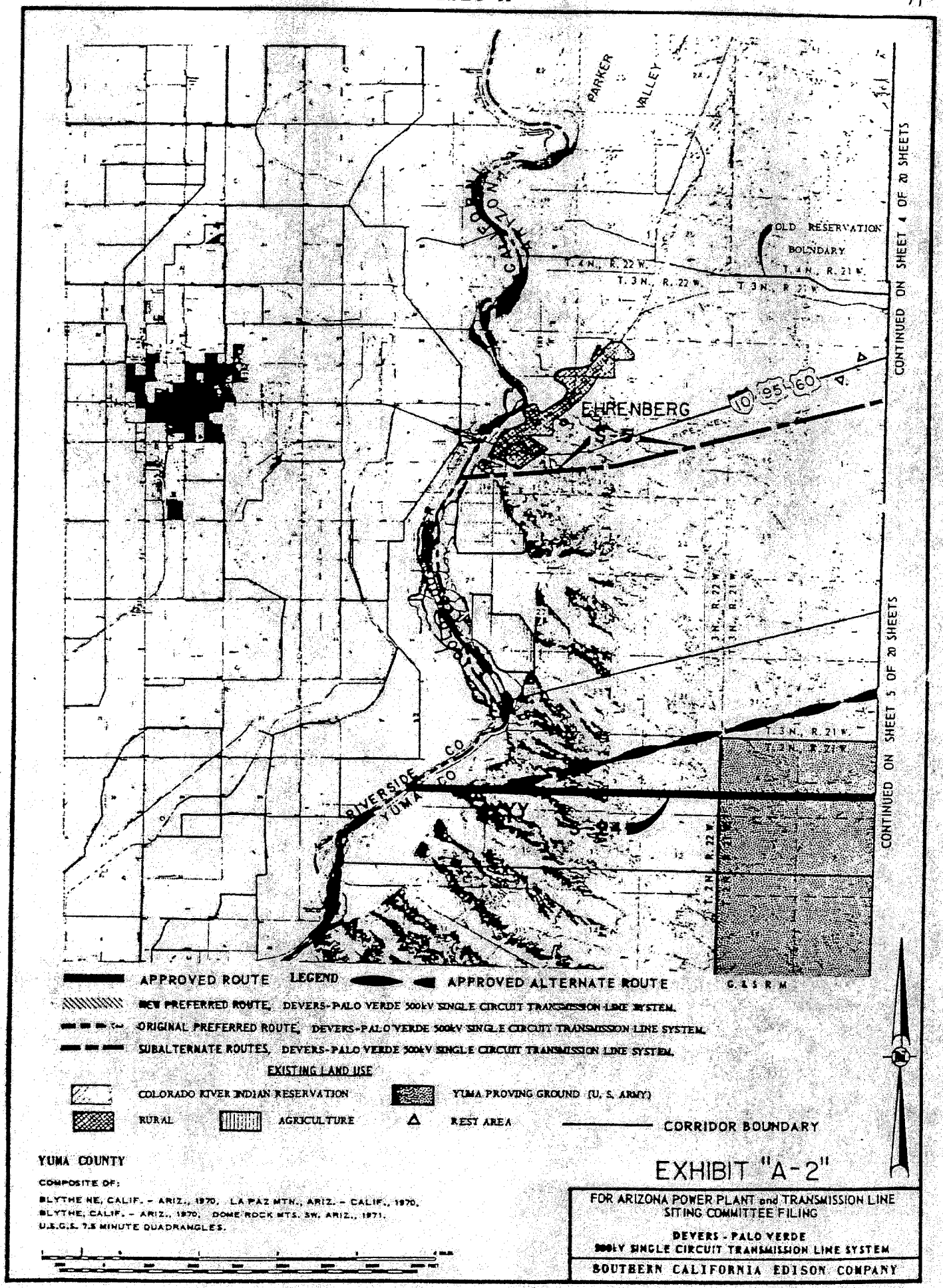
POWER PLANT AND TRANSMISSION
LINE SITING COMMITTEE

By _____
Chairman

CHAIRMAN COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I, G. C. ANDERSON, JR., Executive Secretary of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of this Commission to be affixed, at the Capitol in the City of Phoenix, this 3rd day of August, 1978.

G. C. ANDERSON, JR.
EXECUTIVE SECRETARY



YUMA COUNTY

COMPOSITE OF:

BLYTHE NE, CALIF. - ARIZ., 1970, LA PAZ MTN., ARIZ. - CALIF., 1970,
BLYTHE, CALIF. - ARIZ., 1970, DOME ROCK MTS. SW, ARIZ., 1971.
U.S.G.S. 7.5 MINUTE QUADRANGLES.

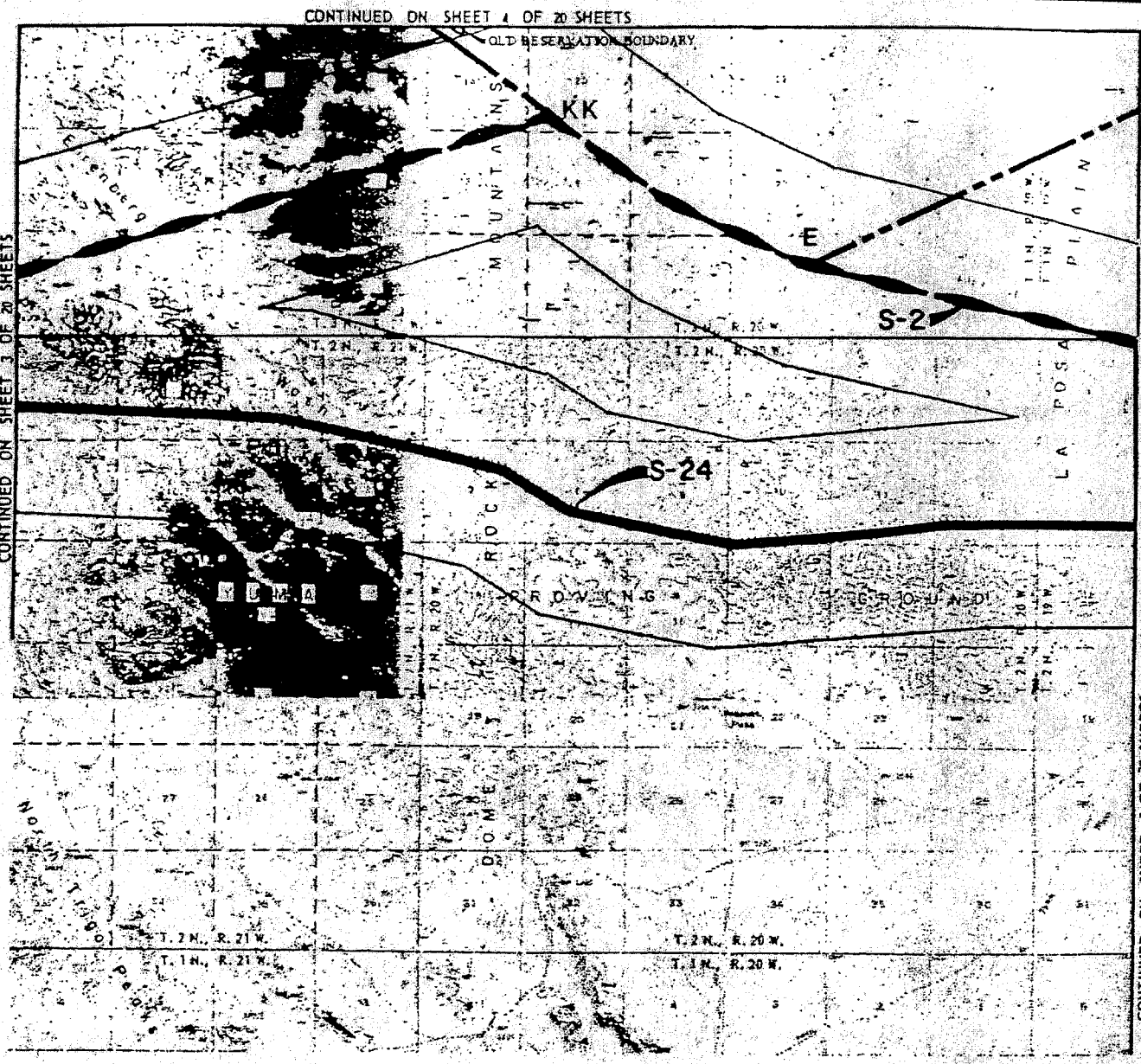
EXHIBIT "A-2"

FOR ARIZONA POWER PLANT and TRANSMISSION LINE SITING COMMITTEE FILING

DEVERS - PALO VERDE
500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM

SOUTHERN CALIFORNIA EDISON COMPANY

A-2



LEGEND

NEW PREFERRED ROUTE, DEVERS-PALO VERDE 500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM.

ORIGINAL PREFERRED ROUTE, DEVERS-PALO VERDE 500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM.

SUBALTERNATE ROUTES, DEVERS-PALO VERDE 500KV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM

APPROVED ROUTE

APPROVED ALTERNATE ROUTE

EXISTING LAND USE

CORRIDOR BOUNDARY

YUMA PROVING GROUNDS (U.S. ARMY)

YUMA COUNTY

COMPOSITE OF:

DOME ROCK MTS. SW, ARIZ., 1971, CUNNINGHAM MTN., ARIZ., 1971
U.S.G.S. 7.5 MINUTE QUADRANGLES.

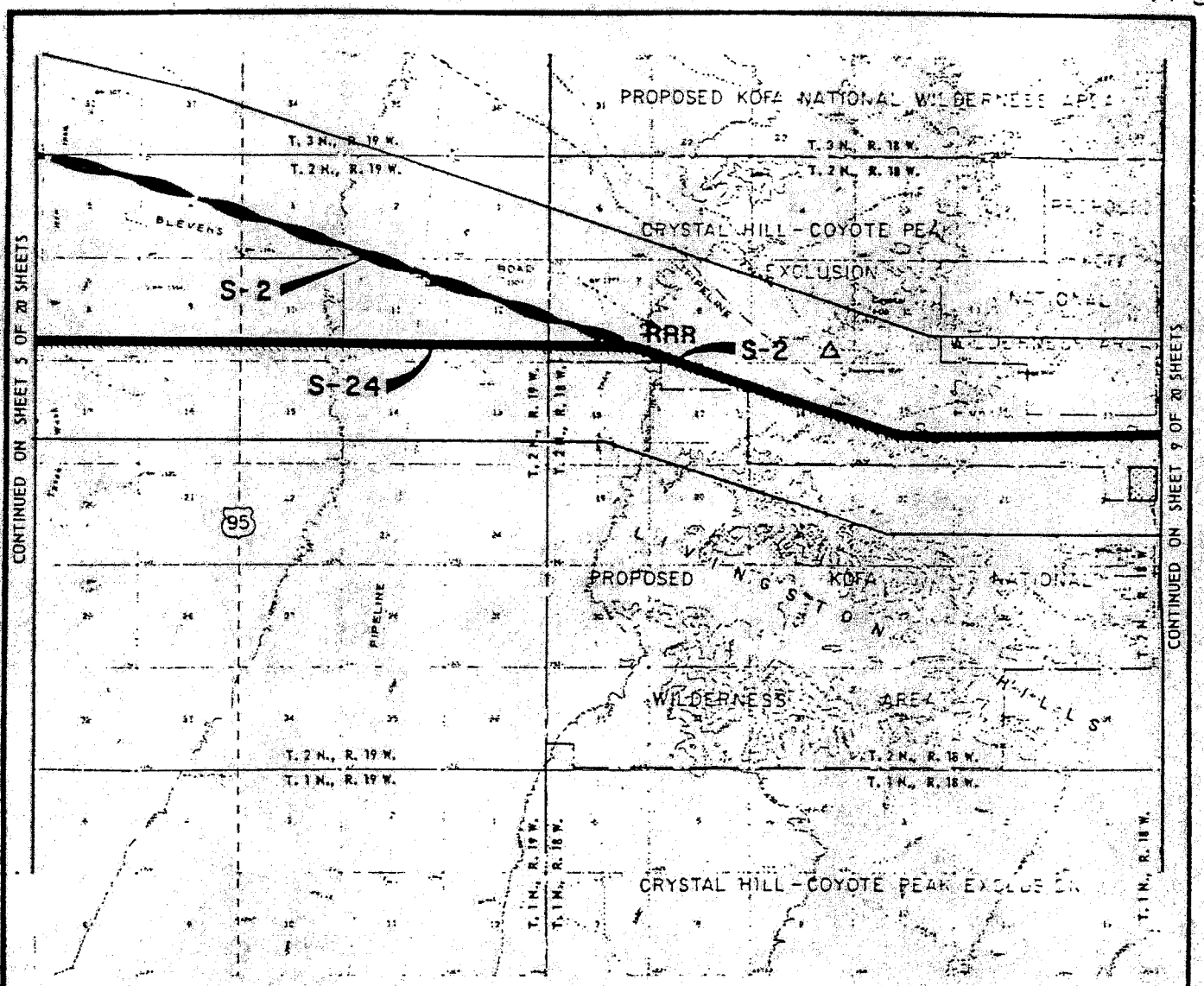
TRIGO PEAKS, ARIZ., 1954.
U.S.G.S. 15 MINUTE QUADRANGLE.

"EXHIBIT A-2"

FOR ARIZONA POWER PLANT and TRANSMISSION LINE SITING COMMITTEE FILING

DEVERS - PALO VERDE
500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM

SOUTHERN CALIFORNIA EDISON COMPANY



LEGEND

APPROVED ROUTE — APPROVED ALTERNATE ROUTE

G & S R M.

NEW PREFERRED ROUTE, DEVERS-PALO VERDE 500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM.

SUBALTERNATE ROUTES, DEVERS-PALO VERDE 500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM.

CORRIDOR BOUNDARY

EXISTING LAND USE

RURAL

KOFA GAME RANGE (EXISTING BOUNDARY)

CRYSTAL SPRINGS CAMPGROUND

YUMA COUNTY

COMPOSITE OF:

CUNNINGHAM MTN., ARIZ., 1971.
U.S.G.S. 7.5 MINUTE QUADRANGLE.

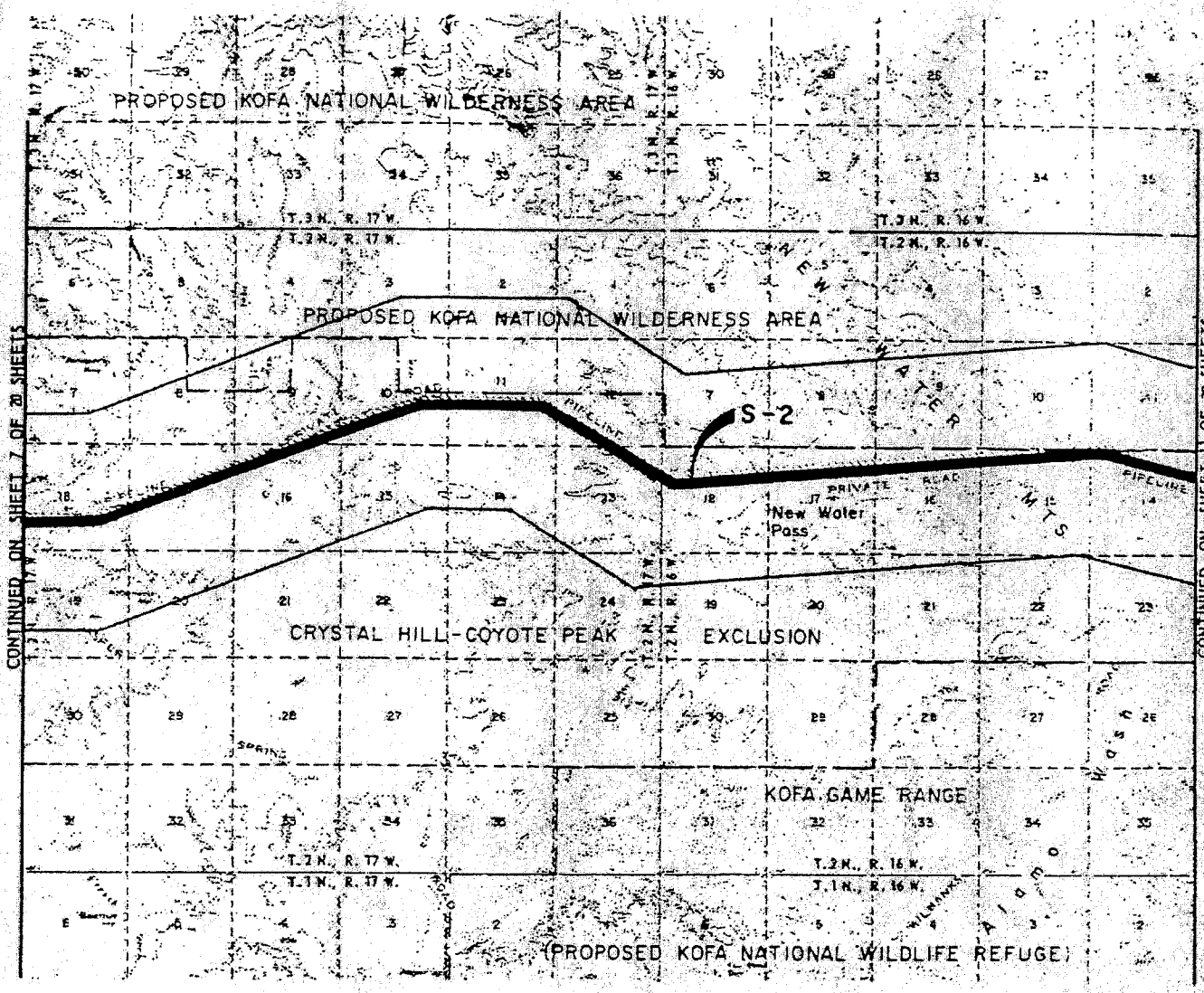
TRIGO PEAK, ARIZ., 1954, LIVINGSTON HILLS, ARIZ., 1962,
QUARTZSITE, ARIZ., 1962.
U.S.G.S. 15 MINUTE QUADRANGLES.

EXHIBIT "A-2"

FOR ARIZONA POWER PLANT and TRANSMISSION LINE SITING COMMITTEE FILING

DEVERS - PALO VERDE
500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM

SOUTHERN CALIFORNIA EDISON COMPANY



LEGEND

G. & S. R. M.

APPROVED ROUTE — CORRIDOR BOUNDARY

NEW PREFERRED ROUTE, DEVERS-PALO VERDE 500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM.

SUBALTERNATE ROUTES, DEVERS-PALO VERDE 500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM.

EXISTING LAND USE

KOFA GAME RANGE (EXISTING BOUNDARY)

YUMA COUNTY

COMPOSITE OF:

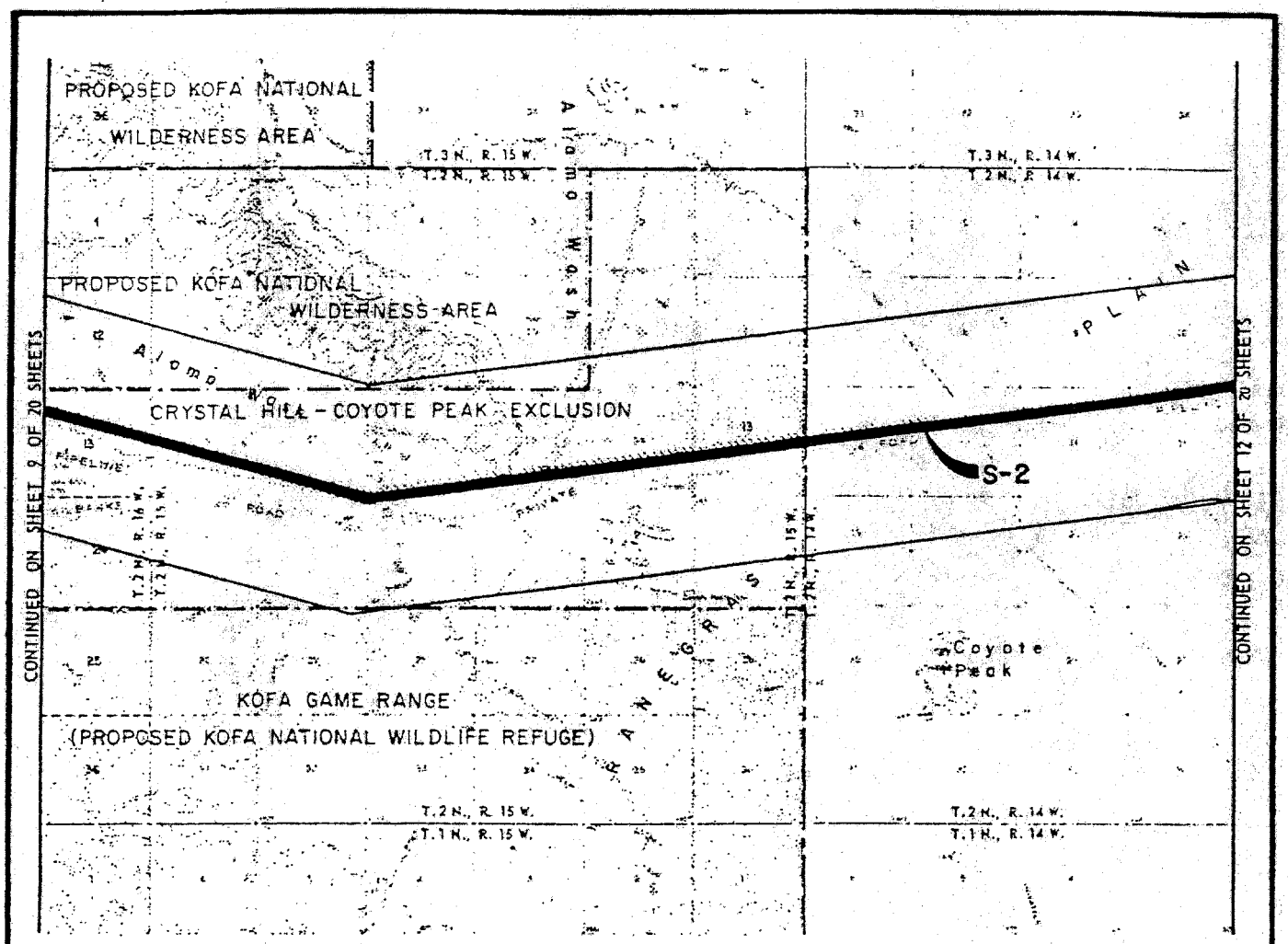
KOFA BUTTE, ARIZ., 1962. LIVINGSTON HILLS, ARIZ., 1962.
QUARTZSITE, ARIZ., 1962. VICKSBURG, ARIZ., 1962.
U.S.G.S. 15 MINUTE QUADRANGLES.

EXHIBIT "A-2"

FOR ARIZONA POWER PLANT and TRANSMISSION LINE SITING COMMITTEE FILING

DEVERS - PALO VERDE
500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM

SOUTHERN CALIFORNIA EDISON COMPANY



LEGEND

APPROVED ROUTE — CORRIDOR BOUNDARY

G. & S. R. M.

NEW PREFERRED ROUTE, DEVERS-PALO VERDE 500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM.

SUBALTERNATE ROUTES, DEVERS-PALO VERDE 500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM.

EXISTING LAND USE

KOFA GAME RANGE (EXISTING BOUNDARY)

YUMA COUNTY

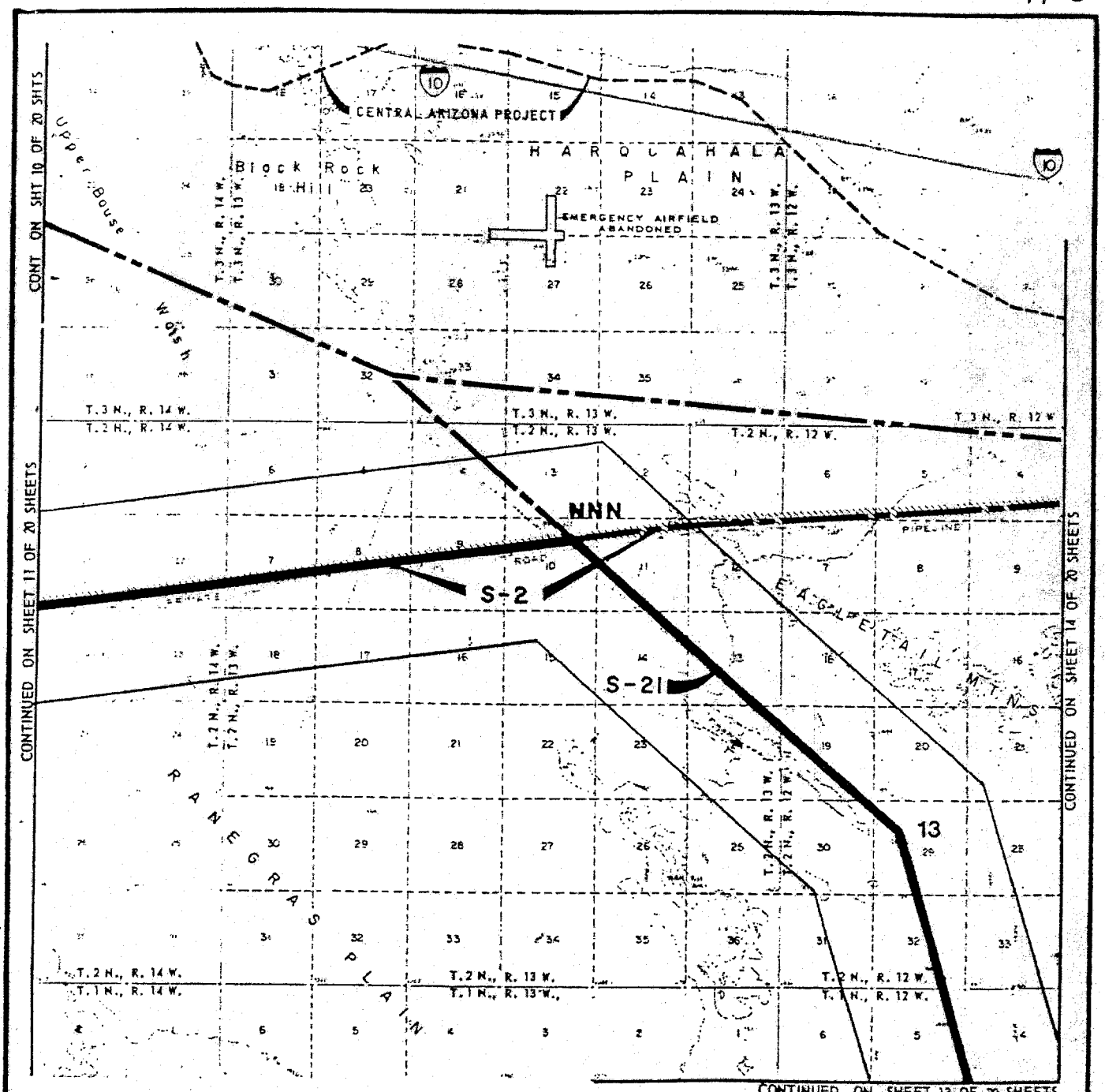
COMPOSITE OF:
HOPE, ARIZ., 1961, KOFA BUTTE, ARIZ., 1962,
LITTLE HORN MOUNTAINS, ARIZ., 1962, VICKSBURG, ARIZ., 1962.
U.S.G.S. 15 MINUTE QUADRANGLES.

EXHIBIT "A-2"

FOR ARIZONA POWER PLANT and TRANSMISSION LINE SITING COMMITTEE FILING

DEVERS - PALO VERDE
500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM

SOUTHERN CALIFORNIA EDISON COMPANY



LEGEND

NEW PREFERRED ROUTE, DEVERS-PALO VERDE 500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM.

ORIGINAL PREFERRED ROUTE, DEVERS-PALO VERDE 500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM.

SUBALTERNATE ROUTES, DEVERS-PALO VERDE 500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM.

APPROVED ROUTE

CORRIDOR BOUNDARY

EXISTING LAND USE

AIR STRIPS

YUMA COUNTY

COMPOSITE OF:
HOPE, ARIZ., 1961, LITTLE HORN MOUNTAINS, ARIZ., 1962.
LONE MOUNTAINS, ARIZ., 1961, EAGLETAIL MOUNTAINS, ARIZ., 1962.
U.S.G.S. 15 MINUTE QUADRANGLES.

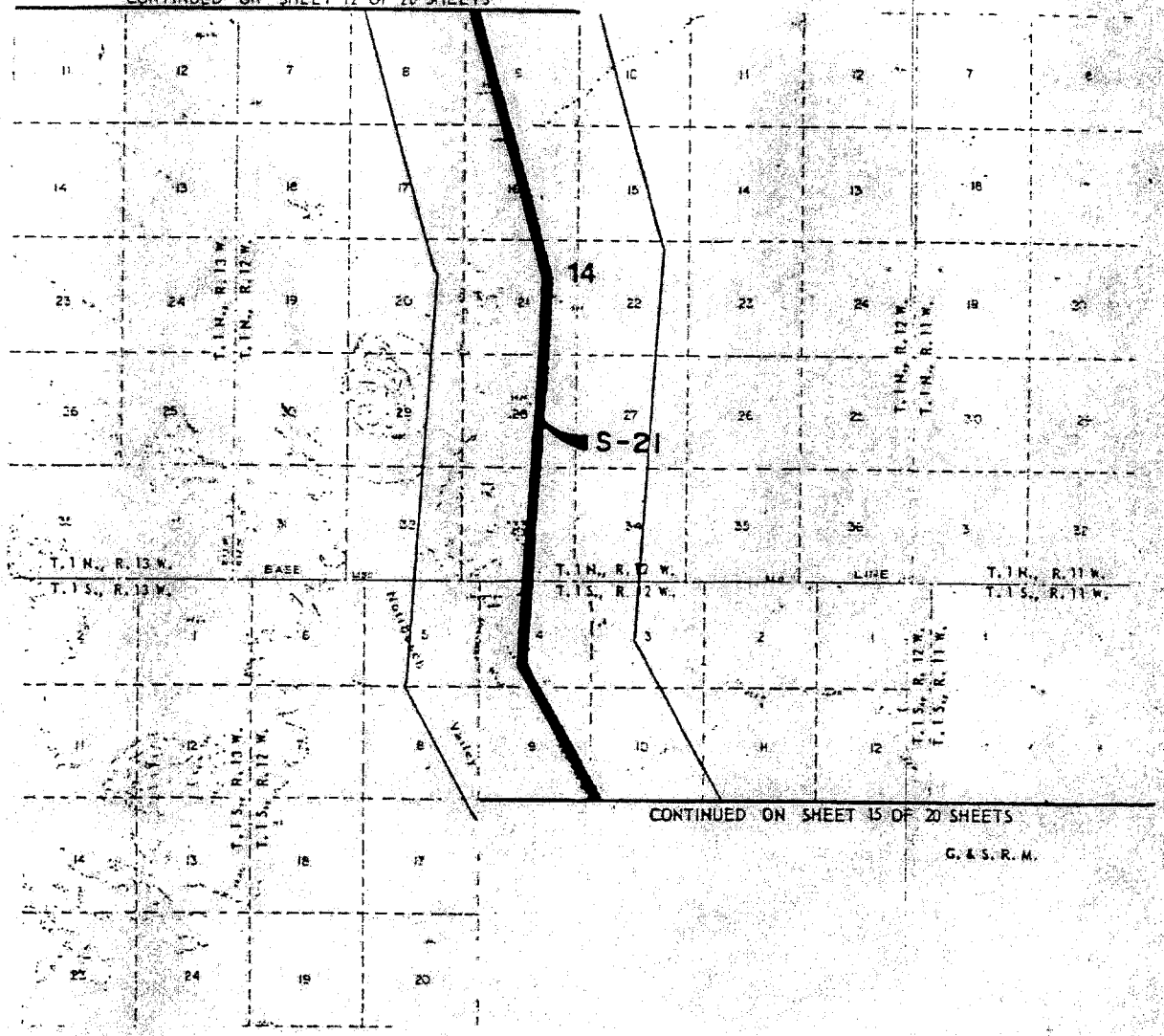
EXHIBIT "A-2"

FOR ARIZONA POWER PLANT and TRANSMISSION LINE SITING COMMITTEE FILING

DEVERS - PALO VERDE
500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM

SOUTHERN CALIFORNIA EDISON COMPANY

CONTINUED ON SHEET 12 OF 20 SHEETS



CONTINUED ON SHEET 15 OF 20 SHEETS

LEGEND

SUBALTERNATE ROUTE, DEVERS-PALO VERDE 500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM.

APPROVED ROUTE

CORRIDOR BOUNDARY

YUMA COUNTY

COMPOSITE OF:

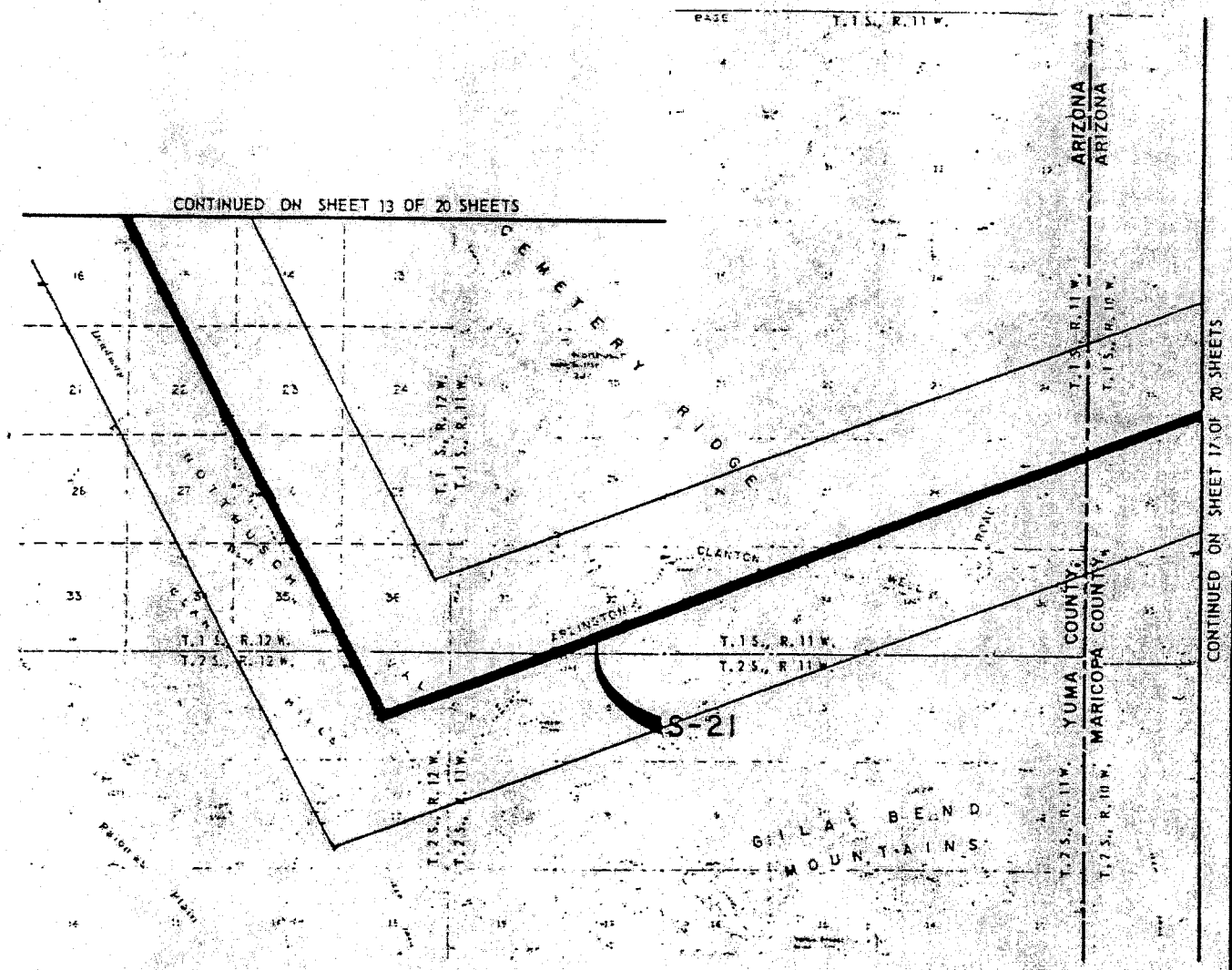
LITTLE HORN MOUNTAINS, ARIZ., 1962,
EAGLETAIL MOUNTAINS, ARIZ., 1962.
U.S.G.S. 15 MINUTE QUADRANGLES.

EXHIBIT "A-2"

FOR ARIZONA POWER PLANT and TRANSMISSION LINE SITING COMMITTEE FILING

DEVERS - PALO VERDE
500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM

SOUTHERN CALIFORNIA EDISON COMPANY



LEGEND

SUBALTERNATE ROUTE, DEVERS-PALO VERDE 500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM.

APPROVED ROUTE

CORRIDOR BOUNDARY

YUMA COUNTY
MARICOPA COUNTY

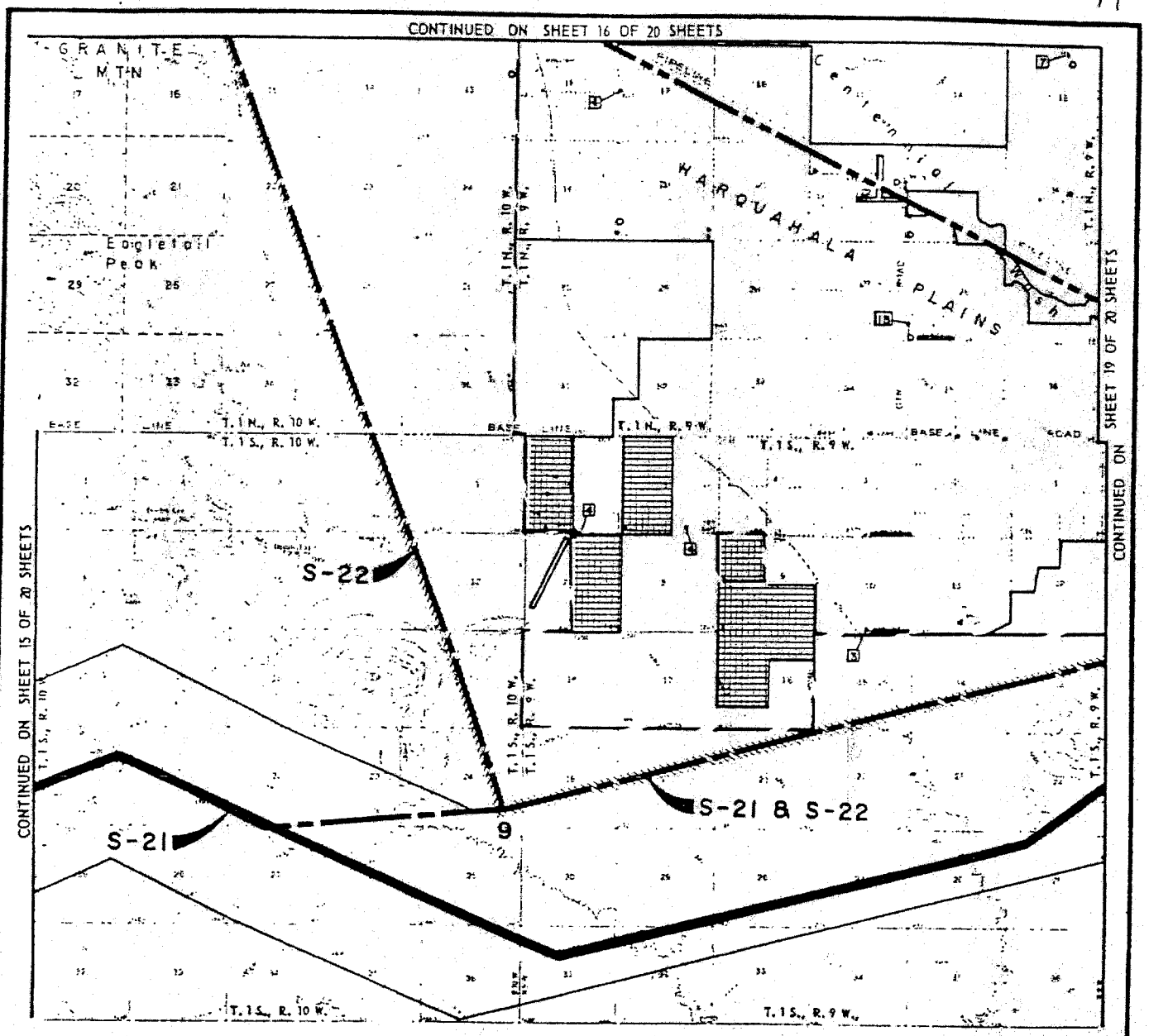
COMPOSITE OF:
LITTLE HORN MOUNTAINS, ARIZ., 1962.
EAGLETAIL MOUNTAINS, ARIZ., 1962.
U.S.G.S. 15 MINUTE QUADRANGLES.

EXHIBIT "A-2"

FOR ARIZONA POWER PLANT and TRANSMISSION LINE SITING COMMITTEE FILING

DEVERS - PALO VERDE
500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM

SOUTHERN CALIFORNIA EDISON COMPANY



LEGEND

APPROVED ROUTE — CORRIDOR BOUNDARY — G & S. R. M.

NEW PREFERRED ROUTE, DEVERS-PALO VERDE 500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM.

ORIGINAL PREFERRED ROUTE, DEVERS-PALO VERDE 500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM.

SUBALTERNATE ROUTES, DEVERS-PALO VERDE 500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM.

EXISTING LAND USE

AGRICULTURE (FEED LOTS, ORCHARDS, FIELDCROPS) — SUBDIVISION

FARM BUILDINGS — INDIVIDUAL DWELLING UNIT — NUMBER OF DWELLING UNITS

AIR STRIPS — INSTITUTIONAL

IRRIGATION DISTRICT

MARICOPA COUNTY

COMPOSITE OF:
EAGLETAIL MOUNTAINS, ARIZ. 1962, CORTEZ PEAK, ARIZ., 1962.
U.S.G.S. 15 MINUTE QUADRANGLE.

EXHIBIT "A-2"

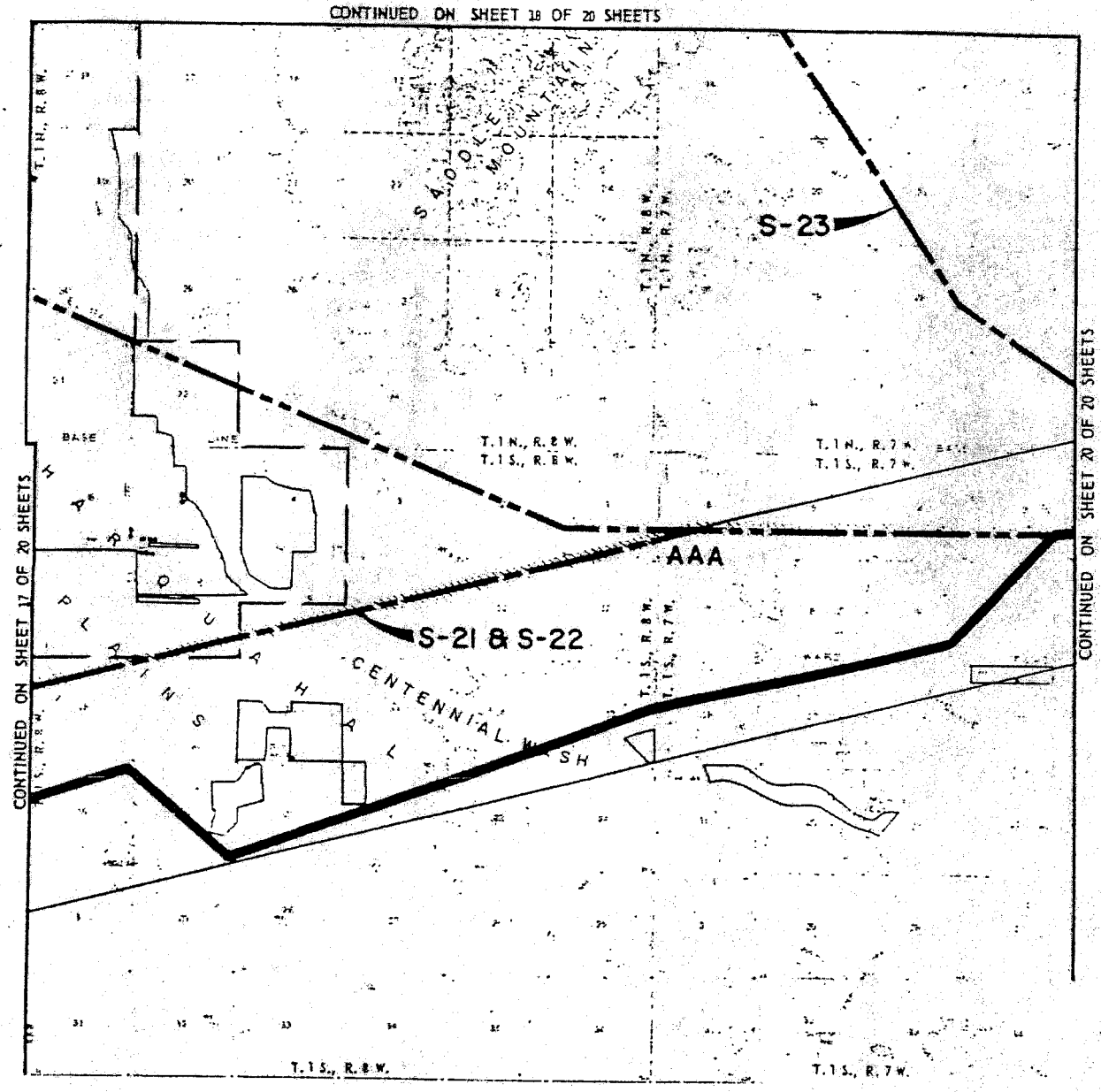
FOR ARIZONA POWER PLANT and TRANSMISSION LINE SITING COMMITTEE FILING

DEVERS - PALO VERDE
500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM

SOUTHERN CALIFORNIA EDISON COMPANY

A-10

CONTINUED ON SHEET 18 OF 20 SHEETS



APPROVED ROUTE LEGEND — CORRIDOR BOUNDARY G. & S. R. M.

NEW PREFERRED ROUTE, DEVERS-PALO VERDE 500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM.

ORIGINAL PREFERRED ROUTE, DEVERS-PALO VERDE 500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM.

SUBALTERNATE ROUTES, DEVERS-PALO VERDE 500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM.

EXISTING LAND USE

AIRSTRIPS — IRRIGATION DISTRICT • INDIVIDUAL DWELLING UNIT

AGRICULTURE (FEED LOTS, ORCHARDS, FIELDCROPS)

MARICOPA COUNTY

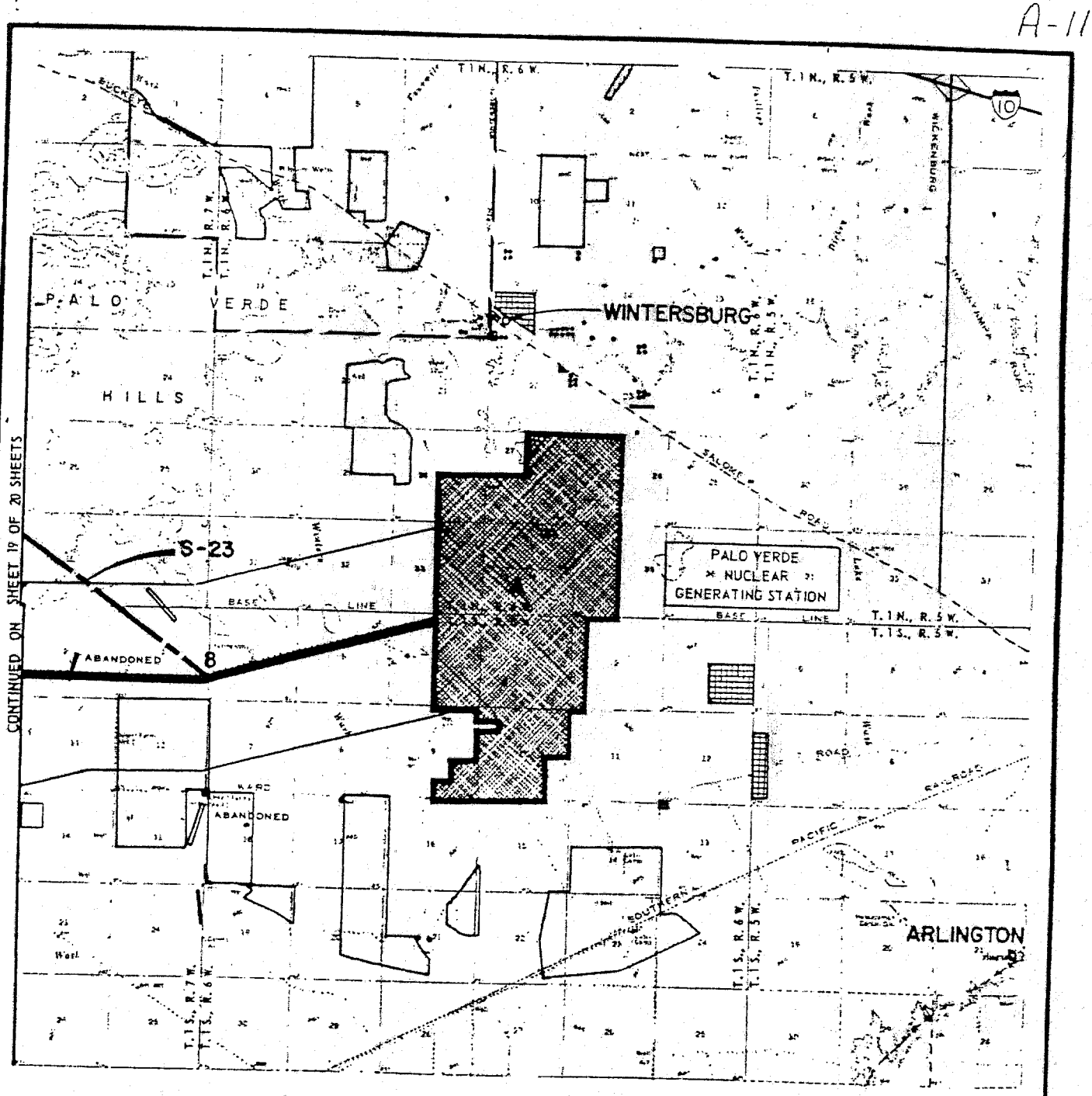
COMPOSITE OF:
ARLINGTON, ARIZ., 1962, CORTEZ PEAK, ARIZ., 1962
U.S.G.S. 15 MINUTE QUADRANGLE.

EXHIBIT "A-2"

FOR ARIZONA POWER PLANT and TRANSMISSION LINE SITING COMMITTEE FILING

DEVERS - PALO VERDE
500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM

SOUTHERN CALIFORNIA EDISON COMPANY



LEGEND

APPROVED ROUTE

CORRIDOR BOUNDARY

G. & S. R. M.

NEW PREFERRED ROUTE, DEVERS-PALO VERDE 500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM.

ORIGINAL PREFERRED ROUTE, DEVERS-PALO VERDE 500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM.

SUBALTERNATE ROUTES, DEVERS - PALO VERDE 500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM.

EXISTING LAND USE

AGRICULTURE (FEED LOTS, ORCHARDS, FIELDCROPS)

AIR STRIPS

INSTITUTIONAL

INDIVIDUAL DWELLING UNIT

SUBDIVISION

IRRIGATION DISTRICT

COMMERCIAL

MARICOPA COUNTY

COMPOSITE OF:

ARLINGTON, ARIZ., 1962.

U.S.G.S. 15 MINUTE QUADRANGLE.

EXHIBIT "A-2"

FOR ARIZONA POWER PLANT and TRANSMISSION LINE SITING COMMITTEE FILING

DEVERS - PALO VERDE

500kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM

SOUTHERN CALIFORNIA EDISON COMPANY

EXHIBIT
S-15
admin notice

BEFORE THE ARIZONA POWER PLANT
AND TRANSMISSION LINE SITING COMMITTEE

In the Matter of the Application of Southern California Edison Company, in conformance with the requirements of Arizona Revised Statutes Section 40-360, et seq., for a Certificate of Environmental Compatibility for two segments of the Arizona Portion of one 500 kV transmission line between the Palo Verde Nuclear Generating Station (under construction) near Wintersburg, Arizona, and the Devers Substation (existing) near Palm Springs, California.	CASE NO. 48 DECISION NO. 51170

CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY

Pursuant to notice given as provided by law, the Arizona Power Plant and Transmission Line Siting Committee ("Committee") held a public hearing at Hearing Rooms Nos. 1 and 2, Arizona Corporation Commission, 2222 W. Encanto Boulevard, Phoenix, Arizona, on May 9, 1980 regarding the Application of Southern California Edison Company (the "Applicant"), in conformance with the requirements of Arizona Revised Statutes §40-360, et seq., for a Certificate of Environmental Compatibility authorizing two segments of the Arizona portion of one 500 kV transmission line between the Palo Verde Nuclear Generating Station near Wintersburg, Arizona, and the Devers Substation near Palm Springs, California.

The following members of the Committee, constituting a majority thereof, were present at the hearing held May 9, 1980 and participated in the vote at the conclusion thereof in the manner hereinafter set forth:

Thomas P. Prose, designee for Robert K. Corbin
Tom Sullivan, designee for Joe Fallini
John Carr, designee for Robert Jantzen
James Ayers, designee for Michael Ramnes
Dennis Sundie, designee for Wesley E. Steiner
Dean Moss, designee for Robert Sternberger
Terry Murray, designee for Larry Landry
Dave Naugle, designee for Jim Weeks
Carl Billings, designee for Bruce Scott
Richard Counts
Clyde S. Roberts
Russ Winkelman
Paul R. Fish

The following members of the Committee did not attend the hearing and did not participate in the vote at the conclusion thereof:

Kenneth R. Geiser
Arlo B. Lee
Arthur N. Lee
Wayne Moody
Orme Lewis, Jr.

The Applicant was represented by attorneys Arthur C. Gehr and Charles A. Bischoff of Snell & Wilmer and H. D. Belknap, Jr., Senior Counsel of the Applicant.

Ms. Doris M. Heisler had filed a petition and notice of intent to be a party on behalf of the Tonopah Valley Association. The Chairman of the Committee denied the petition to intervene of the Tonopah Valley Association, but did permit Ms. Heisler to intervene on behalf of herself.

At the invitation of the Committee, Mr. Clair N. Whitlock, State Director of the Bureau of Land Management,

made an appearance before the Committee, but neither the Bureau of Land Management nor Mr. Whitlock was made a party to the proceeding.

Several persons and organizations made limited appearances and submitted written statements with respect to the Application. These statements were incorporated in the record pursuant to Arizona Revised Statutes §40-360.05(B).

Evidence in support of the Application was submitted by Applicant's witnesses who were cross-examined by members of the Committee.

A statement respecting the Bureau of Land Management's review of and decision on Southern California Edison Company's application for rights-of way for the proposed transmission line was made by Mr. Whitlock, who was cross-examined by members of the Committee.

Evidence in opposition to certain portions of the Application was submitted by Ms. Heisler who was cross-examined by members of the Committee and the Applicant.

At the conclusion of the May 9, 1980 hearing, the Committee, upon motion duly made and seconded and approved by a majority vote of the members present, with Thomas Prose not voting, which vote constituted a majority of the members of the entire Committee, granted Applicant the following Certificate of Environmental Compatibility:

> Applicant Southern California Edison Company is hereby granted a Certificate of Environmental Compatibility

for the construction of two segments of the Arizona portion of one 500 kV transmission line from the Palo Verde Nuclear Generating Station near Wintersburg, Arizona, to the Applicant's Devers Substation, near Palm Springs, California, as shown on the maps attached hereto as Exhibit A (sheets 1 of 11 through 11 of 11), and generally described as follows:

Segment S-5

Segment S-5 starts at Point KK (as shown on Exhibit A-1) at the summit of Copper Bottom Pass in the Dome Rock Mountains and proceeds northwest for four miles parallel to the El Paso Natural Gas Company ("EPNG") pipeline right-of-way to the west side of the Dome Rock Mountains. At this point the segment turns to the southwest and proceeds the remaining seven miles to Point YYY (as shown on Exhibit A-1), where it rejoins the Committee approved alternate route in Case No. 34.

Segment S-23

Segment S-23 starts at Point 8 (as shown on Exhibit A-1) located approximately three miles west of the Palo Verde Nuclear Generating Station south of the Palo Verde Hills. The segment proceeds to the northwest approximately ten miles to the intersection of the Buckeye-Salome Road and Courthouse Road. The segment passes approximately midway between Saddle Mountain and the Palo Verde Hills. At the intersection, the segment turns more to the north and proceeds approximately six miles to a major angle point east of Burnt Mountain.

At Burnt Mountain, the route turns sharply to the west and proceeds approximately two miles through a small pass between Burnt Mountain and The Big Horn Mountains. After

traversing the pass, the segment proceeds approximately seventeen miles to the west generally parallel and south of the Central Arizona Project Aquiduct System to a major angle point located approximately one mile north of Interstate-10 and approximately 4.5 miles southeast of Lone Mountain.

At this angle point, the segment turns sharply to the southwest and proceeds approximately five miles to Point C (as shown on Exhibit A-1) located just north of the EPNG pipeline pump station. From the pump station the segment turns west, and parallels north of the EPNG pipeline right-of-way the remaining eight miles to Point NNN (as shown on Exhibit A-1) where it joins the Committee approved route in Case No. 34.

The two segments of the 500 kV line are to be located within a two mile corridor, the center of which shall be the line designated on the maps comprising Exhibit A as the Committee approved route in Case No. 48. In the event of any discrepancy between the general description above and the specific routing shown on Exhibit A, Exhibit A shall control.

This Certificate of Environmental Compatibility is granted subject to the following conditions:

1. The Applicant shall comply with all applicable nuclear radiation standards, air and water pollution control standards and regulations, and with all applicable ordinances, master plans and regulations of the State of Arizona, and the Counties of Maricopa and Yuma.

2. The Applicant shall cooperate with the Arizona State Game and Fish Department in an attempt to restrict public access to all new roads of the Applicant

necessary for the construction, operation and maintenance of the 500 kV line through the Dome Rock Mountains.

GRANTED THIS 16 DAY OF June, 1980.

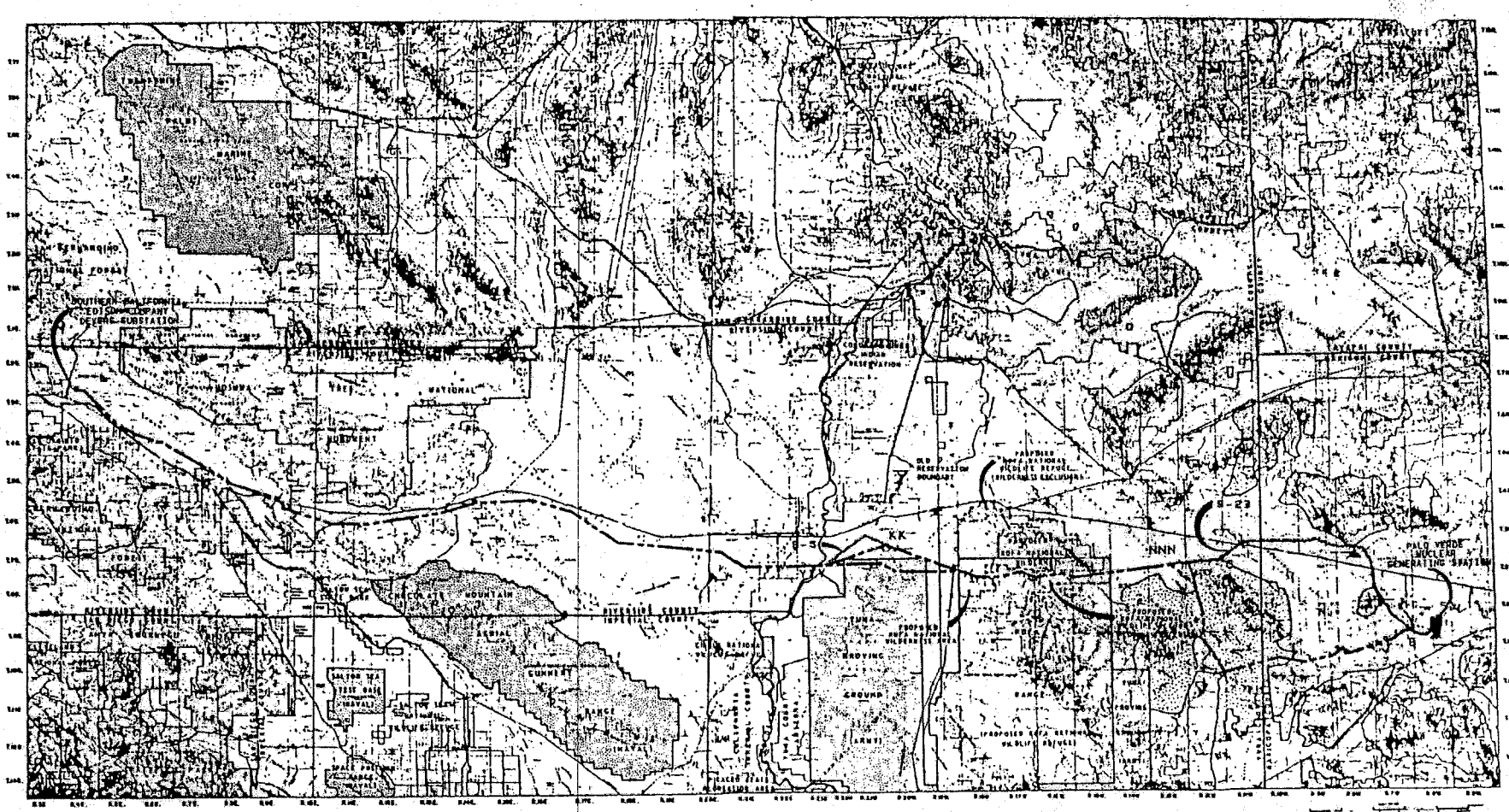
POWER PLANT AND TRANSMISSION LINE SITING COMMITTEE

Thomas P. Prose, Chairman

Chairman Commissioner Commissioner

IN WITNESS WHEREOF, I, G. C. ANDERSON, JR., Executive Secretary of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of this Commission to be affixed, at the Capitol in the City of Phoenix, this 23rd day of July, 1980.

G. C. ANDERSON, JR.
Executive Secretary



LEGEND

COMMITTEE APPROVED ROUTE (CASE NUMBER 48)

COMMITTEE APPROVED ROUTE (CASE NUMBER 34)

COMMITTEE APPROVED ALTERNATE ROUTE (CASE NUMBER 34)

INDIAN RESERVATION

WILDERNESS STUDY AREA

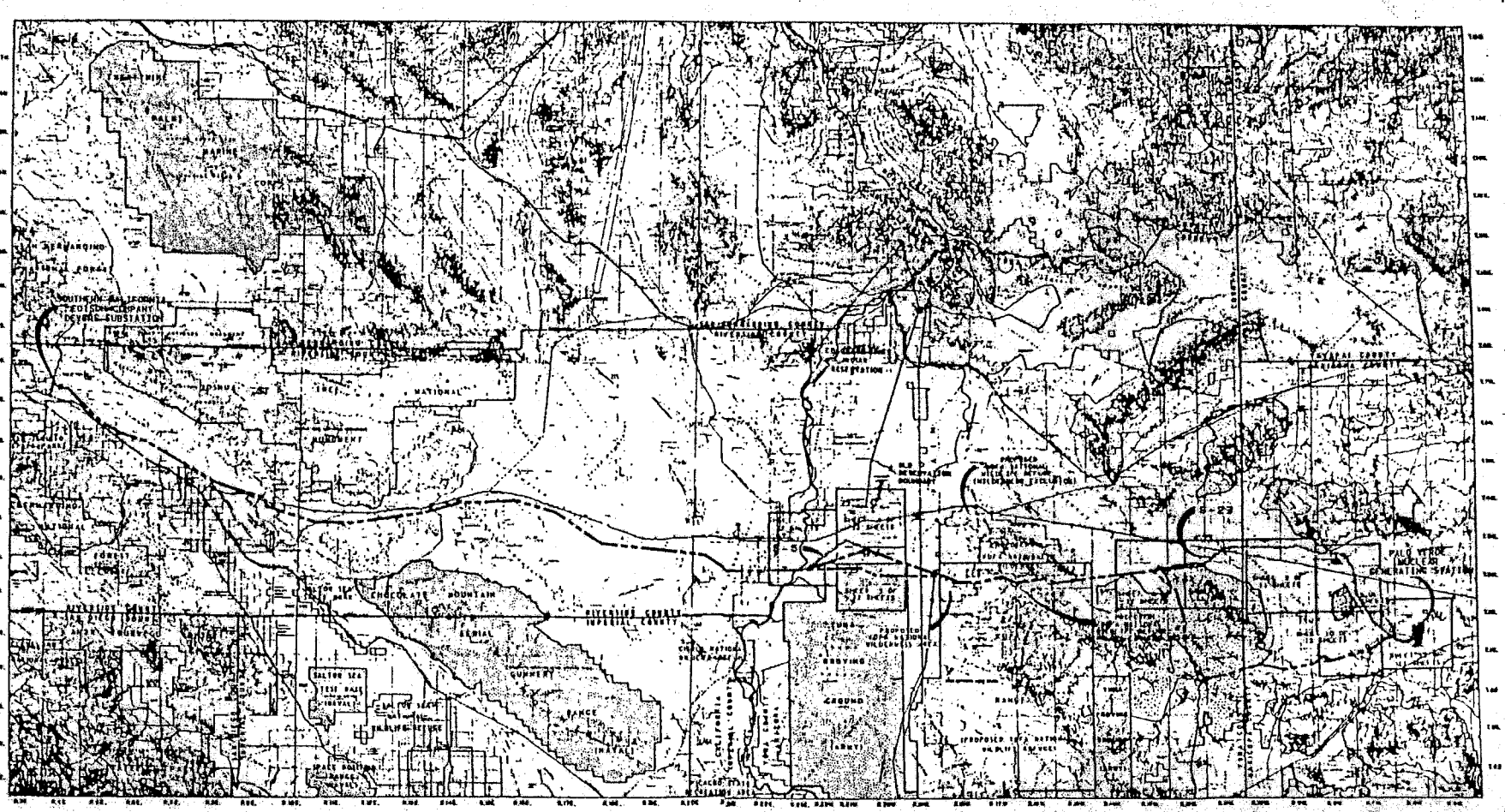
EXHIBIT "A-1"
LOCATION MAP

FOR ARIZONA PUBLIC SERVICE COMPANY'S TRANSMISSION LINE
SITING COMMITTEE FILING

DEVERS-PALO VERDE
500 kV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM

SOUTHERN CALIFORNIA EDISON COMPANY

SHEET 1 OF 11 SHEETS



LEGEND

COMMITTEE APPROVED ROUTE (CASE NUMBER 48)

COMMITTEE APPROVED ROUTE (CASE NUMBER 34)

COMMITTEE APPROVED ALTERNATE ROUTE (CASE NUMBER 34)

INDIAN RESERVATION

WILDERNESS STUDY AREA

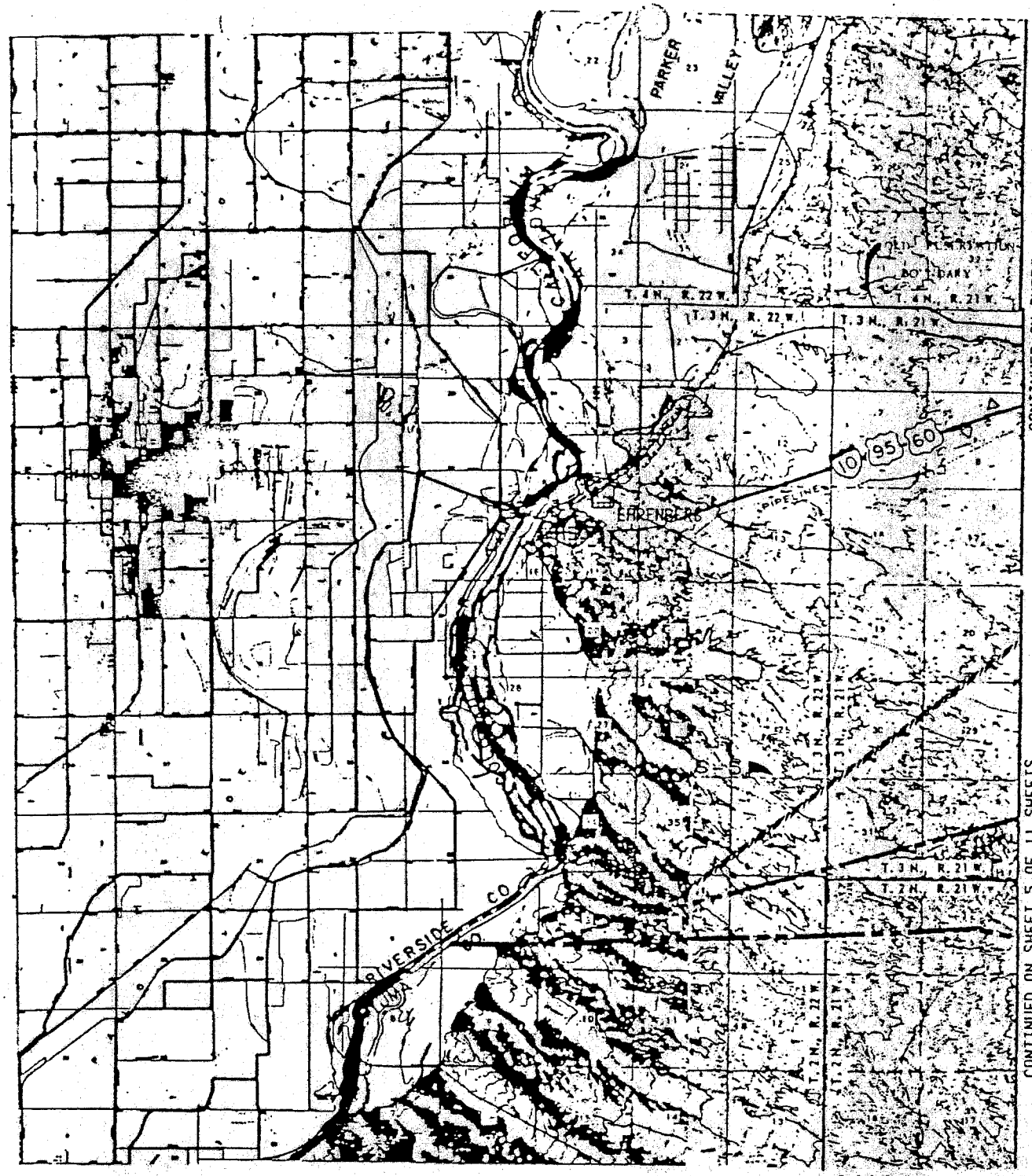
EXHIBIT "A-2"
INDEX MAP

FOR ARIZONA POWER PLANT & TRANSMISSION LINE SITING COMMITTEE FILING

DEVERS-PALO VERDE
500 KV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM

SOUTHERN CALIFORNIA EDISON COMPANY

SHEET 2 OF 11 SHEETS



LEGEND

COMMITTEE APPROVED ROUTE (CASE NUMBER 48)

COMMITTEE APPROVED ROUTE (CASE NUMBER 34)

COMMITTEE APPROVED ALTERNATE ROUTE (CASE NUMBER 34)

EXISTING LAND USE

COLORADO RIVER INDIAN RESERVATION

YUMA PROVING GROUND (U.S. ARMY)

RURAL

AGRICULTURE

REST AREA

SUBDIVISION

YUMA COUNTY

COMPOSITE OF:

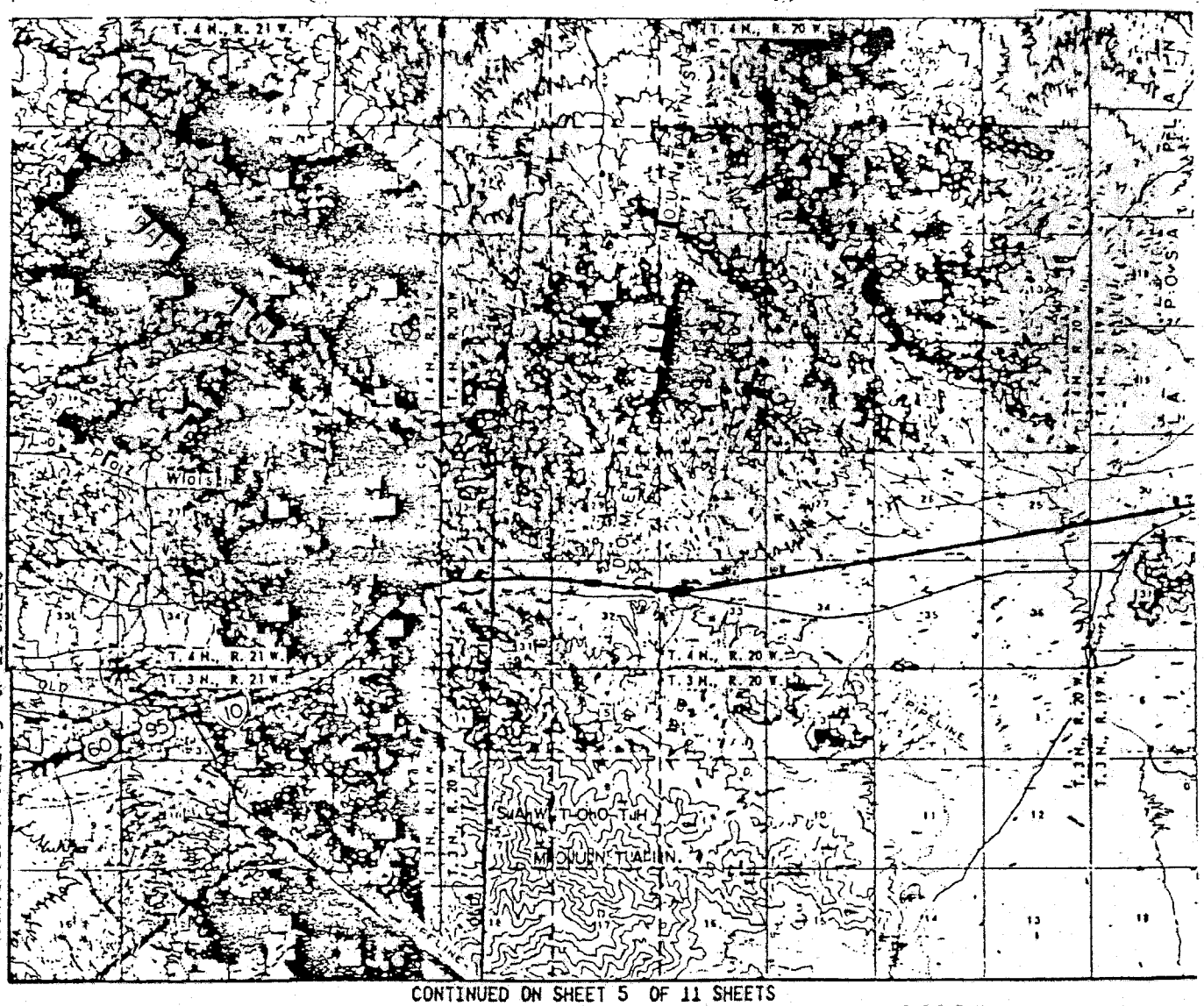
BLYTHE NE, CALIF. – ARIZ., 1970, LA PAZ MTN., ARIZ. – CALIF., 1970,
BLYTHE, CALIF. – ARIZ., 1970, DOME ROCK MTS. SW. ARIZ., 1971.
U.S.G.S. 7.5 MINUTE QUADRANGLES.

EXHIBIT "A-2"

FOR ARIZONA POWER PLANT & TRANSMISSION LINE SITING COMMITTEE FILING

DEVERS-PALO VERDE
500 KV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM

SOUTHERN CALIFORNIA EDISON COMPANY



LEGEND

COMMITTEE APPROVED ROUTE (CASE NUMBER 48)

EXISTING LAND USE

COLORADO INDIAN RESERVATION

YUMA COUNTY

COMPOSITE OF:

LA PAZ MTN., ARIZ. - CALIF., 1970, MIDDLE CAMP MTN., ARIZ., 1971,
DOME ROCK MTS. SW. ARIZ., 1971, CUNNINGHAM MTN., ARIZ., 1971.
U.S.G.S. 7.5 MINUTE QUADRANGLES.

EXHIBIT "A-2"

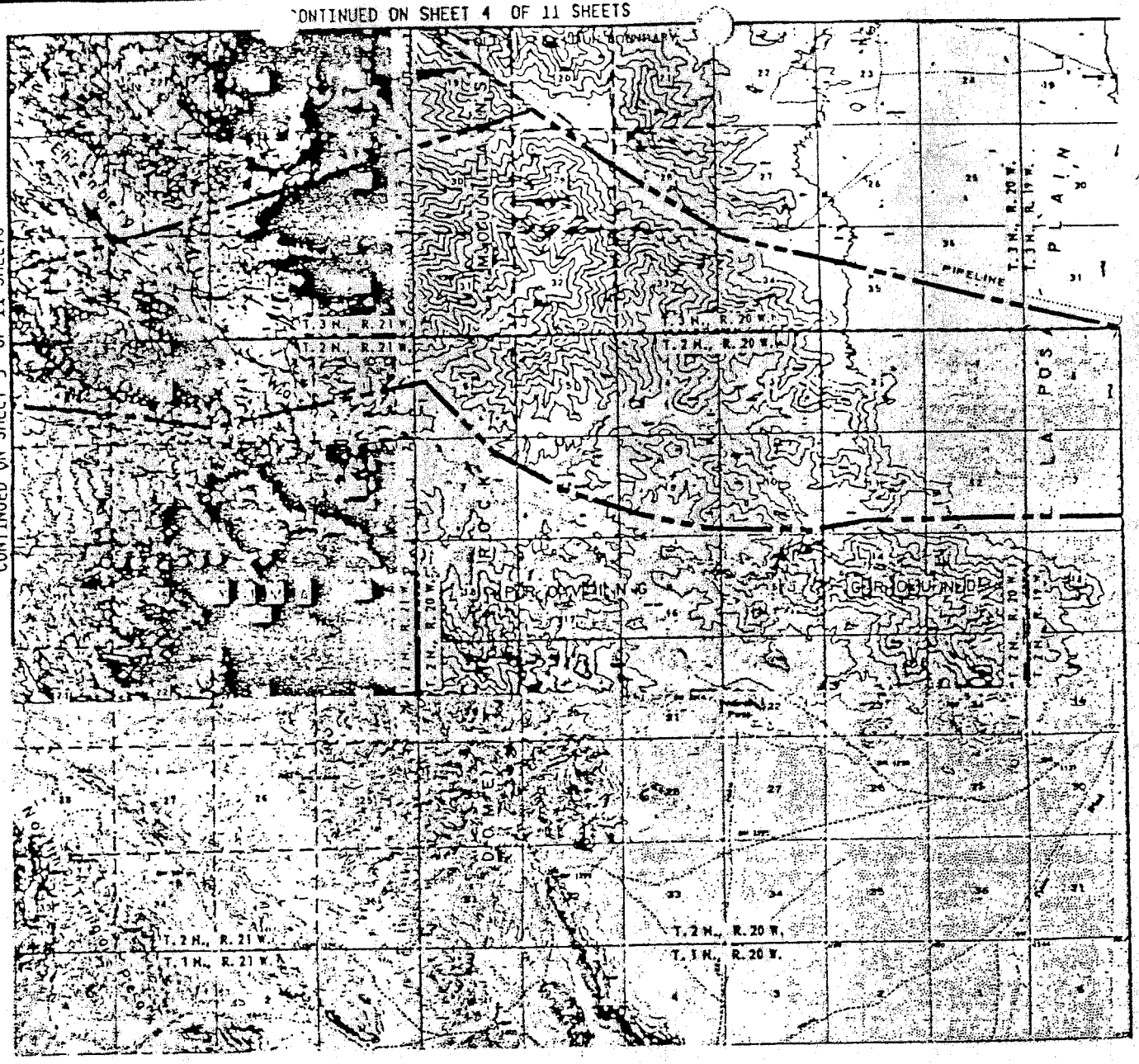
FOR ARIZONA POWER PLANT & TRANSMISSION LINE SITING COMMITTEE FILING

DEVERS-PALO VERDE
500 KV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM

SOUTHERN CALIFORNIA EDISON COMPANY

CONTINUED ON SHEET 4 OF 11 SHEETS

CONTINUED ON SHEET 3 OF 11 SHEETS



LEGEND

COMMITTEE APPROVED ROUTE (CASE NUMBER 48)

COMMITTEE APPROVED ROUTE (CASE NUMBER 34)

COMMITTEE APPROVED ALTERNATE ROUTE (CASE NUMBER 34)

EXISTING LAND USE

YUMA PROVING GROUND (U.S. ARMY)

YUMA COUNTY

COMPOSITE OF:

DOME ROCK MTS. SW. ARIZ., 1971. CUNNINGHAM MTN., ARIZ., 1971.
U.S.G.S. 7.5 MINUTE QUADRANGLES.

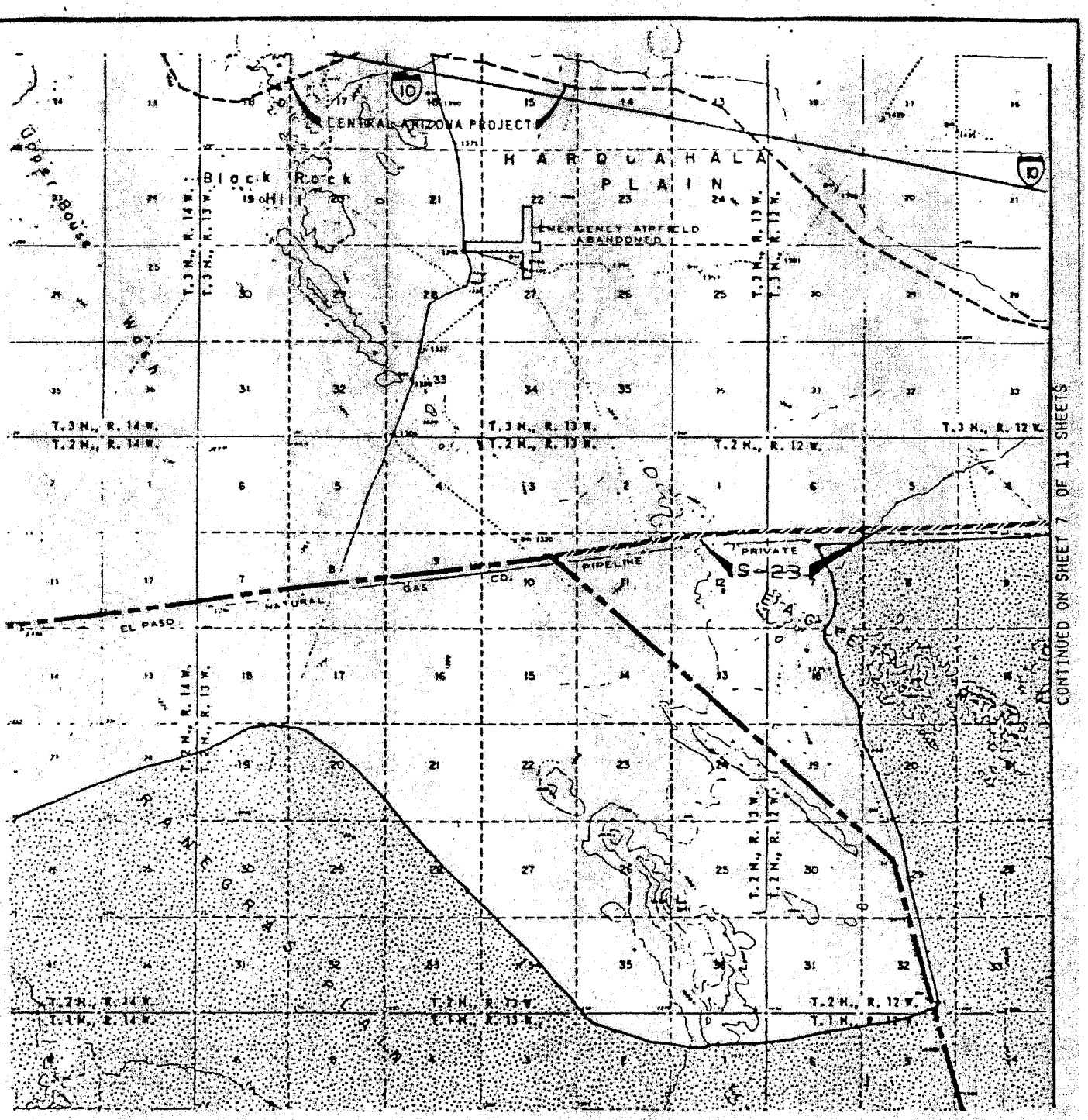
TRIGO PEAKS, ARIZ., 1954.
U.S.G.S. 15 MINUTE QUADRANGLE.

EXHIBIT "A-2"

FOR ARIZONA POWER PLANT & TRANSMISSION LINE SITING COMMITTEE FILING

DEVERS-PALO VERDE
500 KV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM

SOUTHERN CALIFORNIA EDISON COMPANY



G. & S. R. M.

LEGEND

COMMITTEE APPROVED ROUTE (CASE NUMBER 48)

COMMITTEE APPROVED ROUTE (CASE NUMBER 34)

EXISTING LAND USE

AIRSTRIPS

WILDERNESS STUDY AREA

YUMA COUNTY

COMPOSITE OF:
HOPE, ARIZ., 1961. LITTLE HORN MOUNTAINS, ARIZ., 1962.
LONE MOUNTAINS, ARIZ., 1961. EAGLETAIL MOUNTAINS, ARIZ., 1962.
U.S.G.S. 15 MINUTE QUADRANGLES.

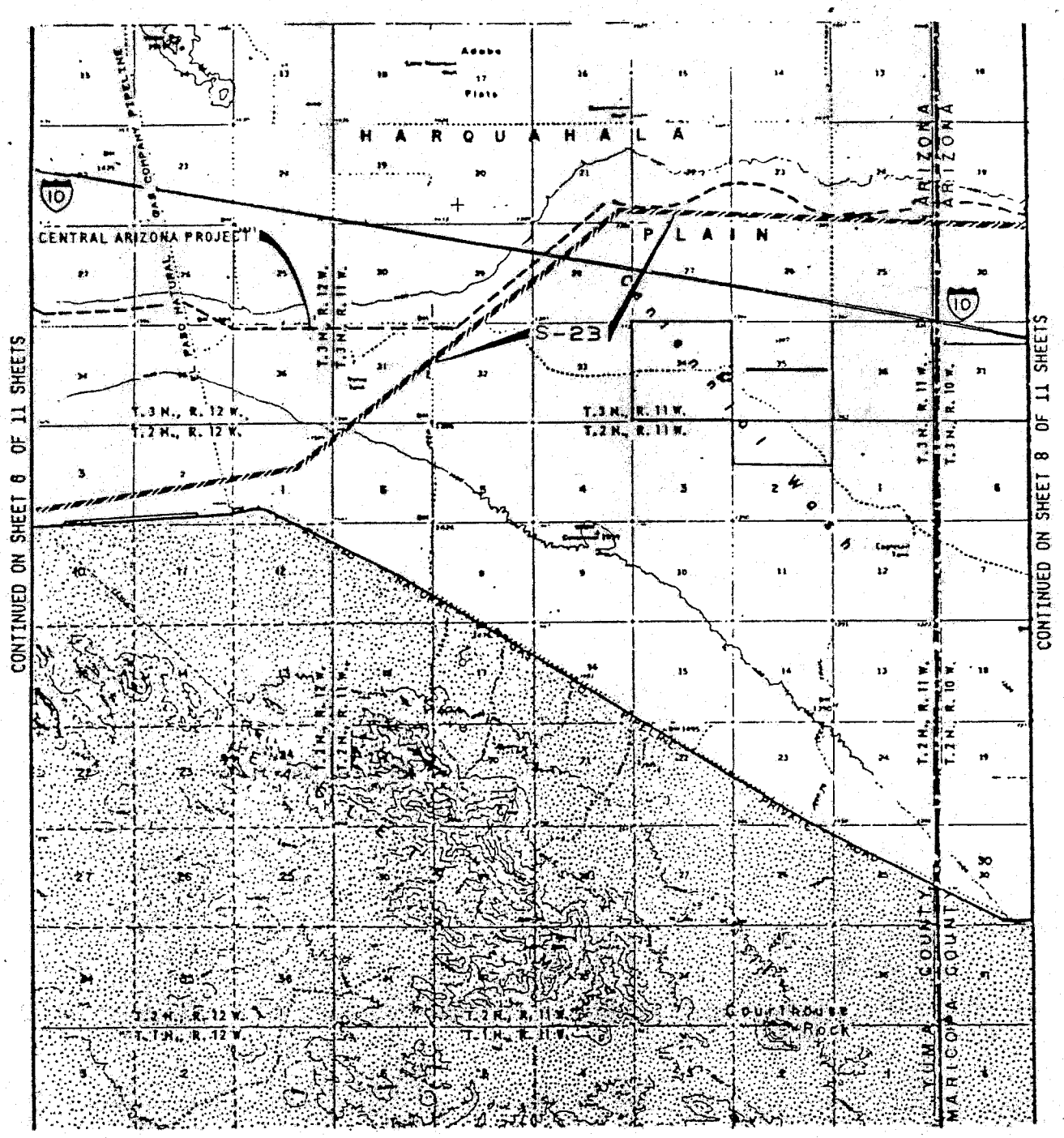
EXHIBIT "A-2"

FOR ARIZONA POWER PLANT & TRANSMISSION LINE SITING COMMITTEE FILING

DEVERS-PALO VERDE
500 KV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM

SOUTHERN CALIFORNIA EDISON COMPANY

SHEET 6 OF 11 SHEE



G. & S. R. M.

LEGEND

COMMITTEE APPROVED ROUTE (CASE NUMBER 48)

EXISTING LAND USE

AIRSTRIPS · INSTITUTIONAL · AGRICULTURE (FEED LOTS, ORCHARDS, FIELDCROPS)

• INDIVIDUAL DWELLING UNIT

WILDERNESS STUDY AREA

YUMA COUNTY
MARICOPA COUNTY

COMPOSITE OF:
LONE MOUNTAIN, ARIZ., 1961, EAGLETAIL MOUNTAINS, ARIZ., 1962.
U.S.G.S. 15 MINUTE QUADRANGLES.

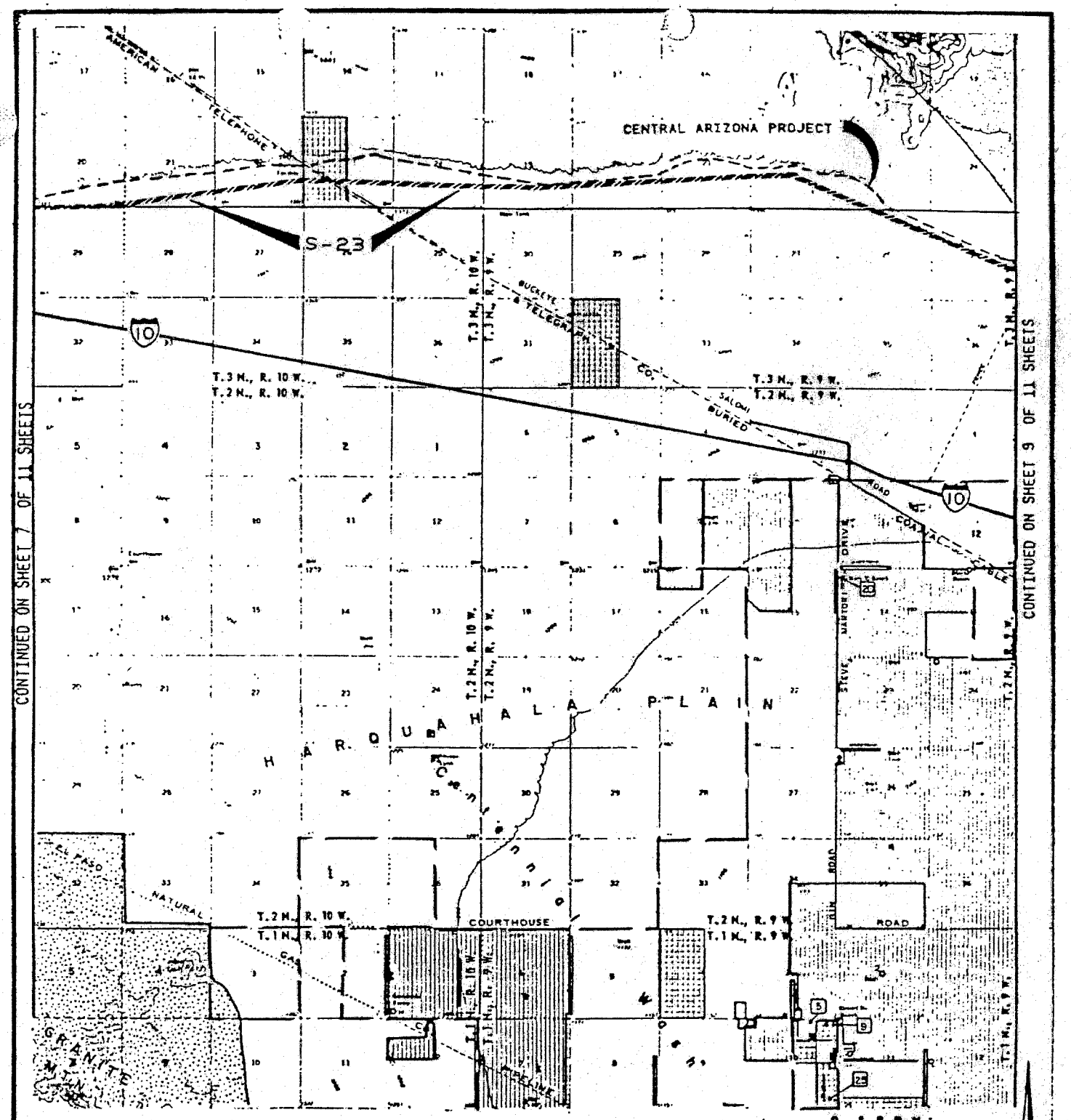
EXHIBIT "A-2"

FOR ARIZONA POWER PLANT & TRANSMISSION LINE SITING COMMITTEE FILING

DEVERS-PALO VERDE
500 KV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM

SOUTHERN CALIFORNIA EDISON COMPANY

SHEET 7 OF 11 SHEE



LEGEND

COMMITTEE APPROVED ROUTE (CASE NUMBER 48)

EXISTING LAND USE

COMMERCIAL — SUBDIVISION — INSTITUTIONAL — WILDERNESS STUDY AREA

AGRICULTURE (FEED LOTS, ORCHARDS, FIELDCROPS) — IRRIGATION DISTRICT

FARM BUILDINGS — INDIVIDUAL DWELLING UNIT — NUMBER OF DWELLING UNITS

AIRSTRIPS

MARICOPA COUNTY

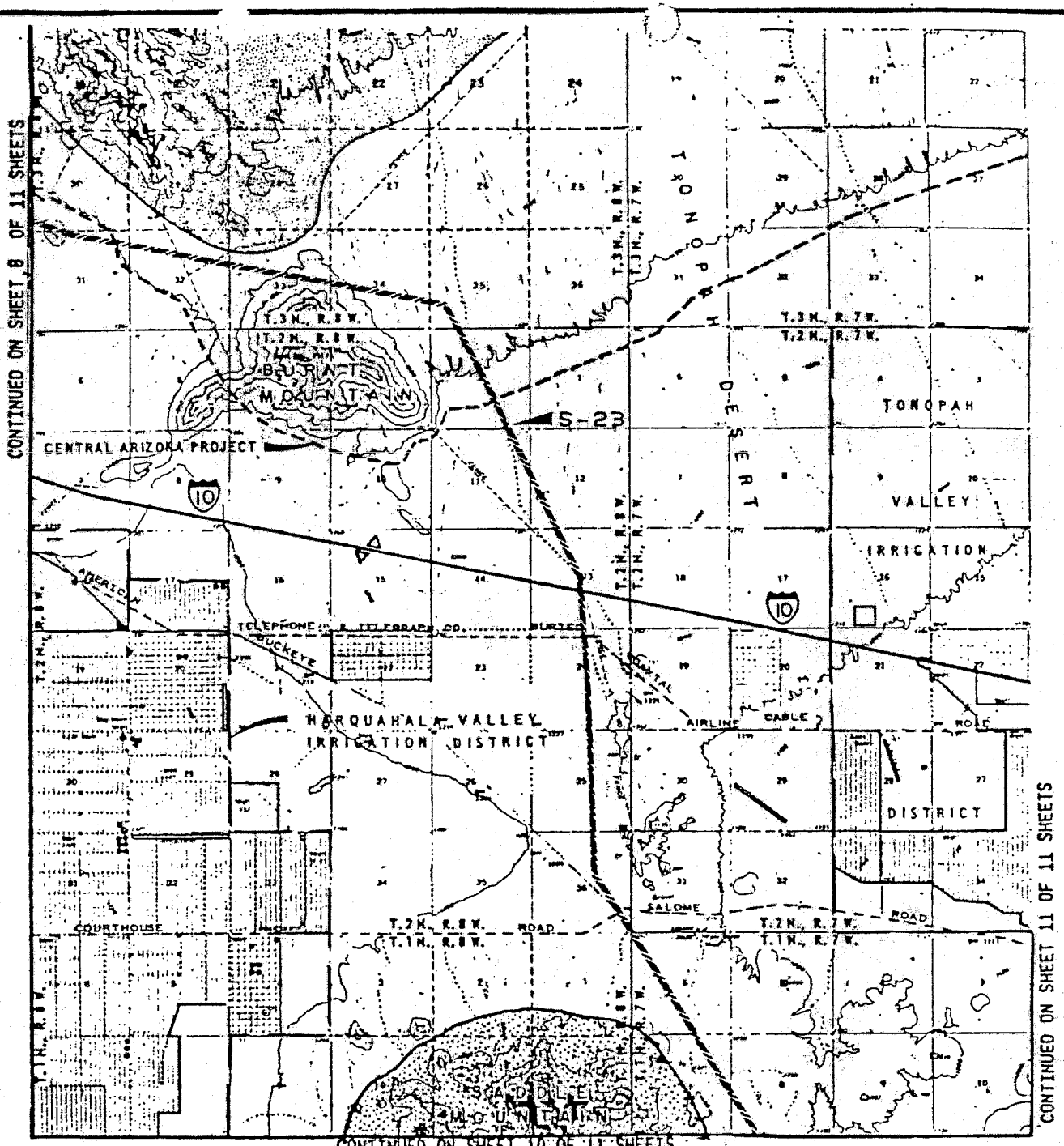
COMPOSITE OF:
BIG HORN MOUNTAINS, ARIZONA, 1961, CORTEZ PEAK, ARIZONA, 1962,
EAGLETAIL MOUNTAINS, ARIZONA, 1962, LONE MOUNTAIN, ARIZONA, 1961,
U.S.G.S. 15 MINUTE QUADRANGLE.

EXHIBIT "A-2"

FOR ARIZONA POWER PLANT & TRANSMISSION LINE SITING COMMITTEE FILING

DEVERS-PALO VERDE
500 KV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM

SOUTHERN CALIFORNIA EDISON COMPANY



LEGEND

COMMITTEE APPROVED ROUTE (CASE NUMBER 48)

EXISTING LAND USE

- AGRICULTURE (FEED LOTS, ORCHARDS, FIELDCROPS)
- AIRSTRIPS
- INDIVIDUAL DWELLING UNIT
- FARM BUILDINGS
- REST AREA
- COMMERCIAL
- SUBDIVISION
- WILDERNESS STUDY AREA

MARICOPA COUNTY

COMPOSITE OF:
BIG HORN MOUNTAINS, ARIZ., 1961, CORTEZ PEAK, ARIZ., 1962,
BELMONT MOUNTAINS, ARIZ., 1962, ARLINGTON, ARIZ., 1962.
U.S.G.S. 15 MINUTE QUADRANGLES.

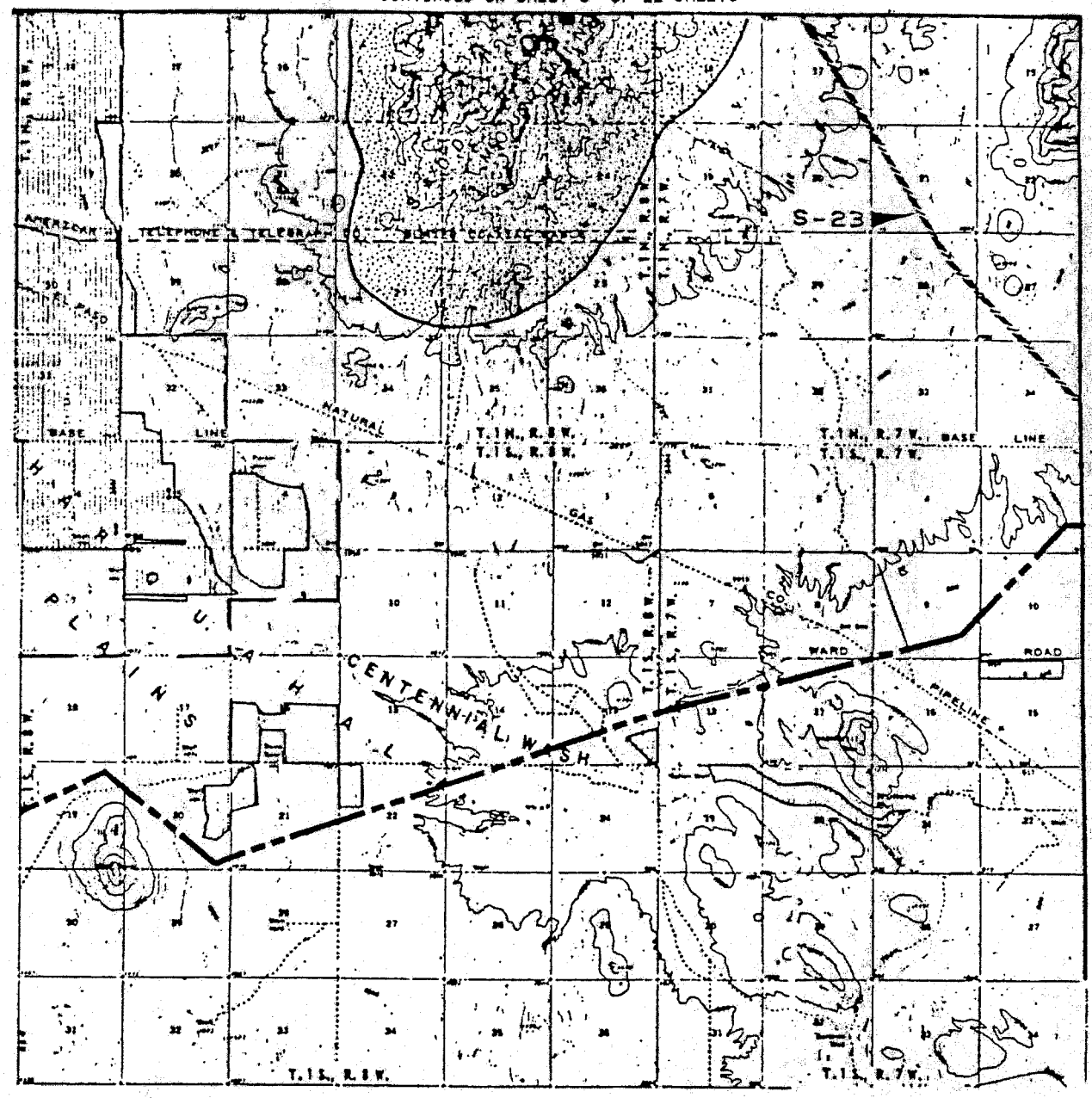
EXHIBIT "A-2"

FOR ARIZONA POWER PLANT & TRANSMISSION LINE SITING COMMITTEE FILING

DEVERS-PALO VERDE
500 KV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM

SOUTHERN CALIFORNIA EDISON COMPANY

CONTINUED ON SHEET 9 OF 11 SHEETS



CONTINUED ON SHEET 11 OF 11 SHEETS

G. & S. R. M.

LEGEND

COMMITTEE APPROVED ROUTE (CASE NUMBER 48)

COMMITTEE APPROVED ROUTE (CASE NUMBER 34)

EXISTING LAND USE

AIRSTRIPS — IRRIGATION DISTRICT • INDIVIDUAL DWELLING UNIT

AGRICULTURE (FEED LOTS, ORCHARDS, FIELDCROPS)

WILDERNESS STUDY AREA

MARICOPA COUNTY

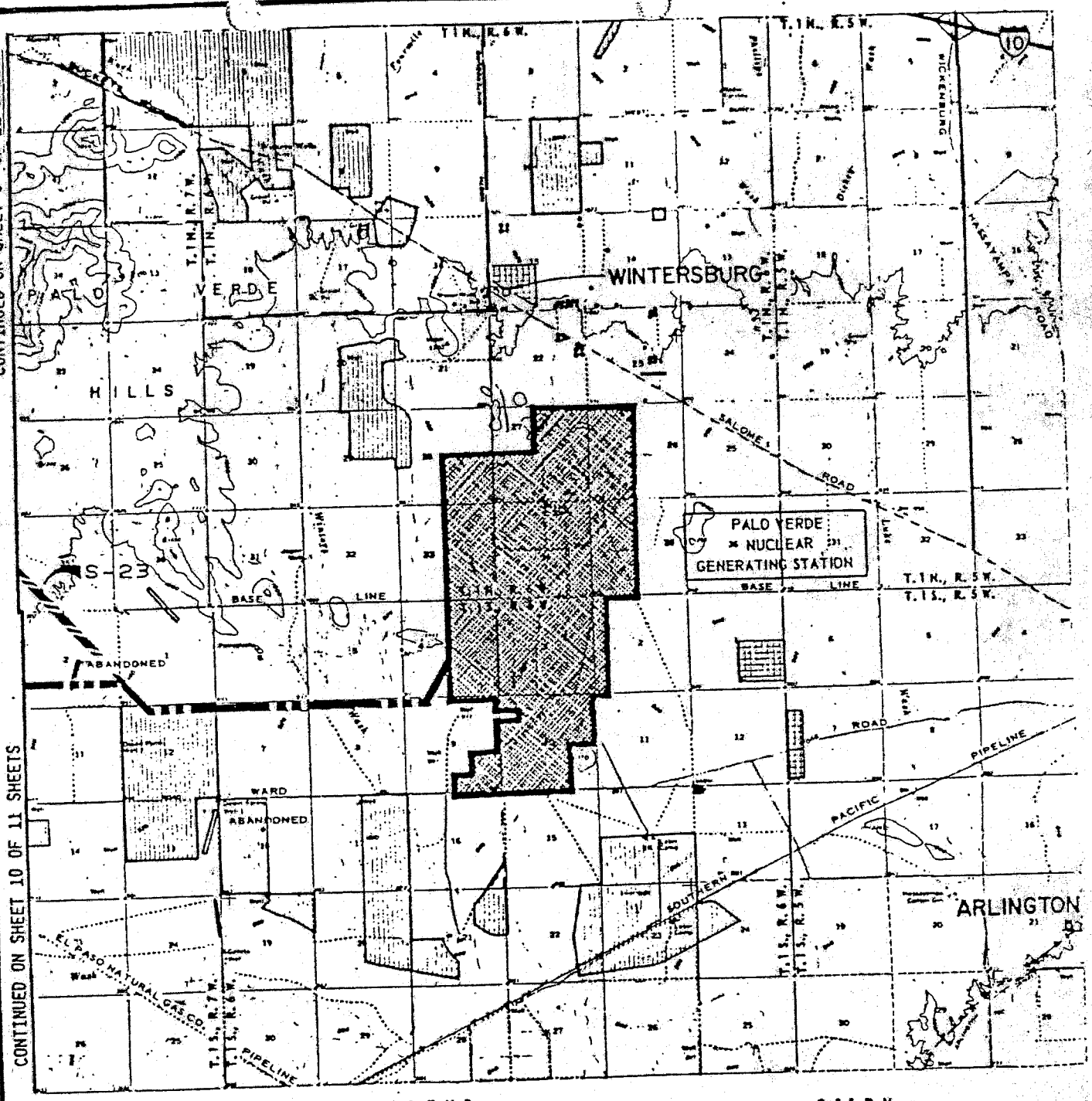
COMPOSITE OF:
ARLINGTON, ARIZ., 1962, CORTEZ PEAK, ARIZ., 1962,
U.S.G.S. 15 MINUTE QUADRANGLE.

EXHIBIT "A-2"

FOR ARIZONA POWER PLANT & TRANSMISSION LINE SITING COMMITTEE FILING

DEVERS-PALO VERDE
500 KV SINGLE CIRCUIT TRANSMISSION LINE SYSTEM

SOUTHERN CALIFORNIA EDISON COMPANY



G. & S. R. M.

LEGEND

COMMITTEE APPROVED ROUTE (CASE NUMBER 48)

COMMITTEE APPROVED ROUTE (CASE NUMBER 34)

EXISTING LAND USE

AIRSTRIPS

IRRIGATION DISTRICT

AGRICULTURE (FEED LOTS, ORCHARDS, FIELDSCROPS)

COMMERCIAL

INSTITUTIONAL

INDIVIDUAL DWELLING UNIT

SUBDIVISION

EXHIBIT "A-2"

MARICOPA COUNTY

COMPOSITE OF:

ARLINGTON, ARIZ., 1962.

U.S.G.S. 15 MINUTE QUADRANGLE.

FOR ARIZONA POWER PLANT & TRANSMISSION LIN
SITING COMMITTEE FILING

DEVERS-PALO VERDE
500 KV SINGLE CIRCUIT TRANSMISSION LINE SYSTE

SOUTHERN CALIFORNIA EDISON COMPANY

SHEET 11 OF 11 SHE

EXHIBIT
S-16
Admitted

ALJ/CFT/tcg

DRAFT

Agenda ID #5776
Ratesetting

Decision **PROPOSED DECISION OF ALJ TERKEURST** (Mailed 6/20/2006)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion into Methodology for Economic Assessment of Transmission Projects.	Investigation 05-06-041 (Filed June 30, 2005)

OPINION ON METHODOLOGY FOR ECONOMIC ASSESSMENT OF TRANSMISSION PROJECTS

(See Attachment B for List of Appearances.)

We agree with the consensus among the parties that Commission requirements regarding economic evaluations of transmission projects should not be overly prescriptive. Instead, today we adopt general principles and provide guidance to establish a framework for economic evaluations to be submitted in CPCN proceedings. The adopted principles, along with minimum requirements for economic evaluations, are appended as Attachment A to this order, and can be summarized as follows:

1. The CAISO's standardized benefit-cost methodology shall be used to measure the economic benefits of proposed transmission projects. The perspective of CAISO ratepayers is of primary importance in a CPCN proceeding, although there is value in reviewing benefit-cost results from other perspectives as well.
2. The CAISO's framework for the computation of potential energy benefits shall be used. Parties shall assess energy benefits using established, credible, and commercially available production cost modeling tools. The applicant may decide whether to include market power mitigation benefits as part of its demonstration of need for a proposed transmission project.
3. In addition to energy benefits, other economic effects of a transmission project may be considered, including economic effects that may not be quantifiable.
4. Economic evaluations shall consider how uncertainty about future system and market conditions affects the likelihood that a transmission project's forecasted benefits will be realized.
5. Economic evaluations shall use baseline resource plans and assumptions about the system outside the applicant's service territory that are consistent with resource plans and system assumptions used in procurement or other recent Commission proceedings, updated as appropriate.

6. Economic evaluations shall consider feasible resource alternatives to the proposed transmission project.

The Commission is taking steps to simplify transmission planning and permitting procedures and make them more efficient, both here and in I.05-09-005 and other venues. Our adoption today of principles and guidance regarding economic evaluations of proposed transmission projects will complement the Commission's streamlining efforts and further the goal of greater coordination and consistency between the Commission and the CAISO. The adopted principles and guidance should be useful to parties that participate in the CAISO review. Parties that provide economic evaluations to the CAISO that are consistent with our guidelines may also submit them in our CPCN proceedings, thus reducing duplication of efforts, the expense of participating both at the CAISO and here, and the time required for the two reviews. Additionally, parties' experience in defending their project evaluations during the CAISO process should narrow issues and streamline the process in a CPCN proceeding here.

II. Background

This investigation has been coordinated with Phase 1 of Application (A.) 05-04-015, the application of Southern California Edison Company (SCE) for a CPCN to construct the Devers-Palo Verde No. 2 (DPV2) transmission project, a proposed 230-mile, 500 kilovolt alternating current transmission line between California and Arizona. DPV2 would connect SCE's existing Devers substation near Palm Springs, California to the existing Harquahala Generating Company switchyard located approximately 49 miles west of Phoenix, Arizona.

On June 30, 2005, the Commission opened I.05-06-041 to consider appropriate principles and methodologies for assessment of the economic

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EXHIBIT
S-17
Admitted

CALIFORNIA
ENERGY
COMMISSION

SUMMER 2006 ELECTRICITY SUPPLY AND DEMAND OUTLOOK

FINAL STAFF REPORT

April 2006
CEC-700-2006-005

Arnold Schwarzenegger, *Governor*

S-18

Statewide (6/29/06 Revised Demand)
Staff Draft 5 Year Outlook

	Resource Adequacy Planning Conventions	2006	2007	2008	2009	2010
1	Existing Generation[1]	56,697	57,977	57,977	58,145	58,145
2	Retirements (Known)	-1,539	0	-584	0	0
3	High Probability CA Additions	2,819	0	752	0	0
4	Net Interchange [2]	13,118	13,118	13,118	13,118	13,118
5	Total Net Generation (MW)	71,095	71,095	71,263	71,263	71,263
6	1-in-2 Summer Temperature Demand (Average)[3]	59,498	60,350	61,216	62,098	62,995
7	Demand Response (DR)	524	524	524	524	524
8	Interruptible/Curtailable Programs	1,603	1,603	1,603	1,603	1,603
9	Planning Reserve[4]	23.1%	21.3%	19.9%	18.2%	16.5%
	Expected Operating Conditions					
	Total Net Generation (MW) (Line 5)	71,095	71,095	71,263	71,263	71,263
10	Outages (Average forced + planned)	-2,695	-2,695	-2,695	-2,695	-2,695
11	Zonal Transmission Limitation[5]	-150	-150	-150	-150	-150
12	Expected Operating Generation with Outages/Limitations[6]	68,250	68,250	68,418	68,418	68,418
13	Expected Operating Reserve Margin (1-in-2)[7]	18.5%	16.4%	14.7%	12.6%	10.7%
	Adverse Conditions					
14	High Zonal Transmission Limitation	-250	-250	-250	-250	-250
15	High Forced Outages	-1,160	-1,160	-1,160	-1,160	-1,160
16	Adverse Temperature Impact (1-in-10)	-3,591	-3,642	-3,695	-3,748	-3,802
17	Adverse Scenario Reserve Margin[7]	7.4%	5.5%	4.0%	2.2%	0.4%
18	Adverse Scenario Reserve Margin w/DR and Interruptibles[8]	11.5%	9.6%	8.0%	6.1%	4.3%
19	Resources needed to meet adverse 7.0% reserve (W/DR & Interruptibles)	0	0	0	472	1,490
20	Resources needed to meet adverse 5.0% reserve (W/DR & Interruptibles)	0	0	0	0	396
21	Resources needed to meet adverse 1.5% reserve (W/DR & Interruptibles)	0	0	0	0	0
22	Existing Generation Without Capacity Contracts[9]	-3,088	-4,028	-7,943	-7,943	-7,943

1 Dependable capacity by station includes 1,080 MW of stations located South of Miguel.
2 2006 estimate of the following Net Imports: DC imports 2,000 MW, SW imports 4,100 MW, NW imports (COI) 4,000 MW, LADWP Control Area imports 2,834 MW, IID Imports 184 MW. Imports with reserves 12,118 MW.
3 Based on preliminary 2007 Demand Forecast for Resource Adequacy Proceedings.
4 Planning Reserve calculation ((Total Generation+Demand Response+Interruptibles)/Normal Demand)-1.
5 Based on CA ISO data.
6 Does not include Demand Response/Interruptible Programs due to Reserve Margins in excess of 5% (Stage 2).
7 Operating Reserve calculation ((Operating Generation-**Imports with Reserves**)/(Demand-**Imports with Reserves**))-1. See Footnote 2.
8 Demand Response and Interruptibles added to Operating Generation in Reserve Margin formula from Footnote 7.
9 Capacity is included in Line 1 and represents plants identified in 2004 CEC Staff Draft Report 100-04-005D Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements

6/30/2006

tabbies
EXHIBIT
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CA ISO (6/29/06 Revised Demand)
Staff Draft 5 Year Outlook

	Resource Adequacy Planning Conventions	2006	2007	2008	2009	2010
1	Existing Generation[1]	45,791	46,265	46,265	46,265	46,265
2	Retirements (Known)	-1,539				
3	High Probability CA Additions	2,013				
4	Net Interchange [2]	10,650	10,600	10,700	10,650	10,600
5	Total Net Generation (MW)	56,915	56,865	56,965	56,915	56,865
6	1-in-2 Summer Temperature Demand (Average)[3]	47,564	48,294	49,033	49,783	50,548
7	Demand Response (DR)	524	524	524	524	524
8	Interruptible/Curtailable Programs	1,403	1,403	1,403	1,403	1,403
9	Planning Reserve[4]	23.7%	21.7%	20.1%	18.2%	16.3%
	Expected Operating Conditions					
	Total Net Generation (MW) (Line 5)	56,915	56,865	56,965	56,915	56,865
10	Outages (Average forced + planned)	-2,255	-2,255	-2,255	-2,255	-2,255
11	Zonal Transmission Limitation[5]	-150	-150	-150	-150	-150
12	Expected Operating Generation with Outages/Limitations[6]	54,510	54,460	54,560	54,510	54,460
13	Expected Operating Reserve Margin (1-in-2)[7]	17.7%	15.5%	13.6%	11.4%	9.3%
	Adverse Conditions					
14	High Zonal Transmission Limitation	-250	-250	-250	-250	-250
15	High Forced Outages	-1,060	-1060	-1060	-1060	-1060
16	Adverse Temperature Impact (1-in-10)	-2,737	-2,779	-2,822	-2,865	-2,909
17	Adverse Scenario Reserve Margin[7]	6.9%	4.9%	3.2%	1.2%	-0.7%
18	Adverse Scenario Reserve Margin w/DR and Interruptibles[8]	11.5%	9.4%	7.6%	5.6%	3.6%
19	Resources needed to meet adverse 7.0% reserve (W/DR & Interruptibles)	0	0	0	618	1,534
20	Resources needed to meet adverse 5.0% reserve (W/DR & Interruptibles)	0	0	0	0	633
21	Resources needed to meet adverse 1.5% reserve (W/DR & Interruptibles)	0	0	0	0	0
21	Existing Generation Without Capacity Contracts[9]	-3,088	-4,028	-7,943	-7,943	-7,943

1 Dependable capacity by station includes 1,080 MW of stations located South of Miguel.

2 2006 estimate of the following Net Imports: **DC imports 2,000 MW, SW imports 4,100 MW, NW imports (COI) 4,000 MW, TID/MID -450MW,** LADWP Control Area imports 1,000 MW. **Imports with own reserves highlighted in bold.**

3 Based on preliminary 2007 Demand Forecast for Resource Adequacy Proceedings.

4 Planning Reserve calculation ((Total Generation+Demand Response+Interruptibles)/Normal Demand)-1.

5 Based on CA ISO data.

6 Does not include Demand Response/Interruptible Programs due to Reserve Margins in excess of 5% (Stage 2).

7 Operating Reserve calculation ((Operating Generation-**Imports with Reserves**)/(Demand-**Imports with Reserves**))-1. See Footnote 2.

8 Demand Response and Interruptibles added to Operating Generation in Reserve Margin formula from Footnote 7.

9 Capacity is included in Line 1 and represents plants identified in 2004 CEC Staff Draft Report 100-04-005D Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements

6/30/2006

CA ISO NP26 (6/29/06 Revised Demand)
Staff Draft 5 Year Outlook

	Resource Adequacy Planning Conventions	2006	2007	2008	2009	2010
1	Existing Generation	24470	24417	24417	24417	24417
2	Retirements (Known)	-219				
3	High Probability CA Additions	166				
4	Net Interchange [1]	550	650	600	550	500
5	Total Net Generation (MW)	24,967	25,067	25,017	24,967	24,917
6	1-in-2 Summer Temperature Demand (Average)[2]	20,769	21,098	21,431	21,768	22,113
7	Demand Response (DR)	322	322	322	322	322
8	Interruptible/Curtailable Programs	316	316	316	316	316
9	Planning Reserve[3]	23.3%	21.8%	19.7%	17.6%	15.6%
	Expected Operating Conditions					
10	Outages (Average forced + planned)	-1,100	-1,100	-1,100	-1,100	-1,100
11	Zonal Transmission Limitation[4]	0	0	0	0	0
12	Expected Operating Generation with Outages/Limitations[5]	23,867	23,967	23,917	23,867	23,817
13	Expected Operating Reserve Margin (1-in-2)[6]	15.3%	14.0%	11.9%	9.9%	7.9%
	Adverse Conditions					
14	High Zonal Transmission Limitation	0	0	0	0	0
15	High Forced Outages	-500	-500	-500	-500	-500
16	Adverse Temperature Impact (1-in-10)	-647	-657	-667	-678	-688
17	Adverse Scenario Reserve Margin[7]	9.4%	8.1%	6.1%	4.2%	2.3%
18	Adverse Scenario Reserve Margin w/DR and Interruptibles[8]	12.4%	11.1%	9.1%	7.1%	5.2%
19	Resources needed to meet adverse 7.0% reserve (W/DR & Interruptibles)	0	0	0	0	404
20	Resources needed to meet adverse 5.0% reserve (W/DR & Interruptibles)	0	0	0	0	0
21	Resources needed to meet adverse 1.5% reserve (W/DR & Interruptibles)	0	0	0	0	0
22	Existing Generation Without Capacity Contracts[8]	-1,018	-1,018	-2,663	-2,663	-2,663

[1] 2006 estimate of the following Net Imports: **NW imports (COI) 4,000 MW minus exports to SP26 3,000 MW and TID/MID 450MW.**
[2] Based on preliminary 2007 Demand Forecast for Resource Adequacy Proceedings
[3] Planning Reserve calculation ((Total Generation+Demand Response+Interruptibles)/Normal Demand)-1.
[4] Based on CA ISO data.
[5] Does not include Demand Response/Interruptible Programs due to reserve margins in excess of 5% (Stage 2).
[6] Operating Reserve calculation ((Operating Generation-**Imports with Reserves**)/(Demand-**Imports with Reserves**))-1. See Footnote 1.
[7] Demand Response and Interruptibles added to Operating Generation in Reserve Margin formula from Footnote 6.
[8] Capacity is included in Line 1 and represents plants identified in 2004 CEC Staff Draft Report 100-04-005D Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements

6/30/2006

CA ISO SP26 (6/29/06 Revised Demand)
Staff Draft 5 Year Outlook

		2006	2007	2008	2009	2010
Resource Adequacy Planning Conventions						
1	Existing Generation[1]	21321	21848	21848	21848	21848
2	Retirements (Known)	-1,320				
3	High Probability CA Additions	1,847				
4	Net Import	10,100	10,100	10,100	10,100	10,100
5	Total Net Generation (MW)	31,948	31,948	31,948	31,948	31,948
6	1-in-2 Summer Temperature Demand (Average)[3]	27,960	28,375	28,796	29,223	29,657
7	Demand Response (DR)	202	202	202	202	202
8	Interruptible/Curtailable Programs	1,087	1,087	1,087	1,087	1,087
9	Planning Reserve[4]	18.9%	17.1%	15.4%	13.7%	12.1%
Expected Operating Conditions						
10	Outages (Average forced + planned)	-1,155	-1,155	-1,155	-1,155	-1,155
11	Zonal Transmission Limitation[5]	-150	-150	-150	-150	-150
12	Expected Operating Generation with Outages/Limitations[6]	30,643	30,643	30,643	30,643	30,643
13	Expected Operating Reserve Margin (1-in-2)[7]	12.3%	10.2%	8.1%	6.1%	4.2%
Adverse Conditions						
14	High Zonal Transmission Limitation	-250	-250	-250	-250	-250
15	High Forced Outages	-560	-560	-560	-560	-560
16	Adverse Temperature Impact (1-in-10)	-1,901	-1,929	-1,958	-1,987	-2,017
17	Adverse Scenario Reserve Margin[7]	-0.1%	-1.9%	-3.7%	-5.5%	-7.2%
18	Adverse Scenario Reserve Margin w/DR and Interruptibles[8]	5.3%	3.4%	1.5%	-0.4%	-2.2%
19	Resources needed to meet adverse 7.0% reserve (W/DR & Interruptibles)	402	876	1,358	1,846	2,342
20	Resources needed to meet adverse 5.0% reserve (W/DR & Interruptibles)	0	392	865	1,344	1,831
21	Resources needed to meet adverse 1.5% reserve (W/DR & Interruptibles)	0	0	2	465	936
22	Existing Generation Without Capacity Contracts (Information Only)[9]	-2,070	-3,010	-5,280	-5,280	-5,280

[1] Dependable capacity by station includes 1,080 MW of stations located South of Miguel.

[2] 2006 estimate of the following Net Imports: **DC imports 2,000 MW, SW imports 4,100 MW,** Imports from NP26 3,000 MW, LADWP Control Area imports 1,000 MW. **Imports with own reserves highlighted in bold.**

[3] Based on preliminary 2007 Demand Forecast for Resource Adequacy Proceedings.

[4] Planning Reserve calculation ((Total Generation+Demand Response+Interruptibles)/Normal Demand)-1.

[5] Based on CA ISO data.

[6] Does not include Demand Response/Interruptible Programs due to Reserve Margins in excess of 5% (Stage 2).

[7] Operating Reserve calculation ((Operating Generation-**Imports with Reserves**)/(Demand-**Imports with Reserves**))-1. See Footnote 2.

[8] Demand Response and Interruptibles added to Operating Generation in Reserve Margin formula from Footnote 7.

[9] Capacity is included in Line 1 and represents plants identified in 2004 CEC Staff Draft Report 100-04-005D Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements

6/30/2006

Southern California Edison

2006 Request for Offers
New Gen RFO

Transmittal Letter

August 14, 2006
V3.0 revised September 6, 2006

EXHIBIT
S-19
admitted

SOUTHERN CALIFORNIA
EDISON®
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A. GENERAL INFORMATION

A.1. In accordance with CPUC Decision 06-07-029, Southern California Edison Company ("SCE") seeks to acquire, with this Request for Offers ("RFO")[1], the exclusive right to schedule and dispatch, pursuant to a power purchase agreement (as executed by both parties, the "Definitive Agreement"), electrical Capacity, Energy, Ancillary Services and Resource Adequacy Benefits from new, clean, and efficient resources[2]. Except as noted in Section A.2, this RFO encompasses two separate schedules for Offer submittal (as defined below), selection of winning bids and negotiation of Definitive Agreements. The requirements herein are identical for both schedules except as otherwise noted. The "Fast Track" schedule has been designed and is intended for Projects that are well into or have completed the project development cycle and are ready to move forward to the construction phase. These Projects must have a proposed Expected Initial Delivery Date of August 1, 2010 or sooner. The "Standard Track" schedule has been designed to allow Projects to progress through the development cycle concurrently with the RFO evaluation process. These Projects must have a proposed Expected Initial Delivery Date of August 1, 2013 or sooner. **For both tracks, SCE prefers Projects with earlier proposed Expected Initial Delivery Dates.** More details on the proposed schedule for each track are provided in Section C of this Transmittal Letter. Offers for a particular Project may be submitted in either or both tracks. The purpose of this Transmittal Letter is to describe the process by which offers ("Offers") are to be submitted and evaluated in response to this RFO as well as SCE's reservation of rights as set forth in Section I.

A.2. In accordance with the Assigned Commissioner's Ruling ("ACR") issued on August 15, 2006 in rulemaking proceedings 05-12-013 and 06-02-013, SCE will consider, on an expedited basis, Offers for Projects that will be online by August 1, 2007 ("Summer 2007 Projects"). Summer 2007 Projects must have proposed Expected Initial Delivery Dates of August 1, 2007 or sooner, and their PPAs must contain specific and appropriate financial assurances to provide a strong incentive to achieve the established Expected Initial Delivery Date. The deadline for submitting a complete Offer Submittal Package as set forth in Section C.6 of this Transmittal Letter for a Summer 2007 Project, is 11 am PPT on September 19, 2006. SCE will accept and encourages complete Offer Submittal Packages submitted pursuant to this Section prior to September 19, 2006. Sellers ("Seller(s)") submitting Offers under this Section must specify, in a cover letter submitted along with their completed Offer Submittal Package, that their Project is being submitted for consideration as a Summer 2007 Project.

SCE plans to expedite the review process for Summer 2007 Projects. SCE requests Seller cooperation so that SCE can conduct an expedited due diligence review of these Projects. If, after reviewing relevant Project information made

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[1] The RFO includes the terms and conditions of SCE's 2006 Request For Offers for new generation resources as described in the pro forma Power Purchase Agreement ("PPA"), the Offer Sheet, this Transmittal Letter, the RFO Definitions, as defined in Section A.3, any exhibits, attachments or appendices to the foregoing documents, or any other communications promulgated by SCE regarding this solicitation, (collectively the "RFO Documents").

[2] QF Projects are not required to provide dispatchable services or Ancillary Services.

available to SCE, SCE, in its sole discretion and at any time prior to execution of a Definitive Agreement, determines that a proposed Summer 2007 Project cannot or is unlikely to meet the requirements in this Section and the RFO for these Projects, SCE may terminate expedited negotiations with the Seller with respect to that Project. However, if SCE does terminate these expedited negotiations, SCE will continue to consider the Seller's Offer under either the Fast Track or Standard Track if Seller requests.

SCE is currently considering what changes might be necessary or desirable in order to meet the objectives of the ACR and "reach agreement with the bidders and file a request for contract approval with the Commission by November 15, 2006" (*see* ACR, page 6) for Summer 2007 Projects. At this time, for Summer 2007 Projects, SCE is requiring: (a) that the Parties reach final agreement on all commercial terms contained in the PPA, except final monthly capacity pricing and that a Summer 2007 Project's Interconnection Facilities Study be provided to SCE by November 1, 2006; (b) that Sellers provide final, binding monthly capacity pricing on November 6, 2006; and (c) that notification of successful Offers and execution of Definitive Agreements occur by November 9, 2006. Per the ACR, SCE anticipates filing a CPUC application to approve any Definitive Agreements by November 15, 2006. The ACR indicates that the CPUC will target taking action on these Definitive Agreements by January 2007.

At this time, all other RFO requirements will apply to the Summer 2007 Projects. Any changes to the schedule or requirements for Summer 2007 Projects will be promptly communicated to the RFO distribution list.

A.3. Capitalized terms used in this Transmittal Letter that are not otherwise defined have the meanings set forth in Exhibit A.3 hereto (the "RFO Definitions").[3]

A.4. SCE may, in its sole discretion, enter into Definitive Agreements with one or more sellers submitting Offers that will provide the best value to SCE's customers based upon the evaluation criteria discussed below.

A.5. This RFO is not a binding offer by SCE to purchase electric Capacity, Energy, Ancillary Services, Resource Adequacy Benefits, Environmental Attributes, or any other product. SCE reserves the right to reject any or all Offers.

A.6. In the event of any conflict between terms contained in this Transmittal Letter or any of the other RFO Documents, the conflict shall be resolved by the following priority of documents: the PPA (and its Appendices), the Offer Sheet, this Transmittal Letter (and the RFO Definitions which accompany the Offer Sheet and Transmittal Letter), and any other Exhibit or Attachment. Notwithstanding the foregoing, in the event a Definitive Agreement is executed by SCE and Seller, the Definitive Agreement shall control over any RFO Documents.

A.7. Sellers are required to meet all the terms and conditions of the RFO to be eligible to compete in the solicitation process. Sellers are required to follow all instructions contained in this RFO, including but not limited to this Transmittal Letter, the RFO Documents, and their Appendices, Exhibits, Attachments and subsequent amendments. Sellers must respond to all questions contained in the

[3] The RFO Definitions are provided to assist potential bidders in understanding the Transmittal Letter and Offer Sheet. The definitions contained in Appendix A of the PPA will supersede and replace the RFO Definitions to the extent the documents are inconsistent.

RFO Documents, organize their Offers according to the structure specified in the Offer Submittal Package, and provide supporting documentation in the format requested in the Offer Submittal Package. Where documentation is not applicable, Seller should so indicate, and specify why the requested information is not applicable. Sellers should clearly organize and identify all information submitted in their Offers to facilitate review and evaluation.

A.8. Information provided by Seller to SCE pursuant to this RFO will be subject to the disclosure requirements of CPUC Decision 06-06-066.

B. ELIGIBILITY REQUIREMENTS

B.1. New Generation

B.1.1. In this RFO, SCE seeks Offers for the sale of electrical Capacity, Energy, Ancillary Services, and Resource Adequacy Benefits from New Resources, including Repowers, Transmission Projects, and QF Projects as described below, that meet all local, state, and federal rules, regulations, standards, permitting, and interconnection requirements and certifications as applicable.

B.1.1.1. Proper certification shall include but is not limited to compliance with current standards under the California Environmental Quality Act ("CEQA"), the National Environmental Policy Act ("NEPA"), the Federal New Source Review ("NSR"), applicable air pollution control district regulations, SCE, CAISO, or appropriate Participating Transmission Owner's electrical interconnection requirements, natural gas interconnection requirements promulgated by Southern California Gas Company or other applicable gas providers, and applicable water and wastewater discharge regulations.

B.1.1.2. SCE will evaluate the eligibility of any Project on a case-by-case basis.

B.1.2. New Resources

B.1.2.1. A Project will qualify as a New Resource eligible for consideration by SCE in this RFO if the following criteria are met:

B.1.2.1.1. The Project has a remaining design life of at least 30 years after the Initial Delivery Date as attested by an engineering assessment performed by a Professional Mechanical Engineer (with experience acceptable to SCE in its sole discretion) licensed by the State of California; and

B.1.2.1.2. The Project will provide Incremental Capacity to the region of the CAISO's control area known as SP15.

B.1.2.2. The Project will not be considered a New Resource eligible for consideration in this RFO if by the date of this RFO it is currently in operation, under construction, or identified on either of the following reports:

B.1.2.2.1. The CEC's California Power Plants Database of existing operating plants in California as of the date of this RFO and as shown in Exhibit B.1.2.2.1.

B.1.2.2.2. The CEC's Energy Facility Status report under the categories of "Projects On Line" or "Approved/Under Construction" as of the date of this RFO and as shown in Exhibit B.1.2.2.2.

B.1.2.3. Physically relocating a Project from outside of California to the SP15 area is permitted if all other conditions of this RFO are met (including those listed in this Transmittal Letter), the relocated Project meets all environmental requirements and standards, and the relocated Project has obtained a valid operating permit authorizing the relocation and subsequent operation of the relocated Project from the applicable Air Pollution Control District.

B.1.2.4. Repowers

B.1.2.4.1. SCE will evaluate Offers to repower existing generating facilities and may, in its sole discretion, accept an Offer to repower an existing generating facility so long as the conditions below are met. A "Repower" is defined as an overhauled or repaired generating facility which was, prior to the overhaul or repair, operating with all applicable local, state and federal certifications and permits, reaching the end of its projected operating life and, requiring the replacement of one or more generation-related components (specifically turbine or other engine prime mover, electrical generator, heat recovery steam generator, and steam turbine) with new hardware in order to operate for more than another ten years. A Repower must meet all the criteria set forth for New Resources in Sections B.1.2.1 and B.1.2.2 as well as all of the criteria set forth below:

B.1.2.4.1.1. The Repower must result in increased capacity, higher efficiency, lower air emissions and greater reliability than the generating facility prior to the overhaul or repair.

B.1.2.4.1.2. An Offer for a Repower considered under this Section must contain information demonstrating that, absent a significant capital investment, the remaining life of the current generating facility is 10 years or fewer.

B.1.2.5. Projects Outside SP15 Requiring Transmission to SP15

B.1.2.5.1. SCE will evaluate Offers for Projects from existing Generating Units located outside of SP15 that become SP15 resources as the result of constructing new transmission facilities which will connect the existing Generating Units to SP15 ("Transmission Projects"). Seller must submit an interconnection application to the CAISO, execute study agreements, and take all other actions required to meet the deadlines to provide the interconnection studies as identified in the applicable RFO Schedule in Section C. Transmission Projects must meet all the criteria set forth for New Resources in Sections B.1.2.1 and B.1.2.2 as well as all of the criteria set forth below with the exception of the Generating Unit supporting the Project, which is exempt from the requirements of B.1.2.2:

B.1.2.5.1.1. The Project must not be considered a resource of any other control area operator.

B.1.2.5.1.2. The Project must be interconnected directly to the CAISO Grid and not via transmission facilities controlled by another control area operator.

B.1.2.5.1.3. SCE must be able to schedule the output of the Project directly with the CAISO as an SP15 resource, not as an import into SP15.

B.1.2.5.1.4. The Project must become part of the CAISO control area and have a valid PGA with the CAISO during the term of any proposed Definitive Agreement with SCE.

B.1.2.5.1.5. All new transmission lines that are constructed in order to connect to SP15 must be radial connections to SP15.

B.1.2.6. QF Projects

B.1.2.6.1. SCE will evaluate Offers for "QF Projects." A Project will qualify as a QF Project eligible for consideration by SCE in this RFO if it meets the definition of a QF Project set forth in the RFO Definitions. A QF Project must meet all the criteria set forth for New Resources in Sections B.1.2.1 and B.1.2.2 as well as all of the criteria set forth below:

B.1.2.6.1.1. The QF Project must be available for baseload operation over the 7x16 peak period defined as any 16 continuous hours between hours ending 7-24.

B.1.2.6.1.2. The Project must be capable of a net output of at least one MW.

B.2. Independent Generating Units

SCE will accept Offers for Generating Units on a particular Site where other generating units are situated; however, the Generating Unit(s) must operate independently with no shared generating components with the other generating units that may be on the Site.

B.3. Exclusive Output and Dispatch Rights

SCE requires exclusive output and dispatch rights of any Generating Unit(s) throughout the Term of the Definitive Agreement[4].

B.4. Quick Start Capability

SCE prefers Quick-Start Generating Unit(s). A Quick-Start Generating Unit is defined as a Generating Unit that can be started (locally or remotely), synchronized to the transmission grid and attain a specified load within ten minutes of notice.

B.5. Short Term Unit Commitment ("STUC")

SCE requires that the Generating Unit(s) be able to participate in the CAISO STUC market as defined by the CAISO's Market Redesign Technology Upgrade.

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[4] QF Projects are not required to provide dispatchable services.

Generating Unit(s) should be able to start (locally or remotely), synchronized to the system and be available for loading within five hours of notice.

B.6. Black Start Capability

For each Generating Unit in its Offer, Seller must describe any ability to operate as, or become at a later date, a Generating Unit with Black Start capability. Seller must also describe any added costs and/or the impact on the construction schedule, if applicable, associated with such Black Start capability.

B.7. Dispatchability

B.7.1. SCE prefers highly flexible (multiple daily starts, quick ramp rates etc.), lower capacity factor peaking resources. However, less flexible, higher capacity factor resources will also be considered.

B.7.2. With the exception of QF Projects, SCE requires that (i) the Project be dispatchable, (ii) SCE have the right to provide dispatch instructions to the generator for the CAISO Day-Ahead, Hour-Ahead, and Real Time Markets, and (iii) that Generating Units be able to start up and to ramp up within the Project's specifications upon notice by SCE.

B.8. Expected Initial Delivery Date

Any Offer selected must have a proposed Expected Initial Delivery Date as set forth in the applicable RFO Schedule in Section C.

B.9. Term

The maximum term length of each Offer is ten years from the Expected Initial Delivery Date for the Generating Unit with the earliest Expected Initial Delivery Date.

B.10. Quantity

B.10.1. The Generating Units which are associated with each Offer must be rated at least 25 MW, with the exception of QF Projects which must be rated at least one MW.

B.10.2. SCE has been authorized to award Offers up to a total aggregate volume of 1,500 MWs, although SCE reserves the right to determine the final volume in its sole discretion.

B.11. Project Point of Interconnection and Interconnection Procedures

B.11.1. Acceptable Point(s) of Interconnection include the following:

B.11.1.1. An existing substation bus that is electrically connected within SP15 as defined by the CAISO.

B.11.1.2. A transmission or distribution line that only interconnects substation buses that are electrically connected within SP15 boundaries as defined by the CAISO.

B.11.1.3. A new substation bus that will be part of the CAISO Grid, designated as a facility within SP15 and electrically connected to a transmission line that is part of the CAISO Grid. In this case, the transmission line must also connect to at least one existing substation bus that is electrically connected within SP15 as defined by the CAISO. The Interconnection System Impact Study for such offers

must clearly indicate that the new substation bus will be designated as a facility that is within SP15 and will not be subject to inter-zonal congestion.

B.11.1.4. A SCE distribution facility that is electrically connected within SP15 boundaries as defined by the CAISO

B.11.2. A substation bus that is electrically connected outside of the boundary of SP15 will not be considered an acceptable Point of Interconnection.

B.11.3. SCE prefers that Projects be located in the Los Angeles Basin area as defined by the CAISO and as shown in Exhibit B.11.3 hereto.

B.11.4. SCE will consider other locations outside the preferred area, provided that the Project has an acceptable Point of Interconnection as specified in Section B.11.1 above.

B.11.5. For each proposed Project, the Seller is required to provide current, up-to-date reports for the Interconnection System Impact Study and Interconnection Facilities Study that meet the Interconnection Study Requirements required by SCE. If an Interconnection System Impact Study clearly indicates that the Project (i) does not trigger any Network Upgrades and (ii) has no possibility of being assigned, in the future, the cost of Network Upgrades due to the withdrawal of other higher queued projects from the CAISO interconnection process, then an Interconnection Facilities Study will not be required by the date specified in the applicable RFO schedule. However, the CAISO Long-Term Standard Large Generator Interconnection Procedures will require an Interconnection Facilities Study to be completed regardless of what the Interconnection System Impact Study indicates regarding system impacts, so the schedule for such Project must still provide for completion of the Interconnection Facilities Study. The schedule for providing these reports is included in Section C. The Seller must also provide any Interconnection Feasibility Studies that have been performed for the proposed Project. Additionally, within five Business Days of a request from SCE, Seller must request the electronic power-flow file of the base case study from the Participating Transmission Owner, CAISO, or third party consultant for Seller responsible for the Interconnection Studies and provide this data in electronic form to SCE within five Business Days of Seller's receipt of the data.

B.11.6. In addition to the interconnection request that will allow Seller to deliver power to the existing system, Seller is also responsible for obtaining retail back-up service. If the proposed generator is outside of the SCE service territory, it may be necessary for the local utility to provide the retail service.

B.11.7. Questions related to CAISO Tariff applications can be directed to:

Judy Nickel
CAISO
(916) 608-7062
jnickel@caiso.com

B.11.8. Questions related to WDAT applications can be directed to:

Robert Lugo
Manager of Grid Interconnection and Contract Development
Southern California Edison
(626) 302-8501
robert.lugo@sce.com

B.12. Fuel Supply and Interconnection

B.12.1. Seller must be responsible for the cost of all incremental gas-related and gas transportation infrastructure necessary for Seller or SCE to deliver firm fuel to the Project. If the Project is powered by natural gas, then SCE prefers firm gas transportation service to the Project.

B.12.2. Seller must provide a Fuel Supply Plan as set forth in Attachment C.6 in the Offer Sheet (Exhibit C.5).

B.12.3. Seller must provide a site evaluation for gas availability prepared by the gas transportation provider with the Indicative Offer consistent with the applicable RFO Schedule in Section C.

B.13. Scheduling Provisions

B.13.1. Throughout the term of any Definitive Agreement, energy will be scheduled pursuant to the Tariff.

B.13.2. SCE prefers to act as the SC for each Project. For Projects fueled by natural gas, if SCE acts as the SC for the Project, then SCE prefers to be Seller's authorized Fuel Manager. If SCE is not the SC, then SCE will not act as the Fuel Manager.

B.14. Monthly Payment Price Profile

SCE will profile the Capacity payments based on the following Monthly Payment Price Shape Table determined by the heat rate of the Project at maximum loading.

Monthly Payment Price Shape Table

	Heat Rate at P-max (MMBtu/MWh)				
	6 to 7	**>7 to 9**	**>9 to 11**	**>11 to 14**	**>14 to 18**
Jan	95%	75%	50%	20%	10%
Feb	65%	55%	30%	10%	5%
Mar	60%	55%	30%	10%	5%
Apr	60%	55%	30%	10%	5%
May	80%	80%	60%	30%	15%
Jun	105%	105%	75%	45%	40%
Jul	155%	170%	240%	330%	365%
Aug	160%	185%	270%	405%	490%
Sep	135%	155%	200%	240%	205%
Oct	90%	90%	70%	35%	25%
Nov	75%	75%	55%	25%	15%
Dec	120%	100%	90%	40%	20%

B.15. Special Purpose Entity

SCE prefers Sellers that are special purpose entities organized for the sole purpose of owning and operating the Project and which remain special purpose entities for the Term of the Definitive Agreement. Notwithstanding the foregoing, SCE will consider the ownership structure of each Seller on an individual basis, whether the Seller is organized as a special purpose entity or otherwise, and reserves the right in its sole discretion to (i) require any Seller to become a special purpose entity as a condition of executing a Definitive Agreement; and (ii) accept an Offer from any Seller who is not organized as a special purpose entity.

C. RFO SOLICITATION AND OFFER SUBMITTAL PROCESS

C.1. RFO Schedule (Fast Track)

Timeline	Event
August 14, 2006	RFO documents issued
August 28, 2006	Deadline to submit Non-binding Notice of Intent to Offer
September 19, 2006	Deadline to submit Indicative Offer and completed Offer Submittal Package including Interconnection System Impact Study[5] and gas interconnection studies
October 3, 2006	Shortlist notification
December 13, 2006	Deadline to submit Interconnection Facilities Study[6]
January 10, 2007	Deadline to complete negotiations of Definitive Agreement including all operational parameters and variable cost components
January 17, 2007	Deadline to submit Final Offer – limited to monthly Capacity prices
January 24, 2007	Last date for notification of successful Offers and to sign Definitive Agreements
February 2007	Definitive Agreements submitted to CPUC for approval
September 2007	Expected CPUC approval of PPA
August 1, 2010	Latest accepted Expected Initial Delivery Date

[5] Specific Interconnection Study Requirements are contained in the RFO Definitions.

[6] See footnote 5.

C.2. RFO Schedule (Standard Track)

Timeline	Event
August 14, 2006	RFO documents issued
October 10, 2006	Deadline to submit Non-binding Notice of Intent to Offer
January 10, 2007	Deadline to submit Indicative Offer and completed Offer Submittal Package
May 30, 2007	Deadline to submit Interconnection System Impact Study[7] and gas interconnection studies
June 19, 2007	Shortlist notification
December 13, 2007	Deadline to submit Interconnection Facilities Study[8]
January 9, 2008	Deadline to complete negotiations of Definitive Agreement including all operational parameters and variable cost components
January 16, 2008	Deadline to submit Final Offer – limited to monthly Capacity prices
January 23, 2008	Last date for notification of successful Offers and to sign Definitive Agreements
February 2008	Definitive Agreements submitted to CPUC for approval
September 2008	Expected CPUC approval of PPA
August 1, 2013	Latest accepted Expected Initial Delivery Date

C.3. Non-binding Notice of Intent to Offer

Seller should provide the form "Non-binding Notice of Intent to Offer" as shown in Exhibit C.3 by the date identified in the applicable RFO Schedule in Section C.

C.4. Independent Evaluator

In accordance with applicable CPUC decisions, SCE may utilize an Independent Evaluator.

C.5. Offer Deposit

Pursuant to Section F of the Offer Sheet (Exhibit C.5), each Seller must submit an Offer Deposit with its Indicative Offer. The Offer Deposit is due when the Offer Sheet is submitted and will be held until the time specified in Section F of the Offer Sheet.

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[7] See footnote 5.

[8] See footnote 5.

C.6. Offer Submission

C.6.1. SCE will only consider Offers that, as of the Indicative Offer deadline, contain each of the items specified in the Offer Submittal Package set forth in the following table.

Offer Submittal Package To be Provided by All Sellers:		
Document:	Filename:	Notes/Instructions:
1. Offer Sheet	Exhibit C.5 - Offer Sheet.doc	Seller must provide all information required in the Offer Sheet and execute the Offer Sheet and appended Confidentiality Agreement. All required Attachments must be included for the Offer to be deemed complete. Seller must provide redlined MS Word versions of all executed documents by the date specified in Section C.
2. Power Purchase Agreement	Exhibit C.6.1 - Power Purchase Agreement.doc	Seller must provide all proposed revisions as a red-lined MS Word document.

C.6.2. SCE must receive each completed Offer Submittal Package prior to 11:00 a.m. Pacific Prevailing Time on the date specified the applicable RFO Schedule in Section C. SCE must receive four hard copies and one electronic copy of the completed Offer Submittal Package. Each hard copy shall be submitted in a three-ring binder, and the electronic copy shall be stored on a CD. Offers shall be submitted via overnight courier, U.S. mail, or hand delivered as specified in Section C.7. In the case of any conflict between the written documents and electronic versions, the written documents shall be binding. SCE will not be responsible for Offers received after the submittal deadline due to unsuccessful transmission of the Offer Submittal Package.

C.7. Contact Information

The website address for this RFO is:
http://www.sce.com/EnergyProcurement/

Any questions relating to this RFO should be addressed to SCE via email at: NewGenRFO@sce.com or the following:

Benny Wu (626) 302-3230
or
Jesse Bryson (626) 302-3297

Overnight courier, U.S. mail, or hand delivered Offer Submittal Packages shall be sent to:

Benny Wu, RFO for New Generation
Southern California Edison Company
G.O. 1, Quad 1-C
2244 Walnut Grove Avenue
Rosemead, California 91770

D. EVALUATION OF OFFERS

SCE will consider a number of factors in the evaluation of Offers including but not limited to the following: market assessment, transmission impact, Debt Equivalence, environmental characteristics, capacity requirements, portfolio fit, credit, project viability, and concentration risk.

D.1. Market assessment refers to SCE's assessment of the market value of the benefits contained in each Offer versus the costs. Typical elements of costs reflected in Offers include Capacity payments, start up charges, variable operating and maintenance costs, and fuel costs resulting from offer heat rates. Additional costs include transmission and a greenhouse gas adder (these issues are addressed below). The benefits of the Offer include potential realization of energy value (i.e. availability, heat rate and dispatch flexibility) and value of generalized ancillary services (i.e. regulation up, regulation down, spin, and non-spin).

D.2. Transmission impact refers to the cost of Network Upgrades that will be ultimately borne by customers. Such costs will be considered along with the costs of the Offer as described above in Section D.1 to obtain the total cost of the Project to be borne by customers.

D.3. Debt Equivalence is the term used by credit agencies to take into account the fixed financial obligations and their corresponding effect on a utility's balance sheet and credit quality that result from the utility's execution of long term purchase power agreements. SCE may consider the debt equivalent impacts of Offers as an additional cost in accordance with CPUC Decision 04-12-048. SCE may also consider any additional customer costs that may be incurred if the Definitive Agreement is treated as a capital lease.

D.4. Environmental characteristics refer to air emissions including carbon dioxide, nitrogen oxide, sulfur dioxide, particulates and other potential environmental impacts. Run time restrictions due to environmental permit restrictions may be considered when calculating energy value. An explicit Greenhouse Gas ("GHG") emissions adder will be considered in the comparison of resource bids. In CPUC Decision 04-12-048, the CPUC adopted a range of values to explicitly account for the financial risk associated with GHG emissions from $8 to $25 per ton of CO_2. Subsequently, in CPUC Decision 05-04-024, the Commission adopted a fixed value for GHG emissions of $8 per ton of CO_2. Pursuant to these decisions, SCE will use a value of $8 per ton of CO_2 adjusted at an escalation rate of 5% starting in 2004 and consult with its PRG. SCE uses a market simulation model to determine the impact on GHG emissions of adding a generation facility.

D.5. Capacity requirement refers to SCE's need for new Capacity to meet the demand for electricity in Southern California. SCE may select Offers based upon their ability to meet SCE's Capacity needs.

D.6. Portfolio fit refers to the impact of the Offer on (i) the demand and supply balance of electric generation for CAISO's SP15 congestion zone, based on SCE's view of the need and/or CPUC direction, and (ii) the ability of SCE's portfolio to meet SCE's RAR and local RAR. Factors influencing the portfolio fit also include but are not restricted to, the range of Offers that are available for selection, variable costs of production, volume in MW offered, unit flexibility (e.g. ramp rates, start times, ancillary service capabilities), the proposed Expected Initial Delivery Date(s), and the Term of the Definitive Agreement.

D.7. Credit means Seller's capability to perform all of its financial and other obligations under the Definitive Agreement, including but not limited to Seller's ability to provide collateral as described in the PPA. SCE will include a cost adder to Offers requiring SCE to post collateral.

D.8. Project viability refers to the results of any SCE assessment as to the viability of the Project being constructed consistent with the terms of the Offer in order to ensure that the objectives of the RFO are achieved. This may include information included with the Offer, including environmental and permitting information that may affect the project in meeting its Expected Initial Delivery Date, as well as independent and/or proprietary data about a particular Project or Project elements.

D.9. Portfolio Concentration Risk refers to both Physical Concentration Risk and Financial Concentration Risk. Physical Concentration Risk is the risk that electric system reliability and continuity of service to SCE customers will be negatively impacted due to over reliance by SCE on purchases from a particular technology. CPUC Decision 02-10-062 requires SCE to devise a strategy for procuring generation from a variety of fuel sources. Financial Concentration Risk results when SCE has a significant monetary exposure to a single counterparty. CPUC Decision 02-10-062 also requires SCE to mitigate financial concentration by contracting with a variety of counterparties. SCE may consider Physical Concentration Risk and/or Financial Concentration Risk or other similar parameters in the evaluation of any Offer.

E. CREDIT REQUIREMENTS

E.1. Seller Information

E.1.1. Seller must provide the information requested in Section B of the Offer Sheet (Exhibit C.5)

E.2. Credit and Collateral

E.2.1. The credit and collateral terms will be negotiated by SCE and Seller and agreed upon terms will be incorporated into the Definitive Agreement. SCE seeks the credit and collateral terms summarized below.

E.2.2. Seller shall post Delivery Date Security as Performance Assurance to secure its obligations from the period of time from the Effective Date to the Initial Delivery Date for each Generating Unit. The Delivery Date Security for each Generating Unit in the Fast Track shall be the product of

$109,600.00/MW multiplied by the amount of Expected Contract Capacity for each Generating Unit. The Delivery Date Security for each Generating Unit in the Standard Track shall be the product of $54,800.00/MW multiplied by the amount of Expected Contract Capacity for each Generating Unit. The Delivery Date Security shall be held by SCE as security for Seller's obligation to meet the Expected Initial Delivery Date for each Generating Unit. The Delivery Date Security for each Generating Unit shall be posted within two Business Days following the Effective Date.

E.2.3. Seller shall post collateral for exposure above an unsecured credit line, if any, to secure Seller's obligations during the Delivery Period. SCE shall calculate exposure based on the mark-to-market value over a 24 or 48 month time frame. The time frame for calculating the mark-to-market value depends on the length of time it is expected to require to replace the generating technology underlying the Agreement. Sellers with investment grade Credit Ratings, or those with an investment grade rated guarantor, are eligible for an unsecured credit line. Sellers that do not have investment grade Credit Ratings or an investment grade rated guarantor shall also post collateral for an Independent Amount of $30,000/MW or $60,000/MW depending on the underlying technology.

In addition to the above, Seller shall grant to SCE liens in a form acceptable to SCE. SCE will agree to subsequently subordinate its liens to any senior lender, on terms and conditions that are acceptable to SCE. Seller shall agree to certain restrictive covenants in order to preserve the value of SCE's security.

E.2.4. SCE is a California load-serving utility with an investment grade Credit Rating and substantial tangible net worth. Unlike most other energy market participants, SCE operates under a state legislative structure designed to minimize the negative impact that energy market uncertainty may have on a utility's creditworthiness. SCE does not intend to provide collateral under the Definitive Agreement and encourages potential Sellers to submit Offers that do not require SCE to post collateral.

In SCE's evaluation of Offers submitted pursuant to this RFO, SCE will include a cost adder to Offers requiring SCE to post collateral in order to reflect the potential negative impact on SCE's liquidity and to recognize the relative value of bids from Sellers who do not require collateral from SCE.

F. CALIFORNIA CLIMATE ACTION REGISTRY

Seller is on notice that, in OIR 06-04-009 (April 13, 2006), the CPUC determined that it will establish a date by which all power purchase agreements with terms in excess of 3 years executed by SCE shall include a provision requiring any Seller to register with the California Climate Action Registry (CCAR), provided that CCAR's protocols have been modified to allow generation facility-specific registration. Regardless of the date established by the CPUC, Seller shall comply with a generation-facility specific registration requirement once enacted.

G. COMPLIANCE WITH NEW ACCOUNTING STANDARDS

The Parties shall determine, through consultation with their respective independent registered public accounting firms, whether SCE is required to consolidate the Seller's financial statements with SCE's financial statements for financial accounting purposes under (i) Financial Accounting Standard Boards Interpretation No. 46(R), "Consolidation of Variable Interest Entities" or (ii) future guidance issued by accounting profession governance bodies or the United States Securities and Exchange Commission, which affect SCE's accounting treatment for the Agreement.

H. CONDITIONS PRECEDENT

SCE's obligations under any Definitive Agreement shall only become effective upon satisfaction of all conditions precedent set forth the Definitive Agreement including, but not limited to, attainment of Final CPUC Approval of the Definitive Agreement, FERC Approval of the Definitive Agreement, if applicable, and delivery to SCE of all documentation required under the Definitive Agreement.

I. RESERVATION OF RIGHTS

SCE reserves the right at any time, in its sole discretion, to abandon this RFO, to change any dates specified in this RFO, to change the basis for the evaluation of Offers, to terminate further participation in this process by any party, to accept any Offer or to enter into any Definitive Agreement, to evaluate the qualifications of any Seller and/or the terms and conditions of any Offer, to reject any or all proposals or Offers, to prohibit or limit mutually exclusive Offers, to consider additional products, to change any form, document, term or condition used in this RFO at any time during the RFO process, or waive any irregularities, all without notice and without assigning any reasons and without incurring liability of Edison International, SCE or any of their respective subsidiaries, affiliates or representatives to any Seller or any other party. SCE shall have no obligation to consider any Offer submitted. SCE will not reimburse any Seller for its expenses related to this RFO under any circumstances, regardless of whether the bidding process proceeds to a successful conclusion or is abandoned. SCE shall not be deemed to have accepted any Offer, and shall not be bound by any term thereof, unless and until an authorized representative of SCE executes a Definitive Agreement with the Seller.

EXHIBITS

Exhibit A.3:	RFO Definitions
Exhibit B.1.2.2.1:	CEC's California Power Plants Database
Exhibit B.1.2.2.2:	CEC's Energy Facility Status Report
Exhibit B.11.3:	Preferred Area Definition
Exhibit C.3:	Non-binding Notice of Intent to Offer
Exhibit C.5:	Offer Sheet
Exhibit C.6.1:	Power Purchase Agreement

Southern California Edison

2006 Request for Offers
New Gen RFO

Exhibit A.3
RFO Definitions

August 14, 2006
V2.0 revised August 16, 2006

SOUTHERN CALIFORNIA EDISON®
An EDISON INTERNATIONAL® Company

EXHIBIT A.3

RFO DEFINITIONS[1]

"Black Start Unit" has the meaning set forth in Section B.6 of the Transmittal Letter.

"CEC's California Power Plants Database" means the database of currently operational power plants in California created and maintained by the CEC, which can be accessed at http://www.energy.ca.gov/database/index.html.

"CEC's Energy Facility Status" means the current state of each power plant project currently seeking license approval before the CEC, as reported by the CEC at http://www.energy.ca.gov/sitingcases/all_projects.html.

"Confidentiality Agreement" means Attachment J of the Offer Sheet.

"Definitive Agreement" has the meaning set forth in Section A.1 of the Transmittal Letter.

"Federal New Source Review" means the federal permitting program designed to help control emissions from major new stationary sources of pollution, created by the Environmental Protection Agency pursuant to 42 U.S.C. §§ 7411 et seq.

"FERC Certification" means FERC's certification of the qualifying status of QF Projects pursuant to 18 CFR Section 292.207.

"Final Offer" means a binding Offer submitted by Seller pursuant to this RFO conforming to the deadlines and requirements set forth in the RFO schedules contained in Section C of the Transmittal Letter and which if accepted by SCE would provide Seller specific terms for a Definitive Agreement executed by SCE and Seller.

"Fuel Supply Plan" means those requirements of Seller as described in Attachment C.6 of the Offer Sheet.

"Functionally Identical Replacement Exemption" means an SCAQMD approved exemption that would alleviate the requirement for a Project to perform air quality impact modeling, and/or the need to obtain emission offsets (as provided by SCAQMD Rule 1304 (a) (1) & (2)).

"Hour-Ahead Market" has the meaning set forth in the Tariff.

"Heat Recovery Steam Generator" or "HRSG" is a heat exchanger that recovers heat from the hot exhaust gas stream of a gas turbine by heating water into steam for use in a steam turbine to generate power.

"Incremental Capacity" means additional and new Capacity beyond the currently available Capacity within SP15.

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[1] The RFO Definitions are provided to assist potential bidders in understanding the Transmittal Letter and Offer Sheet. The definitions contained in Appendix A of the PPA will supersede and replace the RFO Definitions to the extent the documents are inconsistent.

"Indicative Offer" means a non-binding Offer submitted by Seller pursuant this RFO conforming to the deadlines and requirements set forth in Section C of the Transmittal Letter.

"Letter of Credit" means an irrevocable, nontransferable standby letter of credit, substantially in the form, for the purposes of this Offer Sheet, of Attachment F.1 to the Offer Sheet and acceptable to SCE, issued by a major U.S. commercial bank or the U.S. branch office of a foreign bank with, in either case, a Credit Rating of at least (a) "A-" by S&P and "A3" by Moody's, if such entity is rated by both and S&P and Moody's or (b) "A-" by S&P or "A3" by Moody's, if such entity is rated by either S&P or Moody's, but not both.

"MRTU" means the CAISO's Market Redesign and Technology Upgrade proceeding originally filed with FERC under Docket No. ER02-1656-009, et al. (Tariff Amendment No. 44 MRTU) undertaken to comply with certain FERC orders directing CAISO to modify structural flaws in the market design contained within the CAISO Tariff. CAISO submitted the MRTU Tariff and supporting documentation with FERC on February 9, 2006, and it is now pending in Docket No. ER06-615.

"Non-binding Notice of Intent to Offer" means Exhibit C.3 of the Transmittal Letter.

"Offer Deposit" has the meaning set forth in Section F.1 of the Offer Sheet.

"Offer Sheet" means Exhibit C.5 of the Transmittal Letter.

"Offer Submittal Package" means the documents to be submitted by Seller during the Offer submission process as described in the table within Section C.6.1 of the Transmittal Letter.

"Participating Generator Agreement" or "PGA" has the meaning set forth in the Tariff.

"Power Purchase Agreement" or "PPA" has the meaning set forth in Footnote 1 of the Transmittal Letter.

"Quick-Start Generating Unit" has the meaning set forth in Section B.4 of the Transmittal Letter.

"Real Time Market(s)" has the meaning set forth in the Tariff.

"Repower" has the meaning set forth in Section B.1.2.4.1 of the Transmittal Letter.

"Request for Offers" or "RFO" means this solicitation whose intent and scope is set forth in Section A.1 of the Transmittal Letter.

"RFO Definitions" means this document.

"RFO Documents" has the meaning set forth in Footnote 1 of the Transmittal Letter.

"RFO Schedule" means the timelines describe in the tables contained within Sections C.1 and C.2 (as applicable to each Project) of the Transmittal Letter.

"SCAQMD" means the South Coast Air Quality Management District, created pursuant to California Health and Safety Code Sections 40400 et seq., or any successor thereto.

"Short Term Unit Commitment" or "STUC" has the meaning set forth in Section B.5 of the Transmittal Letter.

"Transmission Project" means has the meaning set forth in Section B.1.2.5.1 of the Transmittal Letter.

"Unit Contingent Capacity" means electrical capacity that is dependent upon the availability and operation of one or more specified Generating Units that Seller either owns or has demonstrable exclusive rights to control.

"Unit Contingent Energy" means Energy produced by a Generating Unit providing Unit Contingent Capacity.

Exhibit B.1.2.2.1
CEC's California Power Plants Database

PP_Map_Report_Master_NO_COORDS

ID	PLANT NAME	PRIMARY FUEL	TECHNOLOGY	COGEN	DATE ONLINE	SERVICE AREA	COUNTY	OWNER	STATUS	TURBIN COUNT	ON-LINE MW
H0550	WTP NO. 2 SUPPLY LINE	HYDRO		NOT COGEN	5/1/1960	PG&E	ALAMEDA	ALAMEDA COUNTY WATER DISTRICT	OPERATIONAL		1.26
G0406	OAKLAND	DISTILLATE OIL	GAS TURBINE	NOT COGEN	11/1/1978	PG&E	ALAMEDA	DUKE ENERGY	OPERATIONAL	3	165
G0375	ALAMEDA	NATURAL GAS	COMBUSTION TURBINE	NOT COGEN	1/1/1956	PG&E	ALAMEDA	NORTHERN CALIFORNIA POWER AGENCY/CSC	OPERATIONAL	2	51.65
G0405	PE - BERKELEY INC.	NATURAL GAS, DISTILL	COMBINED CYCLE	COGEN	5/19/1987	PG&E	ALAMEDA	US TRUST OF NEW YORK	OPERATIONAL	2	28.5
G0540	SUMMIT MEDICAL COGEN	NATURAL GAS		COGEN	3/15/1985	PG&E	ALAMEDA		OPERATIONAL		2.86
G0146	CONTINENTAL CAN - WHITE CAP	NATURAL GAS		NOT COGEN	7/2/1986	PG&E	ALAMEDA	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL		0.6
G0057	BORDEN CHEMICAL	NATURAL GAS		COGEN	11/2/1988	PG&E	ALAMEDA		OPERATIONAL		0.2
G0446	STANFORD ENERGY GROUP	NATURAL GAS		COGEN	1/8/1986	PG&E	ALAMEDA		OPERATIONAL		0.115
W0333	ALTAMONT INFRASTRUCTURE COMPANY - 01W035	WIND	WIND TURBINE	NOT COGEN	12/1/1989	PG&E	ALAMEDA	US WINDPOWER, INC.	OPERATIONAL		72
W0343	ALTAMONT INFRASTRUCTURE COMPANY - 06W146C	WIND	WIND TURBINE	NOT COGEN	1/1/1991	PG&E	ALAMEDA		OPERATIONAL		30
W0347	ALTAMONT INFRASTRUCTURE COMPANY - 16W011	WIND	WIND TURBINE	NOT COGEN	1/5/1987	PG&E	ALAMEDA		OPERATIONAL		23.8
W0331	ZONI WINDSYSTEM PARTNERS LTD - SERIES 85-C	WIND	WIND TURBINE	NOT COGEN	12/30/1985	PG&E	ALAMEDA	GE WIND	OPERATIONAL		18
W0325	FLOWIND PARTNERS 1	WIND	WIND TURBINE	NOT COGEN	1/1/1984	PG&E	ALAMEDA	FLORIDA POWER & LIGHT ENERGY INC.	OPERATIONAL		8.48
W0344	ALTAMONT INFRASTRUCTURE COMPANY - 06W146D	WIND	WIND TURBINE	NOT COGEN	1/1/1991	PG&E	ALAMEDA		OPERATIONAL		1.5
E0106	ALTAMONT GAS RECOVERY	LANDFILL GAS	ACTIVE -FLARE/LFGTE	NOT COGEN	3/1/1989	PG&E	ALAMEDA	BIO ENERGY PARTNERS	OPERATIONAL	2	7
E0118	GAS RECOVERY SYSTEMS - FREMONT	MSW	LANDFILL GAS	NOT COGEN	4/10/1990	PG&E	ALAMEDA	GAS RECOVERY SYSTEMS INC.	OPERATIONAL		3.75
C0005	JACKSON VALLEY ENERGY LP	LIGNITE COAL	STEAM TURBINE	COGEN	1/5/1987	PG&E	AMADOR	JACKSON VALLEY ENERGY PARTNER LP	OPERATIONAL	1	17.99
H0171	ELECTRA	HYDRO	HYDRO,WATER	NOT COGEN	6/29/1948	PG&E	AMADOR	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	3	99
H0516	TIGER CREEK	HYDRO	HYDRO,WATER	NOT COGEN	8/1/1931	PG&E	AMADOR	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	2	58
H0431	SALT SPRINGS	HYDRO	HYDRO,WATER	NOT COGEN	8/1/1931	PG&E	AMADOR	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	2	44
H0380	PARDEE DAM	HYDRO	HYDRO,WATER	NOT COGEN	7/1/1930	PG&E	AMADOR	EAST BAY MUNICIPAL UTILITY DISTRICT	OPERATIONAL	3	23.6
H0558	WEST POINT	HYDRO	HYDRO,WATER	NOT COGEN	11/1/1948	PG&E	AMADOR	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	14.5
H0249	JACKSON VALLEY ID	HYDRO		NOT COGEN	8/1/1982	PG&E	AMADOR	JACKSON VALLEY IRRIGATION DISTRICT	OPERATIONAL		0.455
G0378	MULE CREEK STATE PRISON	NATURAL GAS	INTERNAL COMBUSTION	COGEN	1/1/1989	PG&E	AMADOR	STATE OF CA - DEPT. OF CORRECTIONS	OPERATIONAL	2	3
H0164	EDWARD C. HYATT	PUMPED STORAGE	PUMPED STORAGE, WATER	NOT COGEN	6/1/1968	PG&E	BUTTE	CA DEPT. OF WATER RESOURCES (CDWR)	OPERATIONAL	6	644.25
H0510	THERMALTO	PUMPED STORAGE	HYROELECTRIC PUMPED STORAGE, WATER	NOT COGEN	2/1/1968	PG&E	BUTTE	CA DEPT. OF WATER RESOURCES (CDWR)	OPERATIONAL	4	125.98
H0365	ROE	HYDRO	HYDRO,WATER	NOT COGEN	5/1/1958	PG&E	BUTTE	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	2	120
H0673	WOODLEAF	HYDRO	HYDRO,WATER	NOT COGEN	11/1/1963	PG&E	BUTTE	ORO VILLE - WAYANDOTTE IRRIGATION DISTRICT	OPERATIONAL	1	49
H0191	FORBESTOWN	HYDRO	HYDRO,WATER	NOT COGEN	1/1/1962	PG&E	BUTTE	OROVILLE-WYANDOTTE IRRIGATION DISTRICT (OWID)	OPERATIONAL	1	36.79
H0130	DE SABLA	HYDRO	HYDRO,WATER	NOT COGEN	2/28/1963	PG&E	BUTTE	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	16.6
H0192	FORKS OF BUTTE HYDRO PROJECT	HYDRO		NOT COGEN	3/1/1992	PG&E	BUTTE	HYPOWER, INC	OPERATIONAL	1	13.3
H0263	KELLY RIDGE	HYDRO	HYDRO,WATER	NOT COGEN	1/1/1963	PG&E	BUTTE	ORO VILLE - WAYANDOTTE IRRIGATION DISTRICT	OPERATIONAL	1	9
H0464	SLY CREEK	HYDRO	HYDRO,WATER	NOT COGEN	11/1/1963	PG&E	BUTTE	ORO VILLE - WAYANDOTTE IRRIGATION DISTRICT	OPERATIONAL	1	8
H0092	CENTERVILLE	HYDRO	HYDRO,WATER	NOT COGEN	1/2/1900	PG&E	BUTTE	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	6.4
H0511	THERMALTO DIVERSION DAM	HYDRO	HYDRAULIC TURBINE - CONVENTIONAL	NOT COGEN	7/1/1987	PG&E	BUTTE	CA DEPT. OF WATER RESOURCES (CDWR)	OPERATIONAL	1	3
H0287	UME SADDLE	HYDRO	HYDRO,WATER	NOT COGEN	8/1/1905	PG&E	BUTTE	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	2	2
H0518	TOADTOWN	HYDRO	HYDRO,WATER	NOT COGEN	4/1/1946	PG&E	BUTTE	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	1.6
H0427	KANAKA	HYDRO	HYDRO,WATER	NOT COGEN	2/13/1989	PG&E	BUTTE	STS HYDROPOWER, LTD	OPERATIONAL	1	1.12
H0292	LASSEN STATION/CAMP CREEK	HYDRO		NOT COGEN	5/22/1986	PG&E	BUTTE	LASSEN STATION HYDROELECTRIC LP	OPERATIONAL		0.99
H0104	COAL CANYON	HYDRO	HYDRO,WATER	NOT COGEN	12/1/1907	PG&E	BUTTE	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	0.9
H0344	PERRY LODGING	HYDRO		NOT COGEN	12/6/1983	PG&E	BUTTE	MUD CREEK HYDRO PARTNERS	OPERATIONAL		0.3
G0424	OROVILLE COGEN	NATURAL GAS	GAS TURBINE	COGEN	12/18/1989	PG&E	BUTTE	OROVILLE COGEN LP	OPERATIONAL	7	8.05
E0064	PACIFIC OROVILLE POWER INC.	AG. & WOODWASTE	DIRECT COMBUSTION	NOT COGEN	12/1/1985	PG&E	BUTTE	COVANTA	OPERATIONAL	2	18.75
H0167	COLLIERVILLE	HYDRO		NOT COGEN	11/1/1989	CCWD	CALAVERAS	NORTHERN CALIFORNIA POWER AGENCY	OPERATIONAL	2	253
H0072	COLLIERVILLE POWERHOUSE	HYDRO	HYDRO,WATER	NOT COGEN	1/1/1990	PG&E	CALAVERAS	NORTHERN CALIFORNIA POWER AGENCY	OPERATIONAL	1	249.1
H0346	MURPHYS	HYDRO	HYDRO,WATER	NOT COGEN	1/1/1954	PG&E	CALAVERAS	UTICA POWER AUTHORITY	OPERATIONAL	1	4.5
H0538	UTICA	HYDRO		NOT COGEN	12/1/1953	PG&E	CALAVERAS	NORTHERN CALIFORNIA POWER AGENCY	OPERATIONAL		3.6
H0073	NEW HOGAN POWER PLANT	HYDRO		NOT COGEN	4/1/1989	PG&E	CALAVERAS	CALAVERAS COUNTY WATER DISTRICT	OPERATIONAL	2	2
H0008	ANGELS	HYDRO	HYDRO,WATER	NOT COGEN	1/1/1940	PG&E	CALAVERAS	UTICA POWER AUTHORITY	OPERATIONAL	1	1.4
H0425	ROCK CREEK WD	HYDRO		NOT COGEN	2/25/1986	PG&E	CALAVERAS	ROCK CREEK WATER DISTRICT	OPERATIONAL		0.7
H0469	SCHAADS HYDROELECTRIC FACILITY	HYDRO		NOT COGEN	2/18/1986	PG&E	CALAVERAS		OPERATIONAL		0.23
H0327	MIDDLE FORK	HYDRO		NOT COGEN	12/1/1985	PG&E	CALAVERAS	PLACER COUNTY WATER AGENCY (PCWA)	OPERATIONAL		0.23
C0024	MOHAVE GENERATING STATION	COAL		COGEN	1/1/1971	SCE	CLARK COUNTY	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	2	1636.2
H0501	STOVAL 1 & 2	HYDRO		NOT COGEN	6/20/1983	PG&E	COLUSA	GLENN-COLUSA IRRIGATION DISTRICT	OPERATIONAL	2	0.3
E0102	WADHAM	RICE BY PRODUCTS	DIRECT COMBUSTION	NOT COGEN	5/1/1990	PG&E	COLUSA	WADHAM ENERGY LP	OPERATIONAL	1	27.6
C0008	EAST THIRD STREET POWER PLANT	PET COKE, CRUDE OIL	FLUIDIZED BOILER	NOT COGEN	12/1/1990	PG&E	CONTRA COSTA	GWF POWER SYSTEMS	OPERATIONAL	1	19
C0009	LOVERIDGE ROAD POWER PLANT	PET COKE, CRUDE OIL	FLUIDIZED BOILER	NOT COGEN	12/1/1989	PG&E	CONTRA COSTA	GWF POWER SYSTEMS	OPERATIONAL	1	19
C0012	NICHOLS ROAD POWER PLANT	PET COKE, CRUDE OIL	FLUIDIZED BOILER	NOT COGEN	3/1/1990	PG&E	CONTRA COSTA	GWF POWER SYSTEMS	OPERATIONAL	1	19
C0010	WILBUR EAST POWER PLANT	PET COKE, CRUDE OIL	STEAM TURBINE	NOT COGEN	10/1/1989	PG&E	CONTRA COSTA	GWF POWER SYSTEMS	OPERATIONAL	1	19
C0011	WILBUR WEST POWER PLANT	PET COKE, CRUDE OIL	FLUIDIZED BOILER	NOT COGEN	9/1/1990	PG&E	CONTRA COSTA	GWF POWER SYSTEMS	OPERATIONAL	1	19
G0450	PITTSBURG	NATURAL GAS	STEAM TURBINE	NOT COGEN	7/1/1954	PG&E	CONTRA COSTA	MIRANT CORP.	OPERATIONAL	3	1332
G0783	DELTA ENERGY CENTER	NATURAL GAS	COMBINED CYCLE COGENERATION STEAM TO DOW	COGEN	5/10/2002	PG&E	CONTRA COSTA	CALPINE/BECHTEL	OPERATIONAL	1	861
G0147	CONTRA COSTA	NATURAL GAS	STEAM TURBINE	NOT COGEN	1/1/1964	PG&E	CONTRA COSTA	MIRANT CORP.	OPERATIONAL	2	672
G0760	LOS MEDANOS ENERGY CENTER	NATURAL GAS	COGENERATION, STEAM TO USS-POSCO	NOT COGEN	7/6/2001	PG&E	CONTRA COSTA	CALPINE	OPERATIONAL		555
G0161	CROCKETT COGEN	NATURAL GAS	GAS TURBINE	COGEN	5/1/1996	PG&E	CONTRA COSTA	CROCKETT COGENERATION	OPERATIONAL		247.4
G0613	FOSTER-WHEELER MARTINEZ COGEN L.P.	NATURAL GAS	GAS TURBINE	COGEN	2/23/1987	PG&E	CONTRA COSTA	FOSTER WHEELER POWER SYSTEMS, INC.	OPERATIONAL		113.5
G0755	MARTINEZ REFINING CO.	NATURAL GAS	GAS TURBINE, STEAM TURBINE	COGEN	12/1/1995	PG&E	CONTRA COSTA	MARTINEZ REFINING CO.	OPERATIONAL		99
G0177	CALPINE PITTSBURG	NATURAL GAS, HYDRO	GAS TURBINE	COGEN	7/1/1966	PG&E	CONTRA COSTA	CALPINE	OPERATIONAL	3	74
G0632	SAN FRANCISCO REFINERY	NATURAL GAS		COGEN	5/21/1987	PG&E	CONTRA COSTA		OPERATIONAL		49.9
G0914	RIVERVIEW ENERGY CENTER	NATURAL GAS	GAS TURBINE		5/1/2003		CONTRA COSTA	CALPINE	OPERATIONAL	1	47.3
G0964	MOBILE GT	NATURAL GAS	GAS COMBUSTION TURBINE	NOT COGEN	8/1/1975	PG&E	CONTRA COSTA	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	3	45
G0630	TOSCO &FAR CARBON	NATURAL GAS		COGEN	2/1/1984	PG&E	CONTRA COSTA	TOSCO CORP	OPERATIONAL		27.38
G0509	C & H SUGAR	NATURAL GAS	STEAM TURBINE, WASTE HEAT	COGEN	3/1/1957	PG&E	CONTRA COSTA	C&H SUGAR COMPANY, INC.	OPERATIONAL	3	9.5
G0494	RHONE-POULENC - STAUFFER CHEMICAL	NATURAL GAS	GAS TURBINE/HEAT RECOVERY STEAM GENERATR	COGEN	6/1/1977	PG&E	CONTRA COSTA	STAUFFER CHEMICAL	OPERATIONAL		4
G0101	CHEVRON - CONCORD	NATURAL GAS	GAS TURBINE	COGEN	3/23/1988	PG&E	CONTRA COSTA	CHEVRON U.S.A.	OPERATIONAL		3
G0062	BROOKSIDE HOSPITAL	NATURAL GAS	INTERNAL COMBUSTION	COGEN	10/2/1992	PG&E	CONTRA COSTA		OPERATIONAL		0.948
G0160	CITY OF CONCORD	NATURAL GAS		COGEN	10/1/1985	PG&E	CONTRA COSTA		OPERATIONAL		0.105
W0322	ALTAMONT INFRASTRUCTURE COMPANY - 01W004	WIND	WIND TURBINE	NOT COGEN	1/1/1985	PG&E	CONTRA COSTA	NOLT INC.	OPERATIONAL		110
W0321	WINDDRIVEN, INC.	WIND	WIND TURBINE	NOT COGEN	9/1/1984	PG&E	CONTRA COSTA	WIND DRIVEN LLC	OPERATIONAL		34.7
E0137	NOVE POWER PLANT	LANDFILL GAS	INTERNAL COMBUSTION	NOT COGEN	12/31/1985	PG&E	CONTRA COSTA	NOVE INVESTMENTS INC	OPERATIONAL		3
H0815	WHITE ROCK	HYDRO	HYDRO,WATER	NOT COGEN	6/1/1968	SMUD	EL DORADO	SACRAMENTO MUNICIPAL UTILITY DISTRICT	OPERATIONAL	2	238
H0061	CAMINO	HYDRO	HYDRO,WATER	NOT COGEN	10/1/1963	SMUD	EL DORADO	SACRAMENTO MUNICIPAL UTILITY DISTRICT	OPERATIONAL	2	157
H0253	JAYBIRD	HYDRO	HYDRO,WATER	NOT COGEN	5/1/1961	SMUD	EL DORADO	SACRAMENTO MUNICIPAL UTILITY DISTRICT	OPERATIONAL	2	154
H0289	LOON LAKE	HYDRO	HYDRO,WATER	NOT COGEN	8/1/1971	SMUD	EL DORADO	SACRAMENTO MUNICIPAL UTILITY DISTRICT	OPERATIONAL	1	85.2
H0532	UNION VALLEY	HYDRO	HYDRO,WATER	NOT COGEN	6/1/1963	SMUD	EL DORADO	SACRAMENTO MUNICIPAL UTILITY DISTRICT	OPERATIONAL	1	46.7
H0414	ROBBS PEAK	HYDRO	HYDRO,WATER	NOT COGEN	10/1/1965	SMUD	EL DORADO	SACRAMENTO MUNICIPAL UTILITY DISTRICT	OPERATIONAL	1	29.7
H0167	EL DORADO	HYDRO	HYDRO,WATER	NOT COGEN	1/1/1924	PG&E	EL DORADO	EL DORADO IRRIGATION DISTRICT (EDID)	OPERATIONAL	2	20
H0255	JONES FORK	HYDRO	HYDRO,WATER	NOT COGEN	4/1/1985	SMUD	EL DORADO	SACRAMENTO MUNICIPAL UTILITY DISTRICT	OPERATIONAL	1	11.5
H0096	CHILI BAR	HYDRO	HYDRO,WATER	NOT COGEN	3/1/1965	PG&E	EL DORADO	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	7.2
H0422	ROCK CREEK HYDRO	HYDRO		NOT COGEN	4/24/1986	PG&E	EL DORADO	ROCK CREEK LTD PNSP	OPERATIONAL		3
H0328	TUNNEL HILL	HYDRO		NOT COGEN	12/30/1983	PG&E	EL DORADO		OPERATIONAL		0.6
H0482	SLAB CREEK	HYDRO	HYDRO,WATER	NOT COGEN	7/1/1963	SMUD	EL DORADO	SACRAMENTO MUNICIPAL UTILITY DISTRICT	OPERATIONAL	1	0.45
H0396	SIERRA ENERGY CO.	HYDRO		NOT COGEN	1/1/1986	PG&E	EL DORADO	ROBERT T. SUTER	OPERATIONAL		0.2
H0229	HELMS PUMPED STORAGE	PUMPED STORAGE	PUMPED STORAGE, WATER, TURBINE GENERATOR	NOT COGEN	6/30/1984	PG&E	FRESNO	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	3	1212

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Exhibit B.1.2.2.1
CEC's California Power Plants Database

PP_Map_Report_Master_NO_COORDS

ID	PLANTNAME	PRIMARY FUEL	TECHNOLOGY	COGEN	DATE ONLINE	SERVICE AREA	COUNTY	OWNER	STATUS	TURBIN COUNT	ON-LINE MW
H0161	EASTWOOD	PUMPED STORAGE	PUMPED STORAGE, WATER	NOT COGEN	12/1/1987	SCE	FRESNO	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	1	199.8
H0362	BIG CREEK 3	HYDRO	HYDRO,WATER	NOT COGEN	9/30/1923	SCE	FRESNO	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	5	174.45
H0367	PINE FLAT	HYDRO	HYDRAULIC TURBINE - CONVENTIONAL	NOT COGEN	4/12/1984	PG&E	FRESNO	KINGS RIVER CONSERVATION DISTRICT	OPERATIONAL	3	165
H0256	KERCKHOFF 2	HYDRO	HYDRO,WATER	NOT COGEN	6/1/1983	PG&E	FRESNO	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	156
H0215	HAAS	HYDRO	HYDRO,WATER	NOT COGEN	12/23/1958	PG&E	FRESNO	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	2	144
H0030	BIG CREEK 2A	HYDRO	HYDRO,WATER	NOT COGEN	8/6/1928	SCE	FRESNO	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	2	110
H0020	BALCH 2	HYDRO	HYDRO,WATER	NOT COGEN	11/26/1930	PG&E	FRESNO	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	2	100
H0027	BIG CREEK 1	HYDRO	HYDRO,WATER	NOT COGEN	11/6/1913	SCE	FRESNO	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	4	85.35
H0036	BIG CREEK 8	HYDRO	HYDRO,WATER	NOT COGEN	8/16/1921	SCE	FRESNO	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	2	75
H0026	BIG CREEK 2	HYDRO	HYDRO,WATER	NOT COGEN	12/18/1913	SCE	FRESNO	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	4	66.5
H0272	KINGS RIVER	HYDRO	HYDRO,WATER	NOT COGEN	3/1/1962	PG&E	FRESNO	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	53
H0265	KERCKHOFF 1	HYDRO	HYDRO,WATER	NOT COGEN	8/1/1920	PG&E	FRESNO	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	3	38
H0019	BALCH 1	HYDRO	HYDRO,WATER	NOT COGEN	2/20/1927	PG&E	FRESNO	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	34
H0499	PORTAL	HYDRO	HYDRO,WATER	NOT COGEN	12/22/1956	SCE	FRESNO	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	1	10.8
H0275	KINGS RIVER HYDRO CO.	HYDRO		NOT COGEN	8/16/1990	PG&E	FRESNO	ORANGE COVE IRRIGATION DISTRICT	OPERATIONAL		1
G0905	WELLHEAD POWER PANOCHE, LLC	NATURAL GAS		NOT COGEN	12/14/2001		FRESNO	WELLHEAD POWER PANOCHE, LLC	OPERATIONAL	1	49.9
G0908	CALPEAK POWER PANOCHE, LLC	NATURAL GAS			12/27/2001		FRESNO	CALPEAK	OPERATIONAL		49.615
G0906	WELLHEAD POWER GATES, LLC	NATURAL GAS		NOT COGEN	12/27/2001		FRESNO	WELLHEAD POWER GATES, LLC	OPERATIONAL		46.5
G0536	SANGER POWER & FEED	NATURAL GAS		COGEN	5/1/1991	PG&E	FRESNO	DYNAMIS INC.	OPERATIONAL		39.6
G0131	COALINGA COGEN CO.	NATURAL GAS/EOR	GAS TURBINE	COGEN	1/1/1981	PG&E	FRESNO	COALINGA COGENERATION	OPERATIONAL		38
G0286	PE - KES KINGSBURG LLC	NATURAL GAS, DISTILL		COGEN	12/5/1990	PG&E	FRESNO	PE MANAGEMENT-KINGSBURG, LLC	OPERATIONAL		34.5
G0384	FRESNO COGEN	NATURAL GAS	COMBINED CYCLE	COGEN	12/1/1989	PG&E	FRESNO	FRESNO COGENERATION PARTNERS	OPERATIONAL	2	25
G0904	FRESNO COGEN PARTNERS LP PKR	NATURAL GAS		COGEN	8/16/2001	PG&E	FRESNO	FRESNO COGENERATION PARTNERS	OPERATIONAL	1	21.3
G0100	COALINGA	NATURAL GAS	GAS TURBINE-HEAT RECOVERY STEAM GENERATR	COGEN	11/7/1986	PG&E	FRESNO	CHEVRON U.S.A.	OPERATIONAL	6	20.7
G0557	AL RESOURCES	NATURAL GAS	GAS TURBINE-HEAT RECOVERY STEAM GENERATR	COGEN	6/5/1990	PG&E	FRESNO	AERA ENERGY LLC	OPERATIONAL		8.5
G0518	SAINT AGNES HOSPITAL	NATURAL GAS	GAS TURBINE	COGEN	11/21/1985	PG&E	FRESNO	SAINT AGNES MEDICAL CENTER	OPERATIONAL	3	2.325
G0312	ROY SHARP JR.	NATURAL GAS		NOT COGEN	11/21/1991	PG&E	FRESNO		OPERATIONAL		0.1
E0062	MENDOTA BIOMASS POWER LTD	WOODWASTE	DIRECT COMBUSTION	COGEN	11/1/1989	PG&E	FRESNO	AES	OPERATIONAL	1	26
E0086	RIO BRAVO FRESNO	WOODWASTE	DIRECT COMBUSTION	NOT COGEN	7/20/1988	PG&E	FRESNO	RIO BRAVO FRESNO	OPERATIONAL	1	28
H0500	STONY GORGE	HYDRO	HYDRO,WATER	NOT COGEN	3/1/1966	PG&E	GLENN	SILICON VALLEY POWER - CITY OF CLARA (CSC)	OPERATIONAL	2	4.9
H0235	HIGHLINE CANAL	HYDRO	HYDRO,WATER	NOT COGEN	3/1/1989	PG&E	GLENN	SILICON VALLEY POWER - CITY OF CLARA (CSC)	OPERATIONAL	1	0.6
H0547	WEA BAKER CREEK PROJECT	HYDRO		NOT COGEN	12/10/1987	PG&E	HUMBOLDT	ALBERT HUNT & BAKER STATON ASSOCIATION	OPERATIONAL		1.6
H0320	MILL AND SULPHUR CREEK PROJECT	HYDRO		NOT COGEN	2/23/1988	PG&E	HUMBOLDT	MILLS & SULPHUR CREEK POWER PLANT PNSP	OPERATIONAL		0.990
G0070	CSU HUMBOLDT	NATURAL GAS		COGEN	12/2/1991	PG&E	HUMBOLDT		OPERATIONAL		0.35
E0063	PACIFIC LUMBER CO.	WOODWASTE	DIRECT COMBUSTION	COGEN	1/1/1989	PG&E	HUMBOLDT	PACIFIC LUMBER CO.	OPERATIONAL	3	32.5
E0037	FAIRHAVEN POWER CO.	WOODWASTE	DIRECT COMBUSTION	NOT COGEN	9/15/1986	PG&E	HUMBOLDT	EEL RIVER SAWMILLS INC.	OPERATIONAL	1	21
T0049	SALTON SEA 3	HYDROTHERMAL	DOUBLE-FLASH CYCLE	NOT COGEN	2/1/1985	SCE	IMPERIAL	SALTON SEA POWER GENERATION LP 3	OPERATIONAL	1	63.97
T0033	HEBER GEOTHERMAL CO.	HYDROTHERMAL	DOUBLE-FLASH CYCLE	NOT COGEN	8/1/1985	IID	IMPERIAL	IMPERIAL POWER SERVICES	OPERATIONAL	1	50
T0016	SALTON SEA 4	GEOTHERMAL	STEAM TURBINE	NOT COGEN	1/1/1997	IID	IMPERIAL	SALTON SEA 4 FISH LAKE POWER GEN	OPERATIONAL	1	51
T0017	SALTON SEA 5	GEOTHERMAL	GEOTHERMAL		6/1/2000		IMPERIAL	SALTON SEA POWER LLC	OPERATIONAL	1	49.9
T0051	SECOND IMPERIAL GEOTHERMAL	HYDROTHERMAL	DOUBLE-FLASH CYCLE	NOT COGEN	8/1/1993	SCE	IMPERIAL	SECOND IMPERIAL GOETHERMAL CO.	OPERATIONAL	2	46
T0015	JJ ELMORE	HYDROTHERMAL	DOUBLE-FLASH CYCLE	NOT COGEN	12/11/1990	IID	IMPERIAL	ELMORE LP	OPERATIONAL	1	42
T0053	VULCAN	HYDROTHERMAL	DOUBLE-FLASH CYCLE	NOT COGEN	12/1/1985	SCE	IMPERIAL	VULCAN/BN GEOTHERMAL POWER CO.	OPERATIONAL	2	39.72
T0012	AW HOCH	HYDROTHERMAL	DOUBLE-FLASH CYCLE	NOT COGEN	10/1/1986	IID	IMPERIAL	DEL RANCH LP	OPERATIONAL	1	35.8
T0034	JM LEATHERS	HYDROTHERMAL	DOUBLE-FLASH CYCLE	NOT COGEN	11/1/1989	IID	IMPERIAL	LEATHES LP	OPERATIONAL	1	35.8
T0062	ORMEST	HYDROTHERMAL	BINARY CYCLE	NOT COGEN	12/1/1986	SCE	IMPERIAL	ORMESA GEOTHERMAL	OPERATIONAL	1	31.2
T0043	ORMESA GEOTHERMAL II	HYDROTHERMAL	BINARY CYCLE	NOT COGEN	12/31/1987	SCE	IMPERIAL	ORMESA GEOTHERMAL	OPERATIONAL	1	24
T0048	SALTON SEA 2	HYDROTHERMAL	SINGLE-FLASH CYCLE	NOT COGEN	3/5/1990	SCE	IMPERIAL	SALTON SEA POWER GENERATION LP 2	OPERATIONAL	3	20
T0021	GEM II	HYDROTHERMAL	DOUBLE-FLASH	NOT COGEN	4/1/1989	IID	IMPERIAL	GEM RESOURCES	OPERATIONAL	1	16.5
T0022	GEM III	HYDROTHERMAL	DOUBLE-FLASH	NOT COGEN	5/1/1989	IID	IMPERIAL	GEM RESOURCES	OPERATIONAL	1	16.5
T0066	ORMESA IH	HYDROTHERMAL	BINARY CYCLE	NOT COGEN	12/1/1989	SCE	IMPERIAL	ORMESA GEOTHERMAL	OPERATIONAL	1	14.4
T0063	ORMESA IE	HYDROTHERMAL	BINARY CYCLE	NOT COGEN	12/1/1988	SCE	IMPERIAL	ORMESA GEOTHERMAL	OPERATIONAL	1	14.4
T0073	CE TURBO LLC	GEOTHERMAL	GEOTHERMAL	NOT COGEN	7/26/2000	PG&E	IMPERIAL	CE TURBO LLC	OPERATIONAL	1	11.5
T0047	SALTON SEA 1	HYDROTHERMAL	SINGLE-FLASH CYCLE	NOT COGEN	7/1/1826	IID	IMPERIAL	SALTON SEA POWER GENERATION LP 1	OPERATIONAL	1	10
H0151	DROP 4	HYDRO	HYDRAULIC TURBINE - CONVENTIONAL	NOT COGEN	2/25/1941	IID	IMPERIAL	IMPERIAL IRRIGATION DISTRICT	OPERATIONAL	2	19.6
H0149	DROP 2	HYDRO	HYDRAULIC TURBINE - CONVENTIONAL	NOT COGEN	12/30/1933	IID	IMPERIAL	IMPERIAL IRRIGATION DISTRICT	OPERATIONAL	2	10
H0150	DROP 3	HYDRO	HYDRAULIC TURBINE - CONVENTIONAL	NOT COGEN	2/20/1941	IID	IMPERIAL	IMPERIAL IRRIGATION DISTRICT	OPERATIONAL	2	9.8
H0471	SENATOR WASH	HYDRO		NOT COGEN	8/1/1985	IID	IMPERIAL	UNITED STATES BUREAU OF RECLAMATION (USBR)	OPERATIONAL		7.2
H0365	PILOT KNOB	HYDRO	HRDRO,WATER	NOT COGEN	1/1/1957	IID	IMPERIAL	IMPERIAL IRRIGATION DISTRICT	OPERATIONAL	2	7
H0148	SIPHON DROP	HYDRO		NOT COGEN	1/1/1937	IID	IMPERIAL	YUBA COUNTY WATER USERS ASSOCIATION	OPERATIONAL		4
H0152	DROP 5	HYDRO	HYDRAULIC TURBINE - CONVENTIONAL	NOT COGEN	3/1/1962	IID	IMPERIAL	IMPERIAL IRRIGATION DISTRICT	OPERATIONAL	2	4
H0147	DROP 1	HYDRO		NOT COGEN	10/19/1964	IID	IMPERIAL	IMPERIAL IRRIGATION DISTRICT	OPERATIONAL	3	3.85
H0160	EAST HIGHLINE	HYDRO	HYDRO,WATER	NOT COGEN	9/12/1984	IID	IMPERIAL	IMPERIAL IRRIGATION DISTRICT	OPERATIONAL	1	2.42
H0146	DOUBLE WEIR	HYDRO	HYDRO,WATER	NOT COGEN	1/2/1900	IID	IMPERIAL	IMPERIAL IRRIGATION DISTRICT	OPERATIONAL	2	0.66
H0651	TURNIP	HYDRO	HYDRAULIC TURBINE - CONVENTIONAL	NOT COGEN	10/1/1964	IID	IMPERIAL	IMPERIAL IRRIGATION DISTRICT	OPERATIONAL	1	0.4
G0190	EL CENTRO	NATURAL GAS	STEAM TURBINE, COMBINED CYCLE	NOT COGEN	7/1/1992	IID	IMPERIAL	IMPERIAL IRRIGATION DISTRICT	OPERATIONAL	4	80
G0604	ROCKWOOD	NATURAL GAS	COMBUSTION TURBINE	NOT COGEN	8/1/1979	IID	IMPERIAL	IMPERIAL IRRIGATION DISTRICT	OPERATIONAL	2	40
G0059	BRAWLEY	DISTILLATE OIL	COMBUSTION TURBINE	NOT COGEN	6/27/1986	IID	IMPERIAL	IMPERIAL IRRIGATION DISTRICT	OPERATIONAL	2	20
E0042	MESQUITE RESOURCE RECOVERY PROJECT	AG & ANIMAL WASTE	STEAM TURBINE, GRATE	NOT COGEN	1/1/1988	SCE	IMPERIAL	NEW CHARLESTON POWER 1 LP	OPERATIONAL	1	17.89
T0010	COSO FINANCE PARTNERS UNIT 1-3	HYDROTHERMAL	DOUBLE FLASH CYCLE	NOT COGEN	8/18/1987	SCE	INYO	COSO OPERATING CO.	OPERATIONAL	3	102.1
T0011	COSO ENERGY DEVELOPERS UNIT 4-6	HYDROTHERMAL	DOUBLE FLASH CYCLE	NOT COGEN	1/13/1990	SCE	INYO	COSO OPERATING CO.	OPERATIONAL	3	99.59
T0008	COSO ENERGY DEVELOPERS UNIT 7-9	HYDROTHERMAL	DOUBLE FLASH CYCLE	NOT COGEN	3/9/1989	SCE	INYO	COSO OPERATING CO.	OPERATIONAL	3	99.59
H0110	CONTROL GORGE	HYDRO	HYDRO,WATER	NOT COGEN	4/1/1952	LADWP	INYO	LOS ANGELES DEPT. OF WATER & POWER	OPERATIONAL	1	37.5
H0043	BISHOP CREEK 4	HYDRO	HYDRO,WATER	NOT COGEN	9/20/1905	SCE	INYO	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	5	7.855
H0042	BISHOP CREEK 3	HYDRO	HYDRO,WATER	NOT COGEN	6/12/1913	SCE	INYO	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	3	7.84
H0216	HAIWEE	HYDRO	RUN-OF-RIVER, FRANCIS TURBINE, OWENS VLY	NOT COGEN	7/18/1927	LADWP	INYO	LOS ANGELES DEPT. OF WATER & POWER	OPERATIONAL	2	5.14
H0044	BISHOP CREEK 5	HYDRO	HYDRO,WATER	NOT COGEN	6/1/1919	SCE	INYO	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	2	4.532
H0040	BIG PINE	HYDRO	RUN-OF-RIVER, HYDRAULIC TURBINE, OWENS V	NOT COGEN	7/29/1925	LADWP	INYO	LOS ANGELES DEPT. OF WATER & POWER	OPERATIONAL	1	3.2
H0364	PHEASANT VALLEY	HYDRO	RUN-OF-RIVER, HYDRAULIC TURBINE-PLINE	NOT COGEN	2/1/1958	LADWP	INYO	LOS ANGELES DEPT. OF WATER & POWER	OPERATIONAL	1	3.2
H0116	COTTONWOOD	HYDRO	RUN-OF-RIVER, FRANCIS TURBINE	NOT COGEN	11/13/1908	LADWP	INYO	LOS ANGELES DEPT. OF WATER & POWER	OPERATIONAL	2	2.8
H0045	BISHOP CREEK 6	HYDRO	HYDRO,WATER	NOT COGEN	3/12/1913	SCE	INYO	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	1	1.6
H0142	DIVISION CREEK	HYDRO	RUN-OF-RIVER, FRANCIS TURBINE	NOT COGEN	3/22/1909	LADWP	INYO	LOS ANGELES DEPT. OF WATER & POWER	OPERATIONAL	1	0.65
H0410	CINNAMON RANCH	HYDRO	RUN-OF-RIVER	NOT COGEN	4/25/1986	SCE	INYO	RICHARD MOSS	OPERATIONAL		0.155
G0016	MT. POSO COGENERATION	NATURAL GAS/EOR	STEAM TURBINE	COGEN	8/1/1988	PG&E	KERN	MT POSO COGENERATION CO.	OPERATIONAL	1	63.64
G0022	RIO BRAVO POSO	COAL	STEAM TURBINE	COGEN	9/1/1989	PG&E	KERN	RIO BRAVO POSO	OPERATIONAL	1	33
G0018	RIO BRAVO JASMIN	PETROLEUM COKE	STEAM TURBINE	COGEN	9/1/1989	SCE	KERN	RIO BRAVO JASMIN	OPERATIONAL	1	33
H0268	KERN RIVER 1	HYDRO	HYDRO,WATER	NOT COGEN	5/19/1907	SCE	KERN	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	4	40.175
H0269	KERN RIVER 3	HYDRO	HYDRO,WATER	NOT COGEN	3/22/1921	SCE	KERN	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	2	36.8
H0367	KERN HYDRO OLCESE	HYDRO		NOT COGEN	5/18/1988	PG&E	KERN	OLCESE WATER DISTRICT	OPERATIONAL		16
H0084	ISABELLA HYDROELECTRIC PROJECT	HYDRO	DAM-SITE HYDRO	NOT COGEN	1/1/1990	SCE	KERN	ISABELLA PARTNERS	OPERATIONAL	2	13.9
H0048	ROREL	HYDRO	HYDRO,WATER	NOT COGEN	12/31/1904	SCE	KERN	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	3	12
H0267	KERN CANYON	HYDRO	HYDRO,WATER	NOT COGEN	8/1/1921	PG&E	KERN	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	11.5
G0781	LA PALOMA GENERATING PROJECT	NATURAL GAS	COMBINED CYCLE	NOT COGEN	1/1/2003	PG&E	KERN	PACIFIC GAS AND ELECTRIC COMPANY NATIONAL	OPERATIONAL	4	968
G0759	ELK HILLS	NATURAL GAS	GAS TURBINE	NOT COGEN	7/24/2003	PG&E	KERN	SEMPRA & OXY	OPERATIONAL		500

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ID	PLANTNAME	PRIMARY FUEL	TECHNOLOGY	COGEN	DATE ONLINE	SERVICE AREA	COUNTY	OWNER	STATUS	TURBIN COUNT	ON-LINE MW
G0784	SUNRISE POWER PROJECT	NATURAL GAS	FIRED COGENERATION (FOR TEOR)	COGEN	6/26/2001	PG&E	KERN	TEXACO	OPERATIONAL		320
G0293	KERN RIVER COGEN	NATURAL GAS	GAS TURBINE	COGEN	8/1/1985	SCE	KERN	KERN RIVER COGEN	OPERATIONAL	4	300
G0690	SYCAMORE COGEN	NATURAL GAS	GAS TURBINE	COGEN	1/1/1988	SCE	KERN	SYCAMORE COGENERATION CO	OPERATIONAL	4	300
G0860	SUNRISE II COMBINED CYCLE EXPANSION	NATURAL GAS		NOT COGEN	6/1/2003		KERN	TEXACO	OPERATIONAL		265
G0658	MIDWAY-SUNSET COGEN	NATURAL GAS/EOR	GAS TURBINE	COGEN	5/1/1989	SCE	KERN	MIDWAY-SUNSET COGENERATION CO	OPERATIONAL	3	242
G0339	MCKITTRICK COGEN	NATURAL GAS	GAS TURBINE	COGEN	10/16/1991	PG&E	KERN	EL PASO MERCHANT ENERGY	OPERATIONAL	3	72
G0315	LIVE OAK COGEN	NATURAL GAS	GAS TURBINE	COGEN	3/16/1991	PG&E	KERN	EL PASO MERCHANT ENERGY	OPERATIONAL	1	68.62
G0426	BEAR MOUNTAIN LTD.	NATURAL GAS	GAS TURBINE	COGEN	10/16/1995	PG&E	KERN	EL PASO MERCHANT ENERGY	OPERATIONAL	1	68.62
G0386	MOJAVE COGEN	NATURAL GAS	GAS TURBINE, STEAM TURBINE	COGEN	12/7/1990	SCE	KERN	MOJAVE COGENERATION CO	OPERATIONAL	2	56.4
G0258	HIGH SIERRA LTD.	NATURAL GAS	GAS TURBINE	COGEN	1/1/1988	PG&E	KERN	EL PASO MERCHANT ENERGY	OPERATIONAL	2	53.6
G0176	DOUBLE "C" LTD.	NATURAL GAS	GAS TURBINE	COGEN	10/1/1988	PG&E	KERN	EL PASO MERCHANT ENERGY	OPERATIONAL	2	53.6
G0292	KERN FRONT LTD.	NATURAL GAS	GAS TURBINE	COGEN	6/1/1989	PG&E	KERN	EL PASO MERCHANT ENERGY	OPERATIONAL	1	53.6
G0516	SOUTH BELRIDGE COGEN	NATURAL GAS	GAS TURBINE	COGEN	12/1/1995	PG&E	KERN	CAL RESOURCES LLC	OPERATIONAL		46
G0425	CHALK CLIFF COGEN	NATURAL GAS	GAS TURBINE	COGEN	6/1/1990	PG&E	KERN	EL PASO MERCHANT ENERGY	OPERATIONAL	1	47
G0040	BADGER CREEK LTD.	NATURAL GAS	GAS TURBINE	COGEN	3/16/1991	PG&E	KERN	EL PASO MERCHANT ENERGY	OPERATIONAL	1	47
G0525	BORON	NATURAL GAS	GAS TURBINE	COGEN	6/1/1984	SCE	KERN	U.S. BORAX AND CHEMICAL CO	OPERATIONAL		45
G0409	OILDALE COGEN	NATURAL GAS	GAS TURBINE	COGEN	12/29/1984	PG&E	KERN	OILDALE ENERGY LLC	OPERATIONAL		40
G0355	MIDSET COGEN	NATURAL GAS	GAS TURBINE	COGEN	3/16/1989	PG&E	KERN	MIDSET COGENERATION	OPERATIONAL	1	39
G0638	BERRY COGEN - MIDWAY SUNSET	NATURAL GAS	GAS TURBINE	COGEN	1/16/1997	PG&E	KERN	BERRY PETROLEUM	OPERATIONAL		38.77
G0558	SEKR COGEN	NATURAL GAS		COGEN	1/31/1989	PG&E	KERN	TEXACO	OPERATIONAL		34.468
G0173	DAIMOLDALE COGEN	NATURAL GAS	GAS TURBINE	COGEN	11/30/1989	PG&E	KERN	DIAMOND ENERGY INC.	OPERATIONAL	1	31
G0102	CHEVRON CYMRIC	NATURAL GAS	GAS TURBINE	COGEN	10/15/1982	PG&E	KERN	CHEVRON U.S.A.	OPERATIONAL	6	26.3
G0356	MIDSUN	NATURAL GAS		COGEN	4/1/1986	PG&E	KERN	MIDSUN PARTNERS	OPERATIONAL		26
G0368	BERRY PETROLEUM CO.	NATURAL GAS		COGEN	3/14/1985	PG&E	KERN		OPERATIONAL		17
G0107	CHEVRON - TAFT	NATURAL GAS	GAS TURBINE	COGEN	7/26/1982	PG&E	KERN	CHEVRON U.S.A.	OPERATIONAL		12.5
G0601	NORTH MIDWAY	NATURAL GAS	GAS TURBINE	COGEN	10/1/1987	PG&E	KERN	TEXACO	OPERATIONAL	3	10.97
G0600	TEXACO - MCKITTRICK	NATURAL GAS	GAS TURBINE	COGEN	10/1/1994	PG&E	KERN	TEXACO	OPERATIONAL	3	10.969
G0599	LOST HILLS	NATURAL GAS		COGEN	10/6/1985	PG&E	KERN	TEXACO	OPERATIONAL		10.968
G0775	OCCIDENTAL OF ELK HILLS INC.	NATURAL GAS		COGEN	11/2/1994	PG&E	KERN	OCIDENTAL OF ELK HILLS, INC.	OPERATIONAL		10
G0595	ARCO - FEE "A"	NATURAL GAS	GAS TURBINE	COGEN	6/25/1986	PG&E	KERN	ARCO	OPERATIONAL	2	7.926
G0597	ARCO - FEE "C"	NATURAL GAS	GAS TURBINE	COGEN	2/26/1987	PG&E	KERN	ARCO	OPERATIONAL	2	7.45
G0627	DOME PROJECT	NATURAL GAS	GAS TURBINE	COGEN	9/2/1988	PG&E	KERN	NUEVO ENERGY CO	OPERATIONAL	2	6.6
G0216	FRITO-LAY	NATURAL GAS	GAS TURBINE	COGEN	4/2/1986	PG&E	KERN	FRITO-LAY INC	OPERATIONAL		6
G0031	ARCO OXFORD	NATURAL GAS		COGEN	9/19/1984	PG&E	KERN	ARCO	OPERATIONAL		5.2
G0556	CAL RESOURCES - N. MIDWAY SUNSET	NATURAL GAS		COGEN	6/19/1988	PG&E	KERN	AERA ENERGY LLC	OPERATIONAL		4.25
G0644	WELLPORT PROJECT	NATURAL GAS	GAS TURBINE	COGEN	1/27/1990	PG&E	KERN	NUEVO NERGY CO	OPERATIONAL	1	3.8
G0596	ARCO - FEE "B"	NATURAL GAS	GAS TURBINE	COGEN	4/28/1987	PG&E	KERN	ARCO	OPERATIONAL	1	3.726
G0522	M.H. WHITTIER GAL	NATURAL GAS		COGEN	10/6/1986	PG&E	KERN		OPERATIONAL		0.5
W0313	MOJAVE 16, 17, 18	WIND	WIND TURBINE	NOT COGEN	8/17/1990	SCE	KERN	SEAWEST ENERGY GROUP	OPERATIONAL	346	85
W0312	MOJAVE 3, 4, 5	WIND	WIND TURBINE	NOT COGEN	8/17/1990	SCE	KERN	SEAWEST ENERGY GROUP	OPERATIONAL	300	75
W0255	CANNON ENERGY CORP	WIND	WIND TURBINE	NOT COGEN	12/31/1983	SCE	KERN	FLORIDA POWER & LIGHT ENERGY INC.	OPERATIONAL		65
W0270	TEHACHAPI POWER PURCHASE TRUST	WIND	WIND TURBINE	NOT COGEN	12/15/1986	SCE	KERN	TEHACHAPI PWR PUR CONTR TRUST	OPERATIONAL		60
W0267	ESI ENERGY, INC. - 6063	WIND	WIND TURBINE	NOT COGEN	11/1/1989	SCE	KERN	DIFWIND FARMS LIMITED	OPERATIONAL		48
W0256	CABAZON POWER PARTNERS, LLC	WIND	WIND TURBINE	NOT COGEN	1/23/1984	SCE	KERN	ENRON WIND	OPERATIONAL		39.75
W0289	ESI ENERGY, INC. - 6065	WIND	WIND TURBINE	NOT COGEN	7/22/1991	SCE	KERN	SKY RIVER PARTNERSHIP	OPERATIONAL		36.725
W0262	ESI ENERGY, INC. - 6057	WIND	WIND TURBINE	NOT COGEN	11/17/1984	SCE	KERN	FLORIDA POWER & LIGHT ENERGY INC.	OPERATIONAL		33.6
W0319	OAK CREEK ENERGY SYSTEMS INC.	WIND	WIND TURBINE	NOT COGEN	2/10/1986	SCE	KERN		OPERATIONAL		30.5
W0297	CANNON ENERGY CORP - 6002	WIND	WIND TURBINE	NOT COGEN	1/1/1988	SCE	KERN	FLORIDA POWER & LIGHT ENERGY INC.	OPERATIONAL		26
W0276	ZOND SYSTEMS, INC. - 6044	WIND	WIND TURBINE	NOT COGEN	12/5/1985	SCE	KERN	ZOND SYSTEMS INC	OPERATIONAL		22.5
W0320	CALWIND RESOURCES, INC	WIND	WIND TURBINE	NOT COGEN	3/26/1991	SCE	KERN	CALWIND RESOURCES INC	OPERATIONAL		22.425
W0291	ESI ENERGY, INC. - 6067	WIND	WIND TURBINE	NOT COGEN	2/14/1991	SCE	KERN	SMITH WIND ENERGY CORP.	OPERATIONAL		20.925
W0290	ESI ENERGY, INC. - 6066	WIND	WIND TURBINE	NOT COGEN	5/23/1991	SCE	KERN	SKY RIVER PARTNERSHIP	OPERATIONAL		19.8
W0275	ZOND SYSTEMS, INC. - 6043	WIND	WIND TURBINE	NOT COGEN	11/13/1985	SCE	KERN	ZOND SYSTEMS INC	OPERATIONAL		17
W0296	ESI ENERGY, INC. - 6061	WIND	WIND TURBINE	NOT COGEN	12/31/1985	SCE	KERN	FLORIDA POWER & LIGHT ENERGY INC	OPERATIONAL		11.9
W0284	CALWIND RESOURCES, INC	WIND	WIND TURBINE	NOT COGEN	12/30/1984	SCE	KERN	CALWIND RESOURCES INC	OPERATIONAL		8.7
W0301	WINDLAND, INC.	WIND	WIND TURBINE	NOT COGEN	12/27/1985	SCE	KERN	WINDLAND INC.	OPERATIONAL		7.735
W0304	VICTORY GARDEN PHASE IV PARTNER - 6103	WIND	WIND TURBINE	NOT COGEN	1/2/1990	SCE	KERN	ENRON WIND CORP.	OPERATIONAL		6.675
W0303	VICTORY GARDEN PHASE IV PARTNER - 6102	WIND	WIND TURBINE	NOT COGEN	3/17/1990	SCE	KERN	ENRON WIND CORP.	OPERATIONAL		6.675
W0272	ZOND SYSTEMS, INC. - 6040	WIND	WIND TURBINE	NOT COGEN	9/1/1984	SCE	KERN	ZOND SYSTEMS INC.	OPERATIONAL		6.525
W0305	VICTORY GARDEN PHASE IV PARTNER - 6104	WIND	WIND TURBINE	NOT COGEN	4/11/1990	SCE	KERN	ENRON WIND CORP.	OPERATIONAL		6.9
W0274	ZOND SYSTEMS, INC. - 6042	WIND	WIND TURBINE	NOT COGEN	10/17/1985	SCE	KERN	ZOND SYSTEMS INC.	OPERATIONAL		6.77
W0308	ZOND SYSTEMS, INC. - MONOLITH XII	WIND	WIND TURBINE	NOT COGEN	7/9/1987	SCE	KERN	ZOND SYSTEMS INC.	OPERATIONAL		6.72
W0282	WINDLAND, INC.	WIND	WIND TURBINE	NOT COGEN	12/29/1982	SCE	KERN	WINDLAND INC.	OPERATIONAL		6.547
W0271	ZOND SYSTEMS, INC. - 6039	WIND	WIND TURBINE	NOT COGEN	2/1/1984	SCE	KERN	ZOND SYSTEMS INC.	OPERATIONAL		6.24
W0273	ZOND SYSTEMS, INC. - 6041	WIND	WIND TURBINE	NOT COGEN	12/1/1984	SCE	KERN	ZOND SYSTEMS INC.	OPERATIONAL		6.016
W0309	ZOND SYSTEMS, INC. - MONOLITH XIII	WIND	WIND TURBINE	NOT COGEN	6/30/1987	SCE	KERN	ZOND SYSTEMS INC.	OPERATIONAL		5.67
W0306	ZOND SYSTEMS, INC. - MONOLITH X	WIND	WIND TURBINE	NOT COGEN	6/10/1987	SCE	KERN	ENRON WIND CORP.	OPERATIONAL		5.04
W0286	CTV MANAGEMENT GROUP - 6028	WIND	WIND TURBINE	NOT COGEN	12/1/1983	SCE	KERN	CORAM ENERGY GROUP LTD	OPERATIONAL		5.0399
W0307	ZOND SYSTEMS, INC. - MONOLITH XI	WIND	WIND TURBINE	NOT COGEN	6/30/1987	SCE	KERN	ZOND SYSTEMS INC.	OPERATIONAL		4.99
W0294	CTV MANAGEMENT GROUP - 6089	WIND	WIND TURBINE	NOT COGEN	4/22/1986	SCE	KERN	CTV MANAGEMENT GROUP	OPERATIONAL		4.36
W0284	OAK CREEK ENERGY TRUST - ZEPHYR PARK PROJECT	WIND	WIND TURBINE	NOT COGEN	12/1/1983	SCE	KERN	ZEPHYR PARK	OPERATIONAL		4.2
W0256	MOGUL ENERGY CORP	WIND	WIND TURBINE	NOT COGEN	6/24/1982	SCE	KERN	OAK CREEK ENERGY SYSTEMS	OPERATIONAL		4
W0263	WINDSONG ENERGY, INC.	WIND	WIND TURBINE	NOT COGEN	12/26/1982	SCE	KERN	JOHN W. HORTON	OPERATIONAL		2.4
W0285	WINDRIDGE, INC.	WIND	WIND TURBINE	NOT COGEN	8/1/1985	SCE	KERN	WINDRIDGE INC.	OPERATIONAL		2.34
W0280	CTV MANAGEMENT GROUP	WIND	WIND TURBINE	NOT COGEN	12/6/1985	SCE	KERN	CORAM ENERGY GROUP LTD	OPERATIONAL		1.8
E0029	DELANO ENERGY CO. INC.	AG. & WOODWASTE	DIRECT COMBUSTION	NOT COGEN	1/1/1990	SDG&E	KERN	AES	OPERATIONAL	1	66
C0007	HANFORD	PETROLEUM COKE, CRUE	FLUIDIZED BOILER	COGEN	9/1/1990	PG&E	KINGS	HANFORD LP	OPERATIONAL	1	24
G0867	GWF HENRIETTA	NATURAL GAS		NOT COGEN	7/1/2002		KINGS	GWF POWER SYSTEMS	OPERATIONAL		96
G0832	GWF HANFORD PEAKER	NATURAL GAS	BROWN FIELD	NOT COGEN	9/1/2001		KINGS	GWF POWER SYSTEMS	OPERATIONAL		95
E0033	DINUBA ENERGY INC.	AG. & WOODWASTE	DIRECT COMBUSTION	COGEN	10/1/1985	PG&E	KINGS	UC FRESNO	OPERATIONAL		13
T0060	BIG GEYSER 13 & 16	DRY STEAM	STEAM TURBINE,	NOT COGEN	9/12/1980	PG&E	LAKE	GEYSERS POWER CO., LLC	OPERATIONAL	1	75
T0050	CALISTOGA 19	DRY STEAM		NOT COGEN	3/14/1984	PG&E	LAKE	GEYSERS POWER CO., LLC	OPERATIONAL	2	55
T0027	QUICK SILVER 16	DRY STEAM	STEAM TURBINE,	NOT COGEN	10/1/1985	PG&E	LAKE	GEYSERS POWER CO., LLC	OPERATIONAL	1	61
T0046	SONOMA 3	DRY STEAM		NOT COGEN	12/1/1983	PG&E	LAKE	GEYSERS POWER CO., LLC	OPERATIONAL	1	38
T0007	WEST FORD FLAT 4	DRY STEAM		NOT COGEN	9/1/1986	PG&E	LAKE	GEYSERS POWER CO., LLC	OPERATIONAL	2	27
T0025	BEAR CANYON 7	DRY STEAM		NOT COGEN	9/1/1988	PG&E	LAKE	GEYSERS POWER CO., LLC	OPERATIONAL	2	16.6
H0243	INDIAN VALLEY HYDRO	HYDRO		NOT COGEN	9/15/1983	PG&E	LAKE	CATALYST ENERGY	OPERATIONAL		3.335
H0576	YOLO COUNTY FLOOD	HYDRO	HYDRO,WATER	NOT COGEN	9/7/1985	PG&E	LAKE	YOLO COUNTY FLOOD CONTROL	OPERATIONAL	3	2.9
T0001	AMEDEE GEOTHERMAL VENTURE I	HYDROTHERMAL	BINARY	NOT COGEN	8/1/1988	LASSEN M	LASSEN	AMEDEE GEOTHERMAL VENTURE 1	OPERATIONAL	2	3
T0054	WINEAGLE DEVELOPERS 1	HYDROTHERMAL	BINARY	NOT COGEN	8/1/1985	PG&E	LASSEN	WINEAGLE DEVELOPMENT, LP	OPERATIONAL		0.7
H0311	MALACHA HYDRO LP	HYDRO		NOT COGEN	12/7/1988	PG&E	LASSEN	MALACHA HYDRO LIMITED PARTNERS	OPERATIONAL		26
E0041	HI POWER CO.	WOODWASTE	DIRECT COMBUSTION	COGEN	7/26/1989	LASSEN M	LASSEN	CMS	OPERATIONAL	1	33
E0062	SPI- SUSANVILLE	WOODWASTE	DIRECT COMBUSTION	COGEN	11/1/1985	PG&E	LASSEN	SIERRA PACIFIC INDUSTRIES, INC.	OPERATIONAL	2	14.34
E0056	MT. LASSEN POWER	WOODWASTE	DIRECT COMBUSTION	COGEN	6/1/1985	PG&E	LASSEN	COVANTA	OPERATIONAL	1	13.3

This spreadsheet shows the contents of http://www.energy.ca.gov/database/index.html#powerplants on August 14, 2006.
Some columns have been removed from this data due to space limitations

Exhibit B.1.2.2.1
CEC's California Power Plants Database

PP_Map_Report_Master_NO_COORDS

ID	PLANT NAME	PRIMARY FUEL	TECHNOLOGY	COGEN	DATE ONLINE	SERVICE AREA	COUNTY	OWNER	STATUS	TURBIN COUNT	ON-LINE MW
C0023	INTERMOUNTAIN 1 & 2	COAL		COGEN	1/1/1987	LADWP	LOS ANGELES	LOS ANGELES DEPT. OF WATER & POWER	OPERATIONAL	2	1840
C0002	BP WEST COAST PRODUCT LLC WILLMINGTON CALCINER	PETROLEUM COKE	COAL FIRED BOTTOMING CYCLE	COGEN	12/1/1982	SCE	LOS ANGELES	BP WEST COAST PRODUCTS LLC	OPERATIONAL	1	35.8
H0057	WILLIAM E. WARNE	HYDRO	HYDROELECTRIC TURBINE - CONVENTIONAL	NOT COGEN	11/23/1982	SCE	LOS ANGELES	CALIF. DEPT. OF WATER RESOURCES	OPERATIONAL	2	76.145
H0441	SAN FRANCISQUITO 1	HYDRO	RUN-OF-RIVER, TURBINE PIPELINE, AQUEDUCT	NOT COGEN	4/16/1917	LADWP	LOS ANGELES	LOS ANGELES DEPT. OF WATER & POWER	OPERATIONAL	4	69.375
H0440	SAN FRANCISQUITO 2	HYDRO	RUN-OF-RIVER, TURBINE PIPELINE, AQUEDUCT	NOT COGEN	7/6/1920	LADWP	LOS ANGELES	LOS ANGELES DEPT. OF WATER & POWER	OPERATIONAL	3	42
H0058	ALAMO	HYDRO	HYDROELECTRIC TURBINE - CONVENTIONAL	NOT COGEN	7/7/1986	SCE	LOS ANGELES	CALIF. DEPT. OF WATER RESOURCES	OPERATIONAL	1	17.1
H0090	CASTAIC POWERHOUSE	PUMPED STORAGE	PUMPED STORAGE,WATER, PONDAGE	NOT COGEN	7/11/1973	LADWP	LOS ANGELES	LOS ANGELES DEPT. OF WATER & POWER	OPERATIONAL	7	1326
H0541	VENICE	HYDRO	HYDRAULIC TURBINE - PIPELINE	NOT COGEN	5/1/1982	SCE	LOS ANGELES	METROPOLITAN WATER DISTRICT	OPERATIONAL	11	10.12
H0189	FOOTHILL	HYDRO	RUN-OF-RIVER, FRANCIS TURBINE, AQUADUCT	NOT COGEN	10/6/1971	LADWP	LOS ANGELES	LOS ANGELES DEPT. OF WATER & POWER	OPERATIONAL	1	10
H0457	SAN DIMAS	HYDRO	HYDRAULIC TURBINE - PIPELINE	NOT COGEN	3/1/1981	SCE	LOS ANGELES	METROPOLITAN WATER DISTRICT	OPERATIONAL	1	9.92
H0188	FOOTHILL FEEDER	HYDRO	HYDRAULIC TURBINE - PIPELINE	NOT COGEN	4/1/1961	SCE	LOS ANGELES	METROPOLITAN WATER DISTRICT	OPERATIONAL	2	9.04
H0472	SEPULVEDA CANYON	HYDRO	HYDRAULIC TURBINE - PIPELINE	NOT COGEN	3/1/1962	LADWP	LOS ANGELES	METROPOLITAN WATER DISTRICT	OPERATIONAL	1	8.64
H0436	SAN FERNANDO	HYDRO	RUN-OF-RIVER, TURBINE/PIPELINE, AQUEDUCT	NOT COGEN	10/22/1922	LADWP	LOS ANGELES	LOS ANGELES DEPT. OF WATER & POWER	OPERATIONAL	2	6.4
H0442	SAN GABRIEL HYDRO PROJECT	HYDRO	HYDROELECTRIC	NOT COGEN	10/17/1987	SCE	LOS ANGELES	SAN GABRIEL HYDROELECTIC ASSOCIATES	OPERATIONAL	2	4.975
H0014	AZUSA	HYDRO	HYDRAULIC TURBINE - CONVENTIONAL	NOT COGEN	2/1/1948	PASADEN	LOS ANGELES	CITY OF PASADENA	OPERATIONAL	1	2
H0193	FRANKLIN	HYDRO	RUN-OF-RIVER, FRANCIS TURBINE, AQUEDUCT	NOT COGEN	6/3/1521	LADWP	LOS ANGELES	LOS ANGELES DEPT. OF WATER & POWER	OPERATIONAL	1	2
H0412	RIO HONDO	HYDRO	HYDRAULIC TURBINE - PIPELINE	NOT COGEN	4/1/1984	SCE	LOS ANGELES	METROPOLITAN WATER DISTRICT	OPERATIONAL	1	1.91
H0076	EAST PORTAL GENERATOR	HYDRO	PRESSURE-REDUCING STATION	NOT COGEN	10/1/1984	SCE	LOS ANGELES	CALLEGUAS MWD	OPERATIONAL	1	1.25
H0443	SAN DIMAS WASH	HYDRO	HYDRO,WATER	NOT COGEN	1/28/1986	SCE	LOS ANGELES	SAN GABRIEL VALLEY MUNICIPAL WTR DIST.	OPERATIONAL	1	1.05
H0211	GREG AVENUE	HYDRO	HYDRAULIC TURBINE - PIPELINE	NOT COGEN	12/1/1975	LADWP	LOS ANGELES	METROPOLITAN WATER DISTRICT	OPERATIONAL	1	1
H0291	LOS ANGELES COUNTY FLOOD CONTROL DISTRICT	HYDRO	PRESSURE-REDUCING STATION	NOT COGEN	12/23/1985	SCE	LOS ANGELES	WEATHERLY PRIVATE CA	OPERATIONAL		0.93
H0467	SAWTELLE	HYDRO	RUN-OF-RIVER, TURBINE - PIPELINE	NOT COGEN	6/1/1966	LADWP	LOS ANGELES	LOS ANGELES DEPT. OF WATER & POWER	OPERATIONAL	1	0.8
H0514	THREE VALLEYS MWD - MIRAMAR	HYDRO	P.R. STATIONPRESSURE-REDUCING STATION	NOT COGEN	4/13/1987	SCE	LOS ANGELES	THREE VALLEYS M W D	OPERATIONAL		0.52
H0542	VERDUGO	HYDRO		NOT COGEN	12/1/1984	SCE	LOS ANGELES	CITY OF GLENDALE	OPERATIONAL		0.4
H0515	THREE VALLEYS MWD - WILLIAMS AVE. STATION	HYDRO	PRESSURE-REDUCING STATION	NOT COGEN	4/3/1987	SCE	LOS ANGELES	THREE VALLEYS M W D	OPERATIONAL		0.35
H0242	DOMINGUEZ GAP BARRIER	HYDRO	P.R. STATIONPRESSURE-REDUCING STATION	NOT COGEN	12/30/1986	SCE	LOS ANGELES	G SQUARED ENGY NO. 2	OPERATIONAL		0.275
H0513	THREE VALLEYS MWD - FULTON RD. STATION	HYDRO	PRESSURE-REDUCING STATION	NOT COGEN	4/2/1987	SCE	LOS ANGELES	THREE VALLEYS M W D	OPERATIONAL		0.2
H0466	SANTA MONICA	HYDRO		NOT COGEN	3/1/1984	SCE	LOS ANGELES	CITY OF SANTA MONICA	OPERATIONAL		0.15
H0553	WALNUT VALLEY WD - #1	HYDRO	PRESSURE-REDUCING STATION	NOT COGEN	10/17/1984	SCE	LOS ANGELES	WALNUT VALLEY WATER DISTRICT	OPERATIONAL		0.125
G0011	ALAMITOS GENERATING STATION	DISTILLATE OIL	STEAM TURBINE, GAS TURBINE	NOT COGEN	9/1/1956	SCE	LOS ANGELES	AES CORP.WILLIAMS	OPERATIONAL	5	2087
G0246	HAYNES	NATURAL GAS	STEAM TURBINE, NATURAL GAS	NOT COGEN	1/1/1962	LADWP	LOS ANGELES	LOS ANGELES DEPT. OF WATER & POWER	OPERATIONAL	6	1570
G0490	REDONDO BEACH GENERATING STAT	NATURAL GAS		NOT COGEN	1/1/1948	SCE	LOS ANGELES	AES CORP.	OPERATIONAL		1317
G0585	SCATTERGOOD	NATURAL GAS	STEAM TURBINE, NATURAL GAS	NOT COGEN	12/1/1958	LADWP	LOS ANGELES	LOS ANGELES DEPT. OF WATER & POWER	OPERATIONAL	3	803
G0194	EL SEGUNDO	NATURAL GAS	STEAM TURBINE	NOT COGEN	8/1/1964	SCE	LOS ANGELES	NRG/DYNEGY POWER	OPERATIONAL	2	708
G0019	LONG BEACH	NATURAL GAS	COMBUSTION TURBINE, STEAM TURBINE	NOT COGEN	1/1/1976	SCE	LOS ANGELES	LONG BEACH GENERATION LLC	OPERATIONAL	9	577
G0648	VALLEY	NATURAL GAS	STEAM TURBINE, NATURAL GAS	NOT COGEN	1/1/1954	LADWP	LOS ANGELES	LOS ANGELES DEPT. OF WATER & POWER	OPERATIONAL	4	517
G0045	HARBOR	NATURAL GAS	COMBINED CYCLE, GAS TURBINE	COGEN	1/1/1949	LADWP	LOS ANGELES	LOS ANGELES DEPT. OF WATER & POWER	OPERATIONAL	6	472
G0035	WATSON COGEN	NATURAL GAS	GAS TURBINE, STEAM TURBINE	COGEN	9/1/1998	SCE	LOS ANGELES	WATSON COGENERATION	OPERATIONAL	6	398
G0236	GRAYSON	NATURAL GAS	STEAM & COMBUSTION TURBINE, COMB. CYCLE	NOT COGEN	4/1/1963	GLENDALE	LOS ANGELES	CITY OF GLENDALE	OPERATIONAL	8	272.5
G0363	TORRANCE REFINERY	NATURAL GAS	GAS TURBINE, STEAM TURBINE	COGEN	5/1/1987	SCE	LOS ANGELES	MOBIL OIL COMPANY	OPERATIONAL	3	222.7
G0061	BROADWAY	NATURAL GAS	STEAM TURBINE	NOT COGEN	1/1/1965	PASADEN	LOS ANGELES	CITY OF PASADENA	OPERATIONAL	3	162
G0410	OLIVE	NATURAL GAS	STEAM TURBINE, GAS TURBINE	NOT COGEN	1/1/1989	BURBANK	LOS ANGELES	BURBANK WATER AND POWER	OPERATIONAL	4	152.6
G0006	AES PLACERITA	NATURAL GAS	GAS TURBINE,STEAM TURBINE	COGEN	12/1/1988	SCE	LOS ANGELES	AES CORPORTATION, APPLIED ENERGY SERVICE	OPERATIONAL	3	160
G0246	HARBOR COGEN	NATURAL GAS	GAS TURBINE	COGEN	4/1/1989	SCE	LOS ANGELES	HARBOR COGENERATION CO	OPERATIONAL	1	81.7
G0329	MAGNOLIA	NATURAL GAS	STEAM TURBINE, COMBINED CYCLE	NOT COGEN	1/1/1943	BURBANK	LOS ANGELES	BURBANK WATER AND POWER	OPERATIONAL	4	81.7
G0760	LOS ANGELES REFINERY	NATURAL GAS	GAS TURBINE	COGEN	1/1/1987	SCE	LOS ANGELES	TOSCO CORP.	OPERATIONAL	2	66.5
G0231	GLENARM	NATURAL GAS	COMBUSTION TURBINE	NOT COGEN	1/1/1955	PASADEN	LOS ANGELES	CITY OF PASADENA	OPERATIONAL	2	60.6
G0776	TEXACO LOS ANGELES REFINERY	NATURAL GAS	GAS TURBINE	NOT COGEN	1/1/1983	LADWP	LOS ANGELES	EQUILON ENTERPRISES LLC, LA REFINING	OPERATIONAL		60
G0988	COLDGEN - SUNLAW COGEN #1	NATURAL GAS	COMBUSTION TURBINE/TOPPING CYCLE	COGEN	5/1/1984	SCE	LOS ANGELES	SUNLAW ENERGY CORP/COGEN PARTNERSHIP	OPERATIONAL		56
G0754	COLDGEN - SUNLAW COGEN #2	NATURAL GAS	COMBUSTION TURBINE/TOPPING CYCLE	COGEN	1/1/1986	SCE	LOS ANGELES	SUNLAW ENERGY CORP/COGEN PARTNERSHIP	OPERATIONAL		56
G0084	CARSON COGEN CO.	NATURAL GAS	GAS TURBINE, STEAM TURBINE	COGEN	1/1/1990	SCE	LOS ANGELES	CARSON COGENERATION COMPANY	OPERATIONAL	2	45.6
G0063	LAKE ONE	NATURAL GAS	RECLAIMED WATER	NOT COGEN	7/18/2002	BURBANK	LOS ANGELES	BURBANK WATER AND POWER	OPERATIONAL		47
G0925	THUMS GENERATION FACILITY	NATURAL GAS			12/20/2002	SCE	LOS ANGELES	THUMS LONG BEACH COMPANY	OPERATIONAL		47
G0764	UCLA COGEN	NATURAL GAS		COGEN	1/5/1994	SCE	LOS ANGELES	UCLA REGENTS	OPERATIONAL		43
G0763	UCLA COGEN	NATURAL GAS	GAS TURBINE	COGEN	4/1/1990	SCE	LOS ANGELES	UCLA	OPERATIONAL	3	43
G0145	JEFFERSON SMURFIT CORP.	NATURAL GAS	COMBUSTION TURBINE/TOPPING CYCLE	COGEN	12/31/1985	SCE	LOS ANGELES	JEFFERSON SMURFIT CORP.	OPERATIONAL		40
G0562	SAN GABRIEL COGEN	NATURAL GAS	COMBINED CYCLE/TOPPING CYCLE	COGEN	11/1/1985	SCE	LOS ANGELES	TRACTEBEL ELECTRICITY & GAS	OPERATIONAL		36
G0756	CIVIC CENTER COGEN	NATURAL GAS	GAS TURBINE, STEAM TURBINE	COGEN	5/1/1989	SCE	LOS ANGELES	COUNTY OF LOS ANGELES	OPERATIONAL	2	34.5
G0078	WILMINGTON	WASTE HEAT	STEAM TURBINE	NOT COGEN	1/1/1996		LOS ANGELES	AIR PRODUCTS & CHEMICALS, INC	OPERATIONAL	1	31.9
G0672	NORWALK ENERGY	NATURAL GAS	GAS TURBINE	COGEN	9/10/1987	SCE	LOS ANGELES	WHEELABRATOR NORKWALK EGY CO	OPERATIONAL	1	30.75
G0652	VERNON	NATURAL GAS	INTERNAL COMBUSTION	NOT COGEN	1/1/1933	VERNON	LOS ANGELES	CITY OF VERNON	OPERATIONAL	7	30.6
G0167	PITCHESS COGEN	NATURAL GAS	GAS TURBINE	COGEN	7/14/1988	SCE	LOS ANGELES	COUNTY OF LOS ANGELES	OPERATIONAL	2	28.3
G0765	LINDE WILMINGTON	NATURAL GAS	COMBINED CYCLE	COGEN	1/1/1989	SCE	LOS ANGELES	PRAXAIR INCORPORATED	OPERATIONAL		28
G0174	DIESEL8	DIESEL		NOT COGEN		VERNON	LOS ANGELES		OPERATIONAL		26
G0158	TOTAL ENERGY FACILITY	DIGESTER GAS	GAS TURBINE COMBINED CYCLE	COGEN	8/12/1995	SCE	LOS ANGELES	L. A. COUNTY SANITATION DISTRICTS	OPERATIONAL	4	26
G0203	N.P. COGEN INC.	NATURAL GAS	COMBINED CYCLE/TOPPING CYCLE	COGEN	11/29/1982	SCE	LOS ANGELES	GE CONTRACTURAL SERVICES	OPERATIONAL		24.7
G0032	PLACERITA UNIT I	NATURAL GAS	I.C. TOPPING CYCLE	COGEN	12/1/1985	SCE	LOS ANGELES	ARCO	OPERATIONAL		21.76
G0033	PLACERITA UNIT II	NATURAL GAS	I.C. TOPPING CYCLE	COGEN	12/1/1985	SCE	LOS ANGELES	ARCO	OPERATIONAL		21.76
G0565	SMURFIT POMONA MILL	NATURAL GAS	GAS TURBINE	COGEN	6/1/1983	SCE	LOS ANGELES	SMURFIT NEWPRINT CORP.	OPERATIONAL		16.3
G0034	ARCO PETROLEUM PRODUCTS CO.	NATURAL GAS	STEAM TURBINE	COGEN	5/1/1985	SCE	LOS ANGELES	ACRO PETROLEUM PRODUCTS	OPERATIONAL		13.2
G0014	PEBBLY BEACH	DIESEL	INTERNAL COMBUSTION	NOT COGEN	1/1/1966		LOS ANGELES		OPERATIONAL	8	9.4
G0757	CALIFORNIA INSTITUTE OF TECHNOLOGY	NATURAL GAS	STEAM TURBINE, GAS TURBINE	COGEN	3/1/1984	SCE	LOS ANGELES	CALIFORNIA INSTITUTE OF TECHNOLOGY	OPERATIONAL	2	5.3
G0028	ANDERSON LITOGRAPH CO.	NATURAL GAS	GAS TURBINE COMBINED CYCLE	COGEN	7/16/1995	SCE	LOS ANGELES		OPERATIONAL		5
G0485	RHONE-POULENC - DOMINQUEZ PLANT	NATURAL GAS	PROCESS STEAM PLANT/BOTTOMING CYCLE	COGEN	8/5/1976	SCE	LOS ANGELES	RHONE-POULENC BASIC CHEMICALS	OPERATIONAL		4.8
G0456	POMONA POWER FACILITY	NATURAL GAS	COMBUSTION TURBINE/TOPPING CYCLE	COGEN	10/4/1987	SCE	LOS ANGELES	POMONA G P INC	OPERATIONAL		3.3
G0437	PAPER PAK PRODUCTS	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	10/1/1984	SCE	LOS ANGELES	PAPER PAK PRODUCTS	OPERATIONAL	1	1.4
G0521	LUNDY - THAGARD OIL	NATURAL GAS	COMBINED CYCLE/TOPPING CYCLE	COGEN	4/15/1991	SCE	LOS ANGELES	LUNDAY THAGARD CO	OPERATIONAL		1.4
G0756	CBS STUDIOS	NATURAL GAS		COGEN	1/1/1988	PG&E	LOS ANGELES	ONSITE ENERGY, CORP	OPERATIONAL		1.4
G0262	LOS ANGELES COLD STORAGE	NATURAL GAS	INTERNAL COMBUSTION	COGEN	8/1/1949		LOS ANGELES	LOS ANGELES COLD STORAGE	OPERATIONAL	3	1.35
G0054	BIOLA UNIVERSITY	NATURAL GAS	GAS TURBINE	COGEN	4/11/1990	SCE	LOS ANGELES	BIOLA UNIVERSITY	OPERATIONAL	2	1.2
G0582	ST. JOHN'S HOSPITAL AND HEALTH CENTER	NATURAL GAS	COMBUSTION TURBINE/TOPPING CYCLE	COGEN	2/5/1992	SCE	LOS ANGELES	ST. JOHN'S HOSPITAL & HEALTH CENTER	OPERATIONAL		1.08
G0621	TECHNI-CAST CORP.	NATURAL GAS		COGEN	4/1/2002		LOS ANGELES	TECHNI-CAST CORP.	OPERATIONAL		1.063
G0025	QUEEN MARY	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	3/30/1989	SCE	LOS ANGELES	WRATHER PORT PROPERTIES	OPERATIONAL		1
G0762	ST. LUKE MEDICAL CENTER	NATURAL GAS		COGEN	1/1/1983	SCE	LOS ANGELES	ORINDNA HEALTH CORPORATION	OPERATIONAL		1
G0544	SANTA MONICA BAY HOTEL	NATURAL GAS	CT/INDUSTRIAL TOPPING CYCLE	COGEN	11/17/1986	SCE	LOS ANGELES	LDEWS SANTA MONICA BEACH HOTEL	OPERATIONAL		0.95
G0457	POMONA VALLEY COMMUNITY HOSPITAL	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	2/15/1987	SCE	LOS ANGELES	POMONA VALLEY COMMUNITY HOSPITAL	OPERATIONAL		0.8
G0046	BENTLEY MILLS	NATURAL GAS	PHOTOVOLTAIC ENGINE	COGEN		SCE	LOS ANGELES	BENTLEY MILLS	OPERATIONAL		0.8
G0237	GREAT WESTERN MALTING CO.	NATURAL GAS	GAS FUELED RECIPROCATING ENGINE	COGEN	1/3/1995	SCE	LOS ANGELES		OPERATIONAL		0.75
G0579	SOUTHERN CALIFORNIA GAS	NATURAL GAS	GAS FUELED RECIPROCATING ENGINE	COGEN	10/30/1987	SCE	LOS ANGELES	SO CALIFORNIA GAS CO.	OPERATIONAL		0.55
G0445	PETROMINERALS CORP.	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	6/24/1988	SCE	LOS ANGELES	PETROMINERALS CORP.	OPERATIONAL		0.6
G0170	DECOGEN	NATURAL GAS	NATURAL GAS	COGEN	4/28/1994	SCE	LOS ANGELES		OPERATIONAL		0.5
G0464	PRESBYTERIAN INTERCOMMUNITY HOSPITAL	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	11/9/1983	SCE	LOS ANGELES	PRESBYTERIAN INTERCOMM. HOSPITAL	OPERATIONAL		0.48
G0251	HENRY MAYO NEWHALL MEMORIAL HOSPITAL	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	2/23/1987	SCE	LOS ANGELES	HENRY MAYO NEWHALL MEMORIAL	OPERATIONAL		0.45
G0043	METAL SURFACES	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	6/9/1993	SCE	LOS ANGELES		OPERATIONAL		0.35

This spreadsheet shows the contents of http://www.energy.ca.gov/database/index.html#powerplants on August 14, 2006.
Some columns have been removed from this data due to space limitations

ID	PLANT NAME	PRIMARY FUEL	TECHNOLOGY	COGEN	DATE ONLINE	SERVICE AREA	COUNTY	OWNER	STATUS	TURBIN COUNT	ON-LINE MW
G0074	CSU LONG BEACH - POOL	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	8/31/1987	SCE	LOS ANGELES	CSU LONG BEACH	OPERATIONAL		0.2
G0614	SOUTHERN CALIFORNIA GAS - SCAQMD	OIL/GAS	FUEL CELL/WASTEHEAT RECOVERY	COGEN	4/10/1992	SCE	LOS ANGELES		OPERATIONAL		0.3
G0606	THE EPISCOPAL HOME	NATURAL GAS	GAS FUELED RECIPROCATING ENGINE	COGEN	1/1/1986	SCE	LOS ANGELES	THE EPISCOPAL HOME	OPERATIONAL		0.2
G0125	CLAREMONT TENNIS CLUB	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	7/14/1988	SCE	LOS ANGELES	CLAREMONT TENNIS CLUB	OPERATIONAL		0.2
G0073	CSU LONG BEACH - DORM	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	6/1/1986	SCE	LOS ANGELES	CAL STATE LONG BEACH	OPERATIONAL		0.15
G0091	CERRITOS COLLEGE	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	12/31/1985	SCE	LOS ANGELES	CERRITOS COLLEGE	OPERATIONAL		0.15
G0055	BIXBY KNOLLS TOWERS	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	2/13/1995	SCE	LOS ANGELES		OPERATIONAL		0.124
G0077	MT. SAN ANTONIO GARDENS	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	1/1/1995	SCE	LOS ANGELES	MT SAN ANTONIO GARDENS	OPERATIONAL		0.12
G0300	LA CANADA USD - LA CANADA SCHOOL	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	9/15/1987	SCE	LOS ANGELES		OPERATIONAL		0.12
G0117	CITY OF LONG BEACH - BELMONT PLAZA POOL	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	1/4/1991	SCE	LOS ANGELES	CITY OF LONG BEACH	OPERATIONAL		0.12
G0156	COTUA CHEESE	NATURAL GAS	COGENERATION	COGEN		SCE	LOS ANGELES		OPERATIONAL		0.12
G0607	THE FORUM #1	NATURAL GAS	GAS FUELED RECIPROCATING ENGINE	COGEN	4/1/1988	SCE	LOS ANGELES	THE FORUM	OPERATIONAL		0.115
G0069	CAL POLY UNIVERSITY - POMONA	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	9/3/1987	SCE	LOS ANGELES	CAL POLY - POMONA	OPERATIONAL		0.115
G0650	VANGUARD - ELECTRONIC PLATING	NATURAL GAS	GAS FUELED RECIPROCATING ENGINE	COGEN	2/1/1998	SCE	LOS ANGELES	VANGUARD/ELECTRONIC PLATING	OPERATIONAL		0.1
G0675	WHITTIER UHSD - LA SERNA HS	NATURAL GAS	GAS FUELED RECIPROCATING ENGINE	COGEN	1/4/1990	SCE	LOS ANGELES	LA SERNA HIGH SCHOOL	OPERATIONAL		0.1
G0353	MICRO UTILITY - SAFE PLANTING	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	8/15/1988	SCE	LOS ANGELES	TRAIN JOHNSON POWER	OPERATIONAL		0.1
G0352	MICRO UTILITY - QUAKER	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	12/29/1987	SCE	LOS ANGELES	TRAIN JOHNSON POWER	OPERATIONAL		0.1
G0349	MICRO UTILITY - FOSS PLANTING	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	7/11/1988	SCE	LOS ANGELES	FOSS PLATING INC.	OPERATIONAL		0.1
G0134	COGENIC - ERNE SANITARIUM	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	7/1/1985	SCE	LOS ANGELES	ST ERNE SANITARIUM	OPERATIONAL		0.1
E0112	SOUTHEAST RESOURCE RECOVERY	MSW	MUNICIPAL SOLID WASTE	NOT COGEN	7/6/1987	SCE	LOS ANGELES	SERRF JOINT POWERS AUTHORITY	OPERATIONAL	1	34.6
E0130	PALOS VERDES GAS TO ENERGY FACILITY	LANDFILL GAS	RECIPROCATING ENGINE	NOT COGEN	5/1/1988	SCE	LOS ANGELES	L.A. COUNTY SANITATION DISTRICTS	OPERATIONAL	1	13
E0113	COMMERCE REFUSE TO ENERGY	MSW	STEAM TURBINE	NOT COGEN	11/1/1988	SCE	LOS ANGELES	LA COUNTY SANITATION DICTRICTS	OPERATIONAL	1	11.5
E0129	SPADRA LANDFILL GAS TO ENERGY	LANDFILL GAS	STEAM TURBINE	NOT COGEN	4/1/1991	SCE	LOS ANGELES	L.A. COUNTY SANITATION DISTRICTS	OPERATIONAL	1	9.9
E0143	TOYON	MSW	RECIPROCATING ENGINE	NOT COGEN	12/1/1985	SCE	LOS ANGELES	8300 TUJUNGA AVE CORPORATION	OPERATIONAL	5	9.3
E0142	PENROSE	MSW	RECIPROCATING ENGINE	NOT COGEN	12/1/1985	SCE	LOS ANGELES	8300 TUJUNGA AVE CORPORATION	OPERATIONAL	5	9.25
E0127	PUENTE HILLS RECOVERY	LANDFILL GAS	GAS TURBINE	NOT COGEN	1/1/1984	SCE	LOS ANGELES	L.A. COUNTY SANITATION DISTRICTS	OPERATIONAL	2	7.8
E0168	MM LOPEZ ENERGY LLC	MSW	RECIPROCATING ENGINE	NOT COGEN	1/1/1999	SCE	LOS ANGELES	MINNESOTA METHANE LOPEZ ENERGY LLC	OPERATIONAL	2	6.6
E0152	MM WEST COVINA LLC	MSW	LANDFILL GAS RECOVERY, STEAM TURBINE	NOT COGEN	5/1/1993	SCE	LOS ANGELES	MINNESOTA METHANE WEST COVINA LLC	OPERATIONAL		3.25
H0313	MAMMOTH POOL	HYDRO	HYDRO,WATER	NOT COGEN	3/26/1960	SCE	MADERA	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	2	190
H0034	BIG CREEK 4	HYDRO	HYDRO,WATER	NOT COGEN	6/12/1951	SCE	MADERA	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	2	100.2
H0196	FRIANT HYDRO FACILITY	HYDRO	HYDRO,WATER	NOT COGEN	4/16/1985	PG&E	MADERA	FRIANT POWER AUTHORITY	OPERATIONAL	3	25
H0570	A.G. WISHON	HYDRO	HYDRO,WATER	NOT COGEN	9/1/1910	PG&E	MADERA	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	4	20
H0304	MADERA CANAL	HYDRO		NOT COGEN	7/1/1985	PG&E	MADERA	FRIANT POWER AUTHORITY	OPERATIONAL		8.8
H0457	SAN JOAQUIN 3	HYDRO	HYDRO,WATER	NOT COGEN	7/1/1923	PG&E	MADERA	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	4.2
H0449	SAN JOAQUIN 2	HYDRO	HYDRO,WATER	NOT COGEN	8/1/1917	PG&E	MADERA	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	3.2
H0310	MADERA CHOWCHILLA	HYDRO	HYDRO,WATER	NOT COGEN	2/2/1985	PG&E	MADERA	MADERA-CHOWCHILLA POWER AUTHORITY	OPERATIONAL	1	2.1
H0413	RIVER OUTLET	HYDRO		NOT COGEN	4/1/1985	PG&E	MADERA	FRIANT POWER AUTHORITY	OPERATIONAL		2
H0306	MADERA CANAL - 1923	HYDRO		NOT COGEN	4/1/1985	PG&E	MADERA	MADERA-CHOWCHILLA POWER AUTHORITY	OPERATIONAL		0.925
H0120	CRANE VALLEY	HYDRO	HYDRO,WATER	NOT COGEN	1/1/1910	PG&E	MADERA	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	0.9
H0305	MADERA CANAL - 1174 + 84	HYDRO		NOT COGEN	4/1/1985	PG&E	MADERA	MADERA-CHOWCHILLA POWER AUTHORITY	OPERATIONAL		0.565
H0309	MADERA CANAL STATION 1302	HYDRO		NOT COGEN	4/16/1985	PG&E	MADERA	MADERA-CHOWCHILLA POWER AUTHORITY	OPERATIONAL		0.424
H0448	SAN JOAQUIN 1A	HYDRO	HYDRO,WATER	NOT COGEN	5/1/1919	PG&E	MADERA	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	0.4
G0256	HEUBLEIN WINES	NATURAL GAS		COGEN	8/24/1984	PG&E	MADERA		OPERATIONAL		0.325
E0050	MADERA POWER LLC	AG. & WOODWASTE	DIRECT COMBUSTION	NOT COGEN	7/18/1988	PG&E	MADERA	EPI	OPERATIONAL		28
H0175	NEW EXCHEQUER	HYDRO	HYDRAULIC TURBINE - PIPELINE	NOT COGEN	1/1/1967	PG&E	MARIPOSA	MERCED IRRIGATION DISTRICT (MEID)	OPERATIONAL	1	94.5
H0316	MCSWAIN	HYDRO	HYDRAULIC TURBINE-PIPELINE	NOT COGEN	7/1/1967	PG&E	MARIPOSA	MERCED IRRIGATION DISTRICT (MEID)	OPERATIONAL	1	6
H0401	POTTER VALLEY	HYDRO	HYDRO,WATER	NOT COGEN	1/1/1910	PG&E	MENDOCINO	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL		9.2
H0283	LAKE MENDOCINO	HYDRO	HYDRAULIC TURBINE - CONVENTIONAL	NOT COGEN	3/1/1987	UKIAH	MENDOCINO	CITY OF UKIAH	OPERATIONAL	2	3.6
H0403	BES HYDRO INC.	HYDRO		NOT COGEN	9/30/1987	PG&E	MENDOCINO	BES HYDRO CO	OPERATIONAL		0.4
H0317	MCFADDEN FARM	HYDRO		NOT COGEN	7/1/1983	PG&E	MENDOCINO	EUGEN J M MCFADDEN	OPERATIONAL		0.35
H0452	W R GIANELLI	PUMPED STORAGE	PUMPED STORAGE, WATER	NOT COGEN	5/1/1967	PG&E	MERCED	CA DEPT. OF WATER RESOURCES (CDWR)	OPERATIONAL	8	424
H0363	O'NEILL	PUMPED STORAGE	PUMPED STORAGE, WATER	NOT COGEN	9/1/1967	PG&E	MERCED	UNITED STATES BUREAU OF RECLAMATION (USBR)	OPERATIONAL	6	14.4
H0324	MERCED FALLS	HYDRO	HYDRO WATER	NOT COGEN	7/1/1930	PG&E	MERCED	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	3.6
H0325	MERCED ID - PARKER	HYDRO	HYDRAULIC TURBINR-PIPELINE WATER	NOT COGEN	9/23/1981	PG&E	MERCED	MERCED IRRIGATION DISTRICT (MEID)	OPERATIONAL	1	2.69
H0572	UNITED HYDRO - WOLFSEN BYPASS	HYDRO		NOT COGEN	2/1/1986	PG&E	MERCED	CENTRAL CALIFORNIA IRRIGATION DISTRICT	OPERATIONAL		1
H0300	RETA - CANAL CREEK	HYDRO	HYDRAULIC TURBINE-PIPELINE, WATER	NOT COGEN	11/1/1927	PG&E	MERCED	MERCED IRRIGATION DISTRICT (MEID)	OPERATIONAL	1	0.9
H0301	FAIRFIELD	HYDRO	HYDRAULIC TURBINE-PIPELINE	NOT COGEN	8/2/1983	PG&E	MERCED	MERCED IRRIGATION DISTRICT (MEID)	OPERATIONAL	1	0.9
H0453	UNITED HYDRO INC. #2 - SAN LUIS BYPASS	HYDRO		NOT COGEN	2/1/1986	PG&E	MERCED	CENTRAL CALIFORNIA IRRIGATION DISTRICT	OPERATIONAL		0.675
G0283	SAN JOAQUIN POWER CO.	NATURAL GAS		COGEN	4/19/1991	PG&E	MERCED		OPERATIONAL		10.75
E0043	J.R. WOODS INC.	MSW	LANDFILL GAS	COGEN	1/1/1992	PG&E	MERCED	JR WOOD INC.	OPERATIONAL	1	1.06
T0036	PLES1	HYDROTHERMAL	BINARY CYCLE	NOT COGEN	12/1/1990	SCE	MONO	MAMMOTH-PACIFIC, L.P.	OPERATIONAL	3	15
T0036	MAMMOTH-PACIFIC II	HYDROTHERMAL	BINARY CYCLE	NOT COGEN	12/1/1990	SCE	MONO	MAMMOTH-PACIFIC, L.P.	OPERATIONAL	3	15
T0035	MAMMOTH-PACIFIC I	HYDROTHERMAL	BINARY CYCLE	NOT COGEN	11/1/1984	SCE	MONO	MAMMOTH-PACIFIC, L.P.	OPERATIONAL	2	10
H0226	MIDDLE GORGE	HYDRO	HYDRAULIC TURBINE - PIPELINE	NOT COGEN	5/1/1952	LADWP	MONO	LOS ANGELES DEPT. OF WATER & POWER	OPERATIONAL	1	36
H0228	UPPER GORGE	HYDRO	HYDRAULIC TURBINE - PIPELINE, PONDAGE	NOT COGEN	1/1/1939	LADWP	MONO	LOS ANGELES DEPT. OF WATER & POWER	OPERATIONAL	1	37.5
H0420	RUSH CREEK	HYDRO	HYDRO,WATER	NOT COGEN	10/17/1918	SCE	MONO	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	2	11.85
H0398	POOLE	HYDRO	HYDRO,WATER	NOT COGEN	1/1/1924	SCE	MONO	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	1	11.25
H0296	LUNDY	HYDRO	HYDRO,WATER	NOT COGEN	12/9/1911	SCE	MONO	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	2	3
H0231	MILNER CREEK	HYDRO	RUN-OF-RIVER	NOT COGEN	7/16/1983	SCE	MONO	HESI	OPERATIONAL	1	0.4
H0341	NACIMIENTO HYDROELECTRIC	HYDRO	HYDRO,WATER	NOT COGEN	7/15/1957	PG&E	MONTEREY	MONTEREY COUNTY WATER RESOURCES AGENCY	OPERATIONAL	2	4.35
G0372	MOSS LANDING	NATURAL GAS	STEAM TURBINE	NOT COGEN	1/11/1966	PG&E	MONTEREY	DUKE ENERGY	OPERATIONAL	4	2545
G0019	CALPINE KING CITY COGEN	NATURAL GAS	COMBINED CYCLE	COGEN	5/1/1989	PG&E	MONTEREY	CALPINE KING CITY COGENERATION LLC	OPERATIONAL		130
G0623	CALPINE KING ENERGY CENTER	NATURAL GAS	BROWN FIELD	NOT COGEN	1/14/2002	PG&E	MONTEREY	CALPINE	OPERATIONAL		60
G0520	SALINAS RIVER COGEN	NATURAL GAS	GAS TURBINE	COGEN	3/1/1991	PG&E	MONTEREY	SALINAS RIVER COGEN CO.	OPERATIONAL		49.6
G0547	SARGENT CANYON COGEN	NATURAL GAS	GAS TURBINE	COGEN	2/1/1991	PG&E	MONTEREY	SARGENT CANYON CEOGEN	OPERATIONAL	1	38
G0569	MONTEREY POWER CO.	NATURAL GAS		COGEN	12/29/1990	PG&E	MONTEREY	SUNNYSIDE COGENERATION INC.	OPERATIONAL		6
G0038	ASILOMAR	NATURAL GAS		COGEN	9/6/1985	PG&E	MONTEREY		OPERATIONAL		0.55
E0069	SOLEDAD ENERGY	WOODWASTE	DIRECT COMBUSTION	NOT COGEN	12/22/1990	DWR	MONTEREY	YANKEE ENERGY	OPERATIONAL		15
E0135	MARINA LANDFILL GAS	MSW	LANDFILL GAS	NOT COGEN	12/30/1993	PG&E	MONTEREY	MONTEREY REGIONAL WASTE MGMT DIST.	OPERATIONAL		5.4
E0055	MONTEREY REGIONAL WATER POLLUTION CONTROL COGEN	MSW	DIGESTER GAS	COGEN	8/28/1988	PG&E	MONTEREY	MRWPCA (MONTEREY REGIONAL WATER CENTRAL)	OPERATIONAL		1.74
E0144	SALINAS	MSW	INTERNAL COMBUSTION	NOT COGEN	12/10/1986	PG&E	MONTEREY	PACIFIC RECOVERY CORP	OPERATIONAL	1	1.4
H0043	MONTICELLO	HYDRO	HYDRO,WATER	NOT COGEN	7/7/1983	PG&E	NAPA	SID	OPERATIONAL	3	11.9
G0653	YOUNTVILLE COGEN	NATURAL GAS	GAS TURBINE	COGEN	8/6/1986	PG&E	NAPA	YOUNTVILLE COGEN ASSOC	OPERATIONAL	2	3
G0262	NAPA STATE HOSPITAL	NATURAL GAS	GAS TURBINE	COGEN	1/1/1984	PG&E	NAPA	NAPA STATE HOSPITAL	OPERATIONAL	2	1.6
E0118	AMERICAN CANYON POWER PLANT	LANDFILL GAS	RECIPROCATING ENGINE	NOT COGEN	12/1/1985	PG&E	NAPA	GAS RECOVERY SYSTEMS INC.	OPERATIONAL	2	1.76
H0065	CHICAGO PARK	HYDRO	HYDRO,WATER	NOT COGEN	11/1/1966	PG&E	NEVADA	NEVADA IRRIGATION DISTRICT	OPERATIONAL	1	44
H0157	DUTCH FLAT 2	HYDRO		NOT COGEN	11/1/1965	PG&E	NEVADA	NEVADA IRRIGATION DISTRICT	OPERATIONAL	1	27.3
H0424	ROLLINS	HYDRO	HYDRO,WATER	NOT COGEN	8/1/1980	PG&E	NEVADA	NEVADA IRRIGATION DISTRICT	OPERATIONAL	2	12.15
H0346	NARROWS	HYDRO	HYDRO,WATER	NOT COGEN	12/1/1943	PG&E	NEVADA	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	12
H0490	SPAULDING 1	HYDRO	HYDRO,WATER	NOT COGEN	5/1/1928	PG&E	NEVADA	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	7
H0492	SPAULDING 3	HYDRO	HYDRO,WATER	NOT COGEN	1/1/1929	PG&E	NEVADA	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL		5.8
H0132	DEER CREEK	HYDRO	HYDRO,WATER	NOT COGEN	5/1/1908	PG&E	NEVADA	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	5.5
H0491	SPAULDING 2	HYDRO	HYDRO,WATER	NOT COGEN	7/1/1926	PG&E	NEVADA	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL		4.4
H0351	NEVADA POWER AUTHORITY/BOWMAN POW	HYDRO	HYDRO,WATER	NOT COGEN	8/18/1965	PG&E	NEVADA	NEVADA IRRIGATION DISTRICT	OPERATIONAL		3.6

Exhibit B.1.2.2.1
CEC's California Power Plants Database

PP_Map_Report_Master_NO_COORDS

ID	PLANTNAME	PRIMARY FUEL	TECHNOLOGY	COGEN	DATE ONLINE	SERVICE AREA	COUNTY	OWNER	STATUS	TURBIN COUNT	ON-LINE MW
H0178	FARAD	HYDRO	HYDRAULIC TURBINE - CONVENTIONAL	NOT COGEN	1/1/1933	SPPC	NEVADA	SIERRA PACIFIC RESOURCES	OPERATIONAL	2	2.8
H0347	NIDISCOTTS FLAT	HYDRO	HYDRO,WATER	NOT COGEN	12/14/1984	PG&E	NEVADA	NEVADA IRRIGATION DISTRICT	OPERATIONAL	1	0.85
H0109	COMBIE NORTH	HYDRO	HYDRO,WATER	NOT COGEN	3/24/1968	PG&E	NEVADA	NEVADA IRRIGATION DISTRICT	OPERATIONAL	1	0.33
H0577	YORBA LINDA FEEDER	HYDRO	HYDRAULIC TURBINE - PIPELINE	NOT COGEN	11/1/1981	SCE	ORANGE	METROPOLITAN WATER DISTRICT	OPERATIONAL	1	5.09
H0339	VALLEY VIEW	HYDRO	HYDRAULIC TURBINE - PIPELINE	NOT COGEN	8/1/1985	SCE	ORANGE	METROPOLITAN WATER DISTRICT	OPERATIONAL	1	4.1
H0119	COYOTE CREEK	HYDRO	HYDRAULIC TURBINE - PIPELINE	NOT COGEN	4/1/1984	SCE	ORANGE	METROPOLITAN WATER DISTRICT	OPERATIONAL	1	3.13
H0345	MWD OF ORANGE COUNTY	HYDRO	PRESSURE-REDUCING STATION	NOT COGEN	3/30/1992	SCE	ORANGE	MWD OF ORANGE COUNTY	OPERATIONAL		0.8
H0247	IRVINE RANCH WATER DISTRICT	HYDRO	PRESSURE-REDUCING STATION	NOT COGEN	4/1/1984	SCE	ORANGE	IRVINE RANCH WATER DISTRICT	OPERATIONAL		0.191
G0274	HUNTINGTON BEACH	DISTILLATE OIL	STEAM TURBINE, GAS TURBINE	NOT COGEN	6/1/1978	SCE	ORANGE	AES CORP	OPERATIONAL	4	880
G0026	ANAHEIM GAS TURBINE	NATURAL GAS	GAS TURBINE, NATURAL GAS	NOT COGEN	6/13/1988	ANAHEIM	ORANGE	CITY OF ANAHEIM	OPERATIONAL		45.66
G0023	AMERICAN MCGAW	NATURAL GAS	STEAM TURBINE & GAS TURBINE	COGEN	10/1/1981	SCE	ORANGE	AMERICAN MC GAW	OPERATIONAL		8.6
G0024	AMERICAN MCGAW #2	NATURAL GAS	GAS-TURBINE	COGEN	2/21/1995	SCE	ORANGE	AMERICAN MC GAW	OPERATIONAL		6.1
G0483	ORANGE COUNTY SANITATION DISTRICT PLANT 1	NATURAL GAS	GAS-FUELEDRECIPROCATING ENGINE	COGEN	6/16/1993	SCE	ORANGE	ORANGE COUNTY SANITATION DISTRICT	OPERATIONAL		4.5
G0542	UNOCAL RESEARCH	NATURAL GAS	COMBUSTION TURBINE/TOPPING CYCLE	COGEN	12/27/1990	SCE	ORANGE	UNOCAL	OPERATIONAL		3.623
G0465	RED LION INN	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	6/15/1987	SCE	ORANGE	RED LION INN	OPERATIONAL		0.46
G0507	ROYALTY CARPET MILLS	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	2/15/1995	SCE	ORANGE		OPERATIONAL		0.425
G0110	CHIQUITA WATER RECLAMATION	METHANE	RECIPOCATING ENGINE	NOT COGEN	3/1/1988	SDG&E	ORANGE	SANTA MARGARITA WATER DISTRICT	OPERATIONAL		0.27
G0513	SOUTHERN CALIFORNIA GAS - HYATT REGENCY	NATURAL GAS	FUEL CELL/WASTEHEAT RECOVERY	COGEN	6/14/1992	SCE	ORANGE		OPERATIONAL		0.2
G0013	ALL METALS PROCESSING	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	10/5/1984	SCE	ORANGE		OPERATIONAL		0.175
G0022	AMERICAN CORNERSTONE - HOLIDAY INN	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	6/1/1988	SCE	ORANGE	INTEGRATED TOTAL EGY	OPERATIONAL		0.16
G0520	TURBINE TECH	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	12/8/1988	SCE	ORANGE	TURBINE TECHNOLOGY	OPERATIONAL		0.15
G0427	PCA METAL FINISHING	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	12/15/1984	SCE	ORANGE		OPERATIONAL		0.1
E0117	COYOTE CANYON	LANDFILL GAS	STEAM TURBINE	NOT COGEN	4/1/1989	SCE	ORANGE	GAS RECOVERY SYSTEMS INC.	OPERATIONAL	1	20
E0025	PLANT NO. 2	DIGESTER GAS	DIGESTER GAS/OTHER	NOT COGEN	6/1/1993	SCE	ORANGE	ORANGE COUNTY SANITIATION DISTRICT	OPERATIONAL	6	18
E0194	MM PRIMA DESCHECHA ENERGY LLC	LANDFILL GAS	RECIPROCATING ENGINE	NOT COGEN	1/1/1999	SCE	ORANGE	NEO CORPORATION	OPERATIONAL	2	6.1
E0109	BREA POWER PARTNERS LP	MSW	RECIPROCATING ENGINE	NOT COGEN	12/1/1985	SCE	ORANGE	BREA POWER PARTNERS LP	OPERATIONAL	3	5.4
E0155	ALISO WATER MANAGEMENT AGENCY	DIGESTER GAS	DIGESTER GAS,MUNICIPAL	NOT COGEN	3/1/1997	SCE	ORANGE	SOUTH ORANGE CO. WASTEWATER AUTHORITY	OPERATIONAL	3	1.2
H0275	LOWELL J. STEPHENSON	HYDRO	WATER TURBINE	NOT COGEN	10/1/1966	PG&E	PLACER	PLACER COUNTY WATER AGENCY (PCWA)	OPERATIONAL	2	116
H0406	RALSTON	HYDRO	HYDRO,WATER	NOT COGEN	10/1/1966	PG&E	PLACER	PLACER COUNTY WATER AGENCY (PCWA)	OPERATIONAL	2	78
H0164	DRUM 1	HYDRO	HYDRO,WATER	NOT COGEN	11/28/1913	PG&E	PLACER	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	4	55.5
H0155	DRUM 2	HYDRO	HYDRO,WATER	NOT COGEN	12/18/1955	PG&E	PLACER	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	49.5
H0156	DUTCH FLAT 1	HYDRO		NOT COGEN	3/29/1943	PG&E	PLACER	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	22
H0169	WISE	HYDRO	HYDRO,WATER	NOT COGEN	3/1/1917	PG&E	PLACER	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	2	17.1
H0195	FRENCH MEADOWS	HYDRO	HYDRO,WATER, WATER TURBINE GENERATOR	NOT COGEN	10/1/1966	PG&E	PLACER	PLACER COUNTY WATER AGENCY (PCWA)	OPERATIONAL	1	15
H0357	NEWCASTLE	HYDRO	HYDRO,WATER	NOT COGEN	10/1/1966	PG&E	PLACER	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	11.6
H0217	HALSEY	HYDRO	HYDRO,WATER	NOT COGEN	12/6/1918	PG&E	PLACER	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	11
H0083	CAMP FAR WEST	HYDRO	HYDRO,WATER	NOT COGEN	2/1/1985	SMUD	PLACER	SACRAMENTO MUNCIPAL UTILITY DISTRICT	OPERATIONAL	1	6.8
H0374	OXBOW	HYDRO	HYDRO,WATER, WATER TURBINE GENERATOR	NOT COGEN	10/1/1966	PG&E	PLACER	PLACER COUNTY WATER AGENCY (PCWA)	OPERATIONAL	1	6.1
H0005	ALTA	HYDRO	HYDRO,WATER	NOT COGEN	11/1/1902	PG&E	PLACER	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	2	2
H0054	COMBIE SOUTH	HYDRO	HYDRO,WATER	NOT COGEN	4/25/1984	PG&E	PLACER	NEVADA IRRIGATION DISTRICT	OPERATIONAL	1	1.5
H0226	HELL HOLE	HYDRO	HYDRO,WATER, WATER TURBINE GENERATOR	NOT COGEN	4/30/1983	PG&E	PLACER	PLACER COUNTY WATER AGENCY (PCWA)	OPERATIONAL	1	0.725
H0366	SWISS AMERICA	HYDRO		NOT COGEN	12/23/1985	PG&E	PLACER	SWISS-AMERICAN CO	OPERATIONAL		0.1
G0382	ROSEVILLE	NATURAL GAS	COMBUSTION TURBINE	NOT COGEN	4/1/1996	PG&E	PLACER	NORTHERN CALIFORNIA POWER AGENCY/CSC	OPERATIONAL	2	51.75
G0294	KINGS BEACH	DIESEL	INTERNAL COMBUSTION	NOT COGEN	1/1/1969	SPPC	PLACER	SIERRA PACIFIC POWER COMPANY	OPERATIONAL	6	16.2
E0099	RIO BRAVO ROCKLIN	WOODWASTE	DIRECT COMBUSTION	NOT COGEN	6/1/1989	PG&E	PLACER	RIO BRAVO ROCKLIN	OPERATIONAL	1	28
E0004	SPI- LINCOLN	WOODWASTE	DIRECT COMBUSTION	COGEN	6/1/1957	PG&E	PLACER	SIERRA PACIFIC INDUSTRIES, INC.	OPERATIONAL	2	13
H0023	BELDEN	HYDRO	HYDRO,WATER	NOT COGEN	9/14/1969	PG&E	PLUMAS	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	125
H0068	CARIBOU 2	HYDRO	HYDRO,WATER	NOT COGEN	11/9/1958	PG&E	PLUMAS	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	2	120
H0417	ROCK CREEK	HYDRO	HYDRO,WATER	NOT COGEN	2/1/1950	PG&E	PLUMAS	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	2	112
H0067	CARIBOU 1	HYDRO	HYDRO,WATER	NOT COGEN	6/1/1921	PG&E	PLUMAS	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	3	73.8
H0121	CHESTA	HYDRO	HYDRO,WATER	NOT COGEN	11/29/1949	PG&E	PLUMAS	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	2	70
H0052	BUCKS CREEK	HYDRO	HYDRO,WATER	NOT COGEN	3/4/1928	PG&E	PLUMAS	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	2	58
H0057	BUTT VALLEY	HYDRO	HYDRO,WATER	NOT COGEN	12/31/1958	PG&E	PLUMAS	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	40
H0213	GRIZZLY	HYDRO	HYDRO,WATER	NOT COGEN	11/7/1993	PG&E	PLUMAS	SILICON VALLEY POWER - CITY OF CLARA (CSC)	OPERATIONAL	1	22.95
H0218	HAMILTON BRANCH	HYDRO	HYDRO,WATER	NOT COGEN	8/1/1921	PG&E	PLUMAS	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	2	5.39
H0364	OAK FLAT	HYDRO	HYDRO,WATER	NOT COGEN	11/7/1985	PG&E	PLUMAS	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	1.3
H0209	GRAEAGLE	HYDRO		NOT COGEN	12/28/1981	PG&E	PLUMAS	HENWOOD ASSOCIATES INC. (HAI)	OPERATIONAL	1	0.45
G0461	PORTOLA	DIESEL	INTERNAL COMBUSTION	NOT COGEN	1/1/1960	SPPC	PLUMAS	SIERRA PACIFIC POWER COMPANY	OPERATIONAL	3	5.7
E0061	SPI- QUINCY	WOODWASTE	DIRECT COMBUSTION	COGEN	12/1/1986	PG&E	PLUMAS	SIERRA PACIFIC INDUSTRIES, INC.	OPERATIONAL	2	27.5
E0035	COLLINS PINE CO. PROJECT	WOODWASTE	DIRECT COMBUSTION	COGEN	1/1/1984	PG&E	PLUMAS	COLLINS PINE CO.	OPERATIONAL	1	13.3
H0611	DIAMOND VALLEY LAKE	HYDRO		NOT COGEN	5/1/2001	SCE	RIVERSIDE	METROPOLITAN WATER DISTRICT	OPERATIONAL	1	36.6
H0362	PERRIS	HYDRO	HYDRAULIC TURBINE - PIPELINE	NOT COGEN	5/1/1983	SCE	RIVERSIDE	METROPOLITAN WATER DISTRICT	OPERATIONAL	1	7.94
H0282	LAKE MATHEWS	HYDRO	HYDRAULIC TURBINE - PIPELINE	NOT COGEN	8/1/1960	SCE	RIVERSIDE	METROPOLITAN WATER DISTRICT	OPERATIONAL	1	4.9
H0114	CORONA	HYDRO	HYDRAULIC TURBINE - PIPELINE	NOT COGEN	8/1/1983	SCE	RIVERSIDE	METROPOLITAN WATER DISTRICT	OPERATIONAL	1	2.65
H0509	TEMESCAL	HYDRO	HYDRAULIC TURBINE - PIPELINE	NOT COGEN	4/1/1983	SCE	RIVERSIDE	METROPOLITAN WATER DISTRICT	OPERATIONAL	1	2.65
H0445	SAN GORGONIO 1	HYDRO	HYDRO,WATER	NOT COGEN	12/1/1923	SCE	RIVERSIDE	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	1	1.5
H0136	WHITEWATER	HYDRO	RUN-OF-RIVER	NOT COGEN	4/1/1986	SCE	RIVERSIDE	DESERT WATER AGENCY	OPERATIONAL		1.375
H0444	SAN GORGONIO	HYDRO		NOT COGEN	2/1/1986	SCE	RIVERSIDE	CITY OF BANNING	OPERATIONAL		0.728
H0446	SAN GORGONIO 2	HYDRO	HYDRO,WATER	NOT COGEN	12/1/1923	SCE	RIVERSIDE	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	1	0.7
H0261	LAKE HEMET MWD - NORTH FORK	HYDRO	PRESSURE-REDUCING STATION	NOT COGEN	6/21/1984	SCE	RIVERSIDE	LAKE HEMET MWD	OPERATIONAL		0.65
H0447	SAN GORGONIO UPPER	HYDRO		NOT COGEN	12/1/1986	SCE	RIVERSIDE	CITY OF BANNING	OPERATIONAL		0.41
G0018	WILDFLOWER - INDIGO	NATURAL GAS	GREEN FIELD	NOT COGEN	7/26/2001		RIVERSIDE	INTERGEN	OPERATIONAL		135
G0130	COACHELLA	NATURAL GAS	COMBUSTION TURBINE, NATURAL GAS	NOT COGEN	6/1/1973	IID	RIVERSIDE	IMPERIAL IRRIGATION DISTRICT	OPERATIONAL	4	80
G0823	CLEARWATER COGEMERATION PROJECT	NATURAL GAS	COMBINED CYCLE	COGEN	3/1/2003		RIVERSIDE	CITY OF COLTON	OPERATIONAL	2	49
G0149	CORONA COGEN	NATURAL GAS	GAS TURBINE	COGEN	5/21/1988	SCE	RIVERSIDE	CORONA ENERGY PARTNERS	OPERATIONAL		47
G0812	SPRINGS GENERATION PROJECT	NATURAL GAS	GAS TURBINE	NOT COGEN	7/17/2002		RIVERSIDE	CITY OF RIVERSIDE	OPERATIONAL	4	40
G0119	MUNICIPAL COGEN	NATURAL GAS	GAS TURBINE	COGEN	4/1/1985	SCE	RIVERSIDE	CITY OF PALM SPRINGS	OPERATIONAL	2	1.3
G0120	CITY OF PALM SPRINGS - SUNRISE PLAZA	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	6/13/1985	SCE	RIVERSIDE	CITY OF PALM SPRINGS	OPERATIONAL		0.641
G0184	EUA/RCII - VINTAGE COUNTRY CLUB	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	7/12/1990	SCE	RIVERSIDE	RIDGEWOOD POWER CORP	OPERATIONAL		0.6
G0065	CES ENERGY DORONA - PACIFIC CLAY	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	6/15/1990	SCE	RIVERSIDE	PACIFIC CLAY PRODUCTS	OPERATIONAL		0.6
G0064	CES ENERGY ALBERHILL	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	6/4/1991	SCE	RIVERSIDE	CES ALBERHILL, LTD	OPERATIONAL		0.56
G0183	EUA/RCII - PALM VALLEY COUNTRY CLUB	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	3/25/1991	SCE	RIVERSIDE	THE PALM VALLEY C C	OPERATIONAL		0.41
G0182	EUA/RCII - MONTEREY COUNTRY CLUB	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	7/6/1991	SCE	RIVERSIDE	THE MONTEREY COUNTRY CLUB	OPERATIONAL		0.115
W0252	NAWP INC - 6087	WIND	WIND TURBINE	NOT COGEN	12/18/1985	SCE	RIVERSIDE	AL TECH ENERGY INC.	OPERATIONAL		55
W0250	ZOND SYSTEMS, INC	WIND	WIND TURBINE	NOT COGEN	11/29/1984	SCE	RIVERSIDE	ENRON WIND	OPERATIONAL		29.899
W0334	TRES VAQUEROS	WIND	WIND TURBINE	NOT COGEN	1/4/1988	SCE	RIVERSIDE	INTERNATIONAL WIND COMPANIES	OPERATIONAL	86	26.8
W0288	SAN GORGONIO FARMS, INC	WIND	WIND TURBINE	NOT COGEN	4/16/1986	SCE	RIVERSIDE	SAN GORGONIO WIND FARMS, INC.	OPERATIONAL		27.03
W0295	FORAS ENERGY, INC. - 6090	WIND	WIND TURBINE	NOT COGEN	12/31/1988	SCE	RIVERSIDE	MARK TECHNOLOGIES CO	OPERATIONAL		24.57
W0258	EUI MANAGEMENT PH, INC.	WIND	WIND TURBINE	NOT COGEN	12/31/1986	SCE	RIVERSIDE	EUI MANAGEMENT PH, INC/ENERGY UNLIMITED	OPERATIONAL		19.3
W0311	ZOND SYSTEMS, INC. - 6112	WIND	WIND TURBINE	NOT COGEN	12/1/1985	SCE	RIVERSIDE	PHOENIX ENERGY, LIMITED	OPERATIONAL		19.265
W0318	WINTEC ENERGY, LTD	WIND	WIND TURBINE	NOT COGEN	12/22/1986	SCE	RIVERSIDE	WINTEC, LTD.	OPERATIONAL		18.237
W0300	ENXCO	WIND	WIND TURBINE	NOT COGEN	12/31/1985	SCE	RIVERSIDE	WESTWIND ASSOCIATION	OPERATIONAL		16.207
W0293	FORAS ENERGY, INC.	WIND	WIND TURBINE	NOT COGEN	12/18/1985	SCE	RIVERSIDE	ENERGY CONVERSION	OPERATIONAL		14.154
W0267	LG&E POWER, INC - 6030	WIND	WIND TURBINE	NOT COGEN	12/13/1984	SCE	RIVERSIDE	FRED NOBLE	OPERATIONAL		13.5

This spreadsheet shows the contents of http://www.energy.ca.gov/database/index.html#powerplants on August 14, 2006.
Some columns have been removed from this data due to space limitations

Exhibit B.1.2.2.1
CEC's California Power Plants Database

PP_Map_Report_Master_NO_COORDS

ID	PLANTNAME	PRIMARY FUEL	TECHNOLOGY	COGEN	DATE ONLINE	SERVICE AREA	COUNTY	OWNER	STATUS	TURBIN COUNT	ON-LINE MW
W0335	NORTWIND VAQUERO - SOUZA WINDPARK	WIND	WIND TURBINE	NOT COGEN	1/4/1986	SCE	RIVERSIDE		OPERATIONAL		13
W0277	PHOENIX WEST	WIND	WIND TURBINE	NOT COGEN	1/10/1985	SCE	RIVERSIDE	SEAWEST ENERGY GROUP	OPERATIONAL	220	12.1
W0279	FORAS ENERGY, INC.	WIND	WIND TURBINE	NOT COGEN	10/15/1986	SCE	RIVERSIDE	DIFWIND PARTNERS	OPERATIONAL		11.72
W0298	SEAWEST WIND FARMS	WIND	WIND TURBINE	NOT COGEN	12/1/1985	SCE	RIVERSIDE	SEAWEST ENERGY GROUP	OPERATIONAL	178	11.57
W0281	SUNBELT 1 & 2	WIND	WIND TURBINE	NOT COGEN	3/15/1985	SCE	RIVERSIDE	SEAWEST ENERGY GROUP	OPERATIONAL	89	11
W0283	SAN GORGONIO WESTLANDS II, LLC	WIND	WIND TURBINE	NOT COGEN	11/24/1985	SCE	RIVERSIDE	WINDUSTRIES INC.	OPERATIONAL		9.8
W0302	LG&E POWER, INC. - 6096	WIND	WIND TURBINE	NOT COGEN	3/2/1990	SCE	RIVERSIDE	WIND POWER PARTNERS 1991, LP.	OPERATIONAL		9.35
W0299	DUTCH ENERGY	WIND	WIND TURBINE	NOT COGEN	4/13/1990	SCE	RIVERSIDE	SEAWEST ENERGY GROUP	OPERATIONAL	20	8
W0314	LG&E POWER, INC. - 6118	WIND	WIND TURBINE	NOT COGEN	3/12/1987	SCE	RIVERSIDE	SIGMUND J. LICHTER	OPERATIONAL		6.2
W0269	LG&E POWER, INC. - 6036	WIND	WIND TURBINE	NOT COGEN	12/27/1985	SCE	RIVERSIDE	SAN GORGONIO FARM	OPERATIONAL		6.007
W0281	SAN GORGONIO FARMS, INC.	WIND	WIND TURBINE	NOT COGEN	3/1/1943	SCE	RIVERSIDE	SAN GORGONIO WIND FARMS, INC.	OPERATIONAL		3.089
W0266	ENERGY DEV. & CONSTRUCTION	WIND	WIND TURBINE	NOT COGEN	1/31/1986	SCE	RIVERSIDE	EU MANAGEMENT PH, INC.	OPERATIONAL		3
E0027	MECCA PLANT	AG. & WOODWASTE	DIRECT COMBUSTION	NOT COGEN	1/1/1992	SCE	RIVERSIDE	COLMAC ENERGY	OPERATIONAL		53
E0207	EL SOBRANTE LANDFILL GAS GENERATION	LANDFILL GAS	RECIPROCATING ENGINE		4/26/2004	SCE	RIVERSIDE	WM ENERGY SOLUTIONS	OPERATIONAL		2.49
H0186	FOLSOM DAM	HYDRO	HYDRO WATER	NOT COGEN	2/1/1955	PG&E	SACRAMENTO	UNITED STATES BUREAU OF RECLAMATION (USBR)	OPERATIONAL	3	198.72
H0360	NIMBUS DAM	HYDRO	HYDRO,WATER	NOT COGEN	2/1/1955	PG&E	SACRAMENTO	UNITED STATES BUREAU OF RECLAMATION (USBR)	OPERATIONAL	2	13.5
G0467	PROCTOR & GAMBLE - SMUD	NATURAL GAS	COMBUSTION TURBINE WITH WASTE HEAT	COGEN	3/1/1997	SMUD	SACRAMENTO	SACRAMENTO MUNCIPAL UTILITY DISTRICT	OPERATIONAL	3	163.4
G0076	SPAG	NATURAL GAS	COMBUSTION TURBINE WITH WASTE HEAT	COGEN	6/1/1998	SMUD	SACRAMENTO	SACRAMENTO MUNCIPAL UTILITY DISTRICT	OPERATIONAL	2	146
G0085	CARSON COGEN	NATURAL GAS	COMBUSTION TURBINE WITH WASTE HEAT	COGEN	10/1/1995	SMUD	SACRAMENTO	CENTRAL VALLEY FINANCING AUTHORITY	OPERATIONAL	3	97
G0335	MCCLELLAN	NATURAL GAS	COMBUSTION TURBINE, NATURAL GAS	NOT COGEN	1/1/1998	SMUD	SACRAMENTO	SACRAMENTO MUNCIPAL UTILITY DISTRICT	OPERATIONAL	1	49
S0063	RANCO SECO 1-6	PHOTOVOLTAIC	PHOTOVOLTAIC, SUN	NOT COGEN	8/1/1984	SMUD	SACRAMENTO	SACRAMENTO MUNCIPAL UTILITY DISTRICT	OPERATIONAL	6	3.19
E0263	KIEFER LANDFILL GAS TO ENERGY FACILITY	LANDFILL GAS	METHANE GAS		12/1/1999	SMUD	SACRAMENTO	COUNTY OF SACRAMENTO	OPERATIONAL	1	8.3
W0354	INTERNATIONAL TURBINE RESEARCH, INC.	WIND	WIND TURBINE	NOT COGEN	6/14/1988	PG&E	SAN BENITO	INTERNATIONAL TURBINE RESEARCH	OPERATIONAL		17.435
G0042	CENTURY	NATURAL GAS		NOT COGEN	8/1/2001		SAN BERNADINO	ALLIANCE	OPERATIONAL		40
C0001	ACE COGENERATION	COAL	COAL-FIRED TOPPING CYCLE	NOT COGEN	12/1/1990	SCE	SAN BERNARDINO	ACE COGENERATION COMPANY	OPERATIONAL	11	100
C0017	ARGUS COGEN PLANT	COAL	COAL-FIRED TOPPING CYCLE	COGEN	5/1/1978	SCE	SAN BERNARDINO	US TRUST CO. OF CALIF	OPERATIONAL		65
C0019	TXI RIVERSIDE CEMENT POWER HOUSE	COAL	COAL FIRED BOTTOMING CYCLE	COGEN	6/8/1979	SCE	SAN BERNARDINO	US WEREST FINANCIAL SERVICE INC.	OPERATIONAL		17
H0137	DEVIL CANYON	HYDRO	HYDROELECTRIC TURBINE - CONVENTIONAL	NOT COGEN	12/1/1972	SCE	SAN BERNARDINO	CA DEPT. OF WATER RESOURCES (CDWR)	OPERATIONAL	4	138.23
H0381	PARKER - USBR	HYDRO	HYDRO,WATER	NOT COGEN	12/1/1942	PG&E	SAN BERNARDINO	UNITED STATES BUREAU OF RECLAMATION (USBR)	OPERATIONAL	4	120
H0337	MOJAVE SIPHON	HYDRO	HYDRAULIC TURBINE - PIPELINE	NOT COGEN	8/16/1996	SCE	SAN BERNARDINO	CALIF. DEPT. OF WATER RESOURCES	OPERATIONAL	3	32.775
H0174	ETIWANDA	HYDRO	HYDRAULIC TURBINE - PIPELINE	NOT COGEN	5/1/1994	SCE	SAN BERNARDINO	METROPOLITAN WATER DISTRICT	OPERATIONAL	1	23.9
H0460	SANTA ANA 1	HYDRO	HYDRO,WATER	NOT COGEN		SCE	SAN BERNARDINO	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	4	3.2
H0462	SANTA ANA 3	HYDRO	HYDRO,WATER	NOT COGEN	8/25/1899	SCE	SAN BERNARDINO	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	1	3.1
H0333	MILL CREEK 3	HYDRO	HYDRO,WATER	NOT COGEN	3/1/1903	SCE	SAN BERNARDINO	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	3	3
H0187	FONTANA	HYDRO	HYDRO,WATER	NOT COGEN	12/22/1917	SCE	SAN BERNARDINO	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	2	2.95
H0340	MONTE VISTA WD	HYDRO	PRESSURE-REDUCING STATION	NOT COGEN	8/5/1990	SCE	SAN BERNARDINO	MONTE VISTA WATER DISTRICT	OPERATIONAL		0.869
H0331	MILL CREEK 1	HYDRO	HYDRO,WATER	NOT COGEN		SCE	SAN BERNARDINO	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	1	0.8
H0372	ONTARIO 1	HYDRO	HYDRO,WATER	NOT COGEN	12/1/1902	SCE	SAN BERNARDINO	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	3	0.6
H0296	LYTLE CREEK	HYDRO	HYDRO,WATER	NOT COGEN	10/15/1904	SCE	SAN BERNARDINO	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	2	0.5
H0479	SIERRA	HYDRO		NOT COGEN	1/12/1922	SCE	SAN BERNARDINO	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	2	0.48
H0373	ONTARIO 2	HYDRO	HYDRO,WATER	NOT COGEN	6/13/1963	SCE	SAN BERNARDINO	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	1	0.32
H0348	WFA STATION 1	HYDRO	PRESSURE-REDUCING STATION	NOT COGEN	8/26/1994	SCE	SAN BERNARDINO	WATER FACILITY AUTHORITY	OPERATIONAL		0.224
H0434	SAN BERNARDINO MWD - SITE 1720	HYDRO	PRESSURE-REDUCING STATION	NOT COGEN	7/1/1983	SCE	SAN BERNARDINO	SAN BERNADINO MWD	OPERATIONAL		0.176
G0201	ETIWANDA	DISTILLATE OIL	STEAM TURBINE, GAS TURBINE	NOT COGEN	6/1/1963	SCE	SAN BERNARDINO	RELIANT ENERGY	OPERATIONAL	3	770
G0778	HIGH DESERT POWER PLANT PROJECT	NATURAL GAS	COMBINED CYCLE	NOT COGEN	4/22/2003	SCE	SAN BERNARDINO	CONSTELLATION ENERGY	OPERATIONAL	3	750
G0767	COOLWATER	NATURAL GAS	STEAM TURBINE, COMBINED CYCLE	NOT COGEN	1/1/1961	SCE	SAN BERNARDINO	RELTANT ENERGY	OPERATIONAL	8	726.3
G0256	RIVERSIDE CANAL POWER	NATURAL GAS	STEAM TURBINE	NOT COGEN	8/1/1952	SCE	SAN BERNARDINO	RIVERSIDE CANAL POWER	OPERATIONAL	4	160
G0524	MOUNTAINVIEW POWER CO. - SAN BERNARDINO	NATURAL GAS	STREAM TURBINE	NOT COGEN	1/1/1957	SCE	SAN BERNARDINO	THERMO ECOTEK	OPERATIONAL		126
G0821	DREWS	NATURAL GAS	BROWN FIELD	NOT COGEN	8/15/2001		SAN BERNARDINO	ALLIANCE	OPERATIONAL		40
G0080	ONTARIO MILL	NATURAL GAS	GAS TURBINE	COGEN	1/1/1985	SCE	SAN BERNARDINO	INLAND CONTAINER CORPORATION	OPERATIONAL		34
G0404	CHINO NUG	NATURAL GAS, DISTILL	COMBINED CYCLE/TOPPING CYCLE	COGEN	12/24/1988	SCE	SAN BERNARDINO	ENERGY INITIATIVES, INC.	OPERATIONAL		27.6
G0396	WESTEND	NATURAL GAS	COMBUSTION TURBINE/TOPPING CYCLE	COGEN	6/23/1978	SCE	SAN BERNARDINO	NORTH AMERICAN CHEMICAL CO.	OPERATIONAL		15
G0317	LOMA LINDA UNIVERSITY	NATURAL GAS	GAS TURBINE, STEAM TURBINE, INTERNAL COM	COGEN	4/1/1990	SCE	SAN BERNARDINO	LOMA LINDA UNIVERSITY	OPERATIONAL	2	13.4
G0415	INDECK ONTARIO	NATURAL GAS	GAS TURBINE	COGEN	11/1/1984	SCE	SAN BERNARDINO	INDECK CAPITAL, INC.	OPERATIONAL	2	12
G0522	SAN ANTONIO HOSPITAL	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	9/16/1985	SCE	SAN BERNARDINO	SAN ANTONIO COMMUNITY HOSPITAL	OPERATIONAL	1	1.8
G0614	TRANSAMERICAN PLASTICS	NATURAL GAS	GAS FUELED RECIPROCATING ENGINE	COGEN		SCE	SAN BERNARDINO	TRANSAMERICAN PLASTICS	OPERATIONAL		0.34
G0545	MICRO UTILITY - LAKE ARROWHEAD HILTON	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	9/13/1988	SCE	SAN BERNARDINO	LAKE ARROWHEAD HILTON	OPERATIONAL		0.28
G0654	VICTOR VALLEY COMMUNITY HOSPITAL	NATURAL GAS	GAS FUELED RECIPROCATING ENGINE	COGEN		SCE	SAN BERNARDINO	VICTOR VALLEY HOSPITAL	OPERATIONAL		0.135
G0034	MCANALLY EGG RANCH	NATURAL GAS	NATURAL GAS	COGEN	1/1/1994	SCE	SAN BERNARDINO		OPERATIONAL		0.12
G0487	RIMROCK VILLAGE PARTERSHIP	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	11/1/1989	SCE	SAN BERNARDINO	RIMROCK VILLAGE APARTMENTS	OPERATIONAL		0.12
G0486	RIALTO USD	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	12/20/1989	SCE	SAN BERNARDINO	EISENHOWER HIGH SCHOOL	OPERATIONAL		0.1
S0073	SEGS IX	THERMAL	STEAM TURBINE	NOT COGEN	10/1/1990	SCE	SAN BERNARDINO	LUZ SOLAR PARTNERS LTD IX	OPERATIONAL	1	108.2
S0075	SEGS VI	THERMAL	STEAM TURBINE	NOT COGEN	12/1/1988	SCE	SAN BERNARDINO	LUZ SOLAR PARTNERS LTD VI	OPERATIONAL	1	30
S0074	SEGS V	THERMAL	STEAM TURBINE	NOT COGEN	1/1/1987	SCE	SAN BERNARDINO	LUZ SOLAR PARTNERS LTD V	OPERATIONAL	1	30
S0077	SEGS VIII	THERMAL	STEAM TURBINE	NOT COGEN	12/29/1989	SCE	SAN BERNARDINO	LUZ SOLAR PARTNERS LTD VIII	OPERATIONAL	1	30
S0072	SEGS IV	THERMAL	STEAM TURBINE	NOT COGEN	12/1/1985	SCE	SAN BERNARDINO	LUZ SOLAR PARTNERS LTD IV	OPERATIONAL	1	30
S0071	SEGS III	THERMAL	STEAM TURBINE	NOT COGEN	12/1/1986	SCE	SAN BERNARDINO	LUZ SOLAR PARTNERS LTD III	OPERATIONAL	1	30
S0070	SEGS II	THERMAL	PARABOLIC TROUGH	NOT COGEN	12/31/1985	SCE	SAN BERNARDINO	SUNRAY ENERGY INC	OPERATIONAL	1	30
S0076	SEGS VII	THERMAL	STEAM TURBINE	NOT COGEN	10/1/1990	SCE	SAN BERNARDINO	LUZ SOLAR PARTNERS LTD VII	OPERATIONAL	1	30
S0069	SEGS I	THERMAL	PARABOLIC TROUGH & WIND TURBINE	NOT COGEN	12/30/1984	SCE	SAN BERNARDINO	SUNRAY ENERGY INC	OPERATIONAL	1	13.8
E0209	NM MID VALLEY GENCO LLC	LANDFILL GAS	RECIPROCATING ENGINE				SAN BERNARDINO	ALGONQUIN POWER SYSTEMS LFG, LLC	OPERATIONAL		2.6
E0206	NM MILLIKEN GENCO LLC	LANDFILL GAS	RECIPROCATING ENGINE		7/17/2003	SCE	SAN BERNARDINO	ALGONQUIN POWER SYSTEMS LFG, LLC	OPERATIONAL	2	2.2
E0204	NM COLTON GENCO LLC	LANDFILL GASS	RECIPROCATING ENGINE		4/14/2003	SCE	SAN BERNARDINO	ALGONQUIN POWER SYSTEMS LFG, LLC	OPERATIONAL		1.3
H0408	RED MOUNTAIN	HYDRO	HYDRAULIC TURBINE - PIPELINE	NOT COGEN	3/3/1965	SCE	SAN DIEGO	METROPOLITAN WATER DISTRICT	OPERATIONAL	1	5.9
H0006	ALVARADO HYDRO FACILITY	HYDRO	HYDRO,WATER	NOT COGEN	4/30/1995	SDG&E	SAN DIEGO	SAN DIEGO COUNTY WATER AUTHORITY	OPERATIONAL	1	2.1
H0021	BEAR VALLEY	HYDRO	HYDRAULIC TURBINE - CONVENTIONAL	NOT COGEN	3/15/1996	SDG&E	SAN DIEGO	CITY OF ESCONDIDO	OPERATIONAL	1	1.6
H0016	BADGER FILTRATION PLANT	HYDRO	HYDRO,WATER	NOT COGEN	7/8/1967	SDG&E	SAN DIEGO	SANTA FE IRRIGATION DISTRICT	OPERATIONAL	1	1.485
H0405	PT. LOMA	HYDRO		NOT COGEN	9/1/1984	SDG&E	SAN DIEGO	CITY OF SAN DIEGO	OPERATIONAL		1.35
H0335	MIRAMAR HYDRO FACILITY	HYDRO	HYDRO,WATER	NOT COGEN	4/15/1995	SDG&E	SAN DIEGO	SAN DIEGO COUNTY WATER AUTHORITY	OPERATIONAL	1	0.8
H0369	OLIVENHAIN MUNICIPAL WD	HYDRO	HYDRO,WATER	NOT COGEN	8/30/1988	SDG&E	SAN DIEGO	OLIVENHAIN MUNICIPAL WATER DISTRICT	OPERATIONAL	1	0.45
H0439	SAN FRANCISCO PEAK HYDRO	HYDRO	HYDRO,WATER	NOT COGEN	12/15/1985	SDG&E	SAN DIEGO	CITY OF OCEANSIDE	OPERATIONAL	1	0.35
H0411	RINCON HYDRO	HYDRO	HYDRAULIC TURBINE - CONVENTIONAL	NOT COGEN	1/1/1915	SDG&E	SAN DIEGO	CITY OF ESCONDIDO	OPERATIONAL	2	0.3
N0002	SAN ONOFRE	NUCLEAR	URANIUM	NOT COGEN	1/1/1968	SDG&E	SAN DIEGO	SCE/SDG&E/ANAHEIM/RIVERSIDE	OPERATIONAL	2	2200
G0196	ENCINA	NATURAL GAS	STEAM TURBINES & GAS TURBINE	NOT COGEN	11/1/1954	SDG&E	SAN DIEGO	CABRILLO I LLC (NRG WEST COAST INC)	OPERATIONAL	5	971
G0571	SOUTH BAY	NATURAL GAS	STEAM TURBINE, GAS TURBINE	NOT COGEN	7/1/1960	SDG&E	SAN DIEGO	DUKE ENERGY	OPERATIONAL	5	706
G0269	KEARNY	NATURAL GAS	GAS TURBINE	NOT COGEN	8/15/1969	SDG&E	SAN DIEGO	NRG/DYNEGY POWER	OPERATIONAL	3	207
G0619	WILD-LOWER LARKSPUR	NATURAL GAS	GREEN FIELD	NOT COGEN	7/16/2001		SAN DIEGO	INTERGEN	OPERATIONAL		90
G0233	GOAL LINE	NATURAL GAS	GAS TURBINE	COGEN	6/30/1994	SDG&E	SAN DIEGO	GOAL LINE LP	OPERATIONAL	2	81.4
G0626	NAVAL STATION / NAVALTRAINING CENTER	NATURAL GAS	GAS TURBINE, STEAM TURBINE	COGEN	7/1/1985	SDG&E	SAN DIEGO	DYNERGY POWER AND NRG ENERGY, INC.	OPERATIONAL	2	49.9
G0653	CALPEAK BORDER, LLC PHASE I	NATURAL GAS		NOT COGEN	10/26/2001		SAN DIEGO	CALPEAK	OPERATIONAL		49.5
G0645	CALPEAK ESCONDIDO	NATURAL GAS		NOT COGEN	8/30/2001		SAN DIEGO	CALPEAK	OPERATIONAL		49.5
G0624	RAMCO CHULA VISTA	NATURAL GAS			5/1/2001		SAN DIEGO	RAMCO	OPERATIONAL		49
G0610	CALPEAK POWER EL CAJON, LLC	NATURAL GAS		NOT COGEN	5/23/2002		SAN DIEGO	CALPEAK	OPERATIONAL		46.68
G0599	NORTH ISLAND ENERGY FACILITY	NATURAL GAS	GAS TURBINE	COGEN	6/1/1989	SDG&E	SAN DIEGO	APPLIED ENERGY, INC.	OPERATIONAL	2	35.55

This spreadsheet shows the contents of http://www.energy.ca.gov/database/index.html#powerplants on August 14, 2006.
Some columns have been removed from this data due to space limitations

Exhibit B.1.2.2.1
CEC's California Power Plants Database

PP_Map_Report_Master_NO_COORDS

ID	PLANTNAME	PRIMARY FUEL	TECHNOLOGY	COGEN	DATE ONLINE	SERVICE AREA	COUNTY	OWNER	STATUS	TURBIN COUNT	ON-LINE MW
G0398	NORTH ISLAND	NATURAL GAS	GAS TURBINE	NOT COGEN	6/2/1972	SDG&E	SAN DIEGO	CABRILLO POWER II LLC (NRG WEST COAST INC.)	OPERATIONAL	2	34
G0360	MIRAMAR	NATURAL GAS	COMBUSTION TURBINE	NOT COGEN	6/1/1972	SDG&E	SAN DIEGO	NRG/DYNEGY	OPERATIONAL	1	33
G0369	NAVAL STATION	NATURAL GAS	COMBUSTION TURBINE WITH WASTE HEAT	COGEN	9/1/1976	SDG&E	SAN DIEGO	DYNERGY POWER AND NRG ENERGY, INC.	OPERATIONAL	1	26
G0386	NTC/MCRD ENERGY FACILITY	STEAM & NATURAL GAS	COMBINED CYCLE	COGEN	9/1/1989	SDG&E	SAN DIEGO	APPLIED ENERGY, INC.	OPERATIONAL	2	28.6
G0290	NUTRA SWEET KELCO	NATURAL GAS	GAS TURBINE	COGEN	10/15/1983	SDG&E	SAN DIEGO	KELCO- DIVISION OF MERCK & CO.,INC	OPERATIONAL	3	24
G0385	NTC CENTRAL	NATURAL GAS	COMBUSTION TURBINE WITH WASTE HEAT	COGEN	11/1/1998	SDG&E	SAN DIEGO	SDG&E	OPERATIONAL		16
G0186	EL CAJON	DISTILLATE OIL	GAS TURBINE	NOT COGEN	10/10/1989	SDG&E	SAN DIEGO	NRG/DYNEGY POWER	OPERATIONAL	1	13
G0175	DIVISION	DISTILLATE OIL	GAS TURBINE	NOT COGEN	1/1/1990	SDG&E	SAN DIEGO	NRG/DYNEGY POWER	OPERATIONAL	1	13
G0281	BF GOODRICH COGENERATION PLANT	NATURAL GAS	INTERNAL COMBUSTION	COGEN	4/26/2002		SAN DIEGO	GOODRICH AEOSTRUCTURES GROUP	OPERATIONAL	3	6.495
G0505	CHULA VISTA COGEN	NATURAL GAS	COMBINED CYCLE	COGEN	1/1/1993	SDG&E	SAN DIEGO	ROHR INCORPORATED	OPERATIONAL	3	9
G0568	SOLAR TURBINES INC.	NATURAL GAS	GAS TURBINE	NOT COGEN	3/15/1995	SDG&E	SAN DIEGO	SOLAR TURBINE INC.	OPERATIONAL	2	8.5
G0695	PACIFIC BELL	NATURAL GAS		NOT COGEN		SDG&E	SAN DIEGO	PACIFIC BELL	OPERATIONAL		6.42
G0141	CSC WESTERN CENTER COGEN	NATURAL GAS	TURBINE	COGEN	1/14/1988	SDG&E	SAN DIEGO	COMPUTER SCIENCE CORPORATION	OPERATIONAL		3.5
G0551	SEA WORLD	NATURAL GAS	GAS TURBINE	COGEN	12/15/1969	SDG&E	SAN DIEGO	SEA WORLD, INC.	OPERATIONAL	4	3.5
G0298	KYOCERAPROJECT	NATURAL GAS	RECIPROCATING ENGINE	COGEN	12/22/1998	SDG&E	SAN DIEGO	KYOCERA AMERICA	OPERATIONAL	4	3.2
G0477	R.J. DONOVAN CORRECTIONAL FACILITY	NATURAL GAS	GAS TURBINE	COGEN	12/31/1997	SDG&E	SAN DIEGO		OPERATIONAL	1	3.13
G0533	UNION-TRIBUNE PUBLISHING CO.	NATURAL GAS	GAS TURBINE	COGEN	1/9/1986	SDG&E	SAN DIEGO	COPLEY PRESS, INC	OPERATIONAL	1	3
G0511	SDSU MAIN	NATURAL GAS	GAS TURBINE	COGEN	12/1/1995	SDG&E	SAN DIEGO	SAN DIEGO STATE UNIVERSITY	OPERATIONAL	1	3
G0390	NAVY REG. DATA AUTOMATION CENTER	NATURAL GAS	RECIPROCATING ENGINE	COGEN	11/15/1987	SDG&E	SAN DIEGO	WESTNAVFACENGCOM - CODE 163	OPERATIONAL	4	2.6
G0475	QUALCOMM	NATURAL GAS	GAS TURBINE	COGEN	5/20/1983	SDG&E	SAN DIEGO	QUALCOMM INC	OPERATIONAL	3	2.4
G0588	MEDICAL CENTER HOSPITAL	NATURAL GAS	GAS TURBINE	COGEN	6/19/1986	SDG&E	SAN DIEGO	WESTNAVFACENGCOM - CODE 163	OPERATIONAL	3	2.4
G0247	GROSSMONT HOSPITAL	NATURAL GAS	GAS TURBINE	COGEN	8/13/1984	SDG&E	SAN DIEGO	GROSSMONT HOSPITAL COMM COLLEGE DIST.	OPERATIONAL	2	1.6
G0527	SAN DIEGO POWER & COOLING CO.	NATURAL GAS	RECIPROCATING ENGINE	COGEN	12/1/1984	SDG&E	SAN DIEGO	ONSITE ENERGY, CORP.	OPERATIONAL	2	1.6
G0109	CHILDREN'S HOSPITAL	NATURAL GAS	GAS TURBINE	COGEN	10/15/1983	SDG&E	SAN DIEGO	CHILDREN'S HOSPITAL & HEALTH CENTER	OPERATIONAL	3	1.5
G0640	UCSD	NATURAL GAS	RECIPROCATING ENGINE	COGEN	3/25/1985	SDG&E	SAN DIEGO	UCSD	OPERATIONAL	3	1.5
G0195	ENCINA WATER POLLUTION CONTROL	NATURAL GAS	RECIPROCATING ENGINE	COGEN	7/16/1984	SDG&E	SAN DIEGO	ENCINA WATER POLLUTION CONTROL DISTRICT	OPERATIONAL	3	1.425
G0691	TRW	NATURAL GAS	GAS TURBINE,INTERNAL COMBUSTION	COGEN	6/15/1984	SDG&E	SAN DIEGO	TRW INC.	OPERATIONAL	2	1.3
G0521	SALK INSTITUTE	NATURAL GAS	RECIPROCATING ENGINE	COGEN	8/16/1984	SDG&E	SAN DIEGO	SALK INSTITUTE	OPERATIONAL	2	1.3
G0581	SOUTHWEST MARINE	NATURAL GAS	RECIPROCATING ENGINE	COGEN	10/1/1986	SDG&E	SAN DIEGO	SOUTHWEST MARINE	OPERATIONAL		1.3
G0434	PALOMAR HOSPITAL	NATURAL GAS	GAS TURBINE	COGEN	9/18/1986	SDG&E	SAN DIEGO	PALOMAR MEMORIAL HOSPITAL	OPERATIONAL	2	1.3
G0646	VA HOSPITAL	NATURAL GAS	GAS TRUBINE	COGEN	9/7/1988	SDG&E	SAN DIEGO	VA MEDICAL CENTER	OPERATIONAL	1	0.86
G0265	HOTEL DEL CORONADO	NATURAL GAS	GAS TURBINE	COGEN	12/31/1982	SDG&E	SAN DIEGO	HOTEL DEL CORONADO	OPERATIONAL	1	0.8
G0341	MERCY HOSPITAL II	NATURAL GAS	RECIPROCATING ENGINE	COGEN	12/12/1984	SDG&E	SAN DIEGO	MERCY HOSPITAL AND MEDICAL CENTER	OPERATIONAL		0.8
G0332	MARIOTT HOTEL & MARINA II - SOUTH	NATURAL GAS	RECIPROCATING ENGINE	COGEN	10/27/1987	SDG&E	SAN DIEGO	MARRIOTT ENTERPRISES	OPERATIONAL	1	0.8
G0331	MARIOTT HOTEL & MARINA I - NORTH	NATURAL GAS	RECIPROCATING ENGINE	COGEN	11/7/1986	SDG&E	SAN DIEGO	MARRIOTT ENTERPRISES	OPERATIONAL	1	0.8
G0271	HUNTER INDUSTRIES	NATURAL GAS	RECIPROCATING ENGINE	COGEN	4/23/1988	SDG&E	SAN DIEGO	HUNTER INDUSTRIES	OPERATIONAL	1	0.69
G0310	LE MERIDIEN HOTEL I	NATURAL GAS	RECIPROCATING ENGINE	COGEN	6/13/1988	SDG&E	SAN DIEGO	EUAKORSITE ENERGY, L.P.	OPERATIONAL	1	0.6
G0674	SOUTH BAY REGIONAL CENTER	NATURAL GAS	STEAM TURBINE	COGEN	2/21/1984	SDG&E	SAN DIEGO	COUNTY OF SAN DIEGO	OPERATIONAL		0.6
G0455	POMERADO HOSPITAL	NATURAL GAS	RECIPROCATING ENGINE	COGEN	1/31/1988	SDG&E	SAN DIEGO	PALOMAR POMERADO HOSPITAL DIST.	OPERATIONAL	1	0.35
G0263	HOLIDAY INN EMBARCADERO	NATURAL GAS		COGEN	10/23/1987	SDG&E	SAN DIEGO	GREEN MOUNTAIN CONSULTANTS	OPERATIONAL		0.297
G0015	ALLIANT FOOD SERVICE INC.	NATURAL GAS	RECIPROCATING ENGINE	COGEN	6/21/1983	SDG&E	SAN DIEGO	KRAFT FOOD SERVICES	OPERATIONAL	1	0.29
G0004	919 COAST MANAGEMENT	NATURAL GAS	RECIPROCATING ENGINE	COGEN	1/30/1987	SDG&E	SAN DIEGO	ONSITE ENERGY, CORP.	OPERATIONAL	1	0.23
G0240	GROSSMONT COMMUNITY COLLEGE	NATURAL GAS	RECIPROCATING ENGINE	COGEN	8/25/1986	SDG&E	SAN DIEGO	GROSSMONT HOSPITAL COMM COLLEGE DIST.	OPERATIONAL		0.2
G0667	THE WAVE	NATURAL GAS	RECIPROCATING ENGINE	COGEN	5/27/1993	SDG&E	SAN DIEGO		OPERATIONAL	1	0.12
G0191	EL CONQUISTADOR	NATURAL GAS	RECIPROCATING ENGINE	COGEN	8/1/1986	SDG&E	SAN DIEGO	EL CONQUISTADOR/NW MUTUAL LIFE	OPERATIONAL		0.1
W0278	NAWP INC	WIND	WIND TURBINE	NOT COGEN	1/1/1985	SCE	SAN DIEGO	SEAWEST ENERGY GROUP	OPERATIONAL		4.2
E0205	MIRAMAR LANDFILL	LANDFILL GAS	RECIPROCATING ENGINE		6/21/2003	SDG&E	SAN DIEGO	MM SAN DIEGO, LLC	OPERATIONAL		7.6
E0171	GAS UTILIZATION FACILITY	DIGESTER GAS	INTERNAL COMBUSTION	NOT COGEN	1/1/1985	SDG&E	SAN DIEGO	CITY OF SAN DIEGO	OPERATIONAL		6.8
E0054	MM SAN DIEGO LLC - MIRAMAR	LANDFILL GAS	INTERNAL COMBUSTION	NOT COGEN	7/1/1997	SDG&E	SAN DIEGO	MINNESOTA METHANE SAN DIEGO LLC	OPERATIONAL	1	6.6
E0061	OTAY	LANDFILL GAS	RECIPROCATING ENGINE	NOT COGEN	12/1/1986	SDG&E	SAN DIEGO	PACIFIC RECOVERY CORP	OPERATIONAL	2	3.87
E0202	MM SAN DIEGO LLC - NORTH CITY	LANDFILL GAS	LANDFILL GAS	NOT COGEN	3/1/1999	SDG&E	SAN DIEGO	MINNESOTA METHANE SAN DIEGO LLC	OPERATIONAL	4	3.8
E0094	SYCAMORE SAN DIEGO	LANDFILL GAS	GAS TURBINE	NOT COGEN	12/1/1995	SDG&E	SAN DIEGO	LANDFILL GENERATING PARTNERS	OPERATIONAL	2	1.8
E0075	SAN MARCOS	LANDFILL GAS	GAS TURBINE	NOT COGEN		SDG&E	SAN DIEGO	LANDFILL GENERATING PARTNERS	OPERATIONAL	2	1.8
G0462	POTRERO	NATURAL GAS	GAS TURBINE	COGEN	1/1/1965	PG&E	SAN FRANCISCO	MIRANT CORP	OPERATIONAL	4	362
G0272	HUNTERS POINT	DISTILLATE OIL	GAS COMBUSTION TURBINE,STEAM TURBINE	NOT COGEN	12/1/1949	PG&E	SAN FRANCISCO	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	4	215
G0641	USF	NATURAL GAS	GAS TURBINE	COGEN	6/1/1987	PG&E	SAN FRANCISCO	SAN FRANCISCO STATE UNIVERSITY	OPERATIONAL	1	1.5
E0110	SOUTHEAST DIGESTER GAS COGEN	DIGESTER GAS	INTERNAL COMBUSTION	COGEN	7/1/2002		SAN FRANCISCO	CITY & COUNTY OF SF, PUC, HETCH HETCHY WATER	OPERATIONAL	1	2.1
G0128	J.R. SIMPLOT COMPANY	WASTE HEAT	STEAM TURBINE, WASTE HEAT/SULFURIC ACID	NOT COGEN	9/30/1995		SAN JOAQUIN	J.R. SIMPLOT COMPANY	OPERATIONAL	1	4
C0004	PORT OF STOCKTON DISTRICT ENERGY FACILITY	DISTILLATE OIL	STEAM TURBINE	COGEN	12/1/1989	PG&E	SAN JOAQUIN	ACME IPPOS DEF PARTNERS LP	OPERATIONAL	1	55
H0060	CAMANCHE DAM POWER PLANT	HYDRO	HYDRO,WATER	NOT COGEN	7/1/1963	PG&E	SAN JOAQUIN	EAST BAY MUNICIPAL UTILITY DISTRICT	OPERATIONAL	3	10.66
G0838	GWF TRACY PEAKER	NATURAL GAS	BROWN FIELD	NOT COGEN	6/1/2003		SAN JOAQUIN	GWF POWER SYSTEMS	OPERATIONAL		169
G0529	SAN JOAQUIN COGEN	NATURAL GAS		COGEN	4/1/1990	PG&E	SAN JOAQUIN	EL PASO MERCHANT ENERGY	OPERATIONAL		49.9
C0021	STOCKTON COGEN 1	NATURAL GAS	COAL FIRED	COGEN	3/1/1988	PG&E	SAN JOAQUIN	AIR PRODUCTS & CHEMICALS, INC.	OPERATIONAL		49.9
G0564	RIPON MILL	NATURAL GAS	GAS TURBINE	COGEN	5/1/1988	PG&E	SAN JOAQUIN	RIPON COGEN INC	OPERATIONAL	1	49.5
G0381	NCPA STIG	NATURAL GAS	COMBUSTION TURBINE	NOT COGEN	1/1/1996	LOD	SAN JOAQUIN	NORTHERN CALIFORNIA POWER AGENCY	OPERATIONAL		49
G0228	GIANERA	NATURAL GAS	COMBUSTION TURBINE	NOT COGEN	1/1/1958	SILICON V	SAN JOAQUIN	SILICON VALLEY POWER/CITY OF SANTA CLARA	OPERATIONAL	2	32.31
G0380	LODI	NATURAL GAS	COMBUSTION TURBINE	NOT COGEN	2/1/1988	PG&E	SAN JOAQUIN	NORTHERN CALIFORNIA POWER AGENCY/CSC	OPERATIONAL	1	26.45
G0026	STOCKTON SIERRA 1	NATURAL GAS				PG&E	SAN JOAQUIN		OPERATIONAL		22
G0017	BYRON POWER CO.	NATURAL GAS	GAS TURBINE	COGEN	4/13/1990	PG&E	SAN JOAQUIN	RIDGEWOOD BYRON LP	OPERATIONAL	6	6.5
G0751	CORN PRODUCTS	NATURAL GAS	GAS TURBINE	COGEN	3/2/1988	PG&E	SAN JOAQUIN		OPERATIONAL		2.812
G0585	STOCKTON WWTP	NATURAL GAS		COGEN	11/8/1989	PG&E	SAN JOAQUIN		OPERATIONAL		1.35
G0207	FISHER NURSERY	NATURAL GAS		COGEN	4/4/1986	PG&E	SAN JOAQUIN		OPERATIONAL		0.1
W0336	ALTAMONT INFRASTRUCTURE COMPANY - 01W144	WIND	WIND TURBINE	NOT COGEN	3/1/1988	PG&E	SAN JOAQUIN	GREEN RIDGE SERVICE LLC	OPERATIONAL		367
W0345	ALTAMONT INFRASTRUCTURE COMPANY - 06W146	WIND	WIND TURBINE	NOT COGEN	1/1/1990	PG&E	SAN JOAQUIN	GREEN RIDGE SERVICE LLC	OPERATIONAL		65.1
W0337	ALTAMONT INFRASTRUCTURE COMPANY - 01W146A	WIND	WIND TURBINE	NOT COGEN	1/1/1988	PG&E	SAN JOAQUIN		OPERATIONAL		43.1
W0338	ALTAMONT INFRASTRUCTURE COMPANY - 01W146B	WIND	WIND TURBINE	NOT COGEN	4/1/1988	PG&E	SAN JOAQUIN		OPERATIONAL		30
W0352	PATTERSON PASS WIND FARM	WIND	WIND TURBINE	NOT COGEN	4/2/1985	PG&E	SAN JOAQUIN	INTERNATIONAL WIND COMPANIES	OPERATIONAL	336	21.84
W0341	ALTAMONT INFRASTRUCTURE COMPANY - 06W146A	WIND	WIND TURBINE	NOT COGEN	4/1/1988	PG&E	SAN JOAQUIN		OPERATIONAL		20
W0351	FLOWIND 5-4	WIND	WIND TURBINE	NOT COGEN	1/1/1987	PG&E	SAN JOAQUIN	DFKO	OPERATIONAL		18.99
W0348	FLOWIND 3-4	WIND	WIND TURBINE	NOT COGEN	4/11/1986	PG&E	SAN JOAQUIN	FLOWIND DFKO	OPERATIONAL		18.96
W0350	FLOWIND 5-4	WIND	WIND TURBINE	NOT COGEN	4/11/1986	PG&E	SAN JOAQUIN	FLORIDA POWER & LIGHT ENERGY INC.	OPERATIONAL		18.96
W0349	FLOWIND 4-4	WIND	WIND TURBINE	NOT COGEN	1/1/1987	PG&E	SAN JOAQUIN	DFKO	OPERATIONAL		18.96
W0340	ALTAMONT INFRASTRUCTURE COMPANY - 01W146D	WIND	WIND TURBINE	NOT COGEN	1/1/1991	PG&E	SAN JOAQUIN		OPERATIONAL		15
W0330	TAXVEST	WIND	WIND TURBINE	NOT COGEN	1/22/1983	PG&E	SAN JOAQUIN	SEAWEST ENERGY GROUP	OPERATIONAL	194	12.6
W0339	ALTAMONT INFRASTRUCTURE COMPANY - 01W146C	WIND	WIND TURBINE	NOT COGEN	1/2/1990	PG&E	SAN JOAQUIN		OPERATIONAL		11.9
W0346	ALTAMONT MIDWAY, LTD	WIND	WIND TURBINE	NOT COGEN	4/16/1992	PG&E	SAN JOAQUIN		OPERATIONAL		10.92
W0332	ALTAMONT INFRASTRUCTURE COMPANY - 01W018	WIND	WIND TURBINE	NOT COGEN	3/2/1988	PG&E	SAN JOAQUIN		OPERATIONAL		5.5
W0327	ALTECH I	WIND	WIND TURBINE	NOT COGEN	1/1/1981	PG&E	SAN JOAQUIN	SEAWEST ENERGY GROUP	OPERATIONAL		5.76
W0328	VENTURE WIND	WIND	WIND TURBINE	NOT COGEN	1/22/1983	PG&E	SAN JOAQUIN	SEAWEST ENERGY GROUP	OPERATIONAL	38	2.89
W0326	FLOWIND PARTNERS 2	WIND	WIND TURBINE	NOT COGEN	4/1/1985	PG&E	SAN JOAQUIN		OPERATIONAL		2.7
W0329	VIKING 83	WIND	WIND TURBINE	NOT COGEN	1/22/1983	PG&E	SAN JOAQUIN	SEAWEST ENERGY GROUP	OPERATIONAL	26	1.69
W0324	ESI PROJECT	WIND	WIND TURBINE	NOT COGEN	1/22/1983	PG&E	SAN JOAQUIN	SEAWEST ENERGY GROUP	OPERATIONAL	24	1.3
W0323	SEAWEST ENERGY GROUP (B)	WIND	WIND TURBINE	NOT COGEN	1/22/1983	PG&E	SAN JOAQUIN	SEAWEST ENERGY GROUP	OPERATIONAL	15	0.975
E0096	TRACY BIOMASS PLANT	WOODWASTE	DIRECT COMBUSTION	NOT COGEN	4/26/1990	PG&E	SAN JOAQUIN	GWF POWER	OPERATIONAL	1	20.3

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PP_Map_Report_Master_NO_COORDS

ID	PLANTNAME	PRIMARY FUEL	TECHNOLOGY	COGEN	DATE ONLINE	SERVICE AREA	COUNTY	OWNER	STATUS	TURBIN COUNT	ON-LINE MW
E0032	DIAMOND WALNUT	AG. WASTE	DIRECT COMBUSTION	COGEN	4/1/1981	PG&E	SAN JOAQUIN	DIAMOND WALNUT GROWERS INC.	OPERATIONAL	1	5
H0457	CITY OF SAN LUIS OBISPO - STENNER CANYON	HYDRO		NOT COGEN	5/5/1985	PG&E	SAN LUIS OBISPO	CITY OF SAN LUIS OBISPO	OPERATIONAL		0.782
H0455	SAN LUIS OBISPO	HYDRO		NOT COGEN	7/1/1982	PG&E	SAN LUIS OBISPO	CITY OF SAN LUIS OBISPO	OPERATIONAL		0.68
H0290	LOPEZ WWTP	HYDRO		NOT COGEN	6/1/1984	PG&E	SAN LUIS OBISPO	SAN LUIS OBISPO CO. AND WATER CONTROL DISTRICT	OPERATIONAL		0.12
N0001	DIABLO CANYON	NUCLEAR	STEAM TURBINE	NOT COGEN	1/1/1985	PG&E	SAN LUIS OBISPO	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	2	2160
G0371	MORRO BAY	NATURAL GAS	STEAM TURBINE	NOT COGEN	10/1/1955	PG&E	SAN LUIS OBISPO	DUKE ENERGY	OPERATIONAL	4	1021
G0296	KOCH CALIFORNIA LTD.	NATURAL GAS		COGEN	2/12/1985	PG&E	SAN LUIS OBISPO		OPERATIONAL		0.3
G0536	UNITED COGEN INC.	NATURAL GAS	GAS TURBINE, STEAM TURBINE	COGEN	1/1/1987	PG&E	SAN MATEO	UNITED COGEN	OPERATIONAL	2	31
G0515	SRI INTERNATIONAL	NATURAL GAS	GAS TURBINE	COGEN	3/10/1987	PG&E	SAN MATEO	SRI INTERNATIONAL	OPERATIONAL		6
E0123	MARSH ROAD POWER PLANT	LANDFILL GAS	RECIPROCATING ENGINE	NOT COGEN	12/1/1983	PG&E	SAN MATEO	GAS RECOVERY SYSTEMS INC.	OPERATIONAL	4	2
H0254	JOHN E. HOWARD - MONTECITO WD	HYDRO	PRESSURE-REDUCING STATION	NOT COGEN	1/17/1989	SCE	SANTA BARBARA	MONTECITO WATER DISTRICT	OPERATIONAL		0.13
G0195	ELLWOOD	DISTILLATE OIL	COMBUSTION TURBINE	NOT COGEN	8/1/1974	SCE	SANTA BARBARA	RELIANT ENERGY	OPERATIONAL	1	54
G0002	SANTA YNEZ	NATURAL GAS	COMBUSTION TURBINE/TOPPING CYCLE	COGEN	12/1/1983	SCE	SANTA BARBARA	EXXON COMPANY, U.S.A.	OPERATIONAL		46.3
G0760	O'BRIEN ENERGY SYSTEMS - SANTA MARIA	NATURAL GAS		COGEN	4/1/1996	PG&E	SANTA BARBARA		OPERATIONAL		43
G0453	GAVIOTA	NATURAL GAS	GAS TURBINE	COGEN	12/15/1987	SCE	SANTA BARBARA	POINT ARGUELLO	OPERATIONAL	4	14
G0056	SANTA MARIA COGEN	NATURAL GAS	GAS TURBINE	COGEN	6/21/1988	PG&E	SANTA BARBARA	SANTA MARIA COGEN	OPERATIONAL	1	9.5
G0761	SANTA BARBARA COTTAGE HOSPITAL	NATURAL GAS		COGEN	12/1/1985	PG&E	SANTA BARBARA		OPERATIONAL		6.4
G0578	SOUTHERN CALIFORNIA GAS - UCSB	OIL/GAS	FUEL CELL/WASTEHEAT RECOVERY	COGEN	9/29/1993	SCE	SANTA BARBARA		OPERATIONAL		0.2
G0508	SANTA BARBARA COUNTY JAIL	NATURAL GAS	FUEL CELL/WASTEHEAT RECOVERY	COGEN	1/15/1994	SCE	SANTA BARBARA		OPERATIONAL		0.2
E0095	IMM TAJIGUAS ENERGY LLC	LANDFILL GAS	RECIPROCATING ENGINE	NOT COGEN	8/1/2000	SCE	SANTA BARBARA	NEO CORPORATION	OPERATIONAL	1	3.1
G0886	LOS ESTEROS ENERGY CENTER	NATURAL GAS	STEAM TURBINE	NOT COGEN	3/7/2003		SANTA CLARA	CALPINE	OPERATIONAL	4	180
G0822	GILROY ENERGY CENTER	NATURAL GAS	BROWN FIELD	NOT COGEN	2/13/2002		SANTA CLARA	GILROY ENERGY CENTER, LLC	OPERATIONAL		135
G0229	GILROY COGEN	NATURAL GAS	COMBINED CYCLE	COGEN	9/15/1988	PG&E	SANTA CLARA	CALPINE (GILROY COGEN, LP	OPERATIONAL		123.4
G0080	CARDINAL COGEN	NATURAL GAS	GAS TURBINE, STEAM TUBINE	COGEN	2/20/1988	PG&E	SANTA CLARA	STANFORD UNIVERSITY	OPERATIONAL	2	52.9
G0221	AGNEWS	NATURAL GAS		COGEN	4/1/1991	PG&E	SANTA CLARA	CALPINE	OPERATIONAL		36.1
G0087	SAN JOSE COGEN	NATURAL GAS	GAS TURBINE	COGEN	12/18/1984	PG&E	SANTA CLARA	SAN JOSE COGEN CO	OPERATIONAL	1	6
G0114	CITY OF SANTA CLARA	NATURAL GAS	COMBUSTION TURBINE WITH WASTE HEAT	COGEN	8/1/1962	SILICON V	SANTA CLARA	CITY OF SANTA CLARA	OPERATIONAL		5.8
G0121	SAN JOSE CONVENTION CENTER	NATURAL GAS	GAS TURBINE	COGEN	4/2/1990	PG&E	SANTA CLARA	CITY OF SAN JOSE	OPERATIONAL	1	1.5
E0122	NEWBY ISLAND 2	LANDFILL GAS	RECIPOCATING ENGINE	NOT COGEN	12/1/1987	PG&E	SANTA CLARA	GAS RECOVERY SYSTEMS INC.	OPERATIONAL	2	2.3
E0120	GUADALUPE POWER PLANT	LANDFILL GAS	RECIPROCATING ENGINE	NOT COGEN	1/12/1987	PG&E	SANTA CLARA	GAS RECOVERY SYSTEMS INC.	OPERATIONAL	4	2.6
E0146	BYXBEE PARK SANITARY LANDFILL	LANDFILL GAS	RECIPROCATING ENGINE	NOT COGEN	4/1/1990	PG&E	SANTA CLARA	WPI PACKAGING & MAINTENANCE CO.	OPERATIONAL	2	2
E0179	NEWBY LAND 1	LANDFILL GAS	RECIPROCATING ENGINE	NOT COGEN	9/1/1994	PG&E	SANTA CLARA	GAS RECOVERY SYSTEMS INC.	OPERATIONAL	4	2
E0141	SANTA CLARA	LANDFILL GAS	INTERNAL COMBUSTION	NOT COGEN	12/1/1986	PG&E	SANTA CLARA	PACIFIC RECOVERY CORP	OPERATIONAL	1	1.5
G0661	WATSONVILLE COGEN	NATURAL GAS	STEAM TURBINE, GAS TURBINE	COGEN	6/15/1901	PG&E	SANTA CRUZ	CALPINE	OPERATIONAL	2	31
G0541	SANTA CRUZ COGEN	NATURAL GAS		COGEN	11/1/1985	PG&E	SANTA CRUZ		OPERATIONAL		2.635
G0539	SANTA CRUZ WWTP	NATURAL GAS		COGEN	11/1/1991	PG&E	SANTA CRUZ		OPERATIONAL		0.65
G0098	OWL COMPANIES	NATURAL GAS		COGEN	12/30/1985	PG&E	SANTA CRUZ	OWL COMPANIES	OPERATIONAL		0.6
G0524	UC SANTA CRUZ SPORTS FACILITY	NATURAL GAS		COGEN	9/16/1988	PG&E	SANTA CRUZ		OPERATIONAL		0.29
G0566	WATER STREET JAIL	NATURAL GAS		COGEN	9/1/1987	PG&E	SANTA CRUZ		OPERATIONAL		0.19
H0475	SHASTA	HYDRO	HYDRO,WATER	NOT COGEN	8/1/1944	PG&E	SHASTA	UNITED STATES BUREAU OF RECLAMATION (USBR)	OPERATIONAL	5	669
H0493	SPRING CREEK	HYDRO	HYDRO,WATER	NOT COGEN	1/1/1963	REDDING	SHASTA	UNITED STATES BUREAU OF RECLAMATION (USBR)	OPERATIONAL	2	180
H0250	JAMES B. BLACK	HYDRO	HYDRO,WATER	NOT COGEN	12/1/1965	PG&E	SHASTA	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	2	171
H0391	PIT 5	HYDRO	HYDRO,WATER	NOT COGEN	4/1/1944	PG&E	SHASTA	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	4	156
H0257	JUDGE FRANCIS CARR	HYDRO	HYDRO WATER	NOT COGEN	5/1/1963	PG&E	SHASTA	UNITED STATES BUREAU OF RECLAMATION (USBR)	OPERATIONAL	2	154.4
H0270	KESWICK	HYDRO	HYDRO WATER	NOT COGEN	1/1/1949	PG&E	SHASTA	UNITED STATES BUREAU OF RECLAMATION (USBR)	OPERATIONAL	3	117
H0393	PIT 7	HYDRO	HYDRO,WATER	NOT COGEN	6/1/1965	PG&E	SHASTA	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	2	112
H0390	PIT 4	HYDRO	HYDRO,WATER	NOT COGEN	5/1/1955	PG&E	SHASTA	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	2	95
H0392	PIT 6	HYDRO	HYDRO,WATER	NOT COGEN	5/1/1965	PG&E	SHASTA	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	2	80
H0389	PIT 3	HYDRO	HYDRO,WATER	NOT COGEN	7/1/1925	PG&E	SHASTA	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	3	70
H0388	PIT 1	HYDRO	HYDRO,WATER	NOT COGEN	9/1/1922	PG&E	SHASTA	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	2	61
H0106	COLEMAN	HYDRO	HYDRO,WATER	NOT COGEN	6/19/1976	PG&E	SHASTA	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	13
H0221	HAT CREEK 1	HYDRO	HYDRO,WATER	NOT COGEN	8/1/1921	PG&E	SHASTA	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	9.9
H0222	HAT CREEK 2	HYDRO	HYDRO,WATER	NOT COGEN	9/1/1921	PG&E	SHASTA	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	9.9
H0545	VOLTA 1	HYDRO	HYDRO,WATER	NOT COGEN	4/1/1960	PG&E	SHASTA	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	5
H0321	HATCHET CREEK	HYDRO	HYDRO,WATER	NOT COGEN	1/5/1987	PG&E	SHASTA	MEGA RENEWABLES	OPERATIONAL	1	7
H0371	OLSEN POWER PARTNERS	HYDRO		NOT COGEN	1/3/1990	PG&E	SHASTA	OLSEN POWER PTNS	OPERATIONAL		5
H0295	COVE HYDROELECTRIC	HYDRO	HYDRO,WATER	NOT COGEN	2/20/1990	PG&E	SHASTA	SNOW MOUNTAIN HYDRO LLC	OPERATIONAL	1	6
H0463	SLATE CREEK	HYDRO	HYDRO,WATER	NOT COGEN	12/1/1984	PCORP	SHASTA	SLATE CREEK HYDRO ASSOC.	OPERATIONAL	1	4.2
H0271	KILARC	HYDRO	HYDRO WATER	NOT COGEN	10/1/1903	PG&E	SHASTA	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	2	3.2
H0240	BURNEY CREEK	HYDRO	HYDRO,WATER	NOT COGEN	3/28/1990	PG&E	SHASTA	SNOW MOUNTAIN HYDRO LLC	OPERATIONAL	1	3
H0507	TKO POWER - SOUTH FORK BEAR CREEK	HYDRO		NOT COGEN	1/15/1986	PG&E	SHASTA	TKO POWER INC	OPERATIONAL		3
H0168	EL DORADO HYDRO - MONTGOMERY CREEK HYDRO	HYDRO	HYDRO,WATER	NOT COGEN	1/1/1987	PG&E	SHASTA	EL DORADO HYDRO	OPERATIONAL	1	2.6
H0322	MEGA RENEWABLES - ROARING CRK	HYDRO		NOT COGEN	12/5/1986	PG&E	SHASTA	ROARING CREEK RANCH MEGA RENEWABLES	OPERATIONAL		2
H0323	BIDWELL DITCH	HYDRO	HYDRO,WATER	NOT COGEN	2/22/1987	PG&E	SHASTA	MEGA RENEWABLES	OPERATIONAL	1	2
H0118	COW CREEK	HYDRO	HYDRO,WATER	NOT COGEN	1/1/1907	PG&E	SHASTA	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	2	1.44
H0349	NELSON CREEK	HYDRO	HYDRO,WATER	NOT COGEN	12/19/1988	PG&E	SHASTA	NELSON CREEK POWER INC	OPERATIONAL	1	1.2
H0206	LOST CREEK I	HYDRO	HYDRO,WATER	NOT COGEN	10/9/1989	PG&E	SHASTA	SNOW MOUNTAIN HYDRO LLC	OPERATIONAL	1	1.1
H0237	PONDEROSA FAILY	HYDRO	HYDRO,WATER	NOT COGEN	2/20/1990	PG&E	SHASTA	SNOW MOUNTAIN HYDRO LLC	OPERATIONAL	1	1.1
H0320	MEGA HYDRO #1	HYDRO		NOT COGEN	2/21/1986	PG&E	SHASTA	MEGA HYDRO INC	OPERATIONAL		1
H0316	MCMILLAN HYDRO	HYDRO		NOT COGEN	3/22/1984	PG&E	SHASTA	MCMILLAN HYDRO INC	OPERATIONAL		0.975
H0546	VOLTA 2	HYDRO	HYDRO,WATER	NOT COGEN	10/1/1961	PG&E	SHASTA	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	0.9
H0364	WHISKEYTOWN DAM INSKIP	HYDRO		NOT COGEN	12/1/1986	REDDING	SHASTA	CITY OF REDDING	OPERATIONAL		0.8
H0480	SILVER SPRINGS - MEGA RENEWABLES	HYDRO		NOT COGEN	8/15/1987	PG&E	SHASTA	MEGA RENEWABLES	OPERATIONAL		0.6
H0239	LOST CREEK II	HYDRO	HYDRO,WATER	NOT COGEN	6/15/1989	PG&E	SHASTA	SNOW MOUNTAIN HYDRO LLC	OPERATIONAL	1	0.6
H0506	T&G HYDRO	HYDRO		NOT COGEN	10/15/1984	PG&E	SHASTA	T & G HYDRO	OPERATIONAL		0.34
H0504	SUTTER'S MILL HYDRO	HYDRO		NOT COGEN	6/26/1985	PG&E	SHASTA	FRED N SUTTER, JR.	OPERATIONAL		0.15
H0402	STEVE & BONNIE TETRICK	HYDRO		NOT COGEN	10/14/1983	PG&E	SHASTA	WEBB MORROW	OPERATIONAL		0.1
G0487	REDDING POWER	NATURAL GAS	STEAM TURBINE & COMBUSTION TURBINES	NOT COGEN	11/1/1995	REDDING	SHASTA	CITY OF REDDING	OPERATIONAL	4	97.2
G0563	LASSEN ENERGY	NATURAL GAS	GAS TURBINE	COGEN	5/1/1983	PG&E	SHASTA	WHEELABRATOR LASSEN	OPERATIONAL	1	36.8
G0005	CITY OF REDDING	NATURAL GAS		COGEN	1/4/1989	PG&E	SHASTA	CITY OF REDDING	OPERATIONAL		26
E0085	WHEELABRATOR SHASTA	WOODWASTE	DIRECT COMBUSTION	COGEN	1/1/1987	PG&E	SHASTA	WHEELABRATOR SHASTA ENERGY COMPANY	OPERATIONAL	4	55
E0065	BURNEY FOREST PRODUCTS	WOODWASTE	DIRECT COMBUSTION	COGEN	10/1/1989	PG&E	SHASTA	CONNECTIV	OPERATIONAL	1	35
E0066	BURNEY MOUNTAIN POWER	WOODWASTE	DIRECT COMBUSTION	COGEN	1/1/1985	PG&E	SHASTA	COVANTA	OPERATIONAL	1	11
E0078	SPI- BURNEY	WOODWASTE	DIRECT COMBUSTION	COGEN	10/1/1986	PG&E	SHASTA	SIERRA PACIFIC INDUSTRIES, INC.	OPERATIONAL	1	11
E0174	SPI- ANDERSON	WOODWASTE	DIRECT COMBUSTION	COGEN	1/1/1999	PG&E	SHASTA	WHEELABRATOR	OPERATIONAL	1	3
H0226	HAYPRESS HYDROELECTRIC	HYDRO	HYDRO,WATER	NOT COGEN	4/11/1988	PG&E	SIERRA	HAYPRESS HYDROELECTRIC INC	OPERATIONAL	2	10
H0467	STAMPEDE	HYDRO	RUN-OF-RIVER, WATER	NOT COGEN	6/1/1989	PG&E	SIERRA	UNITED STATES BUREAU OF RECLAMATION (USBR)	OPERATIONAL	2	3.7
H0429	SALMON CREEK	HYDRO		NOT COGEN	11/28/1984	PG&E	SIERRA	HENWOOD ASSOCIATES, INC.	OPERATIONAL	1	0.5
G0178	DOWNIEVILLE	DIESEL	COMBUSTION TURBINE	NOT COGEN	1/1/1966	PG&E	SIERRA	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	0.7
E0064	SPI- LOYALTON	WOODWASTE	DIRECT COMBUSTION	COGEN	10/1/1989	SPPC	SIERRA	SIERRA PACIFIC INDUSTRIES, INC.	OPERATIONAL	1	11
H0112	COPCO 2	HYDRO	HYDRAULIC TURBINE - CONVENTIONAL	NOT COGEN	7/1/1926	PCORP	SISKIYOU	PCORP	OPERATIONAL	2	270
H0111	COPCO 1	HYDRO	HYDRAULIC TURBINE - CONVENTIONAL	NOT COGEN	1/1/1918	PCORP	SISKIYOU	PCORP	OPERATIONAL	2	20
H0245	IRON GATE	HYDRO	HYDROELECTRIC	NOT COGEN	2/1/1962	PCORP	SISKIYOU	PCORP	OPERATIONAL	1	18
H0284	LAKE SISKIYOU	HYDRO		NOT COGEN	11/1/1960	PCORP	SISKIYOU	SYNERGICS INC	OPERATIONAL		5

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PP_Map_Report_Master_NO_COORDS

ID	PLANTNAME	PRIMARY FUEL	TECHNOLOGY	COGEN	DATE ONLINE	SERVICE AREA	COUNTY	OWNER	STATUS	TURBIN COUNT	ON-LINE MW
H0177	FALL CREEK	HYDRO	HYDRO,WATER	NOT COGEN	9/1/1903	PCORP	SISKIYOU	PCORP	OPERATIONAL	3	2.2
H0477	SHASTA RIVER	HYDRO		NOT COGEN	3/1/1984	PCORP	SISKIYOU	DEWEY B. SMITH	OPERATIONAL		0.1
H0404	PRATHER CREEK	HYDRO		NOT COGEN	7/1/1983	PCORP	SISKIYOU	TKO POWER INC	OPERATIONAL		0.1
G0909	CALPEAK POWER VACA DIXON LLC	NATURAL GAS			6/21/2002		SOLANO	CALPEAK	OPERATIONAL		49.95
G0916	GOOSE HAVEN ENERGY CENTER	NATURAL GAS	GAS TURBINE		1/1/2003		SOLANO	CALPINE	OPERATIONAL		48.1
G0913	WOLFSKILL ENERGY CENTER	NATURAL GAS	GAS TURBINE		3/1/2003		SOLANO	CALPINE	OPERATIONAL	1	48.1
G0916	CREED ENERGY CENTER	NATURAL GAS	GAS TURBINE		1/1/2003		SOLANO	CALPINE	OPERATIONAL	1	48.1
G0915	LAMBIE ENERGY CENTER	NATURAL GAS	GAS TURBINE		1/1/2003		SOLANO	CALPINE	OPERATIONAL	1	48.1
G0902	VALERO UNIT 1 & 2	NATURAL GAS	COMBUSTION TURBINE, BROWN FIELD	NOT COGEN			SOLANO	VALERO REFINING CO.	OPERATIONAL	1	47.7
G0072	CALIFORNIA MEDICAL FACILITY	NATURAL GAS		COGEN		PG&E	SOLANO		OPERATIONAL		1.6
G0169	SOLANO COGEN	NATURAL GAS	GAS TURBINE	COGEN	6/15/1989	PG&E	SOLANO	SOLANO COUNTY	OPERATIONAL	2	1.45
G0116	CITY OF FAIRFIELD	NATURAL GAS		COGEN	8/15/1984	PG&E	SOLANO		OPERATIONAL		0.775
G0547	CITY OF VACAVILLE - COMMUNITY CENTER	NATURAL GAS		COGEN	7/8/1986	PG&E	SOLANO		OPERATIONAL		0.46
W0355	HIGH WINDS PROJECT	WIND	WIND TURBINE		12/23/2003	PG&E	SOLANO	SACRAMENTO MUNICIPAL UTILITY DISTRICT	OPERATIONAL		162
W0342	ALTAMONT INFRASTRUCTURE COMPANY - 06W146B	WIND	WIND TURBINE	NOT COGEN	1/1/1990	PG&E	SOLANO		OPERATIONAL		18.8
W0356	MONTEZUMA HILLS - SMUD	WIND	WIND TURBINE			SMUD	SOLANO	SACRAMENTO MUNICIPAL UTILITY DISTRICT	OPERATIONAL		10
T0006	COLDWATER CREEK	DRY STEAM		NOT COGEN	6/1/1985	PG&E	SONOMA	SACRAMENTO MUNICIPAL UTILITY DISTRICT	OPERATIONAL	1	130
T0039	GEOTHERMAL 1	DRY STEAM		NOT COGEN	1/1/1983	PG&E	SONOMA	NORTHERN CALIFORNIA POWER AGENCY	OPERATIONAL	2	110
T0040	GEOTHERMAL 2	DRY STEAM		NOT COGEN	1/1/1985	PG&E	SONOMA	NORTHERN CALIFORNIA POWER AGENCY	OPERATIONAL	2	110
T0055	MCCABE 5 & 6	DRY STEAM	STEAM TURBINE	NOT COGEN	12/1/1971	PG&E	SONOMA	GEYSERS POWER CO., LLC	OPERATIONAL	2	78
T0085	RIDGE LINE 7 & 8	DRY STEAM	STEAM TURBINE	NOT COGEN	1/1/1972	PG&E	SONOMA	GEYSERS POWER CO., LLC	OPERATIONAL	2	63
T0088	EAGLE ROCK 11	DRY STEAM	STEAM TURBINE	NOT COGEN	5/31/1975	PG&E	SONOMA	GEYSERS POWER CO., LLC	OPERATIONAL	1	60
T0026	LAKEVIEW 17	DRY STEAM	STEAM TURBINE	NOT COGEN	12/19/1982	PG&E	SONOMA	GEYSERS POWER CO., LLC	OPERATIONAL	1	68
T0029	SOCRATES 18	DRY STEAM	STEAM TURBINE	NOT COGEN	2/15/1983	PG&E	SONOMA	GEYSERS POWER CO., LLC	OPERATIONAL	1	57
T0061	SULPHUR SPRINGS 14	DRY STEAM	STEAM TURBINE	NOT COGEN	9/12/1980	PG&E	SONOMA	GEYSERS POWER CO., LLC	OPERATIONAL	1	66
T0039	COBB CREEK 12	DRY STEAM	STEAM TURBINE	NOT COGEN	3/1/1979	PG&E	SONOMA	GEYSERS POWER CO., LLC	OPERATIONAL	1	60
T0030	GRANT 20	DRY STEAM	STEAM TURBINE	NOT COGEN	10/16/1985	PG&E	SONOMA	GEYSERS POWER CO., LLC	OPERATIONAL	1	44
T0023	AIDLIN 1	DRY STEAM	STEAM TURBINE	NOT COGEN	6/16/1989	PG&E	SONOMA	GEYSERS POWER CO., LLC	OPERATIONAL	2	15.6
H0465	WARM SPRINGS	HYDRO	HYDRO,WATER	NOT COGEN	12/1/1988	PG&E	SONOMA	SONOMA COUNTY WATER AGENCY (SCWA)	OPERATIONAL	1	2.79
G0077	LAGUNA PLANT COGEN FACILITY	NATURAL GAS	INTERNAL COMBUSTION	NOT COGEN	1/1/2002		SONOMA	CITY OF SANTA ROSA	OPERATIONAL	3	2.7
E0196	CENTRAL LF (SONOMA) PHASE II	LANDFILL GAS	INTERNAL COMBUSTION ENGINE	NOT COGEN	6/1/1996		SONOMA	SONOMA DEPT. OF TRANSPORTATION & PUBLIC WORKS	OPERATIONAL	4	3.2
E0195	CENTRAL LF (SONOMA) PHASE I	LANDFILL GAS	INTERNAL COMBUSTION ENGINE	NOT COGEN	7/1/1995		SONOMA	SONOMA DEPT. OF TRANSPORTATION & PUBLIC WORKS	OPERATIONAL	4	3.2
H0458	FRANKENHEIMER	HYDRO	HYDRO,WATER	NOT COGEN	2/12/1983	PG&E	STANISLAUS	SOUTH SAN JOAQUIN IRRIGATION DISTRICT	OPERATIONAL	1	5.3
H0530	TURLOCK LAKE	HYDRO	HYDRO,WATER	NOT COGEN	7/1/1980	TID	STANISLAUS	TURLOCK IRRIGATION DISTRICT	OPERATIONAL	3	3.3
H0276	LA GRANGE	HYDRO	HYDRO,WATER	NOT COGEN	1/1/1924	TID	STANISLAUS	TURLOCK IRRIGATION DISTRICT	OPERATIONAL	2	3.25
H0465	WOODWARD	HYDRO	HYDRO,WATER	NOT COGEN	4/16/1982	PG&E	STANISLAUS	SOUTH SAN JOAQUIN IRRIGATION DISTRICT	OPERATIONAL	1	2.65
H0234	HICKMAN	HYDRO	HYDRO,WATER	NOT COGEN	9/1/1979	PG&E	STANISLAUS	TURLOCK IRRIGATION DISTRICT	OPERATIONAL	1	1.2
H0599	STONE DROP	HYDRO	HYDRO,WATER	NOT COGEN	4/1/1984	MID	STANISLAUS	MODESTO IRRIGATION DISTRICT	OPERATIONAL	1	0.2
G0679	WOODLAND (& II)	NATURAL GAS	COMBUSTION TURBINE WITH WASTE HEAT, CC	COGEN	12/3/1993	MID	STANISLAUS	MODESTO IRRIGATION DISTRICT	OPERATIONAL	2	129.4
G0336	MCCLURE	DISTILLATE OIL	COMBUSTION TURBINE	NOT COGEN	1/1/1980	MID	STANISLAUS	MODESTO IRRIGATION DISTRICT	OPERATIONAL	2	117
G0016	ALMOND	NATURAL GAS	COMBINED CYCLE	NOT COGEN	7/22/1982	TID	STANISLAUS	TURLOCK IRRIGATION DISTRICT	OPERATIONAL	1	49.5
G0662	WALNUT	NATURAL GAS	GAS-FUELED TURBINE	NOT COGEN	5/1/1986	TID	STANISLAUS	TURLOCK IRRIGATION DISTRICT	OPERATIONAL	2	46.5
G0264	HERSHEY CHOCOLATE	NATURAL GAS	INTERNAL COMBUSTION	COGEN	2/5/1989	PG&E	STANISLAUS		OPERATIONAL	1	6.2
E0150	STANISLAUS RESOURCE RECOVERY FACILITY	MSW	STEAM TURBINE	NOT COGEN	1/1/1998	PG&E	STANISLAUS	COVANTA STANISLAUS, INC	OPERATIONAL	1	22.5
H0540	SOUTH SUTTER WATER	HYDRO		NOT COGEN	7/7/1965	PG&E	SUTTER	SOUTH SUTTER WATER DISTRICT (SSWD)	OPERATIONAL		0.395
G0779	SUTTER POWER PROJECT	NATURAL GAS	COGENERATION, STEAM TO USS-POSCO	NOT COGEN	7/22/2001	PG&E	SUTTER	CALPINE	OPERATIONAL		540
G0238	GREENLEAF UNIT ONE	NATURAL GAS	GAS TURBINE, STEAM TUBINE	COGEN	1/11/1969	PG&E	SUTTER	CALPINE	OPERATIONAL		61.4
G0239	GREENLEAF UNIT TWO	NATURAL GAS	GAS TURBINE	COGEN	10/12/1989	PG&E	SUTTER	CALPINE	OPERATIONAL		49.5
G0686	YUBA CITY COGEN	NATURAL GAS	GAS TURBINE	COGEN	4/1/1990	PG&E	SUTTER	YUBA CITY COGEN PARTNERS LP	OPERATIONAL	1	49
G0919	YUBA CITY ENERGY CENTER	NATURAL GAS	GAS TURBINE	COGEN	7/1/2002	PG&E	SUTTER	CALPINE	OPERATIONAL	1	48.1
G0917	FEATHER RIVER ENERGY CENTER	NATURAL GAS	GAS TURBINE		12/1/2002		SUTTER	CALPINE	OPERATIONAL	1	48.1
G0588	YUBA CITY WWTP	NATURAL GAS		COGEN	6/2/1989	PG&E	SUTTER		OPERATIONAL		0.14
H0244	INSKIP	HYDRO	HYDRO,WATER	NOT COGEN	10/1/1976	PG&E	TEHAMA	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	6
H0465	SOUTH	HYDRO	HYDRO,WATER	NOT COGEN	12/1/1979	PG&E	TEHAMA	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	7
H0046	BLACK BUTTE	HYDRO	HYDRO,WATER	NOT COGEN	10/1/1968	PG&E	TEHAMA	SILICON VALLEY POWER - CITY OF CLARA (CSC)	OPERATIONAL	1	6.2
H0520	TRINITY	HYDRO	HYDRO,WATER	NOT COGEN	12/1/1964	PG&E	TRINITY	UNITED STATES BUREAU OF RECLAMATION (USBR)	OPERATIONAL	2	140
H0007	BIG CREEK WATER WORKS	HYDRO	HYDRO,WATER	NOT COGEN	1/7/1967	PG&E	TRINITY	BIG CREEK WATER WORKS LTD	OPERATIONAL		5
H0426	KEKAWAKA POWER	HYDRO	HYDRO,WATER	NOT COGEN	12/27/1989	PG&E	TRINITY	STS HYDROPOWER LTD	OPERATIONAL	1	4.95
H0241	GOSSEUN HYDROELECTRIC	HYDRO	HYDRO,WATER	NOT COGEN	4/10/1983	PG&E	TRINITY	HUMBOLDT BAY MWD	OPERATIONAL	2	2
H0512	THREE FORKS	HYDRO		NOT COGEN	4/1/1993	PG&E	TRINITY	M&H BURKESS	OPERATIONAL		1.3
H0566	PAN PACIFIC HYDRO WEBER FLAT PROJECT	HYDRO		NOT COGEN	1/11/1984	PG&E	TRINITY	PAN PACIFIC HYDRO INC	OPERATIONAL		0.975
H0286	LEWISTON	HYDRO	HYDRO WATER	NOT COGEN	1/1/1964	PG&E	TRINITY	UNITED STATES BUREAU OF RECLAMATION (USBR)	OPERATIONAL	1	0.35
H0381	CEDAR FLAT HYDRO	HYDRO		NOT COGEN	1/8/1984	PG&E	TRINITY	BC HYDRO INC	OPERATIONAL		0.3
H0262	TERMINUS HYDROELECTRIC	HYDRO	HYDROELECTRIC	NOT COGEN	3/16/1990	SCE	TULARE	KAWEAH RIVER POWER AUTHORITY	OPERATIONAL	1	17
H0523	TULE	HYDRO	HYDRO,WATER	NOT COGEN	1/1/1914	PG&E	TULARE	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	6.4
H0251	KAWEAH 3	HYDRO	HYDRO,WATER	NOT COGEN	5/29/1913	SCE	TULARE	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	2	4.6
H0526	TULE RIVER	HYDRO	HYDRO,WATER	NOT COGEN	9/14/1909	SCE	TULARE	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	2	2.52
H0256	KAWEAH 1	HYDRO	HYDRO,WATER	NOT COGEN	5/5/1929	SCE	TULARE	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	1	2.25
H0260	KAWEAH 2	HYDRO	HYDRO,WATER	NOT COGEN	9/13/1929	SCE	TULARE	SOUTHERN CALIFORNIA EDISON COMPANY	OPERATIONAL	1	1.8
H0603	SUCCESS POWER PROJECT	HYDRO		NOT COGEN	12/1/1986	SCE	TULARE	LOWER TULE RIVER IRRIGATION DISTRICT	OPERATIONAL		1.4
G0285	KAWEAH HOSPITAL	NATURAL GAS	GAS TURBINE	COGEN	7/14/1984	SCE	TULARE	KAWEAH DELTA DISTRICT HOSPITAL	OPERATIONAL	2	1
G0619	TULARE DETENTION FACILITY	NATURAL GAS	GAS FUELED RECIPROCATING ENGINE	COGEN	5/5/1987	SCE	TULARE	COUNTY OF TULARE	OPERATIONAL		0.55
E0082	SIERRA POWER CORP.	WOODWASTE	DIRECT COMBUSTION	NOT COGEN	1/24/1986	PG&E	TULARE	SIERRA FOREST PRODUCTS	OPERATIONAL	1	1.1
E0101	MM TULARE ENERGY LLC	LANDFILL GAS	GAS TURBINE COMBINED CYCLE	NOT COGEN	5/8/1998	SCE	TULARE	MINNESOTA METHANE TULARE ENERGY LLC	OPERATIONAL	2	1.8
H0353	NEW MELONES	HYDRO	HYDRO,WATER	NOT COGEN	8/1/1979	PG&E	TUOLUMNE	UNITED STATES BUREAU OF RECLAMATION (USBR)	OPERATIONAL	2	300
H0144	DON PEDRO	HYDRO	HYDRO,WATER	NOT COGEN	1/1/1971	PG&E	TUOLUMNE	TURLOCK IRRIGATION DISTRICT/MODESTO IRRIGATION DISTRICT	OPERATIONAL	4	170.8
H0141	DION R. HOLM	HYDRO	HYDRO,WATER	NOT COGEN	8/1/1960	PG&E	TUOLUMNE	CITY & COUNTY OF SAN FRANCISCO-HETCH HETCHY	OPERATIONAL	2	165
H0274	R C KIRKWOOD	HYDRO	HYDRO,WATER	NOT COGEN	1/1/1967	PG&E	TUOLUMNE	CITY & COUNTY OF SAN FRANCISCO-HETCH HETCHY	OPERATIONAL	3	117.63
H0601	MOCCASIN	HYDRO	HYDRO,WATER	NOT COGEN	1/1/1969	PG&E	TUOLUMNE	CITY & COUNTY OF SAN FRANCISCO-HETCH HETCHY	OPERATIONAL	2	100
H0498	STANISLAUS	HYDRO	HYDRO,WATER	NOT COGEN	3/1/1963	PG&E	TUOLUMNE	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	91
H0140	DONNELLS-CURTIS	HYDRO	HYDRO WATER	NOT COGEN	7/1/1956	PG&E	TUOLUMNE	TRI-DAM PROJECT	OPERATIONAL	1	54
H0327	TULLOCH	HYDRO	HYDRO,WATER	NOT COGEN	5/1/1958	PG&E	TUOLUMNE	OAKDALE & S. SAN JOAQUIN IRRIGATION DIST	OPERATIONAL	2	17
H0519	SAND BAR	HYDRO	HYDRO,WATER	NOT COGEN	5/15/1966	PG&E	TUOLUMNE	TRI-DAM POWER AUTHORITY	OPERATIONAL	1	16.2
H0022	BEARDSLEY	HYDRO	HYDRO,WATER	NOT COGEN	7/1/1956	PG&E	TUOLUMNE	TRI-DAM POWER AUTHORITY	OPERATIONAL	1	9.99
H0495	SPRING GAP	HYDRO	HYDRO,WATER	NOT COGEN	9/1/1921	PG&E	TUOLUMNE	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL		7
H0355	NEW SPICER	HYDRO	HYDRO,WATER	NOT COGEN	11/1/1989	PG&E	TUOLUMNE	NORTHERN CALIFORNIA POWER AGENCY	OPERATIONAL	3	6
H0595	UPPER DAWSON	HYDRO	HYDRO,WATER	NOT COGEN	11/1/1963	TID	TUOLUMNE	TURLOCK IRRIGATION DISTRICT	OPERATIONAL		6
H0336	MOCCASIN LOWHEAD	HYDRO	HYDRO,WATER	NOT COGEN	6/1/1966	PG&E	TUOLUMNE	CITY & COUNTY OF SAN FRANCISCO-HETCH HETCHY	OPERATIONAL	1	2.9
H0363	PHOENIX	HYDRO	HYDRO,WATER	NOT COGEN	2/1/1940	PG&E	TUOLUMNE	PACIFIC GAS AND ELECTRIC COMPANY	OPERATIONAL	1	2
E0100	PACIFIC ULTRAPOWER CHINESE STATION	WOODWASTE	DIRECT COMBUSTION	NOT COGEN	6/4/1988	PG&E	TUOLUMNE	ULTRAPOWER	OPERATIONAL	1	27.5
E0036	SPI- SONORA	WOODWASTE	DIRECT COMBUSTION	COGEN	2/1/2001	PG&E	TUOLUMNE	SIERRA PACIFIC INDUSTRIES, INC	OPERATIONAL	1	4
H0533	SANTA FELICIA	HYDRO	HYDRO,WATER	NOT COGEN	6/1/1967	SCE	VENTURA	UNITED WATER CONSERVATION DISTRICT	OPERATIONAL	2	1.42
H0079	SANTA ROSA HYDRO STATION/CALLEGUA	HYDRO	PRESSURE-REDUCING STATION	NOT COGEN	7/1/1976	SCE	VENTURA	CALLEGUAS MWD	OPERATIONAL		0.25
G0421	ORMOND BEACH	NATURAL GAS	STEAM TURBINE	NOT COGEN	1/1/1971	SCE	VENTURA	RELIANT ENERGY	OPERATIONAL	2	1492

This spreadsheet shows the contents of http://www.energy.ca.gov/database/index.html#powerplants on August 14, 2006.
Some columns have been removed from this data due to space limitations

Exhibit B.1.2.2.1
CEC's California Power Plants Database

PP_Map_Report_Master_NO_COORDS

ID	PLANTNAME	PRIMARY FUEL	TECHNOLOGY	COGEN	DATE ONLINE	SERVICE AREA	COUNTY	OWNER	STATUS	TURBIN COUNT	ON-LINE MW
G0030	MANDALAY	DISTILLATE OIL	STEAM TURBINE, GAS TURBINE	NOT COGEN	5/1/1959	SCE	VENTURA	RELIANT ENERGY	OPERATIONAL	3	560
G0468	OXNARD II	NATURAL GAS	GAS TURBINE	COGEN	1/1/1984	SCE	VENTURA	PROCTOR & GAMBLE	OPERATIONAL	1	49.5
G0180	SITHE ENERGIES	NATURAL GAS	COMBINED CYCLE/TOPPING CYCLE	COGEN	4/13/1990	SCE	VENTURA	SITHE ENERGIES, INC.	OPERATIONAL		48.5
G0403	CAMARILLO NUG	NATURAL GAS	COMBINED CYCLE/TOPPING CYCLE	COGEN	12/27/1985	SCE	VENTURA	ENERGY INITIATIVES, INC.	OPERATIONAL		28.04
G0602	ROCKWELL INTL	NATURAL GAS	MISCELLANEOUS/BOTTOMING CYCLE	COGEN	5/30/1993	SCE	VENTURA	ROCKWELL INTERNATIONAL	OPERATIONAL		26
G0577	HUENEME PAPER MILL	NATURAL GAS	GAS TURBINE	COGEN	3/14/1986	SCE	VENTURA	WILLIAMETTE INDUSTRES INC	OPERATIONAL		29
G0469	OXNARD I	NATURAL GAS	GAS TURBINE	COGEN	11/7/1989	SCE	VENTURA	PROCTER & GAMBLE	OPERATIONAL	1	19.295
G0543	UNOCAL RINCON COGEN	NATURAL GAS	STEAM TURBINE/ENHANCED OIL RECOVERY	COGEN	2/20/1992	SCE	VENTURA	UNOCAL	OPERATIONAL		3.5
G0503	ROCKWELL INTL - KALINA	NATURAL GAS	MISCELLANEOUS/BOTTOMING CYCLE	COGEN	8/25/1992	SCE	VENTURA	ROCKWELL INTERNATIONAL	OPERATIONAL		3.5
G0556	VINTAGE PETROLEUM	NATURAL GAS	COMBUSTION TURBINE/TOPPING CYCLE	COGEN	3/11/1990	SCE	VENTURA	CONOCO, INC.	OPERATIONAL		3.3
G0526	US GOVERNMENT, NAVAL ENGINEERING COMMAND	NATURAL GAS	COMBUSTION TURBINE/TOPPING CYCLE	COGEN	5/1/1989	SCE	VENTURA	NAVAL FACILITIES ENGINEERING CO	OPERATIONAL		0.8
G0123	CITY OF VENTURA - EASTSIDE WTR RENOVATION	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	4/2/1992	SCE	VENTURA	CITY OF VENTURA	OPERATIONAL		0.548
G0002	DOUBLETREE HOTEL	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	11/3/1989	SCE	VENTURA	DOUBLE TREE HOTEL	OPERATIONAL		0.2
G0425	OXNARD HS	NATURAL GAS	GAS-FUELED RECIPROCATING ENGINE	COGEN	5/29/1990	SCE	VENTURA	OXNARD HIGH SCHOOL	OPERATIONAL		0.12
E0126	OXNARD	LANDFILL GAS	INTERNAL COMBUSTION	NOT COGEN	12/1/1985	SCE	VENTURA	PACIFIC RECOVERY CORP	OPERATIONAL	3	5.55
E0208	SIMI VALLEY LANDFILL GAS GENERATION	LANDFILL GAS	RECIPROCATING ENGINE		5/2/2004	SCE	VENTURA	WM ENERGY SOLUTIONS	OPERATIONAL		2.49
E0211	OXNARD WWTP	LANDFILL GAS	RECIPROCATING ENGINE	COGEN	1/12/1982	SCE	VENTURA	CITY OF OXNARD	OPERATIONAL	3	1.5
G0639	UC DAVIS	NATURAL GAS	GAS TURBINE	COGEN	3/26/1987	PG&E	YOLO	UNIVERSITY OF CALIFORNIA DAVIS	OPERATIONAL	1	3
E0105	WOODLAND BIOMASS POWER LTD	AG. & WOODWASTE	DIRECT COMBUSTION	NOT COGEN	5/1/1989	PG&E	YOLO	XCEL ENERGY	OPERATIONAL	1	26
E0184	MM YOLO POWER LLC FACILITY	LANDFILL GAS	RECIPROCATING ENGINE	NOT COGEN	12/1/1996	PG&E	YOLO	MINNESOTA METHANE, YOLO POWER LLC	OPERATIONAL	5	2.85
H0352	COLGATE	HYDRO	HYDRO,WATER	NOT COGEN	10/7/1969	PG&E	YUBA	YUBA COUNTY WATER AGENCY (YCWA)	OPERATIONAL	2	325
H0354	NEW NARROWS	HYDRO	HYDRO,WATER	NOT COGEN	12/1/1970	PG&E	YUBA	YUBA COUNTY WATER AGENCY (YCWA)	OPERATIONAL		40
H0362	YUBA COUNTY WATER	HYDRO	HYDRO,WATER	NOT COGEN	1/29/1990	PG&E	YUBA	YUBA COUNTY WATER AGENCY (YCWA)	OPERATIONAL		2
H0544	BROWNS VALLEY IRRIGATION DISTRICT	HYDRO		NOT COGEN	6/29/1984	PG&E	YUBA	BROWNS VALLEY IRRIGATION DISTRICT	OPERATIONAL		0.995
H0053	FISH POWER	HYDRO	HYDRO,WATER	NOT COGEN	9/30/1988	PG&E	YUBA	YUBA COUNTY WATER AGENCY (YCWA)	OPERATIONAL	1	0.16

This spreadsheet shows the contents of http://www.energy.ca.gov/database/index.html#powerplants on August 14, 2006.
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Exhibit B.1.2.2.2
CEC's Energy Facility Status Report

CALIFORNIA ENERGY COMMISSION - ENERGY FACILITY STATUS

Updated: 8/9/2006

COLOR KEY:

- Operational / On Line
- Approved
- In Review
- On-line date is expected to be delayed beyond the date shown.
- Expected and disclosed
- Planned but undisclosed
- On hold, suspended, cancelled or approval expired. According to developers of projects whose construction is on hold, the new on-line date will be determined when the markets are favorable and financing is available.

	Projects On Line (Arranged By Date On Line)	Docket Number	Status	Capacity (MW)	Construction Completed (percent)	Location	Date Approved	Construction Start Date	Original On-line Date	Current or Actual On-line Date*
1a	Sunrise Simple Cycle - Texaco & Edison Mission E.	98-AFC-4	Operational	320	100	Kern Co.	12/06/00	12/07/00	7/01	6/27/2001
2	Sutter - Calpine	97-AFC-2	Operational	540	100	Sutter Co.	04/14/99	07/01/99	7/01	7/2/2001
3	Los Medanos (Pittsburg) - Calpine	98-AFC-1	Operational	555	100	Contra Costa	08/17/99	09/17/99	7/01	7/9/2001
4	Wildflower Larkspur - Intergen	01-EP-1	Operational	90	100	San Diego Co.	04/04/01	04/05/01	7/01	7/16/01
5	Wildflower Indigo 1,2&3 - Intergen	01-EP-2	Operational	135	100	Riverside Co.	04/04/01	04/05/01	7/01-9/01	7/26-9/10/01
6	Drews - Alliance	01-EP-5	Operational	40	100	San Bernardino	04/25/01	04/26/01	9/01	8/15/01
7	Hanford - GWF	01-EP-7	Operational	95	100	Kings Co.	05/10/01	05/11/01	9/01	9/01/01
8	Century - Alliance	01-EP-4	Operational	40	100	San Bernardino	04/25/01	04/26/01	9/01	9/15/01
9	Escondido - Calpeak	01-EP-10	Operational	49.5	100	San Diego Co.	06/06/01	06/07/01	9/01	9/30/01
10	Border - Calpeak	01-EP-14	Operational	49.5	100	San Diego Co.	07/11/01	07/12/01	9/01	10/26/01
			Subtotal On Line 2001	1,914						
11	Gilroy 1 - Calpine	01-EP-8	Operational	135	100	Santa Clara Co.	05/21/01	05/22/01	9/01	Units 1&2: 1/29/02 Unit 3: 2/20/02
12	King City - Calpine	01-EP-6	Operational	50	100	Monterey Co.	05/02/01	05/03/01	9/01	1/14/2002
13	Delta - Calpine	98-AFC-3	Operational	887	100	Contra Costa	02/09/00	04/01/00	7/02	5/10/2002
14	Henrietta Peaker - GWF	01-AFC-18	Operational	96	100	Kings Co.	03/07/02	03/08/02	6/02	7/1/2002
15	Moss Landing Unit 1 & 2 - Duke	99-AFC-4	Operational	1,060	100	Monterey Co.	10/25/00	11/28/00	6/02	7/11/2002
16	Huntington Beach - AES	00-AFC-13	Operational	450	100	Orange Co.	05/10/01	05/31/01	11/01	Unit 3: 7/31/02 Unit 4: 8/7/03
17a	Valero Cogen. Unit 1	01-AFC-5	Operational	51	100	Solano Co.	10/31/01	11/05/01	6/02	10/18/2002
			Subtotal On Line 2002	2,729						
18	La Paloma - PG&E Natl. Units 1, 2, 3 & 4	98-AFC-2	Operational	1,124	100	Kern Co.	10/06/99	01/01/00	3/02	Units 1&2: 1/10/03 Units 3&4: 3/7/03
19	Los Esteros-Calpine Units 1, 2, 3 & 4	01-AFC-12	Operational	180	100	Santa Clara Co.	7/2/2002 Recertified 3/16/2005	07/08/02	5/03	3/7/03
20	High Desert - Constellation	97-AFC-1	Operational	830	100	San Bernardino	05/03/00	05/01/01	7/03	4/22/2003
21	Tracy Peaker - GWF	01-AFC-16	Operational	169	100	San Joaquin Co.	07/17/02	07/22/02	4/03	6/1/2003
1b	Sunrise Comb. Cycle - Texaco & Mission (amendment to application: 98 AFC-4 but not counted as separate plant)	98-AFC-4C	Operational	265	100	Kern Co.	11/19/01	12/21/01	6/03	6/1/2003
22	Woodland II Combined Cycle - Modesto Irrigation District	01-SPPE-1	Operational	80	100	Stanislaus Co	09/19/01	02/21/02	5/03	6/6/2003
23	Blythe - Calthress & FPL	99-AFC-8	Operational	520	100	Riverside Co.	03/21/01	04/27/01	4/03	7/15/2003
24	Elk Hills - Sempra & Oxy	99-AFC-1	Operational	500	100	Kern Co.	12/06/00	06/08/01	12/02	7/24/2003
			Subtotal On Line 2003	3,668						
			Subtotal On Line 2004	0						
25	Donald Von Raesfeld Power Plant - (Pirn) Silicon Valley Power	02-AFC-3	Operational	147	100	Santa Clara Co.	9/9/03	9/10/03	12/04	3/24/2005
26	Pastoria Phase 1& 2 - Calpine	99-AFC-7	Operational	750	100	Kern Co.	12/20/00	10/3/01	1/03	Phase 1: 5/4/05 Phase 2: 9/19/05
27	Metcalf - Calpine	99-AFC-3	Operational	600	100	Santa Clara Co.	9/24/01	1/15/02	7/03	5/27/2005
28	Kings River Conservation Dist. Peaker	03-SPPE-2	Operational	97	100	Fresno Co.	5/19/04	11/04	5/05	9/19/2005
29	Magnolia - SoCal Power Authority	01-AFC-6	Operational	328	100	Los Angeles Co.	3/5/03	7/21/03	5/05	9/22/2005
30	Malburg - City of Vernon Combined Cycle	01-AFC-25	Operational	134	100	Los Angeles Co.	5/20/03	9/11/03	11/05	10/17/2005
31	Mountainview - SCE	00-AFC-2	Operational	1,056	100	San Bernardino	3/21/01	9/1/01, res. 3/15/04	6/03	Unit 3: 12/9/05 Unit 4: 1/19/06
			Subtotal On Line 2005	3,112						
32	SMUD Combined Cycle Phase 1	01-AFC-19	Operational	500	100	Sacramento Co.	9/9/03	10/31/03	6/05	2/24/06
33	Walnut Energy Center - Turlock Irrigation District	02-AFC-4	Operational	250	100	Stanislaus Co	2/18/04	3/15/04	4/06	2/28/06
34	Palomar Escondido - Sempra	01-AFC-24	Operational	546	100	San Diego Co.	8/6/03	6/1/04	3/06	4/1/06
35	Riverside Energy Resource Center - City of Riverside	04-SPPE-1	Operational	96	100	Riverside Co.	12/15/04	2/23/05	11/05	Unit 1: 6/1/06 Unit 2: 7/26/06
36	Ripon Simple Cycle - MID	03-SPPE-1	Operational	95	100	San Joaquin Co.	2/4/04	10/4/2004, Restart 4/1/05	4/05	6/21/06
			Subtotal On Line 2006	1,487						
			ON-LINE TOTAL	**12,910**						

	Approved / Under Construction (Arranged By On-Line Date)	Docket Number	Status	Capacity (MW)	Construction Completed (percent)	Location	Date Approved	Construction Start Date	Original On-line Date	Current On-line Date*
1	Roseville Combined Cycle - Roseville	03-AFC-1	Construction	160	48	Placer Co.	4/13/05	8/18/05	12/07	11/1/07
2	Inland Empire - Calpine (4)	01-AFC-17	Construction	800	18	Riverside Co.	12/17/03	8/29/05	12/05	6/1/2008
			Under Construction Subtotal	**960**						

	Approved / Not Under Construction (Arranged By Orig. On-Line Date)	Docket Number	Status	Capacity (MW)	Construction Completed (percent)	Location	Date Approved	Construction Start Date	Original On-line Date	Current On-line Date*
17b	Valero Cogen. Unit 2	01-AFC-5	Const. On Hold	51	0	Solano Co.	10/31/01	11/5/2001	12/02	Const. on hold
1	Otay Mesa - Calpine	99-AFC-5	Const. On Hold	590	9	San Diego Co.	4/18/01	9/10/01, Restart 6/21/04	7/03	Const. on hold
2	Contra Costa - Mirant	00-AFC-1	Const. On Hold	530	7	Contra Costa	5/30/01	8/30/01	8/03	Const. on hold
3	Russell City - Calpine (5)	01-AFC-7	On Hold	600	0	Alameda Co.	9/11/02	On Hold	12/04	On Hold
4	East Altamont - Calpine	01-AFC-4	On Hold	1,100	0	Alameda Co.	8/20/03	On Hold	7/05	On Hold
5	Salton Sea Geothermal (3) - Cal Energy	02-AFC-2	On Hold	215	0	Imperial Co.	12/17/03	6/15/06	1/06	On Hold
6	San Joaquin Valley Energy Center - Calpine	01-AFC-22	On Hold	1,087	0	Fresno Co.	1/14/04	On Hold	1/06	On Hold
7	Morro Bay - L.S. Power (1)	00-AFC-12	On Hold	1,200	0	S. Luis Obispo	8/2/04	On Hold	On Hold	On Hold
8	Tesla Combined Cycle - FPL	01-AFC-21	On Hold	1,120	0	Alameda Co.	6/16/04	On Hold	On Hold	On Hold
9	El Segundo Repower-Dynegy/NRG	00-AFC-14	On Hold	630	0	Los Angeles Co.	12/23/04	On Hold	On Hold	On Hold
10	Blythe II Combined Cycle - Blythe Energy LLC	02-AFC-1	On Hold	520	0	Riverside Co.	12/14/05	On Hold	On Hold	On Hold
A	Three Mountain - Covanta	99-AFC-2	Approval Expired 4/17/2006	500	0	Shasta Co.	5/16/01	On Hold	12/03	Approval Expired 4/17/2006
B	Western Midway-Sunset - Mission	99-AFC-9	Approval Expired 5/21/2005	500	0	Kern Co.	3/21/01	On Hold	7/03	Approval Expired 5/21/2005
C	United Golden Gate Phase 1 - El Paso	00-AFC-5	Approval Expired	51	0	San Mateo Co.	3/7/01	On Hold	7/01	Approval Expired
D	Pegasus Energy - Delta Power	01-EP-9	Cancelled	181	0	San Bernardino	6/6/01	cancelled	cancelled	Cancelled
E	Chula Viste 2 - Ramco	01-EP-3	Cancelled	62	0	San Diego Co.	6/13/01	cancelled	cancelled	Cancelled
F	Hanford Energy Park - GWF (2)	00-SPPE-1	Cancelled	99	0	Kings Co.	4/11/01	cancelled	cancelled	Cancelled
			Total Not Under Construction	9,036						
			Approved and Available for Construction	7,643						
			Total Cancelled or License Expired Subtotal (A-F)	1,393						
			Approved Total	**22,906**						

Available for Construction 7,643

This spreadsheet shows the contents of http://www.energy.ca.gov/siltingcases/all_projects.html on August 14, 2006

Exhibit B.1.2.2.2
CEC's Energy Facility Status Report

CALIFORNIA ENERGY COMMISSION - ENERGY FACILITY STATUS

	Projects in Review (Arranged By Estimated Decision Date)	**Docket Number**	**Process**	**Capacity (MW)**	**Project Type**	**Location**	**Date Filed**	**Estimated Decision Date**		**Estimated On-line Date****
1	Pastoria Simple Cycle addition - Calpine	05-AFC-1	12-mo. AFC	160	Expansion	Kern Co.	4/29/05	8/06		Unknown
2	SF Reliability Project - City of SF	04-AFC-1	12-mo. AFC	145	Brown Field	San Francisco	3/18/04	8/06		3/08
3	Los Esteros Comb. Cycle - Calpine	03-AFC-2	12-mo. AFC	140	Brown Field	Santa Clara Co.	12/30/03	8/06		Unknown
4	Blythe 1 TLine - Blythe Energy, LLC	99-AFC-8C	Amendment	230 kV	T-line	Riverside Co.	10/12/04	9/06		Unknown
5	Niland Peakers - IID	06-SPPE-1	SPPE	93	Green Field	Imperial Co.	3/13/2006	10/06		5/08
6	El Centro Unit 3 Repower - IID {6}	06-SPPE-2	SPPE	85	Expansion	Imperial Co.	5/19/2006	12/06		5/09
7	Walnut Creek Energy Center - Edison Mission Energy (peaker)	05-AFC-2	12-mo. AFC	500	Green Field	Los Angeles Co.	11/22/05	1/07		8/08
8	**Bottle Rock Geothermal - U.S. Renewables Group**	**79-AFC-4C**	**Amendment**	**20**	**Repower**	**Lake Co.**	**8/4/2006**	**2/07**		**Unkown**
9	Sun Valley Energy Project - Edison Mission Energy (peaker)	05-AFC-3	6/12 mo. AFC	500	Green Field	Riverside Co.	12/1/2005	2/07		8/08
10	Avenal Combined Cycle - National Power	01-AFC-20	12-mo. AFC	600	Green Field	Kings Co.	10/9/01	7/07		Unknown
11	Highgrove Grand Terrace Peaker - AES	06-AFC-2	6/12-mo. AFC	300	Expansion	San Bernardino Co.	5/25/2006	8/07		9/08
12	South Bay Replacement - L.S. Power	06-AFC-3	12-mo AFC	620	Replacement	San Diego Co.	6/30/2006	9/07		5/10
13	Vernon Power Plant - City of Vernon	06-AFC-4	12-mo AFC	943	Brownfield	Los Angeles Co.	6/30/2006	9/07		8/09
14	**EIF Firebaugh/Panoche - Energy Investors Fund**	**06-AFC-5**	**12-mo. AFC**	**400**	**Greenfield**	**Fresno Co.**	**8/2/2006**	**7-Oct**		**Unknown**
			Under Review Total	**4,506**						
	Projects Announced (Arranged By Estimated Filing Date)		**Process**	**Capacity (MW)**	**Project Type**	**Location**	**Estimated Filing Date**			
1	Hybrid Gas-Solar - City of Victorville		12-mo AFC	550	Greenfield	San Bernardino Co.	08/06			
2	EIF Fresno/Bullard - Energy Investors Fund		12-mo AFC	100	Brownfield	Fresno Co.	08/06			
3	CVP Colusa - E&L Westcoast		12-mo AFC	660	Greenfield	Colusa Co.	09/06			
4	Humboldt Power Plant - PG&E		12-mo AFC	163	Replacement	Humboldt Co.	09/06			
5	Stirling Solar Thermal One - Stirling Energy		12-mo AFC	850	Greenfield	San Bernardino Co.	12/06			
6	Stirling Solar Thermal Two - Stirling Energy		12-mo AFC	900	Greenfield	Imperial Co.	02/07			
7	Encina - NRG		12-mo AFC	400	Brownfield	San Diego Co.	03/07			
8	Central Valley South Energy Center - Central California Power		Unknown	217	Unknown	Tulare Co.	Unknown			
9	Clean Hydrogen Power Project - BP/ARCO & Edison Mission Energy		12-mo AFC	500	Brownfield	Los Angeles Co.	Unknown			
10	Cosumnes - SMUD		12-mo AFC	500	Expansion	Sacramento Co.	Unknown			
11	Envirepel Biomass - Envirepel		12-mo AFC	90	Greenfield	San Diego Co.	Unknown			
12	MMC Chula Vista Expansion - MMC Energy, Inc.		12-mo AFC	94	Expansion	San Diego Co.	Unknown			
13	Russell City 2 - Calpine		6-mo AFC	600	Brownfield	Alameda Co.	Unknown			
14	Starwood Firebaugh/Panoche - Starwood Power		12-mo AFC	120	Greenfield	Fresno Co.	Unknown			
			Announced Total	**5,744**						
	Projects Planned		**Process**	**Capacity (MW)**	**Project Type**	**Location**	**Estimated Filing Date**			
	Municipal Combined Cycle 1		12-mo AFC	250	Comb Cycle	Unknown	Unknown			
	Municipal Combined Cycle 2		12-mo AFC	255	Comb Cycle	Unknown	Unknown			
	Municipal Combined Cycle 3		12-mo AFC	500	Comb Cycle	Unknown	Unknown			
	Refinery Cogen		12-mo AFC	125	Unknown	Northern California	Unknown			
			Planned Total	**1,130**						

Bold text in table identifies a change from the previous report.
* Estimated on-line date if construction is not delayed.

** Estimated on-line date if approved & constructed as proposed.

Projects in italics and an "EP" Docket Number are emergency peakers

Megawatts in [ ] are not included in totals.

{1} 1,021 MW replaced with 1,200 MW for a net increase of 179 MW

{2} Project approved but replaced by Hanford-GWF (01-EP-7).

{3} 30 MW organic rankine cycle amendment approved 5/11/05.

{4} 130 MW amendment approved 6/22/05.

{5} Calpine needs to obtain a new or amended Decision for a new site for the Russell City Project (01-AFC-7).

{6} El Centro project is repower of 44 MW Unit 3 at Imperial Irrigation District El Centro Generating Station with 128 MW new facility, for a net increase of 84 MW.

Greenfield - undeveloped site
Brownfield - developed site

Expansion - New unit at existing power plant site, no loss of existing generation

Repower - Modification of existing equipment

Replacement - Demolition of old plant and construction of new plant

On Hold indicates the applicant has suspended work.

Suspended indicates the committee has suspended the proceeding.

Exhibit 11.3 Preferred Area Definition

Redefinition of LA Basin LCR Area by CAISO

LA Basin Area Boundary Transmission Lines

1) San Onofre - San Luis Rey #1, #2, & #3 230 kV Lines
2) San Onofre - Talega #1 & #2 230 kV Lines
3) Lugo - Mira Loma #1, #2 & #3 500 kV Lines
4) Sylmar - Eagle Rock 230 kV Line
5) Sylmar - Gould 230 kV Line
6) Vincent - Mesa Cal #1 230 kV Line
7) Antelope - Mesa Cal #1 230 kV Line
8) Vincent - Rio Hondo #1 & #2 230 kV Lines
9) Eagle Rock - Pardee #1 230 kV Line
10) Devers - Palo Verde 500 kV Line
11) Devers - Coachelv # 1 230 kV Line
12) Mirage - Ramon # 1 230 kV Line
13) Mirage - Julian Hinds 230 kV Line

Exhibit 11.3 Preferred Area Definition

Redefinition of LA Basin LCR Area by CAISO

LA Basin Area Boundary Substations

1. San Onofre 230 kV
2. Mira Loma 500 kV
3. Eagle Rock 230 kV
4. Gould 230 kV
5. Mesa Cal 230 kV
6. Rio Hondo 230 kV
7. Eagle Rock 230 kV
8. Devers 500 kV
9. Mirage 230 kV

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SOC Plans And Procedures
Organizational Charts
Marketing & Energy Affiliates
Transmission Provider Shared Facilities
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Employee Transfers
Deviations From FERC Order 2004
Potential Merger Partners As Affiliates
Consent To Share Non-Affiliate Information
Discretion Exercised Under Terms of Tariff
Discounts Offered For Transmission Service
Summary Of CPUC Affiliate Rules
California ISO
SCE Transmission Information
Edison News
SCE Response to Supreme Court Decision
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Advice Letters
Distribution Manuals
SCE Affiliate Notices
Energy Efficiency Filings
Open Access Information
SCE Load Profiles
Line and Service Extension Rules
Renewable and Alternative Power
Proceedings Before the California Public Utilities

Regulatory - FERC Standards of Conduct

Response Strong to SCE's Effort to Attract Investment in Power Plants

SCE has secured a power reserve margin of 115% for this summer, but concerned about resource adequacy in the future, the utility in April issued a Request for Offers (RFO) to solicit bids for power contracts with development of new plants. Response to the RFO was strong, according to SCE senior VP of Power Procurement Pedro Pizarro.

"We are seeking up to 1,500 MWs," Pizarro says. "We received contract proposals totaling many times that amount."

The RFO solicits bids for contracts lasting up to 10 years for new or re-powered plants that could be online between June 1, 2006, and August 1, 2008.

"These contracts would benefit all customers who are served from the transmission grid in Southern California," Pizarro said. "Therefore, as part of the RFO plan, we have asked the CPUC to support appropriate allocation of the new generation benefits and costs among all customers in the region."

SCE currently supplies about two-thirds of the customer load in the Southern California area served by the CAISO.

A short list of bidders has been selected by SCE to submit final offers by Sept. 14. A CPUC decision is expected in December.

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EXHIBIT
tabbies
S-20
admitted

FEDERAL ENERGY REGULATORY COMMISSION

WASHINGTON, D.C. 20426

NEWS RELEASE

NEWS MEDIA CONTACT
Barbara A. Connors
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FOR IMMEDIATE RELEASE
September 21, 2006
Docket Nos. ER06-615-000, et al.
and ER02-1656-024

COMMISSION CONDITIONALLY ACCEPTS CAISO MARKET REDESIGN, ORDERS SYSTEMS TO BE TESTED, READY BEFORE IMPLEMENTATION

The Federal Energy Regulatory Commission today conditionally accepted the California Independent System Operator's (CAISO) Market Redesign and Technology Upgrade (MRTU) proposal, concluding that the tariff reforms will bring important corrections and improvements to the CAISO markets necessary to enhance reliability of the grid, protect customers from market manipulation, and to promote infrastructure development.

Many of the MRTU tariff revisions address known market-design flaws, including those that contributed to the California energy crisis of 2000-2001. These flaws impede the ability of the CAISO to reliably deliver low-cost energy and unnecessarily restrict customers from access to supplies of choice, including long-term supplies.

The Commission conditionally accepted the CAISO's proposal, directing significant changes in the MRTU tariff to address concerns raised by commenters, and requires technical conferences to address, among other things, concerns about operational rules that differ between the CAISO and providers of transmission service in the West outside of California, commonly referred to as "seams" issues.

"California's market redesign is the product of more than six years of analysis, stakeholder input, coordination with state authorities and Commission guidance. The purpose of the MRTU order is clear: to prevent a recurrence of the California and Western power crisis from 2000-2001. Once in place, MRTU will do that by helping to provide adequate electricity supply in California, by fixing market rules flaws, and by guarding against market manipulation," Chairman Joseph T. Kelliher observed.

"So today, by fixing many of the inherent flaws in California's market design that contributed to the 2000-2001 Western energy crisis, we take important steps to address remaining shortcomings in California's existing market structure and protect Western consumers against a repeat of the energy crisis. And by enhancing system reliability and

EXHIBIT
S-21
admitted

improving market power mitigation, we create an environment more conducive to investment in sorely needed energy infrastructure in California and throughout the West," Chairman Kelliher said.

Today's 400-page order responds to the CAISO's 8,000-page filing and the numerous and lengthy comments filed by market participants both inside and outside California, pertaining to the various elements of the proposed market design. The Commission conditioned its acceptance in numerous areas and noted that CAISO must submit a number of compliance filings. The Commission also ordered three technical conferences to address specific MRTU elements.

"Although these reforms are significant, it is important to keep in mind that the changes are incremental and supplement the existing market structure," the Commission said, calling the redesigned market an important step in promoting the development of effectively competitive markets that will bring benefits to power customers.

The Commission, in setting November 1, 2007, as the effective date for implementing the new market design, emphasized that it is "strongly committed to a sound and orderly MRTU implementation plan and will not allow that to be sacrificed for the sake of expedience." The Commission ordered protections to ensure that systems are tested and ready before they are implemented.

With today's order, the Commission addressed three of the key factors that contributed to the California and Western energy crisis of 2000-2001: the lack of adequate resources, flawed market rules, and market manipulation.

Significant components of the MRTU Tariff approved today include:

- a more effective system for managing congestion;
- a financially-binding day-ahead market;
- system improvements that will increase operational efficiency and enhance reliability;
- a more transparent pricing system;
- improved market power mitigation measures;
- the opportunity for demand response resources to participate in the ISO markets; and
- a process that respects the resource adequacy requirements established by the California Public Utilities Commission and other Local Regulatory Authorities, with provisions to allow the CAISO to procure additional capacity if needed.

The following are among the significant changes that the Commission ordered to the CAISO's MRTU proposal:

- To address the jurisdictional concerns raised by some parties, the Commission rejected the CAISO's proposal to apply a 15 percent generating reserve requirement to all load-serving entities (LSEs) that serve load in the CAISO Control Area. Instead, for LSEs not subject to the jurisdiction of the California Public Utilities Commission, the Commission allows the 15 percent requirement to be applied only as a default if that LSE in California fails to identify its reserve requirement.
- The Commission rejected the CAISO's request for an exception or delay in complying with the Long-Term Firm Transmission Rights Final Rule, and directs it to comply with that Final Rule in order to expedite the provision of long-term transmission rights to users of the grid

The Commission also required that the CAISO certify to the Commission at least 60 days prior to MRTU implementation that the software and markets will work as expected.

The existing CAISO market was implemented in April 1998. As early as January 2000, the Commission had determined that the CAISO's method of managing congestion contained a serious flaw, which was later considered a contributing factor in the energy crisis of 2000-2001. In December 2001, the Commission directed the CAISO to create a new day-ahead market along with a revised congestion management plan. Since that time, numerous Commission orders provided further guidance to the CAISO in developing its proposed market design.

The Commission approved market power mitigation measures in the MRTU proposal, including continued bid caps on energy and ancillary services, and improved measures to protect against the exercise of market power in discrete areas where insufficient competitive generation exists.

California's existing market design ignores large areas of transmission congestion until the last minute (or "real time"), and as a result allows buyers and sellers to submit schedules that cannot be accommodated on the transmission system. In contrast, the MRTU will use a locational pricing system and computer modeling of the grid that identifies constraints as early as the day ahead so that the CAISO can adjust scheduling accordingly.

With the new design, the CAISO will be able to identify transmission bottlenecks ahead of time, better allocate use of transmission facilities and make more efficient use of transmission and generation resources to serve load, and provide system reserves on a least-cost basis. This system will provide the system operator and market participants

with detailed price information and help determine locations for development of needed generation and transmission facilities.

A system of locational prices will reflect the market price of what power is worth at various locations given the physical limitations of the transmission system. Increased transparency in real-time prices and congestion costs should provide better information on market-driven locational siting alternatives for investment in generation and transmission, the Commission said. However, the Commission asked for more detail on locational pricing and directed the CAISO to supplement its tariff filing within 30 days.

In addition to addressing tariff language for elements approved in prior Commission orders, today's order also addressed issues not previously before the Commission in concept. The order directed three technical conferences to be convened to address the allocation of resource adequacy import capacity, Business Practice Manuals and the so-called seams issues.

The Commission also directed the parties interested in further developing demand response in the CAISO markets to provide proposals to the Commission that detail new avenues for incorporating price-responsive demand in MRTU.

Among other things, the Commission order directs the CAISO to:

- comply with the Commission's Long-Term Firm Transmission Rights Final Rule;
- report quarterly on meetings with neighboring control areas on seams issues;
- file quarterly performance reports once MRTU is implemented;
- implement reserve shortage scarcity pricing within 12 months of the November 1, 2007, initial MRTU implementation; and
- develop and implement interim measures to counteract incentives for Load Serving Entities to underschedule (this measure is to remain in place until convergence bidding is implemented).

In a separate order (ER02-1656-024), the Commission today accepted a CAISO compliance filing and "perfect hedge" proposal, designed to provide financial protection to existing transmission contracts holders against any congestion charges that may arise under the locational pricing in the proposed MRTU tariff.

STAFF'S OPENING STATEMENTS

EXHIBIT
S-22
Admitted

OVERVIEW OF TOPICS

- Relevant law
- Staff's general position on the project
- Proposed conditions

TOPICS

- Relevant law
  - Transmission siting is currently in a paradigm shift
  - Section 1241 of EPAct 2005 and Order 679
  - FERC NOPR on Discrimination and Preference in Transmission Service
  - Section 216(b) of EPAct 2005
  - *Grand Canyon Trust v. ACC,* 210 Ariz. 50 (App. 2005)
  - Arizona Revised Statutes § 40-360 *et seq*.

FERC ORDER 679

FERC Docket RM06-4-000
July 20, 2006

Quote Part 1
¶ 20

"The incentives adopted by this Final Rule are properly understood only in the context of the traditional regulatory principles they seek to further. The longstanding rule is that utility rate regulation must adequately balance both consumer and investor interests."

FERC ORDER 679 (con't.)

FERC Docket RM06-4-000
July 20, 2006

Quote Part 2
¶ 20

"***It is not enough to ensure that investors are properly compensated, and it is not enough to ensure that consumers are protected against excessive rates. Our policies must ensure both outcomes and, in doing so, strike the appropriate balance between these twin objectives***."
(emphasis added).

FERC ORDER 679 (con't.)

FERC Docket RM06-4-000
July 20, 2006

Quote Part 3
¶ 20

"In striking that balance, the courts have recognized that there is no single formula for establishing a just and reasonable rate."

FERC NOPR

FERC Dockets RM05-25-000 and RM05-17-000 – May 19, 2006

Quote Part 1
¶ 52

"Specifically, Order No. 888 does not require sufficient coordination, openness, and transparency in transmission planning to ensure that new infrastructure is constructed to meet the needs of all eligible customers on a not unduly discriminatory basis."

FERC NOPR

FERC Dockets RM05-25-000 and RM05-17-000 – May 19, 2006

Quote Part 2
¶ 52

"Without adequate coordination and open participation, market participants have minimal input or insight into whether a particular transmission plan treats all loads and generators comparably." (emphasis added).

FERC NOPR

FERC Dockets RM05-25-000 and RM05-17-000 – May 19, 2006

Quote Part 3
¶ 52

"To ensure that truly comparable transmission service is provided by all public utility transmission providers, ***including RTOs and ISOs, we propose to amend the pro forma OATT to require coordinated, open, and transparent transmission planning on both a sub-regional and regional level***." (emphasis added).

Grand Canyon Trust v. ACC

210 Ariz. 30, 35, 107 P.3d 356, 361 (App. 2005)

"The **factors the Siting Committee must consider** in deciding whether to issue a CEC are set forth in A.R.S. § 40-360.06. **These factors contain sufficient breadth to allow the Siting Committee to consider the need for power as a factor in considering a CEC application should it choose to do so.** The statute also allows the Siting Committee to "impose reasonable conditions upon the issuance of a" CEC. A.R.S. § 40-360.06(A)." (emphasis added)

A.R.S. § 40-360.06(A)(9)

- "Any additional factors which require consideration under applicable federal and state laws pertaining to any such site."

Grand Canyon Trust v. ACC

210 Ariz. 30, 38, 107 P.3d 356, 365 (App. 2005)

- In *Grand Canyon Trust*, the court specifically held that the Commission may consider need for wholesale power both in and out of state. The court noted that the balancing statute gives the Commission "***considerable discretion*** . . . in how to determine need under the statute."

(emphasis added)

Section 216(b) of EPAct 2005

- FERC backstop authority may be invoked if:
- "The State commission or entity with siting authority withholds approval of the facilities for more than one year after an application is filed or one year after the designation of the relevant national interest corridor, whichever is later, or

Section 216(b) of EPAct 2005
(continued)

- "***the State conditions the construction or modification of the facilities in such a manner that the proposal will not significantly reduce transmission congestion in interstate commerce or is not economically feasible.***" (emphasis added).

STAFF'S POSITION

- Arizona utilities and ratepayers should cooperate in sub-regional and regional markets
- Applicant has failed to meet the standard which treats ***all loads*** and generators comparably

STAFF'S POSITION

- Staff opposes the Application as filed
- Staff proposes conditions that, if adopted in their entirety, would make the project acceptable
- Staff will not endorse or recommend the project for approval
- If its proposed conditions are accepted, Staff will not oppose the project.
- Staff requests a finding of fact on its position

STAFF'S PROPOSED CONDITIONS

1. The Applicant must agree to make good faith efforts to encourage regional access to natural gas storage facilities in southern California.

   Mr. Gray will provide more detail about this condition in his presentation.

STAFF'S PROPOSED CONDITIONS (con't.)

2. Staff proposes two options for assuring reliability of the grid and power plants interconnected to the Palo Verde Hub.

   Mr. Smith will provide more detail for this condition and all of the remaining conditions proposed by Staff. The options are:

STAFF'S PROPOSED CONDITIONS (con't.)

2a. Separate PVD2 from PVD1 with sufficient distance to achieve certain reliability goals, and not use the double circuit towers in Copper Bottom Pass for PVD2;

OR

STAFF'S PROPOSED CONDITIONS (con't.)

2b. Lower the ability to schedule PVD2 to a level that does not require a Special Protection Scheme. The Application must annually demonstrate that the scheduling limit meets certain reliability goals, or must request a lower rating from the appropriate regulatory authority.

STAFF'S PROPOSED CONDITIONS (con't.)

3. Terminate PVD2 at the Harquahala Junction Switchyard. The Harquahala Junction Switchyard must be jointly owned by the Palo Verde to TS5 participants, and may include the Applicant. The Harquahala Junction Switchyard to Hassayampa 500 kV line must be owned by the TS5 particpants, and may include the Applicant.

STAFF'S PROPOSED CONDITIONS (con't.)

4. Staff proposes two options related to commercial practices at the Palo Verde Hub, to be effective prior to commencing operations of PVD2:

STAFF'S PROPOSED CONDITIONS (con't.)

4a. The Applicant must file with FERC and receive approval to modify the tariff free zone. The new tariff free zone would include all transmission lines currently interconnecting power plants to the Palo Verde Switchyard and the Hassayampa Switchyard;

OR

STAFF'S PROPOSED CONDITIONS (con't.)

4b. File an executed agreement with owners of the Harquahala Generating Station, the TS5 participants, and any other participant in this proceeding who would like to use the Harquahala to Hassayampa 500 kV line. The agreement would allow tariff free use of the line. The parties owning the line must agree to assume pro-rata obligations to add new transmission between these switchyards if needed in the future.

STAFF'S PROPOSED CONDITIONS (con't.)

5. The Commission has previously placed conditions on power plants interconnected to the Palo Verde Hub. These conditions include identification of control area authority and reliability obligations. These conditions must be maintained.

(con't.)

STAFF'S PROPOSED CONDITIONS (con't.)

5. (con't)

If the owners of these plants decide to discontinue operations as a generator control area, they must file an application with the Commission. The obligations may only be transferred to an Arizona control area to which they are connected.

STAFF'S PROPOSED CONDITIONS (con't.)

6. Staff proposes two related but separate conditions to delineate operational control between the Cal ISO and the forming WestConnect RTO. Both conditions are required and are not options.

STAFF'S PROPOSED CONDITIONS (con't.)

6a. APS shall have operational control of the Harquahala Junction Switchyard, the Harquahala Junction Switchyard to Hassayampa Switchyard, the termination of PVD2 at the Harquahala Junction Switchyard, and the termination of the line from the Harquahala Junction Switchyard to the Harquahala Generating Station.

STAFF'S PROPOSED CONDITIONS (con't.)

6b. The Applicant executes a binding written agreement with the Cal ISO to limit its control area. Initially, the Cal ISO control area must end at the Devers substation. The Cal ISO control area may be extended to any future switchyard interconnecting with the line between Devers and the California border with Arizona.

(con't.)

STAFF'S PROPOSED CONDITIONS (con't.)

6b. (con't.)

The Applicant may need to construct a new switchyard interconnected with PVD2 between Harquahala Junction Switchyard and the California border. The Applicant must file the executed written agreement prior to commencing operations of the line.

H

Court of Appeals of Arizona,Division 1, Department D.
GRAND CANYON TRUST; The Land and Water Fund of the Rockies, Plaintiffs-Appellants,
v.
ARIZONA CORPORATION COMMISSION, Defendant-Appellee,
andTucson Electric Power Company, Intervenor-Appellee.
No. 1 CA-CV 04-0079.

Feb. 22, 2005.
Review Denied June 28, 2005.

Background: After Arizona Corporation Commission issued decision authorizing construction of additional coal-powered electric generating unit, challengers to decision filed an action to modify or set it aside. The Superior Court, Maricopa County, No. CV 03-000436, Ruth Harris Hilliard, J., affirmed Commission's decision, and challengers appealed.

Holdings: The Court of Appeals, Snow, J., held that:

4(1) Commission applied appropriate test in balancing need for adequate supply of electric power with desire to minimize effect thereof on environment;

6(2) Commission did not err in concluding that power company's customers included wholesale customers; and

11(3) power company was not entitled to statutory attorney fees.

Affirmed.

West Headnotes

[1] Public Utilities 317A 194

317A Public Utilities
317AIII Public Service Commissions or Boards
317AIII(C) Judicial Review or Intervention
317Ak188 Appeal from Orders of Commission
317Ak194 k. Review and Determination in General. Most Cited Cases

Public Utilities 317A 195

317A Public Utilities
317AIII Public Service Commissions or Boards
317AIII(C) Judicial Review or Intervention
317Ak188 Appeal from Orders of Commission
317Ak195 k. Presumptions in Favor of Order or Findings of Commission. Most Cited Cases
In an action challenging a decision by the Arizona Corporation Commission, the challenger was required to demonstrate by clear and convincing evidence that the Commission's determination was unreasonable, and the correct inquiry was whether there was substantial evidence supporting the Commission's decision; only new evidence presented to the superior court, which was uncontroverted, was entitled to presumptions in favor of its truthfulness.

[2] Public Utilities 317A 194

317A Public Utilities
317AIII Public Service Commissions or Boards
317AIII(C) Judicial Review or Intervention
317Ak188 Appeal from Orders of Commission
317Ak194 k. Review and Determination in General. Most Cited Cases
In an action challenging a decision by the Arizona Corporation Commission, the challenger may present evidence that was not presented to the Commission.

[3] Public Utilities 317A 195

317A Public Utilities
317AIII Public Service Commissions or Boards
317AIII(C) Judicial Review or Intervention
317Ak188 Appeal from Orders of Commission
317Ak195 k. Presumptions in Favor of Order or Findings of Commission. Most Cited Cases
In an action challenging a decision by the Arizona Corporation Commission, the submission of evidence that was not presented to the Commission is entitled to presumptions in favor of its truthfulness, so long as the proffered evidence is admissible and is uncontroverted.

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EXHIBIT
S-23
admin notice

[4] Electricity 145 8.6

145 Electricity
145k8.6 k. Environmental Considerations in General. Most Cited Cases
In the context of a challenge to the Arizona Corporation Commission's decision to authorize construction of an additional coal-powered electric generating unit, the Commission applied the appropriate test in balancing the need for an adequate supply of electric power with the desire to minimize the effect thereof on the environment; although the balancing test by the Commission was not required pursuant to a party's request within 15 days of the Siting Committee's written decision, a condition of the certificate of environmental compatibility (CEC) itself required the statutory balancing, and the Commission complied with that condition. A.R.S. § 40-360.07, subd. B.

[5] Public Utilities 317A 194

317A Public Utilities
317AIII Public Service Commissions or Boards
317AIII(C) Judicial Review or Intervention
317Ak188 Appeal from Orders of Commission
317Ak194 k. Review and Determination in General. Most Cited Cases
The appellate court defers to an interpretation by the Arizona Corporation Commission of the Commission's own requirements unless that interpretation is clearly erroneous.

[6] Electricity 145 8.6

145 Electricity
145k8.6 k. Environmental Considerations in General. Most Cited Cases
In its decision to authorize construction of an additional coal-powered electric generating unit, the Arizona Corporation Commission did not err in concluding that the power company's customers included wholesale power customers; to the extent that the definition of a customer in the certificate of environmental compatibility (CEC) condition was a matter of law, the Commission itself placed the term in the CEC, and the Commission's interpretation of the term was entitled to deference.

[7] Electricity 145 8.6

145 Electricity
145k8.6 k. Environmental Considerations in General. Most Cited Cases
In its decision to authorize construction of an additional coal-powered electric generating unit, the Arizona Corporation Commission did not abrogate its statutory responsibility to independently conduct a balancing of need for power with the environmental cost of obtaining it; the Commission set forth at length the analysis in which it balanced the need for power with the desire to minimize the environmental and ecological impacts necessary to obtain that power. A.R.S. § 40-360.07, subd. B.

[8] Electricity 145 8.6

145 Electricity
145k8.6 k. Environmental Considerations in General. Most Cited Cases
In its decision to authorize construction of an additional coal-powered electric generating unit, the Arizona Corporation Commission, by including wholesale power as part of the overall need for more electricity, was not required to specifically quantify the need for wholesale power within the state; the statute requiring the Commission to balance the need for power with the environmental cost of obtaining it gave the Commission considerable discretion in how to determine need, and it could not be said that in an integrated wholesale market, the need for wholesale power both in and out of the state would not affect the availability of power for consumers in Arizona. A.R.S. § 40-360.07, subd. B.

[9] Electricity 145 8.4

145 Electricity
145k8.4 k. Generating Facilities in General. Most Cited Cases
On appeal from the decision by the Arizona Corporation Commission to authorize construction of an additional coal-powered electric generating unit, the Court of Appeals would decline to address the issue of whether a joint development agreement between power companies affected determination of the need for the additional generating unit, where there was no joint development agreement in the record.

[10] Electricity 145 8.4

145 Electricity
145k8.4 k. Generating Facilities in General. Most Cited Cases
On appeal from a decision by the Arizona

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Corporation Commission to authorize construction of an additional coal-powered electric generating unit, evidence of events occurring subsequent to the Corporation Commission hearing was not admissible evidence that the court could consider.

[11] Costs 102 194.25

102 Costs
102VIII Attorney Fees
102k194.24 Particular Actions or Proceedings
102k194.25 k. In General. Most Cited Cases

Electricity 145 8.4

145 Electricity
145k8.4 k. Generating Facilities in General. Most Cited Cases
After prevailing on appeal from the decision by the Arizona Corporation Commission to authorize construction of an additional coal-powered electric generating unit, power company was not entitled to recover statutory attorney fees from the parties who challenged the construction; statute made no provision for the government to recover fees against the party challenging its decision, and power company had intervened on the side of the Commission to defend the Commission's decision. A.R.S. § 12-348.

[12] Statutes 361 210

361 Statutes
361VI Construction and Operation
361VI(A) General Rules of Construction
361k204 Statute as a Whole, and Intrinsic Aids to Construction
361k210 k. Preamble and Recitals. Most Cited Cases
In the context of interpreting a statute, when the legislature specifies its purpose in the session law that contains the statute, it is appropriate to interpret the statutory provisions in light of that enacted purpose.

****358** Arizona Center for Law in the Public InterestBy TimothyM. Hogan, Phoenix, Attorneys for Plaintiffs-Appellants.
Arizona Corporation Commission Legal Division, By ChristopherC. Kempley, Timothy J. Sabo, Janice Alward, Phoenix, Attorneys for Defendant-Appellee.
Roshka Heyman & DeWulf, PLC, By RaymondS. Heyman, Darlene M. Wauro, Phoenix, Attorneys for Intervenor-Appellee Tucson Electric.

***32** OPINION

SNOW, Judge.

¶ 1 Plaintiffs-Appellants Grand Canyon Trust [FN1] and The Land and Water Fund of the Rockies [FN2] (collectively "the Trust") appeal from the superior court's decision affirming a decision of the Arizona Corporation Commission ("the Commission") authorizing the construction of a fourth coal-powered electric generating unit at Tucson Electric Power's Springerville Generating Station. For the following reasons, we affirm.

FN1. Grand Canyon Trust is a nonprofit organization based in Flagstaff, Arizona. Its goal is to protect the natural resources of the Grand Canyon and the Colorado Plateau.

FN2. The Land and Water Fund of the Rockies is a nonprofit regional environmental law and policy center dedicated to serving the Rocky Mountain States.

FACTS AND PROCEDURAL HISTORY

¶ 2 In 1986, Tucson Electric Power ("TEP") filed an application for a certificate of environmental compatibility ("CEC") so that it could construct a fourth electric generating unit at its existing Springerville Generating Station. In Arizona, prior to constructing a plant or transmission line, a utility must obtain a CEC from the Power Plant and Transmission Line Siting Committee ("the Siting Committee").[FN3] The CEC must be approved and promulgated in an order by the Commission. A.R.S. § 40-360.07(A) (2001).

FN3. The Power Plant and Transmission Line Siting Committee of Arizona is established by the Commission pursuant to Arizona Revised Statutes ("A.R.S.") section 40-360.01 (2001). Its purpose is to review applications for the construction of transmission lines and plants, taking into account environmental factors in determining the suitability of the proposed site. A.R.S. § 40-360.06(A) (2001).

¶ 3 In late 1986 the Siting Committee issued a CEC to TEP for the construction of Unit 4. The CEC was approved by the Commission in Decision No. 55477.

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As approved, the CEC was subject to several conditions, one of which required that, prior to undertaking any construction on Unit 4, TEP obtain from the Commission an order finding that the electricity to be produced by that unit was necessary to provide an " 'adequate, economical and reliable supply of electric power' to its customers all in accordance with the requirements of A.R.S. § 40-360.07(B)."

¶ 4 Fourteen years later, in 2001, TEP's parent company announced plans to begin construction on Units 3 and 4 at Springerville.[FN4] Grand Canyon thereafter filed with ****359 *33** the Commission a Motion to Rescind, Alter or Amend its decisions granting CECs for the construction of Units 3 and 4. Grand Canyon argued that, given the substantial amount of time that had passed since those CECs had been issued, the Commission should require TEP to file amended CEC applications reflecting current environmental factors. The moving party also argued that there was no need for Unit 4. TEP filed a Motion to Dismiss Grand Canyon's Motion to Rescind. It also filed an Application for Hearing to address "the issue of the need for a fourth generating unit" at the Springerville location.

FN4. In 1977 TEP had obtained a CEC for the construction of Units 1, 2, and 3 at the Springerville site. By 2001, Units 1 and 2 had already been constructed, but construction on Unit 3 had not yet begun.

¶ 5 TEP and Grand Canyon stipulated that the parties could address in a single hearing updated environmental impact data for Units 3 and 4 and the need for Unit 4. The Commission then conducted an evidentiary hearing over five days in November 2001 on the stipulated subjects. The Commission ultimately issued decision No. 65347 determining that "TEP ha[d] made the requisite showing of need for Unit 4" and that the "conditions contained in Commission Decision No. 55477 concerning the authority to construct Springerville Generating Station Unit 4 have been met."

¶ 6 In its decision, the Commission rejected Grand Canyon's argument that only TEP's retail customers should be considered in determining whether the output of Unit 4 was needed. But, the order did further condition the construction of Unit 4 on "firm wholesale contracts for the power output from Units 3 and 4 [being] in place prior to commencement of construction." Applications for rehearing were denied by operation of law. A.R.S. § 40-254(A) (2001).

¶ 7 Pursuant to A.R.S. § 40-254 the Trust filed an action in superior court to modify or set aside the Commission's decision. TEP intervened. The parties stipulated that, given the substantial evidentiary record developed in proceedings before the Commission, the action should be submitted to the superior court on dispositive motions similar to appellate briefs. The superior court affirmed the Commission's decision and entered judgment in favor of the Commission and TEP, and the Trust timely appealed. We have jurisdiction pursuant to A.R.S. § 12-2101(B)(2003).

DISCUSSION

A. Standard Of Review

[1] ¶ 8 The Trust asserts that, because the superior court ruled against it as a matter of summary judgment, we must view all disputed issues of fact in its favor. *See Tonto Creek Estates Homeowners Ass'n v. Ariz. Corp. Comm'n,* 177 Ariz. 49, 55, 864 P.2d 1081, 1087 (App.1993) (citation omitted). That argument is correct only as to new evidence presented to the superior court.

¶ 9 The statute that provides for a challenge to a decision of the Commission in superior court specifies that the trial to be given such a challenge "shall conform, as nearly as possible, and except as otherwise prescribed by this section, to other trials in civil actions." A.R.S. § 40-254(C). However, one of the principal statutory exceptions to this right specifies: "In all trials, actions and proceedings the burden of proof shall be upon the party adverse to the commission ... to show by clear and satisfactory evidence that [the commission's order] is unreasonable or unlawful." A.R.S. § 40-254(E).

¶ 10 This provision mandates several departures from normal civil procedure. Not only does it mandate a higher burden of proof for the plaintiff than otherwise exists in an ordinary civil case,[FN5] but, because the plaintiff's burden of proof is to establish "in all proceedings" that the Commission's order is either unlawful or unreasonable, the superior court must evaluate the determinations already made by the Commission.

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FN5. " 'Clear and satisfactory' [evidence] is the same as 'clear and convincing' [evidence]." This is a higher burden of proof than the "preponderance of the evidence" standard which plaintiffs must meet in most civil cases. *Tucson Elec. Power Co. v. Arizona Corp. Comm'n,* 132 Ariz. 240, 243, 645 P.2d 231, 234 (1982).

¶ 11 To be sure, "both the superior court and this court may depart from the Commission's****360 *34** legal conclusions or interpretation of a statute and determine independently whether the Commission erred in its interpretation of the law." *Babe Invs. v. Arizona Corp. Comm'n,* 189 Ariz. 147, 150, 939 P.2d 425, 428 (App.1997) (citation omitted). However, when the plaintiff challenges a factual determination of the Commission, the superior court is not free to overturn it unless the plaintiff demonstrates by "clear and convincing" evidence that the Commission's determination is unreasonable. In making this assessment Arizona courts uphold such determinations if they are supported by substantial evidence. *Tucson Elec. Power,* 132 Ariz. at 243-44, 645 P.2d at 234-35 (court may disturb Commission's finding of fact only if it is not reasonably supported by evidence, is arbitrary or is otherwise unlawful); *Arizona Corp. Comm'n v. Citizens Util. Co.,* 120 Ariz. 184, 187, 584 P.2d 1175, 1178 (App.1978) (same). Such a review is very different from assuming that all facts alleged by the Trust are true. *Havasu Heights Ranch & Dev. Corp. v. Desert Valley Wood Prods., Inc.,* 167 Ariz. 383, 387, 807 P.2d 1119, 1123 (App.1990) (citations omitted) ("In reviewing factual determinations, our respective roles begin and end with determining whether there was substantial evidence to support the administrative decision.... The question whether substantial evidence supports the state land commissioner's order does not raise material issues of fact; it presents a question of law.").

[2][3] ¶ 12 In an action challenging a Commission decision, the challenger may present evidence that was not presented to the Commission. *Arizona Corp. Comm'n v. Pac. Motor Trucking Corp.,* 116 Ariz. 465, 467, 569 P.2d 1363, 1365 (App.1977).[FN6] So long as the proferred evidence is admissible, and is uncontroverted, it is entitled to presumptions in favor of its truthfulness. *Eastwood Elec. Co. v. R.L. Branaman Contractor, Inc.,* 102 Ariz. 406, 410, 432 P.2d 139, 143 (1967); *Mortensen v. Knight,* 81 Ariz. 325, 305 P.2d 463, 464 (1956). However, the presumption of truthfulness that may attach to such new evidence does not change the nature of the superior court's inquiry or the plaintiff's statutory burden of proof. The inquiry remains whether, even in light of the new evidence, there is substantial evidence supporting the Commission's decision. If so, the presumed truthfulness of the new evidence does not result in a modification of the Commission's order.

FN6. Although new evidence may be raised, new issues may not. A.R.S. § 40-253(C) (2001).

¶ 13 The parties here, by stipulation, submitted their appeal from the Commission's determination based on the record that was created in the Commission proceedings. *Tonto Creek Estates,* 177 Ariz. at 55, 864 P.2d at 1087. The Trust supplemented that factual record with the affidavit of SRP's Manager of Energy and Information, Charlie Duckworth, who described negotiations that were continuing between TEP and SRP on an amended joint development agreement and the likely terms of the amended agreement. Because the superior court resolved the action by motion, and the facts in the affidavit were not contested, we presume the truthfulness of the facts contained therein. We do not, however, presume the truthfulness of the Trust's factual allegations that were determined adversely to the Trust by the Commission. Instead, we determine, as presumably did the superior court, whether those determinations were supported by substantial evidence. Thus we evaluate the Commission's legal determinations *de novo,* and we review its factual conclusions to determine whether they are supported by substantial evidence taking into account any new uncontested evidence offered and assuming its truthfulness.

B. The Merits

¶ 14 In its appeal, the Trust argues first that the superior court erred when it did not apply the legal standard set forth in A.R.S. § 40-360.07(B) to the Commission's proceedings. Second, it argues that when appropriate criteria are considered, there was not substantial evidence to support the Commission's decision that TEP had complied with the conditions in its 198€ CEC.

1. The Commission Applied A.R.S. § 40-360.07(B).

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[4] ¶ 15 According to its plain terms, A.R.S. § 40-360.07(B) requires the Commission,**361 *35, upon a challenge to a decision of the Siting Committee concerning a CEC, to "balance, in the broad public interest, the need for an adequate, economical and reliable supply of electric power with the desire to minimize the effect thereof on the environment and the ecology of this state." The parties disagree about the extent to which A.R.S. § 40-360.07(B) governed the proceedings below. The Trust argues that the superior court held that the balancing was inapplicable to this action and such a holding is error. We do not read the superior court minute entry affirming the Commission's decision as holding that the balancing was not required in this case, but merely that it was not required by the statute governing the issuance of CECs. We agree with the superior court's reasoning in that regard.

¶ 16 The Trust argues on appeal as it did below that every applicant for a CEC must comply with the requirements of § 40-360.07(B). In this case, the Trust argues the Commission deferred compliance by placing the statutory requirement in the CEC and requiring that the statutory balancing occur shortly prior to construction. Even though this deferral amounted to more than fourteen years, the Trust argues that the requirement still must be met or the CEC is invalid. We reject this argument.

¶ 17 In interpreting statutory provisions we consider the individual provisions of a statute "in the context of the entire statute." *Burlington N. & Santa Fe Ry. Co. v. Ariz. Corp. Comm'n*, 198 Ariz. 604, 607, ¶ 15, 12 P.3d 1208, 1211 (App.2000); *Prudential v. Estate of Rojo-Pacheco*, 192 Ariz. 139, 148, 962 P.2d 213, 222 (App.1997) (reviewing specific statute in the context of its overall statutory scheme with the goal of achieving consistency among related provisions). By its plain terms A.R.S. § 40-360.07 does not require that the Commission engage in the balancing specified by subsection (B) in every case. It only requires that the Commission do so when a party requests that the Commission review the Siting Committee's written decision concerning a CEC within fifteen days of its issuance.[FN7]

FN7. The factors the Siting Committee must consider in deciding whether to issue a CEC are set forth in A.R.S. § 40-360.06. These factors contain sufficient breadth to allow the Siting Committee to consider the need for power as a factor in considering a CEC application should it choose to do so. The statute also allows the Siting Committee to "impose reasonable conditions upon the issuance of a" CEC. A.R.S. § 40-360.06(A).

¶ 18 In this case, no party requested that the Commission review the Siting Committee's issuance of the CEC, and the Commission thus "affirmed and approved" the CEC subject to conditions without making the review in subsection (B). Thus, in this case, the statutory scheme does not require that the Commission balance need against minimizing environmental costs, and the superior court was correct in so concluding.

¶ 19 However, even if the statute did not require that the balancing occur, one of the conditions placed in the CEC itself did require the statutory balancing. TEP argues, however, that because the hearing was for the Commission to ascertain whether TEP had complied with the condition placed in the CEC by the Commission, we should give the Commission's interpretation of its own condition great deference. That is only partly correct. The condition at issue here contained two requirements. First, it required that the power generated by Unit 4 be "necessary ... for [TEP] to provide an 'adequate, economical and reliable supply of electric power' to its customers." Second, the Siting Committee required that TEP's construction of Unit 4 be "in accordance with the requirements of A.R.S. § 40-360.07(B)." [FN8]

FN8. The condition required:
[T]hat the Applicant obtain from the Arizona Corporation Commission ..., within one year prior to Applicant undertaking any preparatory engineering, design or construction efforts pertaining to Unit No. 4, an order, pursuant to hearing, confirming that the electric energy to be produced by Unit No. 4 is necessary in order for the Applicant to provide an "adequate, economical and reliable supply of electric power" to its customers, all in accordance with the requirements of A.R.S. § 40-360.07(B).

[5] ¶ 20 The first requirement was imposed by the Commission without incorporating external standards. Thus, we defer to the Commission's interpretation of its own **362 *36 requirement unless that interpretation is clearly erroneous. *Marco Crane & Rigging v. Ariz. Corp. Comm'n*, 155 Ariz. 292, 294, 746 P.2d 33, 35 (App.1987) (deferring to interpretation of Commission-approved tariffs); *MCI*

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Worldcom Network Servs., Inc. v. FCC, 274 F.3d 542, 547 (D.C.Cir.2001) (stating that the court will allow an agency's interpretation of the intended effect of its own order to control unless clearly erroneous).

¶ 21 However, the second requirement, that the power be necessary "in accordance with the requirements of A.R.S. § 40-360.07(B)," incorporated a statute into the condition. In such a case, the deference the Commission is otherwise due is limited by the requirements of the statute. *Babe Invs.*, 189 Ariz. at 150, 939 P.2d at 428 (courts "determine independently whether the Commission erred in its interpretation of the law"); *Navajo County v. Prop. Tax Oversight Comm'n*, 203 Ariz. 491, 494, ¶ 8, 56 P.3d 65, 68 (App.2002) (same). Further the Commission's incorporation of A.R.S. § 40-360.07(B) as a condition in the CEC requires TEP to establish compliance with the statutory balancing even though it would not have been required to do so by the statute alone.

¶ 22 In this case, however, the Commission decision itself states that "[i]n arriving at its Decision herein, the Commission has balanced, in the broad public interest, the need for an adequate, economical and reliable supply of electric power with the desire to minimize the effect thereof on the environment and ecology of the state." This is the precise balancing required by A.R.S. § 40-360.07(B). Thus, the Commission applied the appropriate balancing and we do not read the superior court's decision as holding that such balancing was not required.

2. The Commission Did Not Err in Considering TEP's Wholesale Customers.

[6] ¶ 23 The Commission in its order both found as a matter of fact, and concluded as a matter of law, that TEP's customers included wholesale power customers. The Trust argues that the Commission erred in doing so.

¶ 24 The Trust argues that in 1971, when the Siting Committee statutes were passed, the electric power utility industry was a regulated monopoly in Arizona. Under that monopoly, the Trust suggests, the "need" for power was defined by reference to the need for power of Arizona retail power consumers, not by utilities who would purchase power wholesale from an Arizona utility for sale to other consumers. Thus, the Trust argues, in 1987 when the Siting Committee required that the Unit be necessary to meet the needs of TEP's customers, it would not have meant the entities to which TEP sold power on a wholesale basis.

¶ 25 When in the 1990s the Commission adopted a regulatory model more oriented to competition, it increased the ability of electric utilities to produce power and sell it on a wholesale basis to other utilities. The new regulatory model increased the demand to produce power in Arizona that was not necessarily destined for Arizona users and distorted the concept of "customers" the Siting Committee intended to include in its original condition.

¶ 26 Even assuming, as the Trust argues, that a competitive market for power generation may increase the number and demand of TEP's wholesale customers, TEP witnesses testified at the Commission that it sold wholesale power even under the previous regulated monopoly model. In 1987, when the condition was placed in the CEC, wholesale customers accounted for twenty percent of TEP's revenues. Such customers included SRP, APS, Phelps Dodge, and others. TEP still sells to these and other customers.

¶ 27 Further, Steve Olea, Assistant Director of the Utilities Division of the Commission, testified that:
[I]f you look at TEP as it really is, [as] a part of the integrated system in the southwest, and again, if you look at all their load, which includes retail, current, future, wholesale, current future and new, and you also consider ... that this Commission has passed competition rules, which means that they're going forward with competition on the generation side, then again, it's my opinion that TEP would need the output from Unit 4. And not only that TEP ****363 *37** would, but that the state would, and right now, the question is how much power does this state really need.

¶ 28 Thus Mr. Olea's testimony, in addition to the testimony provided by TEP, was that the power delivery system in the southwest is an integrated system in which utilities purchase power from each other.

¶ 29 To the extent that the definition of a TEP customer in the CEC condition is a matter of law,[FN9] the Commission itself p'aced the term in the CEC. We thus defer to the Commission's interpretation of the term unless it is clearly erroneous. *Marco Crane & Rigging*, 155 Ariz. at 294, 746 P.2d at 35 (deferring to interpretation of Commission-approved tariffs); *MCI Worldcom Network Servs.*, 274 F.3d at

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547 (stating that the court will allow an agency's interpretation of the intended effect of its own order to control unless clearly erroneous). In light of the above considerations, the Commission's determination that wholesale power customers of TEP are included within its customers for purposes of establishing need is not clearly erroneous.

FN9. The Trust in its briefing acknowledges that TEP sells power to wholesale purchasers, and we do not understand the Trust to challenge the Commission's factual finding that TEP sells power to wholesale customers as lacking substantial evidence. There is, at any rate, substantial evidence in the record to support such a finding.

3. The Commission Did Not Abrogate Its Statutory Responsibilities.

[7] ¶ 30 The Trust next argues that the Commission failed to properly conduct the balancing required by A.R.S. § 40-360.07(B) as incorporated in the CEC. It argues that instead of the Commission independently determining that a need for power existed so that it could balance that need with the desire to minimize the environmental and ecological impact as the statute requires, the Commission merely imposed a requirement that TEP enter wholesale power contracts for the output of Unit 4 prior to construction. Citing this court's recent decision in *Phelps Dodge Corp. v. Arizona Electric Power Co-op., Inc.*, 207 Ariz. 95, 83 P.3d 573 (App.2004), the Trust argues that this amounts to an abrogation of the Commission's independent responsibility to make a determination of the need for power.

¶ 31 The Trust also argues that because the Commission's determination of need relies upon the need for wholesale power, its determination is not supported by substantial evidence because the Commission has made no attempt to quantify the need for wholesale power within the state.

¶ 32 As an initial matter, we reject the Trust's assertion that the Commission made no independent finding of need. In Decision No. 65347 the Commission set forth, at some length, the analysis in which it balanced the need for power with the desire to minimize the environmental and ecological impacts necessary to obtain that power. In discussing the need for power, it first noted that it accepted Mr. Olea's testimony characterizing the nature of the Arizona power market and confirmed that "[a] wholesale customer needs power just as a retail customer needs power." It noted that placing Unit 4 where there were already existing coal-powered generating units would prevent the need for siting new or additional transmission facilities and would minimize the environmental impacts associated with placing a new power facility where none previously existed (a "greenfield" plant siting). It further determined that the increased emissions that might be expected from Unit 4 would be very minimal because, if Unit 4 were constructed, new emission control technology would be required for the existing units resulting in minimal additional emissions overall. The Commission then determined that "the environmental impacts of the proposed expansion do not outweigh the need for [an] adequate, economical and reliable supply of electricity in Arizona."

¶ 33 In its conclusions of law at the end of the order the Commission further determined that "TEP has made the requisite showing of need for Unit 4 pursuant to Decision No. 55477." It also states that, "[i]n arriving at its Decision herein, the Commission has balanced, in the broad public interest, the need for an adequate, economical and reliable supply of electric power with the ****364 *38** desire to minimize the effect thereof on the environment and ecology of the state." These conclusions belie the Trust's argument that the Commission has abrogated to the free market its responsibility to independently conduct the balancing of need for power with the environmental cost of obtaining it. FN10

FN10. In addition to its finding that the power was needed, and that the need justified the environmental cost, the Commission imposed an additional requirement that the unit not be built in the absence of contracts for the power produced. Such a requirement, however, did not take the place of an independent determination of need; it merely provided a guarantee of the Commission's finding that there was a need for such power. As the Commission stated, "[t]he evidence in the record that Unit 4 will not be built without firm contracts in place demonstrates that unneeded generation will not be built."

[8] ¶ 34 While the Commission did not, in its findings, precisely identify or quantify the nature of the need against which it then balanced the steps taken at the Springerville generating location to

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minimize environmental and ecological impacts, the subject of the hearing and the testimony presented concerned the need for the power to be produced by Unit 4. In this case, TEP presented testimony that its retail consumers alone would need the power to be generated by Unit 4. TEP representatives testified that it anticipated the need for approximately 320MW of additional capacity in 2005 and 631MW of additional capacity by 2010 to serve its retail customers. TEP witnesses also introduced testimony that its wholesale customers needed the power to be generated by Unit 4. These customers included SRP, APS, Phelps Dodge, other Arizona-based users and some external wholesale purchasers. The Commission also heard the evaluation of the Commission staff that, given the realities of power generation, there was a need within the state for the power to be generated by Unit 4. The Trust asserts that because the Commission relied on the need for wholesale power to determine the need for Unit 4, it was required to quantify the need for wholesale power within the state to provide substantial evidence to support its determination.

¶ 35 However, the statute itself does not require that the need for power be determined based solely on the power needs of in-state consumers. Nor is there anything in the statute that requires that the "need" for the "adequate, economical, and reliable" power that is to be balanced against the desire to minimize environmental impacts should be determined in any particular way. [FN11] The statute gives the Commission the obligation to conduct the balancing in the broad public interest and leaves considerable discretion to the Commission in how to determine need under the statute. A.R.S. § 40-360.07(B). We cannot say that in an integrated wholesale market the need for wholesale power both in and out of the state will not affect the availability of power for consumers in Arizona. To this extent at least, we cannot say that it is irrelevant to the Commission's assessment of the broad public interest to take into account such considerations in the balancing it conducts pursuant to the statute. To the extent that an argument can be made that good public policy would dictate otherwise, that argument should be made to the legislature. *See Roosevelt Elem. Sch. District v. State*, 205 Ariz. 584, 591 ¶ 33, 74 P.3d 258, 265 (2003); *Schritter v. State Farm Mut. Auto. Ins. Co.*, 201 Ariz. 391, 394, ¶ 17, 36 P.3d 739, 742 (2001) ("The policy argument ... thus should be addressed to the legislature rather than to this court."); *see also State v. Cotton*, 197 Ariz. 584, 591, ¶ 26, 5 P.3d 918, 925 (App.2000) ("[P]olicy arguments are best addressed to the legislature, which is the appropriate forum for determining what, if any, reform is appropriate.").

FN11. There was evidence offered at the hearing that the source diversity provided by a coal-powered generating station enhanced the ability within Arizona to produce a safe, stable and economic power supply.

¶ 36 The testimony introduced at the Commission hearing constitutes "substantial evidence" of the need for the power to be produced by Unit 4, and is sufficient to underpin the Commission's determination of need in balancing that need with the desire to minimize the environmental and ecological costs.

¶ 37 We also reject the Trust's assertion that the reasoning in *Phelps Dodge* supports ****365 *39** its argument here. In *Phelps Dodge,* this court declared a Commission regulation, Ariz. Admin. Code R14-2-1611(A), unconstitutional. 207 Ariz. at 108, ¶ 39, 83 P.3d at 586. That regulation mandated that rates for power that resulted from the competitive market place "shall be deemed to be just and reasonable." *Id.* at 106, ¶ 27, 83 P.3d at 584. Because, however, the Arizona Constitution charges the Commission with setting just and reasonable rates, and because the Commission is required to consider all interests, including interests that may not be accounted for by the free market in doing so, we held that the regulation violated the constitution. *Id.* at 108, ¶ 39, 83 P.3d at 586.

¶ 38 The statute here, however, is distinguishable from the regulation we found unconstitutional in *Phelps Dodge.* While the statute here arguably requires the Commission to make a determination of the need for power just as the Arizona Constitution requires the Commission to set just and reasonable rates, there is nothing in the statute comparable to the invalidated administrative regulation that compels the Commission to accept market determinations of need. Nor, as we have observed, does the statute require the Commission to determine "need" in any particular fashion. The Commission thus may consider the market for power in determining the need for power, and it is difficult to imagine how the Commission could adequately assess the need for power without at least some reference to the market demand.[FN12]

FN12. In *Phelps Dodge* we also noted that the determination of just and reasonable

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> rates need not be totally separated from market forces. 207 Ariz. at 107, ¶ 32, 83 P.3d at 585. "Although the Commission may be influenced by market forces, in determining what rates are 'just and reasonable,' the Commission may not abdicate its constitutional responsibility to set just and reasonable rates by allowing competitive market forces alone to do so." *Id.*

¶ 39 We do not find that the Commission abdicated a statutory responsibility to the market in making its determination of need. We also find that determination to be adequately supported by substantial evidence.

4. The Need of SRP's Customers Was Not At Issue.

[9] ¶ 40 The Trust finally argues that any evidence of need presented by TEP is irrelevant due to the terms of an amended joint development agreement that TEP has entered with SRP pertaining to Unit 4. Under that agreement, the Trust asserts, TEP has transferred the exclusive right to construct Unit 4 to SRP and has superceded the joint development agreement between TEP and SRP that was in place at the time the Commission held the hearing. The amended joint development agreement, however, is not in the record. In their briefs the parties argue about the extent of the transferred right to construct Unit 4 and the interpretation of the amended development agreement. We cannot interpret a document that is not in the record. The Duckworth affidavit, while specifying the terms of the negotiation, makes clear that no agreement has yet been reached. Even accepting the Duckworth affidavit as true, the fact that negotiations are ongoing is not a sufficient basis on which to overturn the Commission's decision.

[10] ¶ 41 The question at issue before the Commission was whether TEP had met the conditions set forth in the CEC. The Commission's determination was that TEP had done so. That is the determination that the superior court reviewed. Events that occurred after the Commission hearing are not admissible evidence that the courts may consider. "[E]vidence of events occurring subsequent to the Corporation Commission hearing is not admissible." *Tucson Elec. Power*, 132 Ariz. at 244, 645 P.2d at 235. We, thus, decline to address such events here.

5. TEP Is Entitled To Costs But Not Fees.

[11] ¶ 42 TEP also requests attorneys' fees pursuant to A.R.S. § 12-348 (2003). Under that statute, "a court shall award fees and other expenses to any party other than this state or a city, town or county which prevails by an adjudication on the merits in ... [a] court proceeding to review a state agency decision pursuant to ... [a] statute authorizing judicial review of agency decisions." A.R.S. § 12-348(A)(2).

****366** 40 ¶ 43 In interpreting a statute, the court's primary goal is to fulfill the purpose of the legislature. *State v. McDermott*, 208 Ariz. 332, 334, ¶ 5, 93 P.3d 532, 534 (App.2004). That is most often accomplished by looking at the plain meaning of the words the legislature places in the statute. *Long v. Napolitano*, 203 Ariz. 247, 258, ¶ 37, 53 P.3d 172, 183 (App.2002) (citations omitted). When, however, the legislature specifies its purpose in the session law that contains the statute, it is appropriate to interpret the statutory provisions in light of that enacted purpose.[FN13]

> FN13. In such cases the statement of legislative purpose is itself enacted and is thus subject to the entire review process by which a bill becomes law. The statement is thus free from some of the vagaries that can otherwise accompany a judicial search for legislative intent.

¶ 44 While not codified with the statute, the legislation enacting A.R.S. § 12-348 set forth both legislative findings and a legislative purpose. 1981 Ariz. Sess. Laws, ch. 208, § 1. The legislative findings specified that there was a disincentive for private parties to challenge governmental action due to the disparity inherent between the parties. *Id.* The governmental agency has extensive resources available to it in defending its decisions while private parties generally have much more limited resources. *Id.* The legislative purpose was thus reducing "the deterrents and the disparity by entitling prevailing parties to recover an award of reasonable attorney fees, expert witness fees and other costs *against the state.*" *Id.* (emphasis added). Thus, the legislation interpreted as a whole does not authorize the court to require any entity other than a governmental entity to pay a fee award to the prevailing party. This conclusion is confirmed by the title of the statute which, in pertinent part, reads "Award of fees and other expenses against the state or a city, town or

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county." A.R.S. § 12-348. Although a title is not part of a law itself, we may look to it for guidance in interpreting a statute. *Pleak v. Entrada Prop. Owners' Ass'n.* 205 Ariz. 471, 474, ¶ 7, 73 P.3d 602, 605 (App.2003), *aff'd,* 207 Ariz. 418, 87 P.3d 831 (2004).

¶ 45 Further, when the governmental agency is the prevailing party, the statute makes no provision for the government to recover fees against the party challenging its decision. It would be inconsistent with the statutory purpose to expose the challenger to the risk of paying the agency's attorneys' fees if the challenger did not prevail. It would similarly be inconsistent with the statutory purpose to allow an attorneys' fees award to be made to private parties who intervene on the side of the state. In this case TEP intervened on the side of the Commission to defend the Commission's decision. While it was TEP's clear right to do so to defend its interests, it would be inconsistent with the statutory purpose to enter a fee award against the Trust and in favor of TEP for the reasons stated above. Thus, we conclude that A.R.S. § 12-348 does not authorize a fee award here.

¶ 46 TEP requests an award of costs pursuant to A.R.S. § § 12-331 (2003) and 12-341 (2003). As a successful party, TEP is awarded its costs on appeal upon compliance with Arizona Rule of Civil Procedure 21.

CONCLUSION

¶ 47 The Trust failed to prove by clear and convincing evidence that the Commission's decision was unlawful or unreasonable. The superior court's decision affirming the Commission ruling is therefore affirmed.

CONCURRING: PATRICIA K. NORRIS, Presiding Judge, and PATRICK IRVINE, Judge.
Ariz.App. Div. 1,2005.
Grand Canyon Trust v. Arizona Corp. Com'n
210 Ariz. 30, 107 P.3d 356, 446 Ariz. Adv. Rep. 20, Util. L. Rep. P 26,904

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STAFF'S PROPOSED CONDITIONS

SOUTHERN CALIFORNIA EDISON
DEVERS TO PALO VERDE 500 kV LINE No. 2
DOCKET NO. L-00000D-06-0295-00130
October 4, 2006

Staff opposes the Application as filed. However, Staff proposes conditions that, if adopted in their entirety, would make the project acceptable. Even if the proposed conditions are adopted, Staff will not endorse or recommend the project for approval. Staff would simply not oppose the project. Staff requests a finding of fact on its position should the Committee and the Commission adopt its proposed conditions.

The following conditions collectively constitute Staff's proposed conditions for the Palo Verde to Devers No. 2 transmission line:

1. Southern California Edison agrees to make good faith efforts to work within future California and regional proceedings to encourage regional access to natural gas storage facilities in California in a manner that addresses natural gas service reliability and efficiency in the region, including Arizona.

2. To ensure the second Palo Verde to Devers 500 kV transmission line does not adversely effect reliability of the Arizona Extra High Voltage (EHV) grid and power plants interconnected at the Palo Verde Hub, one of the following options must be adopted by Southern California Edison for construction of the new line:

   a. The line must be constructed on separate towers or monopoles for its entire length and have sufficient physical separation from the existing Palo Verde to Devers line to assure a common mode outage frequency of less than one in thirty years (per NERC/WECC Planning Standards S-2) or that no cascading outages would occur for such a common mode outage (per NERC Category C.5) without the use of a special protection scheme,

   OR

   b. The WECC rated Path 49 shall not be operated above a level at which a, NERC Category C.5, common mode outage of the two Palo Verde to Devers lines would cause cascading outages unless a special protection scheme were activated. Studies are to be performed annually to establish with WECC such a Path 49 Operational Transfer Capability (OTC) limit for the common mode outage of the two Palo Verde transmission lines. If the Applicant does not want to perform annual studies, the Applicant may choose to request a lower rating of the line from the appropriate regulatory authority. The lower rating must achieve the above goals.

EXHIBIT
S-24
Admitted

3. The second Palo Verde to Devers 500 kV line shall terminate at the new Harquahala Junction Switchyard along with the existing Harquahala to Hassayampa 500 kV line in order to mitigate prevailing reliability risks associated with extreme contingencies in the vicinity of the Palo Verde trading hub. The Harquahala Switchyard is to be jointly owned by the Palo Verde to TS5 participants. The Harquahala Junction Switchyard to Hassayampa Switchyard line is to be jointly owned by Southern California Edison and the same Palo Verde to TS5 transmission participants.

4. To assure that prevailing Palo Verde Hub commercial practices are not compromised by the transmission interconnections at Harquahala Junction Switchyard, Southern California Edison must prior to commencing operation:

   a. File with the Federal Energy Regulatory Commission and receive approval of a request, on behalf of all Palo Verde Hub interconnecting parties, for modification of the transmission tariff free zone at the Palo Verde Hub to include all transmission lines currently interconnecting power plants to either the Palo Verde Switchyard or the Hassayampa Switchyard,

   OR

   b. File with the Arizona Corporation Commission (ACC) an executed transmission agreement with Harquahala Power Plant and the participants of the Palo Verde to TS5 transmission line that establishes that Harquahala Power Plant can schedule its full capacity over the Harquahala Junction Switchyard to Hassayampa Switchyard transmission line without transmission tariff costs and that all three parties will assume pro-rata obligations to share in the cost of an additional transmission line between these two switchyards as needed at some future date.

5. Control area authority and associated operational reliability obligations placed by the ACC upon power plants originally interconnected at the Palo Verde Hub are to be maintained with the new interconnection at Harquahala Junction. Such power plant obligations can be transferred to the transmission control area to which they are interconnected in the event that they desire to discontinue as a generator only control area operator.

6. To assure that non-discriminatory open-access transmission principles are not compromised, commercial barriers to Arizona transmission users do not occur on lines serving as tie lines between CAISO and the forming WestConnect RTO operational footprint, and that no new seams issues between the two RTOs result from the construction of the Palo Verde to Devers 2 transmission line:

    a. Arizona Public Service Company shall have operational control of the Harquahala Junction Switchyard, the Harquahala Junction Switchyard to Hassayampa Switchyard transmission line and the Harquahala Junction Switchyard termination of the second Palo Verde to Devers transmission line and the Harquahala Power Plant line.

    b. The Applicant executes a binding written agreement with the CAISO to limit its control area. The CAISO operational control and transmission tariff application shall initially end at the Devers termination of the Palo Verde to Devers 2 transmission line and may extend eastward to any future switchyard interconnecting with the line between Devers and the Colorado River. This implies a new Southern California Edison transmission tariff will be required should a future switchyard interconnect occur with the Palo Verde to Devers 2 line between Harquahala Junction and the Colorado River. The Applicant must file the executed agreement with the Commission prior to commencing operations of the line.

Study of the Economic Impact of PVD2 Transmission Line on Arizona Consumers

Prepared for Arizona Corporation Commission
September 14, 2006

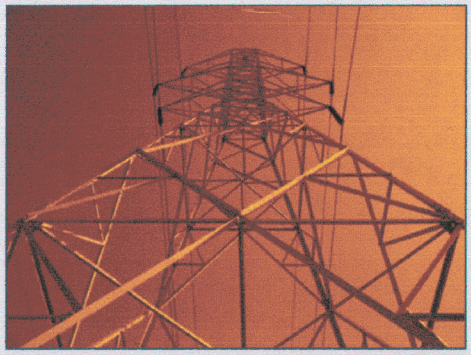

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EXHIBIT
tabbies
S-25
admitted

Features of UPLAN

Functions

- Day-ahead SCUC/SCED
- Supply, demand & portfolio bids
- Bilateral transactions
- Ancillary service model
- Time varying bus level demand
- Full Network Model (DC/AC) marginal/average losses
- Congestion management
- Contingency analysis (N-x)
- Real time imbalance Market Model
- Portfolio bid optimization
- Long-term portfolio optimization
- Structural Volatility analysis

Results

- Day ahead energy LMP
- A/S bids, prices & revenues
- Generator operation, costs, revenues
- Load flow, binding contingencies, PARS, OTDF, PTDF,GSF, RAS, LODF, CRR
- Shadow prices
- Real time LMP distribution
- Capacity prices
- Volatility reports options, VaR, delta, gamma, statistical output

Technology

- MS- SQL server with .net
- Dashboard, report wizard, auto charting
- Distributed (Parallel) processing- scalable cluster manager
- Powerful grouping, filtering, storage management
- Intuitive control of data viewing, manipulation
- Powerful scenario based comparison module
- Security and access privilege

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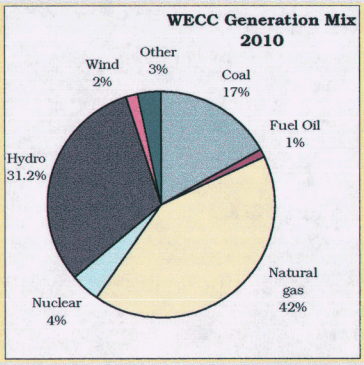
WECC Generation Mix (2010)

WECC Capacity (MW), 2010		
Fuel	MW	%
Coal	37,869	16.9%
Fuel Oil	2,517	1.1%
Natural gas	93,061	41.6%
Nuclear	9,519	4.3%
Hydro	69,750	31.2%
Wind	3,400	1.5%
Other	7,594	3.4%
Grand Total (MW)	223,711	100.0%

Source : EIA 411 A & B Filing



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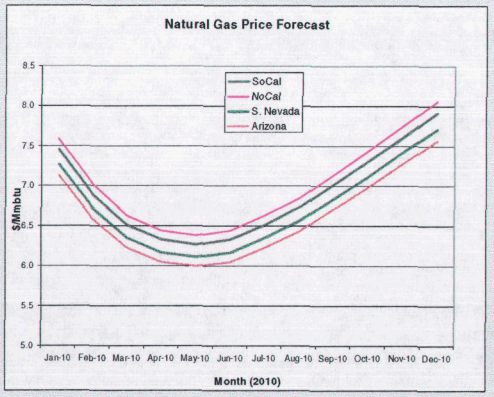
Natural Gas Price Forecast

Year 2010 $/Mmbtu

Month	SoCal	NoCal	S. Nevada	Arizona
Jan-10	7.46	7.59	7.27	7.13
Feb-10	6.89	7.02	6.72	6.59
Mar-10	6.51	6.63	6.35	6.23
Apr-10	6.33	6.44	6.17	6.05
May-10	6.27	6.38	6.11	6.00
Jun-10	6.33	6.44	6.17	6.05
Jul-10	6.51	6.63	6.35	6.23
Aug-10	6.73	6.85	6.56	6.43
Sep-10	7.02	7.14	6.84	6.71
Oct-10	7.31	7.44	7.12	6.99
Nov-10	7.61	7.75	7.42	7.28
Dec-10	7.92	8.06	7.71	7.57



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Demand Forecast (2010)

	Annual Peak (MW)	Annual Energy (GWh)
Area	2010	2010
Arizona-New Mexico-Southern Nevada	30,142	142,973
California-Mexico Power Area	63,080	337,118
Northwest Power Pool Area	64,078	373,912
Rocky Mountain Power Area	11,975	67,515
Total WECC in UPLAN*	154,107	921,516

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Revised PVD2 Plan of Service (POS)

- Build new Harquahala-Devers 500 kV line
- Build new Devers-Valley 500 kV #2 line
- 230 kV Circuit Breaker Replacements and Upgrades
- Reactive Power Equipment
- SPS to Mitigate DPV1 and DPV2 outage
- Annual Fwd. Cap Path 49. Limit increased from 8055 MW to 9255 MW

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Export /Import

EXPORT FROM ARIZONA (2010)

TO ZONE	W/O PVD2		W/ PVD2		Difference In Flow (GWh)	Difference In Revenue ($1000)
	FLOW (GWh)	EXPORT REVENUE ($1000)	FLOW (GWh)	EXPORT REVENUE ($1000)		
CS_IMPERIAL	843	47,536	820	48,310	(23)	774
CS_LADWP	20,468	1,153,852	19,749	1,173,281	(719)	19,429
CS_SANDIEGO	8,300	457,636	7,901	454,270	(399)	(3,366)
CS_SOCALIF	26,868	1,522,209	33,835	2,019,006	6,967	496,797
NEVADA	4,933	292,776	4,901	301,979	(32)	9,203
NEW MEXI	6,089	340,293	5,389	314,985	(700)	(25,308)
PACE	2,720	160,493	2,748	171,551	28	11,058
WAPA R.M	1,046	61,801	962	60,938	(84)	(863)
TOTAL	71,267	4,036,596	76,305	4,544,320	5,038	507,724

IMPORT TO ARIZONA (2010)

FROM ZONE	W/O PVD2		W/ PVD2		Difference In Flow (Gwh)	Difference In Revenue ($1000)
	FLOW (GWh)	EXPORT REVENUE ($1000)	FLOW (GWh)	EXPORT REVENUE ($1000)		
CS_IMPERIAL	647	39,616	709	42,957	62	3,341
CS_LADWP	47	3,193	76	5,252	29	2,059
CS_SANDIEGO	737	44,015	657	38,879	(80)	(5,136)
CS_SOCALIF	329	22,236	442	29,308	113	7,072
NEVADA	254	14,854	282	16,523	28	1,669
NEW MEXI	6,914	390,469	7,036	412,263	122	21,794
PACE	208	6,115	680	35,891	472	29,776
WAPA R.M	111	4,082	141	5,426	30	1,344
TOTAL	9,247	524,580	10,023	586,499	776	62

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Consumer Payments & NG Consumption

CONSUMER PAYMENTS (2010)

ZONE	COMSUMER PAYMENTS (Million$)		Difference
	W/O PVD2	W/ PDV2	
ARIZONA	5380	5621	242
CN_PGE	6627	6552	-75
CS_IMPERIAL	258	255	-3
CS_LADWP	2600	2574	-27
CS_SANDIEGO	1791	1775	-16
CS_SOCALIF	8161	8037	-124

NATURAL GAS CONSUMPTION (2010)

Zone Name	Fuel Consumption (MBtu)		Difference
	W/O PVD2	W/ PVD2	
ARIZONA	524,227,828	556,795,603	32567775
CN_PGE	358,307,787	346,608,797	-11698990
CS_IMPERIAL	31,836,822	30,524,249	-1312573
CS_LADWP	86,345,440	83,508,456	-2836984
CS_SANDIEGO	114,393,661	111,123,248	-3270413
CS_SOCALIF	377,840,118	358,593,266	-19246852

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Zonal Prices

ZONAL PRICE (2010)

ZONE	W/O PVD2			W/ PVD2		
	OFF-PEAK ($/MWh)	PEAK ($/MWh)	OVERALL ($/MWh)	OFF-PEAK ($/MWh)	PEAK ($/MWh)	OVERALL ($/MWh)
ARIZONA	49.42	62.98	58.10	50.54	66.93	61.00
CN_PGE	51.65	69.39	62.82	51.21	68.58	62.15
CS_IMPERIAL	52.68	68.36	62.75	51.97	67.39	61.88
CS_LADWP	52.23	69.43	63.32	51.80	68.72	62.71
CS_SANDIEGO	52.87	68.63	63.05	52.21	68.18	62.52
CS_SOCALIF	52.54	69.74	63.62	51.87	68.66	62.69

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Arizona Monthly Prices

Month (2010)	W / O PVD2			W / PVD2		
	OffPeak Price ($/MWh)	OnPeak Price ($/MWh)	Overall Price ($/MWh)	OffPeak Price ($/MWh)	OnPeak Price ($/MWh)	Overall Price ($/MWh)
1	51.18	61.17	57.29	52.93	67.69	61.96
2	46.94	56.21	52.77	47.77	63.74	57.82
3	46.73	60.36	55.53	46.82	61.82	56.51
4	46.34	59.67	55.02	46.37	60.22	55.39
5	42.75	56.10	51.22	44.83	59.11	53.89
6	46.96	64.00	58.09	47.51	65.72	59.41
7	50.78	74.57	66.38	51.18	75.49	67.11
8	50.90	72.69	64.72	51.31	72.74	64.91
9	47.99	64.59	58.88	50.60	68.06	62.05
10	52.59	62.12	58.55	53.71	68.88	63.20
11	55.12	61.09	58.80	56.50	69.71	64.64
12	54.74	63.14	59.98	56.90	70.01	65.07
Average	49.42	62.98	58.10	50.54	66.93	61.00

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Q & A

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Resume for Dr. Rajat Deb, LCG Consulting

Dr. Rajat K. Deb is the Founder, President, and Chief Executive Officer of LCG Consulting, Los Altos, California, a corporation devoted to the development of strategic planning software for the electric and gas utility industry and provision of consulting services to the energy industry. Dr. Deb is well known for his pioneering work in developing nodal spot price models and for his extensive published work in the area of competitive modeling, market design, transmission analysis and tariff design. He is the chief architect of the UPLAN system.

Dr. Deb is a widely recognized expert in the fields of competitive energy market modeling, utility systems planning, and operations research. He has directed many large projects in valuation of generation and transmission assets, utility analysis, operations research, and analytic software development in industry and in academic settings. His innovative work has contributed significantly to both theoretical advances and state-of-the-art practical applications for electric and gas utility planning. He has been involved in the deregulation and privatization of the gas and electricity markets in the United States, Australia, United Kingdom, Spain, and various Eastern European countries, such as Estonia. Latvia and Lithuania. He has directed and managed over 100 different asset valuation projects all over the World.

Under his leadership, LCG has conducted numerous restructuring studies on the impact of electricity industry restructuring in the United States and abroad, and has developed and supported models for all aspects of short-and long-term planning for these industries. Dr. Deb is among the first to research the implications of competitive pricing and marketing and to develop models to analyze competitive power markets. In 1989, LCG built the first daily competitive planning model for the privatized electrical industry in the United Kingdom. In 1991, LCG developed the first competition-based national pool model for the Iberdrola, S.A., the largest utility in Spain. In the United States, LCG has built the multi-area power market model for California, regional pooling models for New England and the PJM Pool, and municipal power marketing models for Michigan and the model of ISOMOU (Eastern Interconnect) for the EPRI ancillary market and system adequacy study.

Dr. Deb holds a Master's degree in Operations Research and a Ph.D. in Computer Science from Syracuses University, Syracuse, New York. He was a professor of Operations Research at Stanford University, professor of Decision and Information Sciences at Santa Clara University, and chaired the Department of Computer Science at the State University of New York, Oswego. Dr. Deb has published widely in power systems analysis, operations research and computer science.

REPRESENTATIVE EXPERIENCE

Dr. Deb has performed evaluation of deregulation alternatives for all the reliability regions of North America, Europe, Asia and Africa. In particular, he conducted studies for European electricity market liberalization in the U.K., Spain, Latvia, Estonia, Lithuania, Greece, and Slovakia. In Taiwan, he directed a large-scale study on tariff design and electricity market restructuring. His pioneering work in electricity market design has set the standard for restructuring analysis throughout the U.S. Dr. Deb has advised the leading organizations and institutions all over the world as shown below.

Client	Project Description
Airtricity	Market Analysis of wind energy in Texas
Austin Energy	Compressed Air Energy Storage (CAES) feasibility and risk assessment

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Client	Project Description
Russian Federal Grid Company	Directed the valuation of transmission investment in Russian Federation
RAO UESR	Forecasting electricity prices and revenues, and valuing assets in the wholesale electricity market for Unified Energy System of Russia
California Public Utilities Commission, California, U.S.A.	Directed and managed the largest ever valuation of generation assets in the U.S., i.e., 74-unit hydroelectric system pf PG&E.
Electric Power Research Institute, California, U.S.A./United States Congress	Directed and managed the project to explore the economic viability of coal in electric power generation in the U.S.
Diamond Generation Company, California	Project Leader for the Pumped Storage Hydro Unit Valuation in Southern Nevada.
Taiwan Power Company, Taipei, Taiwan	Project Director for Liberalization of Taiwan Electricity Market, Transmission and Distribution (T&D) Power Wheeling Tariff Design
CAES Development Company, Houston, Texas, U.S.A.	Project Leader for the valuation of Compressed Air Energy Storage Units.
Duke Energy North America, L.L.C., Houston, Texas	Project Leader for the valuation of generating plant in Florida.
Tractebel Power Inc., Houston, Texas,	Directed and managed the valuation of Danskammer and Roseton Generating Plants in New York state.
Kansai Electric Power Company, Osaka, Japan	Managed a study and wrote a report on Stranded Costs, Power Contracts and Competition Transition Costs for California's Utilities.
California Energy Commission, Sacramento, California	Designed different options for market design and treatment for stranded cost and reliability analysis.
Zimbabwe Electricity Supply Authority, Harare, Zimbabwe	Developed the Financial Model for Asset Valuation and managed the valuation of the entire portfolio of generating assets.
Electric Power Research Institute, California, U.S.A.	Directed Demand-Side Information System (DSIS) and networking (EPRINET) projects.
Electric Power Research Institute, Palo Alto, California, U.S.A.	Developed Customer Preference Model in association with Booze-Allen & Hamilton.
Iberdola, S.A and Espinosa, Madrid, Spain	Built the Spanish Pooling Model and Developed methodologies for regulating the operations of electrical plants in Spain. In-depth study of deregulation in Spain.
Scottish Power, U.K	Built first daily competitive planning model for the privatized electrical industry in the U.K.

Client	Project Description
Pacific Gas and Electric Company San Francisco, California	Valuation of all the Hydroelectric Generation Assets of PG&E for California Public Utilities Commission
Alliant Energy Resources Wisconsin	Impact of MISO LMP-based Market Design on Generating Assets in Illinois, Alliant Energy Resources
California Public Utilities Commission, California,	PG&E Divestiture – Assessment of Extensive Repowering at the Kern Power Plant Site
Alliant Energy Resources Wisconsin	Valuation of Armstrong facility's injection bus in PJM-West, a proposed combined cycle unit in City of Marshall, Minnesota and a combustion Turbine unit in North Carolina for Alliant Energy Resources
Lexecon, Inc Boston Massachusetts	Market simulation and assessment of the stranded cost of First Energy's generation assets and testimony support for Lexecon, Inc
Dominion Virginia Power	Asset valuation of Bath County Pumped Storage unit and FTR calculation for Dominion Virginia Power
Tractabel Houston, Texas	Valuation of Danskamer and Roseton Generating Plants for Tractebel Power
Electric Power Research Institute Palo Alto, California	Market-Based Valuation of New Coal-Fired Generation, EPRI-LCG Joint Study
Alberta Balancing Pool Calgary. Alberta	Valuation and Auction of Sheerness and Genesee units for Alberta Balancing Pool
Alliant Energy Resources	Due Diligence Study and Assessment of potential revenues of Neenah Combustion Turbine Plant in Wisconsin for CoBank
Blue Diamond Power Partner Los Angeles, California	Operation and Valuation of a 400 MW Pumped Storage Unit in southern Nevada for Blue Diamond Power Partner
East Kentucky Power Cooperative	Real Options Case Study: Asset Valuation of East Kentucky Power Cooperative (EKPC) New Generation Options
Dayton Power and light Dayton, Ohio	Valuation FTRs for r all DPL busses and generators
Royce Power Ventures	Market Analysis of New Units in the ECAR Region for Rolls-Royce Power Ventures
Calpine corporation San Jose. California	Price Forecast and Valuation of New Units in the MAPP Regional Market for Calpine
Duke Energy	Valuation of St. Lucie combined cycle unit in Florida for Duke Energy

Client	Project Description
Sempra Energy San Diego, California	Generation and transmission analysis for assessing potential energy and ancillary service revenues of a proposed 600 MW combined cycle generator in Southern California for Sempra Energy
San Diego Gas and Electric San Diego, California	Portfolio/Contract Design and Assessment – Optimal portfolio analysis for power contracts for SDG&E
Sacramento Municipal Utility District Sacramento, California	Portfolio analysis and selection of short-term contracts for Sacramento Municipal Utility District (SMUD)
Public Power Authority City of Burbank, California	Strategic resource analysis & plan for Southern California Public Power Authority/City of Burbank
for Kansai Electric Power Company, Osaka, Japan	Stranded costs, power contracts and competitive transition costs for California's IOUs for Kansai Electric Power Company, Osaka, Japan
KUIC, Kauai	Integrated resource planning study
Exelon Power Team Philadelphia,	Nodal spot prices and ancillary service market analysis for extended PJM with AEP, ComEd, and Virginia Dominion
Dominion Virginia Power Virginia	Cost-Benefit analysis of Dominion Virginia Power joining PJM
TXU Energy, Houston, Texas	NEPOOL Congestion Study for TXU Energy, Houston, Texas
Allegheny Energy	Cost-Benefit analysis of Allegheny Energy joining PJM
BC Hydro Vancouver, BC, Canada	Designing Tariffs for Electricity Transmission and Distribution in Taiwan RTO West LMP Study: Determination of Generation and Transmission Revenue of BC Hydro Assets
EPCOR Calgary, Alberta	Impact of proposed transmission tariff on energy and ancillary service markets and transmission expansion in Alberta, Canada
Federal Transmission Grid Moscow, Russia	Development of methodology for expansion evaluation for Russian transmission grid
Electric Power Research Institute Palo Alto, California	FERC Order 2000 and Analysis of Ancillary Service Requirements: Revenues from A/S and Operational Flexibility, EPRI
TXU Trading Houston, Texas	Analysis of the proposed New England ISO and transition from a tight power pool to an ISO-like structure – Impact on electricity prices and FTRs

Client	Project Description
California Energy Commission Sacramento, California	Evaluating Alternative Market and Pricing Designs for California Regulators (Docket No. EC96-19-001 & ER96-1663-001)
Alliant Energy	Asset Valuation in Ontario for Alliant Energy Resources and WPS Energy, Inc
Sempra Energy San Diego, California	Locational electricity price forecasting and payment of Reliability Must Run (RMR) units for Sempra Energy
Taiwan, Japan, Malaysia, Russia, Spain, England, Baltic and other parts of the world	Directed and managed many large scale projects in more than 20 countries
All NERC regions, US congress, AID, EPRI and regulatory groups	Dr Deb has conducted more than 100 studies in every NERC region and many state and federal agencies

Dr. Deb is the chief architect or the UPLAN suite of models and has led the development of the following successful software products:

- UPLAN 7 performs coordinated opportunity cost-based energy and ancillary service procurement, congestion management, full-fledged contingency analysis with Security Constrained Unit Commitment (SCUC) and Economic Dispatch (SCED).
- Network Power Model (NPM) for detailed generation, transmission and market share analysis. This is the only LMP model fully compliant with the U.S. FERC Standard Market Design.
- Merchant Plant Model for assessment of new entrants and their impact on future prices.
- Volatility Model for managing risks arising from uncertainties in the market prices and other investments.
- Multi-area Maintenance Scheduling Model: Determines the maintenance schedule that minimizes the total costs and maintains reliability.
- Ancillary Service Model: identifies the generation that is qualified to provide ancillary services to provide energy.
- Power Stack: Runs UPLAN in a distributed computing environment to dramatically reduce the run- time by an order of magnitude.
- PLATO Database: A relational database which contains data for electric Plants, Loads, stranded Assets, Transmission, and Operations for all utilities and IPPs in the entire North America.
- WinUPLAN-G: An Integrated Gas Resource Planning and Nomination Model
- UTRACK: A Daily Tracking and Database Management System
- UPLAN-IRP performs optimal generation planning, production costing and reliability analysis, demand-side management (DSM) evaluation, cost-benefit evaluation, rates and revenue analysis, financial projections, and optimal resource planning.

- UPLAN-III: Electric Utility Strategic Planning Model
- Dynamic System Optimizer (DSO): A state-of-the-art optimization model for Integrated Resource Planning
- UPLAN-C: Detailed Hourly Chronological Model
- Cogen: A cogeneration model for steam and electric dispatch
- Power Pool: Power Pooling Model used in conjunction with UPLAN-C in U.K., Spain and several U.S. utilities.
- Long Range and Short Range Financial Models for gas and electric utilities.
- EnergyOnline: An Internet service with the latest information about restructuring in the U.S. electric industry.
- Second Wind: A commercial program to link remote databases over heterogeneous platforms and used by more than 2000 organizations.
- DSIS: A multi-million dollar on-line Demand Side (Management) Information System developed and maintained on behalf of EPRI. This is the largest on-line DSM database in the world.

EDUCATION

Name of the School	Dates Attended	Degree Obtained
School of Computer and Information Sciences, Syracuse University, Syracuse, New York, U.S.A.	June 1969- May 1972	Ph.D. in Systems and Information Science
Department of Operations Research and Industrial Engineering, Syracuse University, Syracuse, New York	June 1968- May 1969	M.S. in Operations Research
Indian Institute of Technology, Kharagpur, India	July 1958 – May 1962	B.Tech. (With Honors) in Engineering

EMPLOYMENT RECORD

DATES	COMPANY, LOCATION	TITLE	JOB DESCRIPTION
1983-Present	LCG Consulting, Los Altos, California, U.S.A.	President, and Chief Executive Officer	Founder of the corporation
1977 - 1983	Electric Power Research Institute, Palo Alto, CA, U.S.A.	Independent Consultant	Review of five-year research and development plan for the United States utility industry
1979-1985	Leavy School of Business, University of Santa Clara, Santa Clara, CA, U.S.A.	Associate Professor	Professor of Decision Sciences

Dates	Company, Location	Title	Job Description
1977-1979	Department of Operations Research, Stanford University, Stanford, CA, U.S.A.	Associate Professor	Professor of Operation Research
1973-1977	Department of Computer Science, State University of New York, Oswego, New York, U.S.A.	Chairman,	Chairman and Professor of Computer Science
1965-1967	Canadair Division of General Dynamics, Montreal, Canada	Industrial Engineer	Cost estimation and budget control of the F-5 aircraft program
(1965)	M/S Hunter-Douglas N. V., Rotterdam, Holland	Project Engineer	Design of aluminum reprocessing plant including smelting, casting, rolling and finishing plants

BOOKS & JOURNAL ARTICLES

Transmission Investment Valuations: Weighing Project Benefits, Rajat K. Deb, The Electricity Journal, March 2004

Generation Reserves: The Grid Security Question, Rajat K. Deb, Public Utilities Fortnightly, January 2004

Market-based Valuation of Coal Generation and Coal R&D in the U.S. Electric Sector, Rajat K. Deb, Pushkar Wagle, Alex Ornatsky, and Lie-long Hsue, EPRI Technical Report (1006954), May 2002

Designing Tariffs for Electricity Transmission and Distribution in Taiwan, Rajat Deb, Keith White, and Lielong Hsue, Taiwan IEEE, May 2002

Generation and Transmission Investments in Restructured Electricity Markets, Rajat K. Deb, Pushkar Wagle and Emmanuel A. Macatangay, Environmental Monitor, Winter 2002

An Analysis of Generation Market Power in the Midwest Interconnect, Rajat K. Deb, Rafael Emmanuel A. Macatangay, and Sidart Deb, The Electricity Journal, March 2002

Multi-Market Modeling of Regional Transmission Organization Functions, Rajat K. Deb, Lie-Long Hsue, Richard Albert and Pushkar Wagle, The Electricity Journal, March 2001, p39-p54.

Surviving and Thriving in the RTO Revolution – How to design tariffs to improve reliability and attract merchant generation, , Rajat K. Deb, Lie-Long Hsue, Richard Albert and Jason Christian, Public Utilities Fortnightly, February 1, 2001

Analyzing Multiple-Product Power Markets – Simulation of Energy and Ancillary Services Prices and System Adequacy, Rajat K. Deb, EPRI Technical Report (1000571), December 2000

Rethinking Asset Values in a Competitive Environment, Rajat K. Deb, Feb. 2000, Public Utilities Fortnightly

Operating Hydroelectric Plants and Pumped Storage Units in a Competitive Environment, Rajat K. Deb, April 2000, Electricity Journal

How to Incorporate Volatility and Risk in Electricity Price Forecast, Rajat K. Deb, Richard Albert, Lie-Long Hsue, and Nicholas Brown, May 2000, Electricity Journal

The Future Course of Demand-Side Management: A Regional Case Study at EPRI, EA-4308 (1985), Ahmad Faruqui, Clark Gellings, EPRI and Rajat K. Deb, LCG Consulting.

Evaluation of Uncertainties in DSM programs: An Integrated Approach (1986), Robert W. Taylor, Public Service Electric & Gas Company and Rajat K. Deb, LCG Consulting.

Multi-area Intertied Network Reliability and Load Carrying Capability (1985), Rajat K. Deb and Charles Schmidt, Department of Quantitative Methods, University of Alabama.

Effective Load Carrying Capability of Interties, (1983), Rajat K. Deb, *IEEE Transactions on Power Apparatus and Systems*, September, 1984)

Economic and Engineering Factors Affecting Generating Unit Size, (1982), Rajat Deb and James Mulvaney, *IEEE Transactions on Power Apparatus and Systems, Vol.* PAS-101, No. 10,3907-3915

Electric Generating System Development (Chapter H, pp 115-132); Effect of Load Profile (Chapter I, pp 133-141), Rajat Deb and James Mulvaney, *Overview and Strategy, 1982 - 1986 Research and Development Program Plan,* (1982), Electric Power Research Institute, Palo Alto, California.

Reliability Models: The Influence of Model Specification in Generation Expansion Planning (A Discussion), (1982) James Mulvaney and Rajat Deb, *IEEE Transactions on Power Apparatus and Systems,* Vol. PAS 101, No. 10, 3677-3678.

The Generating Unit Size Decision, (1980), James Mulvaney and Rajat Deb, Publication No. P-1951-SR, Electric Power Research Institute, Palo Alto, California.

Closure of : Economic and Engineering Factors Affecting Generating Unit Size, (1982), Rajat Deb and James Mulvaney, *IEEE Transactions on Power Apparatus and Systems,* Vol. PAS 102, No. 10, 3917 - 3918.

Economic and Engineering Factors Affecting Generating Unit Size, (1982), abridged version. Rajat K. Deb and James J. Mulvaney, *Power Engineering Review*, Vol. PER-2, No. 10, 45-46

Optimal Dispatching of a Finite Capacity Shuttle, (1978), Rajat Deb, *Management Science*, Vol. 24, No. 13, 1362-1372.

Value of Demand-Side Management: A Case Study, D.E. Jones and R.H. Males (eds.) in Strategic Planning and Marketing for Demand-Side Management, EA 4308, November 1985.

On Generation of Test Data and Minimal Cover of Directed Graphs, (1977), Rajat Deb, *Information Processing*, B. Gilchurst (Editor), North-Holland.

Optimal Control of Batch Service Queues with Switching Costs, (1976), Rajat Deb, *Advances in Applied Probability*, Vol. 8, 177-194.

Optimal Control of Batch Service Queues, (1973), Rajat Deb and Richard F. Serfozo, *Advances in Applied Probability*, Vol. 5, No. 2, 340-361

Optimal Control of Bulk Queues, (1972), Rajat Deb, Ph.D. Dissertation, Syracuse University, Syracuse, New York.

Optimal Average Cost Policies For The Two Terminal Shuttle, (1982), Rajat Deb, Technical Report No. 95, Department of Operations Research, Stanford University, Stanford/ *Management Sciences*, Vol. 33, No.5, 662-669, 1987.

Optimal Control of Poisson Queues With Unknown Intensity and Batch Service, Rajat Deb. *OPSEARCH, Journal of Operations Research.* (forthcoming).

Optimal Control of Bulk Queues With Compound Poisson Arrivals and Batch Service. Rajat Deb. *OPSEARCH, Journal of Operations Research.* October, 1985.

Computation of The Optimal Average Cost Policy For The Two Terminal Shuttle, (1979), Rajat Deb, Technical Report No. 45, Department of Operations Research, Stanford University, Stanford. *Bulletin of The Operations Research Society*, Vol.12 ,1982

Optimal Solution of The Finite Horizon (s,S) Inventory Model, (1974), Rajat Deb and Robert Sargent, Technical Report No. F30602-68-C0013, Rome Air Development Center, Rome, New York. *Bulletin of The Operations Research*, Vol. 22, Supl. 21, p21.

Associative Operating Systems, (1976), Leo H. Groner and Rajat Deb, Technical Report, Department of Computer Science, State University of New York (Funded by National Science Foundation).

Finite Automate and Network Optimization Problems, (1973), Rajat Deb, Technical Report, State University of New York, Oswego.

Optimal Control of Batch Service Queues With Startup and Shutdown Costs, (1973), Rajat K. Deb, *Abstracts of The Management Science*, TIMS XX, Israel, p. 173.

CONSULTING PROJECTS

Below is partial list of recent consulting activities that are directed by Dr. Deb.

Price Forecast & Asset Valuation

- Locational marginal price (LMP) forecast and generating plant valuation by modeling the ERCOT competitive markets for year 2009 for South Texas Electric Cooperative (STEC)
- 2009 ERCOT Nodal Market Study for CPS Energy
- Modeling the ERCOT competitive markets to forecast Locational Marginal Price for year 2009 for City of Greenville, Texas
- CAISO LMP Study for year 2010 based on the MRTU protocol for Sempra Generation
- Locational marginal price (LMP) forecast and generating plant valuation by modeling the ERCOT competitive markets for year 2009 for Bryan Texas Utilities

- Development of electricity price forecasts for Metropolitan Edison Company and Pennsylvania Electric Companies in the PJM Mid-Atlantic region, Lexecon/FTI Consulting
- Forecast of LMPs based on the proposed Texas Nodal Market design and the operations and market revenues of generating units participating in the ERCOT competitive markets for energy and ancillary services for APX
- PJM Western Hub Nodal Price Forecast for the AMP-Ohio specified points
- WECC market simulation for LMP forecasts, station analysis and to evaluate the impacts associated with the implementation of MRTU for FPL Energy
- Locational Marginal Price (LMP) forecast and generating plant valuation by modeling the ERCOT competitive markets for years 2008 and 2012 for GEUS
- Projection of electricity prices for the Mid-Continent Area Power Pool region (MAPP), within the broader eastern North American interconnected electric system for Manitoba Hydro
- Forecasting electricity prices and revenues, and valuing assets in the wholesale electricity market for Unified Energy System of Russia (RAO UESR)
- Valuation of all the Hydroelectric Generation Assets of PG&E for California Public Utilities Commission
- Impact of MISO LMP-based Market Design on Generating Assets in Illinois, Alliant Energy Resources
- PG&E Divestiture Project – Modeling for Extensive Repowering at the Kern Power Plant Site
- Nodal spot prices and ancillary service market analysis for extended PJM with AEP, ComEd, and Virginia Dominion
- Valuation of Armstrong facility's injection bus in PJM-West, a proposed combined cycle unit in City of Marshall, Minnesota and a combustion Turbine unit in North Carolina for Alliant Energy Resources
- Market simulation and assessment of the stranded cost of FirstEnergy's generation assets and testimony support for Lexecon, Inc.
- Asset valuation of Bath County Pumped Storage unit and FTR calculation for Dominion Virginia Power
- Valuation of Danskamer and Roseton Generating Plants for Tractebel Power
- Market-Based Valuation of New Coal-Fired Generation, EPRI-LCG Joint Study
- Coal Option Valuation – Electric Sector Analysis, EPRI-LCG Joint Study
- Valuation and Auction of Sheerness and Genesee units for Alberta Balancing Pool
- Due Diligence Study and Assessment of potential revenues of Neenah Combustion Turbine Plant in Wisconsin for CoBank
- Asset Valuation in Ontario for Alliant Energy Resources and WPS Energy, Inc.
- Optimal portfolio analysis for power contracts for SDG&E
- Portfolio analysis and selection of short-term contracts for Sacramento Municipal Utility District (SMUD)
- Operation and Valuation of a 400 MW Pumped Storage Unit in southern Nevada for Blue Diamond Power Partner
- Real Options Case Study: Asset Valuation of East Kentucky Power Cooperative (EKPC) New Generation Options

- Valuation of a 2,700 megawatt Compressed Air Storage Units in Ohio for CAES Development Company / Haddington Ventures
- Market Analysis of New Units in the ECAR Region for Rolls-Royce Power Ventures
- Price Forecast and Valuation of New Units in the MAPP Regional Market for Calpine
- Valuation of St. Lucie combined cycle unit in Florida for Duke Energy

Generation & Transmission

- Conducted a long-term WECC regional price forecast (a 10-year zonal market simulation a one-year (2010) nodal study) using WECC full network model and the proposed CAISO Market Redesign Technology Upgrade (MRTU) protocol for Sacramento Municipal Utility District to be used in SMUD's marginal cost evaluation of its supply and demand-side options
- Consulting services for developing and benchmarking the Eastern Interconnect Regional Database for Reliant Energy
- Locational Market Price Analysis for Potential Generation Sites - detailed generation and transmission study to simulate the ERCOT market to determine the potential cost impacts associated with the transmission of power to and from specified sites in the ERCOT market for Austin Energy
- Market Dispatch and Financial Modeling - A ten-year (2006 – 2015)gross margin forecast for each generating unit in the Genco (PJM/MISO) for Lexecon/FTI Consulting
- Market Analytics of Wind Energy in Texas for Airtricity
- Compressed Air Energy Storage (CAES) feasibility and risk Assessment for Austin Energy
- Valuation of Transmission Investment for Federal Grid Company in Russian Federation
- Cost-Benefit analysis of Dominion Virginia Power joining PJM
- NEPOOL Congestion Study for TXU Energy, Houston, Texas
- Cost-Benefit analysis of Allegheny Energy joining PJM
- Generation and transmission analysis for assessing potential energy and ancillary service revenues of a proposed 600 MW combined cycle generator in Southern California for Sempra Energy
- Transmission congestion analysis, LMP forecast, and valuation of a proposed new generation plant in Ontario IMO for Coral Energy
- Designing Tariffs for Electricity Transmission and Distribution in Taiwan
- Strategic Resource Analysis & Plan for Southern California Public Power Authority/City of Burbank
- Innovation Needed for Reliability and Market Success in the RTO Revolution: Multi-Market Modeling of Regional Transmission Organization Functions
- RTO West LMP Study: Determination of Generation and Transmission Revenue of BC Hydro Assets
- Impact of proposed transmission tariff on energy and ancillary service markets and transmission expansion in Alberta, Canada
- Determination of consumers' and producers' benefits and transmission analysis of Valley-Rainbow Interconnect Project

- Surviving and Thriving in the RTO Revolution: How to design tariffs to improve reliability and attract merchant generation

Market Power & Testimony Support

- Gas and Electricity Price Forecast for the PG&E Bankruptcy Court
- Divestiture of Hydroelectric Generation Assets of PG&E - California Environmental Quality Act (CEQA) Study
- Market Power Analysis for UtiliCorp's FERC Merger Filing and Testimony Support
- Market Power Analysis of the impact of utility mergers on the competitive environment of the retail electric market in the state of Missouri for Missouri Public Service Commission
- Exercising Market Power in California Energy Market by California IOUs
- Potential Market Power Study of PG&E Hydroelectric Plants for CPUC
- Congestion Management Principles: Expert Witness Testimony before the Energy and Utilities Board (EUB) of Alberta
- Export/Import Study & Congestion Management Expert Witness for EPCOR Power Development Corporation, Alberta, Canada
- Competitive Energy Market Analysis and expert testimony on behalf of Montana Consumer Council on stranded assets and the impact of the competitive market structure on generation costs, total net revenue, system average costs, and MCPs IndeGO
- Modeling Competitive Retail Electricity Market for Utah Division of Public Utilities to study the impact of employing competition to set retail generation prices

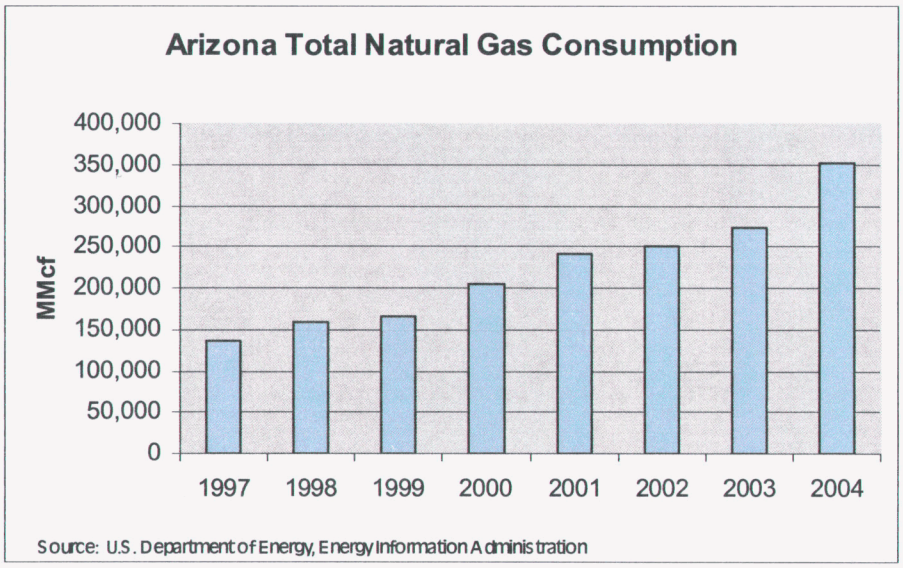
Market Design and Others

- Consulting support for 2006 Integrated Resource Plan development for Kauai island Utility Cooperative (KIUC) – Run UPLAN simulations for selected scenarios to evaluate the costs and benefits of the DSM measures and programs presented to KIUC and determine the optimal integrated plan
- Consulting support for 2006 DSM program implementation for Kauai island Utility Cooperative (KIUC)
- Design consideration for proposed Midwest ISO and FERC response
- FERC Order 2000 and Analysis of Ancillary Service Requirements: Revenues from A/S and Operational Flexibility, EPRI
- Analysis of the proposed New England ISO and transition from a tight power pool to an ISO-like structure – Impact on electricity prices and FTRs
- Evaluating Alternative Market and Pricing Designs for California Regulators (Docket No. EC96-19-001 & ER96-1663-001)
- Analysis of Reserves for the California Independent System Operator Area
- Locational electricity price forecasting and payment of Reliability Must Run (RMR) units for Sempra Energy
- LMP Forecast and RMR Calculation for PacifiCorp
- Stranded Costs, Power Contracts and Competition Transition Costs for California's IOUs for Kansai Electric Power Company, Osaka, Japan

Summary of Natural Gas Issues

Bob Gray, ACC Staff
October 2006

Docket Number: L-00000A-06-0295-00130



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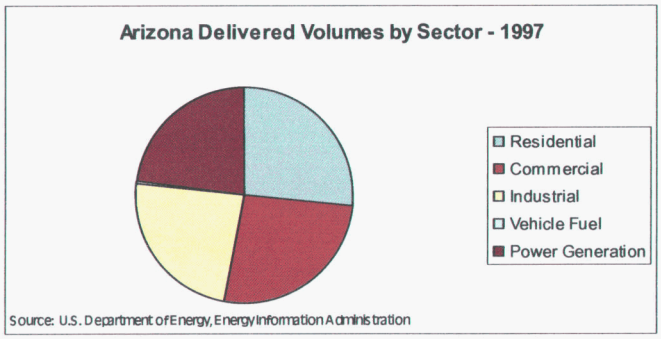

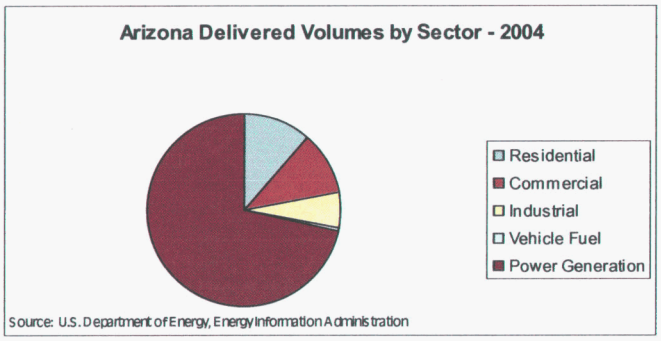

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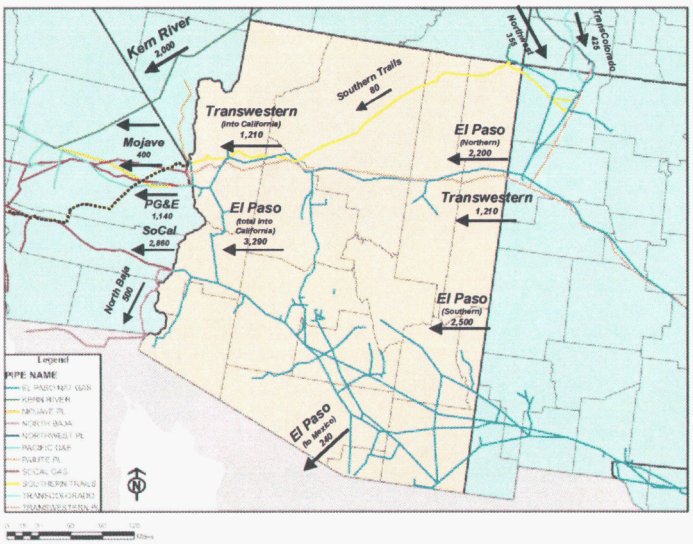
Natural Gas Pipelines In Arizona and Surrounding States



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Source: Arizona Natural Gas Market and Infrastructure Study, EEA, January 5, 2006

Natural Gas Impacts of Proposed Devers – Palo Verde 2 Transmission Line

- Natural gas is the fuel on the margin for electric generation in the Southwest most of the time
- Natural gas demand in the central Arizona is expected to increase as gas-fired generation is run more to provide greater exports to California via the proposed Devers – Palo Verde 2 line, particularly if California fails to construct in-state generation to meet growing demand in California
- The DPV-2 line would increase Arizona's connection to the heavily natural gas reliant California electricity market (natural gas consists of 51.6 % of mwh generated in California in 2004 vs 27.0 % in Arizona). Source: Energy Information Administration

5

Natural Gas Impacts of Proposed Devers – Palo Verde 2 Transmission Line (cont.)

- Additional natural gas demand growth in Arizona resulting from the proposed DPV-2 line will likely require additional acquisition of interstate pipeline capacity by electric generators, possibly via acquisition of existing capacity or construction of new capacity
- The need for development of natural gas storage in Arizona and/or access to storage facilities elsewhere in the Southwest will be exacerbated by the proposed DPV-2 line

6

El Paso Pipeline Rate Case

- El Paso Natural Gas Company currently is before the Federal Energy Regulatory Commission in a general rate case
- Proposals by El Paso to significantly change how its pipeline operates, including implementation of hourly balancing and penalty provisions will likely lead to significant cost increases for pipeline service by electric generators and others in Arizona
- The structure of the natural gas marketplace in the Southwest will be shaped to a significant extent by the outcome of El Paso's rate case
- El Paso has put forth proposals, including elimination of its short-haul rate and bundling of its service offerings, that have competitive implications and create substantial barriers for other natural gas infrastructure developers in Arizona to construct pipeline or storage facilities

7

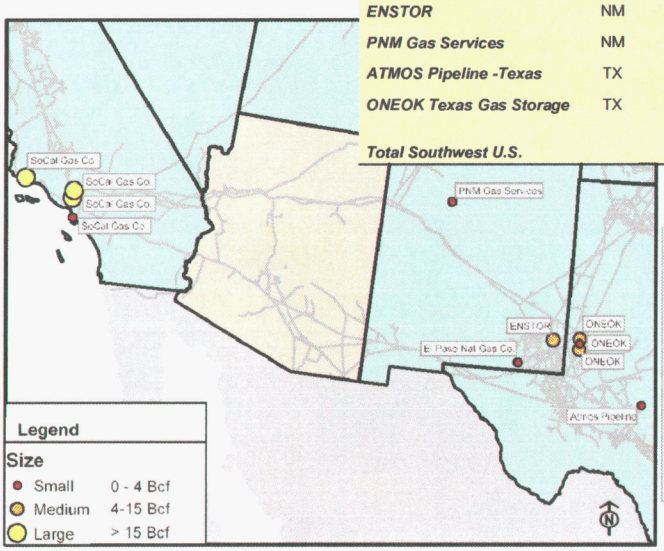
El Paso Pipeline Rate Case

- El Paso's rate case has drawn national attention, with the Electric Power Supply Association, the Edison Electric Institute, the Interstate Natural Gas Association of America, the American Public Gas Association, and the Tennessee Valley Authority making filings in the case
- California parties have repeatedly expressed concerns regarding the impact on natural gas service reliability of growing demand for natural gas-fired electric generation in Arizona and the resulting load swings on the interstate pipeline system
- Significant uncertainty regarding many major issues remains in the El Paso case, as settlement negotiations continue and the case moves toward the hearing phase

8

Southwestern Storage Fields

Operator	State	2005 Working Gas Capacity (Bcf)	Peak Deliverabilit (MMcfd)
Southern California Gas Co.	CA	123.6	3,200
El Paso Natural Gas	NM	20.0	125
ENSTOR	NM	4.5	50
PNM Gas Services	NM	1.1	11
ATMOS Pipeline -Texas	TX	1.3	38
ONEOK Texas Gas Storage	TX	16.4	450
Total Southwest U.S.		146.0	4,529



- Almost 150 Bcf of underground storage in area, not including storage located in northern California
- *No storage in Arizona*

9

Source: Arizona Natural Gas Market and Infrastructure Study, EEA, January 5, 2006

Natural Gas Storage Options for Arizona

- Arizona currently has no natural gas storage facilities within the state and no access to storage which can help Arizona address load changes on a timely basis
- El Paso relies on the Washington Ranch storage facility in west Texas to provide some system flexibility, but Arizona market area storage is needed to address both reliability and cost issues
- El Paso explored building the Copper Eagle storage facility in west Phoenix, but the project was derailed by opposition
- El Paso and Chevron (Unocal) have both explored building a storage facility between Phoenix and Tucson
- The salt dome location north of Kingman, where the Aquilla and Desert Crossing projects have been considered, is not active at this time

10

Recent Natural Gas Infrastructure Developments

- On September 15, 2006, Transwestern Pipeline filed with FERC an application for a certificate of convenience and necessity to construct and operate the Phoenix Expansion Project
- The Phoenix Project would originate in the San Juan basin, would skirt the west side of the Phoenix metro area and end near Coolidge, Arizona. Its anticipated in-service date is 2008.
- The ACC has pre-approved cost recovery for Arizona Public Service and Southwest Gas for costs related to pipeline capacity they would acquire on the Phoenix Project
- On June 28, 2006, El Paso announced plans to develop a salt cavern natural gas storage facility near Eloy, Arizona
- The El Paso storage facility would have a capacity of 3.5 billion cubic feet and El Paso projects the facility will go into service in the 2010-2012 timeframe.

11

Storage and California

- Northern California has storage facilities that could provide some benefit to Arizona shippers, but these facilities are not currently physically accessible
- Southern California has very significant natural gas storage facilities, 123.6 billion cubic feet of capacity in 2005, that are physically accessible for Arizona
- However, California has rules which only allow use of storage in Southern California for in-state California uses
- As California becomes more reliant on natural gas-fired generation imports from Arizona, California should reconsider its decision to not provide interstate access to its storage facilities. Access to even a small portion of the existing natural gas storage facilities in Southern California could enhance natural gas service reliability in the Southwest, benefiting both California and Arizona, and could create a more efficient and reliable regional energy market

12

Summary

- The proposal under consideration in this proceeding would increase natural gas consumption for electric generation in Arizona to meet California needs, exacerbating the need for natural gas storage services in Arizona
- Arizona natural gas consumers, including merchant plants in the Palo Verde area, will incur additional costs due to the lack of storage availability
- Availability of storage to Arizona natural gas consumers would reduce costs and increase natural gas service reliability in the Southwest
- Lack of access to existing storage facilities in the region, specifically in Southern California, is an impediment to natural gas service reliability and efficiency in Arizona and the Southwest
- California should consider regional concerns regarding natural gas storage facility issues as it espouses consideration of regional electric issues in this case

13

Proposed Condition

If the application in this case is approved, Staff recommends adoption of the following natural gas related condition:

- "Southern California Edison agrees to make good faith efforts to work within future California and regional proceedings to encourage regional access to natural gas storage facilities in California in a manner that addresses natural gas service reliability and efficiency in the region, including Arizona"

14

Arizona Corporation Commission

Docket No. L-00000D-06-0295-00130

Palo Verde – Devers 2 500 kV Project

Jerry D. Smith
Electric Utility Engineer

October 4, 2006

ACC Staff Witness

Name :	Jerry D. Smith
Title :	Electric Utility Engineer
Employer:	Arizona Corporation Commission
Address:	Utilities Division 1200 W. Washington Phoenix, AZ 85007

October 4, 2006 Line Siting Case No. 130 2

EXHIBIT
S-28
admitted

Professional Background

- **B.S.E.E – University of New MEXICO**
- **M.S.E.E. – New Mexico State University**
- **Registered Arizona P.E. – Electrical**
- **27 Yrs. Engineering and Management Experience with the Salt River Project**
- **Utility Regulation Experience Since 2/99**

October 4, 2006 Line Siting Case No. 130 3

Context of Case

Siting of Palo Verde – Devers 2 Places the Project at the Confluence of Several Major Public Policy Efforts:

- **EPAct 2005**
  - Sec 368 Western Corridor PEIS
  - Sec 1221 NIETC Congestion Assessment
  - Sec 1221 FERC Transmission Siting Authority
  - Title XII Electricity: ERO and Mandatory Reliability Standards
- **WGA Interstate Transmission Siting Protocol**
- **WECC Transmission Expansion Planning Policy Committee**
- **Transmission Planning Study Groups**
  - STEP: S.W. Transmission Expansion Planning
  - SWAT: S.W. Area Transmission
  - CRT: Colorado River Transmission
- **ACC Biennial Transmission Assessment**
- **New CAISO Tariff –MRTU Effective 11/1/2007**

October 4, 2006 Line Siting Case No. 130 4

Disappointments

- **Siting Process Utilized for This Interstate Line is Not Consistent With The Intent of The WGA Interstate Transmission Line Siting Protocol**
- **No CPUC CEQA EIR / BLM EIS or DOE Sec 386 PEIS Response to ACC Staff Comments About Need for Consideration of Reliability Impacts When Placing Energy Facilities in Common Corridors/Contiguous ROW**
- **Negotiations Between SCE, APS, and Harquahala Have Not Been Timely and Nature of Agreement Has Not Been Divulged**
- **CAISO Made an Appearance in CPUC Proceedings But Not in Arizona Proceedings**
- **SCE Has Proceeded With PVD2 as Sole Owner Without An Open Invitation to Others**
- **Project Traverses Area of Arizona With Express Transmission Interest Noted by CRT Study Participants**

ACC Staff's Challenge

- **Assure Proceeding Achieves the Following :**
  - Establish Sufficient Hearing Record for Commission Consideration of Balancing Test of Project
  - Accommodates Western Wholesale Market Needs While Preserving/Protecting AZ Consumers' Interest
- **How This Testimony Responds to the Challenge**
  - Broadens CPUC's "Tipping Point" Assessment of Project's Economic Value[1]
  - Provides Staff's "Thin Slice" Assessment of Project Benefit to Arizona and the West[2]
  - Offers Staff's Proposed Conditions

[1] **The Tipping Point**, How Little Things Can Make a Big Difference, Malcom Gladwell, 2000.
[2] **Blink**, The Power of Thinking Without Thinking, Malcom Gladwell, 2005

Impressions of CPUC's "Tipping Point" Assessment

- **Merits of SCE/CAISO TEAM Related Studies**
  - Only WECC Sub-region Using Such Models to Compare Effectiveness of Alternatives in Mitigating Congestion
  - Effectively Demonstrated Historical and Potential for Future Transmission Congestion of Path 49 (EOR)
  - Demonstrated Relative Physical Effectiveness of Various Transmission Alternatives in Mitigating Path 49 Congestion
  - Order of Magnitude Fiscal Impact on CAISO/CA Has Been Reasonably Established
- **TEAM Studies Performed by STEP, CAISO and SCE**
  - Assumed No Natural Gas Supply/Delivery Constraints for AZ Plants
  - Did Not Model Actual Market Behavior Outside of CAISO / CA
  - Fiscal Impact on Western Interconnection Appears to be Ill-Defined

October 4, 2006 Line Siting Case No. 130 7

ACC Staff's "Thin Slice" Assessment

- **Regarding Path 49 East of River (EOR)**
  - Considerable Evidence That Path is Congested
  - DOE Considers Path Warrants Remedy
  - PVD2 is One of a Family of Solutions Being Proposed and Implemented
  - PVD2 Addition Not Solely Sufficient to Fully Mitigate Physical Congestion of Path
- **Arizona Resource Adequacy Not Jeopardized**
- **Future Arizona Utility Resources Were Not Modeled in TEAM Studies - Will Likely Ameliorate Implied Arizona Market Impacts of PVD2**

October 4, 2006 Line Siting Case No. 130 8

"Thin Slice" Assessment (Continued)

- **The Only AZ Termination Acceptable to Staff is Harquahala Junction Switchyard**
- **SCE's Proposed PVD2 Line Route, Design and 130 Feet Separation From PVD1 Adds Unacceptable Reliability Risk / Consequences**
- **Use of Special Protection Scheme for Loss of Two Palo Verde to Devers Lines is an Unacceptable Condition Given Staff Efforts to Mitigate Extreme Outage Conditions at Palo Verde Hub**

October 4, 2006 Line Siting Case No. 130 9

ACC Staff Conclusions

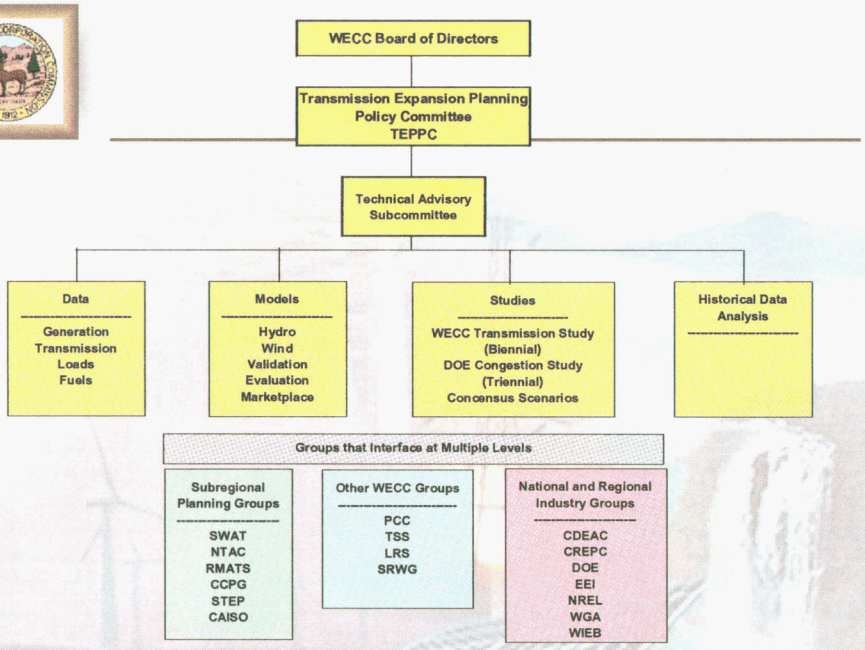
- **Wholesale Market Need for More Transmission Capacity Between Arizona and California has Been Established by The Industry**
- **Palo Verde – Devers 2 is Among a Family of Alternatives Proposed to Mitigate Congestion**
- **Unless Properly Conditioned with Proper Arizona Termination**
  - Proposed Route/Design Adds New Reliability Risks and Consequences
  - Extreme Contingency Risks at Palo Verde Hub Are Not Mitigated and Prevailing Palo Verde Hub Commercial Practices Are Compromised
  - Open Access Seams Issues Between CAISO and Arizona Transmission Network Will Be Exacerbated
- **ACC Staff Proposes Conditions That**
  - Resolves The Above Concerns
  - Preserves/Protects AZ Consumers' Quality of Service Interest
  - While Accommodating The Western Wholesale Market Needs

October 4, 2006 Line Siting Case No. 130 10

ACC Staff Proposed Conditions – Foundation & Purpose -

- Assure Arizona's EHV System Reliability is Not Adversely Impacted
- Mitigate Reliability Risks & Consequences of Extreme Contingencies at Palo Verde Hub
- Ensure Non-discriminatory Open Access Transmission Principals and Palo Verde Hub Commercial Practices Are Not Compromised
- Preserve Operational Reliability Obligations Imposed by ACC on Palo Verde Hub Plants
- Protect Arizona's Access to Limited Natural Gas Pipeline Capacity for AZ Retail Natural Gas Customers and Energy Production for Other EOR Power Plant Customers

October 4, 2006 Line Siting Case No. 130 11



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3rd Biennial Transmission Assessment – Key Conclusions

- Existing and Planned Transmission Facilities Meet Load Serving Requirements of Arizona in a Reliable Manner. (Without the Planned Facilities a Different Conclusion May Have Been Reached)
- The Palo Verde to TS5 to Raceway and Palo Verde to Browning (SEV) Projects Will Significantly Increase the Outlet Capability of the Palo Verde Hub to Arizona.
- Existing Transmission from Palo Verde to California is Inadequate to Allow All Palo Verde Hub Generation Full Access to California Market Under Weak Arizona Market Conditions.

October 4, 2006 Line Siting Case No. 130 13

Applicability of 3rd BTA Key Planning Requirements

- Utilities & Staff to Develop / Implement More Stringent RMR Study Criteria for 2006 BTA.
- Study Extreme Contingency Outages of Arizona's Major Transmission Stations and Generation Hubs to Identify Associated Risks and Consequences if Mitigating Infrastructure Improvements Not Planned.
- Compliance with WECC and NERC (N-1-1): Single Contingency Criteria Overlapped with Bulk Power System Facility Maintenance for Year 1 of the BTA.

October 4, 2006 Line Siting Case No. 130 14

Implementation of 3rd BTA Planning Requirements

- **Study Extreme Contingencies**
  - Lose All Common Voltage Transformers at Each Major Station
  - Update Palo Verde/Hassayampa Hub Assessment
  - Loss of EHV Transmission Corridors
  - Explain How Ten-Yr Plan Facilities Mitigate Impact
  - Protection System:
    - Provide Inventory of All Protection Schemes,
    - Determine Adequacy of Redundancy & Coordination
    - Simulate Events Where Adequacy In Question
    - Quantify Risk Associated w/ Protection Misoperation
- **RMR Study**
  - Study Period: 2006 through 2014
  - Study Most Critical Extreme Contingency For Each Load Area

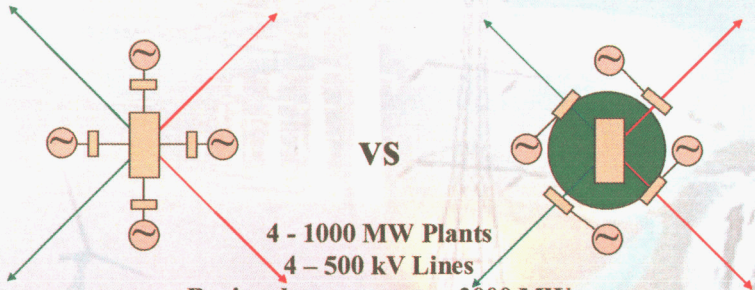
October 4, 2006 Line Siting Case No. 130 15

PV Hub Risk Assessment Recommendations

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

October 4, 2006 Line Siting Case No. 130 16

Hub Concepts



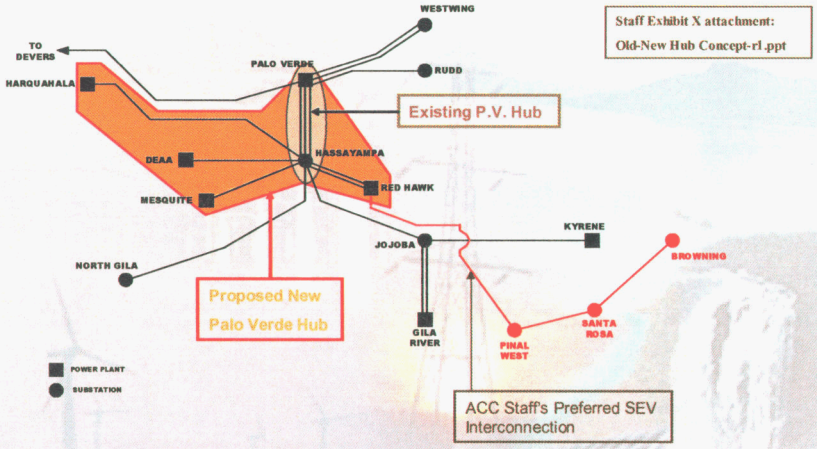
4 - 1000 MW Plants
4 – 500 kV Lines
Regional reserve req. = 3000 MW

Trans. Owner A
Trans. Owner B

Trans. Tariff Free Zone

October 4, 2006 Line Siting Case No. 130 17

Existing & Proposed New Palo Verde Hub



Staff Exhibit X attachment: Old-New Hub Concept-r1.ppt

•ACC Staff proposes the new Palo Verde Hub concept.

•Either APS or SRP will file with FERC for approval of the new P.V. Hub.

October 4, 2006 Line Siting Case No. 130 18

Implications Regarding Future Arizona Resource Needs

"We have nothing to fear but fear itself" – Franklin D. Roosevelt

- Per 2006 WECC power supply assessment - the Desert Southwest becomes deficient in planned reserve margins as early as 2008
- Approved CEC's for 8 Arizona plants totally 5575 MW not yet under construction terminate in 2007 and 2008
- PVD2 enables SCE access to 1200 of 6500 MW new gas-fired generation in AZ / NV[1] beginning in 2009 (Leaves 5300 MW for others)
- Arizona utilities have since 2003 had access to most of the generation for which SCE now seeks access
- Arizona utilities are pursuing Other Resources (many are located outside of Arizona)

[1] Assumed in SCE economic studies, Exhibit B-2 of Application, page 29 and Appendix C

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Arizona Plants Approved But Not Constructed

Plant	Technology	CEC Rating (MW)	Date of CEC Expiration	Project Status
Springerville 4	Coal	380	12/31/2009	2009 Construction Expected
Gila Bend	Combined Cycle	845	12/31/2006	Extension Pending
Bowie	Combined Cycle	1000	5/7/2007	Extension / IGCC Filing Likely
Sundance II	Combustion Turbine	90	7/9/2006	Phase I/II – Complete / Inactive
Arlington Valley II	Combined Cycle	600	5/12/2007	Phase I/II – Complete / Inactive
Redhawk 3 & 4	Combined Cycle	1060	2/23/2010	1 & 2 Complete, 3 & 4 Inactive
Welton Mohawk	Combined Cycle	520	8/18/2008	Seeking Contract
Allegheny La Paz	Combined Cycle	1080	5/16/2007	Inactive
	TOTAL	5575		

October 4, 2006 Line Siting Case No. 130 20

Future Arizona Resource Needs - Other Considerations -

- **APS / SRP have long term RFPs pending for XX MW of base load generation**
  - 1000 MW Desert Rock coal-fired plant proposed in vicinity of Four Corners
  - Ely & Mesquite coal–fired plants proposed in Nevada
  - Northern Lights / Frontier / APS Transwest Express transmission projects will enable Arizona access to new Wyoming Coal and Wind Generation
  - PWCC Contemplating New Nuclear Generation
- **New Mexico projecting 6000 MW wind development for export to / through AZ**
- **ACC 15% RPS in 2025 in rule making process**

October 4, 2006 Line Siting Case No. 130 21

Ratemaking Impacts

Matthew Rowell, ACC Staff
September 2006

Docket Number: L-00000A-06-0295-00130

1

Simulation Model Results

- Staff's Consultant, LCG Consulting ran a production simulation model that estimated the impact of the proposed PVD2 line.
- LCG's model estimated that construction of the PVD2 line would result in a $3 per MWh average increase in wholesale energy prices in Arizona. The model also estimated that the line would result in price decreases in California and other WECC areas.
- These estimates are for 2010 and increases and decreases are relative to the model's estimates for 2010 with no PVD2 line in service.

2

EXHIBIT
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- What is the basic rational for the estimated increase in Arizona wholesale energy prices?
- *Basic* economic theory suggests that the proposed line would drive up the market price for power in AZ. The logic is simple: Transmission between the PV hub and California is currently constrained. California is short power. Increases in transmission capacity will result in an increase in the demand for power at the PV hub. That is, an increase in demand for power generated in Arizona. Assuming all other factors are constant, an increase in demand will result in an increase in the market price for power.
- So the results of the model run are not at all surprising.

3

- What are the implications of this wholesale price increase for Arizona?
- Because of the increase in Arizona wholesale prices LCG's model indicates that Arizona generator's profits will increase by $468 M and total generation in Arizona will increase by 4,221 GWh.

4

- The model indicates that the increase in generator profits will be distributed as follows:

Category	Share of increased profit
AZ Utilities	39%
Merchant Generators	34%
Federally owned Generation	6%
Non-AZ Utilities with Shares of AZ Generation	19%
Other*	3%

*CAWP, CRIIP, USBIA

5

- How will the increase in Arizona generator profits affect Arizona consumers?
- For the 62% of the estimated increased profits that accrue to entities other than Arizona utilities, Arizona consumers will receive virtually no benefit.
- For the 39% of the estimated increased profits that accrue to Arizona utilities, the impact on Arizona consumers is unclear and will vary by utility.

6

- While the estimated increase in wholesale prices has an unambiguously positive impact on Arizona generators, the impact on Arizona consumers is less clear. The model indicates that Arizona consumer benefit will decline by $242 M as a result of the increased wholesale energy prices brought about by PVD2.
- However, Arizona consumers are not 100% reliant on wholesale markets for their energy needs.

7

- Currently, Arizona consumers receive their energy from utilities whose prices are set on a cost of service basis. Thus, if a utility has adequate generation to meet its load, its customers will be largely insulated from increases in spot market prices.
- However, Arizona utilities will *not* own sufficient generation to meet all their loads in 2010.

8

- As a whole, Arizona utilities will be short an estimated 30% of their energy needs in 2010. Thus, Arizona consumers will be exposed to the market for an estimated 30% of their needs.
- To cover this short position Arizona utilities will need to go to the market but not necessarily the spot market. Utilities typically enter into long term contracts with suppliers or build generating units rather than relying on the spot market.

9

- Are the model's estimated impacts on spot market prices likely to influence the cost of long term contracts entered into by Arizona Utilities?
- Yes. The same demand and supply fundamentals that drive up spot market prices in the model will influence the price of long term contracts.

10

- The ratemaking impacts of the PVD2 line will vary by utility:

11

- **APS and AEPCO**
- APS and AEPCO have Commission approved adjustor mechanisms. Through these mechanisms, increases in the cost of purchased power are passed directly on to customers. These increases will be offset by increased profit from off system sales that results from the estimated higher energy prices.
- However, given that these utilities are short power, it is unlikely that the increased profit from off system sales will outweigh the increased costs to consumers resulting from the increase in purchased power prices.
- Off system sales are made on an efficiency basis during off peak periods (when prices are low.) Whereas, purchases made to meet load typically cover peak periods (when prices are high.)

12

- **TEP**
- TEP currently has no adjustor mechanism and is regulated on a cost of service basis. TEP has a relatively large proportion of coal generation relative to its load. TEP does not need to purchase power to the same extent as other Arizona utilities. These factors currently shield TEP's rate payers from fluctuations in market prices.
- However, TEP currently has an application pending before the Commission (Docket No. E-01933A-05-0650) where it is asserting that it is entitled to move away from cost based ratemaking to a market based approach. Depending on how that application is decided, TEP's rates may be based entirely, in part, or not at all by prices prevailing in the market.

13

Need

14

- The above discussion indicates that from an Arizona perspective there is no fundamental need for the PVD2 project. Arizona utilities are faced with the need to procure resources to meet rapidly growing load. The PVD2 project does not address that need.
- The purpose of the PVD2 project is to move energy from Arizona to California.
- "The Project's primary economic benefit is the increased ability to import low-cost generation from the southwest and displace higher-cost generation in California."*
- *February 18, 2005 memorandum from CalISO Staff to CalISO Board of Governors.

15

California's need to import power is driven by its load growth and its historic underinvestment in generation resources. Even now, California does not appear to be adding significant generation in state:

"The only high probability resource additions or retirements included beyond this (2006) summer are the new 153 MW Roseville Energy Park and LADWP replacing a 585 MW plant with a new 600 MW combined cycle project in 2008."*

*Summer 2006 Electricity Supply and Demand Outlook, Final Staff Report, California Energy Commission, April 2006, CEC-700-2006-005

16

- This lack of generation investment in California is apparently driven by cost considerations:
- "Because the southwest has less expensive permitting, land, emission-offset, and labor expenses, the ISO estimated the fixed costs of a new combined –cycle (CC) plant to be about 13 percent less in Arizona than in California. The ISO expects that California generation interconnection costs – those necessary to make generation deliverable to load – will further increase this cost differential. In addition, the ISO expects units in the southwest to have lower operating costs due to lower natural gas costs forecast for that region. Thus, from strictly a unit cost perspective, the ISO ratepayer would benefit more from having access to lower cost units in the Southwest. Constructing new in-state gas-fired generation would also not increase access to the more diverse fuel supply available in the southwest."*
- *February 18, 2005 memorandum from CalISO Staff to CalISO Board of Governors.

17

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California Generation

- Between 2001 and 2005 in-state California Generation increased by 1% while energy imports increased by 53% (in Gigawatt Hours.)
- **Source California Energy Commission**

  CALIFORNIA ELECTRICAL ENERGY GENERATION, 1983 TO 2005
  TOTAL PRODUCTION, BY RESOURCE TYPE
  http://www.energy.ca.gov/electricity/index.html

California Generation 2

- Between 1995 and 2005 in-state California Generation increased by 8% while energy imports increased by 31% (in Gigawatt Hours.)
- **Source California Energy Commission**

  CALIFORNIA ELECTRICAL ENERGY GENERATION, 1983 TO 2005
  TOTAL PRODUCTION, BY RESOURCE TYPE
  http://www.energy.ca.gov/electricity/index.html

California Generation 3

- California did add significant new generation from 2001-2005.
- "In spite of this the CEC found: "Electricity supplies are not keeping up with demand. Construction of new power plants is not proceeding as planned, and the flow of new permit applications has noticeably decreased. Today California has more than 7,000 MW of permitted power plants that have not moved into construction. Adding to the problem, investor-owned utility (IOU) procurement focuses primarily upon near- and mid-term contracts, which perpetuates reliance upon the existing fleet of aging power plants."
- Source: Califrornia Energy Commission 2005 Integrated Energy policy Report
- http://www.energy.ca.gov/2005publications/CEC-100-2005-007/CEC-100-2005-007-CMF.PDF

Arizona Corporation Commission

Exhibit S-30

Supplemental Documents to Presentation of Staff Witness Jerry Smith

Line Siting Case No. 130

tabbies

EXHIBIT

S-30

admitted

INDEX OF DOCUMENTS IN SUPPLEMENT TO JERRY SMITH SLIDE PRESENTATION

1. WGEF Industry Considerations for Military Airspace

2. Comments of the California Public Utilities Commission, United States Department of Energy, Considerations for Transmission Congestion Study and Designation of National Interest Transmission Corridors

3. Section 1221 of EPact 2005

4. Comments of the California Public Utilities Commission in FERC Docket RM06-12-000, August 25, 2006

5. July 31, 2006 WestConnect letter to CA ISO

6. California ISO Wheeling and Congestion Charges Presentation – September 1, 2004

7. WGA Interstate Transmission Siting Protocol – June, 2002

8. Arizona Corporation Commission Utilities Division Staff Comments Regarding Programmatic Environmental Impact Statement – November 28, 2005

9. Arizona Corporation Commission Utilities Division Staff Comments in EIR/EIS – March 10, 2006

10. Jerry Smith E-Mail of December 8, 2004 RE: AZ/CA Transmission Projects

11. Colorado River Transmission Planning Committee Status Update – SWAT – May 4, 2005

12. Southern California Edison Devers-Palo Verde No. 2 Accepted Path 49 Rating Study Report – July 25, 2005

13. Southern California Edison's Responses to Arizona Corporation Commission Staff's Sixth Set of Data Requests – August 1, 2006

14. E-Mail dated July 11, 2005 to Jerry Smith RE: New Palo Verde Hub Concept

15. Devers-Palo Verde 2 Conceptual Planning Study

16. Devers-Palo Verde 2: DPV 1&2 SPS Arming Study (Sept. 28, 2006)

17 FERC Docket AD05-13-000: Joint Boards on Security Constrained Economic Dispatch;

    Study and Recommendations Regarding Security Constrained Economic Dispatch by The Joint Board for the West Region (May 12, 2006)

18. Excerpt from July 10, 2006 Transcript-DPV2: Public Utilities Commission, State of California

19. Alternate Proposed Decision of CPUC President Peevey (Oct. 10, 2006)

20. Comments to Department of Energy of the Public Utilities Commission of California in matter of National Electric Transmission Congestion Study.

1

56th Fighter Wing

WGEF Industry Considerations for Military Airspace

Mr. Kevin O'Berry
Interagency Liaison

U.S. AIR FORCE

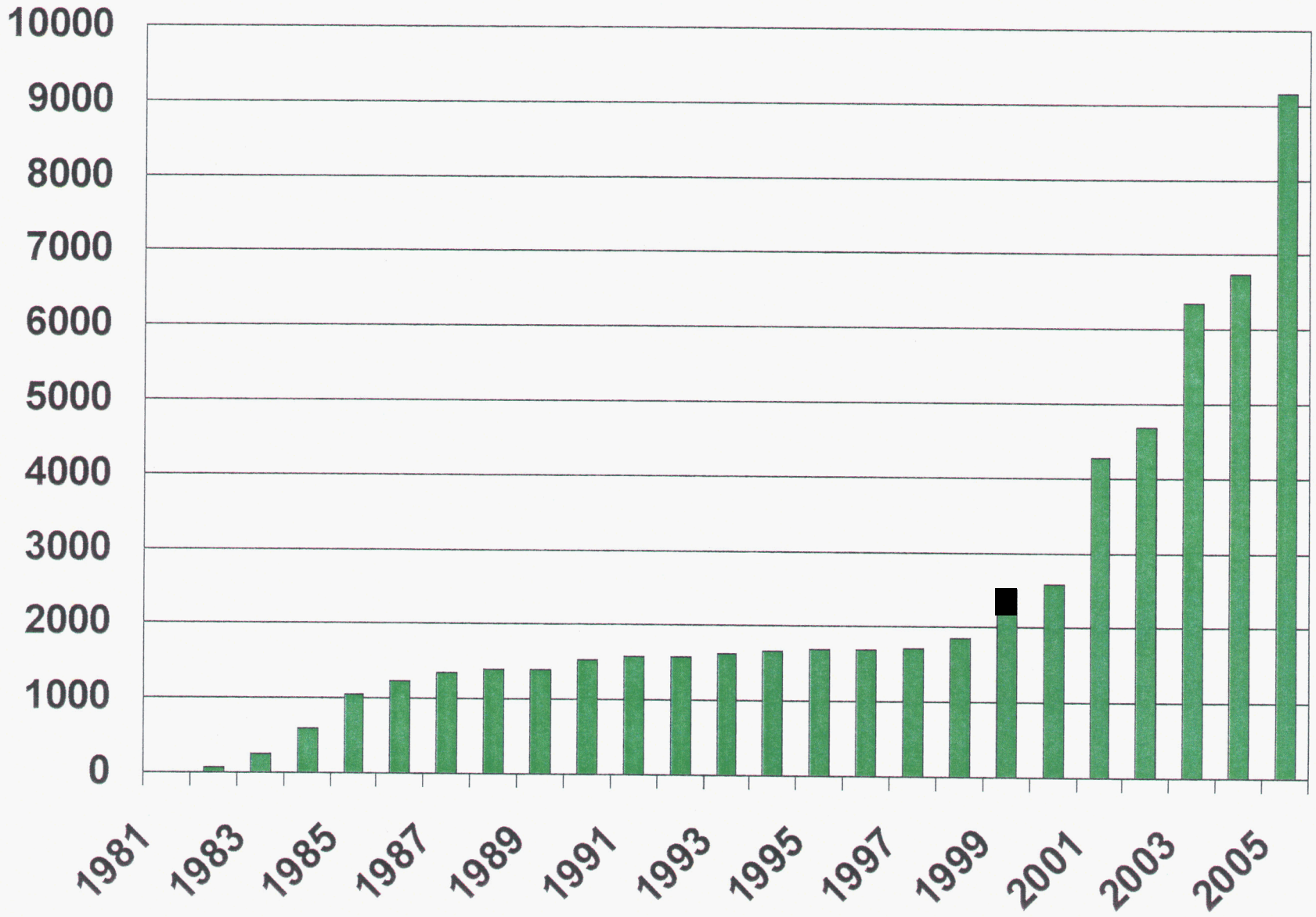
Integrity - Service - Excellence

Outline

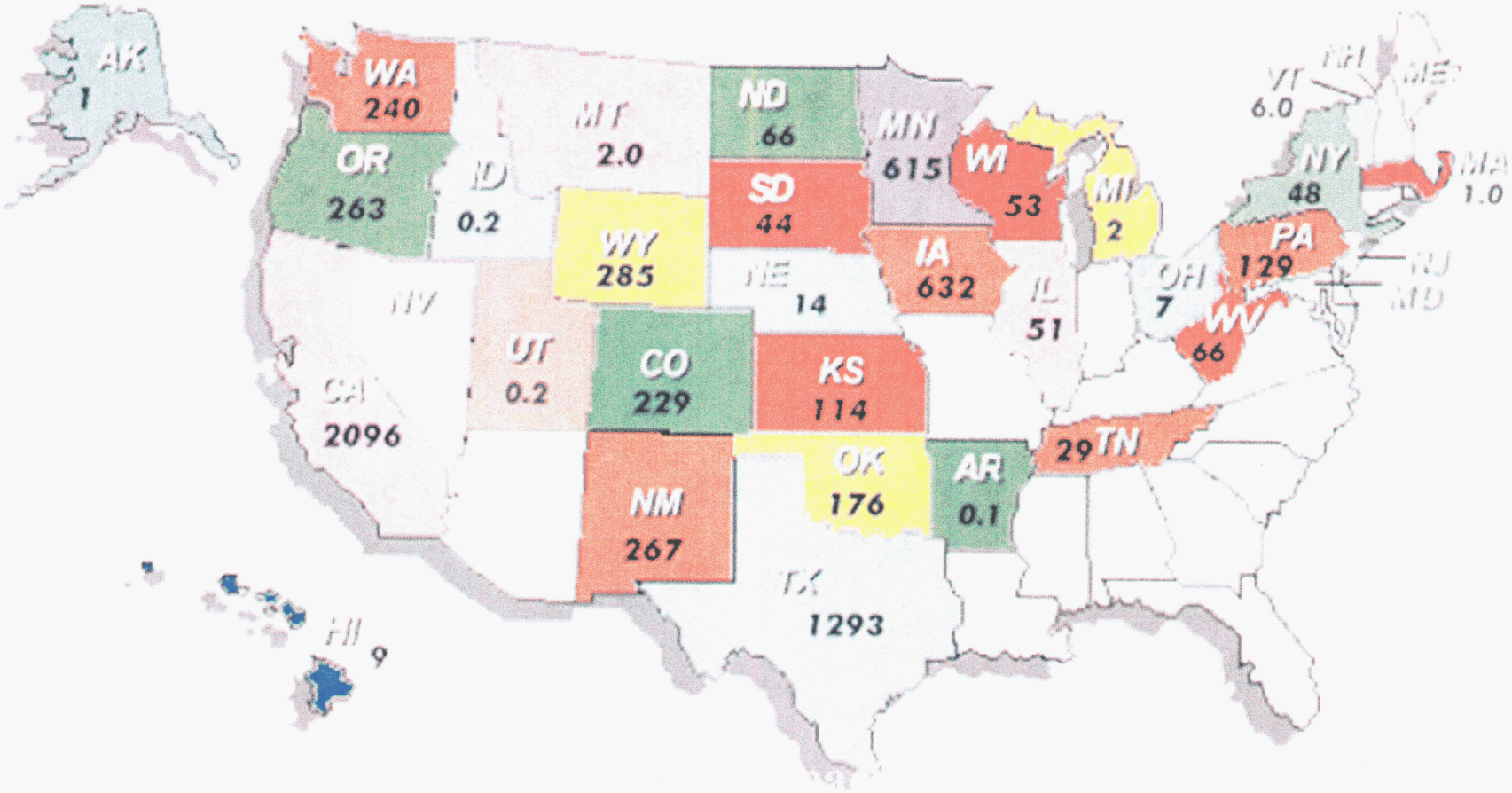
- Wind Energy Background
- Impacts on Military Mission
- WGEF/Military Interests Conflicts
- Tools
- The Way Ahead
- Conclusions

Wind Power

U.S. Installed Capacity (Megawatts): 1981-2005



Wind Energy Projects



WGEF's & Military Ops

Two Primary Issues

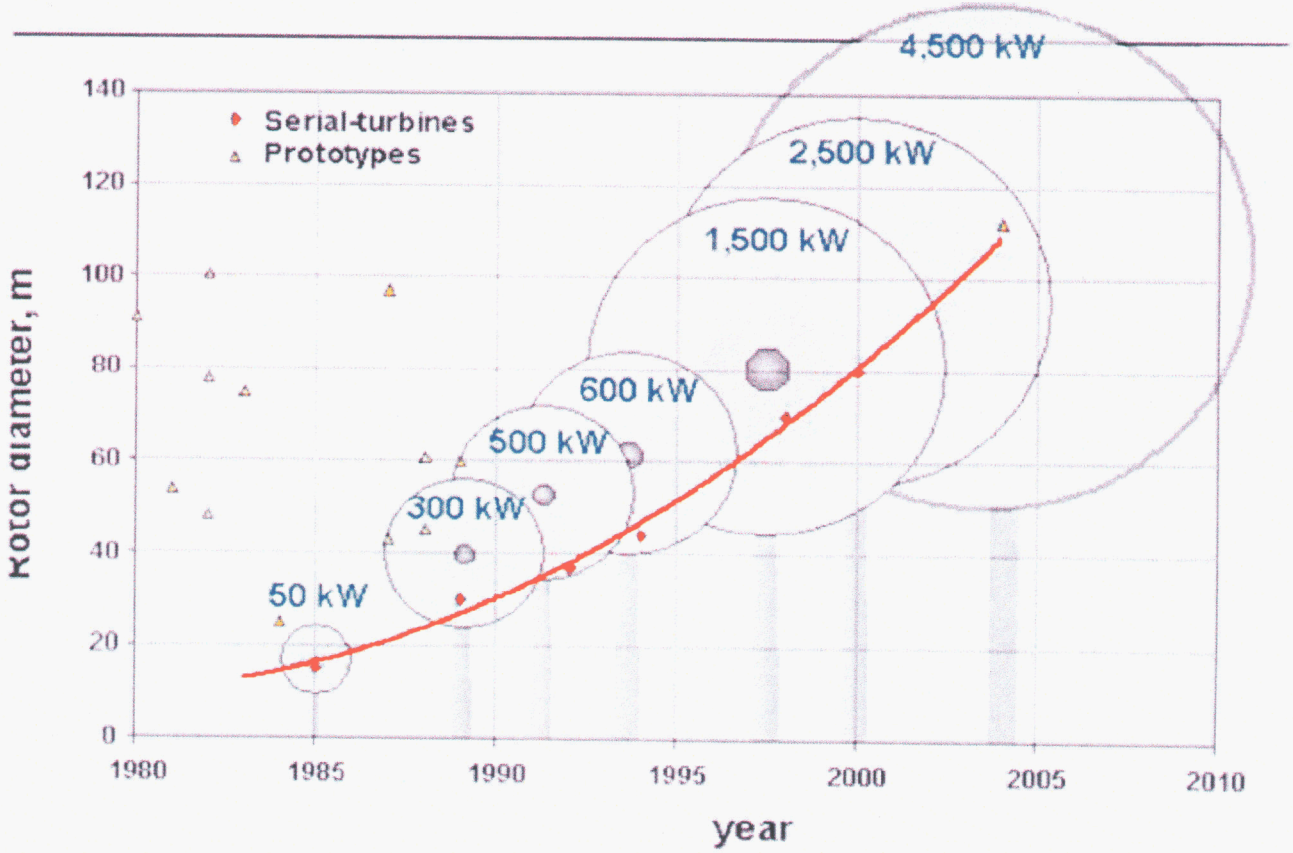
- Obstruction
- Radar Interference

Radar Interference

- Wind turbines can corrupt test environment
  - WGEFs interfere with radar returns
    - Rotation of blades are a source of Doppler clutter
      - Degrades detection performance testing
      - Degrades false alarm testing
      - Degrades ground map testing
- WGEFs need not be within radar line of sight
- 2006 NDAA Section 358
  - Determine WGEF impact to military operations

Why Now?

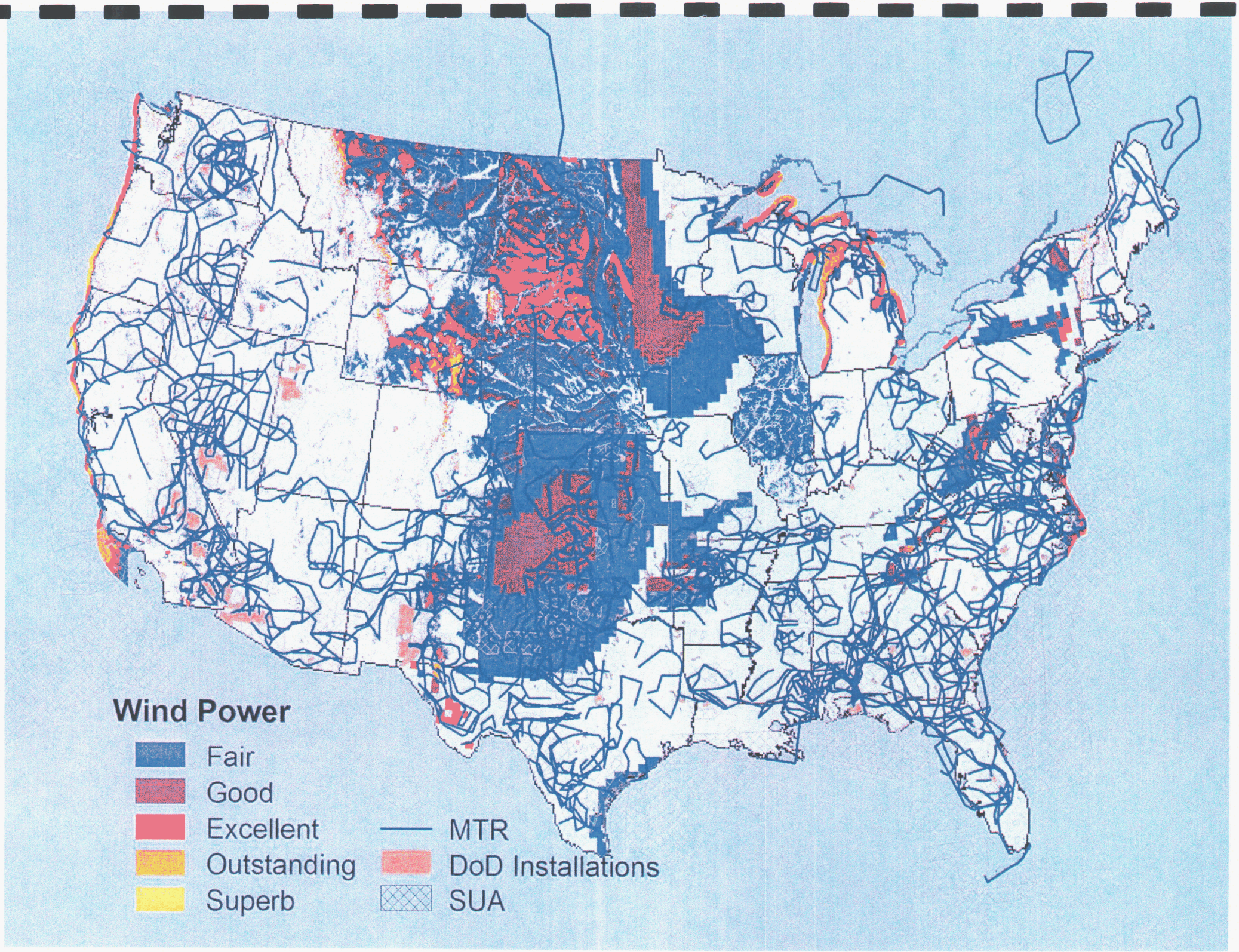
- Wind turbines in the past
  - 80 to 200 feet AGL
- Wind turbines today
  - 350+ feet AGL…and growing!

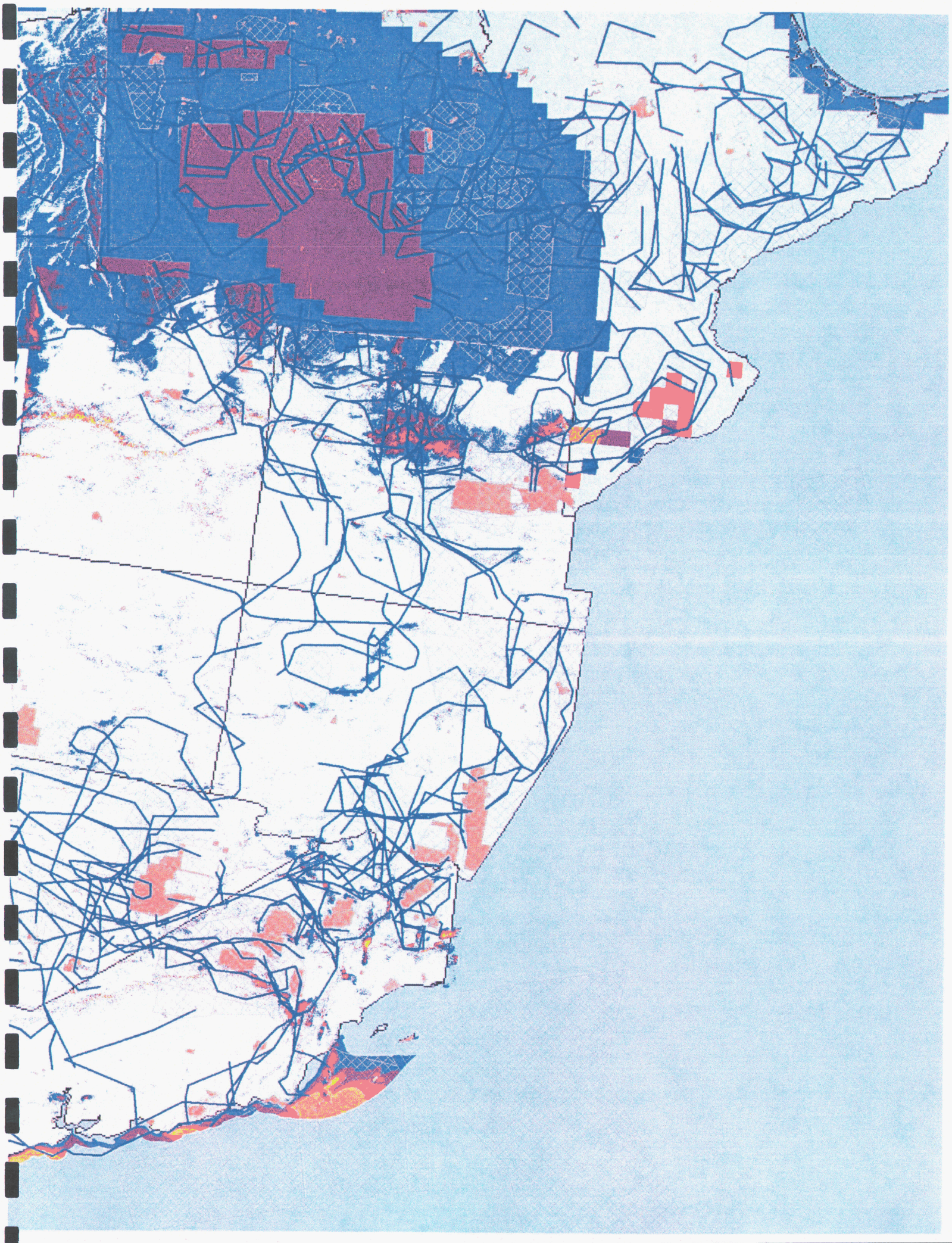


Size Matters

Conflicts

- Significant Wind Resources in military airspace
  - Some airspace is more critical than others
- Vertical infrastructure projects in military use areas
  - MET towers
  - WGEF Projects
- New transmission corridors
- *Lack of awareness of potential interference or impacts to flight safety*


Wind Power
Fair
Good
Excellent
Outstanding
Superb
MTR
DoD Installations
SUA



A Solution

Red-Yellow-Green

(Stoplight)

Strategy

Why R-Y-G?

- Protects our CRITICAL operating areas
- Provides industry clear understanding of military impacts
- Reduces friction within region
- Simplify issues
- Reduce workload
- Provide model for other areas

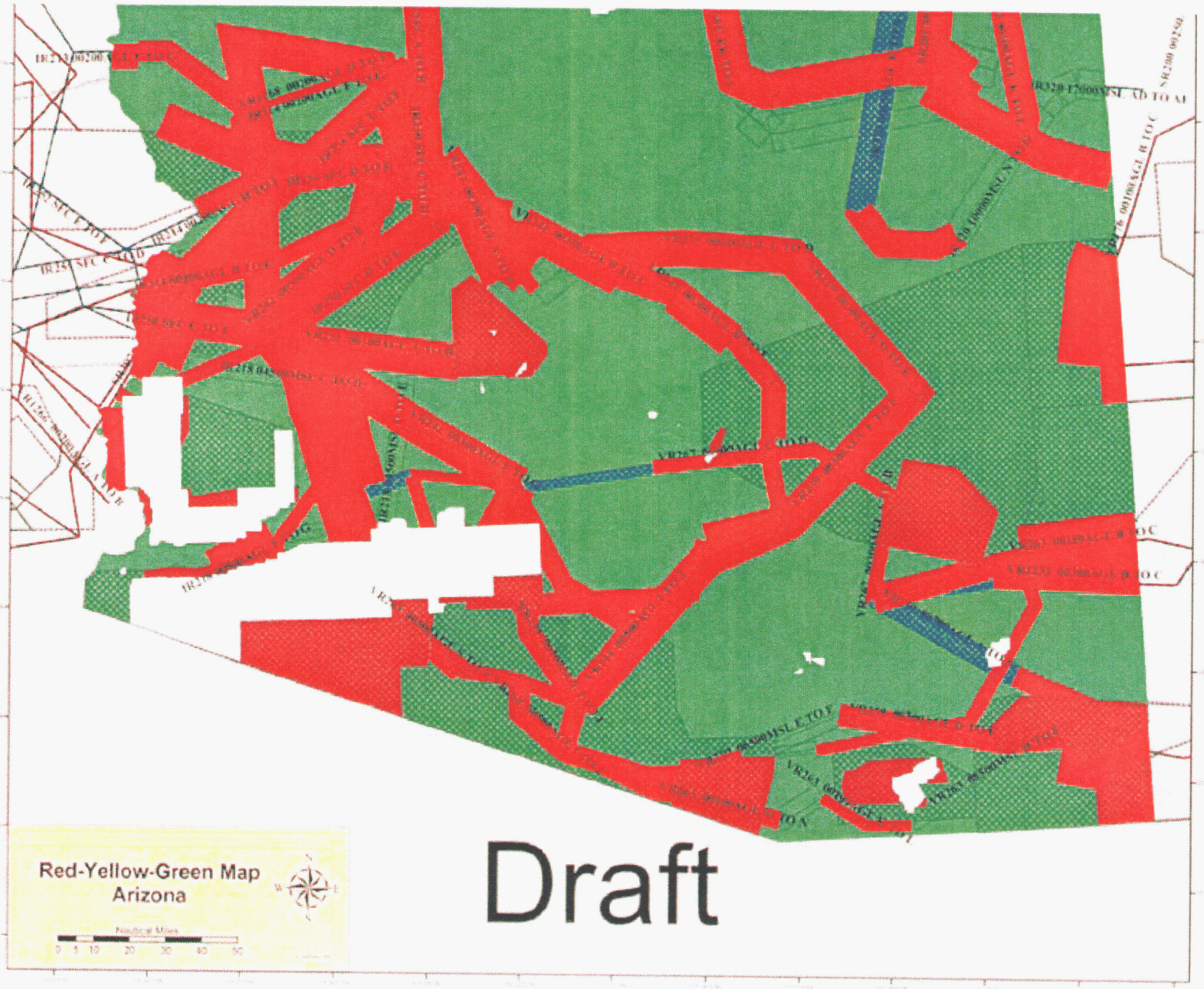
R-Y-G Standard Criteria

- Red
  - Airspace floor 500' or less
  - Height Restriction: All structures over 200 feet
- Yellow
  - Not based on airspace floors
  - Height Restriction: Used for Kern County only so far
    All structures over 400 feet
- Green
  - No Military Training Routes or Special Use Airspace impacted
  - Height restriction: None

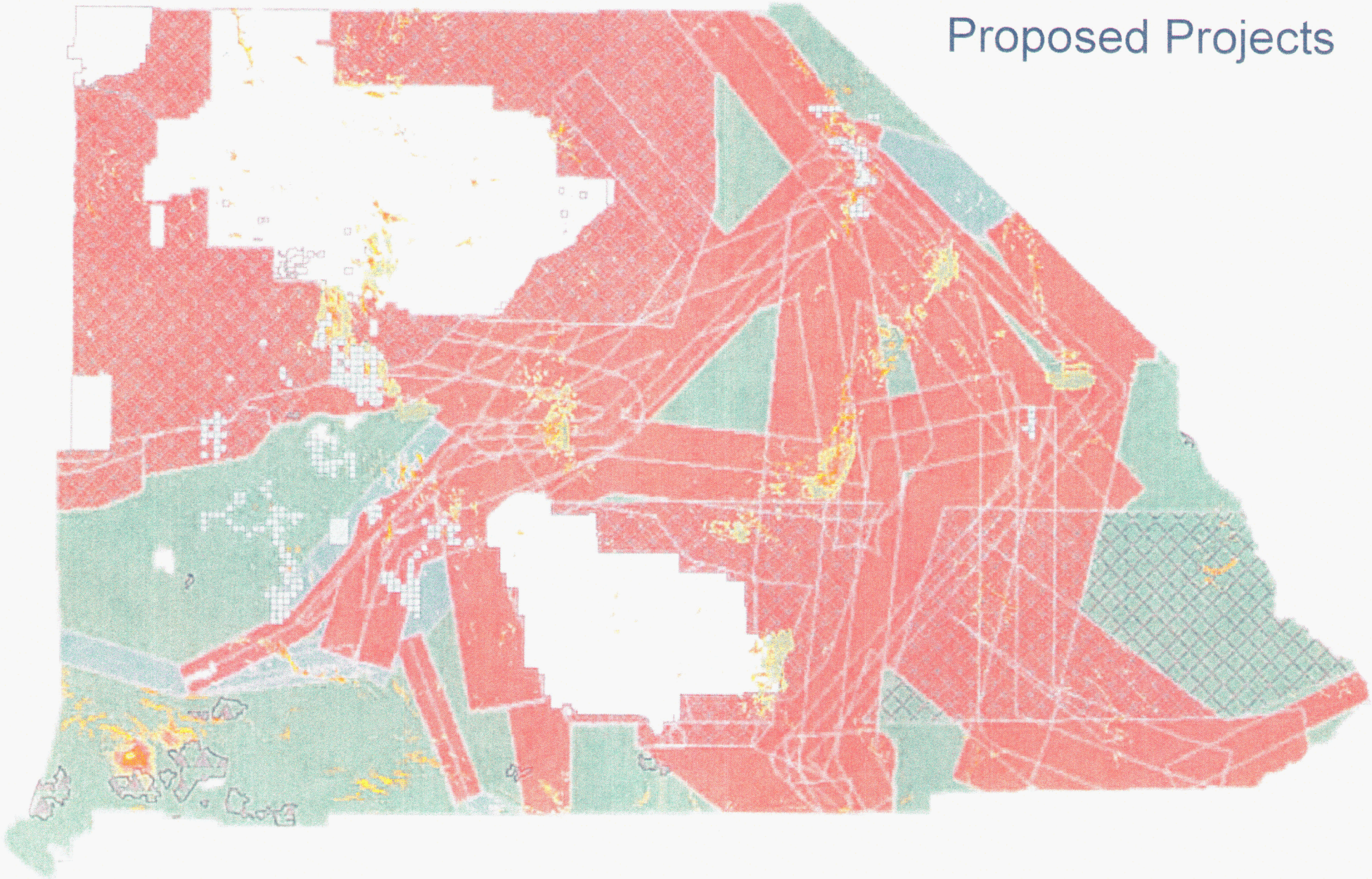
Other Criteria

- Red Hatched
  - Based on radar interference and not associated with MTR or SUA floors
  - Height Restriction: vary based on mission impact
- Blue
  - Airspace floor between 500 and 1000 feet
  - Height Restriction: All structures over 500 feet

Arizona R-Y-G


Red-Yellow-Green Map
Arizona
Nautical Miles
0 5 10 20 30 40 50
Draft

San Bernardino County Example



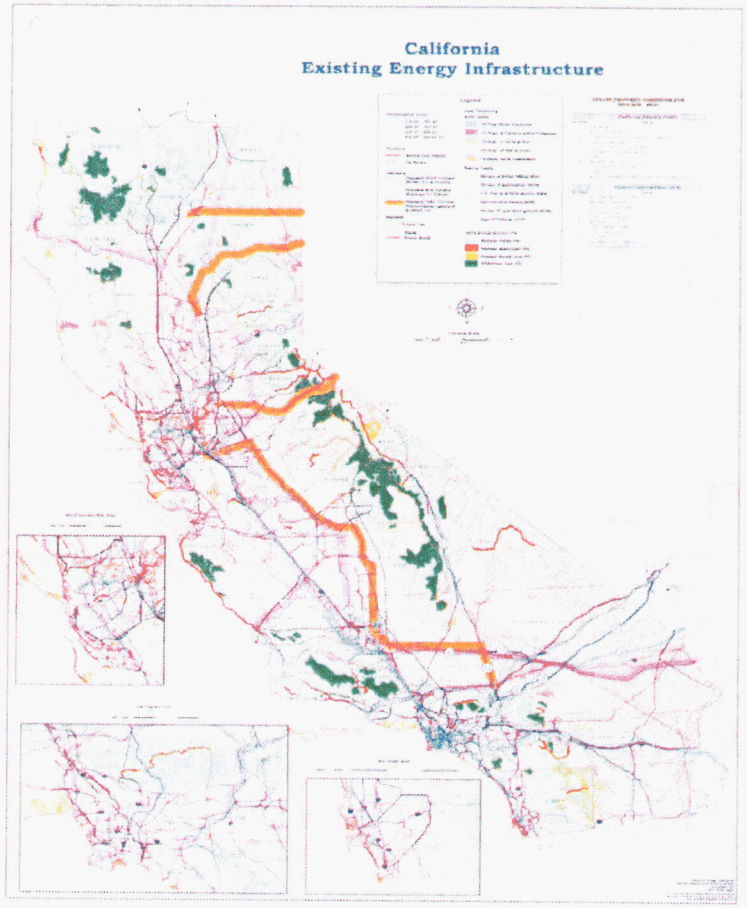
DoD Involvement

- Sustainable Ranges WIPT formed an Energy Oversight Subgroup to address issues related to Energy Policy Act
- OSD engaging DOE to ensure DoD involvement
  - DoD is a Cooperating Agency, but role is limited with no funding
- OSD identifying "No-Go Areas" & criteria

The Future

- Communicate
  - Federal, State, Municipal, Industry
- Available GIS with all applicable layers
- Develop policies to deconflict
- Regional, State & Local coordination forums

California Working Group



- California Energy Commission
- Bureau of Land Management
- Forest Service
- US Park Service
- California Parks
- California State Lands Commission
- Military

Lessons Learned

- Early engagement with project proponents & industry associations
- Robust GIS
- Regional engagement (joint DoD) with land use decision makers
- Regional/local decision/authority
- Dedicated DoD lead (physically located in the area)

Conclusions

- WGEFs & Energy Policy Act of 2005 have the potential for significant mission impacts
- Encroachment from WGEFs is manageable with proactive engagement at the local/regional level & tools like RYG
- OSD & Services are proactive on energy corridors & other possible impacts of Energy Policy Act

The Future is Now!

AIR EDUCATION & TRAINING COMMAND

Integrity - Service - Excellence

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UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY

Considerations for Transmission Congestion Study and	)
Designation of National Interest Electric Transmission Corridors	)

FURTHER COMMENTS OF THE
CALIFORNIA PUBLIC UTILITIES COMMISSION

The Department of Energy (DOE) hosted a public Technical Conference concerning the criteria for evaluation of candidate areas as National Interest Electric Transmission Corridors (NIETCs) on March 29, 2006 in Chicago, Illinois. The chief purpose of the Technical Conference was to discuss key issues raised by commentors' responses concerning the criteria proposed for the evaluation of geographic areas for designation as NIETCs. The California Public Utilities Commission (CPUC) appreciates this opportunity to provide further comments to DOE following up on certain key topics that were discussed at the Technical Conference.

1. **The <u>CPUC Supports the Two-Step Process Proposed by DOE Staff at the May 29 Technical Conference</u>**

At the beginning of the March 29 Technical Conference, DOE Staff proposed a possible new two-step approach to the corridor designation process. Under this suggested approach, DOE would initially identify "Constraint Areas," i.e., areas where a "problem in the transmission infrastructure" has been identified. In designating such Constraint Areas, DOE would remain "agnostic" regarding the appropriateness of a wires or a non-wires solution to the constraint, but the identification of a Constraint Area would lead to further assessments and proposals on the part of the stakeholders in the state or region in question regarding the best and most cost-effective means of resolving the constraint. If this assessment showed that a National Interest Electric Transmission Corridor (NIETC) was still needed, DOE would then proceed to make

such a designation. It is worth noting that this proposed two-step process is entirely consistent with the initial comments submitted by the CPUC and other Western stakeholders in early March, calling for identification and subsequent evaluation of "potential" corridors before any formal designation takes place.

2. DOE Needs to Integrate Its Corridor Designation Process Under EPAct Section 1221 With the Designation of Energy Corridors on Federal Lands Under EPAct Section 368

DOE needs to closely coordinate its process for designating any NIETCs in the Western states with its evaluation and designation of multi-use energy corridors on western federal lands that is already underway pursuant to Section 368 of EPAct. If a potential NIETC entails corridors through federal lands and the Section 368 process has not designated those corridors, then that particular NIETC should not be designated. In the West, where there are extensive federal lands and a preponderance of long transmission distances, potential NIETCs are very likely to pass through federal lands. Accordingly, in the West, it makes sense for DOE to adequately resolve the Section 368 process before designating any NIETCs.

The Section 368 process is especially important, because it will include an environmental review -- essentially a pre-approval -- of routes for transmission and other energy projects through federal lands, which will greatly facilitate transmission siting in the West in general, regardless of NIETC designations.

Coordination of the Section 368 and Section 1221 NIETC processes also supports the two-step NIETC designation process presented by DOE staff at the March 29 meeting. As recommended by Mr. Rob Kondziolka from the Salt River Project at the March 29 conference, congestion and other assessments underlying Constraint Area identification in the Section 1221 process should actively inform the development of Section 368 corridors. In this way, the

designation of federal land energy corridors via the Section 368 process would be a necessary (but not sufficient) pre-condition for ultimate designation of an NIETC that required those corridors.

The results of the Western Area Congestion Study are now being completed by the Western Congestion Assessment Task Force (WCATF) for submission to DOE for use in identifying areas of congestion in the Western Interconnection. This Congestion Study, which will identify congested transmission paths in the West, can and should also serve as a key resource for informing the joint agency process that is working on identifying appropriate multi-use energy corridors through federal land. This Section 368 process is scheduled to complete its work by August of 2007.

Between now and then, the results of the WCATF Congestion Study can and should serve as the basis for concentrated state and regional exploration of whether the best and most cost-effective solutions to the constraints identified by the WCATF study are new transmission lines or reasonably available non-wires alternatives. On a West-wide basis, this state and regional effort can be guided by the new Transmission Expansion Planning Policy Committee (TEPPC) of WECC, whose charter emphasizes "guiding the analyses and modeling for Western Interconnection economic transmission expansion planning." This new function will help WECC members develop and assess impartial, reliable and timely information on the value of expanding the transmission grid in the West. .

While the Section 368 and Section 1221 processes as well as WCATF congestion studies proceed, and the TEPPC assumes its role in West-wide economic transmission planning, on-going transmission planning and evaluation activity in the West has already resulted in specific proposals for major new transmission projects under review at the state level. For example, the

WCATF study identified congestion both east and west of the Colorado River. Two proposed transmission projects that would alleviate this congestion, Devers-Palo Verde 2 and the Sunrise Powerlink, are currently under active review by the CPUC. The CPUC is committed to reviewing these projects in an expeditious manner, consistent with its state statutory requirements for review of project alternatives and addressing project need in terms of ratepayer benefits. The CPUC's review of the Devers-Palo Verde project should be completed by the end of this year, and its review of the Sunrise Powerlink project should be completed sometime in 2007.

By the summer of next year, the Section 368 process, state siting processes for proposed new transmission lines already under review, and the added economic transmission planning focus brought by the WECC's TEPPC will give us in the West, as well as DOE, a very solid idea of whether there is any need to designate any NIETCs in the Western Interconnection. At the March 29 Technical Conference, DOE Staff clearly stated that DOE wanted to move forward on NIETC designation in a careful and thoughtful manner and that DOE did want to coordinate its efforts with regional planning efforts. As the foregoing discussion demonstrates, there already are several on-going transmission-related planning efforts in the Western Interconnection with which DOE can and should coordinate its NIETC designation process. For all of these reasons, in the West, it makes sense for DOE to complete the Section 368 process before designating any NIETCs.

3. DOE Needs to Make Sure that Cost Recovery and Siting Constraints are Adequately Addressed at the *Federal* End, Before Designating Any Corridors that Would Preempt State and Regional Roles

DOE's identification of a Constraint Area should not only trigger deeper state/regional assessment and searches for solutions; it should also trigger efforts by DOE, FERC and other

federal agencies to ensure that incomplete federal cooperation in transmission siting and cost recovery is not hindering a solution. Several speakers at the March 29 Technical Conference, while recognizing that cost recovery does not fall within DOE's domain, noted that the cost recovery/allocation implications of designating NIETCs and processing applications within them are problematic and must be anticipated. A "solution" that cannot be financed is not a solution and raises questions of credibility. For example, in some instances, FERC may be able to help resolve cost recovery issues and thus contribute to a more efficient and timely solution than would be obtainable via NIETC designation plus potentially lengthy and litigious FERC siting preemption.

Similarly, coordinated and expedited project permitting is not only central to DOE's Section 368 initiative regarding "energy corridors on federal lands" but is also equally important to meet permitting timelines for most transmission projects to be sited in the West, whether or not they will be located in a designated NIETC. In this regard, it is our experience in the West that the federal land use agencies can be the most critical players in the siting of new transmission infrastructure. We can have the best planning process in the world, but unless federal land use agencies are actively involved in the planning – as well as the permitting – we cannot keep decisions on schedule. It would be a sad irony if a state is not able to complete its permitting of a transmission line proposed in a designated NIETC within the one-year time frame specified in EPAct because of delays in the environmental permitting process occasioned by a federal agency!

All proposed transmission projects in the West that would cross federal lands – and therefore be subject to review under NEPA – would benefit more from enhanced coordination and responsiveness of federal agency review than they would benefit from the formal

designation of NIETCs. This is yet another reason why in the West, at least, DOE needs to focus its attention on the Section 368 process, and on facilitating transmission development in general. It is the outcome of this Section 368 process, with DOE in the driver's seat, more than the designation of NIETCs that will dramatically facilitate the siting of needed new facilities in the West.

4. At Least in the West, DOE Should be Very Wary of Requests for Early NIETC Designations

At the Technical Conference in Chicago, several stakeholders from the East, in particular, speakers from AEP, TVA and PJM, advocated early designations of NIETCs in areas where existing studies demonstrate the need for new transmission, such as from coal generation areas to major load centers on the eastern seaboard. It may be that such early designations are desired, for legitimate and compelling reasons, by a wide range of stakeholders in the East. However, DOE should most assuredly not take this type of step in the Western Interconnection.

In the Western Interconnection, various collaborative regional and sub-regional transmission planning efforts have already resulted in the identification and designation of major transmission upgrades, and a number of specific projects resulting from these planning efforts are in the active permitting process at the state level, as discussed under item 2 above. State action on these proposed projects, which can be anticipated to occur sometime next year, may well obviate the need for any designation of an NIETC between generation and major population centers in the Southwest. This is precisely the sort of information that DOE needs to take into account as it moves forward on NIETCs.

Thus, although we are "agnostic" as to whether DOE should defer to the wishes of stakeholders in the east for early designations of certain NIETCs, we are sufficiently informed regarding transmission needs and developments in the West to state that DOE should similarly

defer to on-going planning and project evaluation processes in the Western Interconnection and should not designate any NIETCs in the West as long as these processes are moving forward productively.

In this regard, the CPUC notes that in the first round of comments on DOE's NOI, two commentors, specifically San Diego Gas & Electric Company (SDG&E) and the Bay Area Municipal Transmission Group (BAMTG), requested early designation of NIETCs in California. However, neither of these "priority" or early NIETC designation requests is either necessary or reasonable at this time. Both of these projects are already undergoing active permitting processes, and there is no urgent or compelling need for DOE to take action at this time to complicate – and potentially preempt – these on-going permitting processes. At the March 29 conference, DOE staff explicitly stated that they did not want to be "picking winners." However, that is exactly what the early designation requests of SDG&E and BAMTG are asking DOE to do.

Conclusion

In conclusion, DOE should actively pursue the two-step process that it presented at the March 29 Technical Conference. In pursuing this strategy, DOE should be cognizant of, and should incorporate into its processes, the following important policy considerations:

- No NIETC designations, early or otherwise, should occur until DOE, relying on state and/or regional transmission planning processes, has identified a Constraint Area, and has determined that appropriate non-wires solutions are not reasonably available.
- DOE should only make a NIETC designation if a there is an identified wires solution to address an identified Constraint Area and there is a lengthy delay in moving that project forward.

- When a NIETC designation is made, it should be done only if the designation is consistent with analyses performed by regional planning entities, as well as with results of the EPAct Section 368 process, and any such designation must explicitly address state regulatory concerns, including but not limited to state policies favoring energy efficiency, demand-side management and the development of renewable resources.

- No NIETC designation should be made in the West unless and until the existing state and regional planning and siting processes have first had a chance to fully benefit from federal cooperation and coordination in such areas as cost recovery and permitting on federal lands

The CPUC respectfully requests that the DOE consider the above comments in this proceeding.

April 14, 2006

Respectfully submitted,

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San Francisco, CA 94102
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proposed to apply within the region is just, reasonable, not unduly discriminatory or preferential, and in the public interest, whether fees proposed to be assessed within the region are just, reasonable, not unduly discriminatory or preferential, and in the public interest and any other responsibilities requested by the Commission. The Commission may give deference to the advice of any such regional advisory body if that body is organized on an Interconnection-wide basis.

"(k) ALASKA AND HAWAII.—The provisions of this section do not apply to Alaska or Hawaii.".

(b) STATUS OF ERO.—The Electric Reliability Organization certified by the Federal Energy Regulatory Commission under section 215(c) of the Federal Power Act and any regional entity delegated enforcement authority pursuant to section 215(e)(4) of that Act are not departments, agencies, or instrumentalities of the United States Government.

(c) ACCESS APPROVALS BY FEDERAL AGENCIES.—Federal agencies responsible for approving access to electric transmission or distribution facilities located on lands within the United States shall, in accordance with applicable law, expedite any Federal agency approvals that are necessary to allow the owners or operators of such facilities to comply with any reliability standard, approved by the Commission under section 215 of the Federal Power Act, that pertains to vegetation management, electric service restoration, or resolution of situations that imminently endanger the reliability or safety of the facilities.

Subtitle B—Transmission Infrastructure Modernization

SEC. 1221. SITING OF INTERSTATE ELECTRIC TRANSMISSION FACILITIES.

(a) IN GENERAL.—Part II of the Federal Power Act (16 U.S.C. 824 et seq.) is amended by adding at the end the following:

"SEC. 216. SITING OF INTERSTATE ELECTRIC TRANSMISSION FACILITIES.

"(a) DESIGNATION OF NATIONAL INTEREST ELECTRIC TRANSMISSION CORRIDORS.—(1) Not later than 1 year after the date of enactment of this section and every 3 years thereafter, the Secretary of Energy (referred to in this section as the 'Secretary'), in consultation with affected States, shall conduct a study of electric transmission congestion.

"(2) After considering alternatives and recommendations from interested parties (including an opportunity for comment from affected States), the Secretary shall issue a report, based on the study, which may designate any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers as a national interest electric transmission corridor.

"(3) The Secretary shall conduct the study and issue the report in consultation with any appropriate regional entity referred to in section 215.

"(4) In determining whether to designate a national interest electric transmission corridor under paragraph (2), the Secretary may consider whether—

"(A) the economic vitality and development of the corridor, or the end markets served by the corridor, may be constrained by lack of adequate or reasonably priced electricity;

"(B)(i) economic growth in the corridor, or the end markets served by the corridor, may be jeopardized by reliance on limited sources of energy; and

"(ii) a diversification of supply is warranted;

"(C) the energy independence of the United States would be served by the designation;

"(D) the designation would be in the interest of national energy policy; and

"(E) the designation would enhance national defense and homeland security.

"(b) CONSTRUCTION PERMIT.—Except as provided in subsection (i), the Commission may, after notice and an opportunity for hearing, issue one or more permits for the construction or modification of electric transmission facilities in a national interest electric transmission corridor designated by the Secretary under subsection (a) if the Commission finds that—

"(1)(A) a State in which the transmission facilities are to be constructed or modified does not have authority to—

"(i) approve the siting of the facilities; or

"(ii) consider the interstate benefits expected to be achieved by the proposed construction or modification of transmission facilities in the State;

"(B) the applicant for a permit is a transmitting utility under this Act but does not qualify to apply for a permit or siting approval for the proposed project in a State because the applicant does not serve end-use customers in the State; or

"(C) a State commission or other entity that has authority to approve the siting of the facilities has—

"(i) withheld approval for more than 1 year after the filing of an application seeking approval pursuant to applicable law or 1 year after the designation of the relevant national interest electric transmission corridor, whichever is later; or

"(ii) conditioned its approval in such a manner that the proposed construction or modification will not significantly reduce transmission congestion in interstate commerce or is not economically feasible;

"(2) the facilities to be authorized by the permit will be used for the transmission of electric energy in interstate commerce;

"(3) the proposed construction or modification is consistent with the public interest;

"(4) the proposed construction or modification will significantly reduce transmission congestion in interstate commerce and protects or benefits consumers;

"(5) the proposed construction or modification is consistent with sound national energy policy and will enhance energy independence; and

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

"(c) PERMIT APPLICATIONS.—(1) Permit applications under subsection (b) shall be made in writing to the Commission.

"(2) The Commission shall issue rules specifying—

"(A) the form of the application;

"(B) the information to be contained in the application; and

"(C) the manner of service of notice of the permit application on interested persons.

"(d) COMMENTS.—In any proceeding before the Commission under subsection (b), the Commission shall afford each State in which a transmission facility covered by the permit is or will be located, each affected Federal agency and Indian tribe, private property owners, and other interested persons, a reasonable opportunity to present their views and recommendations with respect to the need for and impact of a facility covered by the permit.

"(e) RIGHTS-OF-WAY.—(1) In the case of a permit under subsection (b) for electric transmission facilities to be located on property other than property owned by the United States or a State, if the permit holder cannot acquire by contract, or is unable to agree with the owner of the property to the compensation to be paid for, the necessary right-of-way to construct or modify the transmission facilities, the permit holder may acquire the right-of-way by the exercise of the right of eminent domain in the district court of the United States for the district in which the property concerned is located, or in the appropriate court of the State in which the property is located.

"(2) Any right-of-way acquired under paragraph (1) shall be used exclusively for the construction or modification of electric transmission facilities within a reasonable period of time after the acquisition.

"(3) The practice and procedure in any action or proceeding under this subsection in the district court of the United States shall conform as nearly as practicable to the practice and procedure in a similar action or proceeding in the courts of the State in which the property is located.

"(4) Nothing in this subsection shall be construed to authorize the use of eminent domain to acquire a right-of-way for any purpose other than the construction, modification, operation, or maintenance of electric transmission facilities and related facilities. The right-of-way cannot be used for any other purpose, and the right-of-way shall terminate upon the termination of the use for which the right-of-way was acquired.

"(f) COMPENSATION.—(1) Any right-of-way acquired pursuant to subsection (e) shall be considered a taking of private property for which just compensation is due.

"(2) Just compensation shall be an amount equal to the fair market value (including applicable severance damages) of the property taken on the date of the exercise of eminent domain authority.

"(g) STATE LAW.—Nothing in this section precludes any person from constructing or modifying any transmission facility in accordance with State law.

"(h) COORDINATION OF FEDERAL AUTHORIZATIONS FOR TRANSMISSION FACILITIES.—(1) In this subsection:

"(A) The term 'Federal authorization' means any authorization required under Federal law in order to site a transmission facility.

"(B) The term 'Federal authorization' includes such permits, special use authorizations, certifications, opinions, or other

approvals as may be required under Federal law in order to site a transmission facility.

"(2) The Department of Energy shall act as the lead agency for purposes of coordinating all applicable Federal authorizations and related environmental reviews of the facility.

"(3) To the maximum extent practicable under applicable Federal law, the Secretary shall coordinate the Federal authorization and review process under this subsection with any Indian tribes, multistate entities, and State agencies that are responsible for conducting any separate permitting and environmental reviews of the facility, to ensure timely and efficient review and permit decisions.

"(4)(A) As head of the lead agency, the Secretary, in consultation with agencies responsible for Federal authorizations and, as appropriate, with Indian tribes, multistate entities, and State agencies that are willing to coordinate their own separate permitting and environmental reviews with the Federal authorization and environmental reviews, shall establish prompt and binding intermediate milestones and ultimate deadlines for the review of, and Federal authorization decisions relating to, the proposed facility.

"(B) The Secretary shall ensure that, once an application has been submitted with such data as the Secretary considers necessary, all permit decisions and related environmental reviews under all applicable Federal laws shall be completed—

"(i) within 1 year; or

"(ii) if a requirement of another provision of Federal law does not permit compliance with clause (i), as soon thereafter as is practicable.

"(C) The Secretary shall provide an expeditious pre-application mechanism for prospective applicants to confer with the agencies involved to have each such agency determine and communicate to the prospective applicant not later than 60 days after the prospective applicant submits a request for such information concerning—

"(i) the likelihood of approval for a potential facility; and

"(ii) key issues of concern to the agencies and public.

"(5)(A) As lead agency head, the Secretary, in consultation with the affected agencies, shall prepare a single environmental review document, which shall be used as the basis for all decisions on the proposed project under Federal law.

"(B) The Secretary and the heads of other agencies shall streamline the review and permitting of transmission within corridors designated under section 503 of the Federal Land Policy and Management Act (43 U.S.C. 1763) by fully taking into account prior analyses and decisions relating to the corridors.

"(C) The document shall include consideration by the relevant agencies of any applicable criteria or other matters as required under applicable law.

"(6)(A) If any agency has denied a Federal authorization required for a transmission facility, or has failed to act by the deadline established by the Secretary pursuant to this section for deciding whether to issue the authorization, the applicant or any State in which the facility would be located may file an appeal with the President, who shall, in consultation with the affected agency, review the denial or failure to take action on the pending application.

"(B) Based on the overall record and in consultation with the affected agency, the President may—

"(i) issue the necessary authorization with any appropriate conditions; or

"(ii) deny the application.

"(C) The President shall issue a decision not later than 90 days after the date of the filing of the appeal.

"(D) In making a decision under this paragraph, the President shall comply with applicable requirements of Federal law, including any requirements of—

"(i) the National Forest Management Act of 1976 (16 U.S.C. 472a et seq.);

"(ii) the Endangered Species Act of 1973 (16 U.S.C. 1531 et seq.);

"(iii) the Federal Water Pollution Control Act (33 U.S.C. 1251 et seq.);

"(iv) the National Environmental Policy Act of 1969 (42 U.S.C. 4321 et seq.); and

"(v) the Federal Land Policy and Management Act of 1976 (43 U.S.C. 1701 et seq.).

"(7)(A) Not later than 18 months after the date of enactment of this section, the Secretary shall issue any regulations necessary to implement this subsection.

"(B)(i) Not later than 1 year after the date of enactment of this section, the Secretary and the heads of all Federal agencies with authority to issue Federal authorizations shall enter into a memorandum of understanding to ensure the timely and coordinated review and permitting of electricity transmission facilities.

"(ii) Interested Indian tribes, multistate entities, and State agencies may enter the memorandum of understanding.

"(C) The head of each Federal agency with authority to issue a Federal authorization shall designate a senior official responsible for, and dedicate sufficient other staff and resources to ensure, full implementation of the regulations and memorandum required under this paragraph.

"(8)(A) Each Federal land use authorization for an electricity transmission facility shall be issued—

"(i) for a duration, as determined by the Secretary, commensurate with the anticipated use of the facility; and

"(ii) with appropriate authority to manage the right-of-way for reliability and environmental protection.

"(B) On the expiration of the authorization (including an authorization issued before the date of enactment of this section), the authorization shall be reviewed for renewal taking fully into account reliance on such electricity infrastructure, recognizing the importance of the authorization for public health, safety, and economic welfare and as a legitimate use of Federal land.

"(9) In exercising the responsibilities under this section, the Secretary shall consult regularly with—

"(A) the Federal Energy Regulatory Commission;

"(B) electric reliability organizations (including related regional entities) approved by the Commission; and

"(C) Transmission Organizations approved by the Commission.

"(i) INTERSTATE COMPACTS.—(1) The consent of Congress is given for three or more contiguous States to enter into an interstate compact, subject to approval by Congress, establishing regional transmission siting agencies to—

"(A) facilitate siting of future electric energy transmission facilities within those States; and

"(B) carry out the electric energy transmission siting responsibilities of those States.

"(2) The Secretary may provide technical assistance to regional transmission siting agencies established under this subsection.

"(3) The regional transmission siting agencies shall have the authority to review, certify, and permit siting of transmission facilities, including facilities in national interest electric transmission corridors (other than facilities on property owned by the United States).

"(4) The Commission shall have no authority to issue a permit for the construction or modification of an electric transmission facility within a State that is a party to a compact, unless the members of the compact are in disagreement and the Secretary makes, after notice and an opportunity for a hearing, the finding described in subsection (b)(1)(C).

"(j) RELATIONSHIP TO OTHER LAWS.—(1) Except as specifically provided, nothing in this section affects any requirement of an environmental law of the United States, including the National Environmental Policy Act of 1969 (42 U.S.C. 4321 et seq.).

"(2) Subsection (h)(6) shall not apply to any unit of the National Park System, the National Wildlife Refuge System, the National Wild and Scenic Rivers System, the National Trails System, the National Wilderness Preservation System, or a National Monument.

"(k) ERCOT.—This section shall not apply within the area referred to in section 212(k)(2)(A).".

(b) REPORTS TO CONGRESS ON CORRIDORS AND RIGHTS-OF-WAY ON FEDERAL LANDS.—Not later than 90 days after the date of enactment of this Act, the Secretary of the Interior, the Secretary, the Secretary of Agriculture, and the Chairman of the Council on Environmental Quality shall submit to Congress a joint report identifying—

(1)(A) all existing designated transmission and distribution corridors on Federal land and the status of work related to proposed transmission and distribution corridor designations under title V of the Federal Land Policy and Management Act of 1976 (43 U.S.C. 1761 et seq.);

(B) the schedule for completing the work;

(C) any impediments to completing the work; and

(D) steps that Congress could take to expedite the process;

(2)(A) the number of pending applications to locate transmission facilities on Federal land;

(B) key information relating to each such facility;

(C) how long each application has been pending;

(D) the schedule for issuing a timely decision as to each facility; and

(E) progress in incorporating existing and new such rights-of-way into relevant land use and resource management plans or the equivalent of those plans; and

(3)(A) the number of existing transmission and distribution rights-of-way on Federal land that will come up for renewal within the following 5-, 10-, and 15-year periods; and

(B) a description of how the Secretaries plan to manage the renewals.

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WestConnect
2502 Cemetery Lane
Council, ID 83612

Charles Reinhold – Project Manager
208-253-6916

July 31, 2006

Mr. Yakout Mansour
President & Chief Executive Officer
California Independent System Operator
P.O. Box 639014
Folsom, CA 95763-9014

Dear Yakout:

The WestConnect Participants[1] are writing to invite the CAISO to participate in a series of workshops on seams issues arising from the new market design proposed in the CAISO's Market Redesign and Technology Upgrade (MRTU) filing at FERC.

As you know, comments filed with FERC by the WestConnect Participants and many other intervenors on the MRTU filing expressed concern that the CAISO had not adequately addressed MRTU seams issues. The need to carefully review impacts of MRTU on reliability, operations and markets across the Western Interconnection prior to implementation of the proposed new market design was similarly raised by twelve western U.S. Senators in their June 26, 2006 letter to FERC and acknowledged by FERC Chairman Joseph Kelliher in his July 21, 2006 letter responding to the Senators. To further such review, the WestConnect Participants are prepared to actively collaborate with the CAISO to analyze the seams issues and design appropriate mitigation measures.

At this point, the WestConnect Participants' greatest concerns include:

- the CAISO's ability to curtail exports to external entities from designated Resource Adequacy generation in order to meet load in system emergencies, which could shift the CAISO's operating problems to neighboring control areas;
- the potential for increased congestion on neighboring systems when the CAISO's LMP-based congestion management protocol butts up against the physical rights congestion management protocol at interconnections with the rest of the Western Interconnection; and
- the lack of analysis by the CAISO on projected impacts of MRTU implementation on the reliability of the Western Interconnection.

Jerry Smith of Arizona Public Service Company and I have already initiated discussions with members of your staff to revisit the SSG-WI work done several years ago on congestion

[1] The WestConnect Participants are a group of transmission-providing utilities located in the Southwest and Rocky Mountain areas of the Western Interconnection, currently including Arizona Public Service Company, El Paso Electric Company, Imperial Irrigation District, Nevada Power Company, Public Service Company of Colorado, Public Service Company of New Mexico, Salt River Project, Sierra Pacific Power Company, Southwest Transmission Cooperative, Tri-State Generation and Transmission Association, Tucson Electric Power Company, and three customer service regions of the Western Area Power Administration.

management. The WestConnect Participants wish to build upon those initial discussions with CAISO staff to address impacts of MRTU operations on adjacent control entities and the Western Interconnection as a whole. Our goal is to work collaboratively and expeditiously with the CAISO to develop protocols and practices that eliminate negative impacts.

I suggest a preliminary meeting be set up between a small group of WestConnect Participants and you and your staff in early August, to frame the issues and put together a workshop process. I will call you in the next week to set a date for such a meeting and I also invite you to feel free to call me on my cell phone at (480) 215-0299.

Sincerely,

Charles Reinhold

Charles Reinhold
WestConnect Project Manager

Cc: WestConnect Participants
Federal Energy Regulatory Commission

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200608255105 Received FERC OSEC 08/25/2006 04:38:00 PM Docket# RM06-12-000

STATE OF CALIFORNIA ARNOLD SCHWARZENEGGER, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

August 25, 2006

VIA E-FILING

Magalie Roman-Salas, Secretary
Office of the Secretary
Docket Room
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1A, East
Washington, D.C. 20002

Re: Regulations for Filing Applications for Permits to Site Interstate Electric Transmission Corridors, FERC Docket No. RM06-12-000

Dear Ms. Roman-Salas:

Enclosed for e-filing in the above-docketed case, please find an original electronic filing of the attached document entitled **"NOTICE OF INTERVENTION AND COMMENTS OF THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA."**

Thank you for your cooperation in this matter.

Sincerely,

/s/ Harvey Y. Morris

Harvey Y. Morris
Assistant General Counsel
(415) 703-1086
hym@cpuc.ca.gov

HYM:mpg

246300

200608255105 Received FERC OSEC 08/25/2006 04:38:00 PM Docket# RM06-12-000

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Regulations for Filing Applications for Permits to Site Interstate Electric Transmission Corridors	Docket No. RM06-12-000

NOTICE OF INTERVENTION AND COMMENTS OF THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Pursuant to Rule 214(a)(2) of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or the "Commission") and FERC's June 16, 2006 Notice of Proposed Rulemaking ("NOPR"), the Public Utilities Commission of the State of California ("CPUC") hereby gives notice of its intervention and submits the following comments in the above-docketed proceeding. The CPUC is a constitutionally-established agency charged with the responsibility for regulating electrical and natural gas corporations within the State of California. In addition, the CPUC has a statutory mandate to represent the interests of electrical and natural gas consumers throughout California in proceedings before the FERC.

The names and addresses of persons to whom communications should be addressed are:

Laurence G. Chaset
California Public Utilities Commission
505 Van Ness Avenue, Room 5131
San Francisco, California 94102
(415) 355-5595
e-mail: lau@cpuc.ca.gov

Keith D. White
California Public Utilities Commission
505 Van Ness Avenue, Area 4-A
San Francisco, California 94102
(415) 355-5473
e-mail: kwh@cpuc.ca.gov

COMMENTS

I. INTRODUCTION

On August 8, 2005, the federal Energy Policy Act of 2005 ("EPAct") became law. Section 1221 of EPAct adds a new section 216 to the Federal Power Act ("FPA"), providing for federal siting of electric transmission facilities under certain circumstances. FPA section 216 requires that the Secretary of the Department of Energy ("DOE") identify transmission constraints and authorizes the DOE to designate a geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers as a National Interest Electric Transmission Corridor ("National Corridor").

In discharging these responsibilities, the DOE on August 8, 2006 released its congestion study. One of the two Critical Congestion Areas identified in this report is southern California. The report also identified four Congestion Areas of Concern where more information and analysis are needed to determine the magnitude of and potential solutions to possible large scale congestion problems, and one of these four areas was the San Francisco Bay area in California. DOE requested comments on whether designation of National Corridors would be appropriate in any of the identified areas, how corridor boundaries should be set, and, where a commenter focuses on a specific transmission project, how costs would be allocated.

Once a National Corridor has been designated, FERC has the authority under FPA section 216(b) to issue permits to construct or modify electric transmission facilities in such corridors under certain circumstances. Specifically, FERC has the authority to issue

permits to construct or modify electric transmission facilities if it finds that the State commission or entity with siting authority has withheld approval of the facilities for more than one year after an application is filed or one year after the designation of the relevant National Corridor, whichever is later, or if the State conditions the construction or modification of the facilities in such a manner that the proposal will not significantly reduce transmission congestion in interstate commerce or is not economically feasible.

FPA section 216(c)(2) requires that FERC issue rules specifying the form of, and the information to be contained in, an application for proposed construction or modification of electric transmission facilities in a designated National Corridor, and the manner of service of notice of the permit application on interested persons. Pursuant to this requirement, FERC in its NOPR has proposed to implement new siting procedure regulations, as well as certain modifications to other, existing regulations, including the FERC's regulations implementing the National Environmental Policy Act of 1969 ("NEPA").

Throughout section 1221 of EPAct, there is recognition of the importance of the State's views, including the State commission that has authority to issue certificates of public convenience and necessity and approve the siting of transmission facilities. Thus, not only does the State have a right to present alternatives and recommendations to the DOE concerning the designation of national interest electric transmission corridors (FPA § 216(a)(2)), a State commission with authority to site electric transmission facilities, such as the CPUC, must first be given the opportunity to approve within one year the siting of transmission facilities in a designated national interest electric transmission

corridor, before the FERC's backstop authority can be triggered to process a formal application to site such transmission facilities. *See* FPA § 216(b)(1)(C). If such formal applications are thereafter filed with FERC, it must provide each State in which the transmission facility in question is located a reasonable opportunity to present its views and recommendations. *See* FPA § 216(c). Congress also required the DOE to coordinate to "the maximum extent practicable" with federal agencies and State agencies that are responsible for conducting any separate permitting and environmental reviews. *See* FPA § 216(h)(3). DOE has delegated this statutory duty to FERC.

The CPUC supports efficient and well-planned expansion of the transmission system to maintain reliability, enhance economic efficiency and also to support established energy policies, such as energy diversity and renewable power objectives. The CPUC is currently working with our jurisdictional utilities, the California Independent System Operator, and other stakeholders to implement major transmission expansions over the next 5-10 years in an economically efficient, environmentally sound, and equitably financed manner.

The CPUC agrees with the goal of Congress, FERC, DOE and other federal agencies to expedite the development of such transmission projects, especially through coordination and streamlining of reviews by federal and state agencies as called for under the EPAct and as addressed for in FERC's NOPR. This is an area in which the federal agencies and state agencies can and should work together. However, the CPUC has concerns that FERC's NOPR leaves an unclear and potentially precipitous process for determining that FERC shall take over siting authority from states, and also does not

provide for coordination and sequencing of the state and federal processes in a manner that is efficient overall, or that can be expected with some confidence to be fair or manageable for stakeholders.

The CPUC's Comments cover the following points relating to FERC's NOPR:

- The State's one-year "clock" for processing an application before backstop siting is initiated should not be started until the state application is complete.

- FERC should provide the same urgency and priority in coordinating and expediting federal agency approvals of siting applications at the ***state*** level as it proposes to provide for any projects subsequently brought before FERC, and in particular should not deem the one-year clock for a state's processing of an application to have run out if the state process is being delayed by federal approvals.

- The NOPR provides for both pre-filing and filing processes at FERC, yet does not clarify how the FERC processes will be sequenced and coordinated with state siting processes in a manner that is efficient and that limits potential confusion and burdens for stakeholders.

- Regulations implementing NEPA should clarify that consideration of project alternatives in FERC's backstop siting process is in no way limited to or biased in favor of alternatives located in National Corridors, and should fully include information and findings regarding alternatives as developed within state siting processes.

- The proposed regulations should more fully address how the project proponent proposes and expects to initially finance the project and ultimately recover its costs.

A. The State's One-Year "Clock" for Processing an Application Should Not be Deemed to Have Started Until the State Application is Complete

As provided for in § 50.5(e)(8) of proposed new Section 50, Code of Federal Regulations, Applications for Permits to Site Interstate Electric Transmission Facilities, FERC may terminate the pre-filing process if the applicant makes inadequate progress in

providing information, including updates on the status of state applications for permits or other authorizations, while § 50.5 (f) states that FERC will determine when the pre-filing process is complete such that an applicant may file an application.

In order to expeditiously process the application, FERC needs the applicant to provide all the information required for an application upfront, not only in the prefiling process in proposed §50.5, but also in the extensive requirements of the formal application in proposed §§ 50.6 and 50.7. Therefore, in proposed §50.8 FERC can reject an application if it patently fails to comply with applicable statutory requirements or FERC rules, regulations or orders.

FERC should recognize that in order to expeditiously fulfill their siting roles, States require a similar opportunity to conduct their permitting processes, including determining when an applicant has met all of the substantive, State requirements such that an application can be deemed complete and can be filed. Only at this point should the "clock" be started for the one year's time in which a State may act on an application before triggering FERC backstop authority.

State agencies, such as the CPUC, have no reason to delay necessary transmission projects and realize the substantial benefits that would occur from the elimination of transmission capacity constraints and congestion. Just as FERC needs the applicant to provide all the information required for an application upfront in order to expeditiously process the application, so, too, do the State agencies need complete information in applications filed with them. Therefore, FERC should clarify in its proposed § 50.8, when FERC states that it may terminate the pre-filing process "[i]f the applicant fails to

respond to any request for additional information, fails to provide sufficient information, or is not making sufficient progress towards completing the pre-filing process," that would include the failure of the applicant to completely comply with the State commission's application filing requirements or the applicant's recalcitrance in the State commission proceeding. Therefore, if applications filed with the States do not comply with the States' filing requirements, FERC should clarify it would not start the clock for the one-year time frame required to invoke FERC's backstop authority. Such support from the FERC would facilitate the States' ability to expeditiously and meaningfully process the applications within one year and make the actual utilization of FERC backstop processes unnecessary.

The ultimate objective of Section 1221 of the EPAct is efficient solution of transmission congestion problems, not necessarily encouraging federal backstop siting of transmission. Where State siting processes are enhanced by expedited federal agency approvals, plus FERC support for State processes and an elevated sense of urgency to avoid the necessity of federal backstop siting, then the ultimate objective will have been met. In fact, it will have been met with greater efficiency and expedition than if FERC's backstop siting authority is utilized and an entirely new, additional and duplicative administrative process must first commence after the one-year State process has taken place. The FERC process should only be, and with this clarification may only have to be, invoked as a last resort.

B. FERC's Role in Coordinating Federal Agency Approvals Should Extend to the State Permitting Process, and Delay of Such Approvals Should Not Be A Valid Reason for Initiating Backstop Siting

FERC's NOPR notes that the Secretary has delegated to FERC the EPACT-mandated lead role in coordinating all applicable Federal authorizations and related environmental review. Concerning this role, FPA Section 216(h)(4)(A), as well as FERC's NOPR, provide for establishment of "prompt and binding intermediate milestones and ultimate deadlines" regarding federal agency review and authorizations. To further the ultimate objective of efficient transmission siting, and to avoid the perverse outcome of a state siting process being preempted by federal siting due to delayed action by other federal agencies, FERC should exercise the same coordinating role and urgency in expediting any applicable federal agency review of applications during the time an application is filed at the state level, as it requires for applications to FERC.

By expediting state siting processes, this can support overall efficient transmission siting in a faster and less contentious manner than by first coordinating the other federal agencies only when FERC's backstop authority is invoked. For fairness and to encourage efficient action on applications at the state level, FERC's rules should make it explicitly clear that the one-year state siting clock should not be deemed to have run out when a year has passed since a completed application was filed, if the state process is being held up by federal agency approvals, or delays related to "another provision of Federal law" which FPA Section 216 (h)(4)(B) provides as a basis for extending FERC's own application process beyond its prescribed one year.

C. FERC Rules Need to Provide for Efficient Sequencing and Coordination with State Siting Processes

The NOPR provides for both pre-filing and filing processes at FERC, and yet does not clarify how the FERC processes will be sequenced and coordinated with state siting processes. FERC can rationalize the overall transmission siting process and minimize the drawbacks of parallel processes if it establishes clear criteria and procedures for how to incorporate information from state siting processes. FPA Section 216(h)(5)(B) provides that "the Secretary [now delegated to FERC] and the heads of other agencies shall streamline the review and permitting of transmission within corridors…by fully taking into account prior analyses and decisions…" In the event FERC's backstop authority is invoked with a formal application, FERC's rules should therefore provide for full use by any FERC backstop siting process of information, analyses, findings, decisions, and stakeholder notification and participation that have already been established in a state siting process.

In addition to the law, it makes practical sense for the federal backstop siting process to incorporate information and findings from state siting processes, not only for shear efficiency, but additionally to minimize confusion, burden and contention among stakeholders facing multiple processes.

D. Regulations Implementing NEPA Should Clarify that Alternatives are in No Way Limited to Alternatives Located in National Corridors, and Should Include Information and Findings on Alternatives Developed in State Siting Processes

The purpose of the backstop siting process required by EPAct is to expedite, where necessary, the solution of congestion problems in identified problem areas. This does not mean there should be a bias in favor of a proposed transmission project in a National Corridor, or alternatives that are also located in such a corridor. An efficient and open siting process requires that the full range of applicable alternatives be fairly considered, just as would be done for applications not falling within FERC's backstop siting authority. This should be recognized where alternatives are addressed in the proposed pre-filing process via § 50.5(e)(5) and in new rules implementing NEPA via §380.16 (k). Furthermore, when the FERC process coordinates with and makes full use of information from the state siting process as the CPUC recommends above, this should explicitly be required to include all information and findings on alternatives developed in the state siting process, as a starting point for considering alternatives in the federal process.

E. Proposed Regulations Do Not Adequately Address Applicants' Proposed Financing and Cost Recovery

In proposed §50.6 (g) FERC would require an applicant to provide "a general description of project financing" and under § 50.7(i) an applicant would be required to provide estimates of construction costs and of the estimated capital and annual operations and maintenance costs for each proposed environmental measure. The above information

requirements should be expanded to include any other costs for which the applicant intends to seek recovery, such as costs for studies and permitting.

Furthermore, if an application for a proposed transmission project is filed with FERC to invoke its backstop siting process, then presumably the project has encountered obstacles with siting processes and/or stakeholders in the state or region where the project is located. To provide adequate transparency regarding the financial impact of the project on that state or region, and also to adequately inform affected stakeholders, the description of project financing required in an application to FERC should identify the specific mechanism(s) by which the applicant will seek cost recovery over what period of time, what categories of ratepayers costs would be recovered from (such as interconnecting generators versus load-serving entities in certain locations), and what rate or other incentives the applicant proposes to seek, including those pursuant to FERC's recent decision in RM06-4-000.

II. CONCLUSION

Under section 1221 of EPAct, there should be coordinated efforts between the state and federal agencies in review of transmission projects in the National Corridors. The CPUC respectfully submits that FERC should clarify its rules consistent with the

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discussion, above, in order to make the overall siting process, and solutions to congestion problems, as efficient, meaningful and expeditious as possible.

Dated: August 25, 2006

Respectfully submitted,

RANDOLPH L. WU
HARVEY Y. MORRIS
LAURENCE G. CHASET

By: *Laurence G. Chaset*

Laurence G. Chaset

Attorneys for the
Public Utilities
Commission of the State of California
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CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing document to be served upon all known parties in this proceeding by e-mail upon each party identified in the official service list compiled by the Secretary in this proceeding.

Dated at San Francisco, California, this 25th day of August, 2006.

/s/ Harvey Y. Morris

Harvey Y. Morris

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Submission Contents

Notice of Intervention & Comments of the Public Utilities Commission of the State of California
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CALIFORNIA ISO

California Independent
System Operator

California ISO Wheeling and Congestion Charges

Jeff Miller
California ISO

September 1, 2004

Overview

- Wheeling Charges
  - Losses – Based on TMM or GMM
  - Core Reliability Requirement
- Congestion Charges
  - Firm Transmission Rights - Today
  - Congestion Revenue Rights - Future

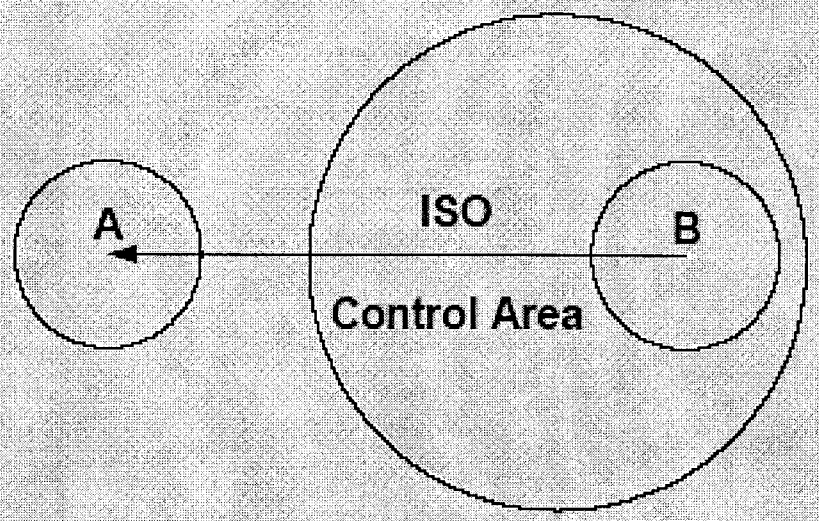
Wheeling Charges

- Charge assessed to SCs with schedules exiting/leaving the ISO Controlled Grid
- Based on gross exports, not net
- Based on actual flows (not always what you scheduled- may be curtailed)
- If exit point is below 200 kV, a Low Voltage Wheeling Access Charge is also incurred

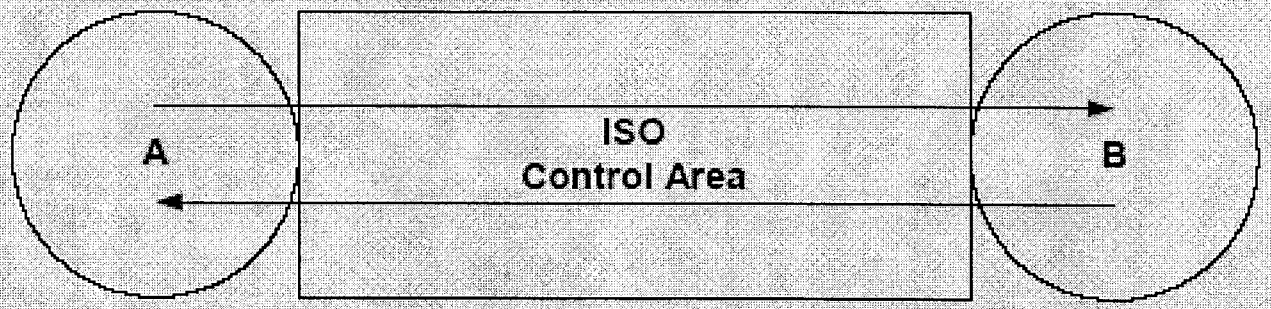
Wheeling Charges

- Wheeling Charges are Assessed on Energy Leaving the ISO Controlled Grid
  - Wheeling Out
  - Wheeling through
  - Wheeling to Non-PTO Load

Wheeling Out



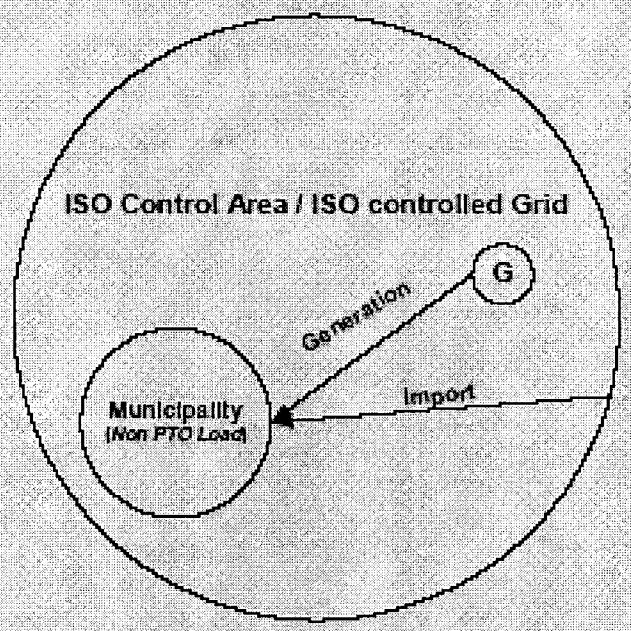
Wheeling Through



CALIFORNIA ISO

California Independent
System Operator

Wheeling to Non-PTO Load



Non-PTO Load

High Voltage vs. Low Voltage

High Voltage Wheeling Access Charges (HVAC)

- 200 kV and above
- ISO Grid wide rate (transition over 10 years- began Jan '01)
- Revenues spread to all TAC Areas/PTOs

Low Voltage Wheeling Access Charge (LVAC)

- Below 200 kV
- Utility specific rate
- Revenues flow back to specific utility

Example Charges

(for explanatory proposes only)

- Example base charge
  - Palo Verde to PG&E load - $0/MWh
  - Palo Verde to COB - $2.40/MWh
  - Devers to COB - $2.40/MWh
- Additional charges:
  - Losses – ISO delivers full schedule and bills for cost of making up losses
  - Core reliability requirement – Varies based on coincident demand of SC
  - Transaction charge - $1.49 per schedule
  - Congestion – Only if path is congested

Losses

- Meter Multipliers
  - Apply to generators and tie lines
  - Varies by location
  - Varies each hour
  - Posted on Oasis
- Generator Meter Multiplier Examples
  - South Bay – 0.9696
  - Big Creek – 1.0085
- Example Tie Meter Multiplier
  - Palo Verde - 0.95670
  - Malin – 0.98720

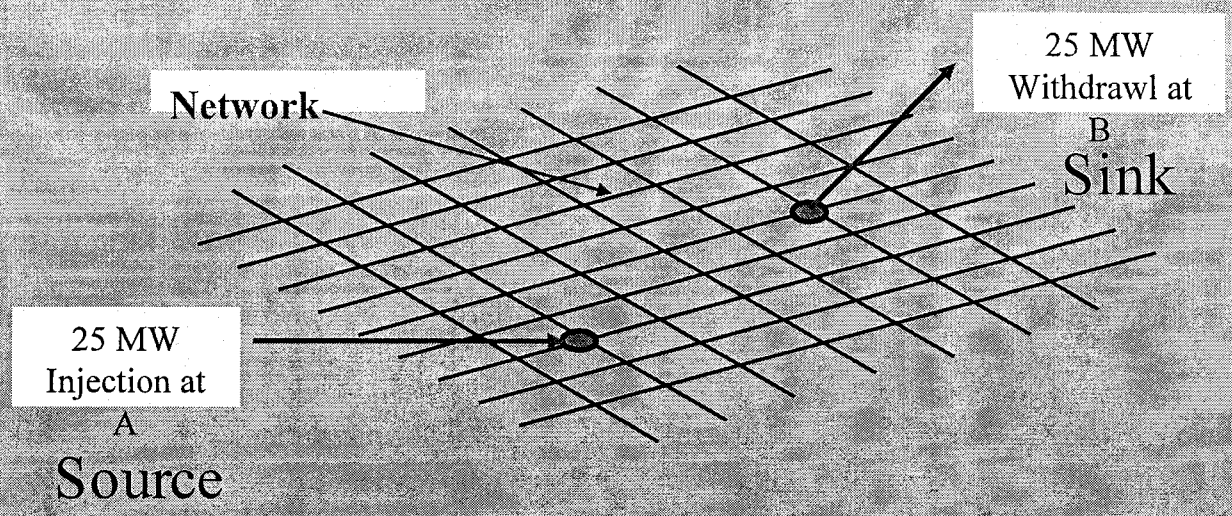
Congestion Charges

- ISO systems determine the cost of congestion for each hour
- Congestion costs may be hedged through the purchase of FTRs
- In the future, FTRs will transition to CRRs (with the implementation of nodal pricing)

Congestion Revenue Rights

- Point to Point Right (Source to Sink)
- CRR Holder is Obligated to Receive (or Pay) the difference in LMP Between Sink and Source
  - (LMP at Node A-LMP at Node B)xMW

Example



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Protocol Among the Members of the Western Governors Association, The U.S. Department of the Interior, The U.S. Department of Agriculture, The U.S. Department of Energy, and The Council on Environmental Quality Governing the Siting and Permitting of Interstate Electric Transmission Lines in the Western United States

A. BACKGROUND

1. Open transmission access has accelerated the regionalization of electric power markets in the West. Existing electric transmission systems that were generally designed to move power within local utility systems, bring power from generation sites to regulated utility customers, and interconnect neighboring utilities to improve reliability with some coordination transactions are now increasingly being used to enable power sales across large geographic areas.

2. The transmission system in the continental United States is organized into three separate electric interconnections. The Western Interconnection, which covers all or parts of 14 Western states, two Canadian provinces and northwest Mexico, has a different transmission topology than the other interconnections because of highly variable seasonal demand within the interconnection and the long distances between where the power is generated and where it is consumed. In the West, power sales have taken place across large geographic areas and between regions for decades.

3. Generally, authority to site transmission lines and grant the power of eminent domain for the construction of new transmission facilities has been exercised by the states.

4. Although Western states have a sterling record in permitting interstate transmission lines, expanding regional wholesale electricity markets and the preponderance of federally-administered lands in the West necessitate closer cooperation among states, local governments, federal agencies and tribal governments to ensure an efficient permitting and siting of new interstate transmission facilities.

5. This Protocol is a step in implementing the *Memorandum of Understanding Among the U.S. Department of Energy, U.S. Department of the Interior, U.S. Department of Agriculture, U.S. Environmental Protection Agency, Council on Environmental Quality, and the Members of the Western Governors' Association Regarding Energy Development and Conservation in the Western United States*, signed in 2001.

B. POLICY POSITION

1. The purpose of this Protocol is to establish a framework that will enable affected states, local governments, federal agencies and tribal governments to participate in a systematic, coordinated, joint review process for siting and permitting of interstate transmission lines in the Western Interconnection.

2. The Protocol is intended to increase the efficiency of the siting process by including all affected governmental entities with authority for siting and permitting interstate transmission facilities. It is the intent of Western Governors to work with the appropriate local governments, federal land management agencies, and tribal governments and solicit their participation on Project Teams established under this Protocol.

3. The Western Governors believe that a coordinated joint review process involving states, local governments, federal agencies, and tribes can expedite the siting and construction of needed transmission facilities to better ensure adequate, affordable and reliable electricity supply to Western consumers.

4. When linked with a pro-active regional transmission planning and implementation process that considers transmission and non-transmission alternatives and appropriate systems for financing new transmission and alternatives, a coordinated, interstate joint review of proposed interstate transmission facilities will enable identification and consideration of interstate needs, facilitate the construction of needed transmission, and ensure that the public interest is protected.

C. OBJECTIVES IN DEVELOPING A COORDINATED JOINT REVIEW PROCESS

1. Create an efficient environmental review process that results in documents that can be shared and used by all entities with jurisdiction in the siting and permitting process.

2. Establish and periodically review joint time lines for the conduct and timely completion of review and regulatory decision-making.

3. Establish a common understanding of the informational needs, regulatory requirements, and public interest issues prior to the environmental review proceeding.

4. Eliminate duplication of agency pre-application, scoping, and permit review meetings among affected state, local, federal and tribal authorities.

5. Create a transparent streamlined review process that is structured, user friendly and predictable.

6. Facilitate early notification and sharing of information among affected states, local governments, federal agencies, tribal governments and the project sponsors.

7. Preserve and protect authority of each affected state, local government, tribal government, and federal agency.

D. IMPLEMENTATION

1. To implement this process, the parties to this agreement will adopt the following elements as part of the coordinated joint review of specific proposed interstate transmission projects:

   a. Designation of a Project Team – The governors of states affected by a proposed transmission line shall convene a team of appropriate representatives from each state to coordinate the review of a proposed project and to ensure the timely notification, consultation, and joint sharing of information and solicitation of recommendations among states, local jurisdictions, and other affected parties. Representatives of federal agencies (and federal agency teams) and tribal governments with permitting or land management responsibilities shall be invited to join the Project Team. Participation on the Project Team shall in no way diminish the responsibilities or authority of any member.

   b. Determination of Need – The Project Team shall evaluate assessments of the need for the project developed through regional transmission planning processes and other processes and shall provide the assessments and their evaluation, as necessary, to any agency. The Project Team's evaluation shall in no way bind determinations and decisions made by the appropriate state, federal, tribal, and local authorities.

   c. Federal Agencies' Responsibilities – The appropriate federal land management agency(ies) will participate on the Project Team, as necessary, to expedite the siting review process and improve efficiencies of the application process consistent with Executive Order 13212. The Fish and Wildlife Service will commit to consult and cooperate by participating early and, as appropriate and as resources are available, throughout the review process to assist the Project Team members in meeting their Endangered Species Act and Migratory Bird Treaty Act compliance requirements. The Bureau of Land Management, Forest Service and Fish and Wildlife Service will follow the process described in the August 30, 2000, *Memorandum of Agreement – Endangered Species Act Section 7 Programmatic Consultations and Coordination among the Bureau of Land Management, Forest Service, National Marine Fisheries Service and Fish and Wildlife Service.*

d. Decisions, Activities, and Records – The Project Team shall establish procedures to encourage joint activities, records, and decisions regarding planning, evaluating, and monitoring of a proposed transmission line or facility. The specific activities which the Project Teams and other interested parties agree to perform jointly, the manner of execution, including level of detail, methodology, management and staff interaction, dollar value, and such other items as the parties deem necessary and appropriate shall be negotiated and clearly set forth in work plans and/or subsequent agreements covering individual energy projects. Any decision issued by a state, federal or local authority which is appealed or protested is not binding on the decisions that may be issued by other agencies who are members of the Project Team.

e. Consolidated Environmental Review – The activities which the parties hereby agree to undertake jointly may include, but are not limited to: preparation of environmental assessments and environmental impact statements, as appropriate; the evaluation of baseline conditions of the natural, social, and economic environment; evaluation of potential impacts of a project and alternatives; public involvement efforts; monitoring impacts of project construction and operation; and all other activities that are required to determine compliance with federal, state, local, and tribal laws and regulations. The Project Team shall jointly develop procedures for a consolidated environmental review of a proposed project.

f. Timelines –The Project Team shall establish and periodically review common, mutually agreeable deadlines for activities, reviews, and decisions. The Project Team will identify where joint decisions are to be made, and by whom. Timelines will include and account for the time that may be needed to address and dispose of disputes or administrative appeals of decisions made by all jurisdictional authorities, should such disputes or appeals of decisions be filed.

g. Information Requests – The Project Team shall serve as a clearinghouse for agency requests for information from developers of the proposed project and provide information to the developer about necessary permits, licenses, approvals, processes, and information requirements.

h. The Project Team shall provide that all non-proprietary or non-privileged information on the project and the work of the Team is available to the public, to the extent allowed by law. Among other methods, the Project Team will develop and maintain an internet-based information system that links to the permitting processes and activities of state, federal, tribal, and local agencies. Such transparent information will help to develop a common understanding of the project among permitting agencies and with the public.

i. Project-specific agreements will be developed and may be modified or amended by written mutual agreement among the parties, and terminated by mutual agreement or after 30 days' written notice by any party.

j. Each Project Team shall establish procedures that can be used to address disagreements on subjects, including, but limited to, scheduling, data requirements, data adequacy and jurisdictional issues raised by the participating entities.

2. Western governors will work with grid organizations in the West, including the Western Electricity Coordinating Council, the Mid-Continent Area Power Pool, the Western Utility Group and any Regional Transmission Organizations that form in the West, and others to facilitate the exchange of information needed by appropriate federal, state, tribal, and local agencies for planning, siting, and reviewing permit applications.

3. The Federal Power Marketing Administrations (PMA) support efforts to streamline and expedite the transmission facility siting process. Each PMA shall review their siting process for federal interstate transmission lines in order to ensure the provision of timely notification and joint sharing of information, and to explore the possibility of consolidating required reviews.

4. Nothing in this Protocol shall be construed to limit, repeal, or in any manner modify the existing legal rights, privileges, and duties of the signatories to this protocol as provided by agreement, statute or any other law or applicable court decision. Nothing in this Protocol shall commit federal agencies to enter into any contract or other binding obligation.

5. Nothing in this Protocol may be construed to obligate the United States to any current or future expenditure of resources in advance of the availability of appropriations from Congress.

E. AUTHORITIES

The National Environmental Policy Act of 1969, 42 U.S.C. 4321, 4331(b) provides the authority for the Federal Government's participation in this Protocol. Additional authority is provided to the Bureau of Land Management under the Federal Land Policy and Management Act, 43 U.S.C. 1701, 1737 (b), to the Fish and Wildlife Service under the Fish and Wildlife Coordination Act, 16 U.S.C. 661, and to the Bureau of Indian Affairs under the Synder Act, 35 U.S.C. 2, 13, and 25 U.S.C. 324.

F. ADMINISTRATIVE PROVISIONS

1. The Governors intend that all states in the Western Interconnection sign the Protocol and will seek to secure the same from the appropriate federal agencies, tribal governments and Canadian provinces.

2. Each signatory to this Protocol will provide the Western Governors' Association with the name of a point of contact within the appropriate governmental agency for the implementation of this Protocol, including the necessary notifications herein.

3. Governors will give copies of this Protocol to state agencies with responsibilities for the review of transmission proposals.

4. Any party to the Protocol can unilaterally withdraw its participation in the agreement.

6. The Protocol can be amended or modified if all parties agree.

7. Upon signature, the protocol immediately will be effective and the Governors intend that executive orders or other administrative action to implement this Protocol be completed within 120 days of the signing.

8. The Western Governors' Association, through its affiliate, the Western Interstate Energy Board, will provide a report on the implementation of this Protocol at each annual meeting of the Association, and may provide interim reports as warranted.

9. The signatories will review the Protocol and its implementation on an annual basis.

Jane Dee Hull — 6/23/02
Chair of the Western Governors' Association — Date

Judy Martz — _____
Vice Chair of the Western Governors' Association — Date

Jim Geringer — 6/23/02
WGA Lead Governor for Energy — Date

Jim Geringer — 6/23/02
WGA Lead Governor for Energy — Date

_____ for — 6/23/02
Secretary of Energy — Date

Secretary of Agriculture	Date 7/22/02
Secretary of the Interior	Date 6/23/02
Chairman, Council on Environmental Quality	Date 6/20/02
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COMMISSIONERS
JEFF HATCH-MILLER - Chairman
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

BRIAN C. McNEIL
Executive Director

ARIZONA CORPORATION COMMISSION

November 28, 2005

Julia Souder
U.S. Department of Energy
Office of Electricity Delivery and Energy Reliability
1000 Independence Avenue, SW.
Washington, DC 20585

Re: Notice of Intent to Prepare a Programmatic Environmental Impact Statement, Amended Relevant Agency Land Use Plans, Conduct Public Scoping Meetings, and Notice of Floodplain and Wetlands Involvement. **Federal Register Doc. 05-19375**

Ms. Souder:

Utilities Division staff members (Staff) of the Arizona Corporation Commission were unable to attend the November 3, 2005 scoping meeting in Phoenix, Arizona. Therefore, I am taking this opportunity to formally submit Staff's written comments. We applaud federal agencies efforts to prepare programmatic environmental impact statements ("PEIS") for the designation of energy corridors on federal lands in the 11 western states.

It is assumed the objective of the PEIS effort is to facilitate more timely and expedient siting of energy facilities over federal rights of way. However, there are several factors that may limit the successful achievement of that objective. The following areas of concern appear to not be adequately addressed by the proposed PEIS process. Staff believes these concerns must be addressed in the larger context of establishing corridors suitable for energy facilities that will be sited in Arizona.

1. Pre-determining corridors over federal lands with National Environmental Policy Act (NEPA) environmental reviews should be very helpful in shortening the siting process prevalent today for energy facilities. However, does the proposed process implicitly preclude future consideration of alternative corridors over federal lands once the PEIS has resulted in a set of designated utility corridors in the West? If so, then the process may be flawed for the reasons outlined below.

2. The PEIS process is progressing concurrent with the EPAct 2005 required DOE Transmission Congestion Study to identify congested transmission paths that may warrant designation as National Interest Transmission Corridors. While the use of the term "corridor" may differ in these two concurrent federal processes, there remains a strong possibility that the Congestion Study may identify the need for transmission facilities not yet envisioned by the electric industry. Such facilities would therefore not be among the energy facilities identified for the PEIS process. Future transmission lines needed to mitigate the National

Interest Transmission Corridor concerns may also not align with the corridors being contemplated by the PEIS efforts.

3. Determining how many corridors are actually needed and establishing appropriate compatible corridor uses requires consideration of more than just environmental issues. Arizona revised statute A.R.S. §40-360.06 lists the spectrum of factors that must be considered in siting electric facilities in Arizona. Several of these factors are not environmental in nature. Furthermore, A.R.S. §40-360.07.B requires the Arizona Corporation Commission to "balance, in the broad public interest, the need for an adequate, economical and reliable supply of electric power with the desire to minimize the effect thereof on the environment and ecology of this state." Such a balancing test should be equally appropriate for siting energy corridors over federal lands.

4. Reliability and physical security of multiple energy facilities in common corridors is a location specific and case by case matter. It is in the broader public's interest to consider the following non-environmental factors before proposing to place multiple facilities in a common corridor:

    a. Functionality of the proposed co-located energy facilities,
    b. Critical infrastructure implications,
    c. Interdependence of multi-disciplined energy facilities,
    d. Timely access to co-located facilities for maintenance and repairs

5. Considerations listed in items 2 through 4 may establish a need for separate or additional corridors rather than co-locating all future energy faciltiites in a common or specified PEIS corridor. If so, then an effective federal process for modifying and supplementing the designated corridors resulting from the proposed PEIS process is needed.

It is our hope that the above comments will be helpful to federal agencies as you proceed with the PEIS assessment for energy corridors over federal lands in the West. Don't hesitate to contact us if we can be of further assistance in this matter.

Sincerely,

Ernest G. Johnson
Director
Utilities Division

EGJ:jds

cc: Arizona Power Plant and Transmission Line Siting Committee
Steve Olea, Assistant Director, Utilities Division
Chris Kempley, Chief Legal Council

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PROPOSED DEVERS - PALO VERDE NO. 2 TRANSMISSION LINE PROJECT
U.S. BUREAU OF LAND MANAGEMENT
JANUARY 18, 2006 PUBLIC SCOPING MEETING

ARIZONA CORPORATION COMMISSION UTILITIES DIVISION STAFF COMMENTS
Submitted March 10, 2006

On December 27, 2005, the Arizona Corporation Commission ("ACC" or "Commission") received notice of public scoping meetings scheduled for January 18 and 19, 2006. The notice indicated the scoping meetings were for the purpose of obtaining input from agencies and the public on the scope and content of the Environmental Impact Report ("EIR") / Environmental Impact Statement ("EIS") being prepared for the proposed Devers – Palo Verde No. 2 Transmission Line Project ("DPV2").

ACC Utilities Division Staff ("Staff") Member, Jerry D. Smith, was in attendance on January 18. He is assigned as the principle ACC witness for the project when Southern California Edison ("SCE") files an application with the ACC for a Certificate of Environmental Compatibility ("CEC"). The following comments and questions are submitted on his behalf. Mr. Smith has limited his remarks to the section of the transmission line project between the Palo Verde Nuclear Generating Station ("Palo Verde") and Devers 500 kV Substation.

Comments Regarding NEPA Process

Staff offers the following comments regarding the National Environmental Policy Act ("NEPA") scoping efforts for the DPV2 project. The preparation of the EIR/EIS for the DPV2 project is occurring concurrently with federal agency efforts to prepare a Programmatic Environmental Impact Statement ("PEIS") for energy corridors over federal lands in the 11 western states in compliance with Section 368 of EPAct 2005. Staff submitted scoping comments on the PEIS which can be found on the U.S. Department of Energy website.[1] Staff concerns raised in the PEIS regarding the need for a broader consideration when contemplating placing multiple energy facilities in a common corridor applies equally to the DPV2 project's EIR/EIS process. For brevity, Staff's PEIS comments are not repeated here but are incorporated by reference. Nevertheless, our request is that such common corridor concerns receive comparable and consistent treatment in both federal environmental processes impacting existing or proposed energy corridors in Arizona.

Material available to those attending the January 18 and 19, 2006 DPV2 scoping meeting in Arizona was limited to notices of the public scoping meetings in California and Arizona, an assortment of project fact sheets, and a copy of the overhead presentation material. There was no one present at the Arizona scoping meeting to respond to questions raised by those in attendance regarding the need for the proposed project. At least in California there were regulatory hearings affording the public some awareness of the need for the facility before a public EIR/EIS scoping meeting took place.

[1] http://corridoreis.anl.gov/scopingcomments/docs/EnergyCorridorProgrammaticEISComment0011.pdf

It is evident that the NEPA environmental review for the DPV2 project has been designed to take full advantage of the California Environmental Quality Act ("CEQA") process. This is most evident in that SCE's Proponent's Environmental Assessment ("PEA") filed with the California Public Utilities Commission ("CPUC") is the sole source of environmental assessment information available at present. Similarly, the deadline for public comments regarding scoping documents was set as January 20, 2006. This was well after the November 1, 2 and 3, 2005 scoping meetings in California. However, it was the day immediately following conclusion of the Arizona scoping meetings. This lead several individuals in attendance on January 18, 2006, to offer "due process" concerns regarding proper notice and lead time for submittal of public comment. Staff finds merit with those public comments.

Staff is similarly concerned with the level of sufficiency of the PEA as it relates to matters in Arizona and NEPA obligations of federal agencies in the preparation of an EIR/EIS. The regional need for SCE's proposed action to construct a second Palo Verde to Devers transmission line is not adequately developed in the PEA. Establishing the regional need will hopefully answer some of the questions posed by attendees of the January 18 scoping meeting.

The purpose of an EIS is to inform the public of the reasonable alternatives which would avoid or minimize impacts or enhance the quality of the human environment.[2] While the PEA does address alternative routes for the DPV2 project it does not sufficiently address the null alternative, other transmission alternatives, or non-wire alternatives. Since the proposed DPV2 project predominantly traverses federal lands in Arizona, the ACC will rely upon the federal agencies preparing the EIR/EIS to ensure that SCE provides sufficient and proper evidence of regional need, technical alternatives to the proposed action, and the cumulative effects on the human environment of the proposed action.

Staff is aware of four proposed transmission projects that could be viewed as an alternative to the DPV2 project in meeting SCE's stated objective of DPV2 increasing California's access to low-cost energy from the Southwest.[3] These alternative transmission projects are viable with differing technical impacts, vary in lead time necessary to implement, and imply alternative environmental impacts. In addition to being a near term alternative to the DPV2 project they may also serve as supplemental or complimentary transmission improvements necessary for the long term delivery of energy within the region. Therefore the cumulative impact of the following alternatives warrants consideration.[4]

1. Upgrade of the existing WECC rated transmission path 49 (East of River or "EOR") between Arizona and Southern California. The project name is EOR 9000+.
2. A Dine Navajo Transmission Project between Four Corners in New Mexico and Marketplace in Nevada with an Arizona interconnection at Moenkopi. This 500 kV transmission line is already permitted by the ACC.
3. Upgrade of the SCE Moenkopi to Eldorado transmission line.
4. A second Palo Verde Hub to North Gila 500 kV transmission line contained in the Arizona Public Service Company ten year transmission plan filed with the ACC.

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[2] 40 CFR Section 1502.1
[3] SCE, Proponent's Environmental Assessment, pg 2-1.
[4] 40 CFR Section 1508.7

Non-wires alternatives such as new generation in California offer a comparable means of meeting consumer energy needs in Southern California. Similarly, re-powering the SCE Mohave Power Plant with the proper environmental upgrades is another attainable non-wires alternative. It should be noted that the operational status of the Mohave Power Plant shapes the technical performance and effectiveness of the various transmission alternatives noted previously. It is recommended that the cumulative environmental impact of these non-wire alternatives should be compared to the proposed action that would build a new transmission line and increase gas-fired energy production in Arizona to meet California consumer needs.

More importantly, the cumulative impacts of SCE's proposed action should also include the environmental impacts associated with any additional energy infrastructure needed to enable the wholesale transactions envisioned with the DPV2 project. The existing capacity of the natural gas pipeline serving Arizona power plants is not adequate to support the DPV2 project assumed increased energy production from those same plants. Access to such "low-cost" gas-fired energy has been described as the economic foundation justifying the DPV2 transmission project. New natural gas pipeline capacity will therefore need to be sited and constructed to enable the increased Arizona gas-fired energy to be delivered to California or any other market. Without such new natural gas pipeline capacity the economic justification of the DPV2 project is flawed.

Reliability Considerations

SCE indicates one of the four objectives of building the proposed transmission project is to "provide increased reliability of supply, insurance value against extreme events, and flexibility in operating California's transmission grid.[5]" This reliability objective is fundamentally sound given that EPAct 2005 has placed mandatory national reliability compliance authority with the Federal Energy Regulatory Commission ("FERC"). Section 1221 of EPAct 2005 also calls for identification of National Interest Electric Transmission Corridors based upon criteria still under development that may incorporate similar reliability objectives. Nevertheless, SCE's reliability objective seems to be compromised to some degree by three technical design features reported in their PEA.

Map 1-1[6] indicates the proposed new DPV2 transmission line physically crosses the existing Palo Verde – Devers line in the vicinity of Quartzsite, Arizona. Similarly, Map 3-3 indicates a possible crossover would occur due east of the Harquahala Generating Station. Then Figure 3-3 depicts a double circuit structure, 241 feet in height, accommodating two 500 kV circuits on the same structure.

Line crossings and multiple circuits on common structures merit special scrutiny for reliability purposes. Therefore, please ascertain whether either Devers – Palo Verde 500 kV line will physically cross the other. If the lines do actually cross, please determine if such crossings are technically required or could the physical line crossings be avoided? Please clarify whether these crossings are simply jogs in the new right of way resulting from swapping to the opposing side of the existing right of way.

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[5] Proponent's Environmental Assessment, pg 2-1.
[6] *Id.*, pg 1-3.

Is the height of the double circuit structure of Figure 3-3 solely a result of it being designed for attaching two lines? All other 500 kV structures proposed in the PEA are no more than 150 feet in height. Are there geographical or terrain impediments to constructing a second line in a right of way contiguous with the existing line where the double circuit structures of Figure 3-3 are located? Can the double circuit 500 kV structures be replaced by single circuit structures as proposed throughout the remainder of the Devers – Palo Verde No. 2 500 kV line project?

System Protection System

Sec 2.4.4 of SCE's PEA indicates a System Protection System ("SPS") will be required to mitigate post-transient voltage violations to the Western Electricity Coordinating Council ("WECC") system planning criteria. The SPS would interrupt 900 MW of generation in the Palo Verde area and 900 MW of SCE load. Staff is concerned with the service reliability implications for Arizona consumers if the SPS is implemented. In fact, the ACC has adopted a policy position in prior power plant and transmission line siting cases and via its Biennial Transmission Assessment ("BTA") process that an SPS should not be considered an acceptable technical option when proposing new electric infrastructure in Arizona.

Staff understands the proposed SPS is required for a simultaneous outage of both the existing line and the proposed line between Palo Verde and Devers. Such an outage must be considered by WECC criteria as a credible outage because both lines are on common structures for a three mile section through Copper Bottom Pass as depicted in Figure 3-3. Since SCE originally constructed this three mile section on double circuit structures they claim there is "no need to build additional structures or acquire additional right-of-way."[7]

Please determine if there are any environmental conditions currently prevailing that would preclude construction of a second line on separate structures through Copper Bottom Pass. Are there any means of mitigating environmental concerns that would otherwise prohibit such construction? Are there environmentally acceptable alternative routes to the three mile long right of way through Copper Bottom Pass?

Subalternate Routes

SCE indicates that the Harquahala – West subalternative may become its preferred route if the Palo Verde Hub to TS-5 line is constructed in a manner that would preclude SCE from entering Harquahala Switchyard from the east.[8] The Palo Verde Hub to TS-5 transmission line project has already received a CEC from the Commission.[9] Arizona Public Service Company ("APS") reported in a December 30, 2005 compliance filing with the ACC that a term sheet had been provided to SCE and Harquahala Power Plant regarding a possible interconnection at a new Harquahala Junction 500 kV Switchyard. Negotiations among the three parties are continuing. However, a conclusion that such an interconnection is eminent would be premature at this time. Therefore, it is appropriate that the Harquahala – West Subalternate route be retained as an

[7] *Id.*, pg 3-12.
[8] *Id.*, pg 3-14.
[9] ACC Decision No. 68063, Docket No. L-00000D-05-0128, August 17, 2005.

option to assure SCE physical access to the Harquahala Power Plant via a Devers – Palo Verde No. 2 transmission line.

SCE indicates in its PEA that it views the Palo Verde Switchyard as an alternative to its termination at the Harquahala Power Plant Switchyard.[10] The Palo Verde Subalternate route is depicted on Map 3-3. This subalternative is also impacted by SCE, Harquahala Power Plant and APS negotiations referenced in our comments regarding the Harquahala – West Subalternative. Furthermore, SCE indicates "there may be adequate capacity in the Harquahala – Hassayampa 500 kV line prior to 2015 to accommodate both the TS5 and DPV2 project requirements."[11] Adoption of this subalternative could lead to four 500 kV transmission lines between Palo Verde and Hassayampa Switchyards and the location envisioned as Harquahala Junction Switchyard. The Harquahala Junction Switchyard was depicted on the map displayed at the scoping meeting on January 18, 2006. However, Staff noted that there is no mention of the Harquahala Junction Switchyard in the PEA or depiction of it on Map 3-3. Nevertheless, the Palo Verde Subalternative route should be retained as an option until such time that the termination and interconnected grid needs and uses of the Harquahala – Hassayampa 500 kV line, the Palo Verde Hub – TS5 500 kV line and the Devers – Palo Verde No. 2 500 kV line are resolved.

Summary of Comments

The scope of the EIR/EIS process should be expanded to address inadequacies of the PEA. A more fully developed record is needed regarding: 1) the null alternative; 2) the regional justification of the project; 3) consideration of technical alternatives to the proposed action; and 4) the cumulative effects of all associated new energy infrastructure. Staff seeks clarification regarding several design features viewed as potentially adversely impacting the reliable service objectives of the Devers – Palo Verde No. 2 project. Staff also questions the necessity for SCE to perpetuate use of 3 miles of 500 kV double circuit structures that would lead to implementing a SPS that could compromise reliable electric service in Arizona and California. Finally, Staff supports inclusion and continued consideration of the Harquahala – West Subalternative and the Palo Verde Subalternative routes until such time that the long term transmission grid needs interconnected at Palo Verde are resolved.

Submitted by,

Jerry D. Smith
Electric Utility Engineer
Arizona Corporation Commission
1200 W. Washington
Phoenix, Arizona 85007
(602) 542-7271

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[10] *Id.*, page 3-14.
[11] *Id.*, page 2-22.

10

Jerry Smith

From: Jerry Smith [jsmith@cc.state.az.us]
Sent: Wednesday, December 08, 2004 1:33 PM
To: Robert.Smith@aps.com; Aperez@caiso.com; JMiller@caiso.com; KBagley@rwbeck.com; Dana.Cabbell@sce.com; Patricia.Arons@sce.com; Ronald.Nunnally@sce.com; Steven.Mavis@sce.com; KPatel@semprautilities.com; BKKeel@srpnet.com; JCHsu@srpnet.com; REKondzi@srpnet.com
Cc: Laurie.Woodall@ag.state.az.us; Del Smith; Jerry Smith; Prem Bahl; Steven Olea; Jason Gellman
Subject: AZ/CA Transmission Projects

Follow Up Flag: Follow up
Flag Status: Red

Attachments: AZ-CAStudyComments.doc; XmnBtlNk.ppt

AZ-CAStudyComments.doc (44 KB)... XmnBtlNk.ppt (457 KB)

This note is to provide ACC Staff comments regarding the on-going study efforts in the STEP, SWAT, and WATS study forums and the WECC Rating Process for the:

1. Path 49 Upgrades (Sempra)
2. Palo Verde to Devers 2 500 kV line (SCE)
3. EOR +9000 EHV Upgrades (SRP)

Workload and travel budget constraints have limited recent ACC Staff participation in the above study and peer review forums. I would speak to each of you personally regarding my concerns but find time is also limited. Therefore I am using this note to offer my personnel observations to each of you as key individuals providing leadership in the subject study forums.

Studies of the above projects are being performed in collaborative forums intended to afford industry participation and peer review. These forums can become self serving if project sponsors fail to adequately address stakeholder needs or industry participants concerns. There were comments at the ACC's September 24, 2004 Biennial Transmission Assessment (BTA) Workshop that indicate less than a consensus is being achieved in some study forums for this reason. I recommend reading of pages 128 - 132 and 142 - 149 of the 9/24/04 BTA Workshop transcript for insights regarding this concern. The transcript is available from Arizona Reporting Services, Inc at www.az-reporting.com under ACC Docket No. E-00000D-03-0047.

There is an enormous volume of study results beginning to accumulate for the subject transmission system improvements. Plans for additional study work in the various study forums is moving forward. This record will prove to be invaluable when seeking regulatory approval or sighting approval of the projects. However, the ACC Staff is concerned that there are some issues that are not yet being addressed or studied. I have organized my thoughts in the attached document under three major headings:

1. Path Ratings and Nomograms
2. Siting of Competing or Complimentary Projects
3. Concerns Unique to Palo Verde Hub

I welcome any and all feedback to the attached document. You can contact me by phone or e-mail. I have limited my distribution of the document to afford each of you the opportunity to seek clarification of my concerns or correct any misunderstandings I may have of where the various study processes are headed. More importantly, I am trying to give you an indication of what the ACC Staff will be considering as projects seek regulatory support or approval from the Arizona Corporation Commission. Use and distribute the contents of

this note as you feel appropriate.

Proposed Arizona / California Transmission Projects
ACC Staff Comments
December 8, 2004

The following comments are offered by the Arizona Corporation Commission ("ACC") Engineering Staff ("Staff"). Our comments are not intended to reflect the opinion or views of our Commissioners or official policy of our Commission. Our comments are offered in the spirit of advising the industry of issues and concerns that Staff will be considering as proposed transmission projects seek regulatory approval or line siting support and approval before the ACC. The electric industry is encouraged to address these issues and concerns within the various transmission study efforts in progress or being proposed in the Southwest Transmission Expansion Plan ("STEP"), Southwest Area Transmission ("SWAT"), and Western Area Transmission System ("WATS") transmission planning study forums and the Western Electricity Coordinating Council ("WECC") Rating Process. Consistent treatment of these issues among the various study forums is also encouraged.

ACC Staff's comments address transmission studies for three proposed Arizona ("AZ") / California ("CA") transmission projects:

1) Sempra's Path 49 (East of River) upgrades,
2) Southern California Edison's ("SCE") second Palo Verde to Devers 500 kV line and
3) Salt River Project's ("SRP") EOR +9000 Upgrade of East of River ("EOR") facilities.

Staff's comments are also applicable to other future projects that may be proposed between Arizona and California. Staff's comments are not intended to infer or preclude support or endorsement of any individual transmission project or combination of projects. Each project will be considered by Staff on its own merits.

Path Ratings and Nomograms

ACC Staff supports the STEP study efforts to refine and redefine path nomograms of the transmission interfaces between southern California and neighboring electric systems. Recent studies have shown that the actual relationship between various transmission paths, and lines within a path, do not necessarily correlate to prior planning and operating nomograms. New generation in Arizona, Nevada, and northern Mexico coupled with varying load patterns are redistributing actual flows on individual transmission lines such that individual line constraints are reached prior to the maximum path ratings being achieved. Similarly, studies have shown that the stability limits are being redefined by the machine inertia modeled as operational at new generation locations. Each phenomenon compromises the usefulness of existing nomograms for managing transmission congestion across the respective transmission paths.

Staff is hopeful that the STEP study work to refine existing path nomograms or develop a new series of path nomograms will conclude quickly. This will assure that transmission constraints are properly identified on a forward looking basis. In the meantime, the wholesale

market will continue to falsely presume that the system's ability to accommodate transmission transactions is reflected by the existing path ratings and associated nomograms.

Each of the three AZ/CA proposed transmission projects are striving to establish new path ratings for Path 49 (EOR) in the WECC rating process. It is my hope that these path rating study efforts will not conclude without resolution of the STEP effort to refine or redefine effective nomograms for the interface between Arizona and Southern California. That does not mean I see no value in establishing a new EOR path rating. However, it would seem fruitless to argue for a path rating (using old nomogram practices) that may turn out to be less than effective in managing transmission congestion over the various transmission paths.

I have attached a series of power point slides to conceptually reflect the generic concerns I am raising here. I have assumed N-1 thermal loading limitations for establishing the available transmission capacity ("ATC"). Example 1 demonstrates how local constraints can limit extra high voltage ("EHV") transmission delivery. Example 2 demonstrates that even though new generation interconnects with an EHV transmission path it may also be constrained by local transmission constraints thereby stranding portions of the new generation and leaving the local system to rely on local reliability-must-run ("RMR") generation for load growth beyond the local constraint capability. Example 3 demonstrates how building new local transmission can resolve the local import constraint, resolve the stranded generation and enable the full capability of the EHV system to be realized. Hopefully, the message is obvious: it is important to recognize the actual constraint in a delivery system and not just focus on path ratings of a segment of the system that is being upgraded.

Siting of Competing or Complimentary Projects

Staff is not concerned with ownership of new facilities or who has transmission rights (physical or financial) over various paths provided the transmission service is non-discriminatory and does not perpetuate or create pan-caked transmission rates for transmission customers. This is a fundamental reason for the position Staff is taking regarding new path ratings. Nevertheless, there seems to be a race between the three proposed Arizona / California transmission line projects to establish a new path rating for Path 49 (EOR) resulting from construction of each respective project. My previous PowerPoint example, described under the previous heading, suggests this may be immaterial in regard to actual ability to facilitate market transactions between generators and load centers. In other words, local system improvements to resolve transmission limitations that are more constraining than the Path 49 rating may free up additional capacity of the pre-existing system. I would suggested the Path 49 path rating resulting from the short term STEP improvements in Southern California should be determined without any of the three Arizona / California transmission Projects.

Secondly, the Palo Verde to Devers #2 and EOR $^{+}$9000 projects should be viewed as complimentary projects to Sempra's proposed EOR upgrades. Neither project could achieve its maximum path rating without the presumption of Sempra's project. Furthermore, Staff does not view the Palo Verde to Devers #2 and EOR $^{+}$9000 projects as competing projects. They are striving to maximize the Path 49 rating via deliveries between a common resource location and

different market (load center) locations. All of this seems to reinforce Staff's previous comments about the importance of redefining the performance characteristics of the various system elements with new path rating measures.

While Staff does not view the three proposed Arizona / California projects as competing projects, it is recognized that other parties may. This is evident given the nature of comments received in Staff's third Biennial Transmission Assessment ("BTA") process. Staff's Third Biennial Transmission Assessment Report is posted on the Commission's website at: http://www.cc.state.az.us/utility/electric/BTA-11-30-04.pdf

Each of the three proposed Arizona / California transmission projects will be consider on their own merit even if they were found to be competing projects rather than complimentary projects. Siting of multiple competing generation projects at the Palo Verde Hub without the benefit of accompanying transmission improvements serves as an example of how competing projects have been accommodated in Arizona's siting process. Staff will consider how each project technically improves the regional transmission system, to what degree a project mitigates system risks prevailing at the Palo Verde Hub and to what degree the project mitigates transmission congestion without creating new commercial barriers to energy transactions.

Concerns Unique to the Palo Verde Hub

Staff has documented in its Third Biennial Transmission Assessment[1] the evolution of its concerns regarding the Palo Verde Hub and associated transmission system. Staff has expressed concerns over the past few years regarding:

1) Transmission constraints limiting interconnected Hub generation to less than full output,
2) Mitigation of system risks associated with extreme Hub outage events, and
3) Creation of potential new commercial barriers as reliability concerns are mitigated.

Staff concludes in its report that "in general the existing and proposed Arizona transmission system meets the load serving requirements of the state in a reliable manner." The Palo Verde east transmission system capability has increased from 3810 MW to 6970 MW since the interconnection of merchant plants at the Palo Verde Hub commenced in 2002. The addition of the proposed Palo Verde to TS5 to Raceway 500 kV lines and the Palo Verde to Pinal West to Browning 500 kV lines between 2007 and 2011 will significantly increase the outlet capacity of the Palo Verde Hub to Arizona.

No transmission improvements have been made to the pre-existing 2800 MW Palo Verde west transmission system. Therefore, Staff also concludes in its third BTA that the existing transmission from Palo Verde to California is inadequate to allow new Palo Verde Hub generation full access to the California market under weak Arizona market conditions. It is Staff's expectation that the three proposed Arizona / California transmission projects will technically demonstrate to what degree they are a remedy for the wholesale market limitation between Arizona, California and Nevada.

[1] ACC, "Third Biennial Transmission Assessment 2004-2013," Section 4.3, pages 51- 59, November 30, 2004.

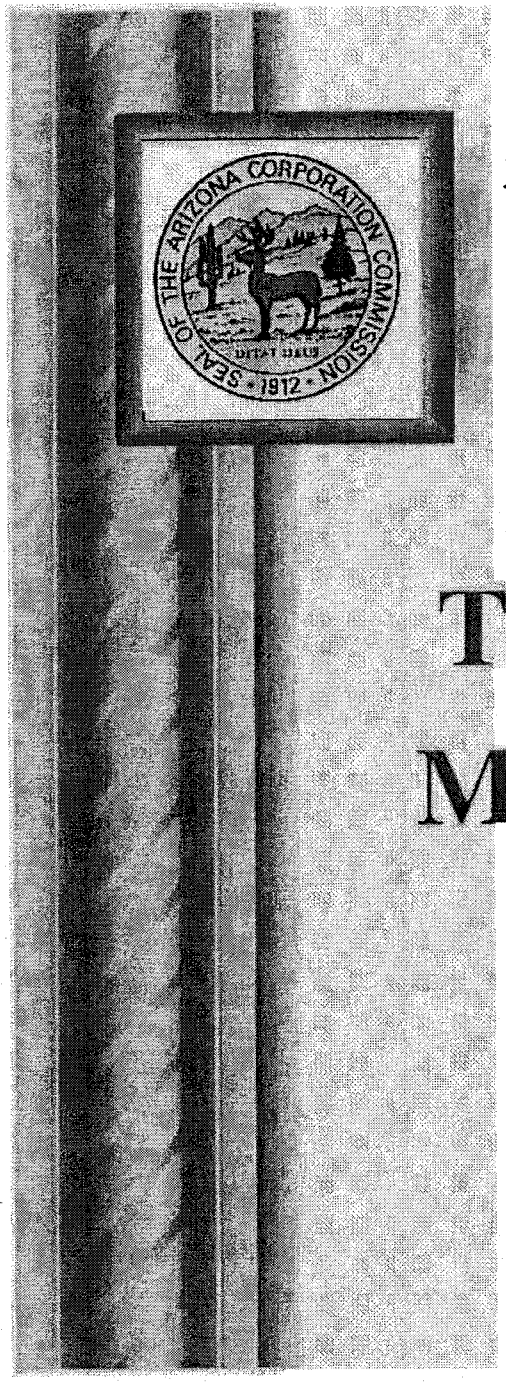
Over the past two years, Arizona has experienced several significant transmission events that have demonstrated that extreme outage events, while presenting an extremely low probability of occurrence, can and have occurred and did impact the Palo Verde Hub. This underscores Staff's prevailing concerns regarding system risks associated with extreme outage events. The West has dodged a couple of bullets, but may not be so lucky in the future.

As a result of these concerns Staff joined APS and SRP in sponsoring an extreme outage guide for large generation hubs for WECC consideration. While the WECC membership at large does not appear to feel such a guide is necessary, a special protection scheme ("SPS") was required of Palo Verde in 2004 to shed Arizona ~~load to~~ gen resolve impacts on the California Oregon Intertie for loss of multiple Palo Verde Hub elements with the Palo Verde units being upgraded by a few megawatts. Such a contradiction in policy consideration is not viewed by Staff as being in the public's best interest. In fact, Staff believes that use of a SPS for outage of multiple elements is inappropriate for transmission planning purposes in the presence of pre-existing risks associated with extreme outage events. Therefore, Staff is concerned with the Palo Verde to Devers 2 proposal to use a SPS to trip ~~load~~ generation in Arizona for loss of both Palo Verde to Devers lines on a common structure. This project will be required to demonstrate to Staff why it is in Arizona consumer's best interest to assume additional exposure to interruption of service in order to allow SCE to construct the second line on common structures with the existing Palo Verde to Devers 500 kV line.

It appears the Northeast Blackout that occurred in 2003 has also heightened concerns of the industry regarding extreme outage events and nuclear power plant facilities. As a result, a System Authorization Request ("SAR") has been submitted on October 20, 2004 to the North American Electric Reliability Council ("NERC") proposing a new standard regarding Grid Reliability of Nuclear Offsite Supply. The concern addressed by this proposed standard seems to parallel quite closely some of Staff's concerns at the Palo Verde Hub.

Therefore, Staff has recommended in its third BTA that the Commission "endorse a requirement that all future interconnections proposed at the Palo Verde Hub, either generation or transmission lines, must perform a risk assessment of the Hub to ascertain to what degree the proposed project mitigates pre-existing risks to extreme outage events. This assessment must precede a project's application for a Certificate of Environmental Capability with the Commission. The recommendations of the Palo Verde Risk Assessment report should be followed if a proposed project would otherwise exacerbate the existing risk at the Hub."

The Commission will be considering Staff's third BTA recommendations at its December 14, 2004 Open Meeting. Future projects will be expected to comply with the resulting Commission Order and Decision if the Commission approves Staff's third BTA recommendations.



Arizona
Corporation
Commission

Transmission Bottlenecks: Market Power In Disguise?

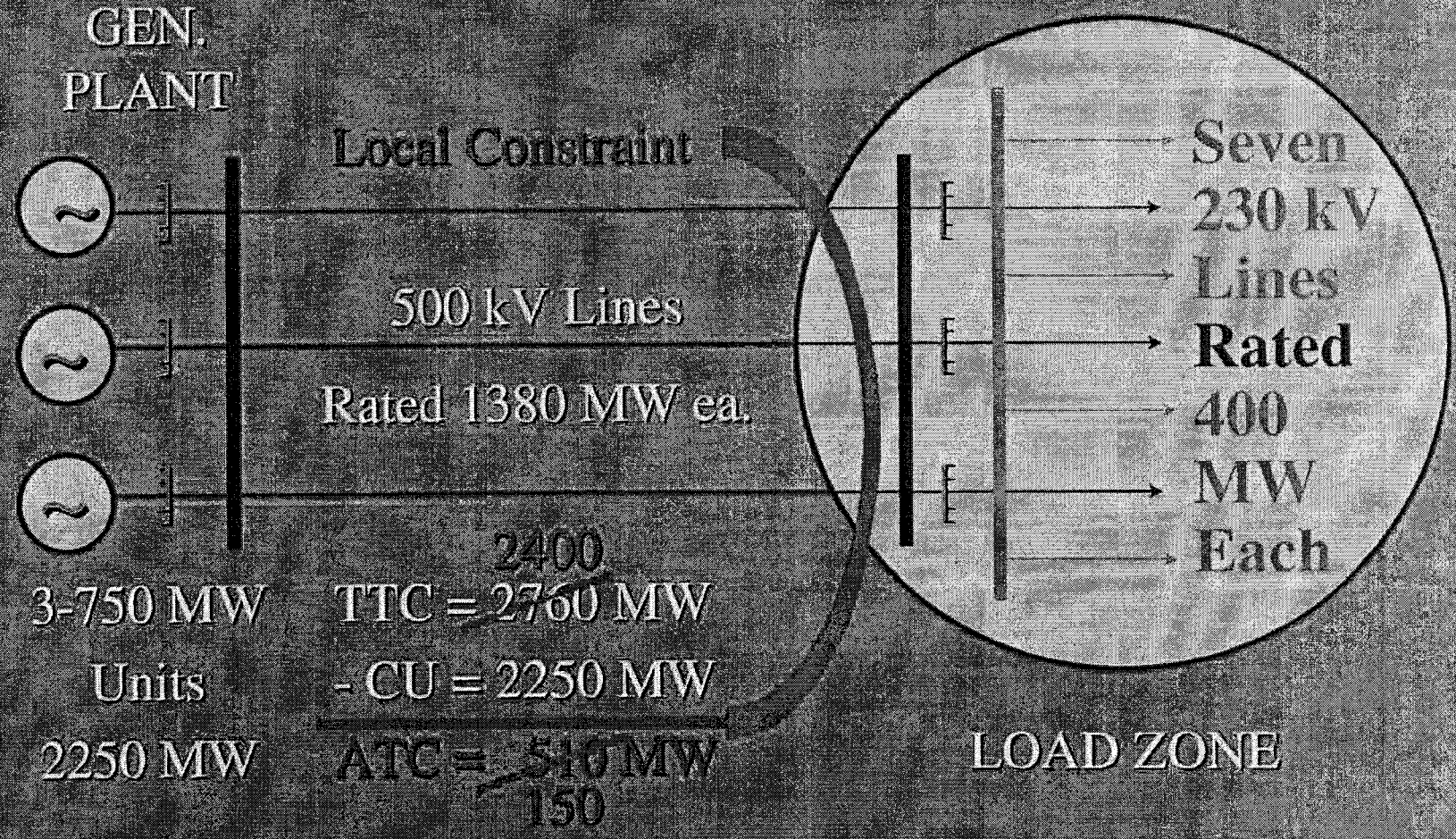
Jerry D. Smith
Utilities Division Engineer

November 8, 2004

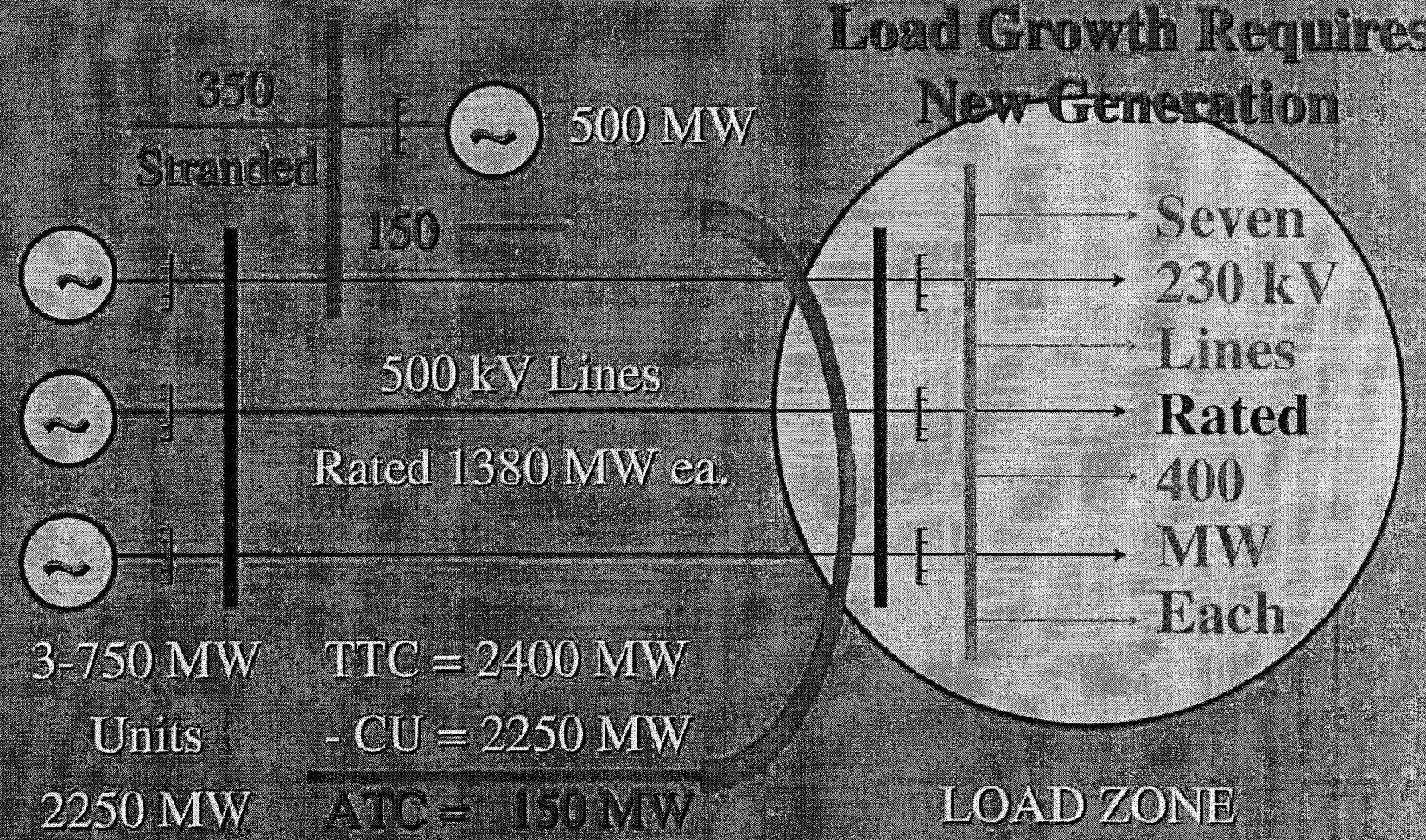
Disclaimer

Concepts and views presented herein are solely the author's and do not necessarily reflect the views or policy of the Arizona Corporation Commission, its Directors or Staff.

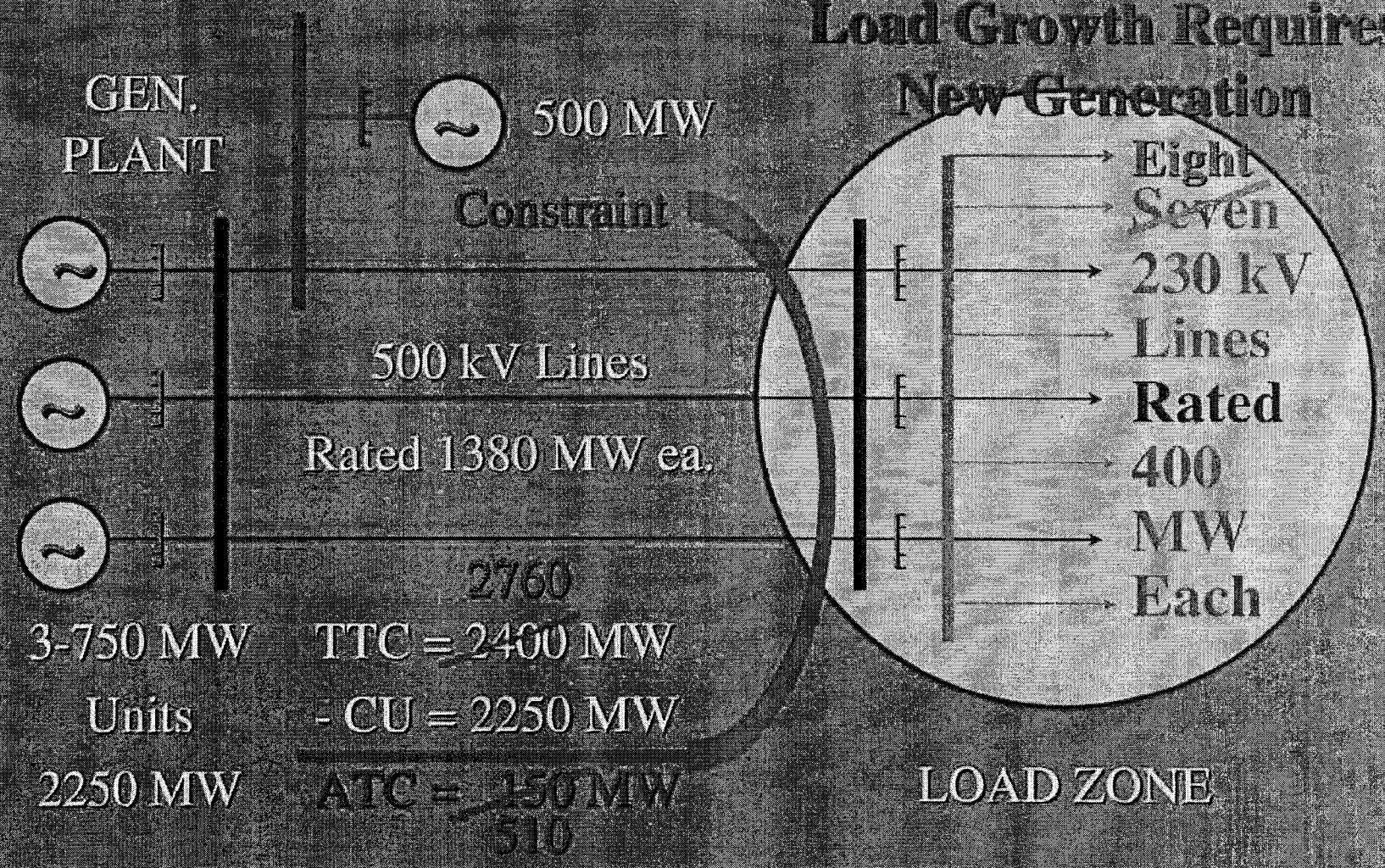
Example 1: Import Constraint



Example 2: Reliability Must-Run



Example 3: Transmission Fix



Questions ?

11

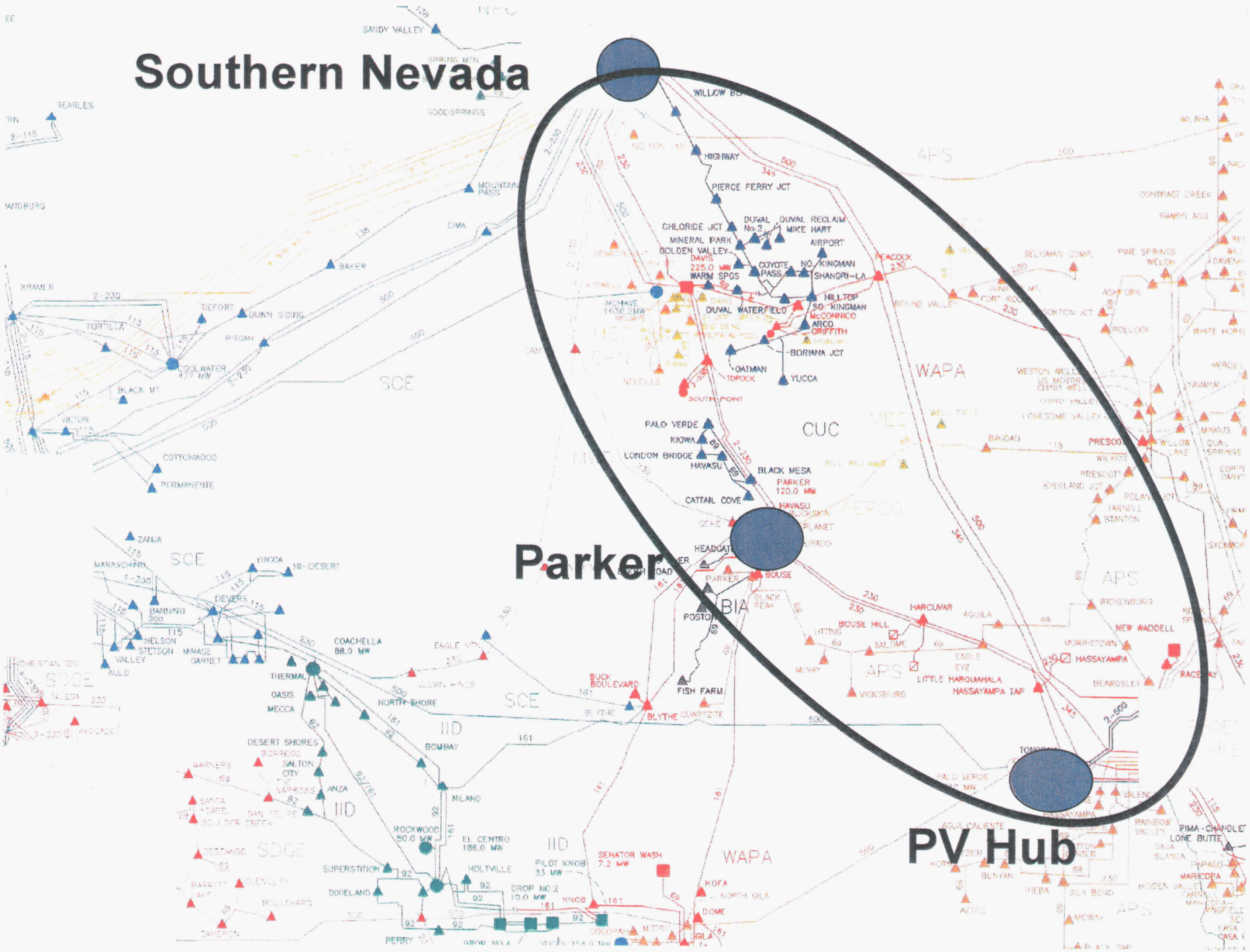
Colorado River Transmission Planning Committee

Status Update

SWAT – May 4, 2005

Western Customer Study

- Effort to Expand Transmission Capacity into Northwestern Arizona
- Study Effort to be Directed by WAPA
- Region Bounded by Palo Verde, Parker, and Southern Nevada


Southern Nevada
Parker
PV Hub
SCE
CUC
WAPA
APS
IID
SDGE
BIA
AEPCO
SANDY VALLEY
SEARLES
GOODSPRINGS
MOUNTAIN PASS
CIMA
BAKER
KRAMER
TIEFORT
DUNN SIDING
TORTILLA
PISGAH
COLWATER 477 MW
BLACK MT.
VICTOR
COTTONWOOD
PERMANENTE
WILLOW BEACH
HIGHWAY
PIERCE FERRY JCT
CHLORIDE JCT
MINERAL PARK
GOLDEN VALLEY
DAVIS 225.0 MW
WARM SPGS
DUVAL
DUVAL No.2
DUVAL RECLAIM
MIKE HART
AIRPORT
COYOTE PASS
NO. KINGMAN
SHANGRI-LA
PEACOCK
MOHAVE 1636.2MW
DUVAL WATERFIELD
HILLTOP
SO. KINGMAN
McCONNICO
ARCO
GRIFFITH
BORIANA JCT
OATMAN
TOPOCK
YUCCA
SOUTH POINT
PALO VERDE
KIOWA
LONDON BRIDGE
HAVASU
BLACK MESA
PARKER 120.0 MW
CATTAIL COVE
HAVASU
HEADGATE
PARKER
BOUSE
POSTON
FISH FARM
BUCK BOULEVARD
BLYTHE
BLYTHE QUARTZITE
HARCUVAR
BOUSE HILL
SALOME
LITTLE HARQUAHALA
HASSAYAMPA TAP
HASSAYAMPA
NEW WADDELL
RACEWAY
ZANJA
YUCCA
HI-DESERT
MARASCHINO
DEVERS
BANNING
NELSON
STETSON
VALLEY
MIRAGE
GARNET
COACHELLA 88.0 MW
THERMAL
OASIS
MECCA
NORTH SHORE
BOMBAY
DESERT SHORES
BORREGO
SALTON CITY
ANZA
NILAND
ROCKWOOD 50.0 MW
EL CENTRO 186.0 MW
HOLTVILLE
SUPERSTITION
DIXIELAND
PERRY
DROP NO.2 10.0 MW
PILOT KNOB 33 MW
SENATOR WASH 7.2 MW
KOFA
DOME
GILA
NORTH GILA
TONOPAH
PALO VERDE
VALENCIA
AGUA CALIENTE
RAINBOW VALLEY
PIMA-CHANDLER
LONE BUTTE
MARICOPA
PRESCOTT
KIRKLAND JCT
WICKENBURG
MORRISTOWN
BEARDSLEY
MIDWAY
VICKSBURG
AGUILA
EAGLE EYE
PINE SPRINGS
WELCH
CONTRACT CREEK
RAMON ASO
WESTON WELL
US MOTOR CLINIC WELL
LONESOME VALLEY
BAGDAD
WILLOW LAKE
MINGUS
QUAIL SPRINGS
CORDE DANTE
SYCAMORE
WILAHA
ROUND VALLEY
POLLOCK
WHITE HORSE
SELIGMAN COMP.
JUNIPER MT.
FORT ROCK
DOKTON JCT
ASH CRK
NEEDLES
SWAN
DAVIS
MOHAVE
CAW
MEC
CPN
NVE
WEL
BILL WILLIAMS
WELL FIELD
PLANET
ORADO
GENE
BLACK PEAK
LITTING
MEVAY
EAGLE VTY
WILLOW HINGS
BUCK BOULEVARD
BLYTHE
WARNERS
SANTA ROSA
BOULDER CREEK
DESCANSO
BLUEGLEN
BOULEVARD
DAVERON
PALEGA
PYCOADO
CHRISTIANITOS
AULD
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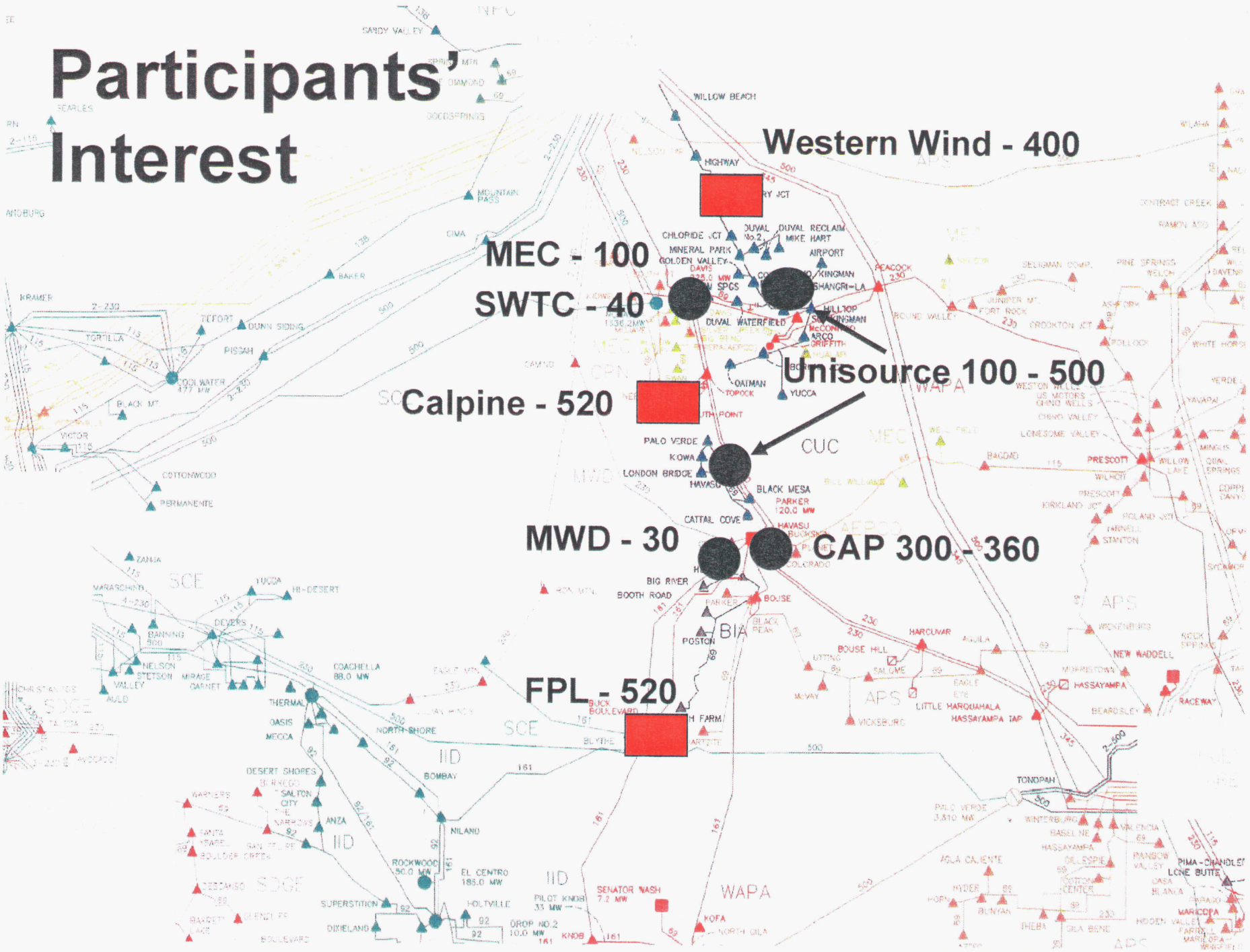
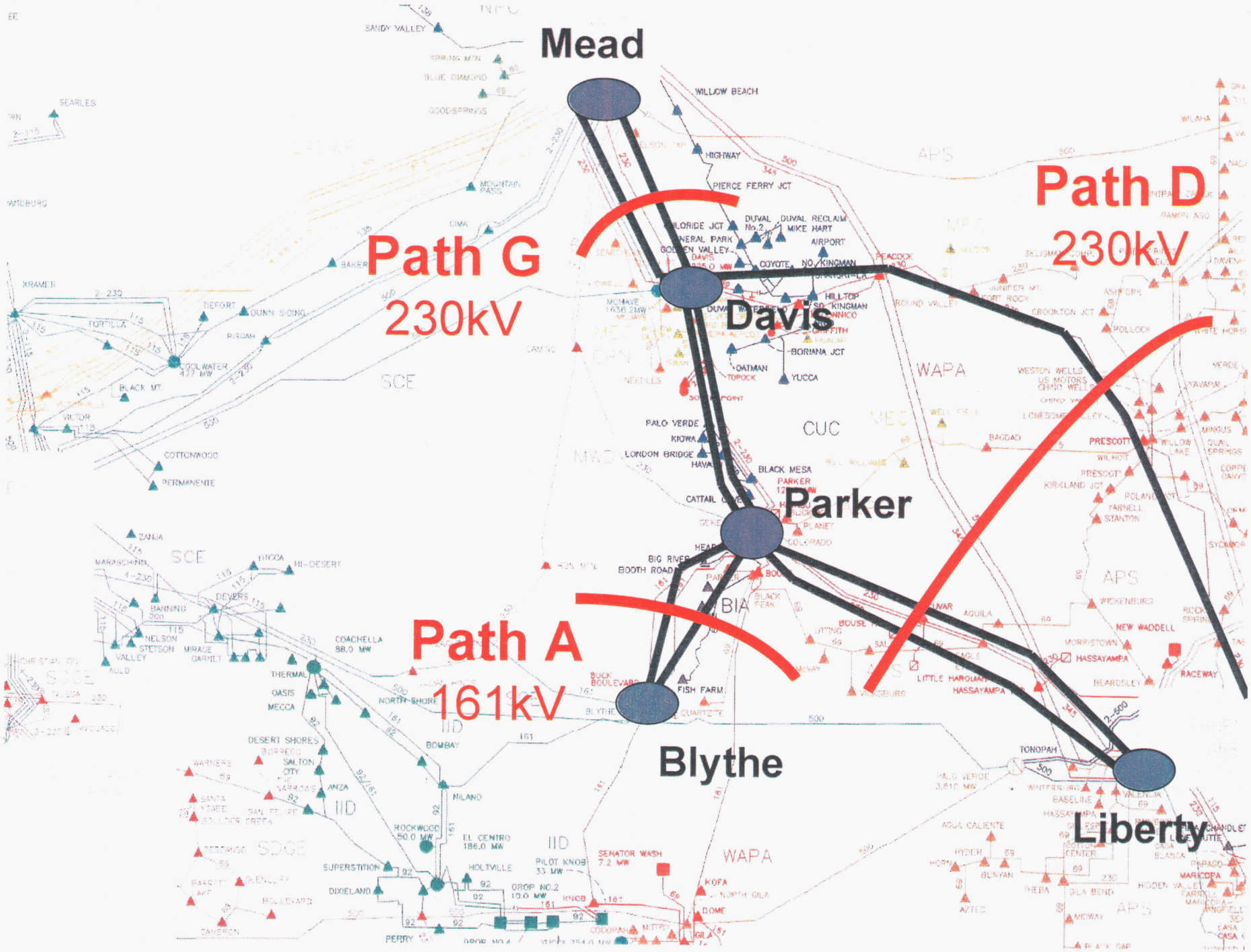
230
161
115
69
92

Participants' Interest



Western Customer Study

- Primarily Looking at the HV Transmission System in the Northwestern Quadrant of Arizona
- Evaluate WAPA's Paths A, D, and G


Mead
Path G
230kV
Davis
Path D
230kV
Parker
Path A
161kV
Blythe
Liberty
SCE
WAPA
CUC
APS
IID
BIA

Western Customer Study

Participants (12):

- LSE (4)
  - Aha Macav
  - Arizona Public Service
  - Mohave Electric Cooperative
  - Unisource Electric Service

Western Customer Study

Participants (12):

- **G&T (1)**
  - Southwest Transmission Coop.
- **Generators (3)**
  - Calpine
  - FP&L
  - Western Wind

Western Customer Study

Participants (12):

State Authorities/Districts (3)

- Arizona Power Authority
- Central Az Water Conservation Dist.
- Metropolitan Water District

Federal PMA (1)

- Western Area Power Administration

Western Customer Study

Open Study Group

Next Meeting – May 18th

Questions:

Kenneth Bagley (R.W. Beck)

480-367-4282

kbagley@rwbeck.com

12

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL Company

DEVERS – PALO VERDE NO. 2 (DPV2)

ACCEPTED PATH 49 RATING STUDY REPORT

VOLUME I – MAIN REPORT

JULY 25, 2005

Prepared by the Western Electricity Coordinating Council (WECC)
And Western Arizona Transmission System (WATS)
Peer Review Group

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APPENDIX F - SCIT ANALYSIS DIAGRAMS & TABLES
APPENDIX G - SIMULTANEOUS DIAGRAMS AND TABLES
APPENDIX H - SENSITIVITY DIAGRAMS AND TABLES

VOLUME II - DYNAMIC STABILITY PLOTS

I PLOTS OF NON-SIMULTANEOUS ANALYSIS
II PLOTS OF SCIT NOMOGRAM ANALYSIS
III PLOTS OF SIMULTANEOUS ANALYSES

I. EXECUTIVE SUMMARY

The Southern California Edison Company (SCE) is proposing to build a 230 mile, Harquahala-Devers 500 kV transmission line. Together with the new 500 kV line, other transmission-related reinforcements and procedures comprise the project plan of service, which is described in section III.B. The project is referred to as Devers-Palo Verde No. 2 or DPV2. DPV2 is being pursued to increase the transfer capability between Arizona and California by 1,200 MW for economic reasons. The planned operating date for DPV2 is 2009.

Like the existing Palo Verde-Devers 500 kV line, DPV2 will be a part of both the Arizona-California East-of-River path (Path 49) and Arizona-California West-of-River path (Path 46) definitions. Owing to this dual nature, the DPV2 Plan of Service (POS) ultimately will be designed to increase the non-simultaneous rating of Path 46 in addition to Path 49. However, the DPV2 Path 46 Rating Study will be done separately and in coordination with the Path 46 rating study to be completed for the Path 49 Series Capacitor Upgrade Project. In addition, owing to the uncertainty of continued operation of the Mohave Generating Plant, two complete DPV2 plans of service were developed, one with and the other without the Mohave Generating Plant in service. The main objective of this DPV2 Path 49 Rating Study (Study) is to establish a new Accepted Rating of 9,255 MW on Path 49 as a result of DPV2.

On October 10, 2003, SCE submitted a notification letter to the Western Electricity Coordinating Council (WECC) Planning Coordination Committee and the WECC Technical Studies Subcommittee formally initiating Phase 1 of the WECC rating process for DPV2. After completing Phase 1 requirements, TSS granted Phase 2 status to DPV2 on September 21, 2004. In addition to the WECC rating process, DPV2 has adhered to the Western Arizona Transmission System (WATS) regional planning requirements. On July 21, 2004, SCE formed a combined WECC/WATS Peer Review Group (PRG) to review and approve the Study, and prepare this final DPV2 Accepted Path 49 Rating Study Report (Report).

Based on the findings of this Study, the DPV2 POS is adequate to increase the Path 49 non-simultaneous rating by 1,200 MW from 8,055 MW to 9,255 MW, while meeting the NERC/WECC Planning Standards and the regional WATS planning requirements. With the inclusion of reactive support equipment in the DPV2 POS, the Southern California Import Transmission (SCIT) path simultaneous capability as defined in the SCIT Nomogram will also be increased by 1,200 MW. In addition, the DPV2 POS is adequate to achieve a 1,200 MW rating increase on Path 49 simultaneously with seven WECC defined Paths 26, 27, 41, 42, 64, 65 and the Centennial path at their respective maximum ratings. Nomograms and/or operating procedures will have to be implemented to mitigate the simultaneous interaction between Path 49 and Path 61. Conceptual nomograms have been developed in this Study. Summaries of the DPV2 POS requirements for each of the analyses are presented in the following Tables I.A and I.B. The POS will be further evaluated and defined during the aforementioned DPV2 Path 46 rating study.

At the request of PRG members, the Study includes assessments of 5 sensitivities for information purposes, which are described in section VIII of this Report. Finally, as described in Section IX of this Report, other studies in support of DPV2 are being conducted independent of this Study and will be reviewed in the appropriate forums.

SCE would like to express its gratitude to PRG members for their professionalism and expertise in providing support to this Study and completing the Report.

TABLE I.A

DPV2 Plan of Service Summary for Mohave On Line Scenario [A]

Analysis	Total Reactive Support (MVAr) [B]	Nomogram	Operating Procedure	SPS
Non-Simultaneous	0	Yes [C]	Yes [C]	Yes [C]
SCIT Nomogram	400	No	Yes [C]	Yes [C]
Path 26	400	No	Yes [C]	Yes [C]
Path 27	400	No	Yes [C]	Yes [C]
Path 41	550	Yes [D]	Yes [C]	Yes [C]
Path 42 [E]	N/A	N/A	N/A	N/A
Path 61	1,200 [G]	Yes [F]	Yes [G]	Yes [C]
Path 64	800	No	Yes [C]	Yes [H]
Path 65	400	No	Yes [C]	Yes [C]
Centennial Path	800	No	Yes [C]	Yes [H]

A – All analyses assume the following core plan of service elements:

1. **Build new Harquahala-Devers 500 kV line**
2. **Rebuild Devers-San Bernardino 230 kV lines #1 and #2**
3. **Rebuild Devers-Vista 230 kV lines #1 and #2**

B – The Reactive Support level shown represents the total amount required uniquely for each analysis (e.g. 800 MVAr is required for the conditions assumed in the Path 64 analysis, however, only 400 MVAr would be required for the conditions assumed in the Path 65 analysis; i.e. they are not additive).

C – Implement an integrated mitigation plan involving nomograms, operating procedures and an SPS (to trip generation in the Palo Verde area and load in Southern California) to relieve thermal overloads on 3 transmission facilities for DPV1 and DPV2 outage. Up to 1,125 MW of generation in Arizona and up to 1,350 MW of load in Southern California may be required for the double line outage.

D – Implement a nomogram to meet the stability criteria for the Hassayampa-N.Gila 500 kV line outage if at least 150 MVAr of shunt capacitors are not installed at Devers 500 kV bus or they are out of service.

E – The request to perform the Path 42 analysis was made for the Mohave Off Line scenario only.

F – Implement an OP to relieve a thermal overload on Victorville-Lugo 500 kV line for 5 line outages.

G – Implement a nomogram to meet the stability criteria for Hassayampa-N.Gila 500 kV line outage in lieu of installing an additional 400 MVAr SVC at Lugo 500 kV bus (i.e. to not exceed the 800 MVAr reactive power capability identified for Path 64 and the Centennial path, which is the basis for the reactive support equipment in the plan of service).

H – Install an SPS to trip up to 400 MW of generation in the Palo Verde area and up to 400 MW of load in Southern California to meet the stability and/or post transient planning standards for DPV1 and DPV2 outage. This requirement may be met with the same SPS to relieve the thermal overloads.

TABLE I.B

DPV2 Plan of Service Summary for Mohave Off Line Scenario [A]

Analysis	Total Reactive Support (MVAr) [B]	Nomogram	Operating Procedure	SPS
Non-Simultaneous	0	Yes [C]	Yes [C]	Yes [C]
SCIT Nomogram	500	No	Yes [C]	Yes [C]
Path 26	500	No	Yes [C]	Yes [C]
Path 27	500	No	Yes [C]	Yes [C]
Path 41	500	No	Yes [C]	Yes [C]
Path 42	500	No	Yes [C]	Yes [C]
Path 61	1,400 [E]	Yes [E]	Yes [D]	Yes [F]
Path 64	1,300	No	Yes [C]	Yes [F]
Path 65	500	No	Yes [C]	Yes [C]
Centennial Path	1,300	No	Yes [C]	Yes [F]

A – All analyses assume the following core plan of service elements:
1. **Build new Harquahala-Devers 500 kV line**
2. **Rebuild Devers-San Bernardino 230 kV lines #1 and #2**
3. **Rebuild Devers-Vista 230 kV lines #1 and #2**

B – The Reactive Support level shown represents the total amount required uniquely for each analysis (e.g. 1,300 MVAr is required for the conditions assumed in the Path 64 analysis, however, only 500 MVAr would be required for the conditions assumed in the Path 65 analysis; i.e. they are not additive).

C – Implement an integrated mitigation plan involving nomograms, operating procedures and an SPS (to trip generation in the Palo Verde area and load in Southern California) to relieve thermal overloads on 3 transmission facilities for DPV1 and DPV2 outage. Up to 1,125 MW of generation in Arizona and up to 1,350 MW of load in Southern California may be required for the double line outage.

D – Implement an OP to relieve a thermal overload on Victorville-Lugo 500 kV line for 3 line outages.

E – Implement a nomogram to meet the stability criteria for Hassayampa-N.Gila 500 kV line outage in lieu of installing an additional 100 MVAr SVC at Devers 500 kV bus (i.e. to not exceed the 1,200 MVAr reactive power capability identified for Path 64 and the Centennial path, which is the basis for the reactive support equipment in the plan of service).

F – Install an SPS to trip up to 400 MW of generation in the Palo Verde area and up to 400 MW of load in Southern California to meet the stability and/or post transient planning standards for DPV1 and DPV2 outage. This requirement may be met with the same SPS to relieve the thermal overloads.

II. STUDY OBJECTIVES AND SCOPE

The main objective of this DPV2 Path 49 Rating Study (Study) is to establish a new Accepted Rating of 9,255 MW on Path 49 as a result of DPV2, since DPV2 will be included in the Path 49 definition. To achieve this new rating, the Study must demonstrate that the Path 49 rating can be increased from 8,055 MW to 9,255 MW while meeting the NERC/ WECC Planning Standards and the regional WATS planning requirements (hereafter jointly referred to as Criteria). Specifically, in accordance with Phase 2 of the WECC "Procedures for Regional Planning Project Review and Rating Transmission Facilities" policy (WECC Rating Policy), the Study is designed to:

- Address comments on the DPV2 Comprehensive Progress Report.
- Address comments on the DPV2 Accepted Path 49 Rating Study.
- Demonstrate conformance with the NERC/ WECC Planning Standards.
- Identify the non-simultaneous transfer capability and simultaneous path transfer capability limits for a specific plan of service.
- Address the mitigation of simultaneous transfer capability problems relative to the existing system.

In addition, the Study included performing limited sensitivity analyses to check the interaction of DPV2 with other similarly situated projects and sub-regional projects to the extent these projects and sub-projects had developed a preferred plan of service that can be modeled in the Study.

The analyses performed in this Study were designed to be rigorous and extensive as indicated by the Study Scope of Appendix A, which provides details on the criteria, assumptions and methodology. As indicated in the Study Scope, essentially two complete analyses were performed owing to the uncertainty of continued operation of the Mohave Generating Plant. One analysis assumes that the Mohave Generating Plant will be in service when DPV2 goes into service in 2009. The other analysis assumes that the Mohave Generating Plant will be shut down.

Like the existing Palo Verde-Devers 500 kV line (DPV1), DPV2 will be a part of both the Path 49 and Arizona-California West-of-River (WOR) Path 46 definitions. Owing to this dual nature, the DPV2 Plan of Service ultimately will be designed to increase the non-simultaneous rating of Path 46 in addition to Path 49. However, the DPV2 Path 46 Rating Study will be done separately and in coordination with the Path 46 rating study is completed for the Path 49 Series Capacitor Upgrade Project (Upgrade Project). Accordingly, the DPV2 Path 46 rating analysis is not included in this Study. The Upgrade Project rating studies performed within the Western Electricity Coordinating Council and the Western Arizona Transmission System reliability forums provides the baseline for performing DPV2 non-simultaneous and simultaneous analyses.

Samples of general instructions for modeling single and double contingencies (also known as "switchdecks") simulated in the dynamic stability and post-transient power flow analyses for the non-simultaneous analysis are provided in Appendix B.

III. PROJECT DESCRIPTION

III.A BACKGROUND

Southern California Edison (SCE) is proposing to build a 230 mile, 500 kV transmission line from the Palo Verde area, near Phoenix, Arizona, to SCE's Devers substation, near Palm Springs, California. Together with the new 500 kV line, other transmission-related reinforcements comprise the overall plan of service. The project is named Devers-Palo Verde No. 2 (DPV2). DPV2 is being pursued to increase the transfer capability between Arizona and California by 1,200 MW. The expected operating date for DPV2 is 2009.

On October 10, 2003, SCE submitted a notification letter to the Western Electricity Coordinating Council Planning Coordination Committee (PCC) and the WECC Technical Studies Subcommittee (TSS) formally initiating Phase 1 of the WECC Rating Process for DPV2. Regional review of DPV2 was performed through the DPV2 Regional Planning Review Group, which met in November of 2003. The DPV2 Regional Planning Compliance Report was submitted to the WECC PCC on June 8, 2004. On September 14, 2004, PCC accepted as complete the DPV2 Regional Planning Compliance Report.

The DPV2 Comprehensive Progress Report (CPR), which provided the analysis used to define DPV2's conceptual plan of service, was submitted to the WECC on April 21, 2004. The DPV2 CPR indicated that the DPV2 plan of service could reliably achieve an incremental increase of 1,200 MW in the non-simultaneous rating of Path 49.

In accordance with the WECC path rating process, TSS granted Phase 2 status to DPV2 on September 21, 2004. On July 21, 2004, SCE formed a combined WECC/WATS Peer Review Group (PRG) to review and approve the Study, and prepare the final DPV2 Accepted Path 49 Rating Study Report (Report).

III.B PLAN OF SERVICE

To reliably increase the Path 49 rating by 1,200 MW while meeting the Criteria, the DPV2 Plan of Service (POS) will need to include the following facilities and procedures. Elements of the POS will be further evaluated and defined during the DPV2 Path 46 rating study and in other independent design studies performed outside of the WECC rating process.

1. Devers - Harquahala 500 kV Line

Build a new 230 mile-500 kV line between Harquahala Generating Company's Harquahala Switchyard in Arizona to SCE's Devers 500 kV Substation near Palm Springs, California. The line will be designed with 2B-2156 ACSR conductor and a nominal 50% series compensation that matches the series compensation equipment on the existing Palo Verde-Devers 500 kV line. The proposed route between Devers and Harquahala parallels the entire length of SCE's existing Palo Verde-Devers 500 kV transmission line, as shown on the diagram of section III.C.

2. Devers – San Bernardino 230 kV lines #1 and #2

Rebuild and reconductor the Devers–San Bernardino 230 kV lines #1 and #2. The original single-circuit 230 kV tower lines will be removed and replaced with new double-

circuit 230 kV tower structures, strung with bundled 1033 ACSR conductor. The conductor on the existing double circuit 230 kV towers will also be replaced with double bundled 1033 ACSR conductor.

3. Devers – Vista 230 kV lines #1 and #2

Rebuild and reconductor the Devers–Vista 230 kV lines #1 and #2. The original single-circuit 230 kV tower lines will be removed and replaced with new double-circuit 230 kV tower structures, strung with bundled 1033 ACSR conductor. The conductor on the existing double circuit 230 kV towers will also be replaced with double bundled 1033 ACSR conductor.

4. 230 kV Circuit Breakers

Replace 13 230 kV circuit breakers at two locations and upgrade 4 circuit breakers at one location on the SCE system, as follows:

- Replace 11 CBs @ Devers Substation
- Replace 2 CBs @ Lewis Substation
- Upgrade 4 CBs @ SONGS Substation (by installing TRV L-G Capacitors)

5. Reactive Power Equipment

As a minimum, install fixed shunt capacitors and SVC capacity at Devers 500 kV substation and SVC capacity at Lugo 500 kV substation as required for the scenarios with Mohave generating station continuing operation or retired, respectively. Below are the specific requirements for each scenario.

	Reactive Power Capacity (MVAr)	
	Mohave On Line	Mohave Off Line
Shunt Capacitors @ Devers 500 kV	300	300
SVCs or equivalent @ Devers 500 kV	500	600
SVCs or equivalent @ Lugo 500 kV	0	400

SCE reserves the right to design and install reactive power equipment and associated control parameters, which may differ with what was modeled in this Study, as long as it can be demonstrated that the performance is as good as or better than the results presented in this Report.

6. Special Protection System (SPS)

Install a Special Protection System (SPS) that will be designed to drop generation in the Palo Verde area and load on SCE's system to ensure acceptable performance for the double contingency loss of the Palo Verde-Devers 500 kV and Harquahala-Devers 500 kV lines. The Study indicated that up to 1,125 MW of generation in the Palo Verde area may need to be tripped and 1,350 MW of load in SCE area may need to be dropped to meet the thermal criteria. Results also show that the generator tripping and load dropping requirements may be much lower if nomograms and operating procedures were integrated into the SPS design. SCE is committed to ensuring that the ultimate SPS mitigation plan will be designed to ensure acceptable performance for the double contingency loss of the Palo Verde-Devers 500 kV and Harquahala-Devers 500 kV lines.

To this end, SCE intends to work closely with the CAISO, Arizona utilities and regulators, and generator owners outside of the WECC rating process to develop a workable generator dropping scheme to satisfy this SPS requirement. SCE plans to form a technical SPS study group comprised of interested stakeholders to develop the study scope and perform the studies as the basis for determining the ultimate SPS requirements. In fact, some internal studies have already been performed by SCE and the Salt River Project., which will be reviewed and discussed within the stakeholder group. The SPS design study will include analyses of different operating conditions, including the Palo Verde hub generation and COI/PDCI transfers. Under the guidance of WATS, the operating procedures currently used for operation of the East of River Path will be amended as needed to cover the double line outage and thermal overloads. The "Palo Verde West Operating Guidelines" and the "Agreement on Operating Procedure for Reduction in Loading on the East of River Path" are enforced by Arizona Public Service as the operator of Path 49 and will be amended as needed. This process will be reviewed and approved by WATS. Also, the specific generation/load dropping scheme will be evaluated carefully in the WECC Remedial Action Scheme Reliability Subcommittee (RASRS) during the design phase.

SCE reserves the right to develop and implement an SPS, which may differ with what was modeled in this Study, as long as it can be demonstrated that the performance is as good as or better than the results presented in this Report.

7. Nomogram

Absent of or in coordination with other remediation, develop and implement the following new nomograms to meet the stability criteria:

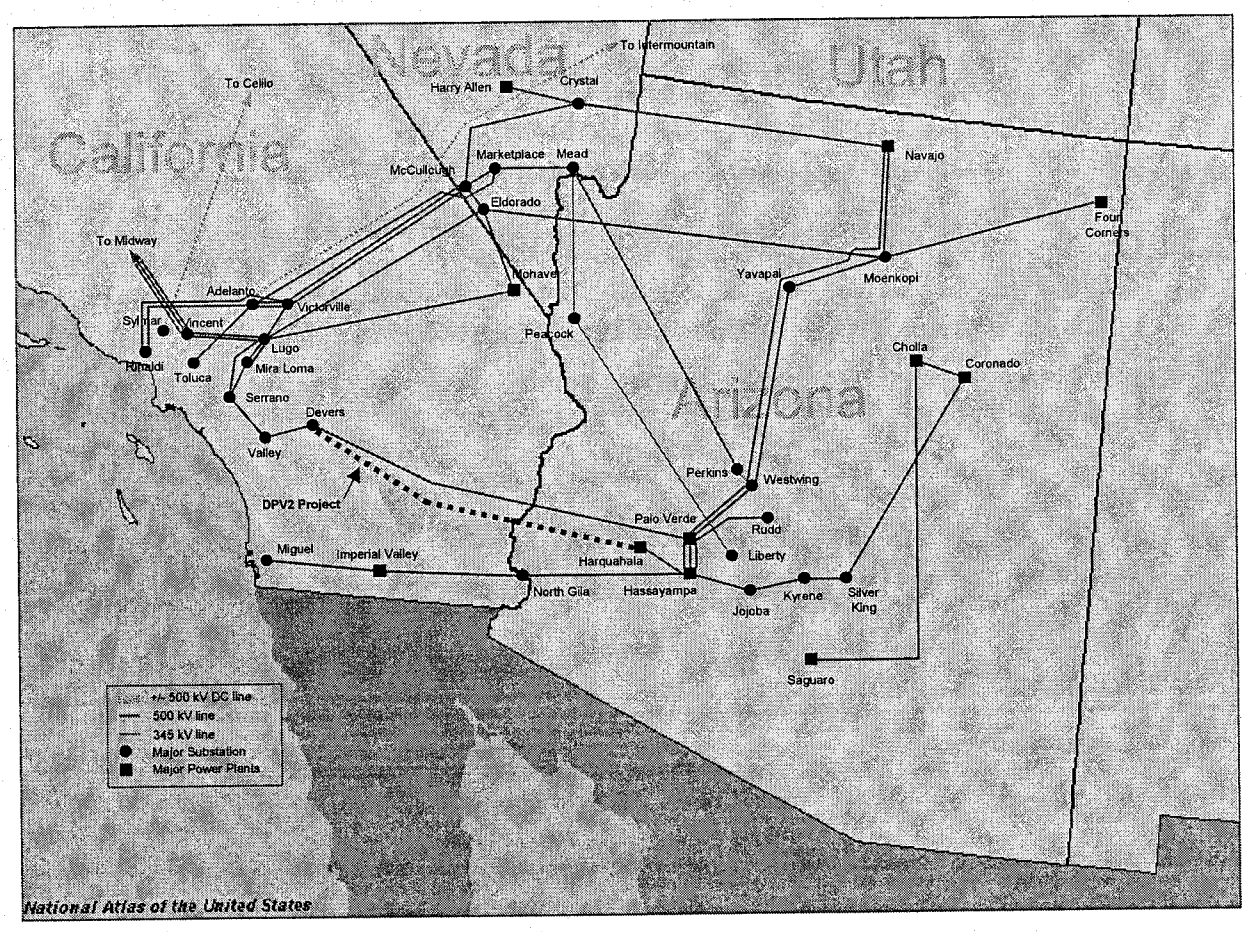
- Path 49 vs. Path 41 for loss of the Hassayampa-N.Gila 500 kV line,
- Path 49 vs. Path 61 for loss of the Hassayampa-N.Gila 500 kV line,
- Perkins phase shifter in vs. out of service for DPV1 and DPV2 double line outage

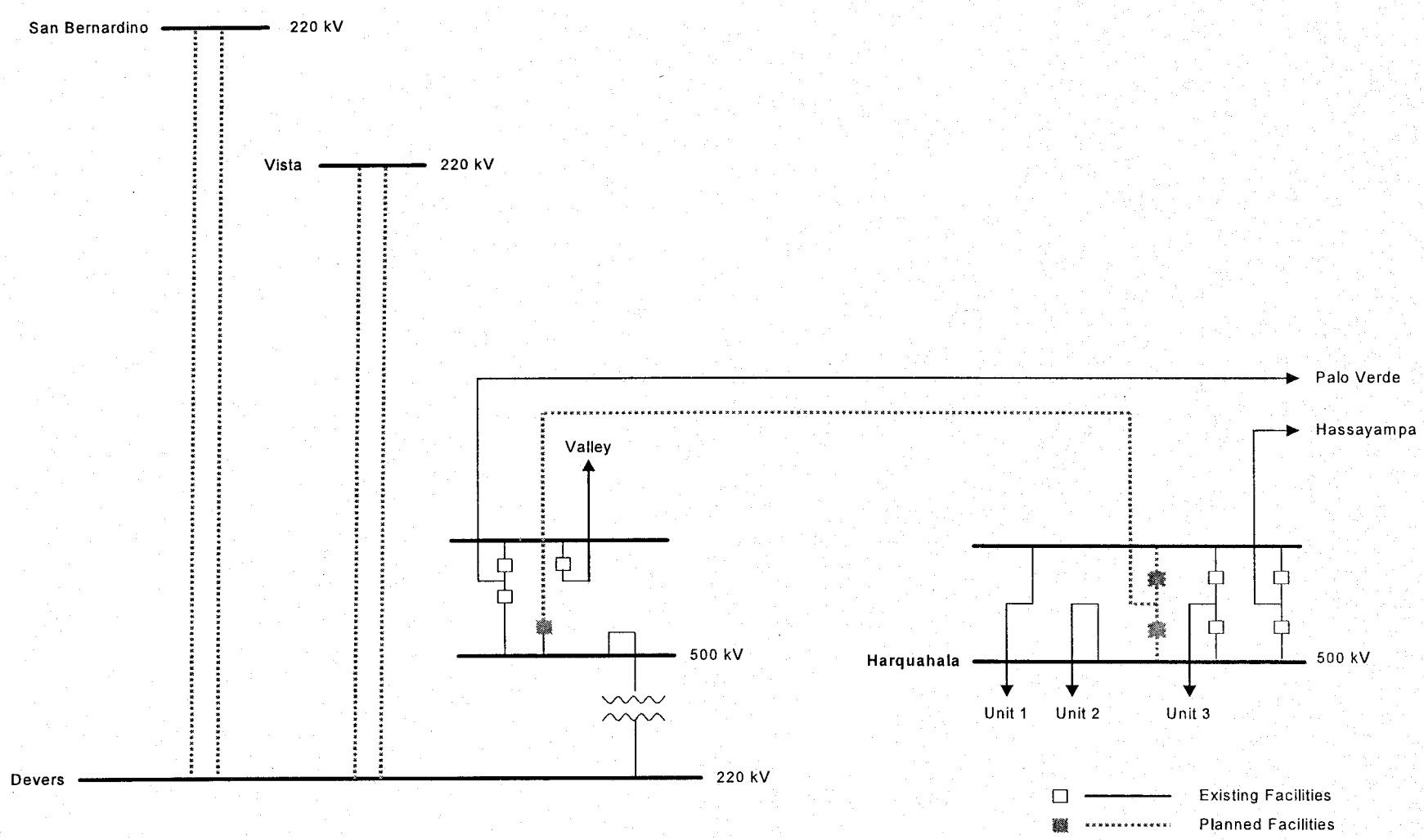
8. Operating Procedures

Absent of or in coordination with other remediation, develop and implement new operating procedures to identify schedule reductions to relieve overloads on:

- Mead-Perkins 500 kV series capacitors and two Perkins phase shifters for loss of the Palo Verde-Devers and the Harquahala-Devers 500 kV lines as part of SPS,
- Victorville-Lugo 500 kV line for the following five single contingencies:
    1. Eldorado-Lugo 500 kV line
    2. Mohave-Lugo 500 kV line
    3. Devers-Valley 500 kV line
    4. N.Gila-IV 500 kV line
    5. Palo Verde-Devers 500 kV line

III.C GEOGRAPHIC MAP OF DPV2 IN RELATION TO DSW TRANSMISSION





III.D CONCEPTUAL ONE LINE DIAGRAM OF DPV2

IV. RESPONSES TO COMMENTS

IV.A DPV2 COMPREHENSIVE PROGRESS REPORT

The DPV2 Comprehensive Progress Report, which provided the analysis used to define the conceptual Plan-of-Service for DPV2, was submitted to the WECC on April 21, 2004. As established in the WECC rating review process, the 60-day review period began on April 21, 2004 and ended on June 21, 2004.

During the 60-day review period, SCE received several comments on the Comprehensive Progress Report. SCE responses to these comments are provided in Appendix C.

IV.B DPV2 ACCEPTED PATH 49 RATING STUDY

Since the formation of the PRG, stakeholders were given several opportunities to review and comment on all aspects of the Study. Throughout the study period, SCE solicited and received comments on the DPV2 rating analysis. SCE responses to these comments are provided in Appendix E.

V. FINDINGS OF NON-SIMULTANEOUS ANALYSIS

V.A OVERALL SUMMARY

In accordance with the WECC Rating Policy, the non-simultaneous analysis is based on the key assumption that Path 49 power flow will be at its maximum target rating of 9,255 MW while flows on other paths may be less than their respective maximum ratings. Details on the criteria, assumptions and methodology for the non-simultaneous analysis are provided in section III on page 6 of the Study Scope (Appendix A). Also, all facilities expected to be in service prior to DPV2 operation were provided by PRG members and represented in the base cases used to perform the analysis. The final non-simultaneous base cases were approved by the PRG.

Results indicate that the DPV2 POS is adequate to achieve a 1,200 MW non-simultaneous rating increase on Path 49 while meeting the Criteria.

Results indicated thermal overloads on three transmission elements (Perkins phase shifters and series capacitors on the Perkins-Mead 500 kV line) for loss of the Palo Verde-Devers 500 kV and Harquahala-Devers 500 kV lines. To the extent these overloaded facilities are not upgraded as part of a future project, SCE will need to develop and implement an SPS in conjunction with nomograms and operating procedures to relieve these overloads.

Details of the Non-Simultaneous Analysis results are provided in Appendix D.

V.B POWER FLOW ANALYSIS RESULTS

The key finding from the power flow analysis is that DPV2 can achieve a 1,200 MW increase in the non-simultaneous rating of Path 49 while meeting the thermal limits of the transmission system. However, in the absence of other pre-DPV2 remediation, employing

an SPS together with nomograms and operating procedures would relieve overloads on the Mead-Perkins 500 kV series capacitors and the two Perkins phase shifters for the double line outage of the Palo Verde-Devers and Harquahala-Devers 500 kV lines.

The "Control Area Summary of Pre-Contingency Base Cases," which was approved by the PRG, is provided in Appendix D.1.a. The "Path Flow Summary of Pre-Contingency Base Cases" is provided in Appendix D.1.b. Also, "Power Flow Diagrams of Pre-Contingency Bases Cases" are provided in Appendix D.1.c.

The "Path 49 Non-Simultaneous Power Flow Analysis Summary," which lists the 5 highest transmission loadings for normal and contingency conditions, is provided in Appendix D.1.d. The following subsections provide highlights of the analysis.

Mohave On Line

1. No transmission element was loaded above 100% of its continuous rating under normal (i.e. non-contingency) conditions in the pre-or-post-project cases. Marginal loadings of 100.8% and 100.6% occurred on the two Perkins phase shifters in the pre-and-post-project cases, respectively, which are considered acceptable by the owners of the equipment.

2. For the single line outage of the Palo Verde-Devers 500 kV line in the pre-project case, marginal loadings of 100.9% of the emergency rating of the series capacitor of the Mead-Perkins 500 kV line and 101.9% of the emergency rating of the two Perkins phase shifters occurred. For the same outage, these loadings dropped well below 100% in the post-project case, as shown in the table below.

	Emergency Loading (%)		
Limiting Element	Pre-Project	Post-Project	Outage
Mead-Perkins Series Cap	100.9	86.3	PVDV
Mead-Perkins Phase Shifters	101.9	86.8	PVDV

3. For the double line outage of the Palo Verde-Westwing 500 kV No. 1 and 2 lines in the pre-project case, a loading of 106.8% of the emergency rating of the Hat WALC-Hassayampa 230 kV line occurred. For the same outage, the loading on this line dropped below 100% in the post-project case, as shown in the table below.

	Emergency Loading (%)		
Limiting Element	Pre-Project	Post-Project	Outage
Hat WALC-Hassyamp 230	106.8	97.8	PVWW1&2

4. For the double line outage of the Palo Verde-Devers and Harquahala-Devers 500 kV lines in the post-project case, loadings of 119.5% of the emergency rating of the series capacitor of the Mead-Perkins 500 kV line and 116.8% of the emergency rating of the two Perkins phase shifters occurred.

5. Implementing an SPS, which trips 1,125 MW of generation at Harquahala and drops 1,350 MW of load in SCE's system, mitigates the thermal overloads caused by the double line outage of the Palo Verde-Devers and Harquahala-Devers 500 kV lines, as

shown in the table below. Pending further studies, an operating procedure may be developed to reduce the amount of generation and load dropping.

Limiting Element	Emergency Loading (%) No SPS	With SPS	Outage
Mead-Perkins Series Cap	119.5	100.8	DPV1&2
Mead-Perkins Phase Shifters	116.8	100.4	DPV1&2

6. Implementing a nomogram and operating procedure, which operates the Perkins phase shifter in an out of service mode, resulted in reducing the thermal overload considerably on the series capacitor of the Mead-Perkins 500 kV line and the Perkins phase shifters. However, thermal overloads occurred on four other transmission lines, three of which had exhibited overloads under pre-DPV2 conditions. Those three lines are the Hat WALC-Hassayampa 230 kV line, the Ave 58-Bannister 161 kV line and the RTAP2-RTP1 92 kV line. IID has indicated that they are in the process of developing future plans to address pre-existing overloads on its system, including the Ave58-Bannister 161 kV line and the RTAP2-RTP1 92 kV line. As a pre-existing overload condition, the owners of the Hat WALC-Hassyamp 230 kV line should determine acceptable mitigation options and work with other affected parties. The fourth overload occurred on the Liberty 345 kV phase shifter. Even assuming separate mitigation of pre-existing overloaded facilities, the thermal overloads on the remaining three transmission facilities marginally exceed their respective limits, as shown in the table below.

Limiting Element	Emergency Loading (%) No SPS	With Nomogram	Outage
Mead-Perkins Series Cap	119.5	102.8	DPV1&2
Mead-Perkins Phase Shifters	116.8	100.6	DPV1&2
Hat WALC-Hassyamp 230	< 90.0	108.1	DPV1&2
AV58TP1-Bannister 161	< 90.0	102.2	DPV1&2
RTAP2-RTP1 92	< 90.0	105.5	DPV1&2
Liberty Phase Shifter	< 90.0	102.8	DPV1&2

7. Implementing an SPS together with a nomogram and operating procedure, which operates the Perkins phase shifter in an out of service mode, resulted in reduced tripping requirements. However, a thermal overload occurred on the Hat WALC-Hassayampa 230 kV line, which had exhibited an overload under pre-DPV2 conditions. As a pre-existing overload condition, the owners of the Hat WALC-Hassyamp 230 kV line should determine acceptable mitigation options and work with other affected parties. Such mitigation could include sympathetic tripping of the Hat WALC-Hassyamp 230 kV line in the event of the N-2 outage. Operating with the SPS, which trips 340 MW of generation at Harquahala and drops 386 MW of load in SCE's system, mitigates the remaining thermal overloads caused by the double line outage of the Palo Verde-Devers and Harquahala-Devers 500 kV lines, as shown in

the table below.

Limiting Element	Emergency Loading (%) No SPS	With SPS/Nmgrm	Outage
Mead-Perkins Series Cap	119.5	94.5	DPV1&2
Mead-Perkins Phase Shifters	116.8	94.3	DPV1&2
Hat WALC-Hassyamp 230	<90.0	103.6	DPV1&2

Mohave Off Line

1. No transmission element was loaded above 100% of its continuous rating under normal (i.e. non-contingency) conditions in the pre-or-post-project cases. Marginal loadings of 100.3% and 100.4% occurred on the two Perkins phase shifters in the pre-and-post-project cases, respectively, which were considered acceptable by the owners of the equipment.

2. For the single line outage of the Palo Verde-Devers 500 kV line in the pre-project case, marginal loadings of 100.7% of the emergency rating of the series capacitor of the Mead-Perkins 500 kV line and 101.6% of the emergency rating of the two Perkins phase shifters occurred. For the same outage, these loadings dropped well below 100% in the post-project case, as shown in the table below.

Limiting Element	Emergency Loading (%) Pre-Project	Post-Project	Outage
Mead-Perkins Series Cap	100.7	85.8	PVDV
Mead-Perkins Phase Shifters	100.6	86.4	PVDV

3. For the double line outage of the Palo Verde-Westwing 500 kV No. 1 and 2 lines in the pre-project case, a loading of 108.8% of the emergency rating of the Hat WALC-Hassayampa 230 kV line occurred. For the same outage, the loading on this line dropped below 100% in the post-project case, as shown in the table below.

Limiting Element	Emergency Loading (%) Pre-Project	Post-Project	Outage
Hat WALC-Hassyamp	108.8	98.4	PVWW1&2

4. For the double line outage of the Palo Verde-Devers and Harquahala-Devers 500 kV lines in the post-project case, loadings of 118.4% of the emergency rating of the series capacitor of the Mead-Perkins 500 kV line and 116.0% of the emergency rating of the two Perkins phase shifters occurred.

5. Implementing an SPS, which trips 1,125 MW of generation at Harquahala and drops 1,350 MW of load in SCE's system, mitigates the thermal overloads caused by the double line outage of the Palo Verde-Devers and Harquahala-Devers 500 kV lines, as shown in the table below. Pending further studies, an operating procedure may be developed to reduce the amount of generation and load

dropping.

Limiting Element	Emergency Loading (%) No SPS	With SPS	Outage
Mead-Perkins Series Cap	118.4	99.5	DPV1&2
Mead-Perkins Phase Shifters	116.0	99.2	DPV1&2
Liberty Phase Shifter	< 90.0	90.8	DPV1&2

V.C DYNAMIC STABILITY ANALYSIS RESULTS

The key finding from the dynamic stability analysis is that DPV2 can achieve a 1,200 MW increase in the non-simultaneous rating of Path 49 without new reactive power equipment or SPS while meeting the voltage dip, damping and frequency deviation limits of the transmission system. Acceptable performance also occurred for the Navajo and Palo Verde generation 7% margin analysis.

The "Path 49 Non-Simultaneous Stability Analysis Summary" is provided in Appendix D.2.a. The following subsections provide highlights of the analysis.

Mohave On Line

1. All machines in the WECC grid remained in synchronism and were damped. Also, all bus voltage dips and frequency deviations were well within their respective limits in both the pre-and-post-project cases.
2. The WECC grid remained stable for loss of either the Palo Verde-Devers 500 kV line or the Hassayampa-N.Gila 500 kV line with 7% unit margin on the Palo Verde generating units.
3. The WECC grid remained stable for loss of either the Navajo-Crystal 500 kV line or the Moenkopi-Eldorado 500 kV line with 7% unit margin on the Navajo generating units.
4. No reactive power equipment or SPS were needed to meet the voltage dip, damping and frequency deviation limits of the transmission system.

Mohave Off Line

1. All machines in the WECC grid remained in synchronism and were damped. Also, all bus voltage dips and frequency deviations were well within their respective limits in both the pre-and-post-project cases.
2. The WECC grid remained stable for loss of either the Palo Verde-Devers 500 kV line or the Hassayampa-N.Gila 500 kV line with 7% unit margin on the Palo Verde generating units.
3. The WECC grid remained stable for loss of either the Navajo-Crystal 500 kV line or the Moenkopi-Eldorado 500 kV line with 7% unit margin on the Navajo generating units.
4. No reactive power equipment or SPS were needed to meet the voltage dip, damping

and frequency deviation limits of the transmission system.

V.D POST-TRANSIENT POWER FLOW ANALYSIS RESULTS

The key finding from the post-transient power flow analysis is that DPV2 can achieve a 1,200 MW increase in the non-simultaneous rating of Path 49 without new reactive power equipment or SPS while meeting the post-transient voltage deviation limits of the transmission system.

The "Path 49 Non-Simultaneous Post Transient Analysis Summary" is provided in Appendix D.3.a. The following subsections provide highlights of the analysis.

Mohave On Line

1. Post-transient voltage deviations did not exceed 5% during single contingencies in both the pre-and-post-project cases.
2. Post-transient voltage deviations did not exceed 10% during double contingencies in both the pre-and-post-project cases.
3. No reactive power equipment or SPS were needed to meet the post-transient voltage deviation limits of the transmission system.

Mohave Off Line

1. Post-transient voltage deviations did not exceed 5% during single contingencies in both the pre-and-post-project cases.
2. Post-transient voltage deviations did not exceed 10% during double contingencies in both the pre-and-post-project cases.
3. No reactive power equipment or SPS were needed to meet the post-transient voltage deviation limits of the transmission system.

VI. FINDINGS OF SCIT NOMOGRAM SIMULTANEOUS ANALYSIS

VI.A OVERALL SUMMARY

In accordance with the WECC Rating Policy, rating studies need to determine simultaneous path transfer capability limits, as appropriate, for a specific plan of service. The Southern California Import Transmission (SCIT) Nomogram is an important simultaneous path that was assessed in this Study. SCIT defines acceptable flow limits on Path 49 in relation to 5 other paths that deliver power to Southern California. To ensure reliable delivery from the Palo Verde Hub to Southern California, the DPV2 POS will be designed to achieve a 1,200 MW rating increase on both Path 49 and the SCIT Path. To this end, the analysis was based on the key assumption that Path 49 and SCIT power flow increases will be made on a 1 to 1 basis (i.e. 1,200 MW increase on Path 49 and the SCIT Path). Details on the criteria, assumptions and methodology for the SCIT nomogram simultaneous analysis are provided in section IV.1 on page 14 of the Study Scope (Appendix A). The final SCIT Nomogram base cases were approved by the PRG.

Results indicate that the DPV2 POS is adequate to achieve a 1,200 MW simultaneous rating increase on Path 49 and the SCIT path while meeting the Criteria.

Results indicate that reactive power equipment needs to be installed in the Devers Substation area to achieve a 1,200 MW rating increase simultaneously on Path 49 and SCIT while meeting the Criteria. Specifically, 400 MVAr or 500 MVAr of reactive support is needed, under the scenario of Mohave on line or off line, respectively. Also, it was shown that different configurations of reactive support (e.g. SVCs, shunt capacitors) could be employed as long as the system performance of each option meets the Criteria.

Implementing an SPS, which trips 1,125 MW of generation at Harquahala and drops 1,350 MW of load in SCE's system, mitigates the thermal overloads caused by the double line outage of the Palo Verde-Devers and Harquahala-Devers 500 kV lines. Pending further studies, an operating procedure may be developed to reduce the amount of generation and load dropping.

No SPS was needed to meet the stability or post transient criteria for the double line outage of the Palo Verde-Devers 500 kV line and the Harquahala-Devers 500 kV line or the Palo Verde-Devers 500 kV line and the Hassayampa-Harquahala 500 kV line.

Details of the SCIT Nomogram analysis results are provided in Appendix F.

VI.B POWER FLOW ANALYSIS RESULTS

The key finding from the power flow analysis is that DPV2 can achieve a 1,200 MW rating increase simultaneously on Path 49 and SCIT while meeting the thermal limits of the transmission system.

The "Control Area Summary of Pre-Contingency Base Cases," which was approved by the PRG, is provided in Appendix F.1.a. The "Path Flow Summary of Pre-Contingency Base Cases" is provided in Appendix F.1.b. Also, "Power Flow Diagrams of Pre-Contingency Bases Cases" are provided in Appendix F.1.c.

The "Path 49 Non-Simultaneous Power Flow Analysis Summary," which lists the 5 highest transmission loadings for normal and contingency conditions, is provided in Appendix F.1.d.1 and Appendix F.1.d.2. The following subsections provide highlights of the analysis.

Mohave On Line

1. No transmission element was loaded above 100% of its continuous rating under normal (i.e. non-contingency) conditions in the pre-or-post-project cases. Marginal loadings of 100.8% and 100.8% occurred on the two Perkins phase shifters in the pre-and-post-project cases, respectively, which were considered acceptable by the owners of the equipment.
2. For the single line outage of the Palo Verde-Devers 500 kV line in the pre-project case, a loading of 105.3% of the emergency rating of the RTAP2 – RTP1 92 kV line and marginal loadings of 100.6% of the emergency rating of the two Perkins phase shifters, occurred. For the same outage, these loadings dropped well below 100% in the post-project case, as shown in the table below.

Limiting Element	Emergency Loading (%) Pre-Project	Post-Project	Outage
RTAP2-RTP1	105.3	78.7	PVDV
Mead-Perkins Phase Shifters	101.9	86.2	PVDV

3. Implementing an SPS, which trips 1,125 MW of generation at Harquahala and drops 1,350 MW of load in SCE's system, mitigates the thermal overloads caused by the double line outage of the Palo Verde-Devers and Harquahala-Devers 500 kV lines. Pending further studies, an operating procedure may be developed to reduce the amount of generation and load dropping.

Mohave Off Line

1. No transmission element was loaded above 100% of its continuous rating under normal (i.e. non-contingency) conditions in the pre-or-post-project cases. Marginal loadings of 100.7% and 100.6% occurred on the two Perkins phase shifters in the pre-and-post-project cases, respectively, which were considered acceptable by the owners of the equipment.
2. For the single line outage of the Palo Verde-Devers 500 kV line in the pre-project case, a loading of 104.1% of the emergency rating of the RTAP2 – RTP1 92 kV line and marginal loadings of 100.7% of the emergency rating of the two Perkins phase shifters, occurred. For the same outage, these loadings dropped well below 100% in the post-project case, as shown in the table below.

Limiting Element	Emergency Loading (%) Pre-Project	Post-Project	Outage
RTAP2-RTP1	104.1	78.3	PVDV
Mead-Perkins Phase Shifters	100.7	86.0	PVDV

3. For the single line outage of the N.Gila-IV 500 kV line in the pre-project case, a loading of 101.5% of the emergency rating of the Elcentsw 161/230 kV transformer bank occurred. For the same outage, this loading dropped below 100% in the post-project case, as shown in the table below.

Limiting Element	Emergency Loading (%) Pre-Project	Post-Project	Outage
ELCENTSW 161/230	101.5	99.8	NGIV

4. Implementing an SPS, which trips 1,125 MW of generation at Harquahala and drops 1,350 MW of load in SCE's system, mitigates the thermal overloads caused by the double line outage of the Palo Verde-Devers and Harquahala-Devers 500 kV lines. Pending further studies, an operating procedure may be developed to reduce the amount of generation and load dropping.

VI.C DYNAMIC STABILITY ANALYSIS RESULTS

The key finding from the dynamic stability analysis is that DPV2 POS must include

reactive power equipment to achieve a 1,200 MW rating increase simultaneously on Path 49 and SCIT while meeting the voltage dip, damping and frequency deviation limits of the transmission system. Study findings indicate the need for 400 MVAr or 500 MVAr of reactive support in the Devers Substation area, under the scenario of Mohave on line and off line, respectively. No SPS is needed.

The "Path 49 Non-Simultaneous Stability Analysis Summary" is provided in Appendix F.2.a.1 and Appendix F.2.a.2. The following subsections provide highlights of the analysis.

Mohave On Line

1. All machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips and frequency deviations were well within their respective limits in the pre-project case.

2. For all contingencies simulated with the exception of the Hassayampa-N.Gila 500 kV line outage and assuming pre-DPV2 reactive support only, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips and frequency deviations were well within their respective limits in the post-project case.

3. Violations of the voltage dip and frequency deviation criteria occurred for loss of the Hassayampa-N.Gila 500 kV line assuming pre-DPV2 reactive support only as shown in Appendix F.2.a.1.

4. For loss of the Hassayampa-N.Gila 500 kV line, with the addition of a 400 MVAr SVC at Devers 500 kV bus, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips and frequency deviations were within their respective limits as shown in Appendix F.2.a.2.

5. No SPS was needed to meet the voltage dip, damping and frequency deviation limits of the transmission system.

Mohave Off Line

1. All machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips and frequency deviations were well within their respective limits in the pre-project case.

2. For all contingencies simulated with the exception of the Hassayampa-N.Gila 500 kV line outage and assuming pre-DPV2 reactive support only, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips and frequency deviations were well within their respective limits in the post-project case.

3. Violations of the voltage dip and frequency deviation criteria occurred for loss of the Hassayampa-N.Gila 500 kV line and assuming pre-DPV2 reactive support only as shown in Appendix F.2.a.1.

4. For loss of the Hassayampa-N.Gila 500 kV line, with the addition of a 500 MVAr of reactive support in various configuration options located in the area of Devers Substation, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips and frequency deviations were within their respective limits as shown in Appendix F.2.a.2.

5. No SPS was needed to meet the voltage dip, damping and frequency deviation limits of the transmission system

VI.D POST-TRANSIENT POWER FLOW ANALYSIS RESULTS

The key finding from the post-transient power flow analysis is that DPV2 can achieve a 1,200 MW increase simultaneously on Path 49 and SCIT while meeting the post-transient voltage deviation limits of the transmission system. Also, no new reactive power equipment or SPS are needed.

The "Path 49 Non-Simultaneous Post Transient Analysis Summary" is provided in Appendix F.3.a. The following subsections provide highlights of the analysis.

Mohave On Line

1. Post-transient voltage deviations did not exceed 5% during single contingencies in both the pre-and-post-project cases.

2. For loss of the Palo Verde–Devers 500 kV line, the post-transient voltage deviation was 5% at Miguel and Iron Mountain buses in the pre-project case only.

3. Post-transient voltage deviations did not exceed 10% during double contingencies in both the pre-and-post-project cases.

4. No reactive power equipment or SPS were needed to meet the post-transient voltage deviation limits of the transmission system.

Mohave Off Line

1. Post-transient voltage deviations did not exceed 5% during single contingencies in both the pre-and-post-project cases.

2. For loss of the Palo Verde–Devers 500 kV line, the post-transient voltage deviation was 5% at Miguel and Iron Mountain buses in the pre-project case only.

3. Post-transient voltage deviations did not exceed 10% during double contingencies in both the pre-and-post-project cases.

4. No reactive power equipment or SPS were needed to meet the post-transient voltage deviation limits of the transmission system.

VII. FINDINGS OF SIMULTANEOUS ANALYSES

In accordance with the WECC Rating Policy, rating studies may need to determine possible simultaneous impacts on other path ratings for a specific project plan of service. At the beginning of this Study, requests were made to assess what impacts DPV2 may have on the following 8 paths.

1. Path 26 (Midway-Vincent)
2. Path 27 (IPPDC)
3. Path 41 (Sylmar)
4. Path 42 (IID)
5. Path 61 (Victorville-Lugo)
6. Path 64 (Marketplace-Adelanto)
7. Path 65 (PDCI)
8. Centennial Path

Details on the criteria, assumptions and methodology for these simultaneous analyses are provided in section IV.2 on page 16 of the Study Scope (Appendix A).

The overall conclusion of the simultaneous analyses is that the DPV2 POS described in section III.B is adequate to achieve a 1,200 MW rating increase on Path 49 simultaneously with seven of eight Paths at their respective maximum ratings while meeting the Criteria. Nomograms and/or operating procedures will be needed to mitigate the simultaneous interactions with Path 61. The DPV2 POS attributed to these simultaneous analyses include increasing the reactive power capability, and implementing nomograms, operating procedures and an SPS.

The dynamic stability analyses performed for these 8 paths identified reactive power levels that met the Criteria. Results indicated that the addition of a 300 MVAr shunt capacitor at Devers 500 kV bus and a 500 MVAr SVC at Devers 500 kV bus will achieve a 1,200 MW rating increase on Path 49 simultaneously with the other paths at their respective ratings in the Mohave On Line Scenario. For the Mohave Off Line Scenario, adding a 300 MVAr shunt capacitor at Devers 500 kV bus, a 600 MVAr SVC at Devers 500 kV bus and a 400 MVAr SVC at Lugo 500 kV bus will achieve a 1,200 MW rating increase on Path 49 simultaneously with the other paths at their respective ratings. Summaries of results of the reactive support analyses are presented in the following Tables VII.A and VII.B for the Mohave On Line and Off Line scenarios, respectively.

Details of the Simultaneous analyses results are provided in Appendix G.

TABLE VII.A

Simultaneous Analyses Reactive Support Summary

Post-DPV2 With Mohave On Line				
	Reactive Support to Meet the Planning Criteria			Stability Results
Path	New Shunt Capacitor @ Devers 500 kV (MVAr)	Add New 2nd SVC @ Devers 500 kV (MVAr)	Install New SVC @ Lugo 500 kV (MVAr)	Transient Voltage Dip (%) and Damping
NERC/WECC Planning Standard - Category B (Loss of Single Element)				
SCIT Benchmark	None	400	None	Valleysc 500 - 24.1 Devrsvc 500 - 23.7 Hi Deser 115 - 23.7 System < 20 cycles Damping >0
26 (Midway-Vincent)	None	400	None	Hi Deser 115 - 18.50 Devers 500 - 19.1 Devrsvc1 500 - 19.1 System < 20 cycles Damping >0
27 (IPPDC)	None	400	None	Hi Deser 115 - 23.7 Valleysc 500 - 24.2 Devrsvc1 500 - 23.8 Hi Deser 115 - 20 cycles Damping >0
41 (Sylmar)	150	400	None	Hi Deser 115 - 23.4 Valleysc 500 - 23.9 Devrsvc1 500 - 23.6 2 SCE 115 = 20 cycles Damping >0
42 (IID-SCE)				
61 (Victorville-Lugo)	300	500	400	El Nido 66 - 25.9 Valleysc 500 - 24.6 Olinda 66 - 24.4 System <= 20.2 cycles Damping >0
64 (Marketplace-Adelanto)	300	500	None	Padua 66 - 24.5 Valleysc 500 - 25.0 Valysvc2 500 - 24.0 System <= 20 cycles Damping >0
65 (PDCI)	None	400	None	Hi Deser 115 - 23.9 Valleysc 500 - 24.2 Devrsvc1 500 - 24.0 System <= 20.2 cycles Damping >0
Centennial	300	500	None	Hi deser 115 - 22.9 Valleysc 500 - 23.7 Devrsvc1 500 - 22.8 System < 20 cycles Damping >0

TABLE VII.B

Simultaneous Analyses Reactive Support Summary

Post-DPV2 With Mohave Off Line				
	Reactive Support to Meet the Planning Criteria			Stability Results
Path	New Shunt Capacitor @ Devers 500 kV (MVAr)	Add New 2nd SVC @ Devers 500 kV (MVAr)	Install New SVC @ Lugo 500 kV (MVAr)	Transient Voltage Dip (%) and Damping
NERC/WECC Planning Standard - Category B (Loss of Single Element)				
SCIT Benchmark	None	500	None	Valleysc 500 - 23.5 Devrsvc 500 - 22.7 Hi Desert 115 - 22.8 System < 20 cycles Damping >0
26 (Midway-Vincent)	None	500	None	Hi Deser 115 - 18.7 Devers 500 - 19.2 Devrsvc1 500 - 19.2 System < 20 cycles Damping >0
27 (IPPDC)	None	500	None	Hi Deser 115 - 22.9 Valleysc 500 - 23.6 Devrsvc1 500 - 22.8 System < 20 cycles Damping >0
41 (Sylmar)	None	500	None	Villa Pk 66 - 24.5 Valleysc 500 - 24.7 Valysvc2 115 - 23.7 30 SCE 115 = 20 cycles Damping >0
42 (IID-SCE)	None	400	None	N. Gila 69 - 11.5 Horsmesa 115 - 11.7 Devrsvc1 500 - 11.0 System < 20 cycles Damping >0
61 (Victorville-Lugo)	300	700	400	Villa pk 66 - 24.9 Serrano 230 - 23.8 Olinda 66 - 23.3 System <= 20.2 cycles Damping >0
64 (Marketplace-Adelanto)	300	600	400	Padua 66 - 23.8 Victorvl 287 - 24.7 Adelsvc 500 - 24.3 System <= 20 cycles Damping >0
65 (PDCI)	None	500	None	Hi Deser 115 - 22.3 Valleysc 500 - 22.8 Devrsvc1 500 - 22.4 System < 20 cycles Damping >0
Centennial	300	600	400	Padua 66 - 24.0 Victorvl 287 - 25.0 Adelsvc 500 - 24.6 System <= 20 cycles Damping >0

VII.A PATH 26

VII.A.1 OVERALL SUMMARY

The analysis is based on the key assumption that Path 49 and Path 26 power flows would be assessed at their respective maximum ratings, being 9,255 MW for Path 49 and 3,700 MW for Path 26. Also, these results are based on the assumption that the reactive power equipment identified in the SCIT Nomogram Simultaneous analysis would be in operation.

Results indicate that the DPV2 POS is adequate to achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 26 at its maximum rating of 3,700 MW while meeting the Criteria.

No SPS was needed to meet the stability or post transient criteria for the double line outage of the Palo Verde-Devers 500 kV line and the Harquahala-Devers 500 kV line or the Palo Verde-Devers 500 kV line and the Hassayampa-Harquahala 500 kV line.

Details of the Path 26 analysis results are provided in Appendix G.(series).1.

VII.A.2 POWER FLOW ANALYSIS RESULTS

The key finding from the power flow analysis is that DPV2 can achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 26 at its maximum rating of 3,700 MW while meeting the thermal limits of the transmission system.

The "Control Area Summary of Pre-Contingency Base Cases" is provided in Appendix G.1.a.1. The "Path Flow Summary of Pre-Contingency Base Cases" is provided in Appendix G.1.b.1. Also, "Power Flow Diagrams of Pre-Contingency Bases Cases" are provided in Appendix G.1.c.1.

The "Path 49 Non-Simultaneous Power Flow Analysis Summary," which lists the 5 highest transmission loadings for normal and contingency conditions, is provided in Appendix G.1.d.1. The following subsections provide highlights of the analysis.

Mohave On Line

1. No transmission element was loaded above 100% of its continuous rating under normal (i.e. non-contingency) conditions in the post-project case. However, a marginal loading of 100.7% occurred on each of the two Perkins phase shifters in the post-project sensitivity case, which was considered acceptable by the owners of the equipment.

2. No transmission element was loaded above 100% of its emergency rating under single contingency conditions in the post-project case. For the double line outage of the Midway-Vincent 500 kV lines #1 & 2, a loading of 99.4% of the emergency rating of the Midway-Vincent 500 kV line #3 occurred. To be able to model the SPS of Path 26, which is required for this double line outage, this double line outage analysis was performed using the post-transient power flow.

3. Implementing an SPS, which trips 1,125 MW of generation at Harquahala and drops 1,350 MW of load in SCE's system, mitigates the thermal overloads caused by the double line outage of the Palo Verde-Devers and Harquahala-Devers 500 kV lines. Pending further studies, an operating procedure may be developed to reduce the amount of generation and load dropping.

Mohave Off Line

1. No transmission element was loaded above 100% of its continuous rating under normal (i.e. non-contingency) conditions in the post-project case. However, a marginal loading of 100.6% occurred on each of the two Perkins phase shifters in the post-project sensitivity case, which was considered acceptable by the owners of the equipment.

2. No transmission element was loaded above 100% of its emergency rating under single contingency conditions in the post-project case. For the double line outage of the Midway-Vincent 500 kV lines #1 & 2, a loading of 99.3% of the emergency rating of the Midway-Vincent 500 kV line #3 occurred. To be able to model the SPS of Path 26, which is required for this double line outage, this double line outage analysis was performed using the post-transient power flow.

3. Implementing an SPS, which trips 1,125 MW of generation at Harquahala and drops 1,350 MW of load in SCE's system, mitigates the thermal overloads caused by the double line outage of the Palo Verde-Devers and Harquahala-Devers 500 kV lines. Pending further studies, an operating procedure may be developed to reduce the amount of generation and load dropping.

VII.A.3 DYNAMIC STABILITY ANALYSIS RESULTS

The key finding from the dynamic stability analysis is that the reactive power equipment identified in the SCIT Nomogram Simultaneous analysis is sufficient to achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 26 at its maximum rating of 3,700 MW while meeting the voltage dip, damping and frequency deviation limits of the transmission system. No SPS is needed.

The "Path 49 Non-Simultaneous Stability Analysis Summary" is provided in Appendix G.2.a.1. The following subsections provide highlights of the analysis.

Mohave On Line

1. All machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips and frequency deviations were well within their respective limits in the post-project case.

2. No SPS was needed to meet the voltage dip, damping and frequency deviation limits of the transmission system.

Mohave Off Line

1. All machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips and frequency deviations were well within their respective limits in the post-project case.

2. No SPS was needed to meet the voltage dip, damping and frequency deviation limits of the transmission system

VII.A.4 POST-TRANSIENT POWER FLOW ANALYSIS RESULTS

The key finding from the post-transient power flow analysis is that the reactive power equipment identified in the SCIT Nomogram Simultaneous analysis is sufficient to achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 26 at its maximum rating of 3,700 MW while meeting the post-transient voltage deviation limits of the transmission system. Also, no SPS is needed.

The "Path 49 Non-Simultaneous Post Transient Analysis Summary" is provided in Appendix G.3.a.1. The following subsections provide highlights of the analysis.

Mohave On Line

1. Post-transient voltage deviations did not exceed 5% during single contingencies in both the post-project case.

2. No SPS was needed to meet the post-transient voltage deviation limits of the transmission system.

Mohave Off Line

1. Post-transient voltage deviations did not exceed 5% during single contingencies in both the post-project case.

2. No SPS was needed to meet the post-transient voltage deviation limits of the transmission system.

VII.B PATH 27

VII.B.1 OVERALL SUMMARY

The analysis is based on the key assumption that Path 49 and Path 27 power flows would be assessed at their respective maximum ratings, being 9,255 MW for Path 49 and 1,920 MW for Path 27. Also, these results are based on the assumption that the reactive power equipment identified in the SCIT Nomogram Simultaneous analysis would be in operation.

Results indicate that the DPV2 POS is adequate to achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 27 at its maximum rating of 1,920 MW while meeting the Criteria.

No SPS was needed to meet the stability or post transient criteria for the double line outage of the Palo Verde-Devers 500 kV line and the Harquahala-Devers 500 kV line or the Palo Verde-Devers 500 kV line and the Hassayampa-Harquahala 500 kV line.

Details of the Path 27 analysis results are provided in Appendix G.(series).2.

VII.B.2 POWER FLOW ANALYSIS RESULTS

The key finding from the power flow analysis is that DPV2 can achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 27 at its maximum rating of 1,920 MW while meeting the thermal limits of the transmission system.

The "Control Area Summary of Pre-Contingency Base Cases" is provided in Appendix G.1.a.2. The "Path Flow Summary of Pre-Contingency Base Cases" is provided in Appendix G.1.b.2. Also, "Power Flow Diagrams of Pre-Contingency Bases Cases" are provided in Appendix G.1.c.2.

The "Path 49 Non-Simultaneous Power Flow Analysis Summary," which lists the 5 highest transmission loadings for normal and contingency conditions, is provided in Appendix G.1.d.2. The following subsections provide highlights of the analysis.

Mohave On Line

1. No transmission element was loaded above 100% of its continuous rating under normal (i.e. non-contingency) conditions in the post-project case. However, a marginal loading of 100.8% occurred on each of the two Perkins phase shifters in the post-project sensitivity case, which was considered acceptable by the owners of the equipment.

2. No transmission element was loaded above 100% of its emergency rating under single contingency conditions in the post-project case.

3. Implementing an SPS, which trips 1,125 MW of generation at Harquahala and drops 1,350 MW of load in SCE's system, mitigates the thermal overloads caused by the double line outage of the Palo Verde-Devers and Harquahala-Devers 500 kV lines. Pending further studies, an operating procedure may be developed to reduce the amount of generation and load dropping.

Mohave Off Line

1. No transmission element was loaded above 100% of its continuous rating under normal (i.e. non-contingency) conditions in the post-project case. However, a marginal loading of 100.6% occurred on each of the two Perkins phase shifters in the post-project sensitivity case, which was considered acceptable by the owners of the equipment.

2. No transmission element was loaded above 100% of its emergency rating under single contingency conditions in the post-project case.

3. Implementing an SPS, which trips 1,125 MW of generation at Harquahala and drops 1,350 MW of load in SCE's system, mitigates the thermal overloads caused by the double line outage of the Palo Verde-Devers and Harquahala-Devers 500 kV lines. Pending further studies, an operating procedure may be developed to reduce

the amount of generation and load dropping.

VII.B.3 DYNAMIC STABILITY ANALYSIS RESULTS

The key finding from the dynamic stability analysis is that the reactive power equipment identified in the SCIT Nomogram Simultaneous analysis is sufficient to achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 27 at its maximum rating of 1,920 MW while meeting the voltage dip, damping and frequency deviation limits of the transmission system. No SPS is needed.

The "Path 49 Non-Simultaneous Stability Analysis Summary" is provided in Appendix G.2.a.2. The following subsections provide highlights of the analysis.

Mohave On Line

1. All machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips and frequency deviations were well within their respective limits in the post-project case.

2. No SPS was needed to meet the voltage dip, damping and frequency deviation limits of the transmission system.

Mohave Off Line

1. All machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips and frequency deviations were well within their respective limits in the post-project case.

2. No SPS was needed to meet the voltage dip, damping and frequency deviation limits of the transmission system

VII.B.4 POST-TRANSIENT POWER FLOW ANALYSIS RESULTS

The key finding from the post-transient power flow analysis is that the reactive power equipment identified in the SCIT Nomogram Simultaneous analysis is sufficient to achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 27 at its maximum rating of 1,920 MW while meeting the post-transient voltage deviation limits of the transmission system. Also, no SPS is needed.

The "Path 49 Non-Simultaneous Post Transient Analysis Summary" is provided in Appendix G.3.a.2. The following subsections provide highlights of the analysis.

Mohave On Line

1. Post-transient voltage deviations did not exceed 5% during single contingencies in both the post-project case.

2. No SPS was needed to meet the post-transient voltage deviation limits of the transmission system.

Mohave Off Line

1. Post-transient voltage deviations did not exceed 5% during single contingencies in both the post-project case.

2. No SPS was needed to meet the post-transient voltage deviation limits of the transmission system.

VII.C PATH 41

VII.C.1 OVERALL SUMMARY

The analysis is based on the key assumption that Path 49 and Path 41 power flows would be assessed at their respective maximum ratings, being 9,255 MW for Path 49 and 1,600 MW for Path 41. Also, these results are based on the assumption that the reactive power equipment identified in the SCIT Nomogram Simultaneous analysis would be in operation.

Results indicate that the DPV2 POS is adequate to achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 41 at its maximum rating of 1,600 MW while meeting the Criteria.

Results indicate that for the Mohave On Line Scenario, if adequate reactive support (at least 150 MVAr shunt capacitor under critical operating conditions) is not in service at Devers 500 kV substation, a nomogram can be implemented to achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 41 at its maximum rating of 1,600 MW while meeting the voltage dip, damping and frequency deviation limits of the transmission system.

No SPS was needed to meet the stability or post transient criteria for the double line outage of the Palo Verde-Devers 500 kV line and the Harquahala-Devers 500 kV line or the Palo Verde-Devers 500 kV line and the Hassayampa-Harquahala 500 kV line.

Details of the Path 41 analysis results are provided in Appendix G.(series).3.

VII.C.2 POWER FLOW ANALYSIS RESULTS

The key finding from the power flow analysis is that DPV2 can achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 41 at its maximum rating of 1,600 MW while meeting the thermal limits of the transmission system.

The "Control Area Summary of Pre-Contingency Base Cases" is provided in Appendix G.1.a.3. The "Path Flow Summary of Pre-Contingency Base Cases" is provided in Appendix G.1.b.3. Also, "Power Flow Diagrams of Pre-Contingency Bases Cases" are provided in Appendix G.1.c.3.

The "Path 49 Non-Simultaneous Power Flow Analysis Summary," which lists the 5 highest transmission loadings for normal and contingency conditions, is provided in Appendix G.1.d.3. The following subsections provide highlights of the analysis.

Mohave On Line

1. No transmission element was loaded above 100% of its continuous rating under normal (i.e. non-contingency) conditions in the post-project case. However, a marginal loading of 100.6% occurred on each of the two Perkins phase shifters in the post-project sensitivity case, which was considered acceptable by the owners of the equipment.

2. Except for the single line outage of the N.Gila-IV 500 kV line, no transmission element was loaded above 100% of its emergency rating under single contingency conditions in the post-project case.

3. For the single line outage of the N.Gila-IV 500 kV line, a loading of 100.8% of the emergency rating of the Elcentsw 161/230 kV transformer bank occurred. The above loading is marginally greater than the loading that occurred for the same outage in the pre-project SCIT nomogram simultaneous case, as shown in the table below. IID has indicated that they are in the process of developing future plans to address this overload.

	Emergency Loading (%)		
Limiting Element	Pre-Project SCIT	Path 41 Case	Outage
ELCENTSW 161/230	100.1	100.8	NGIV

4. Implementing an SPS, which trips 1,125 MW of generation at Harquahala and drops 1,350 MW of load in SCE's system, mitigates the thermal overloads caused by the double line outage of the Palo Verde-Devers and Harquahala-Devers 500 kV lines. Pending further studies, an operating procedure may be developed to reduce the amount of generation and load dropping.

Mohave Off Line

1. No transmission element was loaded above 100% of its continuous rating under normal (i.e. non-contingency) conditions in the post-project case. However, a marginal loading of 100.5% occurred on each of the two Perkins phase shifters in the post-project sensitivity case, which was considered acceptable by the owners of the equipment.

2. No transmission element was loaded above 100% of its emergency rating under single contingency conditions in the post-project case.

3. Implementing an SPS, which trips 1,125 MW of generation at Harquahala and drops 1,350 MW of load in SCE's system, mitigates the thermal overloads caused by the double line outage of the Palo Verde-Devers and Harquahala-Devers 500 kV lines. Pending further studies, an operating procedure may be developed to reduce the amount of generation and load dropping.

VII.C.3 DYNAMIC STABILITY ANALYSIS RESULTS

The key finding from the dynamic stability analysis for the Mohave On Line Scenario is the need to install a 150 MVAr shunt capacitor at Devers 500 kV bus or develop and implement a nomogram to achieve a 1,200 MW rating increase on Path 49

simultaneously with Path 41 at its maximum rating of 1,600 MW while meeting the voltage dip, damping and frequency deviation limits of the transmission system. For the Mohave Off Line Scenario, the reactive power equipment identified in the SCIT Nomogram Simultaneous analysis is sufficient to achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 41 at its maximum rating of 1,600 MW while meeting the voltage dip, damping and frequency deviation limits of the transmission system. No SPS is needed.

The "Path 49 Non-Simultaneous Stability Analysis Summary" is provided in Appendix G.2.a.3. The following subsections provide highlights of the analysis.

Mohave On Line

1. Except for the Hassayampa-N.Gila 500 kV line outage, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips and frequency deviations were well within their respective limits in the post-project case.

2. Violations of the voltage duration criterion occurred for loss of the Hassayampa-N.Gila 500 kV line as shown in Appendix G.2.a.3.1.

3. With the addition of a 150 MVAr shunt capacitor at Devers 500 kV bus, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips, duration and frequency deviations were within their respective limits as shown in Appendix G.2.a.3.2.

4. With the implementation of a nomogram similar to the conceptual nomogram provided in Appendix G.4.a.3, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips, duration and frequency deviations were within their respective limits as shown in Appendix G.2.a.3.3.

5. No SPS was needed to meet the voltage dip, damping and frequency deviation limits of the transmission system

Mohave Off Line

1. All machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips and frequency deviations were well within their respective limits in the post-project case.

2. No SPS was needed to meet the voltage dip, damping and frequency deviation limits of the transmission system

VII.C.4 POST-TRANSIENT POWER FLOW ANALYSIS RESULTS

The key finding from the post-transient power flow analysis is that the reactive power equipment identified in the SCIT Nomogram Simultaneous analysis is sufficient to achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 41 at its maximum rating of 1,600 MW while meeting the post-transient voltage deviation limits

of the transmission system. Also, no SPS is needed.

The "Path 49 Non-Simultaneous Post Transient Analysis Summary" is provided in Appendix G.3.a.3. The following subsections provide highlights of the analysis.

Mohave On Line

1. Post-transient voltage deviations did not exceed 5% during single contingencies in the post-project case.

2. No SPS was needed to meet the post-transient voltage deviation limits of the transmission system.

Mohave Off Line

1. Post-transient voltage deviations did not exceed 5% during single contingencies in the post-project case.

2. No SPS was needed to meet the post-transient voltage deviation limits of the transmission system.

VII.D PATH 42

VII.D.1 OVERALL SUMMARY

The analysis is based on the key assumption that Path 49 and Path 42 power flows would be assessed at their respective maximum ratings, being 9,255 MW for Path 49 and 600 MW for Path 42. Also, these results are based on the assumption that the reactive power equipment identified in the SCIT Nomogram Simultaneous analysis would be in operation. In accordance with the Imperial Irrigation District (IID), who made the request to perform this Path 42 analysis, the analysis was performed on the Mohave off line scenario only.

Results indicate that the DPV2 POS is adequate to achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 42 at its maximum rating of 600 MW while meeting the Criteria.

No SPS was needed to meet the stability or post transient criteria for the double line outage of the Palo Verde-Devers 500 kV line and the Harquahala-Devers 500 kV line or the Palo Verde-Devers 500 kV line and the Hassayampa-Harquahala 500 kV line.

Details of the Path 42 analysis results are provided in Appendix G.(series).4.

VII.D.2 POWER FLOW ANALYSIS RESULTS

The key finding from the power flow analysis is that DPV2 can achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 42 at its maximum rating of 600 MW while meeting the thermal limits of the transmission system.

There were some pre-existing thermal loading violations on the Imperial Irrigation District (IID) and San Diego Gas & Electric (SDG&E) transmission systems under

contingency conditions. These violations occurred in both the pre-and-post project cases. For the most part, the violations were less severe in the post-project cases than in the pre-project cases. However, 5 out of 31 overloads on IID's system resulted in post-project loadings marginally above the pre-project loadings. IID informed the PRG that they are developing future plans to mitigate these overloads. The one overload on SDG&E's system occurred only in the pre-project case.

The "Control Area Summary of Pre-Contingency Base Cases" is provided in Appendix G.1.a.4. The "Path Flow Summary of Pre-Contingency Base Cases" is provided in Appendix G.1.b.4. Also, "Power Flow Diagrams of Pre-Contingency Bases Cases" are provided in Appendix G.1.c.4.

The "Path 49 Non-Simultaneous Power Flow Analysis Summary," which lists the 5 highest transmission loadings for normal and contingency conditions, is provided in Appendix G.1.d.4. The following subsections provide highlights of the analysis.

Mohave Off Line

1. Except for the Rtap2-RTP1 92 kV transmission line, no transmission element was loaded above 100% of its continuous rating under normal (i.e. non-contingency) conditions in the pre-or-post-project cases. However, marginal loadings of 100.5% and 100.6% occurred on the two Perkins phase shifters in the pre-and-post-project cases, respectively, which were considered acceptable by the owners of the equipment.

2. The Rtap2-RTP1 92 kV transmission line was loaded to 103.0% of its continuous rating under normal (i.e. non-contingency) conditions in the pre-project case. The same line had a lower loading of 102.5% in the post-project case, as shown in the table below. IID has indicated that they are in the process of developing future plans to address this overload.

	Emergency Loading (%)		
Limiting Element	Pre-Project	Post-Project	Outage
RTAP2-RTP1 92	103.0	102.5	None

3. For the single line outage of the Palo Verde-Devers 500 kV line in the pre-project case, marginal loadings of 100.8% of the emergency rating of the series capacitor of the Mead-Perkins 500 kV line and 100.5% of the emergency rating of the two Perkins phase shifters occurred. For the same outage, these loadings dropped well below 100% in the post-project case, as shown in the table below.

	Emergency Loading (%)		
Limiting Element	Pre-Project	Post-Project	Outage
Mead-Perkins Series Cap	100.8	85.8	PVDV
Mead-Perkins Phase Shifters	100.5	86.4	PVDV

4. The RTAP2-RTP1 92 kV transmission line on IID's system was loaded above 100%

of its emergency rating under 13 single contingency conditions in the pre-and-post-project cases. For these same 13 outages, the post-project loadings were below the pre-project loadings. One outage involves the new Harquahala-Devers 500 kV line, which exhibited performance similar to that of the existing Palo Verde-Devers 500 kV line outage in the post-project case. In the last outage, the loading dropped below 100% in the post-project case, as shown in the table below. IID has indicated that they are in the process of developing future plans to address this overload.

	Emergency Loading (%)		
Limiting Element	Pre-Project	Post-Project	Outage
RTAP2-RTP1 92	131.9	114.8	PVDV
RTAP2-RTP1 92	121.2	119.4	IVMG
RTAP2-RTP1 92	N/A	114.3	HQDV
RTAP2-RTP1 92	106.0	104.6	MDPK
RTAP2-RTP1 92	105.0	104.3	LGVT
RTAP2-RTP1 92	104.9	104.0	MOEL
RTAP2-RTP1 92	104.9	104.0	NVCR
RTAP2-RTP1 92	104.3	103.8	LGMH
RTAP2-RTP1 92	104.2	103.8	ELLG
RTAP2-RTP1 92	104.1	103.6	MDMK
RTAP2-RTP1 92	101.9	101.4	VTSB
RTAP2-RTP1 92	101.8	101.4	DVOV
RTAP2-RTP1 92	101.7	101.1	DVVT 1
RTAP2-RTP1 92	101.7	101.1	DVVT 2
RTAP2-RTP1 92	100.9	99.0	SRVL

5. The AV58TP1-Bannister 161 kV transmission line on IID's system was loaded above 100% of its emergency rating under two single contingency conditions in the pre-and-post-project cases. For these same 2 outages, the post-project loadings were well below the pre-project loadings. One outage involves the new Harquahala-Devers 500 kV line, which exhibited performance similar to that of the existing Palo Verde-Devers 500 kV line outage in the post-project case, as shown in the table below. IID has indicated that they are in the process of developing future plans to address this overload.

	Emergency Loading (%)		
Limiting Element	Pre-Project	Post-Project	Outage
AV58TP1-Bannister 161	121.6	110.1	IVMG
AV58TP1-Bannister 161	111.4	106.2	PVDV

AV58TP1-Bannister 161	N/A	105.8	HQDV

6. The Niland-Midway 161 kV transmission line on IID's system was loaded above 100% of its emergency rating under three single contingency conditions in the pre-and-post-project cases. For these same 3 outages, the post-project loadings were below the pre-project loadings. One outage involves the new Harquahala-Devers 500 kV line, which exhibited performance similar to that of the existing Palo Verde-Devers 500 kV line outage in the post-project case. In the last two outages, these loadings dropped below 100% in the post-project case, as shown in the table below. IID has indicated that they are in the process of developing future plans to address this overload.

	Emergency Loading (%)		
Limiting Element	Pre-Project	Post-Project	Outage
Niland-Midway 161	116.9	114.6	IVMG
Niland-Midway 161	114.6	104.2	PVDV
Niland-Midway 161	N/A	104.0	HQDV
Niland-Midway 161	102.6	100.5	MDPK
Niland-Midway 161	101.2	99.4	NVCR
Niland-Midway 161	101.1	99.3	MOEL

7. The Niland-CVSUB161 161 kV transmission line on IID's system was loaded above 100% of its emergency rating under a single contingency condition in the pre-project case. For the same outage, this loading dropped below 100% in the post-project case, as shown in the table below. IID has indicated that they are in the process of developing future plans to address this overload.

	Emergency Loading (%)		
Limiting Element	Pre-Project	Post-Project	Outage
Niland-CVSUB161 161	101.8	94.5	PVDV

8. The Ramon-Mirage 230 kV transmission line on IID's system was loaded above 100% of its emergency rating under two single contingency conditions in the pre-and-post-project cases. For these two outages, the loadings in the post-project cases increased a relatively small amount above the loadings in the pre-project cases. In the last outage, the loading dropped below 100% in the post-project case, as shown in the table below. IID has indicated that they are in the process of developing future plans to address this overload.

	Emergency Loading (%)		
Limiting Element	Pre-Project	Post-Project	Outage
Ramon-Mirage 230	143.3	145.0	CODV
Ramon-Mirage 230	100.5	102.2	IVMG
Ramon-Mirage 230	101.6	98.5	PVDV

9. The Coachella-Devers 230 kV transmission line on IID's system was loaded above 100% of its emergency rating under two single contingency conditions in the pre-and-post-project cases. For these two outages, the loadings in the post-project cases increased a relatively small amount above the loadings in the pre-project cases, as shown in the table below. IID has indicated that they are in the process of developing future plans to address this overload.

	Emergency Loading (%)		
Limiting Element	Pre-Project	Post-Project	Outage
Coachella-Devers 230	133.9	135.2	RMMR
Coachella-Devers 230	112.3	113.1	CORM

10. The Coachella-Ramon 230 kV transmission line on IID's system was loaded above 100% of its emergency rating under a single contingency condition in the pre-and-post-project cases. For this outage, the loading in the post-project case increased a relatively small amount above the loading in the pre-project case, as shown in the table below. IID has indicated that they are in the process of developing future plans to address this overload.

	Emergency Loading (%)		
Limiting Element	Pre-Project	Post-Project	Outage
Coachella-Ramon 230	124.3	125.5	CODV

11. The Friars-Mission 138 kV transmission line on SDG&E's system was loaded above 100% of its emergency rating under a single contingency condition in the pre-project case. For the same outage, this loading dropped well below 100% in the post-project case, as shown in the table below.

	Emergency Loading (%)		
Limiting Element	Pre-Project	Post-Project	Outage
Friars-Mission 138	101.0	81.7	PVDV

12. Implementing an SPS, which trips 1,125 MW of generation at Harquahala and drops 1,350 MW of load in SCE's system, mitigates the thermal overloads caused by the double line outage of the Palo Verde-Devers and Harquahala-Devers 500 kV lines. Pending further studies, an operating procedure may be developed to reduce the amount of generation and load dropping.

VII.D.3 DYNAMIC STABILITY ANALYSIS RESULTS

The key finding from the dynamic stability analysis is that the reactive power equipment identified in the SCIT Nomogram Simultaneous analysis is sufficient to achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 42 at its maximum rating of 600 MW while meeting the voltage dip, damping and frequency deviation limits of the transmission system. No SPS is needed.

The "Path 49 Non-Simultaneous Stability Analysis Summary" is provided in Appendix

G.2.a.4. The following subsections provide highlights of the analysis.

Mohave Off Line

1. All machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips and frequency deviations were well within their respective limits in the post-project case.

2. No SPS was needed to meet the voltage dip, damping and frequency deviation limits of the transmission system

VII.D.4 POST-TRANSIENT POWER FLOW ANALYSIS RESULTS

The key finding from the post-transient power flow analysis is that the reactive power equipment identified in the SCIT Nomogram Simultaneous analysis is sufficient to achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 42 at its maximum rating of 600 MW while meeting the post-transient voltage deviation limits of the transmission system. Also, no SPS is needed.

The "Path 49 Non-Simultaneous Post Transient Analysis Summary" is provided in Appendix G.3.a.4. The following subsections provide highlights of the analysis.

Mohave Off Line

1. Post-transient voltage deviations did not exceed 5% during single contingencies in the post-project case. However, a marginal voltage deviation of 5.1% occurred at three Arizona buses (FOOTHILS 69 kV, N.GILA 69 kV and SW1 69 kV).

2. No SPS was needed to meet the post-transient voltage deviation limits of the transmission system.

VII.E PATH 61

VII.E.1 OVERALL SUMMARY

The analysis is based on the key assumption that Path 49 and Path 61 power flows would be assessed at their respective maximum ratings, being 9,255 MW for Path 49 and 2.400 MW for Path 61. Also, these results are based on the assumption that the reactive power equipment identified in the SCIT Nomogram Simultaneous analysis would be in operation.

Results indicate that the DPV2 POS is not adequate to achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 61 at its maximum rating of 2,400 MW while meeting the Criteria.

Results indicate that nomograms, one for thermal and one for stability mitigation, can be implemented to manage a 1,200 MW rating increase on Path 49 simultaneously with Path 61 at its maximum rating of 2,400 MW while meeting the voltage dip, damping and frequency deviation limits of the transmission system. Results also indicate that an operating procedure can be employed in conjunction with the nomogram to reduce Path 61 schedules to relieve thermal overloads on the Victorville-Lugo 500 kV line for 5

single contingency outages.

For the Mohave Off Line scenario, an SPS that trips Arizona generation and drops load in Southern California, is required to meet the voltage deviation criteria for the Palo Verde-Devers 500 kV and the Harquahala-Devers 500 kV double line outage. No SPS was needed for the Mohave On Line scenario to meet the stability or post transient criteria.

Details of the Path 61 analysis results are provided in Appendix G.(series).5.

VII.E.2 POWER FLOW ANALYSIS RESULTS

The key finding from the power flow analysis is that DPV2 cannot achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 61 at its maximum rating of 2,400 MW while meeting the thermal limits of the transmission system. A thermal overload needs to be mitigated. In the absence of other remediation, a nomogram and operating procedure can be employed to reduce schedules to relieve thermal overloads on the Victorville-Lugo 500 kV line for 5 single contingency outages. The analysis was performed on two post-project sensitivity cases representing two nomogram "Corner Points."

The "Control Area Summary of Pre-Contingency Base Cases" is provided in Appendix G.1.a.5. The "Path Flow Summary of Pre-Contingency Base Cases" is provided in Appendix G.1.b.5. Also, "Power Flow Diagrams of Pre-Contingency Bases Cases" are provided in Appendix G.1.c.5.

The "Path 49 Non-Simultaneous Power Flow Analysis Summary," which lists the 5 highest transmission loadings for normal and contingency conditions, is provided in Appendix G.1.d.5. The following subsections provide highlights of the analysis.

Mohave On Line

1. No transmission element was loaded above 100% of its continuous rating under normal (i.e. non-contingency) conditions in the post-project case. However, a marginal loading of 100.8% occurred on each of the two Perkins phase shifters in the two post-project sensitivity cases representing the two nomogram "Corner Points." Corner Point 1 represents flow limits of 8,555 MW and 2,400 MW on Path 49 and Path 61, respectively. Corner Point 2 represents flow limits of 9,255 MW and 1,900 MW on Path 49 and Path 61, respectively. Refer to the conceptual nomogram provided in Appendix G.4.a.5.

2. The Victorville-Lugo 500 kV transmission line on SCE and LADWP's systems was loaded close to 100% of its emergency rating for five single contingency conditions in the post-project case representing nomogram Corner Point 1. For the same outage, this loading dropped well below 100% in the post-project case representing nomogram Corner Point 2, as shown in the table below.

	Emergency Loading (%)		
Limiting Element	Corner Point 1	Corner Point 2	Outage

Victorville-Lugo 500	101.1	94.5	ELLU
Victorville-Lugo 500	97.5	92.1	MOLU
Victorville-Lugo 500	95.6	84.7	DVVL
Victorville-Lugo 500	95.9	82.3	NGIV
Victorville-Lugo 500	95.0	82.2	PVDV

3. Implementing an SPS, which trips 1,125 MW of generation at Harquahala and drops 1,350 MW of load in SCE's system, mitigates the thermal overloads caused by the double line outage of the Palo Verde-Devers and Harquahala-Devers 500 kV lines. Pending further studies, an operating procedure may be developed to reduce the amount of generation and load dropping.

Mohave Off Line

1. No transmission element was loaded above 100% of its continuous rating under normal (i.e. non-contingency) conditions in the post-project case. However, a marginal loading of 100.6% and 100.5% occurred on each of the two Perkins phase shifters in the two post-project sensitivity cases representing the two nomogram "Corner Points," respectively. Corner Point 1 represents flow limits of 8,555 MW and 2,400 MW on Path 49 and Path 61, respectively. Corner Point 2 represents flow limits of 9,255 MW and 1,700 MW on Path 49 and Path 61, respectively. Refer to the conceptual nomogram provided in Appendix G.4.b.5.

2. The Victorville-Lugo 500 kV transmission line on SCE and LADWP's systems was loaded close to 100% of its emergency rating for three single contingency conditions in the post-project case representing nomogram Corner Point 1. For the same outage, this loading dropped well below 100% in the post-project case representing nomogram Corner Point 2, as shown in the table below.

	Emergency Loading (%)		
Limiting Element	Corner Point 1	Corner Point 2	Outage
Victorville-Lugo 500	99.0	82.5	MOLU
Victorville-Lugo 500	99.0	82.3	ELLU
Victorville-Lugo 500	94.7	74.1	NGIV

3. For the single line outage of the N.Gila-IV 500 kV line, a loading of 101.8% of the emergency rating of the Elcentsw 161/230 kV transformer bank occurred in the post-project case representing nomogram Corner Point 2. The above loading is close to the 101.5% loading that occurred for the same outage in the pre-project SCIT nomogram simultaneous case. IID has indicated that they are in the process of developing future plans to address this overload.

	Emergency Loading (%)		
Limiting Element	Corner Point 1	Corner Point 2	Outage
ELCENTSW 161/230	< 90.0	101.8	NGIV

4. Implementing an SPS, which trips 1,125 MW of generation at Harquahala and drops 1,350 MW of load in SCE's system, mitigates the thermal overloads caused by the double line outage of the Palo Verde-Devers and Harquahala-Devers 500 kV lines. Pending further studies, an operating procedure may be developed to reduce the amount of generation and load dropping.

VII.E.3 DYNAMIC STABILITY ANALYSIS RESULTS

The key finding from the dynamic stability analysis for the Mohave On Line Scenario is the need to install a 300 MVAr shunt capacitor at Devers 500 kV bus and an additional 500 MVAr of SVC capacity at Devers 500 kV bus (i.e. 100 MVAr more than required to achieve 1,200 MW increase on the SCIT path) or develop and implement a nomogram to achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 61 at its maximum rating of 2,400 MW while meeting the voltage dip, damping and frequency deviation limits of the transmission system. For the Mohave Off Line Scenario, there is a need to install a 300 MVAr shunt capacitor at Devers 500 kV bus, an additional 700 MVAr of SVC capacity at Devers 500 kV bus (i.e. 200 MVAr more than required to achieve 1,200 MW increase on the SCIT path) and a 400 MVAr SVC at Lugo 500 kV bus or develop and implement a nomogram to achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 61 at its maximum rating of 2,400 MW while meeting the voltage dip, damping and frequency deviation limits of the transmission system. No SPS is needed.

The "Path 49 Non-Simultaneous Stability Analysis Summary" is provided in Appendix G.2.a.5. The following subsections provide highlights of the analysis.

Mohave On Line

1. Except for the Hassayampa-N.Gila 500 kV line outage, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips and frequency deviations were well within their respective limits in the post-project case.

2. Violations of the voltage dip, duration and frequency deviation criteria occurred for loss of the Hassayampa-N.Gila 500 kV line as shown in Appendix G.2.a.5.1.

3. With the addition of a 300 MVAr shunt capacitor and the addition of 500 MVAr of SVC capacity at the Devers 500 kV bus, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips, duration and frequency deviations were within their respective limits as shown in Appendix G.2.a.5.2.

4. With the implementation of a nomogram similar to the conceptual nomogram provided in Appendix G.4.c.5, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips, duration and frequency deviations were within their respective limits as shown in Appendix G.2.a.5.3.

5. No SPS was needed to meet the voltage dip, damping and frequency deviation limits of the transmission system.

Mohave Off Line

1. Except for the Hassayampa-N.Gila 500 kV line outage, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips and frequency deviations were well within their respective limits in the post-project case.

2. Violations of the voltage dip, duration and frequency deviation criteria occurred for loss of the Hassayampa-N.Gila 500 kV line as shown in Appendix G.2.a.5.1.

3. With the addition of a 300 MVAr shunt capacitor and the addition of 700 MVAr of SVC capacity at the Devers 500 kV bus, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips, duration and frequency deviations were within their respective limits as shown in Appendix G.2.a.5.2.

4. With the implementation of a nomogram similar to the conceptual nomogram provided in Appendix G.4.d.5, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips, duration and frequency deviations were within their respective limits as shown in Appendix G.2.a.5.3.

5. No SPS was needed to meet the voltage dip, damping and frequency deviation limits of the transmission system.

VII.E.4 POST-TRANSIENT POWER FLOW ANALYSIS RESULTS

The key finding from the post-transient power flow analysis is that the reactive power equipment identified in the SCIT Nomogram Simultaneous analysis is sufficient to achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 61 at its maximum rating of 2,400 MW while meeting the post-transient voltage deviation limits of the transmission system. No SPS is needed for the Mohave On Line scenario. However, for the Mohave Off Line scenario, an SPS that trips Arizona generation and drops load in Southern California, is required to meet the voltage deviation criteria for the Palo Verde-Devers 500 kV and the Harquahala-Devers 500 kV double line outage.

The "Path 49 Non-Simultaneous Post Transient Analysis Summary" is provided in Appendix G.3.a.5. The following subsections provide highlights of the analysis.

Mohave On Line

1. Post-transient voltage deviations did not exceed 5% during single contingencies in the post-project case.

2. No SPS was needed to meet the post-transient voltage deviation limits of the transmission system.

Mohave Off Line

1. Post-transient voltage deviations did not exceed 5% during single contingencies in the post-project case.

2. Except for the Palo Verde-Devers 500 kV and the Harquahala-Devers 500 kV double line outage, no SPS was needed to meet the post-transient voltage deviation limits of the transmission system.

3. For the Palo Verde-Devers 500 kV and the Harquahala-Devers 500 kV double line outage, an SPS that tripped Harquahala generating units CT1 (240 MW) and ST1 (123 MW) and dropped San Bernardino load (389 MW) resulted in acceptable post-transient voltage deviations.

VII.F PATH 64

VII.F.1 OVERALL SUMMARY

The analysis is based on the key assumption that Path 49 and Path 64 power flows would be assessed at their respective maximum ratings, being 9,255 MW for Path 49 and 1,200 MW for Path 64. Since Path 64 is part of the Path 46 definition, increasing Path 64 flow to its maximum rating of 1,200 MW correspondingly increases Path 46 flows close to its maximum rating. For example, with the Path 64 flow at 1,200 MW in the Mohave On Line scenario, the flow on Path 46 is 11,586 MW, which would be very close to the Path 46 target rating of 11,823 MW. This Path 46 target rating is based on increasing the existing Path 46 rating of 10,118 MW by 505 MW and 1,200 MW for the Upgrade Project and DPV2, respectively. In essence, this sensitivity is providing a glimpse of DPV2 performance requirements needed to achieve a 1,200 MW rating increase on Path 46. Also, this Path 64 base case has the same SCIT flow as the SCIT Benchmark case, in essence, making it another SCIT corner point case.

Results indicate that the DPV2 POS is adequate to achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 64 at its maximum rating of 1,200 MW while meeting the Criteria.

Results indicate that reactive power equipment needs to be installed on the SCE system to achieve a 1,200 MW rating increase simultaneously on Path 49 and Path 64 while meeting the Criteria. Specifically, the addition of a 300 MVAr shunt capacitor at Devers 500 kV bus and a 500 MVAr SVC at Devers 500 kV bus will achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 64 at its maximum rating of 1,200 MW while meeting the voltage dip, damping and frequency deviation limits of the transmission system. For the Mohave Off Line Scenario, adding a 300 MVAr shunt capacitor at Devers 500 kV bus, a 600 MVAr SVC at Devers 500 kV bus and a 400 MVAr SVC at Lugo 500 kV bus will achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 64 at its maximum rating of 1,200 MW while meeting the voltage dip, damping and frequency deviation limits of the transmission system.

An SPS that trips Arizona generation and drops load in Southern California, is required to meet the voltage deviation criteria for the Palo Verde-Devers 500 kV and the Harquahala-Devers 500 kV double line outage.

Details of the Path 64 analysis results are provided in Appendix G.(series).6.

VII.F.2 POWER FLOW ANALYSIS RESULTS

The key finding from the power flow analysis is that DPV2 can achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 64 at its maximum rating of 1,200 MW while meeting the thermal limits of the transmission system.

The "Control Area Summary of Pre-Contingency Base Cases" is provided in Appendix G.1.a.6. The "Path Flow Summary of Pre-Contingency Base Cases" is provided in Appendix G.1.b.6. Also, "Power Flow Diagrams of Pre-Contingency Bases Cases" are provided in Appendix G.1.c.6.

The "Path 49 Non-Simultaneous Power Flow Analysis Summary," which lists the 5 highest transmission loadings for normal and contingency conditions, is provided in Appendix G.1.d.6. The following subsections provide highlights of the analysis.

Mohave On Line

1. No transmission element was loaded above 100% of its continuous rating under normal (i.e. non-contingency) conditions in the post-project case. However, a marginal loading of 100.6% occurred on each of the two Perkins phase shifters in the post-project case.

2. For the single line outage of the N.Gila-IV 500 kV line, a loading of 102.3% of the emergency rating of the Elcentsw 161/230 kV transformer bank occurred in the post-project case. The above loading is marginally greater than the loading that occurred for the same outage in the pre-project SCIT nomogram simultaneous case. IID has indicated that they are in the process of developing future plans to address this overload.

	Emergency Loading (%)		
Limiting Element	Pre-Project SCIT	Path 64 Case	Outage
ELCENTSW 161/230	100.1	102.3	NGIV

3. Implementing an SPS, which trips 1,125 MW of generation at Harquahala and drops 1,350 MW of load in SCE's system, mitigates the thermal overloads caused by the double line outage of the Palo Verde-Devers and Harquahala-Devers 500 kV lines. Pending further studies, an operating procedure may be developed to reduce the amount of generation and load dropping.

Mohave Off Line

1. No transmission element was loaded above 100% of its continuous rating under normal (i.e. non-contingency) conditions in the post-project case.

2. For the single line outage of the N.Gila-IV 500 kV line, a loading of 101.9% of the emergency rating of the Elcentsw 161/230 kV transformer bank occurred in the post-project case. The above loading is marginally greater than the loading that occurred for the same outage in the pre-project SCIT nomogram simultaneous case.

IID has indicated that they are in the process of developing future plans to address this overload.

	Emergency Loading (%)		
Limiting Element	Pre-Project SCIT	Path 64 Case	Outage
ELCENTSW 161/230	101.5	101.9	NGIV

3. Implementing an SPS, which trips 1,125 MW of generation at Harquahala and drops 1,350 MW of load in SCE's system, mitigates the thermal overloads caused by the double line outage of the Palo Verde-Devers and Harquahala-Devers 500 kV lines. Pending further studies, an operating procedure may be developed to reduce the amount of generation and load dropping.

VII.F.3 DYNAMIC STABILITY ANALYSIS RESULTS

The key finding from the dynamic stability analysis for the Mohave On Line Scenario is the addition of a 300 MVAr shunt capacitor at Devers 500 kV bus and a 500 MVAr SVC at Devers 500 kV bus will achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 64 at its maximum rating of 1,200 MW while meeting the voltage dip, damping and frequency deviation limits of the transmission system. For the Mohave Off Line Scenario, adding a 300 MVAr shunt capacitor at Devers 500 kV bus, a 600 MVAr SVC at Devers 500 kV bus and a 400 MVAr SVC at Lugo 500 kV bus will achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 64 at its maximum rating of 1,200 MW while meeting the voltage dip, damping and frequency deviation limits of the transmission system.

The "Path 49 Non-Simultaneous Stability Analysis Summary" is provided in Appendix G.2.a.6.1 and Appendix G.2.a.6.2. The following subsections provide highlights of the analysis.

Mohave On Line

1. Except for the Hassayampa-N.Gila 500 kV single-contingency line outage, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips and frequency deviations were well within their respective limits in the post-project case.

2. Violations of the voltage dip, duration and frequency deviation criteria occurred for loss of the Hassayampa-N.Gila 500 kV line as shown in Appendix G.2.a.6.1.

3. With the addition of a 300 MVAr shunt capacitor and a 500 MVAr SVC at the Devers 500 kV bus, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips, duration and frequency deviations were within their respective limits as shown in Appendix G.2.a.6.2.

4. No SPS was needed to meet the voltage dip, damping and frequency deviation limits of the transmission system.

Mohave Off Line

1. Except for the Hassayampa-N.Gila 500 kV single-contingency line outage and the double contingency of the Palo Verde-Devers 500 kV and Harquahala-Devers 500 kV lines, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips and frequency deviations were well within their respective limits in the post-project case.

2. Violations of the voltage dip, duration and frequency deviation criteria occurred for loss of the Hassayampa-N.Gila 500 kV line as shown in Appendix G.2.a.6.1.

3. With the addition of a 300 MVAr shunt capacitor and a 600 MVAr SVC at the Devers 500 kV bus, and a 400 MVAr SVC at Lugo 500 kV bus, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips, duration and frequency deviations were within their respective limits as shown in Appendix G.2.a.6.2.

4. Violations of the voltage dip, duration and frequency deviation criteria occurred for loss of the Palo Verde-Devers 500 kV and Harquahala-Devers 500 kV lines as shown in Appendix G.2.a.6.1.

5. With the addition of a 300 MVAr shunt capacitor and a 600 MVAr SVC at the Devers 500 kV bus, and a 400 MVAr SVC at Lugo 500 kV bus, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips, duration and frequency deviations were within their respective limits as shown in Appendix G.2.a.6.2.

6. No SPS was needed to meet the voltage dip, damping and frequency deviation limits of the transmission system.

VII.F.4 POST-TRANSIENT POWER FLOW ANALYSIS RESULTS

The key finding from the post-transient power flow analysis is that the reactive power equipment identified in the SCIT Nomogram Simultaneous analysis is sufficient to achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 64 at its maximum rating of 1,200 MW while meeting the post-transient voltage deviation limits of the transmission system. An SPS, which trips Arizona generation and drops load in Southern California, is required to meet the voltage deviation criteria for the Palo Verde-Devers 500 kV and the Harquahala-Devers 500 kV double line outage.

The "Path 49 Non-Simultaneous Post Transient Analysis Summary" is provided in Appendix G.3.a.6. The following subsections provide highlights of the analysis.

Mohave On Line

1. Post-transient voltage deviations did not exceed 5% during single contingencies in the post-project case.

2. Except for the Palo Verde-Devers 500 kV and the Harquahala-Devers 500 kV

double line outage, post-transient voltage deviations did not exceed 10% during double contingencies in the post-project case.

3. For the Palo Verde-Devers 500 kV and the Harquahala-Devers 500 kV double line outage, the post-transient voltage deviation was 10.9% at Miguel 500 kV bus. Implementing an SPS that tripped Harquahala generating units CT1 (240 MW) and ST1 (123 MW) and dropped San Bernardino load (389 MW) resulted in acceptable post-transient voltage deviations. Also, the reactive power equipment identified in the Dynamic Stability Analysis Results in section VII.F.3 was represented.

Mohave Off Line

1. Post-transient voltage deviations did not exceed 5% during single contingencies in the post-project case.

2. Except for the Palo Verde-Devers 500 kV and the Harquahala-Devers 500 kV double line outage, post-transient voltage deviations did not exceed 10% during double contingencies in the post-project case.

3. For the Palo Verde-Devers 500 kV and the Harquahala-Devers 500 kV double line outage, the post-transient voltage analysis did not converge, possibly indicating a voltage collapse. Implementing an SPS that tripped Harquahala generating units CT1 (240 MW) and ST1 (123 MW) and dropped San Bernardino load (389 MW) resulted in convergence and acceptable post-transient voltage deviations. Also, the reactive power equipment identified in the Dynamic Stability Analysis Results in section VII.F.3 was represented.

VII.G PATH 65

VII.G.1 OVERALL SUMMARY

The analysis is based on the key assumption that Path 49 and Path 65 power flows would be assessed at their respective maximum ratings, being 9,255 MW for Path 49 and 3,100 MW for Path 65. Also, these results are based on the assumption that the reactive power equipment identified in the SCIT Nomogram Simultaneous analysis would be in operation.

Results indicate that the DPV2 POS is adequate to achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 65 at its maximum rating of 3,100 MW while meeting the Criteria.

No SPS was needed to meet the stability or post transient criteria for the double line outage of the Palo Verde-Devers 500 kV line and the Harquahala-Devers 500 kV line or the Palo Verde-Devers 500 kV line and the Hassayampa-Harquahala 500 kV line.

Details of the Path 65 analysis results are provided in Appendix G.(series).7.

VII.G.2 POWER FLOW ANALYSIS RESULTS

The key finding from the power flow analysis is that DPV2 can achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 65 at its maximum rating of 3,100

MW while meeting the thermal limits of the transmission system.

The "Control Area Summary of Pre-Contingency Base Cases" is provided in Appendix G.1.a.7. The "Path Flow Summary of Pre-Contingency Base Cases" is provided in Appendix G.1.b.7. Also, "Power Flow Diagrams of Pre-Contingency Bases Cases" are provided in Appendix G.1.c.7.

The "Path 49 Non-Simultaneous Power Flow Analysis Summary," which lists the 5 highest transmission loadings for normal and contingency conditions, is provided in Appendix G.1.d.7. The following subsections provide highlights of the analysis.

Mohave On Line

1. No transmission element was loaded above 100% of its continuous rating under normal (i.e. non-contingency) conditions in the post-project case. However, a marginal loading of 100.7% occurred on each of the two Perkins phase shifters in the post-project sensitivity case, which was considered acceptable by the owners of the equipment.

2. No transmission element was loaded above 100% of its emergency rating under single contingency conditions in the post-project case.

3. Implementing an SPS, which trips 1,125 MW of generation at Harquahala and drops 1,350 MW of load in SCE's system, mitigates the thermal overloads caused by the double line outage of the Palo Verde-Devers and Harquahala-Devers 500 kV lines. Pending further studies, an operating procedure may be developed to reduce the amount of generation and load dropping.

Mohave Off Line

1. No transmission element was loaded above 100% of its continuous rating under normal (i.e. non-contingency) conditions in the post-project case. However, a marginal loading of 100.6% occurred on each of the two Perkins phase shifters in the post-project sensitivity case, which was considered acceptable by the owners of the equipment.

2. No transmission element was loaded above 100% of its emergency rating under single contingency conditions in the post-project case.

3. Implementing an SPS, which trips 1,125 MW of generation at Harquahala and drops 1,350 MW of load in SCE's system, mitigates the thermal overloads caused by the double line outage of the Palo Verde-Devers and Harquahala-Devers 500 kV lines. Pending further studies, an operating procedure may be developed to reduce the amount of generation and load dropping.

VII.G.3 DYNAMIC STABILITY ANALYSIS RESULTS

The key finding from the dynamic stability analysis is that the reactive power equipment identified in the SCIT Nomogram Simultaneous analysis is sufficient to

achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 65 at its maximum rating of 3,100 MW while meeting the voltage dip, damping and frequency deviation limits of the transmission system. No SPS is needed.

The "Path 49 Non-Simultaneous Stability Analysis Summary" is provided in Appendix G.2.a.7. The following subsections provide highlights of the analysis.

Mohave On Line

1. All machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips and frequency deviations were well within their respective limits in the post-project case.

2. No SPS was needed to meet the voltage dip, damping and frequency deviation limits of the transmission system.

Mohave Off Line

1. All machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips and frequency deviations were well within their respective limits in the post-project case.

2. No SPS was needed to meet the voltage dip, damping and frequency deviation limits of the transmission system

VII.G.4 POST-TRANSIENT POWER FLOW ANALYSIS RESULTS

The key finding from the post-transient power flow analysis is that the reactive power equipment identified in the SCIT Nomogram Simultaneous analysis is sufficient to achieve a 1,200 MW rating increase on Path 49 simultaneously with Path 65 at its maximum rating of 3,100 MW while meeting the post-transient voltage deviation limits of the transmission system. Also, no SPS is needed.

The "Path 49 Non-Simultaneous Post Transient Analysis Summary" is provided in Appendix G.3.a.7. The following subsections provide highlights of the analysis.

Mohave On Line

1. Post-transient voltage deviations did not exceed 5% during single contingencies in both the post-project case.

2. No SPS was needed to meet the post-transient voltage deviation limits of the transmission system.

Mohave Off Line

1. Post-transient voltage deviations did not exceed 5% during single contingencies in both the post-project case.

2. No SPS was needed to meet the post-transient voltage deviation limits of the transmission system.

VII.H CENTENNIAL PATH

VII.H.1 OVERALL SUMMARY

The analysis is based on the key assumption that Path 49 and the Centennial Path power flows would be assessed at their respective maximum ratings, being 9,255 MW for Path 49 and 3,000 MW for the Centennial Path. The flow on the Centennial Path is driven in large part to the heavy concentration of generation in the local southern Nevada area. The output of this local area generation is in large measure being scheduled to California over Path 46. Therefore, increasing the Centennial Path flow to its maximum rating of 3,000 MW correspondingly increased Path 46 flows close to its maximum expected rating. Like the Path 64 sensitivity analysis, this sensitivity is also providing a glimpse of DPV2 performance requirements needed to achieve a 1,200 MW rating increase on Path 46. Also like the Path 64 base case, this Centennial Path base case has the same SCIT flow as the SCIT Benchmark case, in essence, making it another SCIT corner point case.

Results indicate that the DPV2 POS is adequate to achieve a 1,200 MW rating increase on Path 49 simultaneously with the Centennial Path at its maximum rating of 3,000 MW while meeting the Criteria.

Results indicate that reactive power equipment needs to be installed on the SCE system to achieve a 1,200 MW rating increase simultaneously on Path 49 and the Centennial Path while meeting the Criteria. Specifically, the addition of a 300 MVAr shunt capacitor at Devers 500 kV bus and a 500 MVAr SVC at Devers 500 kV bus will achieve a 1,200 MW rating increase on Path 49 simultaneously with the Centennial Path at its maximum rating of 3,000 MW while meeting the voltage dip, damping and frequency deviation limits of the transmission system. For the Mohave Off Line Scenario, adding a 300 MVAr shunt capacitor at Devers 500 kV bus, a 600 MVAr SVC at Devers 500 kV bus and a 400 MVAr SVC at Lugo 500 kV bus will achieve a 1,200 MW rating increase on Path 49 simultaneously with the Centennial Path at its maximum rating of 3,000 MW while meeting the voltage dip, damping and frequency deviation limits of the transmission system.

An SPS that trips Arizona generation and drops load in Southern California, is required to meet the voltage deviation criteria for the Palo Verde-Devers 500 kV and the Harquahala-Devers 500 kV double line outage.

Details of the Centennial Path analysis results are provided in Appendix G.(series).8.

VII.H.2 POWER FLOW ANALYSIS RESULTS

The key finding from the power flow analysis is that DPV2 can achieve a 1,200 MW rating increase on Path 49 simultaneously with the Centennial Path at its maximum rating of 3,000 MW while meeting the thermal limits of the transmission system.

The "Control Area Summary of Pre-Contingency Base Cases" is provided in Appendix G.1.a.8. The "Path Flow Summary of Pre-Contingency Base Cases" is provided in Appendix G.1.b.8. Also, "Power Flow Diagrams of Pre-Contingency Bases Cases" are provided in Appendix G.1.c.8.

The "Path 49 Non-Simultaneous Power Flow Analysis Summary," which lists the 5 highest transmission loadings for normal and contingency conditions, is provided in Appendix G.1.d.8. The following subsections provide highlights of the analysis.

Mohave On Line

1. No transmission element was loaded above 100% of its continuous rating under normal (i.e. non-contingency) conditions in the post-project case. However, a marginal loading of 100.6% occurred on each of the two Perkins phase shifters in the post-project case.

2. For the single line outage of the N.Gila-IV 500 kV line, a loading of 102.5% of the emergency rating of the Elcentsw 161/230 kV transformer bank occurred in the post-project case. The above loading is marginally greater than the loading that occurred for the same outage in the pre-project SCIT nomogram simultaneous case. IID has indicated that they are in the process of developing future plans to address this overload.

	Emergency Loading (%)		
Limiting Element	Pre-Project SCIT	Centennial Case	Outage
ELCENTSW 161/230	100.1	102.5	NGIV

3. Implementing an SPS, which trips 1,125 MW of generation at Harquahala and drops 1,350 MW of load in SCE's system, mitigates the thermal overloads caused by the double line outage of the Palo Verde-Devers and Harquahala-Devers 500 kV lines. Pending further studies, an operating procedure may be developed to reduce the amount of generation and load dropping.

Mohave Off Line

1. No transmission element was loaded above 100% of its continuous rating under normal (i.e. non-contingency) conditions in the post-project case.

2. For the single line outage of the N.Gila-IV 500 kV line, a loading of 101.4% of the emergency rating of the Elcentsw 161/230 kV transformer bank occurred in the post-project case. The above loading is marginally smaller than the loading that occurred for the same outage in the pre-project SCIT nomogram simultaneous case. IID has indicated that they are in the process of developing future plans to address this overload.

	Emergency Loading (%)		
Limiting Element	Pre-Project SCIT	Centennial Case	Outage
ELCENTSW 161/230	101.5	101.4	NGIV

3. Implementing an SPS, which trips 1,125 MW of generation at Harquahala and drops 1,350 MW of load in SCE's system, mitigates the thermal overloads caused by the double line outage of the Palo Verde-Devers and Harquahala-Devers 500 kV lines. Pending further studies, an operating procedure may be developed to reduce the amount of generation and load dropping.

VII.H.3 DYNAMIC STABILITY ANALYSIS RESULTS

The key finding from the dynamic stability analysis for the Mohave On Line Scenario is the addition of a 300 MVAr shunt capacitor at Devers 500 kV bus and a 500 MVAr SVC at Devers 500 kV bus will achieve a 1,200 MW rating increase on Path 49 simultaneously with the Centennial Path at its maximum rating of 3,000 MW while meeting the voltage dip, damping and frequency deviation limits of the transmission system. For the Mohave Off Line Scenario, adding a 300 MVAr shunt capacitor at Devers 500 kV bus, a 600 MVAr SVC at Devers 500 kV bus and a 400 MVAr SVC at Lugo 500 kV bus will achieve a 1,200 MW rating increase on Path 49 simultaneously with the Centennial Path at its maximum rating of 3,000 MW while meeting the voltage dip, damping and frequency deviation limits of the transmission system.

The "Path 49 Non-Simultaneous Stability Analysis Summary" is provided in Appendix G.2.a.8.1 and Appendix G.2.a.8.2. The following subsections provide highlights of the analysis.

Mohave On Line

1. Except for the Hassayampa-N.Gila 500 kV single-contingency line outage, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips and frequency deviations were well within their respective limits in the post-project case.

2. Violations of the voltage dip, duration and frequency deviation criteria occurred for loss of the Hassayampa-N.Gila 500 kV line as shown in Appendix G.2.a.8.1.

3. With the addition of a 300 MVAr shunt capacitor and a 500 MVAr SVC at the Devers 500 kV bus, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips, duration and frequency deviations were within their respective limits as shown in Appendix G.2.a.8.2.

4. No SPS was needed to meet the voltage dip, damping and frequency deviation limits of the transmission system.

Mohave Off Line

1. Except for the Hassayampa-N.Gila 500 kV single-contingency line outage and the double contingency of the Palo Verde-Devers 500 kV and Harquahala-Devers 500 kV lines, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips and frequency deviations were well within their respective limits in the post-project case.

2. Violations of the voltage dip, duration and frequency deviation criteria occurred for loss of the Hassayampa-N.Gila 500 kV line as shown in Appendix G.2.a.8.1.

3. With the addition of a 300 MVAr shunt capacitor and a 600 MVAr SVC at the Devers 500 kV bus, and a 400 MVAr SVC at Lugo 500 kV bus, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips, duration and frequency deviations were within their respective limits as shown in Appendix G.2.a.8.2.

4. Violations of the voltage dip, duration and frequency deviation criteria occurred for loss of the Palo Verde-Devers 500 kV and Harquahala-Devers 500 kV lines as shown in Appendix G.2.a.8.1.

5. With the addition of a 300 MVAr shunt capacitor and a 600 MVAr SVC at the Devers 500 kV bus, and a 400 MVAr SVC at Lugo 500 kV bus, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips, duration and frequency deviations were within their respective limits as shown in Appendix G.2.a.8.2.

6. No SPS was needed to meet the voltage dip, damping and frequency deviation limits of the transmission system.

VII.H.4 POST-TRANSIENT POWER FLOW ANALYSIS RESULTS

The key finding from the post-transient power flow analysis is that the reactive power equipment identified in the SCIT Nomogram Simultaneous analysis is sufficient to achieve a 1,200 MW rating increase on Path 49 simultaneously with the Centennial Path at its maximum rating of 3,000 MW while meeting the post-transient voltage deviation limits of the transmission system. However, an SPS, which trips Arizona generation and drops load in Southern California, is required to meet the voltage deviation criteria for the Palo Verde-Devers 500 kV and Harquahala-Devers 500 kV double line outage.

The "Path 49 Non-Simultaneous Post Transient Analysis Summary" is provided in Appendix G.3.a.8. The following subsections provide highlights of the analysis.

Mohave On Line

1. Post-transient voltage deviations did not exceed 5% during single contingencies in the post-project case.
2. Except for the Palo Verde-Devers 500 kV and the Harquahala-Devers 500 kV double line outage, post-transient voltage deviations did not exceed 10% during double contingencies in the post-project case.
3. For the Palo Verde-Devers 500 kV and the Harquahala-Devers 500 kV double line outage, the post-transient voltage deviation was 10.9% at Miguel 500 kV bus. Implementing an SPS that tripped Harquahala generating units CT1 (240 MW) and ST1 (123 MW) and dropped San Bernardino load (389 MW) resulted in acceptable

post-transient voltage deviations. Also, the reactive power equipment identified in the Dynamic Stability Analysis Results in section VII.H.3 was represented.

Mohave Off Line

1. Post-transient voltage deviations did not exceed 5% during single contingencies in the post-project case.
2. Except for the Palo Verde-Devers 500 kV and the Harquahala-Devers 500 kV double line outage, post-transient voltage deviations did not exceed 10% during double contingencies in the post-project case.
3. For the Palo Verde-Devers 500 kV and the Harquahala-Devers 500 kV double line outage, the post-transient voltage analysis did not converge, possibly indicating a voltage collapse. Implementing an SPS that tripped Harquahala generating units CT1 (240 MW) and ST1 (123 MW) and dropped San Bernardino load (389 MW) resulted in convergence and acceptable post-transient voltage deviations. Also, the reactive power equipment identified in the Dynamic Stability Analysis Results in section VII.H.3 was represented.

VIII. FINDINGS OF SENSITIVITY ANALYSES

In accordance with the WECC Rating Policy, the rating study may need to assess reliability impacts of DPV2 together with other similarly situated projects. At the beginning of this Study, the EOR9000+ Project (EOR9000) was identified as a Phase 2 project. EOR9000 plans to increase Path 49 by 1,245 MW in the 2008 timeframe. To the extent criteria violations were found in the combined Phase 2 sensitivity analysis, mitigation measures would be identified that allow the combined Phase 2 projects to meet the Criteria. At a point in time when it becomes clear that both DPV2 and EOR9000 will be built, a rating study of the combined DPV2 and EOR9000 projects should be jointly pursued by the respective project sponsors.

Analyses of sensitivities, which are not related to other similarly situated Phase 2 projects or involved with existing paths, may be performed at the mutual agreement of the project sponsor and the entity making the request. Four requests of this type were made. To the extent that criteria violations were found in these sensitivities, no attempt was made at identifying mitigation measures in this Study. Below is the overall list of the five sensitivity analyses evaluated in this Study.

1. EOR9000
2. APS PV-TS5
3. SWAT CRT Midpoint Substation
4. IID 200 MW Request
5. MWD Pump Load Off

Details on the criteria, assumptions and methodology for these sensitivity analyses are provided in section V on page 18 of the Study Scope (Appendix A).

The conclusion of the similarly situated DPV2 and EOR9000 sensitivity analysis is that the DPV2 POS described in section III.B is not adequate to achieve a combined 2,445 MW rating increase on Path 49 while meeting the Criteria. Enhancements to the DPV2 POS, which would

be required to meet the Criteria, include additional reactive support, more operating procedures, possibly more nomograms and an augmented SPS.

Results of the non-similarly situated sensitivities were mixed. The DPV2 POS is adequate to achieve a 1,200 MW rating increase on Path 49 simultaneously with APS's PV-TS5 project in service while meeting the Criteria. The SWAT CRT's Midpoint Substation sensitivity results indicated that power flowed from the 230 kV transmission grid to the Midpoint Substation, which was opposite of the desired flow direction. As for IID's request for an additional 200 MW on DPV2, the DPV2 POS is not adequate to achieve a 1,400 MW rating increase on Path 49 without additional reactive support. Finally, the DPV2 POS is adequate to achieve a 1,200 MW rating increase on Path 49 with MWD pump loads off line.

Details of the Sensitivity analyses results are provided in Appendix H.

VIII.A EOR9000+ PROJECT SENSITIVITY

VIII.A.1 OVERALL SUMMARY

The analysis is based on the key assumption that the Path 49 power flow would be assessed at its maximum rating of 10,500 MW assuming both DPV2 and EOR9000+ Projects in service. This 10,500 MW Path 49 rating is based on the assumption that DPV2 and the EOR9000+ Project would add 1,200 MW and 1,245 MW, respectively, to the current Path 49 rating of 8,055 MW.

The increase in SCIT path flow resulting from schedules to California was 1,200 MW for DPV2 and 645 MW for the EOR9000+ project. Also, these results are based on the assumption that the reactive power equipment identified in the SCIT Nomogram Simultaneous analysis would be in operation.

Results indicate that both DPV2 and EOR9000+ Projects can achieve a 10,500 MW rating increase on Path 49 while meeting the Criteria if enhancements to the DPV2 POS are made. These enhancements include additional reactive support, more operating procedures, possibly more nomograms and an augmented SPS.

Details of the EOR9000 analysis results are provided in Appendix H.(series).1.

VIII.A.2 POWER FLOW ANALYSIS RESULTS

The key finding from the power flow analysis is that both DPV2 and EOR9000+ Projects can achieve a 10,500 MW rating increase on Path 49 while meeting the thermal limits of the transmission system. However, additional reactive equipment and an operating procedure may be required to meet the thermal criteria. For the Mohave On Line Scenario, the addition of 700 MVAr and 100 MVAr of shunt capacitors at Devers and Valley 500 kV buses, respectively, will contribute to meeting the Criteria. Also, the addition of 1,200 MVAr, 200 MVAr and 800 MVAr of SVC capacity at Devers, Valley and Lugo 500 kV buses, respectively, will achieve a combined 2,445 MW rating increase on Path 49 while meeting the thermal limits of the transmission system. For the Mohave Off Line Scenario, the addition of 800 MVAr and 100 MVAr of shunt capacitors at Devers and Valley 500 kV buses, respectively, will contribute to meeting the Criteria. Also, the addition of 1,500 MVAr, 200 MVAr and 1,200 MVAr of SVC capacity at Devers, Valley and Lugo 500 kV buses, respectively, will achieve a

combined 2,445 MW rating increase on Path 49 while meeting the thermal limits of the transmission system. In addition, thermal overloads need to be mitigated. In the absence of other remediation, an operating procedure could be employed to reduce schedules to relieve thermal overloads on two transmission facilities. An alternative mitigation is to develop and implement a nomogram to achieve the 2,445 MW Path 49 rating increase, which could reduce the number and amount of the aforementioned enhancements.

The "Control Area Summary of Pre-Contingency Base Cases" is provided in Appendix H.1.a.1. The "Path Flow Summary of Pre-Contingency Base Cases" is provided in Appendix H.1.b.1. Also, "Power Flow Diagrams of Pre-Contingency Bases Cases" are provided in Appendix H.1.c.1.

The "Path 49 Non-Simultaneous Power Flow Analysis Summary," which lists the 5 highest transmission loadings for normal and contingency conditions, is provided in Appendix H.1.d.1. The following subsections provide highlights of the analysis.

Mohave On Line

1. No transmission element was loaded above 100% of its continuous rating under normal (i.e. non-contingency) conditions in the post-projects case.
2. Except for loss of the N.Gila – IV 500 kV line, no transmission element was loaded above 100% of its emergency rating under single contingency conditions in the post-projects case.
3. For loss of the N.Gila – IV 500 kV line, the power flow case did not converge, possibly indicating unacceptable performance. Adding reactive power equipment identified in the Dynamic Stability Analysis Results in the corresponding section VIII.A.3 allowed convergence, but resulted in a loading of 101.9% of the emergency rating of the Elcentsw 161/230 kV transformer bank.
4. An operating procedure could be employed to reduce schedules and consequently lower the loading on the Elcentsw 161/230 kV transformer bank to below its emergency rating.

Mohave Off Line

1. No transmission element was loaded above 100% of its continuous rating under normal (i.e. non-contingency) conditions in the post-project case.
2. Except for loss of the N.Gila–IV 500 kV line, the Hassayampa–N.Gila 500 kV line, and the Vista–San Bernardino 230 kV line # 2, no transmission element was loaded above 100% of its emergency rating under single contingency conditions in the post-projects case.
3. For loss of the N.Gila–IV 500 kV line, the power flow case did not converge, possibly indicating unacceptable performance. Adding reactive power equipment identified in the Dynamic Stability Analysis Results in the corresponding section VIII.A.3 allowed convergence, but resulted in a loading of 108.7% of the emergency rating of the Elcentsw 161/230 kV transformer bank.

4. An operating procedure could be employed to reduce schedules and consequently lower the loading on the Elcentsw 161/230 kV transformer bank to below its emergency rating.
5. For loss of the Hassayampa–N.Gila 500 kV line, the power flow case did not converge, possibly indicating unacceptable performance. Adding reactive power equipment identified in the Dynamic Stability Analysis Results in the corresponding section VIII.A.3 allowed convergence and loadings below 100% of the facilities emergency ratings.
6. For loss of the Vista–San Bernardino 230 kV line # 2, a loading of 102.1% of the emergency rating of the Etiwanda-San Bernardino 230 kV line occurred in the post-projects case.
7. An operating procedure could be employed to reduce schedules and consequently lower the loading on Etiwanda-San Bernardino 230 kV line to below its emergency rating.

VIII.A.3 DYNAMIC STABILITY ANALYSIS RESULTS

The key finding from the dynamic stability analysis for the Mohave On Line Scenario is the addition of 700 MVAr and 100 MVAr of shunt capacitors at Devers and Valley 500 kV buses, respectively, will contribute to meeting the Criteria. Also, the addition of 1,200 MVAr, 200 MVAr and 800 MVAr of SVC capacity at Devers, Valley and Lugo 500 kV buses, respectively, will achieve a combined 2,445 MW rating increase on Path 49 while meeting the voltage dip, damping and frequency deviation limits of the transmission system. For the Mohave Off Line Scenario, the addition of 800 MVAr and 100 MVAr of shunt capacitors at Devers and Valley 500 kV buses, respectively, will contribute to meeting the Criteria. Also, the addition of 1,500 MVAr, 200 MVAr and 1,200 MVAr of SVC capacity at Devers, Valley and Lugo 500 kV buses, respectively, will achieve a combined 2,445 MW rating increase on Path 49 while meeting the voltage dip, damping and frequency deviation limits of the transmission system. An alternative mitigation is to develop and implement a nomogram to achieve the 2,445 MW Path 49 rating increase.

An SPS, which trips Arizona generation and drops load in Southern California, is required to meet the stability criteria for two double contingencies: the Palo Verde-Devers 500 kV and Harquahala-Devers 500 kV lines, and the Palo Verde-Devers 500 kV and Hassayampa-Harquahala 500 kV lines.

The "Path 49 Non-Simultaneous Stability Analysis Summary" is provided in Appendix H.2.a.1.1 and Appendix H.2.a.1.2. The following subsections provide highlights of the analysis.

Mohave On Line

1. Except for the Hassayampa-N.Gila 500 kV single-contingency line outage, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips and frequency deviations were well within their respective limits in the post-projects case.

2. Violations of the voltage dip, duration and frequency deviation criteria occurred for loss of the Hassayampa-N.Gila 500 kV line as shown in Appendix H.2.a.1.1.
3. With the addition of a 700 MVAr shunt capacitor and a 1,200 MVAr SVC at the Devers 500 kV bus, a 100 MVAr shunt capacitor at the Valley 500 kV bus and a 100 MVAr SVC at each of the two Valley 115 kV buses, and a 800 MVAr SVC at the Lugo 500 kV bus, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips, duration and frequency deviations were within their respective limits during the Hassayampa-N.Gila 500 kV line outage, as shown in Appendix H.2.a.1.2.
4. A conceptual nomogram of the Hassayampa-N.Gila 500 kV line outage for this EOR9000+ sensitivity was not developed in this study. However, by implementing a nomogram similar to the conceptual nomogram provided in Appendix G.4.a.5 for Path 61, the WECC stability criteria could be met. This could be explored in a possible WECC rating study in the future, which would seek a Path 49 rating with both DPV2 and EOR9000+ projects.
5. Though not developed in this study, an SPS dropping generation in Arizona may provide acceptable performance for the Hassayampa-N.Gila 500 kV line outage. This could be explored in a possible WECC rating study in the future, which would seek a Path 49 rating with both DPV2 and EOR9000+ projects.
6. Except for the two double contingency outages of the Palo Verde-Devers 500 kV and Harquahala-Devers 500 kV lines, and the Palo Verde-Devers 500 kV and Hassayampa-Harquahala 500 kV lines, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips and frequency deviations were well within their respective limits in the post-projects case.
7. For the two double contingency outages, implementing an SPS that tripped Harquahala generating units CT1 (240 MW), CT2 (240 MW), ST1 (125 MW), ST2 (125 MW) and ST3 (125 MW) and dropped load at San Bernardino (389 MW) and Walnut (432 MW) resulted in acceptable bus voltage dips and frequency deviations. Also, the reactive power equipment identified in item 3 above was represented.

Mohave Off Line

1. Except for the Hassayampa-N.Gila 500 kV single-contingency line outage, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips and frequency deviations were well within their respective limits in the post-projects case.
2. Violations of the voltage dip, duration and frequency deviation criteria occurred for loss of the Hassayampa-N.Gila 500 kV line as shown in Appendix H.2.a.1.1.
3. With the addition of a 800 MVAr shunt capacitor and a 1,500 MVAr SVC at the Devers 500 kV bus, a 100 MVAr shunt capacitor at the Valley 500 kV bus and a 100 MVAr SVC at each of the two Valley 115 kV buses, and a 1,200 MVAr SVC at the Lugo 500 kV bus, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips, duration and frequency deviations were within their respective limits during the Hassayampa-N.Gila 500 kV line outage, as

shown in Appendix H.2.a.1.2.

4. A conceptual nomogram of the Hassayampa-N.Gila 500 kV line outage for this EOR9000+ sensitivity was not developed in this study. However, by implementing a nomogram similar to the conceptual nomogram provided in Appendix G.4.a.5 for Path 61, the WECC stability criteria could be met. This could be explored in a possible WECC rating study in the future, which would seek a Path 49 rating with both DPV2 and EOR9000+ projects.
5. Though not developed in this study, an SPS dropping generation in Arizona may provide acceptable performance for the Hassayampa-N.Gila 500 kV line outage. This could be explored in a possible WECC rating study in the future, which would seek a Path 49 rating with both DPV2 and EOR9000+ projects.
6. Except for the two double contingency outages of the Palo Verde-Devers 500 kV and Harquahala-Devers 500 kV lines, and the Palo Verde-Devers 500 kV and Hassayampa-Harquahala 500 kV lines, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips and frequency deviations were well within their respective limits in the post-projects case.
7. For the two double contingency outages, implementing an SPS that tripped Harquahala generating units CT1 (240 MW), CT2 (240 MW), ST1 (125 MW), ST2 (125 MW) and ST3 (125 MW) and dropped load at San Bernardino (389 MW) and Walnut (432 MW) resulted in acceptable bus voltage dips and frequency deviations. Also, the reactive power equipment identified in item 3 above was represented.

VIII.A.4 POST-TRANSIENT POWER FLOW ANALYSIS RESULTS

The key finding from the post-transient power flow analysis is that the reactive power equipment identified in the SCIT Nomogram Simultaneous analysis is sufficient for both DPV2 and EOR9000+ Projects to achieve a 10,500 MW rating increase on Path 49 while meeting the post-transient voltage deviation limits of the transmission system. However, an SPS, which trips Arizona generation and drops load in Southern California, is required to meet the voltage deviation criteria for the Palo Verde-Devers 500 kV and the Harquahala-Devers 500 kV double line outage.

The "Path 49 Non-Simultaneous Post Transient Analysis Summary" is provided in Appendix H.3.a.1. The following subsections provide highlights of the analysis.

Mohave On Line

1. Post-transient voltage deviations did not exceed 5% during single contingencies in the post-project case.
2. Except for the Palo Verde-Devers 500 kV and the Harquahala-Devers 500 kV double line outage, post-transient voltage deviations did not exceed 10% during double contingencies in the post-project case.
3. For the Palo Verde-Devers 500 kV and the Harquahala-Devers 500 kV double line outage, the post-transient power flow case did not converge, possibly indicating unacceptable performance. Implementing an SPS that tripped Harquahala

generating units CT1 (240 MW), CT2 (240 MW), ST1 (125 MW), ST2 (125 MW) and ST3 (125 MW) and dropped load at San Bernardino (389 MW) and Walnut (432 MW) resulted in acceptable post-transient voltage deviations. Also, the reactive power equipment identified in the Dynamic Stability Analysis Results in the corresponding section VIII.A.3 was represented.

Mohave Off Line

1. Post-transient voltage deviations did not exceed 5% during single contingencies in the post-project case.
2. Except for the Palo Verde-Devers 500 kV and the Harquahala-Devers 500 kV double line outage, post-transient voltage deviations did not exceed 10% during double contingencies in the post-project case.
3. For the Palo Verde-Devers 500 kV and the Harquahala-Devers 500 kV double line outage, the post-transient power flow case did not converge, possibly indicating unacceptable performance. Implementing an SPS that tripped Harquahala generating units CT1 (240 MW), CT2 (240 MW), ST1 (125 MW), ST2 (125 MW) and ST3 (125 MW) and dropped load at San Bernardino (389 MW) and Walnut (432 MW) resulted in acceptable post-transient voltage deviations. Also, the reactive power equipment identified in the Dynamic Stability Analysis Results in the corresponding section VIII.A.3 was represented.

VIII.B APS PV-TS5 PROJECT SENSITIVITY

VIII.B.1 OVERALL SUMMARY

The analysis is based on the key assumption that the Path 49 power flow would be assessed at its maximum rating of 9,255 MW assuming both DPV2 and PV-TS5 Projects in service. This 9,255 MW Path 49 rating is based on the assumption that DPV2 would add 1,200 MW and the PV-TS5 Project would add nothing to the current Path 49 rating of 8,055 MW. Also, these results are based on the assumption that the reactive power equipment identified in the SCIT Nomogram Simultaneous analysis would be in operation.

Results indicate that the DPV2 POS is adequate to achieve a 9,255 MW rating increase on Path 49 with both DPV2 and PV-TS5 Projects while meeting the Criteria.

No SPS was needed to meet the Criteria for the double line outage of the Palo Verde-Devers 500 kV line and the Harquahala-Devers 500 kV line or the Palo Verde-Devers 500 kV line and the Hassayampa-Harquahala 500 kV line.

Details of the APS PV-TS5 analysis results are provided in Appendix H.(series).2.

VIII.B.2 POWER FLOW ANALYSIS RESULTS

The key finding from the power flow analysis is that both DPV2 and PV-TS5 Projects can achieve a 9,255 MW rating increase on Path 49 while meeting the thermal limits of the transmission system.

The "Control Area Summary of Pre-Contingency Base Cases" is provided in Appendix H.1.a.2. The "Path Flow Summary of Pre-Contingency Base Cases" is provided in Appendix H.1.b.2. Also, "Power Flow Diagrams of Pre-Contingency Bases Cases" are provided in Appendix H.1.c.2.

The "Path 49 Non-Simultaneous Power Flow Analysis Summary," which lists the 5 highest transmission loadings for normal and contingency conditions, is provided in Appendix H.1.d.2. The following subsections provide highlights of the analysis.

Mohave On Line

1. No transmission element was loaded above 100% of its continuous rating under normal (i.e. non-contingency) conditions in the post-projects case. However, a marginal loading of 100.7% occurred on each of the two Perkins phase shifters in the post-project case.
2. No transmission element was loaded above 100% of its emergency rating under single contingency conditions in the post-projects case.

Mohave Off Line

1. No transmission element was loaded above 100% of its continuous rating under normal (i.e. non-contingency) conditions in the post-projects case. However, a marginal loading of 100.6% occurred on each of the two Perkins phase shifters in the post-project case.
2. No transmission element was loaded above 100% of its emergency rating under single contingency conditions in the post-projects case.

VIII.B.3 DYNAMIC STABILITY ANALYSIS RESULTS

The key finding from the dynamic stability analysis is that the reactive power equipment identified in the SCIT Nomogram Simultaneous analysis is sufficient for both DPV2 and PV-TS5 Projects to achieve a 9,255 MW rating increase on Path 49 while meeting the voltage dip, damping and frequency deviation limits of the transmission system. No SPS is needed.

The "Path 49 Non-Simultaneous Stability Analysis Summary" is provided in Appendix H.2.a.2. The following subsections provide highlights of the analysis.

Mohave On Line

1. All machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips and frequency deviations were well within their respective limits in the post-project case.
2. No SPS was needed to meet the voltage dip, damping and frequency deviation limits of the transmission system.

Mohave Off Line

1. All machines in the WECC grid remained in synchronism and were damped, and all

bus voltage dips and frequency deviations were well within their respective limits in the post-project case.

2. No SPS was needed to meet the voltage dip, damping and frequency deviation limits of the transmission system.

VIII.B.4 POST-TRANSIENT POWER FLOW ANALYSIS RESULTS

The key finding from the post-transient power flow analysis is that the reactive power equipment identified in the SCIT Nomogram Simultaneous analysis is sufficient for both DPV2 and PV-TS5 Projects to achieve a 9,255 MW rating increase on Path 49 while meeting the post-transient voltage deviation limits of the transmission system. Also, no SPS is needed.

The "Path 49 Non-Simultaneous Post Transient Analysis Summary" is provided in Appendix H.3.a.1. The following subsections provide highlights of the analysis.

Mohave On Line

1. Post-transient voltage deviations did not exceed 5% during single contingencies in both the post-project case.
2. No SPS was needed to meet the post-transient voltage deviation limits of the transmission system.

Mohave Off Line

1. Post-transient voltage deviations did not exceed 5% during single contingencies in both the post-project case.
2. No SPS was needed to meet the post-transient voltage deviation limits of the transmission system.

VIII.C SWAT CRT MIDPOINT SUBSTATION SENSITIVITY

VIII.C.1 OVERALL SUMMARY

The analysis is based on the key assumption that the Path 49 power flow would be assessed at its maximum rating of 9,255 MW assuming both DPV2 and a conceptual Midpoint Substation project are in service. This 9,255 MW Path 49 rating is based on the assumption that DPV2 would add 1,200 MW and the Midpoint Substation would add nothing to the current Path 49 rating of 8,055 MW.

Power flow results indicated that power flowed from the 230 kV transmission grid to the Midpoint Substation, which was opposite of the desired flow direction. Because of this reversed flow result, the requester of this sensitivity stated that no further analysis is warranted.

Details of the SWAT CRT Midpoint Substation analysis results are provided in Appendix H.(series).3.

VIII.C.2 POWER FLOW ANALYSIS RESULTS

The key finding from the power flow analysis is that in the absence of a phase shifter at Midpoint Substation, the power flows from the 230 kV grid to the Midpoint Substation.

The "Control Area Summary of Pre-Contingency Base Cases" is provided in Appendix H.1.a.3. The "Path Flow Summary of Pre-Contingency Base Cases" is provided in Appendix H.1.b.3. Also, "Power Flow Diagrams of Pre-Contingency Bases Cases" are provided in Appendix H.1.c.3.

Mohave On Line

1. The power flow from Midpoint Substation to the 230 kV grid with or without the pre-existing Buck Blvd phase shifter in service are reversed, as shown in the table below. The flows were metered at the Midpoint 500/230 kV transformer. The Midpoint phase shifter was out of service in both cases. The negative value indicates power is flowing from the 230 kV grid to the 500 kV system.

	Power Flow (MW)	
Transmission Line	w/ Phase Shifter	w/o Phase Shifter
Midpoint-Buck Blvd 230 kV	-2.4	-8.5

Mohave Off Line

1. The power flow from Midpoint Substation to the 230 kV grid with or without the pre-existing Buck Blvd phase shifter in service are reversed, as shown in the table below. The flows were metered at the Midpoint 500/230 kV transformer. The Midpoint phase shifter was out of service in both cases. The negative value indicates power is flowing from the 230 kV grid to the 500 kV system.

	Power Flow (MW)	
Transmission Line	w/ Phase Shifter	w/o Phase Shifter
Midpoint-Buck Blvd 230 kV	-1.2	-5.2

VIII.D IID 200 MW REQUEST SENSITIVITY

VIII.D.1 OVERALL SUMMARY

The analysis is based on the key assumption that the Path 49 power flow would be assessed at its maximum rating of 9,455 MW assuming a 1,400 MW DPV2 project. This 9,455 MW Path 49 rating is based on the assumption that DPV2 would add 1,200 MW plus an additional 200 MW based on the IID's request to the current Path 49 rating of 8,055 MW. Also, these results are based on the assumption that the reactive power equipment identified in the SCIT Nomogram Simultaneous analysis would be in operation.

Results indicate that the DPV2 POS is not adequate to achieve a 9,455 MW rating increase on Path 49 while meeting the Criteria, without additional reactive support.

No SPS was needed to meet the Criteria for the double line outage of the Palo Verde-Devers 500 kV line and the Harquahala-Devers 500 kV line or the Palo Verde-Devers 500 kV line and the Hassayampa-Harquahala 500 kV line.

Details of the IID 200 MW Request analysis results are provided in Appendix H.(series).4.

VIII.D.2 POWER FLOW ANALYSIS RESULTS

The key finding from the power flow analysis is that DPV2 including the IID 200 MW request can achieve a 9,455 MW rating increase on Path 49 while meeting the thermal limits of the transmission system.

The "Control Area Summary of Pre-Contingency Base Cases" is provided in Appendix H.1.a.4. The "Path Flow Summary of Pre-Contingency Base Cases" is provided in Appendix H.1.b.4. Also, "Power Flow Diagrams of Pre-Contingency Bases Cases" are provided in Appendix H.1.c.4.

The "Path 49 Non-Simultaneous Power Flow Analysis Summary," which lists the 5 highest transmission loadings for normal and contingency conditions, is provided in Appendix H.1.d.4. The following subsections provide highlights of the analysis.

Mohave On Line

1. No transmission element was loaded above 100% of its continuous rating under normal (i.e. non-contingency) conditions in the post-project case. However, a marginal loading of 100.6% occurred on each of the two Perkins phase shifters in the post-project case.
2. No transmission element was loaded above 100% of its emergency rating under single contingency conditions in the post-project case. However, a marginal loading of 100.6% occurred on the Knob – Pilot Knob 161 kV line for loss of the N.Gila-IV 500 kV line.

Mohave Off Line

1. No transmission element was loaded above 100% of its continuous rating under normal (i.e. non-contingency) conditions in the post-projects case. However, a marginal loading of 100.5% occurred on each of the two Perkins phase shifters in the post-project case.
2. No transmission element was loaded above 100% of its emergency rating under single contingency conditions in the post-projects case.

VIII.D.3 DYNAMIC STABILITY ANALYSIS RESULTS

The key finding from the dynamic stability analysis is that the reactive power equipment identified in the SCIT Nomogram Simultaneous analysis is not sufficient for DPV2 including the IID 200 MW request to achieve a 9,455 MW rating increase on Path 49 while meeting the voltage dip, damping and frequency deviation limits of the transmission system. No SPS is needed.

The "Path 49 Non-Simultaneous Stability Analysis Summary" is provided in Appendix H.2.a.4. The following subsections provide highlights of the analysis.

Mohave On Line

1. Except for the Hassayampa-N.Gila 500 kV single-contingency line outage, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips and frequency deviations were well within their respective limits in the post-project case.
2. Violations of the voltage dip, duration and frequency deviation criteria occurred for loss of the Hassayampa-N.Gila 500 kV line as shown in Appendix H.2.a.4.
3. No SPS was needed to meet the voltage dip, damping and frequency deviation limits of the transmission system.

Mohave Off Line

1. Except for the Hassayampa-N.Gila 500 kV single-contingency line outage, all machines in the WECC grid remained in synchronism and were damped, and all bus voltage dips and frequency deviations were well within their respective limits in the post-project case.
2. Violations of the voltage dip, duration and frequency deviation criteria occurred for loss of the Hassayampa-N.Gila 500 kV line as shown in Appendix H.2.a.4.
3. No SPS was needed to meet the voltage dip, damping and frequency deviation limits of the transmission system.

VIII.D.4 POST-TRANSIENT POWER FLOW ANALYSIS RESULTS

The key finding from the post-transient power flow analysis is that the reactive power equipment identified in the SCIT Nomogram Simultaneous analysis is sufficient for DPV2 including the IID 200 MW request to achieve a 9,455 MW rating increase on Path 49 while meeting the post-transient voltage deviation limits of the transmission system. Also, no SPS is needed.

The "Path 49 Non-Simultaneous Post Transient Analysis Summary" is provided in Appendix H.3.a.4. The following subsections provide highlights of the analysis.

Mohave On Line

1. Post-transient voltage deviations did not exceed 5% during single contingencies in both the post-project case.
2. No SPS was needed to meet the post-transient voltage deviation limits of the transmission system.

Mohave Off Line

1. Post-transient voltage deviations did not exceed 5% during single contingencies in both the post-project case.
2. No SPS was needed to meet the post-transient voltage deviation limits of the transmission system.

VIII.E MWD PUMP LOAD OFF LINE SENSITIVITY

VIII.E.1 OVERALL SUMMARY

The analysis is based on the key assumption that the Path 49 power flow would be assessed at its maximum rating of 9,255 MW with the MWD pump loads off line. This sensitivity was limited to power flow analysis based on the requester's concern over possible impact on meeting facility thermal limitations.

Results indicate that the DPV2 POS is adequate to achieve a 9,255 MW rating increase on Path 49 with the MWD pump loads off line while meeting the Criteria

Details of the MWD Pump Load Off Line analysis results are provided in Appendix H.(series).5.

VIII.E.2 POWER FLOW ANALYSIS RESULTS

The key finding from the power flow analysis is that DPV2 with the MWD pump loads off line can achieve a 9,255 MW rating increase on Path 49 while meeting the thermal limits of the transmission system.

The "Control Area Summary of Pre-Contingency Base Cases" is provided in Appendix H.1.a.5. The "Path Flow Summary of Pre-Contingency Base Cases" is provided in Appendix H.1.b.5. Also, "Power Flow Diagrams of Pre-Contingency Bases Cases" are provided in Appendix H.1.c.5.

The "Path 49 Non-Simultaneous Power Flow Analysis Summary," which lists the 5 highest transmission loadings for normal and contingency conditions, is provided in Appendix H.1.d.5. The following subsections provide highlights of the analysis.

Mohave On Line

1. No transmission element was loaded above 100% of its continuous rating under normal (i.e. non-contingency) conditions in the post-projects case. However, a marginal loading of 100.8% occurred on each of the two Perkins phase shifters in the post-project case.
2. No transmission element was loaded above 100% of its emergency rating under single contingency conditions in the post-projects case.

Mohave Off Line

1. No transmission element was loaded above 100% of its continuous rating under normal (i.e. non-contingency) conditions in the post-projects case. However, a marginal loading of 100.6% occurred on each of the two Perkins phase shifters in the post-project case.
2. No transmission element was loaded above 100% of its emergency rating under single contingency conditions in the post-projects case.

IX. OTHER STUDIES

Other studies described below are being performed separately to address specific aspects of the DPV2 project. These studies are not part of this Study and are being presented as information only. SCE will continue to perform these studies until completion and report findings to the PRG. SCE will pursue any mitigation actions including additions to the DPV2 plan of service that may be identified in these other studies to meet local, regional and WECC area planning and/or operational requirements.

1 **SWITCHABLE SHUNT LINE REACTOR STUDY**

This study was performed to determine the feasibility of making the shunt line reactors on the Devers-Palo Verde 500 kV #1 and 2 lines switchable rather than fixed. Given an open ended line condition, transmission and substation equipment may be exposed to unacceptably high voltages on the open-ended line. Results indicated that due to unacceptably high open-ended line voltages, the shunt line reactors must remain fixed.

2 **SPS ARMING STUDY**

The DPV2 Comprehensive Progress Report indicated the need to trip generation in Arizona and load in Southern California to achieve acceptable performance for the double contingency outage of the Devers-Palo Verde 500 kV #1 and 2 lines. This SPS Arming Study is focused on identifying more broadly and completely all of the criteria violations and key parameters (i.e. drivers) impacting this N-2 outage. Among others, the following potential drivers will be included in the study:

- Path 66 (COI) at appropriate heavy to maximum flow
- Palo Verde Hub at appropriate heavy to maximum flow

Also, the study will identify other possible mitigation options and evaluate the effectiveness of dropping generation at different locations in Arizona and in different amounts. Other options include tripping generation only and dropping load only in Southern California.

3 **SHORT CIRCUIT STUDY**

The Short Circuit Study is focused on determining any short circuit duty impacts on neighboring transmission systems due to DPV2. A separate review group has been formed to perform the study. The DPV2 Short Circuit Review Group has developed a study plan and is performing short circuit studies.

4 **SUB SYNCHRONOUS RESONANCE (SSR) STUDY**

SCE has contracted Mitsubishi Electric Power Products, Inc. to perform studies to determine any Sub Synchronous Resonance impacts on the Palo Verde generating plant due to DPV2. Also, impacts on the Navajo generating plant due to raising the series compensation to 70% on the Mohave-Lugo 500 kV line will be assessed.

5 **PALO VERDE HUB – EXTREME CONTINGENCY STUDY**

SCE has been working with representatives of Arizona Public Service, the Salt River Project and the Arizona Corporation Commission to identify extreme contingencies

that need to be analyzed to assess the impact of DPV2 on system performance. This study will be performed and reviewed under the guidance of WATS.

6. PALO VERDE SIMULTANEOUS GENERATION CAPABILITY STUDY

SCE agrees to perform stakeholder - approved studies to determine the impact of the DPV2 Project, with a rating of 1200 MW, on the simultaneous generating capability, SGC, at the Palo Verde/Hassayampa Hub. If the analysis results show an impact to the SGC, then SCE will identify appropriate mitigation. This study work will be performed and reviewed under the guidance and approval of WATS.

7. IMPACT OF DVP2 ON PALO VERDE – COI INTERACTION

SCE agrees to perform stakeholder - approved studies to determine the impact of the DPV2 Project, with a rating of 1200 MW, on the Palo Verde – COI interface. Transfers on the COI Interface are limited by the simultaneous outage of 2 units of Palo Verde. This study sensitivity will determine the impact, if any, of the simultaneous two line outage of Palo Verde–Devers 500kV and Harquahala–Devers 500kV. There have been studies performed by SCE that have found a need for a Hassayampa generation and SCE local load SPS to mitigate the loss of the 2 lines for SCE local load voltage dip criteria violations. The preliminary results of the stability analysis show a need for approximately 400 MW of load and generation each that needs to be in the SPS. The ultimate value of load and generation required to be in the SPS is dependant on the choice of many variables and the results may be higher in magnitude. This study work will be performed and reviewed under the guidance and approval of WATS.

X. APPENDICES

APPENDIX A - STUDY SCOPE
APPENDIX B - DYNAMIC AND POST TRANSIENT SWITCH DECKS
APPENDIX C - SCE RESPONSES TO COMMENTS ON WECC CPR
APPENDIX D - PATH 49 ANALYSIS DIAGRAMS & TABLES
APPENDIX E - SCE RESPONSES TO COMMENTS ON PATH 49 STUDY
APPENDIX F - SCIT ANALYSIS DIAGRAMS & TABLES
APPENDIX G - SIMULTANEOUS DIAGRAMS AND TABLES
APPENDIX H - SENSITIVITY DIAGRAMS AND TABLES

13

BEFORE THE ARIZONA POWER PLANT AND

TRANSMISSION LINE SITING COMMITTEE

IN THE MATTER OF THE APPLICATION OF SOUTHERN CALIFORNIA EDISON COMPANY AND ITS ASSIGNEES IN CONFORMANCE WITH THE REQUIREMENTS OF ARIZONA REVISED STATUTES SECTIONS 40-360.03 AND 40-360.06 FOR A CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY AUTHORIZING CONSTRUCTION OF A 500kV ALTERNATING CURRENT TRANSMISSION LINE AND RELATED FACILITIES IN MARICOPA AND LA PAZ COUNTIES IN ARIZONA ORIGINATING AT THE HARQUAHALA GENERATING STATION SWITCHYARD IN WESTERN MARICOPA COUNTY AND TERMINATING AT THE DEVERS SUBSTATION IN RIVERSIDE COUNTY, CALIFORNIA	)	Docket No. L-00000A-06-0295-00130 Case No. 130

SOUTHERN CALIFORNIA EDISON COMPANY'S OBJECTIONS AND RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S SIXTH SET OF DATA REQUESTS

Southern California Edison Company ("SCE") submits the following objections and responses to the Arizona Corporation Commission Staff's ("Staff") Sixth Set of Data Requests in the above-referenced docket.

GENERAL OBJECTIONS TO ALL DATA REQUESTS

1. SCE objects to each and every Request to the extent it seeks information subject to the attorney-client privilege, work product doctrine or any other privilege recognized by the State of Arizona. In responding to these Requests, SCE does not waive, but preserves, all such privileges.

2. SCE objects to each and every Request to the extent it seeks information that is confidential, sensitive, competitive in nature or proprietary to it. In responding to these requests, SCE does not waive, but preserves, its claim that request for customer and market information is confidential.

3. SCE objects to each and every Request to the extent that it is unreasonably burdensome, overly broad or not reasonably calculated to lead to the discovery of admissible evidence.

4. SCE objects to each and every one of Staff's definitions and/or instructions to the extent it purports to abrogate any of SCE's rights, or add to any of SCE's obligations under, the Arizona Rules of Civil Procedure or the Commission's Rules.

5. SCE objects to each and every Request to the extent it imposes any burden not expressly permitted under Commission's Rules or the Arizona Rules of Civil Procedure.

6. SCE objects to each and every Request to the extent that it calls for information already in the possession, custody and control of Staff.

7. SCE objects to each and every Request to the extent it seeks information outside of the Staff's possession, custody or control.

8. SCE expressly reserves the right to supplement or amend its objections and responses as necessary.

SCE incorporates the foregoing General Objections into each response as if fully set forth therein.

SPECIFIC DATA RESPONSES

JDS-6.1 Please provide a summary of the July 7 disturbance that resulted in a tower on the existing DPV line being destroyed. The news media reported that service to California customers was interrupted due to the outage of the existing line. Please provide a detailed explanation that either substantiates or refutes the media's claim that customers were without service due to this N-1 event. What were the prevailing system conditions at the time the disturbance occurred?

RESPONSE: Tower M162-T2 on the Devers-Palo Verde 500 kV line failed at approximately 3:30 pm PDT on Saturday, July 1, 2006, as a result of an exceptionally strong wind micro-burst during strong convectional storms occurring near Desert Center, California. At the time of the tower failure, the Devers-Palo Verde 500 kV line was carrying approximately 1500 MW of load and SCE's area load was approximately 19,000 MW. No customers were interrupted or without service as a result of the N-1 event. In accordance with operating procedure, the line was tested approximately four minutes after tower failure and the resulting three phase fault at tower M162-T2 caused a low voltage condition on SCE's Devers and Valley Systems. SCE recorded a momentary interruption of fifteen distribution circuits as a result of the test and low voltage condition. The interrupted circuits were automatically restored and SCE's customers continued to be served.

JDS-6.2 Are other existing DPV transmission line towers of the same vintage, design and construction as the tower that was destroyed? If the tower that was destroyed is not typical of all other towers, including those in Copper Bottom Pass, please explain its uniqueness. What was the height of the tower that was damaged?

RESPONSE: The tower which failed on the Devers-Palo Verde 500 kV line (tower M162-T2) was a type EMT single-circuit suspension tower which had an overall height of 172 feet. There are approximately 70 other Type EMT towers in place on the line. In comparison, there are approximately 587 Type EMS single-circuit suspension towers in place on the Devers-Palo Verde 500 kV line. The Type EMT tower was designed to have slightly greater loading capability than the Type EMS tower and was used in place of the EMS tower where heavier loading conditions were encountered. The tower is not typical of towers in Copper Bottom Pass. The towers used through the Copper Bottom Pass area are double-circuit towers, both suspension and dead end.

JDS-6.3 Please explain how the CAISO Market Redesign & Technology Upgrade (MRTU) initiative will impact the operational and commercial uses of the proposed 2nd Palo Verde to Devers 500 kV line and scheduling of capacity and energy produced at any power plants interconnected to the same line. What system elements of the DPV2 Project will CAISO have operational control of and to what elements will their tariffs apply? Does this include the Harquahala power plant?

RESPONSE: SCE does not expect that the CAISO's MRTU initiative will significantly affect the operational and commercial uses of the proposed DPV2 facility when compared to today's market design. Given DPV2's proposed operating date in 2009 and MRTU's proposed operating date of November 2007, SCE anticipates that MRTU will have been running for many months before DPV2 is operating. Other than the use of revised templates and new interface systems between the CAISO and market participants, the submission of schedules for power plants connected to DPV2 is not expected to change from today's practices on existing transmission facilities due to the MRTU initiative. One expected difference between today's market and that under the MRTU proposal is that there will not be a physical scheduling priority associated with the type of transmission rights offered under MRTU (Congestion Revenue Rights). Such a priority exists today with Firm Transmission Rights.

SCE's proposed project envisions a 500 kV transmission path from Devers Substation to the Harquahala 500 kV Switchyard, and from Harquahala 500 kV Switchyard to Hassayampa Substation. Under that proposal, the Devers-

Harquahala 500 kV line, the Harquahala 500 kV Switchyard and power plant, and the Harquahala-Hassayampa 500 kV line would be part of the CAISO Control Area and subject to the CAISO Tariff. Note that the CAISO would not have "operational control" of the Harquahala power plant. SCE and APS have been engaged in negotiations for a potential arrangement in which SCE and APS would jointly own the facilities between the Harquahala Junction Switchyard and the Hassayampa substation. Under this alternative arrangement, the Devers-Harquahala Junction 500 kV line would likely be incorporated into the CAISO control area and subject to the CAISO Tariff. However, the Harquahala Junction Switchyard, the Harquahala switchyard and power plant, and the Harquahala-Hassayampa 500 kV line would likely fall within the footprint of APS's control area. However, these arrangements being negotiated between SCE and APS have not been finalized.

JDS-6.4 Please provide a copy of the CAISO electronic presentation material given to CRT on September 1, 2004 per your response to JDS-4.7.

RESPONSE: A copy of the CAISO electronic presentation material for the CRT on September 1, 2004 is attached.

JDS-6.5 Will CAISO's MRTU initiative result in any modifications, deletions or additions to the material presented to CRT on September 1, 2004? If so, please elaborate.

RESPONSE: Insofar as SCE is aware, the CAISO's presentation is consistent with the CAISO's MRTU initiative. See, for example, the discussion at slides 11 through 13 concerning Firm Transmission Rights and Congestion Revenue Rights.

JDS-6.6 SCE has acknowledged several agreements already exist regarding the existing DPV line, the proposed second DPV line and the Harquahala Generating Station. Were there any regulatory approvals for any of the existing agreements? If so, who had jurisdictional authority and what was the assigned case or docket number or decision number? Was CAISO approval required for any of the same existing agreements? If yes, then identify the agreement(s)?

RESPONSE: Regulatory approvals were not required for the existing agreements between SCE and the Harquahala Generating Company. No jurisdictional service was provided by SCE to Harquahala Generating Company pursuant to the option or license agreements. If SCE were to exercise the option and thereafter provide transmission service, through the CAISO, to the generating station, SCE would file the appropriate agreement with the Federal Energy Regulatory Commission. CAISO approval was not required for the option or license agreements because the facilities that are the subject of the agreements were not transmission additions or upgrades to the CAISO controlled grid.

JDS-6.7 Will regulatory approval be required for any interconnection alternative of the DPV2 Project or any proposed interconnection agreement for the DPV2 project? If so, then who has jurisdiction and under what statutory authorization?

RESPONSE: Regulatory approvals will be required for interconnection with the DPV2 project. FERC has jurisdiction over interconnection agreements under Sections 201, 202, 210, and 212 of the Federal Power Act. If SCE must construct certain facilities to carry out the interconnection, the CPUC has jurisdiction under California Public Utilities Code Sections 1001, 1003.5, and 1004 et seq., and the California Environmental Quality Act to review the public convenience and necessity of the facilities. If the interconnection were to require the construction of a transmission line in Arizona, the Arizona Corporation Commission would review the environmental compatibility under Arizona Revised Statutes Sections 40-360.03 et seq.

JDS-6.8 If interconnections occur in the future along the length of the new DPV2 line, will regulatory approval be required? If so, then who has jurisdiction and under what current statutory authorization? Will CAISO approval be required for such future interconnections? Will CAISO tariffs and operational control apply to such interconnections?

RESPONSE: Future interconnections with the new DPV2 line will require regulatory approvals. See response to JDS 6.7, above. CAISO approval will be required for future interconnections. The CAISO would have operational control of the interconnection and transmission service would be provided in accordance with the CAISO Tariff.

JDS-6.9 SCE failed to provide, an unredacted copy of the Supplemental Direct Testimony filed with CPUC on June 1, 2006 and the associated Appendix A material referenced in Section II of that testimony as requested by Staff in JDS-4.2. Instead, you provided a table dated 6-15-06 with preliminary cost estimates for the various alternatives. That table did provide an estimate of the variety of alternative costs including the newly announced change in plan of service with a Devers–Valley 500 kV line in lieu of the rebuild of the existing four 230 kV lines west of Devers. But you failed to include estimates for the Harquahala Junction Switchyard Alternative.

Staff is aware that SCE filed a Phase II Supplemental Direct Testimony with the CPUC on July 7, 2006 that was unredacted and included all of the requested cost data for the project including the Harquahala Junction Alternative (Alternative 3). Exhibit B of that Supplemental Direct Testimony was dated 7-7-06 and filed at the CPUC two days after filing a response to Staff data request JDS-4.2.

a. Please explain why your response to Staff's data requests failed to include cost estimates for the Harquahala Junction Switchyard Alternative. Doesn't your failure to provide Staff with timely cost infraction and waiting to provide that information until after it is filed at CPUC contradict the procedural goals outlined in the Western Governors' Interstate Transmission Line Siting Protocol?

b. Do the cost estimates being provided in both regulatory forums reflect total project cost or only those costs SCE believes it will be obligated to fund if joint participation facilities are involved?

RESPONSE: a. The responses provided to the ACC staff on July 5, 2006 were prepared primarily during the last few days of June and finalized on July 5. When SCE provided the response to JDS 4.2 on July 5, 2006, it was developing the new cost estimates and preparing the Supplemental Direct Testimony dated July 7, 2006, for the CPUC proceedings. On July 5, SCE provided cost estimates based on completed work, not work in progress. The new estimates were not completed until shortly before they were served on parties to the CPUC proceedings. SCE's actions in the first week of July were consistent with its good-faith attempt to provide full responses to the ACC Staff and SCE regrets any misunderstanding that may have resulted.

b. The cost estimates SCE has provided in both forums are a forecast of SCE's costs, assuming the Los Angeles Department of Water and Power does not participate in funding the project. The estimates are subject to further refinement and may also change due to additional negotiations with other parties.

JDS-6.10 The SCE reply to JDS-4.3 was largely "non-responsive." Other than having established prior contractual rights with Harquahala Generating Company no evidence is offered that substantiates that the Harquahala Switchyard Alternative is superior to the Harquahala Junction Switchyard. Getting an agreement with parties for the Harquahala Junction Switchyard Alternative and CAISO approval does not necessarily mean it is a superior alternative. Does SCE care to amend and supplement its response to this question? Please identify the author of all responses to this data request.

RESPONSE: Without contractual arrangements, an alternative cannot be constructed. It was on this basis that SCE answered JDS 4.3 as to why SCE concluded that interconnection at the Harquahala Generating Station Switchyard was the preferred option. SCE supplements its response to JDS 4.3 by noting that it now has an agreement in principle by staff employees at both APS and SCE for the Harquahala Junction Switchyard. That agreement has not received final approval by members of management with signature authority at SCE, nor presumably at APS. SCE anticipates that such approval will be obtained when additional details are resolved. SCE will soon submit the Harquahala Junction Switchyard alternative to the CAISO for its approval. Michael Mackness prepared this response.

JDS-6.11 The SCE reply to JDS-4.4 was also largely "non-responsive." Would a Harquahala Junction Switchyard interconnection fulfill the three CAISO prerequisites for approval?

a. Does a jointly developed Harquahala Junction Switchyard with a five-mile shorter length of line from Devers reduce the cost of the DPV2 Project? Please cite supporting evidence previously filed with the CPUC or in this ACC Docket.

b. Does the Harquahala Junction Switchyard Alternative create additional congestion or reliability concerns? If so, please explain. In fact doesn't this alternative mitigate reliability and commercial transmission pancaking issues raised by ACC Staff? Provide and cite technical study results supportive of your response.

c. Doesn't SCE's testimony filed before the CPUC already state that it believes the ACC favors a Harquahala Junction Switchyard interconnection over that of a Palo Verde Switchyard termination or Harquahala Generator Switchyard interconnection?

If the answer to each of the above questions is yes, then doesn't the Harquahala Junction Alternative comply with the CAISO's prerequisite conditions?

RESPONSE: a. The cost of the Harquahala Junction Switchyard alternative is less than those of SCE's originally-proposed project. See Table II-1 of the prepared supplemental direct testimony in the CPUC proceedings.

b. The Harquahala Junction Switchyard Alternative does not create additional congestion or reliability concerns. SCE is in the process of obtaining the

CAISO's concurrence with this conclusion. Although such analysis would resolve reliability concerns, it does not resolve "commercial transmission pancaking issues." The attached PDF labeled DPV2_Path49RatingReport_aprvd.pdf contains the sensitivity with TS5 indicating no negative impact on achieving the 1,200 MW rating increase.

c. SCE's prepared supplemental direct testimony provided in the CPUC proceedings stated that "the ACC and ACC staff appear to disfavor the Palo Verde Alternative…." Therefore, in the supplemental direct testimony, SCE requested that the CPUC approve "Alternate 3," the Harquahala Junction Alternative and Devers-Valley No. 2.

It is SCE's position that the Harquahala Junction Switchyard alternative complies with the CAISO's conditions. SCE is in the process of obtaining the ISO's concurrence with that conclusion.

JDS-6.12 The SCE response to JDS-4.5 implies an approval from CAISO must be obtained prior to parties reaching an agreement for interconnection at an ACC approved Harquahala Junction Switchyard. Please explain why SCE cannot reach an agreement for an interconnection at a proposed switchyard in Arizona without CAISO approval. Was CAISO approval a prerequisite requirement for the existing SCE options agreement with Harquahala Generating Company? If so, please cite action taken by CAISO regarding the current SCE agreement with Harquahala Generating Company.

RESPONSE: SCE sought CAISO approval of the DPV2 project prior to applying for a certificate of public convenience and necessity from the CPUC. The Harquahala Junction Switchyard would modify certain aspects of the DPV2 project that the CAISO previously approved. Thus, SCE will seek the CAISO's approval of the Harquahala Junction Switchyard alternative. CAISO approval of the existing agreements with the Harquahala Generating Company were not required as explained in SCE's response to JDS 6.6, above.

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Jerry Smith

From: Le, David [DLe@caiso.com]
Sent: Monday, July 11, 2005 11:09 AM
To: Jerry Smith
Cc: KONDZIOLKA ROBERT E; Robert.Smith@aps.com
Subject: RE: New Palo Verde Hub Concept

Jerry,

Thank you for reviewing my last slide. If there are further changes at the Palo Verde E&O meeting, please let me know so I can modify the drawing accordingly. In regards to the CAISO's position, I presented your new Palo Verde Hub concept to Armie Perez and I did not see any objection in regards to technical/reliability issues. However, Armie still needs to check with our Contracts/Legal folks to see if they have any concerns regarding commercial issues. We'll keep you informed once we hear from them.

Thanks,

David Le
California ISO - Grid Planning
Phone: 916.608.7302

-----Original Message-----
From: Jerry Smith [mailto:JSmith@azcc.gov]
Sent: Monday, July 11, 2005 10:05 AM
To: Le, David; KONDZIOLKA ROBERT E; Robert.Smith@aps.com
Subject: RE: New Palo Verde Hub Concept

David, Bob and Rob - I am responding to the series of notes distributed among the three of you regarding redefining the Palo Verde Hub. I am pleased to hear from David that Armie and the CAISO are supportive of the concept. I truly believe we have the unique opportunity to foster a new concept at FERC that blends the merits of reliability considerations and wholesale market interests into one model. I am appreciative of each of your organizations support of this concept.

I also understand SRP's desire for APS (as a FERC jurisdictional utility) to sponsor the filing at FERC. If APS assumes this role it will align well with the siting outcome of the Palo Verde to TS5 transmission line project. (Bob - I will get comments to you today on the proposed letter to the Palo Verde E&O.)

I think the last slide provided by David does an excellent job of visually portraying the concept. However, I do have two questions to pose to the three of you:
1. Do the Hassayampa to Pinal West line participants now intend to interconnect at Redhawk with the initial circuit? If so, David's last slide is a correct portrayal of the new Hub.
2. The ACC has approved eventual termination of the Hassayampa to Pinal West line(s) at Jojoba. Would it be appropriate to include Jojoba and the existing Hassayampa to Jojoba line and the new Redhawk to Jojoba line(s) as part of the new Hub definition? I see some similarities between this issue and the proposal to include the potential Harquahala Junction Station in the new Hub definition.

-----Original Message-----
From: Le, David [mailto:DLe@caiso.com]
Sent: Friday, July 08, 2005 2:05 PM
To: KONDZIOLKA ROBERT E; Robert.Smith@aps.com; Jerry Smith
Subject: RE: New Palo Verde Hub Concept

Bob and Rob,

Thank you for your comments. I have modified the drawing to show the only the lines and

terminals that are part of the new Palo Verde Hub concept (the orange area in the attached file). Please let me know if this revision looks ok to you.

Thanks,

David

-----Original Message-----
From: KONDZIOLKA ROBERT E [mailto:rekondzi@srpnet.com]
Sent: Friday, July 08, 2005 11:45 AM
To: Robert.Smith@aps.com; Le, David; jds@util.cc.state.az.us
Subject: RE: New Palo Verde Hub Concept

I attached a modification of David's original slide that shows the lines in red being proposed as part of the expanded common bus.

-----Original Message-----
From: Robert.Smith@aps.com [mailto:Robert.Smith@aps.com]
Sent: Friday, July 08, 2005 11:38 AM
To: DLe@caiso.com; jds@util.cc.state.az.us
Cc: KONDZIOLKA ROBERT E
Subject: RE: New Palo Verde Hub Concept

But the red dashed lines also contain part of PV-Devers, PV-WW, PV-Rudd, and all of Hassayampa-Jojoba. These lines will not be considered part of the Hub. Again, I would draw four more dark yellow ellipses or ellipsi or whatever in only include the lines you state below.

-----Original Message-----
From: Le, David [mailto:DLe@caiso.com]
Sent: Friday, July 08, 2005 11:26 AM
To: Smith, Robert D(Z88799); jds@util.cc.state.az.us
Cc: rekondzi@srpnet.com
Subject: RE: New Palo Verde Hub Concept

Bob,

Thank you for your comments. In the drawing of the previous email, I have the existing P.V. Hub inside the dark yellow ellipse. The new proposed P.V. Hub is within the red dashed lines, which include the lines coming out of Hassayampa to Harquahala, Arlington, Mesquite, and Redhawk. Please confirm if this is ok.

Thanks,

David

-----Original Message-----
From: Robert.Smith@aps.com [mailto:Robert.Smith@aps.com]
Sent: Friday, July 08, 2005 11:17 AM
To: Le, David; jds@util.cc.state.az.us
Cc: rekondzi@srpnet.com
Subject: RE: New Palo Verde Hub Concept

David, I think it would be more accurate to include the lines from Hassayampa to: Harquahala, Arlington, Mesquite, and Redhawk in Jerry's shading rather than attempting to draw larger circle which might be constued to include part of transmission lines like like PV-Rudd, etc.

Maybe have a separate elipse shaped shaded area for each of these lines.

-----Original Message-----
From: Le, David [mailto:DLe@caiso.com]
Sent: Friday, July 08, 2005 11:11 AM
To: jds@util.cc.state.az.us
Cc: Smith, Robert D(Z88799); rekondzi@srpnet.com
Subject: New Palo Verde Hub Concept
Importance: High

<<Old-New Hub Concept.ppt>>
Jerry, Bob and Rob,

I've put together a single line diagram of the existing and new proposed Palo Verde Hub, based on my conversation with Jerry Smith yesterday for Armie Perez. I used one of the presentation slides that Bob Smith had at the STEP meeting (because it looked great and simple to modify). Please review and confirm the attached drawing. If the drawing doesn't accurately reflect your proposed new P.V. Hub concept, please feel free to modify.

Thanks,

David Le
California ISO - Grid Planning
Phone: 916.608.7302

"MMS <apsc.com>" made the following annotations.

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"MMS <apsc.com>" made the following annotations.

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EDISON
An *EDISON INTERNATIONAL* Company

DEVERS – PALO VERDE NO. 2 (DPV2)

SPS CONCEPTUAL PLANNING STUDY

MAY 10, 2006
(REV.2, WITH ADDENDUM)

EXECUTIVE SUMMARY

Southern California Edison (SCE) is proposing to build a 500 kV transmission line project from the Harquahala substation in the Palo Verde area, near Phoenix, Arizona, to SCE's Devers substation, near Palm Springs, California. The Project is named Devers-Palo Verde No. 2 (DPV2). DPV2 is expected to increase the ratings of WECC Path 49 (EOR) and Path 46 (WOR) flow, and the Southern California import (SCIT) limit, by 1,200 MW. The DPV2 Project will have a plan of service that achieves the rating objectives while meeting relevant reliability criteria. Besides the new 500 kV transmission line, other facilities are required for the DPV2 Project to achieve acceptable reliability performance measures.

In addition to the primary studies for determining the post-DPV2 Path ratings and the associated plan of service, SCE performed this additional SPS Conceptual Planning study. This additional study examined the post-DPV2 project system performance impacts due to N-2 loss of the Devers-Palo Verde 500 kV (DPV1) and Harquahala-Devers 500 kV lines, and identified effective SPS-based mitigation for identified impacts.

The identified system impacts that required evaluation of SPS-based mitigation effectiveness included thermal overloads, excessive post transient voltage drops, and marginal transient stability.

The evaluation of SPS-based mitigation effectiveness determined that dropping load, in conjunction with several coordinated operational measures, will be effective in mitigating the full range of identified system impacts. For each type of system impact identified, the amount of load drop needed to mitigate transmission system performance criteria violations are identified below. The amount of load drop shown below in bold text indicates the worst case, or limiting system condition, for the corresponding system performance measure.

SPS Load Drop Needed to Meet NERC System Performance Criteria

Seasonal Scenario	Thermal Overload	Post-Transient Voltage Deviation	Transient Stability
Heavy Autumn	**-1,250 MW**		
Heavy Summer	*[1]		
Heavy Autumn		-1,590 MW	
Heavy Summer		**-2,090 MW**	
Heavy Autumn			**-390 MW**
Heavy Summer			0 MW

Study findings identified two feasible SPS alternatives, one that uses automated load drop in conjunction with other operational measures, and a second alternative that uses automated load and generation drop. SCE recommends the first SPS alternative as a preferred option. SCE's preferred conceptual SPS plan is

[1] Load drop was needed with the HS stress case to obtain load flow/post-transient solution, and voltage/reactive-need mitigation. Minimum mitigation for load flow thermal problems is indeterminate for HS.

composed of 1) SPS-based automated load drop, 2) a nomogram for Path 61 for flow control and, 3) coordinated operation of the Perkins phase shifter. The information presented in this report will be input to the follow-on development of a detailed plan for a preferred conceptual SPS plan, and associated operating nomograms if needed. SCE will continue the technical development of our DPV2 N-2 SPS mitigation plan within the appropriate stakeholder forums.

INTRODUCTION

Southern California Edison (SCE) is proposing to build a 500 kV transmission line project from the Harquahala substation in the Palo Verde area, near Phoenix, Arizona, to SCE's Devers substation, near Palm Springs, California. The Project is named Devers-Palo Verde No. 2 (DPV2). DPV2 is expected to increase the ratings of WECC Path 49 (EOR) and Path 46 (WOR) flow, and the Southern California import (SCIT) limit, by 1,200 MW. The DPV2 Project must have a plan of service that achieves the rating objectives while meeting relevant reliability criteria.

The DPV2 Project will have a plan of service that achieves the rating objectives while meeting relevant reliability criteria. Besides the new 500 kV transmission line, other facilities are required for the DPV2 Project to achieve acceptable reliability performance measures. The initial DPV2 plan of service included a Special Protection System (SPS) to mitigate a post-transient voltage collapse in southern California and Nevada areas due to loss of both the DPV1 and the Devers-Harquahala 500 kV lines. The SPS originally planned to drop up to approximately 900 MW of generation in the Palo Verde area and approximately 900 MW of load in SCE. The generation and load dropping requirements determined in the DPV2 SPS Arming Study (Study) may be higher or lower than the original 900 MW estimate.

The main objectives of this study as presented in the WATS-approved Study Plan "SPS Arming Study" dated August 28, 2005 (Study Plan) include:

A. Identify more broadly and completely criteria violations and key system parameters due to the double contingency outage of the DPV1 and DPV2 500 kV lines, under reasonable stressed operating conditions.

B. Identify viable alternative mitigation measures to the SPS, including nomograms and operating procedures.

C. If the preferred plan is to go with SPS alone or together with other mitigation measures, then develop a plan to integrate all of the mitigation measures in the most efficient manner.

D. For SPS, minimize SPS actions by identifying the fewest numbers of generating units and load stations to be dropped as part of the SPS.

E. For SPS, identify critical parameters (e.g. line flows, load, phase shifter operation) that exhibit a high degree of influence on the post double contingency performance to reduce the arming exposure.

F. For SPS, determine the relationship between the critical parameters for the purpose of arming generation and load levels for dropping.

STUDY CONDITIONS

Post-DPV2 2009 Heavy Autumn and 2009 Heavy Summer cases were used to perform this study. For each seasonal post-project base case, EOR was stressed to its maximum non-simultaneous rating during the Heavy Autumn, and to a comparably ratioed heavy EOR flow Heavy Summer case[2]. From these initial base cases, several simultaneous stress cases were be developed and evaluated in this SPS Arming Study. Major characteristics of these cases are described below.

1. Base Case Description

The first base case was a product of the DPV2 Path Rating Studies and represents 2009 Heavy Autumn (2009 HA). This case was started from the current WATS-approved Path 49 Series Capacitor Upgrade Project study case that represents 2005 heavy autumn conditions. Area information including load and generation in SCE, Arizona, LADWP, IID, and SDG&E was projected to 2009 HA system conditions. The DPV2 Project (i.e. Harquahala –Devers 500 kV) line and the schedules were added to the pre-project case to develop post-project case and achieve an EOR flow of 9,255 MW.

The second base case represents 2009 Heavy Summer (2009 HS). The HS 2009 was started from SCE's 2004 CAISO Controlled Transmission Expansion Plan "Main System" case for 2009. DPV2 is already included in this case. The area schedules and dispatch were further adjusted to increase EOR flow to its post-DPV2 heavy-flow value. Other significant case modifications for this study were provided by the DPV2 Operational Studies Peer Review Group (DOSPRG). The DOSPRG input that was incorporated included IID's detailed 'Area 8' representation, future 'Silvergate' upgrades on the SDG&E transmission network, and an updated 2009 HA load forecast for SDG&E.

The key attributes of the two seasonal heavy autumn (HA) and heavy summer (HS) base cases used for this study are presented in the tables below.

SPS Arming 2009 HA Base Case (ha09post-sps-00f.sav), Key Attributes

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Load	15,196	3,925	4,266	855	11,754	165	4,372
Losses	370	115	242	41	319	106	56
Generation	10,621	1,541	2,695	1,042	20,867	1,852	3,891
(-)Import/Export	-4,945	-2,499	-1,813	146	8,864	1,511	-537
(Selected interfaces)							
P49 East of River	9,255	[redacted]					
P46 West of River	8,970						

[2] Based on historical EOR Path Flow. Heavy Summer was ratioed per 2005 recorded EOR summer (JUN 1-SEP 15) maximum of 6,024. 6,024/7550 X 9,255 = 7,400 MW

SPS Arming 2009 HS Base Case (hs09post-sps-00f.sav), Key Attributes

Load	23,580	4,936	6,130	1,095	17,711	149	6,098
Losses	611	119	283	56	415	182	96
Generation	14,465	2,800	4,399	1,055	22,991	5,687	6,025
(-)Import/Export	-9,726	-2,255	-2,014	-96	4,865	5,356	-169
(Selected interfaces)							
P49 East of River	7,400						
P46 West of River	9,344						

2. System Stress Sensitivity Cases

In addition to the post-project base cases described above, analysis was performed on a set of post-project system stress sensitivity cases. The target flows for the stressed Path cases are shown below.

HEAVY AUTUMN SENSITIVITIES

DPV2 HA 2009, w/ maximum Path 64 Mead-Adelanto (M-A) stress, critical target flows:
Path 64 M-A flow = 1,200 MW
Path 49 EOR flow = 9,255 MW

DPV2 HA 2009, w/ maximum Path 66 COI stress, critical target flows[3]:
Path 66 COI flow = 4,800 MW
Path 49 EOR flow = 9,255 MW

DPV2 HA 2009, w/ maximum Path 61 Lugo-Victorville stress, critical target flows:
Path 61 flow = 2,400 MW
Path 49 EOR flow = 9,255 MW

DPV2 HA 2009 EOR 9,255 MW w/ maximum Palo Verde area generation, i.e. PV Hub Sensitivity

Palo Verde area generation = 10,075 MW
Aggregate PV-Hassayampa Reactive output -800 MVAR ('buck')
Palo Verde Bus Voltage = 525 kV
Path 49 EOR Flow = 9,255 MW

[3] The Study Plan also cited coincident Path 26 Midway-Vincent Flow at 4,000 MW. Maximizing coincident imports into SCE's load center from both the desert southwest and the northwest, at off-peak load, was not feasible. The amount of internal-area generation turnback would exceed SCE's minimum Must-Take (hydro, nuclear and QF) and Reliability Must Run generation quantities. The aggregate generation on-line in SCE's system from these sources is assumed to be over 7,000 MW for a 2009 scenario.

DPV2 HA 2009, Post-DPV2 Combined with 'EOR 9,000' Project
Add Physical Plan of Service per SRP 10/10/2005 Report
Path 49 EOR Flow = 10,500 MW (9,255 + 1,245 MW)

HEAVY SUMMER SENSITIVITIES[4]

DPV2 HS 2009, w/ maximum Palo Verde area generation, i.e. PV Hub Sensitivity
Palo Verde area generation = 10,075 MW
Aggregate PV-Hassayampa Reactive output = -800 MVAR ('buck')
Palo Verde Bus Voltage = 525 kV
Path 49 EOR Flow = 7,400 MW

3. Generation & Other System Device Assumptions

Following are case attributes for which specific modeling choices were made, and/or tested. These are the same set of generation, and other system device assumptions, of interest that were identified in the Study Plan.

a. Mountainview units, proposed to be connected at SCE's San Bernardino 230 kV Substation, are assumed to be on-line.[5]

b. Mountain Vista units 3 and 4, connected at SCE's Etiwanda 230 kV Substation are assumed to be retired.

c. Both SONGS nuclear units are on-line.

d. Both Mohave Units on line is the base case condition. Mohave off will be evaluated as a sensitivity.[6]

e. Blythe Generation Project I, with a capacity of 520 MW, is assumed to be on-line.

f. Palo Verde nuclear units No. 1 and No. 3 are modeled at a capacity of 1,403 MW on each unit. Palo Verde unit No. 2 is at 1,400 MW.

g. Cases with Perkins phase shifters modeled as in-service, and also out of service either bypassed or at nominal 0 angle.

[4] The Study Plan included a scenario with EOR at post DPV2+EOR9000 non-simultaneous flow level of 10,500 MW. Based on WATS dialog regarding limited relevance of Heavy Summer cases to regional Path studies, this sensitivity was not evaluated. In addition, there are not enough modeled resources available in the Desert Southwest to meet 1) native load, and 2) meet maximum export path flows. The remaining HS09 simultaneous flow stress scenarios were eliminated.
[5] A sensitivity case was developed in the DPV2 Path Rating studies to evaluate the Mountainview units off-line. The results from that earlier study indicated that the Mountainview units, on or off, do not alter the scope of the Plan-of-Service for DPV2.
[6] This is an update to the Study Plan, based on current corporate intention to bring Mohave back to service.

STUDY METHODOLOGY

1. Outage Modeling

This analysis performed a series of sensitivity studies to identify feasible options of load or generation & load, that could be dropped as part of a SPS, to meet the WECC/NERC Planning Standards for double contingency (Level C). There are several Level C line outages identified as credible and within the characteristics of a NERC/WECC Level C contingency relevant to the DPV corridor. The four N-2 Level C outages identified as credible are:

1. Devers asymmetrical bus fault (close-in single-line-to-ground (SLG)) cleared by opening Harquahala-Devers and Palo Verde Devers 500 kV lines.
2. SLG line fault out on the Devers-Palo Verde 500 kV line (at Copper Bottom Pass), cleared by opening Harquahala-Devers and Palo Verde Devers 500 kV lines.
3. SLG line fault out on the Devers-Harquahala line (near Harquahala just ahead of the point where the two DPV lines no longer share the same corridor), cleared by opening Harquahala-Devers and Palo Verde Devers 500 kV lines.
4. SLG line fault out on the Hassayampa-Harquahala 500 kV line (mid-way between the two substations), cleared by opening the Palo Verde-Devers and Hassayampa-Harquahala 500 kV lines.

This study evaluated SPS robustness by evaluating performance under contingency conditions that included an initiating 3-phase fault. While this gives a conservative result, i.e. worst-case system impacts, this will not be the future design basis of any future SPS, since this degree of fault severity exceeds NERC Level C.

2. Identification of Critical System Parameters

Additional sensitivity analysis was performed to quantify the influence that selected system parameters may have on system performance. The following parameters were considered evaluation in this analysis, due to their likely influence:

1. Combined DPV1 and DPV2 Flow
2. Palo Verde-Devers 500 kV Line Flow
3. Hassayampa-N.Gila 500 kV Line Flow
4. West of Miguel Flow
5. EOR Path Flow
6. WOR Path Flow
7. Southern California Edison Load
8. Perkins phase shifter operation
9. Reactive output of the Palo Verde-area generators
10. Others as may be revealed during the analysis

As discussed below in Study Results, this list was narrowed to focus on a subset of parameters that displayed significant influence in early study results.

To determine the degree of impact on system performance, the magnitude of each parameter was varied in 100 MW increments, using the most limiting system condition case, and the relevant system performance measure checked (i.e. bus voltage deviation, phase shifter thermal loading).

Parameters that impact the performance in a significant manner were considered influential, or critical, as compared with those parameters which have little impact on the performance. The goal here was to identify as few parameters as possible, essentially the one or two that stand out as excellent indicators in predicting performance. Those parameters that exhibit a high degree of influence are identified, for future detailed technical evaluation, and consideration for incorporation into future SPS or nomogram design.

An additional system operating attribute was identified for consideration while the study was in progress. This MWD protection scheme opens the J.Hinds-Mirage 220 kV line under certain conditions to protect against potential overload of the Camino-Iron Mountain 220 kV line, for loss of DPV1. For this study, all cases have been screened to identify if the two system conditions are present, for which this protection scheme would need to be invoked.

CONDITION 1. 65 MW flow towards Mirage on the J.Hinds-Mirage 220 kV line, and 206 kV or lower voltage at J. Hinds substation

CONDITION 2. 250 MVA flow on the Iron Mountain-Eagle Mountain 220 kV line

3. Optimization of SPS Actions

The earlier DPV2 Technical Study Report identified the need to drop generation in the Palo Verde area and load in the Southern California area. Specifically, generation at Red Hawk, Panda Gila River and Harquahala generating plants, and load at Padua and Villa Park substations were used to test SPS effectiveness, in the earlier study.

For this study, the Study Plan originally identified the following set of generators to test for mitigation effectiveness, due to their likely influence, and to ensure an adequate population to draw upon:

1. Harquahala
2. Red Hawk
3. Panda Gila River
4. Griffith
5. Four Corners unit 4

As discussed below, effectiveness factors for specific generators were not determined in this study. Primarily, this is because SCE is currently advocating approval of a SPS conceptual plan that does not include generator drop. IF, the ultimate decision is made to pursue an SPS plan that does include generation drop, the above list should not be considered as the only generators that could be effective, or could by included, in a SPS plan. The list of plants above is only a representative, partial list, of potential generation plants who's units could be effective. It should also be noted that this subset of generation plants, listed above, includes a range of owners and ownership types, including, sole utility ownership, sole non-utility(IPP) ownership, and joint utility ownership. There is no intention for this listing above to limit any future *technical* evaluation of plant effectiveness due to ownership type.

However, as this study's analysis progressed it became apparent that 1) credible mitigation schemes that did not need to include generation drop were feasible, and 2) the system performance criteria violations went beyond the voltage collapse/dip violations identified in earlier DPV2 studies.

Therefore, the focus of this study shifted from minimizing SPS-dropped generation, per the Study Plan, to finding a SPS scheme that covered a broader set system performance challenges, including thermal overload, and dynamic stability, in addition to the earlier identified post-transient voltage collapse/dip problem.

Optimizing, for the purpose of this study, consisted of developing a consolidated SPS scheme that provides comprehensive effectiveness across the expanded types of system performance violations identified in this study; thermal overload, post-transient voltage drop, and transient stability damping.

The study's analysis of critical system parameters are provided as an indication of the likely magnitude of various measures, such as a monitored Path's flow, that could be used to trigger arming of a future SPS scheme, or setting limits for a nomogram. Study results that are discussed in the Study Findings report section below are intended in-part as technical input for future work that will continue development of specific SPS details, and any related operating nomograms.

As the study evolved, it was apparent that defining a set of specific arming points for a specific SPS-scheme was premature. The achievable and useful technical goal of this study shifted to 1) determining if an SPS is needed for the critical N-2, 2) determining effectiveness of various *conceptual* SPS schemes under consideration, such as load drop or load and generation drop, and 3) providing input for future detailed SPS design of a specific SPS scheme, once a 'conceptual' plan has been accepted for further development. Therefore, the name of this study, prepared for WATS approval, was updated to "SPS Conceptual Planning Study".

STUDY FINDINGS

1A. Post Transient Analysis Results & Voltage Dip Mitigation

Under both HA and HS seasonal conditions, there were post-transient voltage dip violations that required mitigation. Both load drop and load+generation drop were evaluated as mitigation alternatives.

The table below summarizes the identified post-transient voltage violations, and tested mitigation, for each seasonal base case and sensitivity cases.

HA 2009, Post Transient, V-Dip Mitigation Effectiveness Summary

Load Flow Case, SWT outage file	CA/SCE Load Drop, MW	AZ Gen Drop, MW	PT No Solution, y/n V-dip violations, % Worst V-Dip %	Comments
ha09post-sps-00f.sav (EOR 9255, base case) DPV12-0.swt	-0	-0	Solves, No V-dip violations -6.1% Egl Mtn 161 kV	No Mitigation
ha09post-sps-01.sav (EOR 9255, P64 1,200) DPV12-F1.swt	-1300	-0	No Solution	Load Drop
ha09post-sps-01.sav (EOR 9255, P64 1,200) DPV12-G6.swt	-1,590	-0	Solves No V-Dip Violations -7.1% Egl Mtn 161 kV	Load Drop
ha09post-sps-01.sav (EOR 9255, P64 1,200) DPV12-AC.swt	-390	-250	No Solution	Load Drop & Gen Drop
ha09post-sps-01.sav (EOR 9255, P64 1,200) DPV12-ACxx.swt	-820	-750	Solves No V-Dip Violations -6.9% Egl Mtn 161 kV	Load & Gen Drop
ha09post-sps-02f.sav	-1,300	-0	Solves	Load Drop

(EOR 9255, P66 4,800) DPV12-F1.swt			No V-Dip Violations -8.7% Mig 500 kV	
ha09post-sps-02f.sav (EOR 9255, P66 4,800) DPV12-AC.swt	-390	-250	Solves No V-Dip Violations -8.8% Mig 500 kV	Load Drop & Gen Drop
ha09post-sps-03.sav (EOR 9255, P61 2,400) DPV12-F1.swt	-1,300	-0	No Solution	Load Drop
ha09post-sps-03.sav (EOR 9255, P61 2,400) DPV12-G6.swt	-1,590	-0	Solves No V-Dip Violations -5.7% Mig 500 kV	Load Drop
ha09post-sps-03.sav (EOR 9255, P61 2,400) DPV12-AC.swt	-390	-250	No Solution	Load Drop & Gen Drop
ha09post-sps-03.sav (EOR 9255, P61 2,400) DPV12-ACxx.swt	-820	-750	Solves No V-Dip Violations -5.3% Imp Vly 500 kV	Load & Gen Drop
ha09post-sps-04f.sav (EOR 9255, PV Hub Op Stress) DPV12-0.swt	-0	-0	Solves, No V-dip violations -6.2% Egl Mtn 161 kV	No Mitigation
ha09post-sps-05f.sav (EOR 10500, 'Combo') DPV12-F1.swt	-1,300	-0	Solves V-Dip Violations -10.8% Mig 500 kV	Load Drop
ha09post-sps-05f.sav (EOR 1,500, 'Combo') DPV12-G6.swt	-1,590	-0	Solves No V-Dip Violations -9.1% Mig 500 kV	Load Drop
ha09post-sps-05f.sav (EOR 10500, 'Combo') DPV12-AC.swt	-390	-250	Solves V-Dip Violations -11.0% Mig 500 kV	Load Drop & Gen Drop
ha09post-sps-05f.sav (EOR 10500, 'Combo') DPV12-ACxx.swt	-820	-750	Solves No V-Dip Violations -7.6% Imp Vly 500 kV	Load & Gen Drop
ha09post-sps-06.sav (EOR 9255, P46 11823) DPV12-F1.swt	-1,300	-0	Solves V-Dip Violations -8.7% Egl Mtn 161 kV	Load Drop
ha09post-sps-06.sav (EOR 9255, P46 11823) DPV12-AC.swt	-390	-250	Solves No V-Dip Violations -8.8% Egl Mtn 161 kV	Load Drop & Gen Drop

For the HA 2009 system scenarios, the range of mitigation needed to address post-transient voltage drop violations ranged from none, to either -1,590 MW load drop, or a combination of -820 MW load and -750 MW generation drop.

HS 2009, Post Transient, V-Dip Mitigation Effectiveness Summary

Load Flow Case, SWT outage file	CA/SCE Load Drop, MW	AZ Gen Drop, MW	PT No Solution, y/n V-dip violations, % Worst V-Dip %	Comments
hs09post-sps-00f.sav (EOR 7400, base case) DPV12-G4.swt	-2,090	-0	Solves No V-dip violations -8.8% Iron Mtn 230 kV	Load Drop
hs09post-sps-00f.sav	-1,260	-750	Solves	Load & Gen Drop

(EOR 7400, base case) DPV12-ACxx.swt			No V-dip violations -8.7% Iron Mtn 230 kV	
hs09post-sps-09f.sav (EOR 7400, PV Hub Op Stress) DPV12-G4.swt	-2,090	-0	Solves No V-dip violations -8.4% Iron Mtn 230 kV	Load Drop
hs09post-sps-09f.sav (EOR 7400, PV Hub Op Stress) DPV12-ACxx.swt	-1,260	-750	Solves No V-dip violations -8.6% Iron Mtn 230 kV	Load & Gen Drop

For the HS 2009 system scenarios, the range of mitigation needed to address post-transient voltage drop violations required load drop of -2,090 MW, or a combination of -1,260 MW load and -750 MW generation drop. The overall system scenario with the worst overall post-transient voltage performance was the HS base case.

Selected output logs from post-transient load flow runs are contained in "APPENDIX POST-TRANSIENT".

1B. Transient Analysis Results & Dynamic Stability Mitigation

For the modeled HS seasonal condition, no transient stability, voltage drop, or frequency drop violations were identified for base case, or the PV Hub sensitivity cases.

For the modeled HA seasonal conditions there were several instances of marginally positive damping, approaching critical damping. Marginal positive damping was present for three HA simultaneous flow sensitivity cases, P61 Mead-Adelanto, P66 COI, and P46 WOR. There were no transient voltage or frequency drop violations identified in any of the HA cases. Load drop mitigation was tested for the three HA sensitivity cases that demonstrated marginally damped stability, Load drop mitigation was tested for effectiveness in improving positive damping.

The table below summarizes the three cases that demonstrated marginally positive damping, and the tested load drop mitigation for the three critical HA simultaneous Path sensitivity cases.

HA 2009, Transient, Damping Mitigation Effectiveness Summary

Load Flow Case, SWT outage file	CA/SCE Load Drop, MW	AZ Gen Drop, MW	Positive Damping, y/n	Comments
ha09post-sps-01.sav (EOR 9255, P64 1,200) DPV12-A.swt	-390	-0	Positive Damping	Load Drop marginally damped at -0
ha09post-sps-02f.sav (EOR 9255, P66 4800) DPV12-E.swt	-390	-0	Positive Damping	Load Drop marginally damped at -0
hs09post-sps-06f.sav (EOR 9255, WOR 11,823) DPV12-E.swt	-390	-0	Positive Damping	Load Drop marginally damped at -0

A key result was the demonstration of dynamically stable system performance for mitigation scenarios that asymmetrically drop load, without a balancing amount of generation drop. And, since the amount of mitigation needed for thermal overloads or post-transient voltage deviation exceed the needs for transient stability, no further transient stability analysis was performed.

Transient stability plots are contained in "APPENDIX TRANSIENT".

1C. Load Flow Analysis Results & Thermal Overload Mitigation

The identification of thermal limits that could be mitigated via a SPS scheme was identified in the DPV2 Path Rating studies. Relevant to SPS Arming, the Path Rating studies identified 1) the facilities that are overloaded for the DPV1&2 N-2 outage, 2) three critical system conditions that result in worst-case thermal overloads, and 3) the effective mitigation alternatives.

The table below summarizes the three system scenarios, and the four affected facilities, that define the thermal loading constraints. The loading levels shown are pre-mitigation.

Load Flow, Worst-Case Overloads, Pre-Mitigation

Overloaded Facility Worst System Condition	Perkins Phase Shifters 1 & 2 MVA|% E-Rating	Mead-Perkins Series Capacitors A|% E-Rating	Victorville-Lugo 500 kV line A|% E-Rating	Liberty Phase Shifter MVA|% E-Rating
HA, Path 61 Simultaneous EOR Path Rating Case	**1019|116%**	2262|117%	3282|109%	**604|101%**
HA, PV Hub Operat'l Limit EOR Path Rating Case	1017|116%	**2278|118%**	3269|109%	602|100%
HA, Path 61 Simultaneous WOR Path Rating Case	998|113%	2206|114%	**3430|114%**	594|99%

These critical overloads are significantly lower in the HS case scenarios. One loading issue unique to summer is the overload of the Camino-Iron Mountain 230 kV line. This overload, and confirmation that opening J.Hinds-Mirage 230 kV line mitigates this HS-related issue is discussed in the Critical System Parameters report section below.

"APPENDIX FLOW 1" presents a detailed matrix of all system cases, and the corresponding loadings of these four impacted facilities, "pre-mitigation".

The table below illustrates two of the mitigation options that fully addresses the full range of three critical system scenarios, and four overloaded facilities. The first mitigation option depends on dropping both load and generation. The second preferred option drops load coordinated with several pre-fault operational attributes; Perkins phase shifter operational status and condition (neutral), and uses a nomogram to limit Path 61 flow.

Load Flow, Worst Case Overloads, Post-Mitigation

Overloaded Facility Worst System Condition, Mitigation Scheme	Perkins Phase Shifters 1 & 2 % E-Rating	Mead-Perkins Series Capacitors Amps, & % E-Rating	Victorville-Lugo 500 kV line Amps, & % E-Rating	Liberty Phase Shifter % E-Rating
HA, EOR, Path 61 Simultaneous, Perkins PS holding 1,300 MW N-1 Nomogram Point, P61 @ 1920 MW SCE Load Drop -1,744 MW AZ Gen Drop -1,125 MW	100.8%	1916 | 99.3%	2769 | 92.3%	92.2%
HA, EOR, Path 61 Simultaneous Perkins PS at neutral N-2 Nomogram Point, Path 61@1650 MW SCE Load Drop -1,256 MW	94.0%	1810 | 93.8%	2814 | 93.8%	99.9%
HA, EOR, PV Hub Op Limit, Perkins PS holding 1,300 MW SCE Load Drop -1,744 MW AZ Gen Drop -1,125 MW	100.6%	1924 | 99.7%	2802 | 93.4%	92.1%
HA, EOR, PV Hub Op Limit Perkins PS at neutral SCE Load Drop -1,256 MW	94.1%	1827 | 94.7%	2778 | 92.6%	99.4%
HA, WOR, SCIT, Perkins PS holding 1,300 MW SCE Load Drop -1,744 MW AZ Gen Drop -1,125 MW	100.7%	1915 | 99.2%	<90%	92.1%
HA, WOR, SCIT Perkins PS at neutral SCE Load Drop -1,256 MW	<90%	<90%	<90%	99.9%

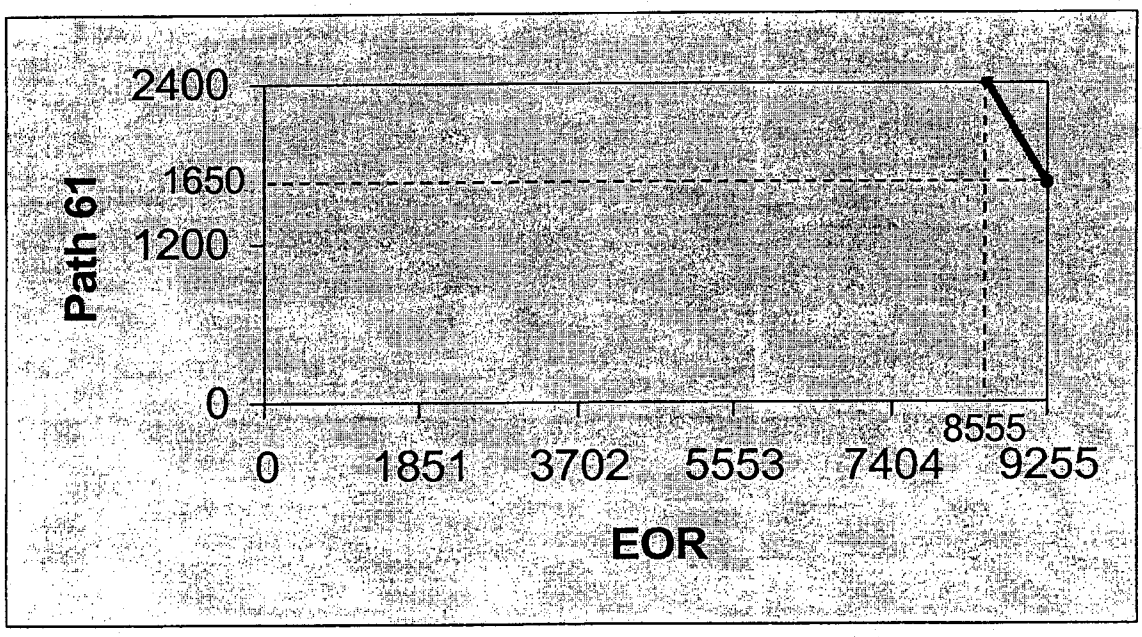
"APPENDIX FLOW 2" presents a detailed matrix of all system cases, and the corresponding loadings of the four impacted facilities, for the full complement of tested mitigation options.

The study findings illustrate that by adding two pre-fault operational coordination issues 1) nomogram for Path 61 flow, and 2) Perkins phase shifter operation, a much simpler automated portion of the SPS is feasible. The simplification is due to no need to incorporate automated generation drop into the SPS. In addition, the modeled post-outage-post-mitigation system performance is generally superior, i.e. lower aggregate loading on the impacted facilities, with the preferred SPS alternative.

The preferred SPS alternative does rely on two operational attributes. First, the Path 61 nomogram evaluated in the Path Rating Study was found to be effective for mitigation of thermal overloads. For the SPS Conceptual Plan study, one of the Path Rating study nomograms was re-evaluated for effectiveness under N-2 conditions with the preferred SPS scheme active. This re-evaluation determined that this nomogram would be effective contingent on completion of upgrade of Victorville-Lugo 500 kV line, as recommended in SCE's 2005 Expansion Plan (see "APPENDIX ADDENDUM" pages 19-21). At the initial knee point, P61 2,400 MW and P49 at 8,555 MW, Victorville-Lugo 500 kV had a post-DPV1&2 outage loading of 3,269 A, or 109% of the line's current emergency rating. In addition, the re-evaluation illustrated that EOR flow is not very effective as a measured/managed system attribute, for a nomogram to manage P61 thermal constraints. This is consistent with current practice, i.e. CAISO's operating procedure T-135 to manage this Victorville-Lugo loading monitors other more relatively effective lines.

EOR – Path 61 N-2 Nomogram for Thermal Mitigation

Mohave On Line



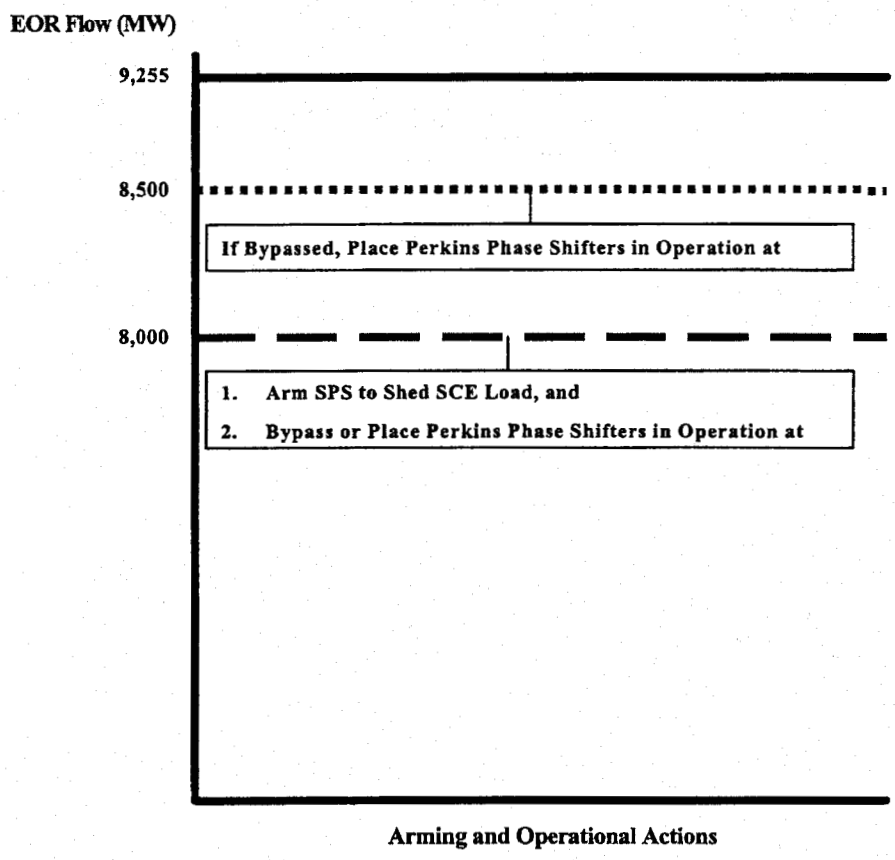
The second operational attribute that will need to be incorporated into the preferred SPS plan is coordinated operation of Perkins phase shifter. The study found that specific phase shifter operating states, above certain EOR flow levels, are needed as part of the preferred SPS option. At 8,000 MW the phase shifter would need to be either bypassed or in-service at neutral angle. And at higher EOR flow levels, 8,500 MW or above, the Perkins phase shifter will need to be in-service and at neutral angle.

The drawing below shows the EOR flow arming points for determining Perkins phase shifter operating condition, and arming load drop.

DPV2 SPS Preferred Conceptual Plan

SPS Arming & Perkins Phase Shifter Operational Diagram

Mohave In Service



This study's modeling of SPS for mitigation of thermal overloads was primarily a means to evaluate effectiveness of various mitigation options, and does not indicate that SPS-based mitigation will be the final solution to be developed for managing N-2 thermal overload problems. Thermal loading time constants typically allow more latitude for use of operating procedures, versus SPS-based automated high speed switching corrective actions. Mitigating voltage collapse or transient instability threat does not afford this temporal latitude, and mitigation for these problems is anticipated to be solved through a high speed automated SPS-based solution.

2. Identified Critical System Parameters

The Study Plan identified the following system parameters to be evaluated for likely influence on system performance.

1. Combined DPV1 and DPV2 Flow
2. Palo Verde-Devers 500 kV Line Flow
3. Hassayampa-N.Gila 500 kV Line Flow
4. West of Miguel Flow
5. EOR Path Flow
6. WOR Path Flow
7. Southern California Edison Load
8. Perkins phase shifter operation
9. Reactive output of the Palo Verde-area generators
10. Others as may be revealed during the analysis

The initial results gave strong indication that the overall flow on aggregate Paths had significant influence the system performance attributes that related to the system performance limitations that pertained to N-2 loss of of DPV1 and DPV2: post transient voltage dips at a several California substations, and thermal loading of several transmission line and/or line related facilities in Arizona. Therefore, this study chose to concentrate on the most impactful variables, after review of initial study results.

1. EOR Path Flow
2. WOR Path Flow
3. Southern California Edison Load
4. Perkins phase shifter operation
5. Reactive output of the Palo Verde-area generators

After review of initial study results, one additional system parameter, SCE 500 kV bus voltage, appeared to be of potential significant relevance to the post-transient non-convergence, for stressed HS cases. This additional system parameter was added to the list for further evaluation. The last system parameter added to the list for further analysis was Mohave generating station operating status: two unit on, versus two units off.

The final list of system parameters selected for further analysis in this study was,

1. EOR Path Flow
2. WOR Path Flow
3. SCE Load

4. Perkins phase shifter operation
5. Palo Verde-area generators reactive output
6. Mohave Generating Station Status
7. SCE 500 kV bus, minimum voltage (HS only)

To test these system parameters, the seasonal case scenario that corresponded to the matching limiting system performance limitations was used: HA for thermal overloads, and HS for post-transient voltage drops. For the HA case, no mitigation was applied. However, with the HS case, some mitigation is needed to obtain a solution. 2,090 MW load drop was used when executing the system parameter testing. It was used uniformly when testing all parameters, so any cross-relationships between the load drop mitigation, and any other system parameter under evaluation would be uniformly applied.

Following is a brief description of the analytic method used to isolate each parameter of interest, to test its specific impact on the limiting system performance violations.

EOR FLOW : Incremented flow in multiples of 100 MW stages, from a nominal 9255 MW for HA cases, and 7,400 MW for HS cases. Modified AZ Area 14 export/interchange to SCE Area 24, and reduced an offsetting amount of SCE Area 24 generation.

WOR FLOW: Incremented flow in multiples of 100 MW stages from a nominal 8,973 MW in the HA case, and 9,288 in the HS case. Modified NV Area 18 export/interchange to SCE Area 24 and/or increased North of Lugo generation, and reduced an offsetting amount of in-basin SCE Area 24 generation.

SCE LOAD : Incremented load in multiples of 100 MW stages from a nominal 15,198 MW in the HA case, and 23,580 in the HS case. Scaled total SCE LA Basin load Zone 240, and increased Zone 240 generation to offset the load increase.

Perkins PS Operation : Ran cases with three operating states, 1) operating and holding flow, 1,300 MW [nominal state], 2) bypassed, and 3) operating at neutral

PV MVAR OUTPUT : Incremented PV generators' Q output in +/-100 MVAR stages from nominal starting point in cases. Changed the PV generators' regulated bus (PV 500 kV) V-schedule as needed to get the target +/-Q output change.

MOHAVE STATUS : Ran cases with both Mohave units on [nominal state], and both units off. SCE internal generation was adjusted to offset the Mohave status change.

MIN SCE 500 kV : Incremented lowest SCE 500 kV bus in +/- 2.5% stages from nominal starting voltage. Lowest bus voltage in the HS stress case used as nominal starting point was 511.2 kV at Mira Loma bus. Set Vsched at the lowest 500 kV bus to the target value, applied a synchronous condenser to establish bus voltage, then locked the synchronous condenser output at the needed Q value, and then ran the outage.

The tables below show the relationship between the incremental change in each system parameter and the

change (or lack of) in the constraining system performance attribute. The constraining system performance attributes vary by season, and are shown in separate tables. The HA constraint is thermal loading, and the HS constraint is post-transient voltage dips.

HA, Critical Thermal Loading Variation VS. System Parameter Change

Perkins-Mead Series Cap. | Liberty-Mead P.S.

% of Emergency Rating Loading, after N-2 outage, no mitigation

STAGES are +/-100MW(MVAR) or +/-1.25% VOLTAGE or Device Status	Stage -3	Stage -2	Stage -1	Stage 0 [Nominal]	Stage +1	Stage +2	Stage +3
EOR FLOW [value]	116% | 99% [8,955]			118% | 100% [9,255 MW]			n/a
WOR FLOW [value]	118% | 99% [8,670 MW]			118% | 100% [8,970 MW]			119% | 100% [9,270 MW]
SCE LOAD [value]	118% | 119% [14,900 MW]			118% | 100% [15,196 MW]			118% | 100% [15,500 MW]
PERKINS P.S. [status]			116% | 97% [bypass]	118% | 100% [flow control]	104% | 100% [0 angle]		
PV GEN MVAR [value]	118% | 100% [36 MVAR]			118% | 100% [339 MVAR]			118% | 100% [648 MVAR]
MOHAVE [status]				118% | 100% [on]	117% | 100% [off]		

HS, Critical Post-Transient V-Dip Variation VS. System Parameter Change

Iron Mountain 230 kV | Imperial Valley 500 kV

% V-Dip, after N-2 outage, -2,090 MW load drop mitigation

STAGES are +/-100MW(MVAR) or +/-5% VOLTAGE or Device Status	Stage -3	Stage -2	Stage -1	Stage 0 [Nominal]	Stage +1	Stage +2	Stage +3
EOR FLOW [value]	-7.5% | -3.6% [7,100]			-8.8% | -4.2% [7,400 MW]			-9.4% | -4.5% [7,700]
WOR FLOW [value]	-8.0% | -4.0% [9,040MW]			-8.8% | -4.2% [9,344 MW]			-9.5% | -4.4% [9,640 MW]
SCE LOAD [value]	-8.3% | -4.1% [23,280 MW]			-8.8% | -4.2% [23,580 MW]			-8.7% | -4.2% [23,880 MW]
PERKINS P.S. [status]			-8.4% | -4.6% [bypass]	-8.8% | -4.2% [flow control]	-8.2% | 4.6% [0 angle]		
PV GEN MVAR [value]	-8.0% | -4.1% [590]			-8.8 | -4.2% [886 MVAR]			-8.9% | -4.1% [1,190]
MOHAVE [status]				-8.8 | -4.2% [on]	-7.2% | -3.8% [off]		
MIN SCE 500 kV [value]			-9.2 | -4.2% [499 kV]	-8.8 | -4.2% [511.2 kV]	-7.9 | -4.0% [524 kV]		

For this study, a particular system parameter was identified as "significant" if it's influence over the system limitations to be mitigated was relatively higher than other parameters. No specific effectiveness factor was used as a screen, or threshold. Significance was strictly a relative measure. The measure used to make this relative judgment was the change in limiting performance value, %-v-dip, or % thermal overload, per unit of system parameter increment, or "stage" as shown in the table above. Based on the this relative basis, the most significant system parameters identified in this study were,

1. EOR Flow (post transient and thermal)
2. WOR Path Flow (post transient and thermal)
3. Perkins phase shifter status and operating condition (thermal)
4. SCE minimum 500 kV bus voltage level (post transient voltage)
5. Mohave Status (post transient voltage)

These measurable system attributes can be used for development of operating nomograms to be used in conjunction with an automated load drop SPS.

Following initiation of the study, MWD requested that an additional set of system parameters be checked in this study; line flows on Camino-Iron Mountain 230 kV, Iron Mountain-Eagle Mountain 230 kV line, and Julian Hinds 230 kV bus voltage (206 kV). SCE also added monitoring of line flows on the Julian

Hinds-Mirage 230 kV line. "APPENDIX MWD" provides these selected statistics from all the study cases. This appendix also provides the 'screening' thresholds for each monitored items that are relevant to other existing protective schemes that protect against thermal overloads from N-1 loss of DPV1. As shown in the appendix, the screening values were not exceeded in any of the study cases, under "pre-fault" conditions. Future detailed SPS development may need to examine the impact to the arming points for the MWD protective schemes.

While the conditional 'screening' criteria used for the existing protective scheme were not exceeded, N-2 loss of DPV1 & DPV2, under HS stress conditions, did result in thermal overload of Camino-Iron Mountain 230 kV and J.Hinds-Mirage 230 kV lines. An additional case with J.Hinds-Mirage 230 kV out of service pre-fault, did show that the MWD overloads are mitigated, and no new criteria violations are triggered. The post-transient logs for both the overload condition, and then the mitigated condition (J.Hinds-Mirage 230 kV out of service) are shown in "APPENDIX MWD".

3. Consolidated SPS and Optimization

The two mitigation alternatives were run on the full complement of study cases to determine what 'consolidated' SPS scheme would mitigate the two bounding types of identified system performance problems; thermal overload and post-transient excessive voltage deviation.

The following two tables illustrate the findings from these final set of post-transient load flow runs.

CONSOLIDATED MITIGATION SCHEME 1
CA LOAD DROP AND OPERATIONAL COORDINATION

SPS Study Case	Thermal Overload, % E-Rating	Voltage Dip, Bus,% Dip	Comments
ha09post-sps-00fp0.sav EOR 9,255	Perkins-Mead 500 kV, 99.8% Liberty PS 230 kV, 98.7%	Iron Mtn 230 kV, -4.3% Imp Vlly 500 kV, -3.8%	Load Drop 1590 MW, Perkins PS Neutral Hass-HAT-WALC 101%
ha09post-sps-01fp0.sav EOR+P64 M-A 1,200	Perkins-Mead 500 kV, <90% Liberty PS 230 kV, 100.0%	Iron Mtn 230 kV, -6.7% Imp Vlly 500 kV, -6.3%	Load Drop 1590 MW, Perkins PS Neutral
ha09post-sps-02fp0.sav EOR+P66 COI 4,800	Perkins-Mead 500 kV, <90% Liberty PS 230 kV, 100.0%	Iron Mtn 230 kV, -6.4% Imp Vlly 500 kV, -6.9%	Load Drop 1590 MW, Perkins PS Neutral
ha09post-sps-03fp0PR.sav EOR+P61 L-V 2,400	Perkins-Mead 500 kV, 93.4% Liberty PS 230 kV, 99.9%	Iron Mtn 230 kV, -5.7% Imp Vlly 500 kV, -6.2%	Load Drop 1590 MW, Perkins PS Neutral, P61=1650
ha09post-sps-04fp0.sav EOR+PV Gen 10,075	Perkins-Mead 500 kV, 94.4% Liberty PS 230 kV, 99.5%	Iron Mtn 230 kV, -5.5% Imp Vlly 500 kV, -6.1%	Load Drop 1590 MW, Perkins PS Neutral,
ha09post-sps-05PR.sav 'combo' EOR 10,500	Perkins-Mead 500 kV, 98.0% Liberty PS 230 kV, 99.4%	Iron Mtn 230 kV, -6.5% Imp Vlly 500 kV, -8.3% Miguel 500 kV, -9.1%	Load Drop 1590, Perkins PS n/a, Hass-HAT-WALC 101%, Santan-Thund 101%
ha09post-sps-06fp0.sav EOR+P46 WOR 11,823	Perkins-Mead 500 kV, <90% Liberty PS 230 kV, 100.4%	Iron Mtn 230 kV, -7.5% Imp Vlly 500 kV, -6.8%	Load Drop 1590 MW, Perkins PS Neutral,
hs09post-sps-00f1-perk0.sav EOR 7,400	Perkins-Mead 500 kV, <90% Liberty PS 230 kV, 99.9%	Iron Mtn 230 kV, -2.2% Imp Vlly 500 kV, -4.7%	Load Drop 2090 MW, Perkins PS Neutral, JH-Mir ST=0 PINPK-PNPKAPS 101%,
hs09post-sps-09fp0-jh.sav EOR+PV Gen 10,075	Perkins-Mead 500 kV, <90% Liberty PS 230 kV, 99.9%	Iron Mtn 230 kV, -2.2% Imp Vlly 500 kV, -4.8%	Load Drop 2090 MW, Perkins PS Neutral, JH-Mir ST=0 PINPK-PNPKAPS 101%,

The post-transient load flow run output logs for this table is contained in "APPENDIX MITIGATION 1".

CONSOLIDATED MITIGATION SCHEME 2

CA LOAD DROP AND AZ GENERATION DROP

SPS Study Case	Thermal Overload, % E-Rating	Voltage Dip, Bus,% Dip	Comments
ha09post-sps-00f1.sav EOR 9,255	Perkins-Mead 500 kV, 100.9% Perkins PS, 100.5%	Iron Mtn 230 kV, -2.6% Imp Vlly 500 kV, -3.1%	Load Drop 1740 MW, Generation Drop 1,200 MW
ha09post-sps-01f1.sav EOR+P64 M-A 1,200	Perkins-Mead 500 kV, 100.8% Perkins PS, 101.4%	Iron Mtn 230 kV, -4.4% Imp Vlly 500 kV, -3.4%	Load Drop 1740 MW, Generation Drop 1,200 MW
ha09post-sps-02f.sav EOR+P66 COI 4,800	Perkins-Mead 500 kV, 100.6% Perkins PS, 99.4%	Iron Mtn 230 kV, -3.6% Imp Vlly 500 kV, -3.7%	Load Drop 1740, Generation Drop 1,200 MW
ha09post-sps-03f.sav EOR+P61 L-V 2,400	Perkins-Mead 500 kV, 99.8% Perkins PS, 101.5%	Iron Mtn 230 kV, -3.5% Imp Vlly 500 kV, -3.4%	Load Drop 1740 MW, Generation Drop 1,200 MW
ha09post-sps-04f.sav EOR+PV Gen 10,075	Perkins-Mead 500 kV, 99.9% Perkins PS, 97.7%	Iron Mtn 230 kV, -2.0% Imp Vlly 500 kV, -2.3%	Load Drop 1740 MW, Generation Drop 1,200 MW
ha09post-sps-05PR.sav 'combo' EOR 10,500	Perkins-Mead 500 kV, <90.0% Perkins PS, n/a	Iron Mtn 230 kV, -4.0% Imp Vlly 500 kV, -5.0%	Load Drop 1740, Perkins PS n/a, Generation Drop 1,200 MW
ha09post-sps-06f.sav EOR+P46 WOR 11,823	Perkins-Mead 500 kV, 100.9% Perkins PS, 102.5%	Iron Mtn 230 kV, -4.1% Imp Vlly 500 kV, -3.8%	Load Drop 1740 MW, Generation Drop 1,200 MW
hs09post-sps-00f1-jh.sav EOR 7,400	Perkins-Mead 500 kV, 100.8% Perkins PS, 98.5%	Iron Mtn 230 kV, -1.2% Imp Vlly 500 kV, -2.6%	Load Drop 2090 MW, Gen Drop 1,200 MW,JH-Mir ST=0 PINPK-PNPKAPS 101%,
hs09post-sps-09f-jh.sav EOR+PV Gen 10,075	Perkins-Mead 500 kV, 100.8% Perkins PS, 97.9%	Iron Mtn 230 kV, -1.2% Imp Vlly 500 kV, -2.5%	Load Drop 2090 MW, Gen Drop 1,200 MW, JH-Mir ST=0 PINPK-PNPKAPS 101%,

The post-transient load flow run output logs for this table is contained in "APPENDIX MITIGATION 2".

The study findings indicate that the preferred plan, using load drop and operational coordination, can mitigate both types of system performance limitations: thermal overloads loads, and post-transient voltage dips.

The study's final scenario evaluated the amount of load drop, in conjunction with the two operational aspects of the preferred SPS, that were needed to mitigate both the thermal and voltage deviation limits.

The consolidated scenario that mitigate constraints are:

PREFERRED LOAD DROP + OPERATIONAL COORDINATION SPS:

1) For HA, 1,590 MW of load drop was needed in conjunction with, revision of the Path 61 nomogram, and having the Perkins phase shifter in service but at 0 degree neutral position. The output for the set of HA cases using this specific mitigation scheme is shown in "APPENDIX MITIGATION 1" pp. 1-22. Please note, there are residual overloads on the modeled 'SECDD' lines, Hassyamp-HAT-WALC 230 kV 101%, and Santan-Thundrst 230 kV 101%.

The Victorville-Lugo 500 kV line overload, and a plan to coordinate a solution to this problem has been identified in SCE's 2005 Transmission Expansion Plan. (See "APPENDIX ADDENDUM" pages 19-21). The future efficacy of this preferred SPS option will be enhanced by this recommended project to upgrade the Victorville-Lugo 500 kV line.

2) For HS, 2,090 MW of load drop was needed. For this scenario, the assumed operational coordination was opening of the Julian Hinds-Mirage 220 kV line. In this scenario, there is a residual overload of 101.4% on the modeled PINPK-PNPKAPS 230 kV SECDD line section. The output for the set of HA cases using this specific mitigation scheme is shown in "APPENDIX MITIGATION1" pp. 23-28.

Further refinement, and optimization, of the SPS presented in this report will be undertaken once the conceptual plan has been approved.

During the course of this study, additional data was collected that could pertain to future design of an operating nomogram. In the course of this study, CAISO hourly historical records from 2005 were provided, and are on file at SCE Transmission Planning. This data could be used as a gauge to more closely match SPS arming characteristics with expected real time operating conditions. Specified ranges of magnitudes and the hours at which they occurred could be determined by reviewing the hourly historical data for EOR flow, or potentially for any other of the measurable parameters that exhibited a high degree of influence. The outcome of this type of analysis could result in defining the relationship of the influential parameters in an operating nomogram for the purpose of arming generating units and load stations. This detailed correlation between historical flow patterns and influential parameters will be incorporated in future technical analysis to support design of any actual SPS and/ and related operating nomograms for the DPV2 project.

STUDY CONCLUSIONS

The identified system impacts that resulted in further evaluation of SPS-based mitigation alternatives include thermal overloads, excessive post transient voltage drops, and marginal transient stability. However, the bounding performance limitations were found to be thermal overloads, and post-transient voltage drops.

The level of SPS-based mitigation that was found effective for the two dominant system performance limitations, thermal overload and excessive post-transient voltage drop, will take care of the marginal damping identified in the transient analysis.

The identified significant system parameters that have the most influence on the system performance problems included, EOR and WOR Path flow, Perkins phase shifter operation, minimum SCE 500 kV voltages, and Mohave operating status. These particular system parameters are candidates for development of a nomogram that could be used in conjunction with a load drop SPS to successfully mitigate the system impacts due to N-2 loss of DPV1 and DPV 2. SCE has opened a dialog with SRP regarding the potential for coordinating operation of the Perkins phase shifter to allow for maximal system utilization. In support of this effort, SCE requested, and received approval, from the MPP E&O Committee to coordinate Perkins PST operation, with the proposed conceptual DPV2 N-2 SPS.

The study's evaluation of SPS effectiveness determined that, in general, dropping load will be effective in mitigating the full range of identified system impacts; thermal overload, post-transient voltage dip, and dynamic stability. For each of type of system impact, the amount of load drop needed to mitigate transmission system performance criteria violations are identified below. The amount of load drop shown below in bold text indicates the worst case, or limiting system condition, for the corresponding system performance measure.

SPS Load Drop Needed to Meet NERC System Performance Criteria

Seasonal Scenario	Thermal Overload	Post-Transient Voltage Deviation	Transient Stability
Heavy Autumn	**-1,250 MW**		
Heavy Summer	*[7]		
Heavy Autumn		-1,590 MW	
Heavy Summer		**-2,090 MW**	
Heavy Autumn			**-390 MW**
Heavy Summer			0 MW

Study findings identified two feasible SPS alternatives, one that uses automated load drop in conjunction with other operational measures, and a second alternative that uses automated load and generation drop. SCE recommends the first SPS alternative as a preferred option. SCE's preferred conceptual SPS plan is composed of 1) SPS-based automated load drop, 2) a nomogram for Path 61 for flow control and, 3) coordinated operation of the Perkins phase shifter. The information presented in this report will be input to the follow-on development of a detailed plan for a preferred conceptual SPS plan, and associated operating nomograms if needed. SCE will continue the technical development of our DPV2 N-2 SPS mitigation plan within the appropriate stakeholder forums.

[7] Load drop was needed with the HS stress case to obtain load flow/post-transient solution, and voltage/reactive-need mitigation. Minimum mitigation for load flow thermal problems is indeterminate for HS.

5/10/2006 ADDENDUM

At the 3/28/06 WATS Meeting, the WATS members asked for three additional study scenarios, and SCE added a fourth, to be completed prior to obtaining WATS approval. The four additional scenarios, presented in this addendum section of the report, are:

1) HA2009 Vicotrville-Lugo 500 kV Path 61 (P61) Simultaneous case at the initial 'knee' point of a conceptual P61 'N-2' nomogram (P61 at 2400 maximum and EOR reduced).

2) HS 2009 case with EOR at full proposed 9,255 MW flow. AZ load to be scaled lower to free up resources to enable modeling of this scenario.

3) HA 2009 Midway-Vincent 500 kV Path 26 (P26) at 4,000 MW, using the P26 load flow case developed by SCE for the DPV2 WOR Path Rating Study.

4) HA 2009 P64 Simultaneous and HS 2009 HS ('worst case conditions), with addition of SCE's 2006 Expansion Plan's proposed future addition of 2 X 150 MVAR shunt capacitors at Mira Loma 500 kV substation.

SCE was also directed to obtain approval from the MPP E&O Committee for approval to coordinate Perkins PST operations with the conceptual DPV2 N-2 SPS.

1) Path 61 Victorville-Lugo 500 kV (P61), 'N-2' Nomogram Initial Knee Point

Earlier DPV2 SPS study results demonstrated successful SPS mitigation of N-2 thermal and voltage deviation violations at one conceptual P61 'N-2' nomogram point: P61 at 1,650 MW and EOR at 9,255 MW. This addendum contains study results at the other knee-point on the conceptual P61 'N-2' nomogram; P61 at 2,400 MW and EOR reduced below 9,255 MW.

For this scenario, a prior identified initial knee point, P61 2,400 MW and P49 at 8,555 MW was evaluated for system performance under the critical N-2, AND implementation of the SPS alternative using load drop, and coordinated operation of the Perkins PST's.

"APPENDIX ADDENDUM Pages 1-2 show the successful mitigation of Victorville-Lugo line overload at the second nomogram knee point, P61=1,650 MW & P49=9,255 MW, for the critical N-2. "APPENDIX ADDENDUM" Pages 6-7[8] show load flow results, following the critical N-2 outage, with EOR reduced to 8,555 MW and P61 at rated 2,400 MW. The SPS used for this scenario was 1,590 MW of load drop and Perkins PST's at neutral (in service, but not holding a schedule). These results show an overload on the Victorville-Lugo 500 kV line at 3,269 A or 109% of it's 3,000 A emergency rating.

[8] The overloads of the SYLMARLA-SYLMAR 2 230 kV and SYLMAR1-SYLMAR S 230 kV shown in the post-transient output for these cases are modeling data issues related to the modeled rating of the tie lines between the PDCI converters and the 230 kV system. The modeled flow from the inverters is under the 3,100 A rating, and thus would not overload the tie lines.

Additional scenarios, at this initial knee point, that tested more aggressive mitigation options are shown on "APPENDIX ADDENDUM pages 8-10 with cross-trip of Victorville-Lugo 500 kV. This scenario appears to be potentially viable. "APPENDIX ADDENDUM " pages 11-12 show results for an SPS alternative that added 1,125 MW of AZ gen drop to the 1,590 MW of CA load drop. Post-outage loading of the Victorville-Lugo 500 kV line fell to 3,049 A, or 102% of the line's emergency rating.

SCE has recommended a coordinated project (SCE/LDWP/CAISO) to upgrade the Victorville-Lugo line. The identification of this overload, and a recommendation to work on a coordinated solution within the context of SCE transmission expansion planning process, is an element of SCE's "CAISO CONTROLLED SCE TRANSMISSION 2006-2015 EXPANSION PLAN", March 31, 2006. The pages from the March 31 report that identify this future(2010) N-1 and N-2 related overload of the Victorville-Lugo 500 kV line, and SCE's recommendation to work on a solution to this overload within SCE's local transmission planning context, are shown in "APPENDIX ADDENDUM pages 19-21. As an indication of a maximum stress condition, SCE tested the simultaneous case, P61 = 2,400 MW and P49 = 9,255 MW, for the critical outage and application of the preferred SPS are shown in "APPENDIX ADDENDUM" pages 3-5. For this scenario, Victorville-Lugo 500 kV line loading is 3,563 A, 119% of emergency rating.

The findings of this evaluation supports SCE's intention to work on an upgrade to the thermal capacity limitation of the Victorville-Lugo 500 kV line. In fact, this finding makes the SCE Expansion Plan recommendation even more imperative, and any project to upgrade this line should be coordinated such that it is online prior to the DPV2 project. As of 5/10/06, SCE's recommendation for a project to mitigate thermal overloads of the Victorville-Lugo 500 kV line is before the CAISO, for their approval.

2) HS 2009 Post-DPV2 Case, with EOR at 9,255 MW

Earlier HS 2009 cases used a ratioed value of EOR flow, based on the relationship between recorded summer-2005 EOR maximum flow (6,024 MW) and existing EOR rating, multiplied by the future EOR Path rating: 6,024 MW/7,550 MW X 9,255 MW = 7,400 MW. The effectiveness of both SPS alternatives has previously been demonstrated for a HS case with EOR at 7,400 MW. SCE believes this 1) establishes a valid starting point for future detailed development of a specific DPV2 SPS plan, and 2) provides the needed information with which WATS can select between the two SPS alternatives presented in this report.

However, to respond to the request made on 3/28/06, additional effort was expended on the HS scenario at very high seasonal EOR flow.

One limitation in modeling EOR at 9,255 MW, under HS peak load conditions is lack of enough modeled AZ and other Desert Southwest (DSW) resources to meet 1) AZ/DSW modeled peak load, AND 2) meet an aggressive export schedule from AZ to CA. To allow for setting up this extreme HS scenario with EOR at 9,255 MW, the WATS members consented to allowing the reduction of modeled AZ load, as a means of allowing set-up of a load flow case, to demonstrate proposed post-DPV2 EOR maximum flow under HS conditions.

To prepare this case AZ load was reduced by a rationg both 'P' MW and 'Q' MVAR in Area 14. The target load reduction of 10% (from 17,711 MW to 15,400 MW in 2.5% stages) with EOR increased accordingly. During case set-up, at an interim EOR flow point of 8,000 MW, the internal SCE 500 kV

voltages fell below an acceptable 515 MW operating values. To allow for continued case set-up, 300 MVAR of shunt caps were added at Mira Loma 500 kV substation, that are a portion of SCE's currently proposed Transmission Expansion Plan ("Bulk System Voltage Support VAR Program), were added to this case to facilitate credible bus voltages.

However, at an interim EOR flow of 8,600 MW, even with addition of SCE's full proposed bulk system voltage support plan, SCE's 500 kV voltages fall to an unacceptable 500 kV at Devers substation. This is well below an acceptable 515 kV, and not a credible condition to evaluate. SCE Expansion Plan's proposed voltage support plan will add 600 MVAR of shunt caps at Mira Loma 500 kV substation, and 150 MVAR of shunt caps at Rancho Vista 500 kV substation

AT THIS POINT, FURTHER DEVELOPMENT OF THIS EXTREME HS CASE WAS SUSPENDED.

3) Path 26 at 4,000 MW, HA 2009 Simultaneous Case

For this analysis, the Path 26 simultaneous case "09sen11823mohon-p26.sav" recently developed for the DPV2 WOR Path Rating Study, was used to evaluate the effectiveness of the two proposed DPV2 SPS alternatives, for this system condition.

The effectiveness of SCE's preferred DPV2 SPS alternative, Load Drop (1,590 MW) + operational coordination, is demonstrated in "APPENDIX ADDENDUM pages 22-24. As shown in the appendix, the limiting thermal constraints were mitigated; Perkins-Mead 500 kV <90% and Liberty PST at 99.7% of their respective emergency ratings. The voltage deviation at the two monitored busses were within criteria; Imperial Valley -6.0%, and Iron Mountain 230 kV -6.1%.

The effectiveness of the other DPV2 SPS alternative, Load (1,590 MW) + Generation (1,125 MW) Drop, is demonstrated in "APPENDIX ADDENDUM pages 25-26. As shown in the appendix, the limiting thermal constraints were mitigated; Perkins-Mead 500 kV 99.8% and Liberty PST at 92.3% of their respective emergency ratings. The voltage deviation at the two monitored busses were within criteria; Imperial Valley -3.6%, and Iron Mountain 230 kV -4.7%.

4) Impact of Future Proposed 300 MVAR of Shunt Capacitors at Mira Loma 500 kV

For this analysis, the impact of the proposed addition of 300 MVAR of shunt capacitors to SCE's Mira Loma 500 kV substation was evaluated. This future upgrade to SCE's system has been identified, and is currently proposed by SCE for CAISO approval, in SCE's CAISO Controlled 2006-2015 Transmission Planning Expansion Plan.

This analysis is similar to the analysis performed for other critical system parameters, as presented above in report section, **"Identified Critical System Parameters"**, pages 16-20. The impact of this proposed system upgrade is demonstrated by showing the change to several key constraining system performance violations. For HA, the constraint is thermal loading on Perkins-Mead 500 kV series capacitors and the Liberty PST. For HS, the constraint is bus voltage deviation at Iron Mountain 230 kV and Imperial Valley 500 kV busses. The results from this analysis are shown in the tables below:

HA, Critical Thermal Loading Variation w/ Future Mira Loma Capacitors

% of Emergency Rating, after N-2 outage, no mitigation

	0 MVAR at Mira Loma	300 MVAR at Mira Loma	CHANGE
Mead-Perkins 500 kV Series Cap	118%	118%	0%
Liberty PST	100%	100%	0%

HS, Critical Post-Transient V-Dip Variation w/ Future Mira Loma Capacitors

% V-Dip, after N-2 outage, -2,090 MW load drop mitigation(needed for solution)

	0 MVAR at Mira Loma	300 MVAR at Mira Loma	CHANGE
Imperial Valley 500 kV Bus	-4.2%	-4.1%	-0.1%
Iron Mountain 230 kV Bus	-8.8%	-8.1%	-0.7%

The proposed future addition of 300 MVAR of shunt capacitors at Mira Loma 500 kV does not have a relatively significant impact on the system performance constraints specific to N-2 of DPV 1 & 2.

However, as discussed above, in report Addendum section 2, these proposed shunt capacitors will play a critical role in facilitating future acceptable pre-fault, i.e. normal condition, voltages on SCE's bulk power system.

The output from the post-transient runs for the cases with the added shunt capacitors, are in "APPENDIX ADDENDUM", pages 29-31.

Request to MPP E&O Committee for Coordinated DPV2 N-2 SPS and Perkins PST Operation

SCE requested, and received approval, for coordinated DPV2 N-2 SPS and Perkins PST operation from the Mead-Phoenix Project E&O Committee at their April 19, 2006 meeting. Approval was received per the conceptual plan. The detailed DPV2 N-2 SPS plan will be presented to the MPP E&O Committee when complete. Any related commercial issues will also be addressed at a future appropriate time.

APPENDIX POST-TRANSIENT

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PSLF OUTPUT LOG	Pages	Comments
ha09post-sps-00f_dpv12_mon_pt-0-cgcc_pt.log	1-2	HA Basecase, EOR 9255, No Mitig
ha09post-sps-00f-EOR8955_dpv12_mon_pt-0-cgcc_pt.log	3-4	HA Basecase, EOR -300 decrement, No Mitig
ha09post-sps-00f-WOR9270_dpv12_mon_pt-0-cgcc_pt.log	5-7	HA Basecase, WOR +300 increment, No Mitig
ha09post-sps-00f-WOR8670_dpv12_mon_pt-0-cgcc_pt.log	8-9	HA Basecase, WOR -300 decrement, No Mitig
ha09post-sps-00f-SCEPLUS300_dpv12_mon_pt-0-cgcc_pt.log	10-11	HA Basecase, SCE Load +300 incre., No Mitig
ha09post-sps-00f-SCEMIN300_dpv12_mon_pt-0-cgcc_pt.log	12-14	HA Basecase, SCE Load -300 decre., No Mitig
ha09post-sps-00f-perk0_dpv12_mon_pt-0-cgcc_pt.log	15-16	HA Basecase, EOR 9255, Perk PS 0 deg., No Load Drop.
ha09post-sps-00f-PVARmin300_dpv12_mon_pt-0-cgcc_pt.log	17-18	HA Basecase, PV MVAR -300 decrement, No Mitig
ha09post-sps-00f-PVARplus300_dpv12_mon_pt-0-cgcc_pt.log	19-20	HA Basecase, PV MVAR +300 increment, No Mitig
ha09post-sps-00e_dpv12_moff_pt-0-cgcc_pt.log	21-23	HA Basecase, Mohave On, No Mitig
.09post-sps-00fl_dpv12_mon_pt-G4-cgcc_pt.log	24-27	HS Basecase, EOR 9255, -2090 Load Drop,
hs09post-sps-00fl-eor7100_dpv12_mon_pt-G4-cgcc_pt.log	28-30	HS Basecase, EOR -300 decre., -2090 Load Drop
hs09post-sps-00fl-eor7700_dpv12_mon_pt-G4-cgcc_pt.log	31-34	HS Basecase, EOR +300 incre., -2090 Load Drop
hs09post-sps-00fl-wor9640_dpv12_mon_pt-G4-cgcc_pt.log	35-38	HS Basecase, WOR +300 incre., -2090 Load Drop
hs09post-sps-00fl-scemin300_dpv12_mon_pt-G4-cgcc_pt.log	39-41	HS Basecase, SCE Load -300 decre., -2090 Load Drop
hs09post-sps-00fl-sceplus300_dpv12_mon_pt-G4-cgcc_pt.log	42-44	HS Basecase, SCE Load +300 incre., -2090 Load Drop
hs09post-sps-00fl-perk0_dpv12_mon_pt-G4-cgcc_pt.log	45-47	HS Basecase, EOR 9255, Perk PS 0 deg., -2090 Drop.
hs09post-sps-00fl-pvarmin300_dpv12_mon_pt-G4-cgcc_pt.log	48-50	HS Basecase, PV MVAR -300 decrement, -2090 Load Drop
hs09post-sps-00fl-pvarplus300_dpv12_mon_pt-G4-cgcc_pt.log	51-54	HS Basecase, PV MVAR +300 increment, -2090 Load Drop
hs09post-sps-00e_dpv12_mon_pt-G4-cgcc_pt.log	55-56	HS Basecase, Mohave On, -2090 Load Drop
hs09post-sps-00fl-MLv499_dpv12_mon_pt-G4-cgcc_pt.log	57-60	HS Basecase, ML @ 499 kV, -2090 Load Drop.
hs09post-sps-00fl-MLv524_dpv12_mon_pt-G4-cgcc_pt.log	61-63	HS Basecase, ML @ 424 kV, -2090 Load Drop.
SPS PREFERRED PLAN, MITIGATION SCENARIOS		
dpv2mohon_sps_p61n-2_noperk_dpv12_mon_pt-G6-cgcc_pt.log	64-66	HA, EOR 9255, Path 61 @ 1650 nomo. point, Perkins PS in-service at 0 deg.,
hs09post-sps-00fl-perk0-JHoff_dpv12_mon_pt-G4-cgcc_pt.log	67-69	HS, EOR 7400, J.Hinds-Mirage 230 kV line out, Perkins PS in-service @ 0 deg.

LOGS ARE CONTAINED IN A SEPARATE ATTACHMENT, "DPV2SPS-APPENDIX POST-TRANSIENT.pdf"

APPENDIX TRANSIENT

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PSLF OUTPUT PLOTS	Pages	Comments
ha09post-sps-00f1_dpv12_moff_pt-0_rev.pdf	1-6	HA Basecase, EOR 9255, No Mitigation, Positive Damping
ha09post-sps-01_dpv12_moff_pt-0_rev_20.pdf	6-10	HA EOR+Path 64 Simul., No Mitigation, Crit. Damping
ha09post-sps-01_dpv12_moff_a_20.pdf	11-15	HA EOR+Path 64 Simul., -390 Load Drop Mitigation, Positive Damping
ha09post-sps-02f_dpv12_moff-0_rev_20.pdf	16-20	HA EOR+Path 66 Simul., No Mitigation, Very Slight Pos./Critical Damping
ha09post-sps-02f_dpv12_moff_a_20_rev.pdf	21-25	HA EOR+Path 66 Simul., -390 Load Drop, Positive Damping
ha09post-sps-03_dpv12_moff_pt-0_rev.pdf	26-30	HA EOR+Path 61 Simul., No Mitigation, Positive Damping
ha09post-sps-04f_1_dpv12_moff_pt-0_rev.pdf	31-35	HA EOR 9255, PV Hub Stress, No Mitigation, Positive Damping
ha09post-sps-05f_dpv12_moff_pt-0_rev.pdf	36-40	HA DPV2+EOR9000, No Mitigation, Positive Damping
ha09post-sps-06_dpv12_moff-0_rev_20.pdf	41-45	HA EOR+WOR Simul., No Mitigation, Very Slight Pos./Critical Damping
.09post-sps-06_dpv12_moff_a_20.pdf	46-50	HA EOR+WOR Simul., -390 Load Drop, Positive Damping
hs09post-pvhub00f-15_dpv12_mohoff_0_chf.pdf	51-55	HS Basecase, EOR >7400, No Mitigation, Positive Damping

PLOTS ARE CONTAINED IN A SEPARATE ATTACHMENT, "DPV2SPS-APPENDIX TRANSIENT.pdf"

APPENDIX FLOW 1

Post-DPV2 With Mohave On Line **Pre-Mitigation Results**

	Transformer Loading Results in MVA - % of Emergency Ratings *** Transmission Loading Results in Amperes - % of Emergency Ratings							
	Perkins Phase Shifters 1 & 2		Mead-Perkins Series Capacitors		Victorville-Lugo 500 kV Line		Liberty Phase Shifter	
Path	EOR Path Rating Analysis	WOR Path Rating Analysis	EOR Path Rating Analysis	WOR Path Rating Analysis	EOR Path Rating Analysis	WOR Path Rating Analysis	EOR Path Rating Analysis	WOR Path Rating Analysis
Outage: DPV1 and DPV2								
Non-Simultaneous	996 - 113.4	1000 - 113.9	2231 - 115.6	2210 - 114.5	2895 - 96.5	3143 - 104.8	603 - 100.5	595 - 99.2
SCIT Benchmark	1011 - 115.2	1015 - 115.6	2243 - 116.2	2255 - 116.8	2957 - 98.6	2938 - 97.9	600 - 100.0	598 - 99.6
26 (Midway-Vincent)	1005 - 114.4	994 - 113.2 [2]	2221 - 115.1	2188 - 113.4 [2]	< 90 %	< 90% [2]	599 - 99.8	594 - 98.9 [2]
27 (IPPDC)	1011 - 115.2	998 - 113.6	2242 - 116.2	2206 - 114.3	2954 - 98.5	3388 - 113.0	601 - 100.1	594 - 99.0
41 (Sylmar)	1014 - 115.5	1001 - 114.0	2248 - 116.5	2211 - 114.6	3069 - 102.3	3182 - 106.1	602 - 100.4	595 - 99.2
61 (Victorville-Lugo) [1]	1032 - 117.5	1002 - 114.2	2284 - 118.3	2208 - 114.4	3883 - 129.5	3805 - 126.8	610 - 101.7	596 - 99.3
61 (Victorville-Lugo) [3, 4]	1019 - 116.1	998 - 113.7	2262 - 117.3	2206 - 114.3	3282 - 109.4	3430 - 114.3	604 - 100.7	594 - 98.9
64 (Marketplace-Adelanto)	1016 - 115.7		2271 - 117.7		3047 - 101.6		599 - 99.9	
65 (PDCI)	1011 - 115.1	997 - 113.6	2239 - 116.0	2194 - 113.7	3060 - 102.0	3282 - 109.4	601 - 100.2	594 - 98.9
Centennial	1017 - 115.8		2274 - 117.8		3055 - 101.8		599 - 99.8	
66 (COI)	1010 - 115.1 [2]		2253 - 116.7 [2]		2919 - 97.3 [2]		599 - 99.8 [2]	
Palo Verde Hub Operational Limit [5]	1017 - 115.8		2278 - 118.0		3269 - 109.0		602 - 100.4	

1 - Information Only; results based on maximum flows on Path 49 & Path 61 for EOR Analysis and Path 46 & Path 61 for WOR Analysis, which are unacceptable operating points due to Nomogram limitations.
2 - Results included SPS that shed Walnut (432 MW) on SCE's system to allow convergence.
3 - Results for EOR Path Rating Analysis based on Path 49 vs Path 61 Nomogram Point with Path 49 flow at maximum rating of 9,255 MW and Path 61 at 1,900 MW.

APPENDIX FLOW 2

	[illegible]									
	Perkins Phase Shifters 1 & 2		[illegible]		[illegible]		[illegible]		[illegible]	
Mitigation and Operating Condition	EOR Path Rating Analysis	WOR Path Rating Analysis	EOR Path Rating Analysis	WOR Path Rating Analysis	EOR Path Rating Analysis	WOR Path Rating Analysis	EOR Path Rating Analysis	WOR Path Rating Analysis	EOR Path Rating Analysis	WOR Path Rating Analysis
No SPS - Perkins Phase Shifters Bypassed	Bypassed	[illegible]	[illegible]	[illegible]	100.2	[illegible]	98.9	[illegible]	94.7	[illegible]
SPS - Perkins Phase Shifters Bypassed [5]	Bypassed	[illegible]	99.6	[illegible]	< 90	[illegible]	90.4	[illegible]	< 90	[illegible]
SPS - Perkins Phase Shifters bypassed and Perkins Phase Shifter EOR Flow Operating Point @ 8,800 MW [2, 6]	Bypassed	[illegible]	99.9	[illegible]	< 90	[illegible]	95.1	[illegible]	< 90	[illegible]
ECIT Benchmark Analysis	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
No SPS - Perkins Phase Shifters holding 1,300 MW schedule	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	97.9	[illegible]	[illegible]	[illegible]	98.9
SPS - Perkins Phase Shifters holding 1,300 MW schedule [4]	[illegible]	100.7	[illegible]	99.2	[illegible]	< 90	[illegible]	92.1	[illegible]	< 90
No SPS - Perkins Phase Shifters @ neutral position	[illegible]	92.4	[illegible]	92.3	[illegible]	96.4	[illegible]	[illegible]	[illegible]	[illegible]
SPS - Perkins Phase Shifters @ neutral position [6]	[illegible]	< 90	[illegible]	< 90	[illegible]	< 90	[illegible]	99.9	[illegible]	97.9
No SPS - Perkins Phase Shifters Bypassed	[illegible]	Bypassed	[illegible]	[illegible]	[illegible]	97.7	[illegible]	98.7	[illegible]	95.8
SPS - Perkins Phase Shifters Bypassed [4]	[illegible]	Bypassed	[illegible]	92.1	[illegible]	< 90	[illegible]	90.3	[illegible]	< 90
SPS - Perkins Phase Shifters bypassed and Perkins Phase Shifter EOR Flow Operating Point @ 8,800 MW [2, 6]	[illegible]	Bypassed	[illegible]	100.1	[illegible]	< 90	[illegible]	95.8	[illegible]	< 90

1 - Results from WOR Rating Study's Pre-DPVZ ECIT Case with maximum EOR and WOR flows (i.e. 8,055 MW and 10,623 MW, respectively) and Perkins Phase Shifters holding schedules
2 - Results based on Path 49 vs Path 61 N-1 Nomogram Point with Path 49 flow at maximum rating of 9,250 MW and Path 61 at 1,900 MW.
3 - Results based on Path 49 vs Path 61 N-2 Nomogram Point with Path 49 flow at maximum rating of 9,255 MW and Path 61 at 1,850 MW.
4 - SPS that trips all Hanaphala units (1,125 MW) and sheds 1,744 MW of Load on SCE's system.
5 - SPS that sheds 1,258 MW of Load on SCE's system.
6 - When EOR flow reaches the Arming Point, place the Perkins Phase Shifters in service @ neutral position.

APPENDIX MWD

PROTECTION SCHEME, ARMING CONDITION 'SCREENING'

LOAD FLOW CASE	MIRAGE - J.HINDS 220 kV LINE FLOW (MW*) Condition 1 ScreenA = >+65	J.HINDS 220 kV BUS VOLTAGE (kV) Condition 1 ScreenB = <206 kV	IRON MTN - EAGLE MTN 220 kV LINE FLOW (MVA) Condition 2 Screen = >250 MVA
ha09post-sps-00a.sav	9.2	230.4	67.2
ha09post-sps-00b.sav	10.4	230.1	67.8
ha09post-sps-00c.sav	11.3	229.7	68.2
ha09post-sps-00d.sav	12.5	229.3	68.9
ha09post-sps-00e.sav	13.8	228.9	69.7
ha09post-sps-00f.sav	4.1	229.3	91.8
ha09post-sps-00g.sav	12.5	228.5	68.7
ha09post-sps-00h.sav	11	228.6	67.3
ha09post-sps-00i.sav	9.5	228.8	65.9
ha09post-sps-01.sav	86	222.6	117.3
ha09post-sps-02f.sav	73.6	224.6	103
ha09post-sps-02f-DRAFT.sav	80.7	222.9	108.9
ha09post-sps-03.sav	85.5	221.7	135.9
ha09post-sps-03a.sav	85.5	221.7	135.9
ha09post-sps-04f.sav	14.3	227.8	70.5
ha09post-sps-04f_1.sav	14.3	227.8	70.5
ha09post-sps-05f.sav	18.2	227.1	67.1
ha09post-sps-06.sav	**92.9**	223.9	114.9
hs09post-sps-00a1.sav	**154.5**	224.8	185.8
hs09post-sps-00b1.sav	**154.3**	224.3	185.2
hs09post-sps-00c1.sav	**154.3**	223.9	184.7
hs09post-sps-00d1.sav	**154.9**	223.3	185
hs09post-sps-00e1.sav	**156.8**	222.6	186.6
hs09post-sps-00f1.sav	**164.6**	220.4	195.3
hs09post-sps-00g1.sav	**156.6**	222.6	186.4
hs09post-sps-00h1.sav	**155.5**	223.1	185.2
hs09post-sps-00i1.sav	**155.2**	223.3	184.9
hs09post-sps-00j1.sav	**154.8**	223.5	184.5
hs09post-sps-00f2.sav	**145**	223	224
hs09post-sps-00m2.sav	**0****	230	86
hs09post-sps-09f2.sav	**149**	222	193

*positive MW value indicates line flow towards Mirage
** Line open, ST=0

POST-TR..S OUTPUT LOG, "hs09post-sps-00f2_dpv12_mon_pt-G6-.. _pt.log" , J.HINDS-MIRAGE CLOSED

hs09post-sps-00f2_dpv12_mon_pt-G6-cgcc_pt.log

PERCENT LOADING WITH USE OF NORMAL RATINGS

FROM BUS	KV	TO BUS	KV	ID	AREA	ZONE	AMPS	MVA	RATING	UNIT	PERCENT
KYRENE	500	JOJOBA	500	#1	14	158	1840.72	1678.14	1999.94	Amps	92.04%
LIBERTY	230	LIBTYPHS	230	#1	14	191	1470.83	583.91	500	MVA	116.78%
LIBERTY	345	PEACOCK	345	#1	19	190	980.55	586.45	850.13	Amps	115.40%
LIBERTY	345	LIBTYPHS	230	#1	14	191	980.55	586.45	600	MVA	97.74%
PINPK	230	PNPKAPS	230	#1	14	140	1738.12	702.85	1600.01	Amps	108.63%
SANTAN	230	THUNDRST	230	#1	14	158	1034.71	418.16	909.95	Amps	113.90%
CACTUS	230	PNPKAPS	230	#1	14	141	861.32	340.28	931.29	Amps	92.49%
CTRYCLUB	230	LINCSTRT	230	#1	14	141	1309.53	519.9	1400.7	Amps	93.49%
ADELANTO	500	MARKETPL	500	#1	26	260	1729.7	1494.99	1889.09	Amps	91.56%
MCCULLGH	500	VICTORVL	500	#1	26	260	1652.52	1453.96	1599.95	Amps	103.29%
MCCULLGH	500	VICTORVL	500	#2	26	260	1629.69	1433.87	1599.95	Amps	102.45%
VICTORVL	500	LUGO	500	#1	24	240	2531.34	2189.6	2771.28	Amps	91.34%
HERMISTN	230	MCNRY S1	230	#1	40	475	1237.99	512.66	1300.04	Amps	95.23%
IMPRLVLY	500	N.GILA	500	#1	22	227	1942.77	1681.53	1899.95	Amps	104.67%
ANTELOPE	230	VINCENT	230	#1	24	240	1206.37	474.04	1149.68	Amps	105.00%
CAMINO	230	IRON MTN	230	#1	24	248	840.99	319.39	763.11	Amps	110.46%
EAGLEMTN	230	J.HINDS	230	#1	24	248	938.78	336.55	899.91	Amps	104.32%
ELDORDO	500	LUGO	500	#1	24	240	1845.23	1622.75	1600.42	Amps	115.30%
J.HINDS	230	MIRAGE	230	#1	24	248	748.13	270.95	599.94	Amps	124.70%
KRAMER	230	LUGO	230	#1	24	247	1142.46	444.67	1199.89	Amps	95.21%
KRAMER	230	LUGO	230	#2	24	247	1142.46	444.67	1199.89	Amps	95.21%
LUGO	500	MOHAVE	500	#1	24	240	1591.11	1392.77	1600.42	Amps	99.66%
MAGUNDEN	230	OMAR	230	#1	24	240	1522.15	601.88	1614.07	Amps	94.38%
MEAD	345	MEAD N	230	#1	19	190	995.59	565.24	600	MVA	95.72%

PERCENT LOADING WITH USE OF EMERGENCY RATINGS

FROM BUS	KV	TO BUS	KV	ID	AREA	ZONE	AMPS	MVA	RATING	UNIT	PERCENT
LIBERTY	230	LIBTYPHS	230	#1	14	191	1470.83	583.91	600	MVA	97.32%

POST-TR OUTPUT LOG, "hs09post-sps-00f2_dpv12_mon_pt-G6 _pt.log" , J.HINDS-MIRAGE CLOSED

PINPK	230	PNPKAPS	230	#1	14	140	1738.12	702.85	1706.95	Amps	101.83%
SANTAN	230	THUNDRST	230	#1	14	158	1034.71	418.16	1099.98	Amps	94.22%
HERMISTN	230	MCNRY S1	230	#1	40	475	1237.99	512.66	1300.04	Amps	95.23%
CAMINO	230	IRON MTN	230	#1	24	248	840.99	319.39	763.11	Amps	110.46%
EAGLEMTN	230	J.HINDS	230	#1	24	248	938.78	336.55	990.03	Amps	94.82%
J.HINDS	230	MIRAGE	230	#1	24	248	748.13	270.95	599.94	Amps	124.70%
KRAMER	230	LUGO	230	#1	24	247	1142.46	444.67	1199.89	Amps	95.21%
KRAMER	230	LUGO	230	#2	24	247	1142.46	444.67	1199.89	Amps	95.21%
MAGUNDEN	230	OMAR	230	#1	24	240	1522.15	601.88	1614.07	Amps	94.38%

Changes in voltage at Devers, Mira Loma, and Vincent

BUS	KV	PRE KV	POST KV	DELTA	PERCENT
DEVERS	230	229.47	233.1	3.62	1.58
DEVERS	500	520.61	545.9	25.28	4.86
MIRALOMA	500	513.47	508.5	-4.98	-0.97
VALLEYSC	500	527.36	542.1	14.76	2.8

MAX AND MIN post contingency Voltages
MAX DEVERS 545.9
MIN LUGOSVC1
505.4

The following buses had changes greater than 5 percent:

N.GILA 500.0 exceeds 5 percent change = 5.7 in area 22
EAGLEMP1 6.9 exceeds 5 percent change = 7.2 in area 24
EAGLEMP2 6.9 exceeds 5 percent change = 7.2 in area 24
EAGLEMTN 66.0 exceeds 5 percent change = 7.1 in area 24
EAGLEMTN 161.0 exceeds 5 percent change = 6.9 in area 24
EAGLEMTN 230.0 exceeds 5 percent change = 7.1 in area 24
IRON MTN 230.0 exceeds 5 percent change = 7.5 in area 24
IRONMTP1 6.9 exceeds 5 percent change = 7.6 in area 24
IRONMTP2 6.9 exceeds 5 percent change = 7.6 in area 24
J.HINDS 230.0 exceeds 5 percent change = 6.3 in area 24
JHINDSP1 6.9 exceeds 5 percent change = 6.3 in area 24

POST-TR OUTPUT LOG, "hs09post-sps-00f2_dpv12_mon_pt-G6 _pt.log" , J.HINDS-MIRAGE CLOSED

JHINDSP2 6.9 exceeds 5 percent change = 6.3 in area 24

WARNING: 12 buses with 5 percent or greater change

POST-TR OUTPUT LOG, "hs09post-sps-00m2_dpv12_mon_pt-Gt .c_pt.log" , J.HINDS-MIRAGE OPEN

PERCENT LOADING WITH USE OF NORMAL RATINGS

FROM BUS	KV	TO BUS	KV	ID	AREA	ZONE	AMPS	MVA	RATING	UNIT	PERCENT
KYRENE	500	JOJOBA	500	#1	14	158	1838.06	1676.21	1999.94	Amps	91.91%
LIBERTY	230	LIBTYPHS	230	#1	14	191	1467.56	583.5	500	MVA	116.70%
LIBERTY	345	PEACOCK	345	#1	19	190	978.37	585.71	850.13	Amps	115.24%
LIBERTY	345	LIBTYPHS	230	#1	14	191	978.37	585.71	600	MVA	97.62%
PINPK	230	PNPKAPS	230	#1	14	140	1737.17	702.67	1600.01	Amps	108.57%
SANTAN	230	THUNDRST	230	#1	14	158	1034.9	418.32	909.95	Amps	113.92%
CACTUS	230	PNPKAPS	230	#1	14	141	860.31	339.99	931.29	Amps	92.38%
CTRYCLUB	230	LINCSTRT	230	#1	14	141	1310.09	520.26	1400.7	Amps	93.53%
ADELANTO	500	MARKETPL	500	#1	26	260	1774.97	1527.01	1889.09	Amps	93.96%
MCCULLGH	500	VICTORVL	500	#1	26	260	1695.02	1487.22	1599.95	Amps	105.94%
MCCULLGH	500	VICTORVL	500	#2	26	260	1670.25	1465.48	1599.95	Amps	105.14%
VICTORVL	500	LUGO	500	#1	24	240	2639.6	2272.89	2771.28	Amps	95.25%
MERCHANT	230	ELDORDO	230	#1	18	182	1455.23	580.91	1600.01	Amps	90.96%
HERMISTN	230	MCNRY S1	230	#1	40	475	1237.99	512.65	1300.04	Amps	95.23%
IMPRLVLY	500	N.GILA	500	#1	22	227	1982.69	1710.46	1899.95	Amps	106.77%
ANTELOPE	230	VINCENT	230	#1	24	240	1208.24	473.87	1149.68	Amps	105.16%
ELDORDO	500	LUGO	500	#1	24	240	1897.97	1664.52	1600.42	Amps	118.59%
KRAMER	230	LUGO	230	#1	24	247	1136.77	443.63	1199.89	Amps	94.74%
KRAMER	230	LUGO	230	#2	24	247	1136.77	443.63	1199.89	Amps	94.74%
LUGO	500	MOHAVE	500	#1	24	240	1625.28	1418.16	1600.42	Amps	101.85%
LUGO	500	RANCHVST	500	#1	24	240	2715.26	2369.23	2999.91	Amps	90.51%
MAGUNDEN	230	OMAR	230	#1	24	240	1524.03	601.73	1614.07	Amps	94.50%
MEAD	345	MEAD N	230	#1	19	190	1005.58	570.46	600	MVA	96.61%

PERCENT LOADING WITH USE OF EMERGENCY RATINGS

FROM BUS	KV	TO BUS	KV	ID	AREA	ZONE	AMPS	MVA	RATING	UNIT	PERCENT
LIBERTY	230	LIBTYPHS	230	#1	14	191	1467.56	583.5	600	MVA	97.25%
PINPK	230	PNPKAPS	230	#1	14	140	1737.17	702.67	1706.95	Amps	101.77%
SANTAN	230	THUNDRST	230	#1	14	158	1034.9	418.32	1099.98	Amps	94.24%

POST-TRI OUTPUT LOG, "hs09post-sps-00m2_dpv12_mon_pt-G6 .c_pt.log" , J.HINDS-MIRAGE OPEN

HERMISTN	230	MCNRY S1	230	#1	40	475	1237.99	512.65	1300.04	Amps	95.23%
KRAMER	230	LUGO	230	#1	24	247	1136.77	443.63	1199.89	Amps	94.74%
KRAMER	230	LUGO	230	#2	24	247	1136.77	443.63	1199.89	Amps	94.74%
LUGO	500	RANCHVST	500	#1	24	240	2715.26	2369.23	2999.91	Amps	90.51%
MAGUNDEN	230	OMAR	230	#1	24	240	1524.03	601.73	1614.07	Amps	94.50%

Changes in voltage at Devers, Mira Loma, and Vincent

BUS	KV	PRE KV	POST KV	DELTA	PERCENT
DEVERS	230	229.16	234.5	5.3	2.31
DEVERS	500	519.36	547.8	28.41	5.47
MIRALOMA	500	512.52	507.1	-5.46	-1.07
VALLEYSC	500	526.32	542.3	15.96	3.03

MAX AND MIN post contingency Voltages
MAX DEVERS
547.8
MIN LUGO 503.8

The following buses had changes greater than 5 percent:

N.GILA 500.0 exceeds 5 percent change = 6.0 in area 22
DEVERS 500.0 exceeds 5 percent change = -5.5 in area 24
DEVRSVC1 500.0 exceeds 5 percent change = -5.5 in area 24
NILAND 161.0 exceeds 5 percent change = 5.3 in area 8

WARNING: 4 buses with 5 percent or greater change

APPENDIX MITIGATION 1

'CONSOLIDATED' SPS, LOAD DROP and OPERATIONAL COORDINATION, LOAD FLOW OUTPUT

LOGS ARE CONTAINED IN A SEPARATE ATTACHMENT, "DPV2SPS-APPENDIX-MITIGATION1.pdf"

APPENDIX MITIGATION 2

'CONSOLIDATED' SPS, CA LOAD DROP and AZ GENERATION DROP, LOAD FLOW OUTPUT

LOGS ARE CONTAINED IN A SEPARATE ATTACHMENT, "DPV2SPS-APPENDIX-MITIGATION2.pdf"

APPENDIX ADDENDUM

see SEPARATE ATTACHMENT,
"DPV2SPS-APPENDIX-ADDENDUM.pdf"

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SOUTHERN CALIFORNIA
EDISON
An *EDISON INTERNATIONAL* Company

DEVERS – PALO VERDE NO. 2 (DPV2)

DPV1&2 SPS ARMING STUDY

SCE LOAD BLOCK ANALYSIS

SEPTEMBER 28, 2006

INTRODUCTION

Southern California Edison (SCE) is proposing to build a 500 kV transmission line project from the Harquahala substation in the Palo Verde area, near Phoenix, Arizona, to SCE's Devers substation, near Palm Springs, California. The Project is named Devers-Palo Verde No. 2 (DPV2). DPV2 is expected to increase the ratings of WECC Path 49 (EOR) and Path 46 (WOR) flow, and the Southern California import (SCIT) limit, by 1,200 MW. The DPV2 Project will have a plan of service that achieves the rating objectives while meeting relevant reliability criteria.

This report is in response to the Devers – Palo Verde No.2 (DPV2), DPV1&2 SPS Arming Study Plan and will provide details to the SCE Load Block analysis.

SCE Load Block Levels

SCE typically drops load by opening SCE 230/66 kV "A" transformer banks. The following SCE substations will be considered for the DPV1&2 SPS: Ellis, Johanna, Padua, San Bernardino, Viejo, Villa Park, Vista and Walnut. **Table 1** tabulates each substation, the number of transformers to be opened for load dropping and base case load amounts from both the 2009 HS and HA base cases.

Table 1. SCE Load Drop Substation

Substation	Number of "A" Bank Transformers	2009 HS Load	2009 HA Load
Ellis	3	609	241
Johanna	2	419	278
Padua	3	658	435
San Bernardino	3	582	389
Walnut	3	689	432
Viejo	2	333	261
Villa Park	3	692	488
Vista	4	692	492
		4673	3016

In developing the "Loss of DPV1&2 Nomogram(s)", it will be determined based on study results whether a finer resolution of load dropping would be beneficial. If so, select SCE Substations will be further refined to include circuit breaker operation for distribution feeders.

SCE Load Block Clearing Times

Load block clearing times of 15 cycles will be used in this study. In addition, it was confirmed with the SCE Operations Department that existing load drop schemes are executed in this time-frame. It is believed that there are no transient stability issues with dropping SCE load; hence, using a very conservative clearing time is not critical.

SCE Load Block Effectiveness

Values listed in **Table 2** are based on the ("Case 1") 2009 heavy autumn base case with Mohave on-line and **Table 3** is based on the ("Case 4") 2009 heavy autumn base case with Mohave off-line. Both base cases have a SCE load of 15,230 MW and EOR flow of 9,255 MW. In addition, the Perkins phase-shift transformers are modeled in the neutral position for both cases. The "Normalized % Change" column is the difference between the "Flow with Load drop" and "Flow with No Load drop"

divided by Load. It can be seen that with the Mohave Generation on-line, all substations are effective for mitigating thermal overloads to the Liberty phase-shift transformer. However, the Ellis, Johanna and Viejo Substations are not effective for mitigating thermal overloads to the Perkins phase-shift transformers and the Perkins – Mead 500 kV line.

Table 2. SCE Load Block Effectiveness – Mohave On-Line.

			Liberty PS Transformers			Perkins PS Transformers			Perkins-Mead 500 kV		
Substation	Load (MW)	% of Total Load	Flow with No Load Drop (MVA)	Flow with Load Drop (MVA)	Normalized % Change	Flow with No Load Drop (MVA)	Flow with Load Drop (MVA)	Normalized % Change	Flow with No Load Drop (Amps)	Flow with Load Drop (Amps)	Normalized % Change
Ellis	241	8.0%	605.1	602.3	-1.19%	821.1	820.4	-0.26%	1814	1814	-0.28%
San Bernardino	389	12.9%	605.1	601.2	-1.02%	821.1	816.1	-1.27%	1814	1803	-3.00%
Johanna	278	9.2%	605.1	602.4	-1.00%	821.1	820.3	-0.28%	1814	1813	-0.49%
Padua	435	14.4%	605.1	601.0	-0.94%	821.1	814.9	-1.41%	1814	1799	-3.48%
Viejo	261	8.7%	605.1	602.7	-0.93%	821.1	821.1	0.03%	1814	1815	0.21%
Walnut	432	14.3%	605.1	601.4	-0.87%	821.1	815.4	-1.31%	1814	1800	-3.33%
Vista	492	16.3%	605.1	600.9	-0.86%	821.1	814.0	-1.43%	1814	1797	-3.60%
Villa Park	488	16.2%	605.1	601.5	-0.75%	821.1	815.2	-1.20%	1814	1799	-3.13%
Total	3016	100.0%									

It can be seen that with the Mohave Generation off-line, all substations are effective for mitigating thermal overloads to the Liberty phase-shift transformer. However, the Ellis, Johanna and Viejo Substations are not effective for mitigating thermal overloads to the Perkins phase-shift transformers and the Perkins – Mead 500 kV line.

Table 3. SCE Load Block Effectiveness – Mohave Off-Line.

			Liberty PS Transformers			Perkins PS Transformers			Perkins-Mead 500 kV		
Substation	Load (MW)	% of Total Load	Flow with No Load Drop (MVA)	Flow with Load Drop (MVA)	Normalized % Change	Flow with No Load Drop (MVA)	Flow with Load Drop (MVA)	Normalized % Change	Flow with No Load Drop (Amps)	Flow with Load Drop (Amps)	Normalized % Change
Ellis	241	8.0%	588.3	585.4	-1.18%	797.9	797.5	-0.16%	1762	1762	0.05%
Viejo	261	8.7%	588.3	585.2	-1.16%	797.9	797.7	-0.07%	1762	1763	0.34%
Johanna	278	9.2%	588.3	585.1	-1.14%	797.9	796.8	-0.41%	1762	1761	-0.58%
San Bernardino	389	12.9%	588.3	584.6	-0.95%	797.9	793.0	-1.26%	1762	1751	-2.91%
Padua	435	14.4%	588.3	584.7	-0.81%	797.9	791.0	-1.60%	1762	1744	-4.09%
Walnut	432	14.3%	588.3	585.0	-0.76%	797.9	791.9	-1.38%	1762	1747	-3.53%
Vista	492	16.3%	588.3	584.6	-0.75%	797.9	790.5	-1.50%	1762	1744	-3.80%
Villa Park	488	16.2%	588.3	584.7	-0.72%	797.9	790.8	-1.45%	1762	1744	-3.75%
Total	3016	100.0%									

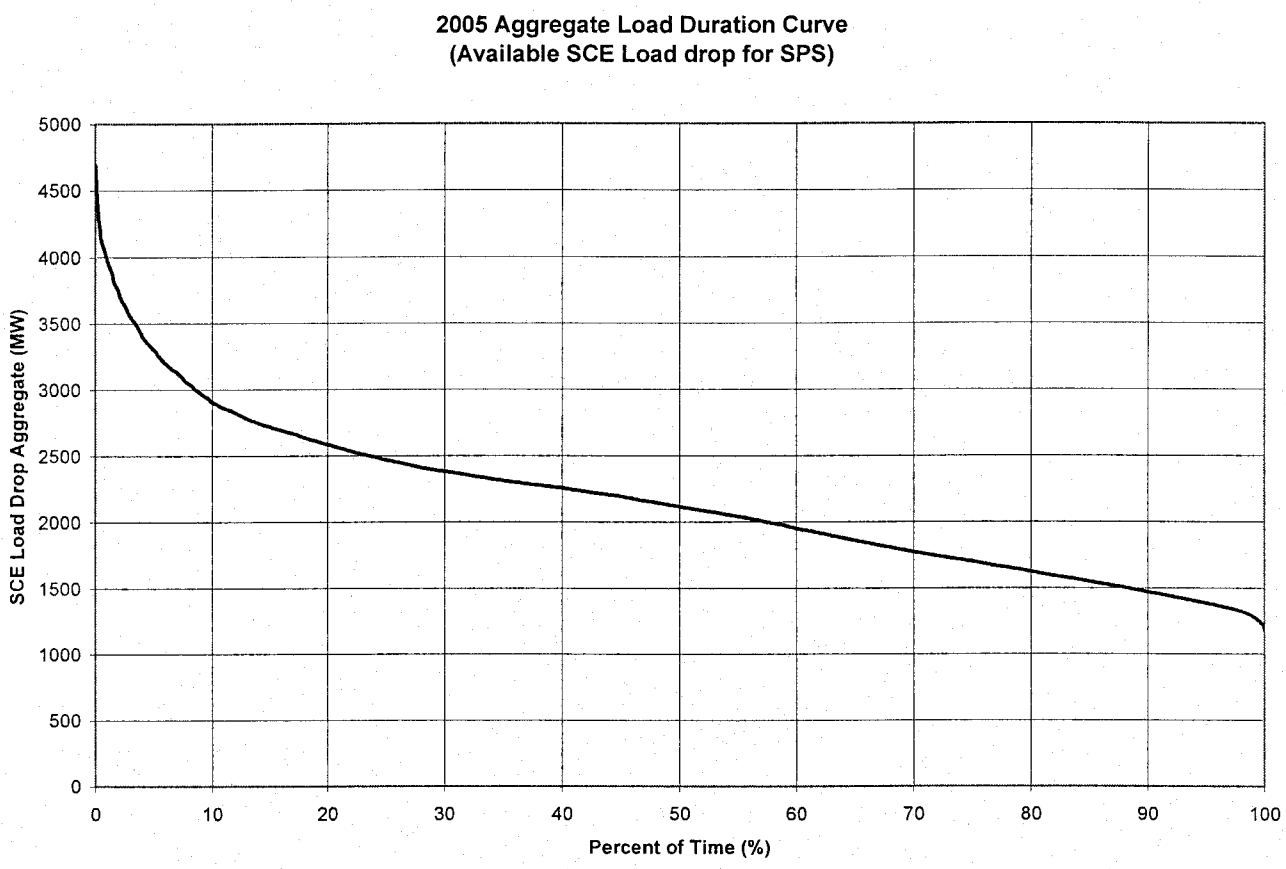
Load drop at the Ellis and Viejo Substations resulted in an increased flow to the Perkins – Mead 500 kV transmission line. However, it was slightly effective in mitigating the Perkins phase-shift transformers. Even though these substations slightly increase the thermal loading to these elements, they do provide post-transient voltage drop mitigation. For example, simulating loss of the DPV1 & 2 lines with no load drop yields a post-transient voltage deviation of 13.5 % at the Eagle Mountain 161 kV bus. By dropping the Ellis Substation load, the post-transient voltage deviation was reduced to 5.2%.

Previous analysis determined that all three elements in **Tables 1 and 2** have been near their thermal ratings for loss of the DPV 1 & 2 lines; however, the Liberty phase-shift transformer typically was the limiting element. Hence, the SPS arming order will be determined based on results of **Table 1** and **2**. In addition, high EOR flows will yield an aggregate load drop amount, which will provide a net decrease to all three elements. Thermal loading to the Perkins phase-shift transformer is mitigated with proper management of placing the phase-shift transformers in service at zero angle or bypassed mode.

Load Duration Curve for the Aggregate SCE Load Blocks

The historical 2005 Ellis, Johanna, Padua, San Bernardino, Viejo, Villa Park, Vista and Walnut Substation loads were aggregated to determine the maximum and minimum amount of total SCE load drop availability throughout the year. **Figure 1** graphs the aggregate load duration curve. It can be seen that the minimum total available SPS is around 1,200 MW and the maximum total available SCE load drop is around 4,700 MW. In addition, it can be seen that the median total available SCE load drop is around 2,100 MW.

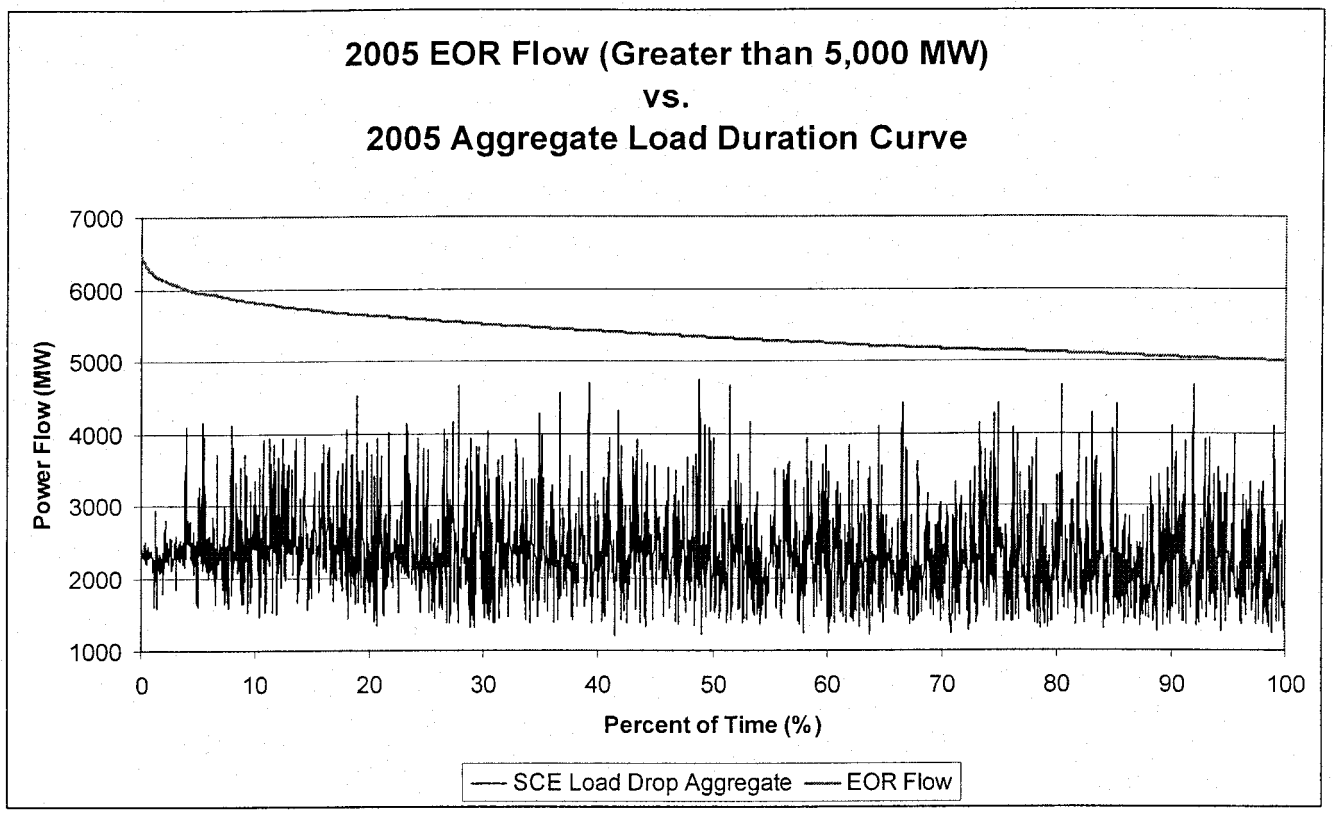
Figure 1. 2005 Aggregate Load Duration Curve.



Based on historical 2005 EOR flow data, it can be determined that the median aggregate SCE load drop availability when EOR flow is greater than 5,000 MW was approximately 2,300 MW. **Figure 2** graphs the 2005 EOR flow (Greater than 5,000 MW) and the aggregate SCE load that corresponds to the particular EOR flow. Based on Phase I studies and **Figure 2**, it appears that adequate SCE load drop will be available for loss of the DPV 1&2 lines. However, the 2005 historical maximum EOR flow

only had a maximum of 6,479 MW, which is significantly less than flows studied. Based on Phase I results, no load arming would be required for EOR flow less than 8,000 MW.

Figure 2. 2005 EOR Flow (Greater than 5,000 MW) vs. Aggregate Load Duration Curve.



East-of-River flows are typically higher during autumn system conditions; hence, a 2005 Aggregate Load duration curve between September and November is graphed in **Figure 3**. It can be seen that the median SCE load drop availability during these months is around 2,215 MW. For EOR flow greater than 5,000 MW during these months, the median SCE load drop availability is around 2,300 MW. **Figure 4** graphs the EOR flow and SCE load drop aggregate for the September to November time frame.

Figure 3. Aggregate Load Duration Curve – September through November.

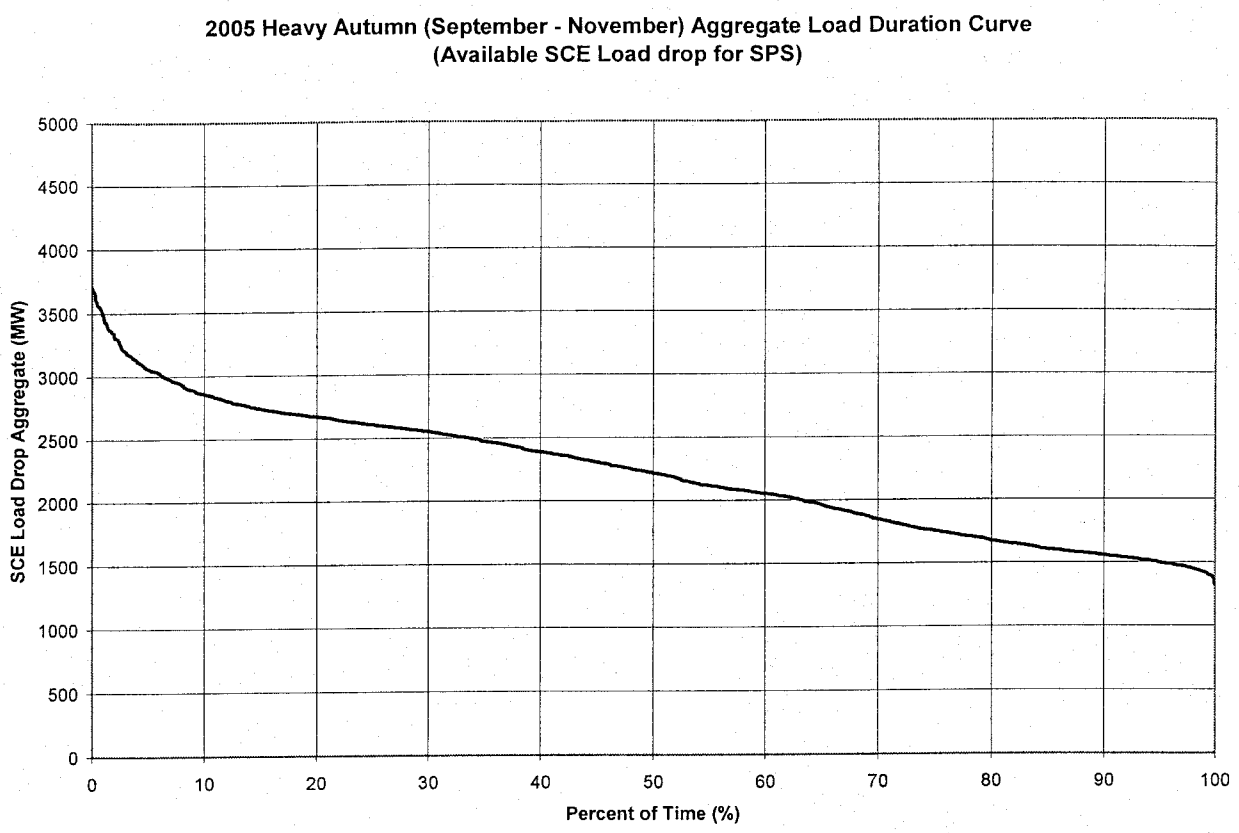
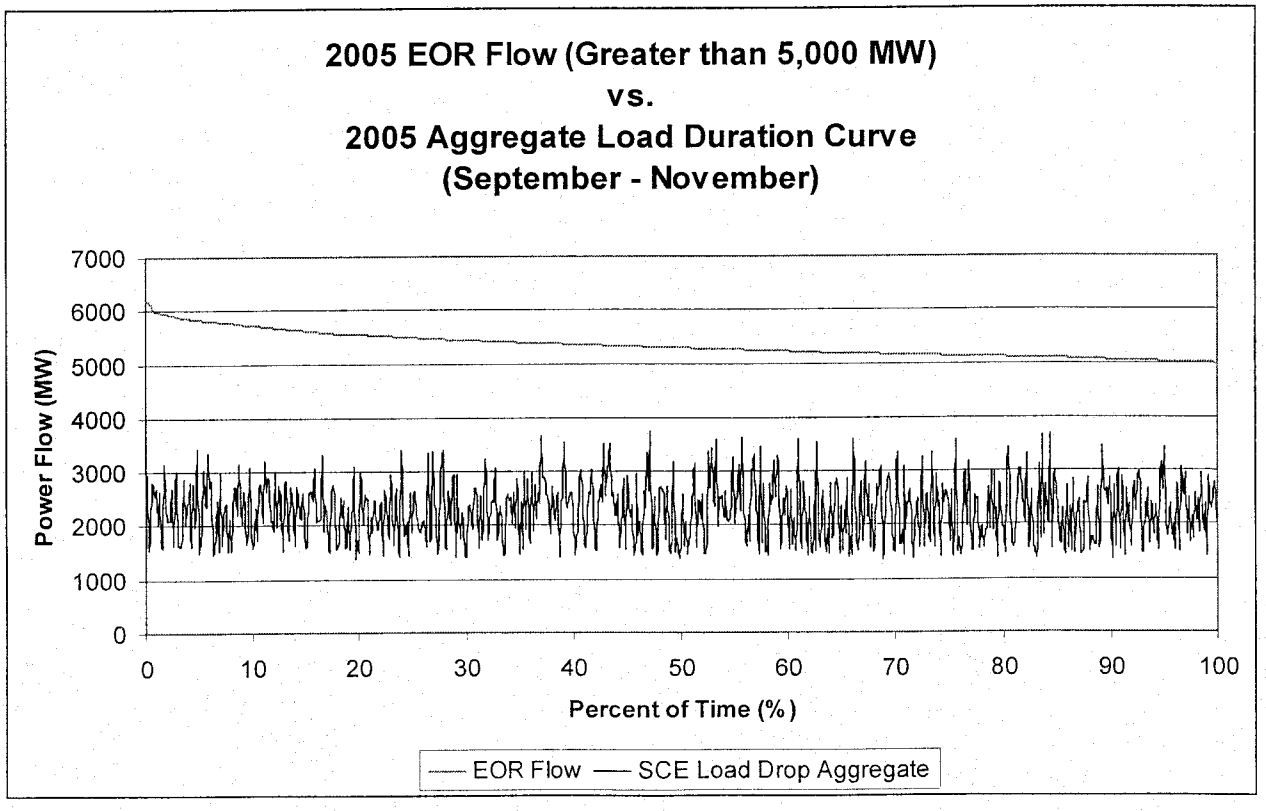


Figure 4. 2005 EOR Flow (Greater than 5,000 MW) vs. Aggregate Load Duration Curve – (September – November).



CONCLUSIONS

Based on the effectiveness results, SCE Substation load arming should be completed in the following order (ranking):

Mohave On-line: Ellis, San Bernardino, Johanna, Padua, Viejo, Walnut, Vista and Villa Park.

Mohave Off-line: Ellis, Viejo, Johanna, San Bernardino, Padua, Walnut, Vista and Villa Park.

The SPS will continue to sum load until it reaches the needed amount of total SCE load drop. It was determined that total historical load drop minimum and maximum amounts are approximately 1,200 to 4,700 MW, respectively. Based on Phase I studies and **Figure 2**, adequate total SCE load drop is available for arming the DVPV1&2 SPS.

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Joint Boards on Security Constrained Economic Dispatch	))	**Docket No. AD05-13-000**

Study and Recommendations Regarding Security Constrained Economic Dispatch

By

The Joint Board for the West Region

May 12, 2006

Executive Summary:
Recommendations of the Federal/State
Joint Board on Economic Dispatch for the West Region

On September 10, 2005, the Federal Energy Regulatory Commission (the Commission) issued its Order Convening Joint Boards Pursuant to Section 223 of the Federal Power Act "to study the issue of security constrained economic dispatch for the various market regions," "to consider issues relevant to what constitutes 'security constrained economic dispatch' and how such a mode of operating . . . affects or enhances the reliability and affordability of service," and "to make recommendations to the Commission."[1]

The West Joint Board consists of the Federal Energy Regulatory Commission and the states of Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, South Dakota, Texas, Utah, Washington and Wyoming.[2]

Our analysis of security constrained economic dispatch (SCED) began with the Commission's definition in the Order: "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities." In the Report, we discuss the basics of SCED and how it functions in the Western Interconnection. Below are short summaries of the major issues considered by the Board and our recommendations to the Commission in this Report.[3] We also address three recommendations made to the Joint Boards by the DOE in The Value of Economic Dispatch, A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005.

1. Independence of dispatcher.

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

Recommendation:
We recommend that independent dispatch entities not be created for their own sake. We do not recommend further analysis at this time. If any further analysis is deemed

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[1] The Order was issued in Docket No. AD05-13-000, Joint Boards on Security Constrained Economic Dispatch.

[2] These states are within the Western Interconnection,with the exceptions of South Dakota and Texas, only portions of which are served from within the interconnection.

[3] Texas's recommendations diverge from the majority, and are contained in the *Texas Perspective on Security Constrained Economic Dispatch*, filed separately in Docket No. AD05-13-000.

warranted, it must include an investigation of the potential benefit to consumers. If further work appears justified on the facts, the affected states and relevant utilities should determine the nature of the dispatching entity to be considered. Where public, cooperative and privately owned entities serve the market under consideration, their participation should be encouraged.

2. Utility dispatch of third party power through contracts.

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

Recommendation:

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

3. Transparency of dispatch information and processes.

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

Recommendation:

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

4. Consolidation of control areas in a region.

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

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

5. Import/export schedule changes within an hour.

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

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

6. Some practical limitations on economic dispatch.

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

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

7. First DOE Recommendation: review dispatch practices.

The DOE recommends that the Joint Boards review selected dispatching entities to determine how they conduct economic dispatch and document the rationale for deviations from "pure" least-cost economic dispatch.

Recommendation:
The Board recommends that this study not be pursued. Such a study would take us deeply into variables and deviations from "pure" economic dispatch without providing

much value. It is at odds with our fundamental conclusion that economic dispatch must remain a flexible concept.

8. Second DOE Recommendation: standardize dispatch contract terms.

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

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

9. Third DOE Recommendation: review dispatch tools.

Existing economic dispatch technology, including software and data used and the underlying algorithms and assumptions, deserve scrutiny.

Recommendation:
We recommend the development and refinement of technological tools to make the best use of existing and proposed facilities.

I. Introduction

This Report of the West Joint Board on Economic Dispatch presents the results of the Joint Board's study of security constrained economic dispatch (SCED) issues, and provides recommendations to the FERC. The West Joint Board is one of four joint boards designated by the Commission under EPAct2005, Section 1298, Economic Dispatch. The members of the West Joint Board are:

Commissioner Suedeen Kelly, Federal Energy Regulatory Commission, Chair of the West Joint Board
Commissioner Marsha H. Smith, Idaho Public Utilities Commission, Vice Chair of the West Joint Board
Commissioner Marc L. Spitzer, Arizona Corporation Commission
Commissioner Dian M. Grueneich, California Public Utilities Commission
Chairman Gregory Sopkin, Colorado Public Utilities Commission
Commissioner Thomas J. Schneider, Montana Public Service Commission
Mr. Richard L. Hinckley, General Counsel, Public Utilities Commission of Nevada
Commissioner E. Shirley Baca, New Mexico Public Regulation Commission
Chairman Lee Beyer, Oregon Public Utility Commission
Commissioner Dustin Johnson, South Dakota Public Utilities Commission
Commissioner Barry Smitherman, Public Utility Commission of Texas
Chairman Ric Campbell, Utah Public Service Commission
Chairman Mark Sidran, Washington Utilities and Transportation Commission
Deputy Chair Kathleen A. "Cindy" Lewis, Wyoming Public Service Commission

The West Joint Board met in public session on November 13, 2005 in Indian Wells, California and on February 13, 2006 in Washington, D.C.

As the Commission noted in the initial order convening the joint boards:

> Each joint board is authorized: (1)"to consider issues relevant to what constitutes 'security constrained economic dispatch'"; (2) to consider "how such a mode of operating an electric energy system affects or enhances the reliability and affordability of service to customers in the region concerned"; and (3) "to make recommendations to the Commission regarding such issues."

This report contains four sections in addition to this introduction: Section II provides a description of the basic concept of SCED used in the study; Section III provides background on the variations in dispatch procedures in the west; and Section IV gives a summary of the issues raised and considered by the Joint Board, together with recommendations to address these issues. The principal source material for this Report include [i] presentations to the Joint Board, [ii] written comments submitted to the Joint

Board, [iii] discussions among the Joint Board members at Board meetings and otherwise, [iv] the DOE report under EPAct 2005, Section 1234[4], and [v] the responses to the DOE survey of economic dispatch under Section 1234.

II. Security Constrained Economic Dispatch: the Basics

For purposes of the joint boards' studies, the FERC adopted the following definition of security constrained economic dispatch:

> "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."[5]

This definition describes the basic way all utilities in the region endeavor to dispatch their own and purchased resources to meet electricity load. The basics of SCED are described in this section to establish a common understanding of the process before addressing issues and recommendations.

There are a number of unique challenges to supplying electricity: production must occur simultaneously with demand; demand varies greatly over the course of a day, week, and seasons; the costs of generation from different units and different types of units vary greatly; and scheduled and unplanned outages in a generator fleet and expected and unexpected conditions on the transmission network affect which generation units can be used to serve load reliably. SCED is an optimization process that takes account of these factors in selecting the generating units to dispatch to deliver a reliable supply of electricity at the lowest cost possible under given conditions.

The economic dispatch process occurs in two stages, or time periods: day-ahead unit commitment (planning for tomorrow's dispatch) and unit dispatch (dispatching the system in real time).

In the *unit commitment* stage, operators must decide which generating units should be committed to be on-line for each hour, typically for the next 24-hour period (hence the term "day ahead"), based on the load forecast. In selecting the most economic generators to commit, operators must take into account each unit's physical operating

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[4] *The Value of Economic Dispatch, A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005*, United States Department of Energy, November 7, 2005.

[5] September 30, 2005, Order at ¶14.

characteristics, such as how quickly output can be changed, maximum and minimum output levels, and minimum time a generator must run once it is started. Operators must also take into account generating unit cost factors, such as fuel and non-fuel operating costs and costs of environmental compliance.

Operators must also consider other factors that may affect what resources should be included in the next day dispatch, such as required environmental limits on annual unit output, and non-power uses of hydro resources. These factors can affect the eventual cost of utilizing the resource, but cannot be easily translated into daily or hourly production costs.

In addition, conditions that can affect the transmission grid must also be taken into account to ensure that the optimal dispatch can meet load reliably. This is the "security" aspect of the commitment analysis. Factors that can affect grid capabilities include generation and transmission facility outages, transmission path congestion (line capacities as affected by loading levels and flow direction), inadvertent loop flow and the weather. If the security analysis indicates that the optimal economic dispatch cannot be carried out reliably, relatively expensive but better situated generators may have to replace cheaper units.[6] Operators might perform the unit commitment analysis a few times during the day before actually committing generators for the next day dispatch.

In the *unit dispatch* stage, operators must decide in real time the level at which each available resource (from the unit commitment stage) should be operated, given the actual load and grid conditions, such that overall production costs are minimized while the necessary level of service is maintained. Actual conditions will vary from those forecasted in the day-ahead commitment and operators must adjust the dispatch accordingly. As part of real time operations, demand, generation, and interchange (imports and exports) must be kept in balance to maintain a system frequency of 60 Hz (per NERC standards). This is usually done by using Automatic Generation Control (AGC) to change the generation dispatch as needed. In addition, transmission flows must be monitored to ensure that they stay within reliability limits and voltage stays within reliability ranges. If transmission flows exceed accepted ranges, the operator must take corrective action, which could involve curtailing schedules, changing the dispatch, or shedding load. Operators may check conditions and issue adjusted unit dispatch instructions as often as every five minutes. The Western Electricity Coordinating Council (WECC) provides reliability related service throughout the Western Interconnection and closely monitors the condition of the network.

[6] This is known as "out of merit" dispatch.

III. Economic Dispatch in the West

The practice of economic dispatch in the West varies by area. For purposes of this report, we will organize the discussion around the four areas used by WECC. These subregions[7] are shown in Figure 1 and are as follows:

- Northwest Power Pool Area (Northwest)
- California-Mexico Power Area (California)
- Arizona-New Mexico-Southern Nevada Power Area (Southwest)
- Rocky Mountain Power Area (Rockies)

The overall pattern of dispatch in the West depends to a large extent on differences between the resources and loads in each area. The Northwest has an abundance of hydropower and a load that peaks during the winter, while the Southwest has a load that peaks during the summer. As a result, a historical pattern of flows has developed where power in the summer flows from available hydropower in the north to peak loads in the south, while power in the winter flow from south to north to meet the peak loads in the northwest. The north-south transmission system has developed to support this pattern, and provides for overall economic utilization of generation resources when water conditions permit. In a similar way, the main fuel sources for thermal power generation, coal and natural gas, tend to be in the Rockies or to the east in Texas and Oklahoma, while the major population centers are to the west, in California and the Pacific Northwest. The electric transmission systems reflect the need to move power west from coal generation; this movement of power is less seasonal than the north-south movement, as much of the power comes from baseload plants that run year round.

The CAISO is the one multi-utility area market in the west that is centrally organized and dispatched. The remainder of the areas in the west perform economic dispatch on a cooperative but decentralized basis, with a form of control area or utility dispatch similar to the basic dispatch described in the previous section. However, there is considerable variation in individual practices in each area that distinguish the way economic dispatch is practiced. The variations in regional practice are discussed briefly below.

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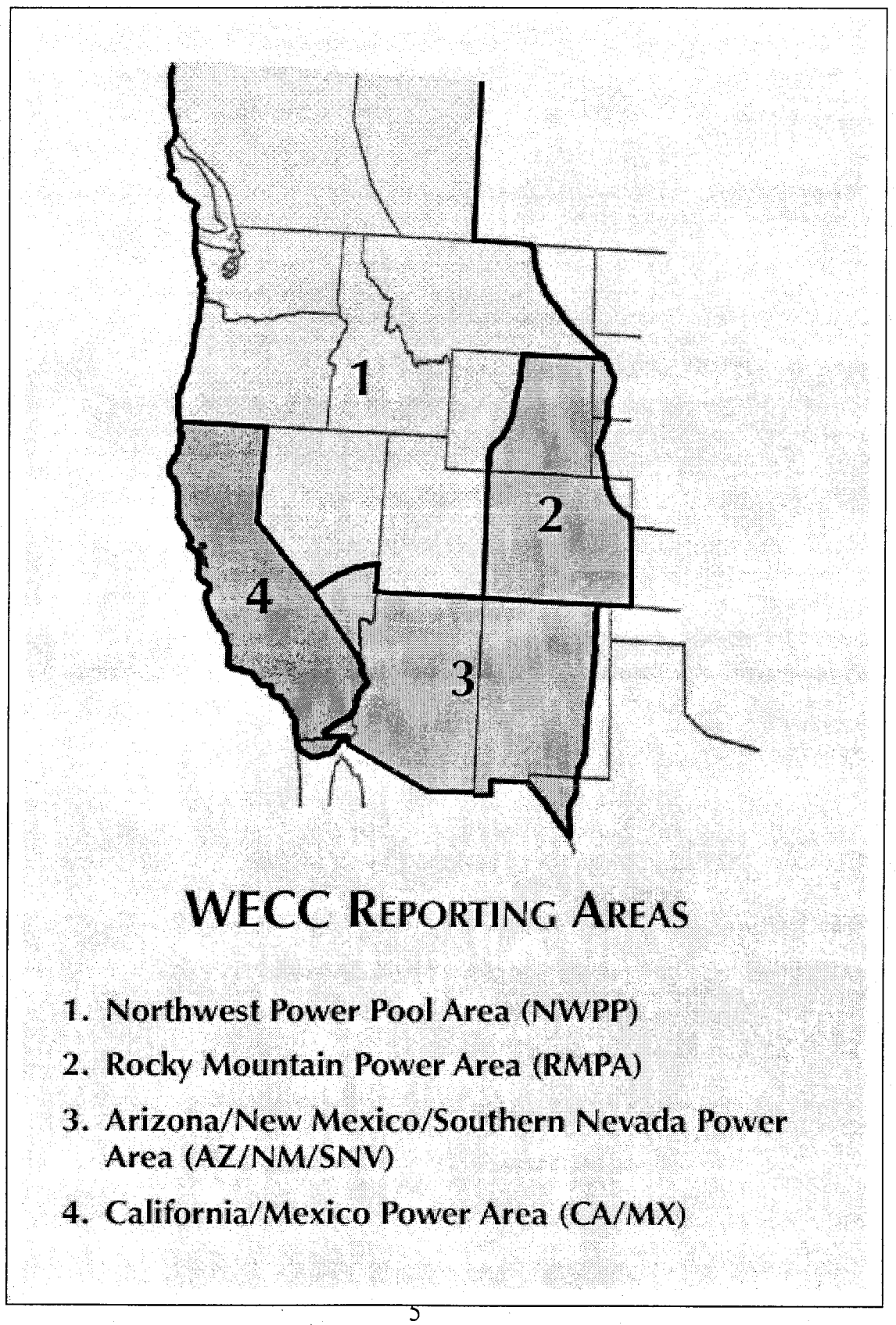
[7] Because the Western Interconnection is coextensive with the area being studied by the West Joint Board, Commissioner Smith recommended using the term "subregion" when referring to less than the entire Western Interconnection region. Transcript of February 13, 2006, meeting of West Joint Board, hereinafter Tr. 2, pp. 49-50.

Figure 1. Western Regions for Economic Dispatch Discussion



A. Northwest

Although significant hydropower resources exist throughout the west, they dominate power generation in the Northwest. Fifty eight percent of capacity in the Northwest is conventional hydropower; seventy nine percent of the total western hydropower resources occur in the Northwest.[8] In the west as a whole, hydropower accounts for thirty four percent of the total capacity.[9] This level of hydropower resources alters the way economic dispatch is performed in the Northwest and in the entire west, making western dispatch issues significantly different from those in the Eastern Interconnection and ERCOT.

Several characteristics of hydropower have direct implications for dispatch in the Northwest:

- Economic dispatch needs to consider the overall optimization of hydropower and thermal resources, making the problem of resource optimization much more difficult than it is in a power system based exclusively or primarily on thermal resource capacity.
- Hydropower generation resources in the Northwest are highly interdependent, so that they need to be dispatched as a coordinated system for power generation, rather than as separate, independent power sources.
- Conventional hydropower is generally limited by the total available energy stored in the water behind the dams, not by the total generating capacity of the resource.
- Hydropower can generally be dispatched very quickly when available, providing an abundance of low cost, rapidly dispatchable capacity to an extent not present in the other North American interconnections.

These characteristics have led to a long history of coordination in the Northwest, beginning around 40 years ago with the Columbia River Treaty with Canada and the Pacific Northwest Coordination Agreement (PNCA), and including the Mid-Columbia Hourly Coordination Agreement (MCHA). The PNCA enables both Federal and Non-Federal projects to operate as a single utility owner to optimize power and nonpower river demands, while the MCHA optimizes the hydraulic operation of seven dams on the Columbia River. The MCHA permits hydropower resources to provide load following for much of the Northwest load, and hydropower resources also provide regulation and reserves at a low cost.

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[8] WECC, 2005 Information Summary, Total Existing and Planned Generation, p. 6.

[9] *Id.*

Another factor affecting Northwest dispatch is operation of BPA's transmission assets, which are closely connected to the operation of hydropower resources. Historically, the coordinated operation of the system of dams meant that all power was treated equally regardless of location on the system, so that a megawatt had the same value at any location. Until relatively recently, there were few constraints on the BPA transmission system, so there was sufficient transmission capacity to ensure that coordination would work successfully. In the last few years, there have been an increasing number of internal constraints; and BPA is now moving toward a power flow based methodology to more accurately capture transmission effects in dispatch.[10]

The coordination of power and non-power uses leads to determining the optimum power operation *within* the non-power constraints. This optimum operation is distinct from the objective of minimizing short term operating costs. The valuation of hydropower resources for short term dispatch presents unique challenges when such a high percentage of resource is low cost in the short term and potentially high (and uncertain) in value over the longer term.

Although the presence of hydropower in the Northwest significantly affects the overall operation and dispatch of the power system, the basic dispatch remains decentralized and economic dispatch is conducted on a utility by utility basis rather than being coordinated centrally. Plans for the development of a RTO in the Northwest are not being actively considered; but Columbia Grid has recently begun efforts to form a grid organization in the Pacific Northwest.

Based on the responses to the DOE survey and the utility presentations at the initial meeting of the West Joint Board, utility dispatch in the Northwest is similar to the basic model described in the Section II, once operations are adjusted for the presence and limitations of hydropower. The main difference is less emphasis on day-ahead unit commitment of thermal resources to provide load following and reserves, because hydropower is generally the lowest cost alternative for these functions and will be used when available. Utilities report dispatching a mix of their own generation, independent generation committed under contract, and wholesale spot market purchases, combined to achieve the lowest cost from the resources available. These dispatch decisions are generally made before the operating day, either in the day ahead planning or earlier, and take into account factors other than strict operating costs, such as environmental limits, fuel contract terms, opportunity cost of company-owned hydropower, and similar factors.

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[10] BPA, Economic Dispatch in the Pacific Northwest, presentation to the meeting of the West Joint Board for the Study of Economic Dispatch, Palm Springs, CA, November 13, 2005. (FERC Docket No. AD05-13-000)

Although planning for dispatch may take into account a wider range of sources, hourly or real time adjustments are often restricted to company owned resources or resources under contract that permit the utility sufficient flexibility in the terms of the dispatch.

B. California

The California ISO (CAISO) performs an economic dispatch covering most of California, with the exception of some control areas.[11] Formed in 1998, the CAISO dispatches a single control area, corresponding to the former control areas of California's three largest Investor Owned Utilities. Prior to the formation of the CAISO, each of the three control areas performed single utility economic dispatch, by dispatching their own resources and other resources under their control. This dispatch was similar to the basic dispatch process described in Section II, using the costs of the generation resources to establish the order of the dispatch and running the lowest cost resources available, given the security constraints of the system.

The CAISO consolidated the dispatch of the three utilities into a single dispatch for approximately 45,000 MW of California peak load, by balancing generation and load every 10 minutes based on market bids from generation resources. This balancing market was similar to the previous control area balancing function in that lower cost generation resources were dispatched before higher cost resources; however, the traditional utility costs were replaced by bids to the CAISO. This change altered the economic dispatch process in two fundamental ways: [i] all resources capable of being dispatched were eligible to submit bids on an equal basis, and [ii] the market bids that replaced the utility production cost estimates were no longer required to be tied to actual production costs of the utility.

In October 2004, the CAISO began the Real Time Market Application (RTMA), a new market application that plans a 5 minute dispatch for 2 hours in the future, dispatches online resources on a 5 minute basis in real time, and starts "fast start" resources on a 15 minute interval. A Market Redesign and Technology Upgrade (MRTU), planned for late 2007, will include the use of market bidding for day ahead planning and unit commitment, and greater detail in representation of the transmission grid for more accurate representation of the security constraints in the economic dispatch decision. These changes will enhance the dispatch processes of the CAISO, but will not change the basic differences between the CAISO dispatch and dispatch in the rest of the west: CAISO will continue to perform the only centralized, multiple-utility, market-bid-based

[11] Examples of control areas inside California, but not included in the CAISO dispatch are the Los Angeles Department of Water and Power in Southern California, Sacramento Municipal Utility District in Northern California, and a few others throughout the state.

economic dispatch in the west. Although the CAISO is the only area in the West with this type of dispatch, its operation has significant effects on dispatch in the rest of the west because the total load in California is large (approximately thirty percent of the summer peak load for the west)[12] and California relies on significant imports from the rest of the west. Because California is so closely dependent on imports from the rest of the west, and because long distance power transactions are an important factor in overall power flow, the centralized dispatch in the CAISO has greater direct impact on other areas in the WECC than comparably-sized centralized dispatch in the Eastern Interconnection has on other areas in the east.

The CAISO dispatch includes all resources needed to serve the load, both those that can be dispatched on a 5-minute basis and those that are not capable of responding to 5-minute dispatch signals. The non-dispatchable resources include generating plants that must be run for longer time periods, such as nuclear plants, as well as imports into the CAISO control area. These imports follow scheduling procedures set for the WECC as a whole, and must conform to fixed hourly schedules for exchanging power between control areas. Although imports are eligible to bid into the CAISO market for dispatch in real time, they must do so on an hourly basis and cannot be varied in the real time dispatch.

The CAISO is still evaluating the current implementation of real time dispatch, the RTMA, but notes two changes from the previous economic dispatch.[13] First, prices have become more volatile and the fluctuation of the dispatch has increased. This result is consistent with the change in the design of the dispatch, which was intended to promote more frequent balancing of generation and load and produce market prices that more closely mirrored that balance. Second, RTMA has improved the handling of "start up" problems, including improved pricing of import/export bids. Coordination of the balance of hourly exports/imports and 5-minute generation dispatch continues to be a challenge, however, particularly when load is rapidly fluctuating.

C. Southwest and the Rockies

Although the Southwest and Rockies are separate areas, they have a single reliability coordinator, located at the WECC Rocky Mountain/Desert Southwest Reliability Center (RDRC) in Colorado. Both areas rely principally on thermal resources, but face somewhat different issues in performing economic dispatch. The Southwest has a larger amount of hydropower capacity in the generation mix, and has a significantly greater

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[12] Based on a summer peak load of 141,100 in 2004, *WECC, 2005 Information Summary*, p. 2.

[13] *Assessment of Economic Dispatch Practices at the CAISO*, initial Meeting of the West Joint Board on Economic Dispatch, November 13, 2005, p. 18.

level of trade with California.

Natural gas is the largest single source of generation in the Southwest, followed by coal and nuclear. Hydropower also plays a significant role, with slightly over ten percent of the total area capacity. Dispatch throughout the area is by individual utilities that perform unit commitment and economic dispatch of the own resources, supplemented by resources controlled by contract and purchases from the spot market. Generally, the large base load plants are located near fuel sources that are remote, and in some cases hundreds of miles away from the load centers. These base load units may be jointly owned, each with its own dedicated capacity that needs to be dispatched. Consequently, the availability of transmission facilities is a factor that must be taken into account in the economic dispatch. This general pattern of utility dispatch is followed by large investor owned utilities such as Arizona Public Service, large projects such as the Salt River Project, and smaller cooperatives and public power entities. Thus the Southwest dispatch is similar to the basic model described in the Section II, and does not have the extensive procedures needed to coordinate the dispatch of the hydropower resources of the Northwest, nor has it adopted the centralized dispatch procedures used in the CAISO. Active spot markets exist at the Palo Verde, Four Corners and Mead hubs, providing a basis for price discovery in the Southwest and points of reference for including wholesale purchases in the economic dispatch.[14]

El Paso Electric (EPE), the only Texas electric provider in the Western Interconnection, is a small part of that grid, and is in a particularly constrained area to the extent that, in the short run, moving to a broader regional dispatch may have little impact for EPE. However, Texas believes there are longer-term regional and national benefits that could be obtained from a more coordinated dispatch through more efficient fuel use and the development of the competitive wholesale electricity market in the western region.[15]

Like the Southwest, the Rockies generation resources are largely thermal, with coal being the largest generation resource, followed by natural gas, and dispatch follows the single utility approach, together with use of resources under contract and spot market purchases. The utilities serving this area utilize WECC's services in coordinating and promoting electric system reliability on the Western Interconnection. WECC supports efficient competitive power markets, open and non-discriminatory transmission access among members (including, e.g., BPA, CAISO, LADWP, and many privately and cooperatively held utilities serving throughout the West), provides a forum for resolving transmission access disputes, and fosters coordination of the operating and planning activities of its members.

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[14] *See,* DOE survey comments of APS, Salt River Project and Arizona Electric Power Cooperative on the use of wholesale spot purchases in the dispatch.

[15] *Texas Perspective on Security Constrained Economic Dispatch*, p1.

D. Western Systems Power Pool

Trading between utilities and between sub-regions of the West improves the dispatch of resources. Such trade is enhanced by the Western Systems Power Pool (WSPP). As discussed above, there is a long history in the West of both seasonal (north-south) and resources-to-load (east-west) power movement. For these reasons, there has been an active wholesale electricity market in the West for decades. This market became more formalized in 1987, when FERC approved the WSPP. The WSPP has provided a platform for short-term transactions throughout the Western Interconnection for economy energy, unit commitment, and firm sales or exchange services. With over 220 WSPP members (virtually all market participants), the WSPP agreements are the most widely used standardized power sales contracts in the electric industry.

As a result, this readily available platform for day-ahead and real-time transactions adds an important dimension to SCED in the West. (Even entities within the CAISO, many of which are WSPP members, can use the WSPP agreements to import power if the transmission capability exists.) It allows Western electricity market participants to use risk management strategies more effectively in order to meet their load service obligations at the lowest cost practicable and in a reliable manner. These wholesale activities provide enhanced operational flexibility, particularly when water available for hydroelectric generation is subnormal, unplanned generation or transmission outages occur or transmission constraints exist. They also provide economic flexibility based on how wholesale prices compare with marginal generation costs. Thus, the ability to trade electricity on a West-wide basis greatly influences the process of economic dispatch.

This has led to the development of numerous robust wholesale trading hubs in the Western Interconnection, such as Mid-Columbia, Palo Verde, California-Oregon Border, North Path 15, and South Path 15, where numerous wholesale electricity purchases and sales occur on a daily basis. Sales volumes and prices at these hubs are reported on a voluntary basis to ICE (IntercontinentalExchange Inc.), Dow Jones, and other reporting services, aggregated by hub, and made public daily. Sales by jurisdictional utilities are also reported to FERC in Electronic Quarterly Reports.

IV. Issues and Recommendations

This section describes the issues considered by the Joint Board, and identifies any recommended approaches for addressing these issues..

The Joint Board makes two general observations regarding any approach to issues relating to SCED. First, Joint Board members generally believed that there should not be a "one size fits all" approach to the use of SCED. Differences among the areas in the west, and often differences within each area, are too large to warrant recommending a

single form of SCED for all areas or utilities. Second, the focus of changes from current practices should be at the state or local level. Regional or subregional changes should be based on collaborative efforts among utilities, other market participants and states, rather than on legislative or regulatory initiatives at the federal level.

Recommendations from the DOE report to Congress on the value of economic dispatch are discussed at the end of this section.

A. Observations

Introduction

A number of general issues have been raised about the nature of economic dispatch, its scope and uses, and implications for affordable and reliable service to electricity consumers. These general issues include:

- Relative importance of hourly dispatch costs
- Least cost production may not be lowest cost for the ratepayer
- The broad choice between cost-based and bid-based dispatch

Relative importance of economic dispatch.

Some board members and market participants expressed the desire to put the implications of economic dispatch in an overall cost perspective. In terms of total overall cost, economic dispatch, when framed in terms of daily and hourly dispatch, was felt to be relatively unimportant compared to long term investment in generation and transmission.[16]

Least cost production may not be lowest cost for the ratepayer.[17]

This issue was raised by several board members, in reference to environmental costs, the nonpower issues of hydropower scheduling, and other considerations. The concern was that many factors are considered in the unit dispatch decision that cannot be easily translated into short term monetary terms, so that exclusive emphasis on minimizing daily or hourly production costs could prove to be more expensive to the ratepayer in the long run.

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[16] Commissioner Schneider,Transcript of first West Joint Board meeting (Tr.) at 116.

[17] Commissioner Beyer, Tr. at 114.

Choice of cost based or bid based dispatch.

This issue focused on the idea that economic dispatch often arose in the context of choice between two different systems of dispatch. The cost-based system referred to the basic single utility dispatch where a utility dispatched its own units based on its own generation costs and other factors, and was compared to a system with a separate grid operator that dispatched generation resources based on bids to supply power and then set a market price for the power based on the bids. Each overall approach gave rise to different sets of specific issues regarding the factors to consider for SCED. One board member noted the existence of these different approaches, and proposed that the board not recommend a single approach to this issue.[18]

B. Specific Dispatch Issues

Introduction

The specific dispatch issues raised varied by subregion, with different issues raised in each of the areas of the west, and by market segment within regions, and with different issues raised by utilities, independent power producers, grid operators and state regulators. These specific issues are listed below and discussed in the remainder of this section.

- Independence of dispatcher
- Utility dispatch of third party power through contracts
- Transparency of dispatch information and processes
- Consolidation of control areas
- Regional scope benefits
- Import/export schedule changes within an hour

Independence of dispatcher.

A representative from the independent power producers (IPPs) recommended that some type of independent transmission dispatch was needed so that independent power producer resources could be fully integrated in the hour-to-hour operation of the dispatch.[19] In discussion, the IPP representative stated that dispatcher independence was

[18] Commissioner Campbell, Tr. at 110
[19] Mr. Kahn, Tr. at 91.

a prerequisite for merit order dispatch.[20]

Board discussion:

There are three dispatch models employed in the Western Interconnection: [i] the California Independent System Operator (CAISO), [ii] individual utilities performing economic dispatch within their control areas, and [iii] public and private utilities cooperating to dispatch the Northwest's multi-owner hydroelectric system.[21] All three models may be assisted by the WSPP. Faced with a variety of different operating scenarios and the issues they raise, including those concerned with the performance of independent operators, states should be allowed to deal with these issues themselves. Texas states that "having an independent grid coordinator with access to comprehensive regional information can significantly enhance reliability and market operations."[22] However, there is little enthusiasm among other Joint Board Members for creating new independent dispatchers where the current system is functioning properly; and "joining or not joining a regional dispatch entity should be up to each utility and the negotiation with their regulatory body."[23] Decisions on dispatcher independence should be flexible and responsive to the needs of the state [24] Independent entities should not be created for their own sake:

> Where utilities perform dispatch functions and do so fairly and efficiently, they should not be supplanted with an independent dispatcher simply for the sake of having one. Utilities operating in such a manner should be involved with the development of independent dispatching entities.[25]

In addition to a general caution regarding significant changes to existing dispatch practices, two recommendations were put forward: (1) keep any structural changes flexible and sensitive to the needs of the states; and (2) make changes voluntary wherever possible.[26] Several board members cited this issue in their summary remarks.[27] In addressing the question, regulators should remember that both public and private entities serve load in many areas. All have duties to serve the public but all do not have the same

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[20] Mr. Kahn, in response to a question from Commissioner Grueneich concerning whether a utility would always favor its own generation, Tr. at 94.

[21] Commissioner Campbell, Tr. 2, p. 38; and Commissioner Smith, Tr. 2., p. 38.

[22] *Texas Perspective on Security Constrained Economic Dispatch*, p2.

[23] Mr. Brown, Tr. 2., p37.

[24] Commissioner Sidran, Mr. Brown and Commissioner Grueneich, Tr. 2, pp. 36-39.

[25] *Wyoming Discussion Points*, February 3, 2006, p. 1.

[26] Ms. Edwards, Tr. at 73.

[27] Commissioner Greuneich, Tr. at 111; Commissioner Beyer, Tr. at 115.

level or type of regulatory oversight.[28]

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

Utility dispatch of third party power through contracts.

This issue was cited by both utilities and non-utilities, with utilities sometimes arguing that it was difficult to obtain sufficient performance and reliability from third party contracts. One utility stated the primary difficulty with incorporating non-utility generation in their dispatch was their "inability to complete alternative actions in a swift and economic manner."[29] Independent power producers stated the opposite position, arguing that their generation was flexible and capable of being very responsive, but that they were often denied the ability to dispatch power by utility generation owners who controlled the dispatch, particularly in the case of hourly dispatch and ancillary services.[30]

Board discussion:
This issue describes the ongoing tension among IPPs and incumbent utilities on the subject of IPP integration; and the independent producers should play a constructive and full role in the development of a system capable of accommodating them. IPP integration should be approached as part of a cooperative effort, overseen on a subregional level by appropriate entities or on an interconnection-wide level by WECC through its committee process. Entities should carefully consider the potential reliability and dispatchability impact of the IPP on the Western Interconnection or relevant portions thereof and should make sure that the IPP bears its fair share of the costs of integration with the system, including the up-front cost of creating any independent dispatch capability to accommodate their participation. Thus, consideration of "merit order" dispatch should be done in the context of an overall cooperative effort and not as a goal in and of itself. The ultimate end of the effort is to serve the consumers better and more efficiently, and consideration of when to dispatch will likely have less monetary impact on consumers

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[28] Commissioner Sidran, Tr. 2, p. 40.
[29] Portland General Electric response to DOE survey, p. 2.
[30] Mr. Kahn, Tr. at 88.

than will wise choices of what resources to build.[31]

Further progress will require basic contract commitments by IPPs regarding dispatchability and other issues. EPSA and EEI proposals to develop standard contract terms should be encouraged.[32] In summary, Commissioner Kelly cited the following member's observation as the consensus of the Joint Board that it should:

"Encourage contractual commitments by independent producers to provide energy in a manner consistent with the utility's dispatch, but do not require utilities to purchase nonutility power."[33]

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

Transparency of dispatch information and processes.

One of the benefits cited for an independent entity dispatching all resources in a region was the ability to provide a transparent process for the dispatch. One utility representative argued that full value economic dispatch would not be fully realized without this transparency.[34] Without the independence condition, sharing sensitive real-time information between a utility transmission provider and third parties can be viewed as an impediment to dispatching economically.[35]

Board discussion:
Transparency of information and process can enhance the dispatch function, but the desire to promote transparency should not drive the decision as to whether or not an independent dispatch entity is needed. Transparency is not an end in itself. It can further some of the goals of economic dispatch, but should not serve as a rationale for creating

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[31] See, *Wyoming Discussion Points*, February 3, 2006, pp. 2-4.

[32] See discussion of the Second DOE Recommendation in section C of this document.

[33] Tr. 2, p. 41; and Attachment C to Supplemental Notice of Second West Joint Board Meeting in FERC Docket No. AD05-13-000, p. 1.

[34] Mr. Larson, Tr. at 49.

[35] Discussion between Commissioner Smith and Mr. Larson, Tr. at 53 and 54.

an independent entity to achieve transparency. Furthermore, one board member observed that too much market knowledge can potentially foster collusion which can do damage to the market ostensibly being helped.[36] Transparency of information can be a benefit to a region, but that benefit is not in itself sufficient to support a mandate for regional economic dispatch.[37]

In a related observation, the Department of Energy suggested that there should be further study of the "impact of the accuracy of load forecasting and quality load forecasting on the results of economic dispatch." If the quality of forecasted information is low, the resulting dispatch may be wasteful. DOE suggested the study look at the costs of suboptimal forecasting and "ways to improve the quality of forecasting to improve economic dispatch."[38]

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

Consolidation of control areas in a region.

The current single-utility dispatch means that each utility first determines a dispatch for its own area with only limited knowledge of conditions in other areas. In the Western Interconnection, WECC provides important real time information on the status of the grid which assists dispatchers. However, coordination among control areas may sometimes be based on limited information on generation availability in other areas and constraints on transmission available for imports and exports between control areas, when compared to the information available within each control area. The larger the number of areas, the greater the potential benefit of consolidating control areas, in principle, arising from better information available to the dispatchers and better control over generation and transmission resources. Some presenters recommended that control areas be consolidated, citing the large number in an area like the Northwest.[39] Others argued that there were potential benefits to SCED from consolidation, without taking a position on whether the benefits of consolidation would exceed the costs.[40] Texas cited the ERCOT example of combining ten control areas into one as providing evidence of significant

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[36] Commissioner Schneider, Tr. 2, p. 44.
[37] Commissioner Sidran, Tr. 2, p. 42.
[38] Ms. Silverstein, Tr. 2, p. 62.
[39] Mr. Kahn, Tr. at 89.
[40] BPA in comments submitted in the docket.

benefits from control area consolidation and regional dispatch.[41]

Board discussion

Consolidation of control areas should be approached rationally rather than making consolidation an aim in itself. Single utilities do not dispatch in an informational vacuum, but frequently are in contact with relevant control centers and entities throughout the Western Interconnection. Very large control areas encounter problems in dealing with 15-minute import/export exchange to ameliorate problems of scheduling on the hour. However, it is also true that larger control areas can be a positive development if the integration of smaller control areas makes operational sense. This is especially true for wind resources which can benefit from being part of larger and hence more diverse control areas. The focus should be on the technological advisability of consolidation and not on simply reaching the goal of larger and larger control areas.[42] The geography of the West has already helped to create relatively large control areas, which is not always the case in other parts of the nation. We therefore must be careful to examine the costs and usefulness of further consolidation.[43] WECC's three reliability centers which can see the entire Western Interconnection should be an integral part of the analysis of control centers. WECC is now studying its reliability centers to determine both the number of centers needed in the future and what tools are required to see the whole of the Western Interconnection at once and to issue reliability directives. Commissioner Smith cautioned against creating new single-generator control areas.[44]

Increasing the size of the dispatch region, even without consolidating regions into a single control area, can lead, in principle, to a lower cost dispatch through inclusion of more generation and transmission resources. However, there appeared to be no consensus on whether such regional benefits exist in practice. Some cited regional benefit studies that concluded there were positive net benefits; for example, the representative from the Independent Power Producers cited a recent study for Grid West as demonstrating benefits.[45] One utility representative stated that there were potential benefits from regionalization, without citing a specific study. However, at least some board members felt the current system of utility dispatch coupled with spot and short term market purchases worked efficiently. One board member cited the adage, "If it ain't broke, don't fix it."[46]

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[41] *Texas Perspective on Security Constrained Economic Dispatch*, p1.

[42] Commissioner Campbell, Tr. 2, pp. 45-46; and his comment approving *Wyoming Discussion Points*, February 3, 2006, p. 3.

[43] Commissioners King and Johnson, Tr. 2, pp. 47.

[44] Commissioner Smith, Tr. 2, pp. 47-49.

[45] Mr. Kahn, Tr. at 90.

[46] Commissioner Baca, Tr. at 119.

The west should carefully examine the usefulness of creating larger dispatch regions on an individual basis. Participation by major stakeholders should be assured before meaningful consolidation can take place. The west should draw on the well developed grid management experience of institutions such as WECC, and on the wholesale market facilitation and coordination experience of entities such as WSPP, to assist in deciding whether or not to form larger dispatch -- or control -- areas. Case-by-case examination would better fit with the diversity encountered in the Western Interconnection than would a blanket consolidation mandate.[47]

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

Import/export schedule changes within an hour.

The CAISO identified large hourly schedule changes as a problem for their dispatch. The source of this problem is that schedules between control areas change at the beginning of each hour and remain constant for the hour. Because the CAISO often has large amounts of imported power at the same time that it has large changes in load over the hour, it becomes difficult to accommodate these large blocks of hourly imports while following a volatile load.[48] To address this issue, CAISO recommended spreading the changes out over the hour to decrease the magnitude of each change.[49] Scheduling could still occur on an hourly basis, but each hourly schedule could increase or decrease on a less than one hour basis, for example, on 15 minute intervals. Because scheduling imports and exports between control areas in the west follows a standard protocol, developing the ability to provide schedule varying on 15 minute intervals would require coordinated development of such a change throughout the west.[50] One board member cited this recommendation positively, but there was no further comment from other board members at the initial meeting.[51]

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[47] Commissioner Lewis, Tr. 2, p. 50.
[48] Mr. Rothleder, Tr. at 38.
[49] Mr. Rothleder, Tr. at 41.
[50] Mr. Rothleder, Tr. at 39.
[51] Commissioner Campbell, Tr. at 110.

Board discussion:
Although this is, at this time, a situation most focused on California and the CAISO as it confronts loads which are more volatile than imports over the hour, the Board in general supported the concept.[52] Oregon's experience shows that hourly scheduling of interchanges between utilities is complicated by relatively slow ramp rates which can cause utilities to experience imbalances. Allowing for ramp rate changes, e.g., 10 minutes before and after the hour, could significantly reduce these imbalances. The Board accepted this addition as an important consideration for further work on the topic.[53]

Recommendation:
We recommend that the WECC develop a standard west-wide protocol to address the need for scheduling before, during and after the top of the hour.

Some practical limitations on economic dispatch.

The heavy and increasing reliance on natural gas as a generator fuel must be included in future studies of economic dispatch. Recognizing that it is subject to substantial price volatility, the ideal might be to dispatch the most efficient natural gas plants to make the best possible use of our natural gas resources. The study of the challenges inherent in the use of natural gas may begin with the distinction between economic dispatch and efficient dispatch. The United States Department of Energy has described the differences between these concepts:

> In a recent hearing of the Senate Energy and Natural Resources Committee*, there was great interest in determining whether economic dispatch practices could or should be modified to ensure the most efficient use of scarce natural gas in gas-fired generation units. "Economic dispatch," as noted above, is an optimization process crafted to meet electricity demand at the lowest cost, given the operational constraints of the generation fleet and the transmission system. Although economic dispatch will *usually* run higher efficiency gas-fired units before lower efficiency units, that is not always the case, for a number of possible reasons. "Efficient dispatch" would presumably seek to modify the practice of economic dispatch to ensure that more efficient gas-fired units are *always* used before less efficient units.
>
> Despite DOE's interest in ensuring the efficient use of natural gas for electricity generation and other purposes, it remains skeptical of the merits of "efficient dispatch," for several reasons:

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[52] Commissioners Grueneich and Kelly, Tr. 2, pp. 51-52.
[53] Mr. Brown and Commissioner Kelly, Tr. 2, pp. 52-53

- The fundamental purpose of economic dispatch is to reduce consumers' electricity costs. "Efficient dispatch" would take the dispatch process off this path and increase consumers electricity costs – for benefits that may not be large enough to offset these additional costs.
- Economic dispatch is at best a complex process, and modifications to it must be made with care in order to minimize unanticipated consequences. Modifying it to achieve short-term non-economic policy objectives should be considered only as a last resort.
- A better alternative would be to examine the practice of economic dispatch itself to determine whether modifications are needed to better achieve its traditional objectives – which could by itself lead to more efficient use of natural gas. A review of this kind could be pursued through the regional joint FERC-State boards created by EPAct in Sec. 1298.[54]

* Senate Committee on Energy and Natural Resources, Full Committee Hearing – Hurricane Recovery Efforts, October 27, 2005

Board discussion:
SCED is defined above in Section II of this report sufficiently broadly to include more localized reliability concerns. Therefore, the definition of SCED should not later be so narrowly construed that it makes it impractical or too costly to incorporate such local reliability and other considerations in regional, subregional or state analyses.

California observed, as a practical matter, that it would probably have to keep older and less efficient natural gas-fired plants in operation to deal with more localized issues of reliability and system congestion. This goes to the heart of how we define economic dispatch in the future and means that there must be practical rather than only theoretical assessments of system capabilities and costs. Commissioner Grueneich of California observed that, to accommodate these considerations, either [i] the definition of economic dispatch should be broadened to take such reliability-related issues into account, or [ii] the inquiry should be taken beyond economic dispatch to allow these issues to be considered.

Similarly, California recommends incorporation of renewable generation in the economic dispatch process. In California, economic dispatch also means incorporating the State's policy of encouraging the development of renewable energy sources and the preferred resource loading order. California's "Energy Action Plan II" includes a loading order that identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs followed by renewable generation, combined heat and

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[54] *The Value of Economic Dispatch: A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005*, United States Department of Energy, November 7, 2005, p. 11. Text of report found at http://www.electricity.doe.gov/document/value.pdf

power and distributed generation, and traditional fossil resources. Some other states across the country have also adopted renewable portfolio standards in many ways similar to California's but with different regional goals which reflect public policy in those individual states.[55]

Even with overall goals of trying to address natural gas prices and of implementing direct economic dispatch, the local cost and reliability issues will vary to such an extent that each particular situation should be examined closely -- "on a very decentralized basis."[56]

Better service to the people is the primary goal of this inquiry. Issues of reliability and system congestion can have region-wide implications, but they also have a strong local dimension which can keep purely theoretical economic dispatch from being the best or most realistic solution. The best way to deal with such challenges is to make analyses on a case-by-case basis, not ignoring economic dispatch but recognizing that it is not an end in itself and that it should not be promoted with disregard for its local effects.

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

C. Recommendations from the DOE Report to Congress

The DOE Report to Congress, *The Value of Economic Dispatch*, contains three recommendations that are relevant to the security constrained economic dispatch issues that the Joint Board has been considering. These three recommendations are described below.

First DOE Recommendation: review dispatch practices

FERC-State Joint Boards should consider conducting in-depth reviews of selected dispatch entities, including some IOUs, to determine how they conduct Economic Dispatch.[57] These reviews could document the rationale for all deviations from pure least cost, merit-order dispatch, in terms of procurement, unit commitment and real-time dispatch. The reviews should distinguish entity-specific and regional business practices

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[55] Commissioner Grueneich, Tr. 2, pp. 11-13.

[56] Commissioner Grueneich, Tr. 2, pp. 57-58.

[57] *The Value of Economic Dispatch, A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005*, United States Department of Energy, November 7, 2005, p. 52.

from regulatory, environmental and reliability-driven constraints. These reviews could assist FERC and the states in rethinking existing rules or crafting new rules and procedures to allow IPPs and other resources to compete effectively and serve load.

Board discussion:
The study recommended here was generally seen as being at odds with the general consensus of the Joint Board that economic dispatch has to be a flexible concept, capable of adapting to the varying needs of different states and subregions in the Western Interconnection. The study would take us deeply into variables and deviations from "pure" economic dispatch without providing much value. [58] On the other hand, California, with its substantial unregulated municipal utility presence, could benefit from a better understanding of how these entities make economic dispatch decisions, although jurisdictional and funding issues probably make the issue unripe at this time.[59] The new rules presupposed in this recommendation may be incorrectly assumed necessary. The recommendation is also at odds with the complexity of economic dispatch issues in the Western Interconnection.[60] The Joint Board generally agreed that this recommendation should not be pursued. However, Texas believes that there are potentially significant benefits from SCED that warrant study and disagrees with the recommendation not to pursue further study at this time.[61]

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

Second DOE Recommendation: standardize dispatch contract terms

FERC and DOE should explore EPSA and EEI proposals for more standard contract terms and encourage stakeholders to undertake these efforts.[62] Specifically, the EEI has proposed that [i] IPPs should commit to provide energy at specified prices for specified times to meet unit commitment schedules, and [ii] there should be contractual performance standards with penalties for failure to deliver. EPSA proposed developing technical protocols for placing and accepting supply offers, operational requirements, non-performance penalties, and standard contract forms for routine transactions.

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[58] Commissioner Sidran, Tr. 2, pp. 23-24.
[59] Commissioner Grueneich, Tr. 2, pp. 24-25.
[60] Commissioner Smith, Tr. 2, pp. 25-26; Commissioner Schneider, Tr. 2, p. 26.
[61] Commissioner Smitherman, Tr. at 126-28.
[62] *DOE Report* at p. 51.

Board discussion:

A high level of cooperation already exists in the electric industry and among the non-utility generators regarding contracts.[63] Existing initiatives should be the vehicle for crafting standard language of the kind envisioned in the Recommendation and therefore it should be pursued by industry and the IPPs rather than through duplication by the Joint Board or the federal government. The Recommendation rightly recognizes the value of communication among stakeholders to refine their relationships. The Joint Board recognizes the valuable and ongoing work of the North American Energy Standards Board (NAESB) to promote well crafted standardized contracts to encourage efficiency in the electric and natural gas marketplaces.[64] We also encourage EPSA and EEI to go forward with standard contract language proposals. We believe that these existing initiatives should be monitored and encouraged but not duplicated.[65] Regional differences in some cases may be so pronounced that standard contracts should take them into account. Thus, a Western Interconnection contract might of necessity differ from one employed in the East. We note the difference between on-peak products in the East and the West.[66] Wyoming's comment on this subject summarizes the Joint Board's response to this recommendation: [67]

> We think this recommendation should be pursued on a regional basis rather than on a national basis. The regional variances in grid operating parameters throughout the Western Interconnection make a strong case for allowing development to go forward on a regional basis. This does not mean that standardized terms are per se are a bad idea or that federal resources such as those of the DOE should not play an important collaborative role.

Recommendation:

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

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[63] Mr. Hinckley, Tr. 2, p. 28.

[64] Commissioner Sidran, Tr. 2, p.32

[65] Commissioner Smith, Tr. 2, pp. 31-32.

[66] Commissioner Campbell, Tr. 2, p. 31; and New Mexico Comments of February 13, 2006, p. 3.

[67] Commissioner Lewis, Tr. 2, pp. 28-29; and Commissioner Campbell, Tr. 2, p. 31; and *Wyoming Discussion Points*, February 3, 2006, p. 4.

Third DOE Recommendation: review dispatch tools

Current economic dispatch technology tools deserve scrutiny.[68] These tools include software and data used to implement economic dispatch, as well as the underlying algorithms and assumptions.

Recommendation:
We recommend the development and refinement of technological tools to make the best use of existing and proposed facilities.[69]

[68] DOE Report at p. 53.
[69] Commissioners Smith, Grueneich, and Mr. Hinckley, Tr. 2, pp. 33-34.

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be any effect on a 1200-megawatt rating.

Q All right. Thank you.

A Mm-hmm.

Q Questions were referred to you this morning regarding the Desert Southwest Project. Specifically, I had asked about the consideration of that project that the federal BLM is undertaking. Do you have information regarding that?

A Not any information related to BLM.

Q What about the ISO? Is the ISO looking at Desert Southwest?

A Yes. We've completed technical studies of the Desert Southwest Transmission Project and we have submitted those to the ISO for their review and comment and approval.

Q When you say you submitted it to the ISO, what did you submit to the ISO? Is it a project that involves connecting the IID facilities at Midpoint substation or what?

I should ask you an open-ended question. What did you submit to the ISO?

A Yes. What we submitted -- and I should clarify. IID has not been involved in the Desert Southwest Project as far as what we've been studying. We've been dealing with Desert Southwest transmission project themselves as a separate entity. What we've submitted was a system impact study that we performed for Desert Southwest. And the system impact study

1 includes a variety of alternatives. One of the
2 alternatives is that the Desert Southwest Project would
3 build their own line directly from the Blythe area into
4 Devers. It would be a gen-tie type line.
5 The other alternative is it would be a joint
6 project in essence that we would build the DPV2 project
7 and they would use or expand the capacity of our DPV 2
8 project to be able to bring in their power into Devers.
9 Q So both of those alternatives have been
10 submitted to the ISO?
11 A Yes, they have.
12 Q All right. Under the first alternative where
13 Desert Southwest builds its own line from Blythe to
14 Devers, would that affect the carrying capacity of DPV2?
15 A No.
16 Q It would still be 1200 megawatts?
17 A Still be 1200 megawatts.
18 Q If, under the second alternative, Desert
19 Southwest uses DPV2 to bring its power into Devers,
20 I believe you testified earlier that the carrying
21 capacity of DPV2 would still be maintained at 1200
22 megawatts unless Desert Southwest pays for additional
23 something to increase the carrying capacity. Correct?
24 A Yes, that's correct.
25 Q And what might that be? What could be done to
26 increase the carrying capacity of DPV2?
27 A Sure. What -- on the DPV2 line, we have
28 devices on the line called series capacitors. And those

1 tend to be the limiting element for power flow on DPV2.
2 So what Desert Southwest would do would be expand or
3 upgrade those series capacitors to a higher value so it
4 would be able to essentially increase the capacity of
5 DPV2. So it could accommodate our 1200 megawatts plus
6 Desert Southwest. I believe they have 1,140 megawatts.
7 Q So the carrying capacity of DPV2 would be
8 increased to 2340 megawatts?
9 A Yes.
10 Q In the submittal to the ISO, is that
11 the configuration that was described?
12 A Yes, it was.
13 Q So if the joint project is pursued, is another
14 alternative that the carrying capacity would not be
15 expanded by the full amount needed by the Desert
16 Southwest project? Is that alternative being discussed?
17 A No. In -- maybe I need a little
18 clarification.
19 Do you mean that they want to just participate
20 and schedule the power within the existing 1200
21 megawatts of DPV2?
22 Q At one extreme, yes.
23 A No. It would not -- if they're going to
24 schedule within the 1200 megawatts of DPV2, the power
25 will -- the capacity of the project would still be 1200
26 megawatts.
27 Q But is that alternative being discussed with
28 Desert Southwest?

1 A No, it is not. And the reason why is for
2 the 1200 megawatts, we turn that 1200 megawatts over to
3 the California ISO for their operation, and any market
4 participant can go to the ISO and try to schedule within
5 that 1200 megawatts.
6 So that's a condition that is open to any
7 market participant. So we don't need to discuss that as
8 a separate scenario.
9 Q Under the scenario where Desert Southwest pays
10 for series capacitors upgrades to increase the carrying
11 capacity above 1200 megawatts, would that additional
12 capacity increase not be turned over to the ISO?
13 A That is all being negotiated and discussed
14 right now in those negotiations. There's -- Desert
15 Southwest would not want it turned over to the ISO, but
16 it's all being -- part of negotiation.
17 Q And negotiations between or among whom?
18 A Among Desert Southwest and Edison at this
19 point.
20 Q Does Edison have a position regarding whether
21 that additional capacity should be turned over to the
22 ISO?
23 A I -- it's under negotiation. We can't make an
24 opinion on that at this point.
25 MS. MILLER: Your Honor, I would note: We do have
26 a confidentiality agreement with Desert Southwest. So
27 when it's regards the negotiations, we have to get them
28 to release us.

1 Actually -- and I'm not sure that Ms. Cabbell
2 is the person that's conducting the negotiations either.
3 But that's probably what you're alluding to, is that
4 those are under negotiations.
5 ALJ TERKEURST: Well, I'm trying to see the big
6 picture through individual witnesses. But I mean it
7 sounds like, and I'll ask you, Ms. Miller, rather than
8 the individual witness, but it sounds like from what
9 Ms. Cabbell is saying that whatever happens with
10 the Desert Southwest project, there would still be 1200
11 megawatts of power that would be turned over to the ISO,
12 that the Desert Southwest Project would not be using any
13 of that capacity.
14 MS. MILLER: Absolutely right. Correct, your
15 Honor.
16 ALJ TERKEURST: All right.
17 MS. MILLER: That there will absolutely be 1200
18 megawatts that if -- she's laid out a number of
19 scenarios, but the extra costs will be picked up by
20 Desert Southwest, whether they're expanding the capacity
21 or not. I don't want to repeat what she just said. But
22 sort of the big picture is you said it exactly right;
23 there will be 1200 megawatts available capacity.
24 ALJ TERKEURST: Well, it raises an additional
25 question in my mind. If the carrying capacity of
26 the line can be increased to 2340 megawatts by upgrading
27 the series capacitors, is that an alternative that
28 Edison considered for itself as it was designing

1 the project?

2 MS. MILLER: Your Honor, I think Ms. Cabbell can

3 actually address that. That was in her Phase 1

4 testimony, the alternatives that were considered.

5 WITNESS CABBELL: Yes. We did look at varying

6 amounts of transfer capability increase due to DPV2. And

7 we came to 1200 megawatts because we've been focused on

8 Devers and Palo Verde, but you have to remember the west

9 of Devers system would need to be further upgraded, plus

10 we would need other devices put on the system to support

11 even higher power flows, additional static bar

12 compensators. Those are the devices that help maintain

13 voltage during certain contingencies that need to be

14 added to the grid.

15 So yes, we can expand the capacity, but it

16 becomes a crossover point where it really wasn't going

17 to be economical for us as a project. So that's why we

18 zeroed in on the 1200 megawatts and developed

19 the project scope around the 1200 megawatts.

20 Q And if expanding the capacity of above 1200

21 megawatts requires upgrade to west of Devers the Desert

22 Southwest project would fund those?

23 A Yes, they would.

24 Q All right. Thank you.

25 A Mm-hmm.

26 Q Is the WECC looking at the Desert Southwest

27 project?

28 A Not at this point. Once the final arrangement

1 is determined, then that whole project will have to go
2 through the WECC rating process. But we have not
3 initiated any of that yet because we have to finalize
4 what the program is going to be.
5 Q Do you have a sense how long that will take?
6 A That will probably take approximately 12 to 18
7 months.
8 Q Might that delay construction of DPV2?
9 A No. The rating studies can go on during
10 construction of the project. We don't have to wait for
11 the rating studies to be completed before we initiate --
12 before we start construction.
13 Q All right. I know this may be subject to
14 negotiation, but if the joint project is pursued, would
15 Edison retain ownership of the entire line?
16 A That again is part of the negotiations.
17 Q If the joint project is pursued, do you know
18 how that would affect the project costs that would go
19 into the ISO rates?
20 A I do not know.
21 Q This may be a subject for brief, Ms. Miller,
22 how this all fits together for the commission to meet
23 its obligation to determine the -- whatever the statute
24 says the maximum allowable or maximum reasonable cost of
25 the project.
26 MS. MILLER: Yes, your Honor.
27 ALJ TERKEURST: Do you know the statute I'm
28 talking about?

1 MS. MILLER: Yes, I certainly do.

2 But just for clarification -- and again I'd be
3 happy to brief it -- that we would be asking for
4 the cost cap to be setting on the cost estimates we've
5 presented here. And I think what Ms. Cabbell is trying
6 to say as relates to the Desert Southwest Project, we
7 would do that as a separate project, a project if we
8 ever reached agreement, we might, depending on what
9 the project was, be back here. But it's not what we're
10 asking for in this CPCN application. We're not asking
11 for the Desert Southwest Project in this CPCN
12 application so we wouldn't be asking for those costs to
13 be included.

14 Is that what you're referring, alluding to?

15 ALJ TERKEURST: Well, that's the general concept.
16 But there's also the possibility that your costs may go
17 down as a result of the negotiation. That you may talk
18 to Desert Southwest project into picking up some of
19 the costs that, if there weren't a joint project, you
20 would have to bear.

21 MS. MILLER: Right.

22 ALJ TERKEURST: So that the costs cap, to use that
23 term -- and I know PG&E in particular didn't like using
24 that term -- might be too high as submitted in this
25 case.

26 MS. MILLER: I think in Mr. Salzman's testimony,
27 he is saying that Edison would be willing to, if as a
28 result of any of the negotiations that it enters into

1 what the final bid on the project, once we know
2 the scope and the routes and things out to bid, to
3 submit those costs to the Commission as was done
4 I believe in sort of the -- some of the other CPCNs like
5 Jefferson Martin. The Commission gave the utility
6 the opportunity or told them to submit the costs after
7 final engineering was done because there are many
8 complex areas that are still -- routing, environmental
9 mitigation, all discussed in Mr. Salzman's testimony for
10 which we would have better estimates. And that statute
11 does allow for the utility to update those costs.
12 ALJ TERKEURST: No, I understand. I don't feel
13 completely comfortable having the record with as many
14 loose ends as it has. But I know that's the situation
15 we're in, so we move forward.
16 And this may not be for Ms. Cabbell. Does
17 Edison have an indication of how long it's going to take
18 to resolve this issue regarding the Desert Southwest
19 project?
20 MS. MILLER: Your Honor, that would not be
21 Ms. Cabbell. I think that the witness would have been
22 Mr. Tam, but I think he already left. It would be
23 somewhat speculative anyway at this point in time.
24 You might ask Mr. Starck if can he answer
25 the question, but he can speculate.
26 WITNESS STARCK: We're still in negotiation with
27 the Desert. We've submitted to the studies to the Cal
28 ISO that their reviewing work still needs to be done.

1 We're hoping to get this done as quickly as possible,
2 but there's really no estimate as to when it's going to
3 be become resolved.
4 ALJ TERKEURST: All right. I do ask that Edison
5 inform the Commission as soon as it is resolved.
6 MS. MILLER: We would be happy to, of course, your
7 Honor.

19

STATE OF CALIFORNIA ARNOLD SCHWARZENEGGER, *Governor*

PUBLIC UTILITIES COMMISSION
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FILED
10-10-06
01:48 PM

October 10, 2006

Alternate to Agenda ID# 5776
Ratesetting

TO PARTIES OF RECORD IN INVESTIGATION 05-06-041

Enclosed is the Alternate Proposed Decision of President Peevey to the Proposed Decision of Administrative Law Judge (ALJ) TerKeurst previously mailed to you. This cover letter explains the comment and review period and provides a digest of the alternate proposed decision.

When the Commission acts on this agenda item, it may adopt all or part of it as written, amend or modify it, or set aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Public Utilities Code Section 311(e) requires that an alternate to a proposed decision or to a decision subject to subdivision (g) be served on all parties, and be subject to public review and comment prior to a vote of the Commission.

Parties to the proceeding may file comments on the alternate proposed decision as provided in Article 14 of the Commission's **Rules of Practice and Procedure** (Rules), accessible on the Commission's website at www.cpuc.ca.gov. Pursuant to Rule 14.3 opening comments shall not exceed 15 pages.

Comments must be filed either electronically pursuant to Resolution ALJ-188 or with the Commission's Docket Office. Comments should be served on parties to this proceeding in accordance with Rules 1.9 and 1.10. Electronic copies of comments should be sent to ALJ TerKeurst at at cft@cpuc.ca.gov and President Peevey's advisor Nancy Ryan at ner@cpuc.ca.gov. All parties must serve hard copies on the ALJ and the Assigned Commissioner, and for that purpose I suggest hand delivery, overnight mail or other expeditious methods of service. The current service list for this proceeding is available on the Commission's website at www.cpuc.ca.gov.

/s/ ANGELA K. MINKIN
Angela K. Minkin, Chief
Administrative Law Judge

ANG:tcg

Attachment

ATTACHMENT

I.05-06-041: Order Instituting Investigation on the Commission's Own Motion into Methodology for Economic Assessment of Transmission Projects

Pursuant to Pub. Util. Code Sec. 311(e), the digest of the substantive differences between the Proposed Decision (mailed on June 20, 2006) and the Alternate Proposed Decision (mailed on October 10, 2006) is as follows:

The Proposed Decision declines to adopt the proposal of the California Independent System Operator (CAISO) that a rebuttable presumption of economic efficiency be triggered in a certificate of public convenience and necessity (CPCN) proceeding for a proposed transmission project for which the applicant relies on the study underlying a CAISO determination that the proposed transmission project is cost-ffective.

The Alternate Proposed Decision varies from the Proposed Decision in that it provides that, if the CAISO Board makes certain explicit findings, as set forth in the decision, regarding an economic evaluation of the transmission project proposed in a CPCN proceeding, the evaluation shall be granted a rebuttable presumption. This will shift the burden of proof in favor of the CAISO Board-approved economic evaluation such that parties opposing the proposed project will bear the burden of demonstrating either (1) that the CAISO Board-approved economic evaluation does not comply with the principles and minimum requirements adopted in this decision or (2) that the project is not cost-effective. This grant of a rebuttable presumption goes only to the economic evaluation of a proposed project and will have no impact on the Commission's environmental analysis or other factors that the Commission must consider in evaluating a request for a CPCN.

The Alternate Proposed Decision also requires that, if material facts relied upon in a CAISO Board-approved economic evaluation are inaccurate or become outdated, the applicant shall submit additional information and shall provide an explanation of the additional information's impact on the assumptions and conclusions contained in the economic evaluation.

Decision ALTERNATE PROPOSED DECISION OF PRESIDENT PEEVEY
(Mailed 10/10/2006)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion into Methodology for Economic Assessment of Transmission Projects.	Investigation 05-06-041 (Filed June 30, 2005)

(See Attachment B for List of Appearances.)

OPINION ON METHODOLOGY FOR ECONOMIC ASSESSMENT OF TRANSMISSION PROJECTS

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Attachment A – Principles and Minimum Requirements for the Economic Evaluation of Proposed Transmission Projects

Attachment B – List of Appearances

OPINION ON METHODOLOGY FOR ECONOMIC ASSESSMENT OF TRANSMISSION PROJECTS

I. Summary

The Commission opened Investigation (I.) 05-06-041 in order to consider methodologies for the economic assessment of proposed transmission projects. In today's decision, we adopt general principles and minimum requirements and provide other guidance for economic evaluations of proposed transmission projects that may be submitted in Commission certificate of public convenience and necessity (CPCN) proceedings.

The Commission is taking steps to simplify transmission planning and permitting procedures and make them more efficient, both here and in I.05-09-005 and other venues. Our adoption today of principles and minimum requirements that will apply to all economic evaluations of proposed transmission projects, and the creation of a rebuttable presumption in favor of an economic evaluation approved by the California Independent System Operator (CAISO) Board, will complement the Commission's other transmission project streamlining efforts and further the goal of greater coordination and consistency between the Commission and the CAISO.

A threshold issue in this proceeding has been what deference should be given to determinations by the CAISO regarding the cost-effectiveness and need for a transmission project that is proposed for its economic benefits. The CAISO is a critical player in California's efforts to ensure reliability and economic efficiency of the transmission system. The CAISO's work in developing its Transmission Economic Assessment Methodology (TEAM) has advanced the state of the art in economic evaluations of transmission projects. We agree with and adopt many aspects of the CAISO's TEAM approach. Consequently, as

discussed in Section IV of this order, we will establish a rebuttable presumption with regard to economic evaluations in a CPCN proceeding in favor of a CAISO Board-approved economic evaluation provided: (1) the CAISO Board has made certain explicit findings regarding the economic value of the proposed project; (2) the CAISO Board-approved evaluation is consistent with the principles and minimum requirements set forth herein; and (3) the CAISO Board-approved evaluation is submitted to the Commission within sufficient time to be included within the scope of the proceeding. This rebuttable presumption in favor of a CAISO Board-approved economic evaluation shall be such that parties opposing the proposed project in a CPCN proceeding will bear the burden of demonstrating either (1) that the CAISO Board-approved economic evaluation does not comply with the principles and minimum requirements of this decision or (2) that the project is not cost-effective.

Notwithstanding the foregoing, a CAISO determination of economic value is not a prerequisite to obtaining a CPCN and an applicant retains the right to propose its own economic evaluation. However, we do not grant a rebuttable presumption to an evaluation not approved by the CAISO Board, and any evaluation submitted in a CPCN proceeding shall comply with the requirements of this decision. Further, an applicant shall submit any CAISO economic evaluation of the proposed project into the record of the proceeding.

Another significant issue in this proceeding has been how prescriptive the Commission should be regarding the imposition of standards for economic evaluations submitted in CPCN proceedings. We agree with the consensus among the parties that Commission requirements regarding economic evaluations of transmission projects should not be overly prescriptive, but we also believe such requirements should be sufficient to ensure consistency among

and transparency in economic evaluations submitted in CPCN proceedings. Thus, today we adopt general principles and provide guidance to establish a framework for all economic evaluations submitted in CPCN proceedings. The adopted principles, along with minimum requirements for economic evaluations, are appended as Attachment A to this order, and can be summarized as follows:

1. The CAISO's standardized benefit-cost methodology shall be used to measure the economic benefits of proposed transmission projects. The perspective of CAISO ratepayers is of primary importance in a CPCN proceeding, although there is value in reviewing benefit-cost results from other perspectives as well.
2. The CAISO's framework for the computation of potential energy benefits shall be used. Parties shall assess energy benefits using established, credible, and commercially available production cost modeling tools. The applicant may decide whether to include market power mitigation benefits as part of its demonstration of need for a proposed transmission project.
3. In addition to energy benefits, other economic effects of a transmission project may be considered, including economic effects that may not be quantifiable.
4. Economic evaluations shall consider how uncertainty about future system and market conditions affects the likelihood that a transmission project's forecasted benefits will be realized.
5. Economic evaluations shall use baseline resource plans and assumptions about the system outside the applicant's service territory that are consistent with resource plans and system assumptions used in procurement or other recent Commission proceedings, updated as appropriate.
6. Economic evaluations shall consider feasible resource alternatives to the proposed transmission project.

II. Background

This investigation has been coordinated with Phase 1 of Application (A.) 05-04-015, the application of Southern California Edison Company (SCE) for a CPCN to construct the Devers-Palo Verde No. 2 (DPV2) transmission project, a proposed 230-mile, 500 kilovolt alternating current transmission line between California and Arizona. DPV2 would connect SCE's existing Devers substation near Palm Springs, California to the existing Harquahala Generating Company switchyard located approximately 49 miles west of Phoenix, Arizona.

On June 30, 2005, the Commission opened I.05-06-041 to consider appropriate principles and methodologies for assessment of the economic benefits of transmission projects, including DPV2, that are submitted for Commission approval. The Commission named SCE, Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E) as Respondents to the investigation. As established in the Order Instituting Investigation (OII), the Commission wished to consider, in particular, the CAISO TEAM approach to economic evaluation of transmission projects, both as an evaluative framework and as applied to assess the economic benefits of the DPV2 project. The OII provided that issues then under consideration in I.00-11-001 regarding the methodology for assessment of the economic benefits of transmission projects were subsumed in I.05-06-041, and that the record on these issues developed in I.00-11-001 would be fully available for consideration in I.05-04-061.

A prehearing conference was held in A.05-04-015 and I.05-06-041 on July 20, 2005. The Assigned Commissioner issued the scoping memo for the two proceedings on August 26, 2005. The scoping memo categorized I.05-06-041 as ratesetting and stated that hearings were necessary. The scoping memo also

provided that evidence regarding DPV2 would be received in two phases. Phase 1 would address need issues and the economic methodology used to assess cost effectiveness on a coordinated basis for A.05-04-015 and I.05-06-041. Phase 2, in A.05-04-015 only, is underway to address environmental, routing, updated cost estimates, and other issues related specifically to DPV2. The Commission plans to rule on SCE's CPCN request for authorization to construct DPV2 by the end of 2006. In that decision, we will consider Phase 1 evidence regarding the cost-effectiveness of DPV2 in addition to other CPCN issues considered in Phase 2.

Among other issues in I.05-06-041, the Commission planned to address validation of and reliance on CAISO assessments of need in Commission proceedings. Parties discussed this issue, among others, at a joint workshop held on September 14 – 15, 2005. Based on workshop discussions, a September 27, 2005 Administrative Law Judge (ALJ) ruling determined that a complete validation of the CAISO's TEAM approach should not be pursued at this time. The ALJ ruling established that Phase 1 would address the following issues related to I.05-06-041, in addition to issues related to the need for the DPV2 transmission project under consideration in A.05-04-015:

1. What general principles or methodologies should the Commission employ in assessing the economic benefits of transmission projects within its jurisdiction?
2. Is the CAISO's TEAM approach, as applied to Path 26 and to DPV2, consistent with such general principles or methodologies?
3. Are the following procedures a reasonable approach at this time for the Commission's assessment of the economic benefits of transmission projects?

a. In I.05-06-041, the Commission would adopt principles, a framework for decision-making, and criteria for the economic analysis of transmission lines.

b. In subsequent certificate proceedings, the Commission would evaluate whether the CAISO, in evaluating the economic value for the proposed project, has followed the guidance provided by the Commission in a reasonable manner.

c. If so, the Commission would adopt the CAISO's economic determination, so that the outcomes at the CAISO and the Commission would be consistent.

4. After the Commission adopts general principles or methodologies for assessing the economic benefits of transmission projects, how should the Commission evaluate in a certification proceeding whether the CAISO, in evaluating the cost-effectiveness of the proposed project, has followed the guidance provided by the Commission in a reasonable manner?

5. If the Commission determines in a certification proceeding for a transmission project proposed for its economic benefits that a CAISO assessment of need has followed the guidance provided by the Commission in a reasonable manner, are there additional requirements that must be met in the Commission's determination of economic benefits and need for the project?

6. For those certification proceedings for transmission projects proposed for economic benefits where there is no CAISO assessment of need that the Commission has found to be reasonable and consistent with guidance provided in this investigation, what requirements should the Commission adopt for consideration of economic benefits and need?

We agree with the September 27, 2005 ALJ ruling that consideration of these issues in I.05-06-041, in the context of assessment of need for DPV2, should further the Commission's goal of streamlining transmission planning and help ensure consistency in Commission and CAISO results.

As provided in the September 27, 2005 ALJ ruling, parties filed comments and reply comments on Phase 1 issues. An ALJ ruling dated October 28, 2005 provided further guidance regarding the scope of Phase 1 testimony and evidentiary hearings.

Three days of evidentiary hearings were held in Phase 1 on January 10–12, 2006. The following parties filed opening briefs: the CAISO, SCE, PG&E, SDG&E, Division of Ratepayer Advocates (DRA), The Utility Reform Network (TURN), Bay Area Municipal Transmission Group (BAMx),[1] and Global Energy Decisions, Inc. (Global Energy). All of these parties except BAMx also filed reply briefs. Following the receipt of late-filed exhibits and opening and reply briefs, Phase 1 was submitted on March 24, 2006. No party requested final oral argument before the Commission on Phase 1 issues in its opening brief, as allowed by the scoping memo.

III. Overview of Positions of the Parties

To assist our consideration of the proper principles and methodologies for evaluating the economic benefits of proposed transmission projects, we have the benefit of the Phase 1 record containing four project-specific economic evaluations: the CAISO's evaluation using the TEAM approach of a possible Path 26 upgrade, submitted originally in I.00-11-001, and three separate economic evaluations of the DPV2 project submitted by the CAISO, SCE, and DRA. All parties submitted testimony and took positions regarding the submitted economic evaluations and related issues.

[1] BAMx is an unincorporated association of publicly owned utilities located in the Greater Bay Area. Members include the City of Santa Clara, Alameda Power and Telecom, and City of Palo Alto Utilities.

In today's order, we describe in some detail the principles and methodologies used in each of the four economic evaluations because they assist in our determinations regarding how best to analyze the economic benefits of a proposed transmission project. We provide an overview of the positions of the parties regarding the principles and methodologies for economic evaluations of proposed transmission projects and the manner in which the Commission should consider such evaluations in CPCN proceedings. We then address individual issues.

A. CAISO

The CAISO has been developing its TEAM approach for several years. At the direction of the ALJ in I.00-11-001, the CAISO submitted a report in June 2004 describing the CAISO's TEAM approach and its application to a potential project to upgrade the transmission path between central and southern California, which is commonly called Path 26 (June 2004 Report, which is Attachment 1 to Exhibit 11 in the Phase 1 record). In the June 2004 Report, the CAISO explained that the Path 26 study provided an opportunity to evaluate its TEAM approach in a realistic situation and to gain experience regarding areas for further enhancements. The CAISO concluded that additional refinements to TEAM would be needed to reach a definite conclusion regarding whether a Path 26 upgrade would be economically viable.

In analyzing the DPV2 project proposed by SCE, the CAISO made certain refinements to its TEAM approach. The CAISO has approved the proposed DPV2 project as economically needed.

The CAISO considers five aspects of its methodology, which it calls key principles, to be necessary to any economic evaluation of a proposed

transmission project. While described in more detail in Section V, in summary, the CAISO's key principles include the following:

1. Benefit framework: utilization of a standardized benefit-cost methodology to measure transmission expansion benefits regionally and separately for consumers, producers, and transmission owners.
2. Network representation: measurement of energy benefits using a network model that reflects physical constraints of the transmission grid and forecasts nodal prices.
3. Market prices: measurement of energy benefits using a methodology that forecasts market prices by simulating producer bid strategies, to assess consumer benefits from reduced supplier market power.
4. Uncertainty: assessment of the impact of uncertainty about future market conditions through analysis of a representative set of market scenarios, with assignment of weighting factors (relative probabilities) to the different scenarios so that the expected benefit and range of benefits can be determined.
5. Resource alternatives: identification and consideration of alternative generation, demand-side management, and transmission investment decisions.

In addition to these mandatory key principles, the CAISO described several other TEAM attributes that it considers to be either requirements or recommendations for economic evaluations of proposed transmission projects.

The CAISO urges the Commission to adopt TEAM's key principles as the minimum requirements in any economic evaluation of a proposed transmission project. The CAISO recommends that the Commission determine that in a CPCN proceeding considering a proposed transmission project that the CAISO has already found to be cost effective, a project proponent may rely on the study underlying the CAISO's determination to trigger a rebuttable presumption that the project is cost-effective. In the CAISO's proposal, this

rebuttable presumption would oblige an opposing party to demonstrate either that the project is not economic or that other factors in Public Utilities Code Sections (§§) 1001 and 1002[2] compel or warrant denial of the CPCN. The CAISO submits that adoption of a rebuttable presumption standard is warranted because of the public policy benefits of streamlining infrastructure development and creating greater coordination between Commission and CAISO processes.

The CAISO cites its statutory responsibilities under §§ 334 and 335 and argues that the ability to identify economic transmission projects is an integral part of its responsibility under § 345 to ensure the efficient use of the transmission grid.

Much of the CAISO's description of the TEAM approach is contained in the June 2004 Report, which applies the methodology to the potential Path 26 upgrade. In assessing TEAM, we rely on the detailed description of TEAM in the June 2004 report and on the CAISO's evaluation of DPV2, since that is the state-of-the-art application of the TEAM approach.

To evaluate potential energy benefits of DPV2 (and also Path 26), the CAISO used the PLEXOS DC Optimal Power Flow (DC-OPF) network model. We address system modeling issues in Section V.B.1 of this order. To forecast the amount by which market prices may be bid above system marginal costs, the CAISO used statistical relationships it found historically between price markups above cost and two measurements of system supply and demand conditions, as described in more detail in Section V.B.2.

[2] All references to statutory Sections refer to the Public Utilities Code.

As described in Section V.B.5, the CAISO analyzed the effects of uncertainty on the energy benefits of DPV2 by undertaking 17 system simulations using combinations of variations in load growth, hydro conditions, gas prices, and the degree of market power exhibited in producers' bids. The CAISO also analyzed several contingency scenarios representing extreme events for which it did not assign probabilities and whose results it did not include in the calculated benefit-cost ratios.

The CAISO modeled the energy system throughout the Western Electricity Coordinating Council (WECC) region with and without DPV2 in two years: 2008 and 2013. In calculating benefit-cost ratios for DPV2, the CAISO assumed that the energy benefits it found for 2013 would continue with a 1% real (adjusted for inflation) annual escalation rate through 2057.

In addition to energy benefits, the CAISO quantified and included in the benefit-cost ratios certain non-energy benefits of the DPV2 upgrade.

B. SCE

SCE agrees with the concept of adopting general principles to guide the economic evaluation of proposed transmission projects in CPCN proceedings. SCE emphasizes its view, however, that whatever guidance the Commission provides should not include any requirement that parties use a specific type of computer model or database, or that they forecast the effect of the proposed transmission project on producers' ability to wield market power.

SCE states that, under § 1003, the applicant has the burden of demonstrating in a certificate proceeding that the proposed project is, or will be, required for the public convenience and necessity. SCE is concerned that, in considering the CAISO's proposal to create a rebuttable presumption, the parties confuse the burden of proof with the burden of producing evidence. SCE states

that the applicant in a CPCN proceeding always has the burden of proving that its proposed project is reasonable, and also the burden of producing evidence that supports its request.

SCE is concerned that emphasizing the CAISO's economic evaluation of the need for a project in a certificate proceeding may confuse the CAISO's role with that of the utility applicant. SCE emphasizes its view that the utility applicant must have the ability to choose how best to meet its burden of proof and that the applicant can choose whether to rely on the CAISO's evaluation. SCE suggests that the Commission adopt a modification of the fourth principle that DRA recommends (see Section III.C below) as follows:

> The applicant is responsible for its showing and justification before the Commission. If the CAISO has determined that a project is needed, the applicant should present that fact and may use the CAISO assessment to help it meet its burden of proof. The CAISO is encouraged, but not required, to participate in Commission licensing proceedings.

SCE forecasted DPV2's impact on energy costs using the Global Energy (formerly Henwood) transportation model. SCE studied the period from June 1, 2009—the proposed energization date for DPV2—through December 31, 2015. SCE assumed that estimated 2015 energy benefits would continue at the same level in real terms through 2055, i.e., escalated each year only by inflation. To assess DPV2's benefits over a wide range of load forecasts, natural gas prices, and available hydroelectric generation, SCE utilized stochastic tools (described in more detail in Section V.B.4) to perform 100 simulations, with load forecasts, gas prices, and hydro levels chosen stochastically.

In addition to energy benefits, SCE quantified and included in its benefit-cost analysis the amount by which it expects third-party transmission

revenues to increase with the addition of DPV2, due to the increased revenue requirement used to develop rates for CAISO wheeling service and Existing Transmission Contracts.

C. DRA

DRA recommends that the Commission focus on general principles used to evaluate the economic value of a proposed transmission project, and allow applicants to determine how to apply the adopted principles, subject to Commission scrutiny on a case-by-case basis.

DRA recommends adoption of four principles, which can be summarized as follows:

1. Assessment of energy benefits. Energy benefits should be assessed using an established, credible, and commercially-available production cost modeling tool. Computer model access requirements of §§ 1821 and 1822 should be met consistent with Commission Rules regarding access to computer models,[3] or reasonable alternative computer model access rules may be established on a case-by-case basis.
2. Input assumptions and uncertainty analysis. The applicant should rely on input assumptions developed for the State's most recent major resource planning proceeding. In addition to a base case, uncertainty analyses are appropriate based on alternative assumptions about key variables.
3. Analysis of alternative resource options. The applicant should prepare economic assessments of a variety of resource alternatives to the proposed transmission project, including, but not limited to, other transmission projects, generation projects, demand-side options, and distributed generation.

[3] Cites to Rules refer to the Commission's Rules of Practice and Procedure. The Commission's prior Rules regarding access to computer models have been superseded by new Rules 10.3 and 10.4, effective September 13, 2006.

4. Responsibility of the applicant. The applicant is responsible for its showing and justification before the Commission. The applicant is encouraged, but not required, to coordinate its assessment of the proposed transmission project with the CAISO's assessment of the project.

DRA states that the CAISO's TEAM approach is generally consistent with the four principles DRA recommends, but that the CAISO over-prescribes methodologies to implement the principles, in particular, its requirement that a full network model be used.

DRA opposes the CAISO's recommendation that economic analyses performed by or otherwise found acceptable by the CAISO for its own purposes be granted a rebuttable presumption of reasonableness in Commission CPCN proceedings. DRA argues that the CAISO's rebuttable presumption proposal is inconsistent with the Commission's statutory mandates under §§ 1001 and 1003 and the historical use of rebuttable presumptions. DRA maintains that the CAISO's analysis and findings should be treated like any other facts presented to the Commission and should be accorded the appropriate weight due any evidence that has been tested through the hearing process.

Like SCE, DRA used the Global Energy transportation model for its economic assessments of DPV2. DRA based its modeling of DPV2's potential energy benefits on SCE's analysis, with modifications as DRA deemed appropriate. While SCE performed stochastic analyses, DRA developed a deterministic reference case and several additional market simulations to evaluate DPV2.

To assess the impact of "forecast risk," DRA developed an Uncertainty Margin method to quantify the level of forecast risk that can be accepted. DRA also proposes what it calls a tipping point analysis, in which parties identify

which parameters, assumptions, or relationships drive the conclusions of their economic evaluations.

D. PG&E

PG&E cautions that the Commission should minimize the need for continuing reassessment of principles and criteria endorsed in this proceeding by focusing on general principles rather than particular models or assumptions.

PG&E's view is that, if the CAISO employs general principles articulated by the Commission, the Commission should defer in a CPCN proceeding to the CAISO's finding of need. PG&E argues that pursuant to §§ 334 and 345 and the CAISO's tariff approved by the Federal Energy Regulatory Commission, the CAISO is responsible for determining which transmission projects are needed within its control area. PG&E asserts that, consistent with the CAISO's tariff, the CAISO has the authority to compel construction of transmission upgrades it determines to be needed, subject to right of appeal. PG&E recommends that the Commission adopt the three-step procedural framework identified in Issue 3 in the September 27, 2005 ALJ ruling, on the basis that these procedures would reduce the threat of inconsistent results and would expedite the siting process for proposed transmission projects.

PG&E recommends that Commission consideration of project need issues be limited to verifying that the CAISO applied Commission-recommended principles, and that the Commission not review the merits of the CAISO's analysis unless the CAISO failed to apply one or more of the Commission-recommended principles. PG&E would also support the solution developed by the CAISO of creating a rebuttable presumption, if needed to address legal concerns raised by granting full deference to a CAISO need determination. PG&E submits that such an approach provides more than adequate safeguards

for intervenors in CPCN cases, is consistent with the CAISO's authority over transmission planning, and is well within the Commission's authority to adopt.

Regarding specific guidelines, PG&E generally supports the principles recommended by the CAISO, but takes issue with the CAISO's proposal that use of a network model be required.

E. SDG&E

SDG&E states that the Commission should defer to CAISO need determinations, giving them a rebuttable presumption of validity. In SDG&E's view, if the CAISO follows principles and an analytical framework adopted by the Commission in a reasonable manner, the Commission should adopt the CAISO's need determinations.

SDG&E disagrees with some of the more prescriptive recommendations of the CAISO, in particular its network model requirement and its suggestion that the Seams Steering Group – Western Interconnection (SSG-WI) database be used. SDG&E acknowledges possible complications regarding access limitations to models and databases the CAISO may use, but submits that the Commission must accept these access limitations in order to grant deference to the CAISO need determinations. SDG&E acknowledges that Commission deference to the CAISO may not be appropriate if the Commission wishes to consider a broader range of generation and demand-side alternatives than the CAISO evaluates. SDG&E also cites transmission needed to attain renewable resource goals as a situation where the Commission may approve a proposed transmission project even if the CAISO found it was not needed.

F. TURN

TURN supports Commission endorsement of the CAISO's proposed benefits framework, but recommends that the Commission not endorse the other

elements of TEAM at this time. TURN submits that methods for economic evaluation of proposed transmission projects are still evolving and, it contends, there is no need to halt that evolution by locking into one specific approach.

TURN believes that the three-step procedures identified in Issue 3 in the September 27, 2005 ALJ ruling "move much too far and too fast." TURN believes that the first step, in which the Commission would adopt principles, a framework for decision-making, and criteria for the economic evaluation of transmission lines, is as far as the Commission should go at this time. TURN recommends that the Commission evaluate in CPCN proceedings whether each party has followed any adopted guidelines or has made a reasonable case for modifying those guidelines. TURN opposes any special deference to the CAISO's determination of economic value, citing both legal and practical reasons, including that the CAISO is a private corporation rather than a governmental agency, and that the CAISO does not conduct a public process in which its assumptions and model inputs can be tested and ratepayer concerns fully aired.

TURN argues that the Commission should continue to hear from all parties in CPCN proceedings and should continue to make its decisions based on the overall weight of the evidence. TURN emphasizes its views that the applicant has the burden of proving that its proposed project has economic benefits for ratepayers and that shifting this burden would be inappropriate.

TURN maintains that the TEAM approach, while a valuable work product, is not specific enough to allow the Commission to defer to any one party's proposed implementation of the methodology. TURN maintains that two different parties could undertake analyses consistent with the overall TEAM framework but still reach different conclusions regarding the economics of a

particular project, and that those differences would still need to be examined in a regulatory process.

Regarding the perceived need to shorten the approval process for proposed transmission projects, TURN points out that there is no requirement that a utility present a proposed transmission project to the CAISO first and gain its approval prior to filing a CPCN application. TURN suggests instead that the CAISO and Commission could conduct their analyses in parallel as a way to speed approval of worthy transmission projects.

G. Global Energy

Global Energy does not support the three-step procedures identified in Issue 3 in the September 27, 2005 ALJ ruling. It argues that deference to the CAISO could deprive the Commission of hearing the recommendations and analyses of the applicant and other parties and, since the CAISO does not hold hearings, could deprive parties of a reasonable opportunity to participate in the project evaluation. Global Energy comments that, in order for a more deferential approach to be reasonable, the Commission would have to be highly prescriptive in identifying the principles to be used and the framework and criteria for decision-making. Global Energy asserts that such a prescriptive approach is not practicable now and could quickly become outdated. Global Energy suggests instead that the Commission adopt general guidelines, principles, and methodologies for use by all parties.

Global Energy argues that the type of network model used by the CAISO does not provide what it calls a "true" DC-OPF analysis and is less acceptable than a transportation model such as the one used by SCE and DRA. Global Energy suggests that the Commission provide guidance that, for proposed transmission projects above a specific dollar threshold (e.g., if the

project is expected to cost $500 million or more), parties must perform a more accurate AC-OPF analysis. For smaller projects, Global Energy recommends that the Commission allow a DC-OPF analysis using variable shift factors and with the modeling of non-linear elements such as DC lines, and also allow transportation models if computational experiments show that little bias results from using such models.

H. BAMx

BAMx supports the CAISO's TEAM approach as a useful analytical framework for the economic evaluation of proposed transmission projects. BAMx suggests that the Commission adopt certain elements of the TEAM principles as "safe harbor" principles, with studies in compliance with the adopted principles accorded greater weight in a determination of project need. In particular, BAMx recommends that the Commission give preference to use of a network model and the SSG-WI database. BAMx suggests that the costs of new entry, that is, capacity values, need to be developed to assess project benefits.

IV. Consideration of Economic Benefits in Transmission Project CPCN Proceedings

A. The Need for General Principles and Guidance

In Decision (D.) 01-10-070 issued in I.00-11-001, the Commission recognized that, in a restructured electricity market, traditional methods are inadequate for assessing the economic benefits of proposed transmission projects. At the Commission's request, the CAISO began to develop a generic methodology and analytical tools for economic evaluations of proposed transmission projects in dynamic market conditions. In developing its TEAM approach, the CAISO has made substantial contributions to advancing the art of transmission economic analysis.

Nevertheless, as discussed below in Section V, substantial concerns remain regarding the ability to model aspects of the increasingly complex inter-regional transmission and generation system that serves far-flung geographic areas with different market structures. We are confident that continued developments in system modeling capabilities will allow more accurate estimates of production costs, and that computer advances will reduce processing times and thus allow more refined uncertainty analyses. Any detailed requirements and criteria that we could adopt at this time would need to be revisited and updated as the state of the art in economic assessment progresses.

Transmission projects may be proposed in various configurations and sizes and for various economic purposes, such as inter-regional bulk power transfers, congestion relief, or to meet other intra-regional needs. The wide range of transmission projects that may be proposed for economic reasons would further complicate any efforts to adopt detailed study requirements applicable to them all.

As long as the adopted principles and minimum requirements for economic evaluations are met, there may be value in having economic analyses in CPCN proceedings undertaken using multiple approaches. As an example, both network models and transportation models have strengths and weaknesses, as we discuss in Section V.B.1. Analyses using both approaches may be complementary in some respects and thus provide stronger underpinnings for our need determinations.

For these reasons, we focus on general principles rather than overly prescriptive directives to reduce the need for continuing reassessment of the guidance we adopt today. The minimum requirements will help ensure that

economic evaluations are undertaken consistent with the general principles and guidance provided in today's decision. A common goal of many of the minimum requirements is that each party should explain and justify its study design and should report results in a manner that facilitates understanding of its economic evaluation and comparison with evaluations that may be submitted by other parties.

B. The Role of CAISO Economic Evaluations in Commission CPCN Proceedings

The CAISO, PG&E, and SDG&E assert that the CAISO has primary jurisdiction over need determinations. The Commission has considered similar arguments previously, and has repeatedly affirmed our jurisdiction and statutory responsibility to assess need in a certificate proceeding. (See D.03-05-038; see also D.02-10-065, D.02-10-066, D.01-05-059, and D.01-10-029. See also D.99-09-028 regarding the general issue of transmission jurisdiction.) We see no need to revisit this issue at this time. As we summarized previously:

> [D]eference that consists of adopting the [CA]ISO's need assessment without conducting an independent review cannot substitute for our mandate to consider need for the project under Section 1001. (D.03-05-038, *mimeo.* at 12.)

The CAISO's proposal that its economic evaluations be granted a rebuttable presumption of reasonableness arguably does not reach the level of deference rejected in D.03-05-038. Under the procedures recommended by the CAISO, parties would have the opportunity to challenge the CAISO's findings in the Commission's CPCN proceeding and to introduce evidence to attempt to persuade the Commission that it should not adopt a CAISO need determination.

The Commission has long held that the applicant carries the burden of proof in a certification proceeding, and we reiterate those determinations today. At the same time, we recognize the CAISO's work in the area of economic evaluations and its role in transmission planning.[4] Consequently, provided certain safeguards to protect the public interest and our statutory mandates are met, we conclude it is appropriate to establish a rebuttable presumption regarding economic value in CPCN proceedings in favor of an economic evaluation approved by the CAISO Board and submitted in a CPCN proceeding. This rebuttable presumption in favor of a CAISO Board-approved economic evaluation shall be such that parties opposing the proposed project in a CPCN proceeding will bear the burden of demonstrating either (1) that the CAISO Board-approved economic evaluation does not comply with the principles and minimum requirements of this decision or (2) that the project is not cost-effective.

The safeguards are as follows:

First, in order to be accorded a rebuttable presumption, the CAISO Board must make the following findings with regard to the economic evaluation:

1. That the CAISO process has met the following public participation requirements:
   a. The CAISO has sponsored at least two meetings open to the public with opportunity for public comment both at the meeting and following the meeting, including: (1) an initial meeting, which occurs sufficiently early in the CAISO's assessment process to provide an opportunity to discuss the scope of the proposed economic assessment, including identification of the base case

[4] *See, e.g.,* AB 974 (2006) (An act to add Chapter 3 (commencing with Section 3260) to Part 4 of Division 1 of the Public Utilities Code, relating to electricity).

and other relevant assumptions, as well as resource alternatives and (2) a second meeting to take public comment on the draft economic evaluation prior to its submission to the CAISO Board.

   b. The final economic evaluation ("Final Evaluation") that is submitted to the CAISO Board includes reasoned responses to all public comments by explaining how the comment was addressed in the Final Evaluation, either through incorporation in full, modification, or rejection, and the reasons therefore.
   c. The public participation process has provided interested parties with sufficient time and opportunity (including sufficient access to information) to adequately review and comment on the Draft Evaluation.
2. That the Final Evaluation meets all of the requirements of this decision, as it may be amended by future Commission decisions, including the Principles and Minimum Requirements for the Economic Evaluation of Proposed Transmission Projects set forth as Attachment A to this decision.
3. That the Final Evaluation determines that the proposed project promotes economic efficiency in that it constitutes a cost effective upgrade to the CAISO Controlled Grid based on clearly defined information, assumptions, and weighting or combination of the relevant benefit-cost ratios and other economic criteria, including (but not limited to) difficult to quantify economic benefits, such as system operational benefits.

Second, in order to ensure that the parties to the CPCN proceeding have adequate notice of the role of the CAISO Board-approved economic evaluation and adequate time to prepare any case challenging it, and to avoid delays in the proceeding, the CAISO Board-approved evaluation must be submitted to the Commission within sufficient time to include it in the scope of the proceeding.

Third, to the extent that material facts relied upon in the CAISO Board-approved economic evaluation are inaccurate or become outdated, the applicant shall submit additional information and shall provide an explanation of the

additional information's impact on the assumptions and conclusions contained in the evaluation.

Notwithstanding the foregoing, a CAISO determination of economic value is not a prerequisite to obtaining a CPCN and an applicant retains the right to rely upon its own economic evaluation. However, a rebuttable presumption will not apply to an evaluation not approved by the CAISO Board, and any alternative economic evaluation submitted in a CPCN proceeding shall comply with the principles and minimum requirements of this decision. Further, an applicant shall submit any CAISO economic evaluation of the proposed project into the record of the proceeding.

This grant of a rebuttable presumption goes only to the economic evaluation of a proposed project and will have no impact on the Commission's environmental analysis or other factors that the Commission must consider in evaluating a request for a CPCN. Pursuant to its statutory obligations, the Commission will continue to consider and weigh all relevant factors in reaching a decision on a CPCN application. Thus, for example, a rebuttable presumption regarding project economics will not shift the burden of proof on environmental issues, nor require or mandate the Commission to make any finding of overriding considerations pursuant to Section 15093 of the Guidelines for the Implementation of the California Environmental Quality Act[5] in favor of the project (or in favor of any alternatives identified in the environmental impact report) if the project (or any environmentally preferred alternative) would have unavoidable adverse environmental impacts. Additionally, as the CAISO's

[5] See, Title 14, Chapter 3 of the Code of California Regulations.

comments recognized, factors addressed in §§ 1001 and 1002 may compel denial of a CPCN, notwithstanding a project's economic benefits.

Finally, to prevent delays and/or confusion with regard to pending CPCN proceedings, the rebuttable presumption granted in this decision will not apply to CPCN applications filed with the Commission prior to the effective date of this decision unless the economic analysis complies with the safeguards and requirements of this decision and the assigned commissioner of a pending transmission proceeding issues a ruling that explicitly elects to apply it to that application.

C. The Impact and Application of General Principles

Our adoption today of general principles and guidance regarding economic evaluations of proposed transmission projects, and the creation of a rebuttable presumption in favor of a CAISO Board-approved economic evaluation will further the goal of greater coordination and consistency between the Commission and the CAISO. The adopted principles and minimum requirements should be useful to project proponents, the CAISO, and other parties who may participate both in the CAISO review and in CPCN proceedings before the Commission by providing consistency and transparency across the two forums. Among other things, if CAISO review precedes Commission review of a proposed project, an applicant's experience in defending its project evaluation during the CAISO process should narrow issues and streamline the process in the CPCN proceeding here.

The principles we adopt are applicable to transmission projects proposed wholly or partly on the basis of their expected economic benefits. We recognize that it may be appropriate to tailor the application of these general

principles to the particular project before us. As the CAISO notes, the level of analysis required for inter-regional economic projects may be the most substantial and the analysis needed for intra-regional economic projects may be considerably less complex, particularly if the economic impact is limited primarily to a single area. The Assigned Commissioner or assigned ALJ in a CPCN proceeding may allow parties to deviate from the adopted minimum requirements for economic evaluations with good cause shown, taking case-specific conditions into account, and may impose additional requirements as warranted.

Some transmission projects may be proposed only in part on the basis of economic benefits, and may be expected to have significant other benefits such as enhanced reliability or the ability to deliver power from renewables in furtherance of California's Renewables Portfolio Standard Program (RPS) goals.[6] The principles adopted in today's decision will be applicable in such instances, but we will also consider the other possible benefits in making an overall need determination. Even for a proposed transmission project with significant non-economic benefits, a rigorous economic analysis may be needed, for example, if other projects with different economic benefits could also meet the project's objectives.

Finally, we agree with SCE's suggestion that the applicant in a CPCN proceeding should inform the Commission of a CAISO evaluation of its proposed project, even if it disputes some or all of the CAISO analysis. As discussed above, to the extent it agrees with a CAISO evaluation, the applicant

[6] See §§ 387, 390.1, 299.25, and 399.11, et seq.

may use the CAISO assessment to help meet its burden of proof. We continue to encourage the CAISO to participate actively in our CPCN proceedings.

D. Future Commission Action

Because the state of the art in economic evaluations of proposed transmission projects continues to evolve, it is not clear that further investigation at this time aimed at refining the principles and minimum requirements we adopt today would be warranted. Instead, we anticipate that the Commission will assess the applicability of the adopted principles and guidance in the context of individual CPCN applications, as the need arises. As a result, with the adoption of today's decision we close I.05-06-041.

Notwithstanding the case-study emphasis on the DPV2 project in today's order, we do not determine, at this time, the economic value of that project. We will resolve that question in our later decision in A.05-04-015 addressing SCE's CPCN request. At that time, we will consider all of the relevant factors that affect the cost-effectiveness of DPV2, including issues such as fuel cost and load forecasts that we do not address today. We will assess the parties' economic evaluations of DPV2 on their merits, recognizing that our guidance adopted today in I.05-06-041 was not available when the evaluations were prepared.

V. Principles for Assessment of Economic Benefits of Transmission Lines

Benefits of a proposed transmission project can be evaluated by comparing estimates of total costs that would be incurred without the proposed project and total costs if the proposed project is built. Such comparisons include assumptions about the resource mix, which may differ in the scenarios with and without the proposed project.

In addition to base case (most likely) scenarios, the effects of possible variations in key factors of the analysis, e.g., load growth or fuel prices, also should be considered in assessing likely economic benefits of a proposed project. Identification and consideration of alternative cases or scenarios as a means of addressing uncertainty is addressed in Section V.B.4.

In economic evaluations of proposed transmission projects, there are three general categories of costs and benefits: (1) the change in total production costs, or energy benefits, (2) changes in other quantifiable economic benefits and costs not included in production cost analyses, and (3) factors whose expected economic effects cannot be monetized. These three types of costs and benefits are addressed in Sections V.B, V.C, and V.D, respectively.

A. Benefit Perspectives

In evaluating a proposed transmission project, assessment of the distribution of potential benefits and costs among geographic areas and among various types of market participants is important. Because of the interconnected nature of the Western electricity system, the relevant geographic region affected by a proposed transmission project may be much larger than the CAISO control area, particularly if the project is an inter-regional upgrade such as DPV2.

All four economic evaluations submitted in this proceeding determined energy benefits based upon production cost modeling of the entire WECC area. However, parties generally recommend that any Commission-approved methodology rely primarily upon the economic impacts on CAISO ratepayers—rather than WECC-wide economic impacts—in determining whether to grant a CPCN.

In its June 2004 report, the CAISO described the importance of the various perspectives as follows:

> A critical policy question is which perspective should be used to evaluate projects. The answer depends on the viewpoint of the entity the network is operated to benefit. If the network is operated to maximize benefit to ratepayers who have paid for the network, then some may consider the appropriate test to be the ratepayer perspective. Others say this may be a short-term view, which does not match the long-term nature of the transmission investment. In the long run, it may be both the health of utility-owned generation and private supply which is needed to maximize benefits to ratepayers. Advocates of this view claim that the network is operated to benefit all California market participants (or for society in general) and, therefore, the CAISO participant or Western Electricity Coordinating Council "WECC" perspectives of benefits may be the relevant test.

If a benefit-cost ratio is greater than 1.0 for one perspective but less than 1.0 for another perspective, the proposed transmission project may transfer benefits from one region or stakeholder group to another.

The CAISO describes that quantifiable benefits of proposed transmission expansions can be evaluated from various perspectives, and describes three particular perspectives: the WECC or Societal perspective, the CAISO Ratepayer perspective, and the CAISO Participant perspective. Benefit-cost ratios can be calculated for other perspectives as well, e.g., for other geographic regions such as the Southwest or the Northwest, or other groups of market participants such as non-utility generators or municipal utilities.

The WECC or Societal perspective takes into consideration all market participants in the WECC area. It identifies the net benefit to all consumers (or their load serving entities), producers, and transmission owners or holders of transmission rights in the WECC region. The CAISO describes two versions of the Societal benefit-cost test. The basic Societal test includes all producer revenues, whereas what the CAISO calls the Modified Societal test includes only

the portion of producer profits derived from competitive prices, and excludes additional producer net revenue obtained from uncompetitive market conditions, i.e., through the exercise of market power. The rationale for the Modified Societal test is that, if producers' market power profits are given the same importance as consumer benefits (as occurs in the CAISO's basic Societal test), transfers of market power-derived profits from producers to consumers as a result of a transmission upgrade would net to zero. The CAISO explains that, to the extent policymakers believe there is value in reducing producer monopoly profits, what it calls the Modified Societal test will be more appropriate than the basic Societal test as a measure of the value of a transmission upgrade.

The CAISO describes that the CAISO Ratepayer perspective focuses on the benefits that would accrue to all parties that are responsible for contributing to the transmission revenue requirement balancing account for the CAISO Participating Transmission Owners (PTOs) and who thus directly or indirectly fund the transmission project. In addition to CAISO consumers, utility-retained generation is included in the CAISO Ratepayer perspective because profits from this generation flow into the balancing account. Transmission owners in the CAISO-controlled grid are also included because their congestion revenues and revenues received from the sale of transmission rights flow into the balancing account. The CAISO assumes that utility-retained generation does not exert market power, which may be a reasonable assumption. With this assumption, there is no need for a Modified CAISO Ratepayer test.

The CAISO Participant perspective includes CAISO ratepayers plus California merchant generators (independent power producers). No party evaluated DPV2 from this perspective.

1. Positions of the Parties

The CAISO, SCE, PG&E, DRA, and TURN recommend primary reliance on the CAISO Ratepayer test because it focuses on whether a proposed transmission project will yield benefits to those who pay the costs of the project and aligns closely with the group of customers whose retail rates are established by the Commission. These parties generally recommend that results from other perspectives be reviewed as well.

The CAISO evaluated DPV2 using four perspectives: the Societal test, the Modified Societal test, and two versions of the CAISO Ratepayer test. The CAISO's calculations for what it calls the CAISO Ratepayer (LMP Only) test were based on the assumption that a locational marginal price (LMP) market structure and physical flow-based scheduling would be applicable throughout the WECC. However, most of the WECC operates based on contract path (rather than physical-flow network model) scheduling. For the interfaces between the CAISO control area and external control areas, day-ahead scheduling is based on contract paths and interface scheduling limits, and actual conditions may result in congestion that must be mitigated in real time. The CAISO acknowledges that its LMP-based calculation overestimates the loss of congestion revenue due to DPV2 and underestimates California consumer benefits, compared to what may occur under the scheduling paradigms prevailing now and for the foreseeable future.

The CAISO undertook a second CAISO Ratepayer test for DPV2 to compensate for the inaccuracies of the WECC-wide LMP assumption. The CAISO's simulations for its CAISO Ratepayer (LMP + Contract Path) test for DPV2 utilize selected contractual paths between the CAISO and the Southwest and indicate energy benefits over three times as large as those obtained from its

LMP-based calculation. The CAISO believes that these results more closely reflect DPV2 benefits to CAISO ratepayers under current and anticipated WECC scheduling rules. Recognizing some shortcomings to this adjustment as well, the CAISO believes that "the true answer lies somewhere between the CAISO benefits computed with and without this adjustment."

SCE reported results of its economic evaluation of DPV2 from three perspectives: CAISO Ratepayers, WECC-wide, and the impact to Arizona. DRA reported results of its economic analysis of DPV2 only from the CAISO Ratepayer perspective. Since SCE and DRA forecasted market prices based on marginal production costs and did not include any effects of strategic bidding, the adjustments that the CAISO made to its Societal perspective to obtain a Modified Societal perspective would not be applicable to the SCE and DRA analyses. Also, since SCE and DRA analyses were based on contract flows WECC-wide, the CAISO's variations to the CAISO Ratepayer perspective to compensate for inaccuracies in its LMP-based modeling likewise would not be applicable to their analyses.

In addition to the CAISO Ratepayer perspective, DRA proposes that inter-utility equity issues be considered. DRA states that it will be impossible to guarantee that ratepayers of all three major investor-owned utilities (IOUs) always benefit from a transmission project that provides CAISO-wide benefits. However, it recommends that the Commission verify that no IOU bears a disproportionate share of the project costs. To that end, DRA recommends that IOU-specific benefit-cost ratios be calculated and a project be approved only if no IOU-specific benefit-cost ratio falls below 0.75. SCE and the CAISO maintain that the Commission should license a proposed transmission project if it benefits CAISO customers in aggregate, since its costs will be collected from all CAISO

users. The CAISO maintains that, while each project may not benefit all users equally, over time the aggregate projects as a whole should benefit all CAISO customers.

DRA also proposes that the Commission only approve proposed transmission projects that have an expected benefit-cost ratio of at least 1.25 and an undiscounted payback period of 15 years or less. In DRA's view, this requirement would provide some assurance that ratepayers will receive benefits. TURN states similarly that it would like to see a benefit-cost ratio of at least 1.2, but that proposed transmission projects with benefit-cost ratios between 1.1 and 1.2 could be considered if there are significant non-quantifiable benefits. The CAISO asserts that the Commission should consider any proposed transmission project with a benefit-cost ratio greater than 1.0, and should give weight to other factors such as risk reduction, environmental impacts, State policy considerations, local economic impacts, and deliverability of renewable resources. The CAISO opposes any criterion for an undiscounted payback period, arguing that benefits over the entire economic life of the project should be considered.

2. Discussion

No party disputes that the CAISO's standardized benefit-cost methodology is a reasonable approach to measure the economic benefits of proposed transmission projects, and we adopt it to the extent described in this order. We agree that the perspective of CAISO ratepayers is of primary importance in the Commission's evaluation of a proposed transmission project, since it reflects the effects on customers of the utilities within our jurisdiction.

While CAISO ratepayers include some non-jurisdictional entities,[7] consideration of all CAISO ratepayers is an analytical convenience with minor effects on the analysis. We agree with TURN that there is value in reviewing the cost-benefit results from other perspectives as well.

In a restructured energy market that is not fully competitive, producers and traders may garner monopoly rents through the exercise of market power. When the market price is above costs of the least efficient generator whose output is needed to meet market demand, as occurs in a market that is not fully competitive, efficiency is reduced and consumers are harmed. A transmission expansion may improve the import capability over a transmission path and allow access to additional sources of power, thus reducing producers' ability to exercise market power and lowering production costs. Because consumer benefits arise due to this reduction in monopoly power, we view this as an important benefit of a transmission project. If a party models strategic bidding behavior in its economic analysis, the party should reflect the proposed transmission project's effect in reducing producers' monopoly profits as a benefit of the project. For evaluations that include estimates of the effects of strategic bidding, the Modified Societal perspective, rather than the basic Societal perspective, is the appropriate perspective to use in evaluating the societal benefits of the proposed project.

[7] CAISO ratepayers include some non-Commission jurisdictional customers, including several municipal utilities and public power agencies such as the State Water Project that have joined the CAISO as PTOs. Entities who wheel energy through the CAISO control area and entities with Existing Transmission Contracts whose rates are tied to the PTO transmission revenue requirement also pay Transmission Access Charges and, thus, will also contribute to recovery of the costs of new CAISO transmission projects.

In CPCN proceedings for transmission projects proposed wholly or partly on the basis of expected economic benefits, the applicant and any other party presenting economic evaluations should analyze benefits from, at a minimum, the CAISO Ratepayer perspective and the Societal perspective. If a party attributes benefits to the proposed project due to mitigation of market power, it should report benefit-cost results using both the Societal and the Modified Societal perspectives. Parties may choose to report benefit-cost results using other perspectives as well.

Consistent with the flexibility we have provided, the Assigned Commissioner or assigned ALJ may require that parties in a transmission CPCN proceeding report benefit-cost results from additional perspectives as appropriate. As an example, the CAISO Participant perspective could provide useful insight regarding the impact of a proposed transmission project on merchant generators within the CAISO area as we consider the need for additional generation near California load centers.

We find the CAISO's development of two CAISO Ratepayer perspectives for DPV2 (LMP and LMP + Contract Path), as explained above, to be very helpful in understanding the intricacies of modeling inter-regional power flows under anticipated market conditions. Any party submitting economic evaluations in transmission CPCN proceedings should explain how it models power flows, constraints, and congestion charges throughout the WECC region, to the extent applicable.

We decline to adopt DRA's inter-utility equity proposal, or a pre-specified benefit-cost threshold or payback period that a transmission project must achieve in order to be granted a CPCN. We expect that transmission projects that individually provide benefits to CAISO ratepayers as a whole will,

in the aggregate, benefit customers of each IOU. Additionally, transmission projects may have other benefits and costs in addition to those that can be quantified in a benefit-cost ratio. The Commission will continue to consider and weigh all relevant factors in reaching a decision on a CPCN request.

Parties took differing positions on the discount rate that should be used in calculating benefit-cost ratios. Consistent with our determination in D.05-04-051, the applicant's weighted cost of capital, as adopted most recently by the Commission, should be used as the discount rate in evaluating the benefits of a transmission project. Consistent use of the utilities' weighted cost of capital as a discount rate will facilitate our comparison of proposed transmission projects and alternative investments.

B. Quantification of Energy Benefits

The CAISO, SCE, and DRA all used the CAISO's energy benefits framework to report the change in production costs and thus the potential energy benefits of the studied transmission projects. At the most basic level, energy benefits are the difference between the production costs to serve load in a region without the proposed transmission project and the lower production costs with the upgrade in service. Of course, while transmission upgrades are generally viewed as providing positive energy benefits, this may not be true for all projects or from all perspectives.

A transmission upgrade will lower production costs if it increases market access to economic supply. However, there will be a redistribution of benefits among consumers, producers, and transmission owners. In particular, a transmission project that increases access to economic power will reduce costs to consumers, thus increasing the consumer surplus. At the same time, the project may reduce income for those generators not accessed by the transmission

upgrade, reducing the producer surplus for those generators. It may also reduce transmission owners' congestion revenues and thus the transmission surplus. The energy benefits due to a transmission project consist of the net changes in consumer costs (consumer surplus), producer net income (producer surplus), and congestion revenues flowing to transmission owners or holders of transmission rights (transmission surplus). The sum of the changes in consumer surplus, producer surplus, and transmission surplus equals the change in energy production costs.

The composition of the three components of the energy benefit calculation depends on the geographic area and the market participants' perspective being examined. For example, a WECC Societal benefit calculation would include the effects on all consumers, generators, and transmission owners in the WECC region.

The CAISO Ratepayer perspective considers only changes in consumer procurement costs and generator and transmission profits that affect rates in the CAISO area. From this perspective, the change in consumer surplus is limited to the change in energy procurement costs for consumers in the CAISO area. The change in producer surplus is calculated only for those generation assets owned or controlled by CAISO-area utilities, which may earn less income due to the additional competition from power accessed by the new transmission project. Parties refer to this component of the CAISO Ratepayer benefits calculation as the change in the utility-retained generation producer surplus. Similarly, PTO-owned transmission assets may earn lower congestion revenues because of the increased flow of power over key transmission interfaces. In summary, energy benefits from the CAISO Ratepayer perspective are the net result of the

increase in consumer surplus and changes in the utility-retained generation producer surplus and PTO transmission surplus in the CAISO area.

All parties appear to support the CAISO's conceptual framework as an appropriate representation of the energy benefits of proposed transmission projects. As TURN notes, this framework represents a significant advance in the economic evaluation of transmission lines, since it incorporates changes in congestion revenues, a factor not included in prior analyses. Because it provides a more complete representation of the energy benefits due to a transmission upgrade, we adopt the CAISO's energy benefits framework as reasonable to the extent described in this order.

Parties presenting economic evaluations should report separately the three components of their energy benefit calculations, that is, the changes in consumer surplus, producer surplus, and transmission surplus (congestion revenues), to aid our understanding of their results. This level of detail should be provided for each benefit perspective reported, i.e., the Societal, Modified Societal, CAISO Ratepayer, and any other benefit perspectives reported.

In the following subsections, we address several areas of concern regarding how energy benefit calculations should be performed.

1. System Modeling Requirements

Parties disagree about the type of production cost computer model that should be used to simulate network operation and forecast energy benefits of proposed transmission projects. There are two basic types of production cost models: network models and transportation models (also called transshipment models).

A network model provides a detailed depiction of the transmission network and forecasts physical flows and nodal prices on the network. Network

models can have differing capabilities. An AC-OPF network model is the most complex and most accurate type of production cost model currently available. AC-OPF models typically are used to simulate short periods of time for reliability analyses. Parties agree that it would be expensive and very time-consuming to perform an economic analysis using an AC-OPF model, because of the numerous simulations needed to analyze multiple scenarios and the lengthy time periods to be simulated.

In a DC-OPF network model, simplifying assumptions are made. In particular, a DC-OPF analysis does not model reactive power or variations in voltage magnitudes and phase angles. These simplifications allow a DC-OPF analysis to be less time-consuming than use of an AC-OPF model, but there are tradeoffs in the accuracy of its calculations.

In a transportation model, groups of nodes are aggregated into areas or zones, and power is simulated to flow along simplified contract paths between the zones. The transportation model constrains power flows on paths using specified line limits and multi-line constraints to approximate real-world network constraints. A transportation model calculates zonal prices, whereas a network model calculates nodal LMP prices. To make their complex power flow simulations manageable, network models typically contain a somewhat simplified treatment of generators and their operating constraints, compared to the more detailed treatment of generators that may be undertaken in evaluations using in transportation models.

a) Positions of the Parties

The CAISO states that TEAM requires use of a network model, in order to capture the physical constraints of the transmission grid and impacts of a proposed transmission project on locational marginal prices. The CAISO

maintains that the production cost simulations must, at a minimum, use a network model derived from a WECC power flow case and perform a DC-OPF analysis that models the physical power flows on transmission facilities for each hourly load and generation pattern. The CAISO states that it is acceptable for a DC-OPF model to compute Power Transmission Distribution Factors (also called shift factors) for every hour of the simulation (variable shift factors), or just for the initial hour (fixed shift factors). Use of an AC-OPF analysis would be optional. The CAISO states that transportation models may be sufficient for many types of resource studies, but maintains that approach is insufficient when analyzing a transmission project that will affect regional transmission flows and locational prices.

The CAISO describes that PLEXOS, the DC-OPF network model it used to analyze DPV2 and Path 26, employs a linearized DC-OPF solution and fixed shift factors, and that transmission constraints are enforced explicitly on high-voltage transmission paths. The CAISO stresses that the requirement to utilize a DC-OPF or AC-OPF production cost model does not constitute an endorsement of any particular vendor or software product, and that many vendors offer an acceptable production cost tool.

The CAISO maintains that use of a transportation model is not acceptable because it computes contract transmission flows instead of physical flows and provides zonal rather than nodal price estimates. The CAISO explains that transportation models cannot model the consequences of loop flow limitations accurately, and that with transportation models interfaces need to be derated artificially to account for loop flow impacts.

The CAISO states that the execution times required for network models limit the number of simulations that feasibly can be performed at this

time, although this limitation may be eased in the future. Because of this limitation, the CAISO recommends that the effects of uncertainty be evaluated using a network model to perform as many discrete sensitivity simulations as possible. The CAISO asserts that the larger number of sensitivity cases that can be examined using a transportation model will not enhance the quality of a study because the underlying physical transmission system is not modeled accurately.

SCE, PG&E, SDG&E, DRA, TURN, and Global Energy unite in recommending that the Commission not require use of a network model for the analysis of energy benefits. SCE and DRA used the Global Energy transportation model in evaluating the economic benefits of DPV2.

SCE submits that the utility's choice as to which computer model to use in a particular certificate proceeding may be influenced by a variety of factors, including price, staff availability, regulatory familiarity, and adaptability to a particular project. SCE agrees with the CAISO that it is important to verify that simulated power flows are physically realistic, but maintains this can be done with transport modeling, using power flow models and nomograms such as the Southern California Import Transmission (SCIT) nomograms.[8] SCE describes that the network representation in its economic analysis of DPV2 incorporated SCIT limits to reflect operational constraints and ensure that flow is physically feasible. SCE also performed power flow analyses to demonstrate the physical feasibility of the modeled power flows. SCE concludes that its simulations using a transportation model produce reasonable forecasts of market prices and DPV2 economic benefits.

[8] A nomogram is a chart showing the operational limits for simultaneous use of a set of particular transmission lines.

PG&E's position is that use of transportation models should be allowed, since selected power flow studies and known operational limits can be used to validate the results obtained using a transportation model.

SDG&E asserts that transportation models have certain advantages over network models. It would like to maintain the flexibility to use transportation models. SDG&E reiterates its overall position, however, that the Commission should grant deference to the CAISO's need determinations regardless of the particular model that is employed in obtaining the CAISO's approval for a project.

TURN would prefer to see both network and transportation models employed in certificate proceedings to the extent that time and resources permit, since both types of models have strengths and weaknesses. TURN submits that decision makers can act with greater confidence when both approaches produce the same end result. TURN comments that, if parties' showings using the different types of models produce markedly different results, that would be cause to delve more deeply and seek to determine why that is the case.

Global Energy does not consider the PLEXOS model, as used by the CAISO, to be a "true" DC-OPF model. It asserts that a network model that uses fixed shift factors is less accurate than a properly designed transportation model. In Global Energy's view, the Commission should require that a network model, at a minimum, use variable shift factors and that it model non-linear elements of the grid, namely, DC lines and phase-shifting transformers. Global Energy also submits that it is not clear that the CAISO's model reasonably reflects generation unit commitment and dispatch.

b) Discussion

We agree with the CAISO that it is important to achieve reasonable accuracy in forecasting energy production costs, energy prices, and congestion costs. At the same time, we are not convinced by its arguments that only network models can provide an acceptable level of accuracy in this regard.

We note the assessment of the CAISO Market Surveillance Committee that transportation models have certain advantages and their use may be acceptable under certain conditions:

> [W]e believe that any estimation of transmission benefits should rely upon a full network model, unless computational experiments under a representative range of cost and demand conditions show that little bias results from using a simpler [transportation] model. If indeed there is little such bias, then a [transportation] model may have significant computational advantages, allowing consideration of a more complete range of fuel price, demand, hydrological, and equipment outage scenarios. However, in the absence of a demonstration that insignificant bias results from network simplification, a full network model based upon, at a minimum, a linearized DC load flow should be adopted.

As the record shows, both network models and transportation models have advantages and disadvantages. Because of their more detailed and realistic modeling of the transmission system, network models can provide more accurate forecasts of physical flows on the network and can pinpoint congestion and, in an LMP market, its economic implications with more certainty compared to a transportation model.

At the same time, a simpler transportation model is computationally faster and allows a more complex analysis of uncertainty,

including the ability to perform stochastic analyses of the effects of variability in key factors. Parties point out that economic evaluations using transportation models generally provide more sophisticated modeling of generation resources than those using a network model. Global Energy also raised concerns regarding the accuracy of the CAISO's network model due to its use of fixed shift factors and linear modeling of non-linear system elements.

The CAISO acknowledged the view of the CAISO Market Surveillance Committee that use of a transportation model may be advantageous if separate calculations show that it exhibits little bias. However, the CAISO categorically rejected the use of transportation models, without providing evidence regarding steps that may be taken to verify the adequacy of the results. Nor did it provide evidence regarding the adequacy of the particular steps SCE took in its DPV2 study using power flow analyses and the representation of SCIT nomograms to reflect operational limits.

The anticipated move to an LMP market design for the CAISO may affect the relative desirability of network versus transportation models. The CAISO asserts that a network model is better at modeling an LMP market because it forecasts prices at the nodal level. But, as the CAISO acknowledges, a network model based on physical flows may exhibit significant inaccuracies in scheduling and the allocation of congestion revenues on the interfaces between CAISO and non-LMP areas. Transportation models may provide more accurate modeling of generator operating constraints, but need independent verification regarding the effects of loop flow and the consequent development of prices and line-specific congestion.

In I.00-11-001, the Commission relied on an analysis undertaken for SDG&E by Henwood Energy Services (Henwood, now Global Energy) in

assessing economic benefits of proposed Miguel-Mission and Imperial Valley upgrades. Global Energy explains now that its analysis in I.00-11-001 used transportation modeling capability comparable to that utilized by SCE and DRA in this proceeding to evaluate DPV2. In D.03-02-069, we found the Henwood modeling approach to be reasonable and expressed that we were not concerned "that the modeling effort conducted here represents a simplified tool that must be properly benchmarked against more sophisticated models in order to assure confidence in its use." We remain unconvinced that benchmarking efforts cannot be sufficient to allow reliance on the results of transportation models.

We are likewise unconvinced that the state of the art in modeling the transmission and generation system is such that one type of system model should be required and another rejected. We do not accept the CAISO's position that a network model must be used in an economic evaluation of a proposed transmission project. Instead, we will continue to allow the applicant to choose the type of system model to use to support need for its proposed transmission project. DRA's proposed principle regarding the assessment of energy benefits is most useful in this regard, and we adopt a slightly modified version, as follows:

> Parties shall assess energy benefits using an established, credible, and commercially-available production cost modeling tool. Computer modeling access requirements of §§ 1821 and 1822 shall be met consistent with Rules 10.3, 10.4, and 1.2.

As is now the case, the applicant and any other party submitting economic evaluations in a CPCN proceeding must demonstrate the reasonableness of their modeling efforts. To that end, in their economic evaluations parties should address the accuracy with which their chosen models reflect system operations and market prices under expected market structures,

including the modeling of generation unit commitment and dispatch and the modeling of power flow, constraints, and congestion charges both within the CAISO control area and in other areas included in their analyses.

2. Consideration of Market Power and Strategic Bidding

Expansion of the transmission system may increase the total supply that can be delivered over a transmission path and the number of suppliers that can be accessed to serve load. This allows more efficient production and, in a restructured market, can provide further economic benefits to the extent it reduces the ability of producers to exercise market power. However, parties disagree regarding the desirability of forecasting a proposed transmission project's effect in reducing generators' market power.

a) Positions of the Parties

The CAISO recommends that the assessment of economic benefits of a proposed transmission project include the modeling of strategic bidding and the project's effects in reducing producers' market power and thus consumers' costs. The CAISO states that if a transmission project is shown to be strongly economic under cost-based conditions, with Societal and CAISO Ratepayer benefit-cost ratios over 1.5, it would be reasonable to allow the proponent to choose not to perform a strategic bidding analysis. For other projects proposed for economic reasons, the CAISO maintains that the project proponent must model strategic bidding. The CAISO would not restrict the types of modeling techniques that parties could utilize, except to require that system conditions be reflected dynamically on an hourly basis. The CAISO recommends that some type of benchmarking occur, as an indication of how well

the proposed bid strategies perform in predicting either current or historical regional prices.

In both its Path 26 and DPV2 analyses, the CAISO used an empirical econometric approach to forecast the result of strategic bidding. The CAISO estimated the historical statistical relationship between market-clearing price-cost markups and two variables that measure system supply and demand conditions: the percentage of load that is unhedged, that is, not under forward contract, and the Residual Supply Index. The Residual Supply Index reflects the total supply available to meet load without the largest supplier. The CAISO estimated this statistical relationship between price-cost markups and the two supply/demand measures using CAISO market data from two periods: 1999 to 2000 when suppliers had few long-term contracts with load, and 2002 when some suppliers had large amounts of supply under long-term contracts. The CAISO estimated the relationship of how market-clearing prices were marked up above cost every hour in each of three California regions (south, central, and north). Using that information, the CAISO built a dynamic bid adder mechanism in its market simulation model, according to which merchant suppliers' bids are estimated based on their production costs and market conditions.

While preferring an empirical approach, the CAISO describes that other methods can be used to model strategic bidding behavior, including a game-theoretic approach in which strategic suppliers seek to maximize profits by changing their bidding in response to the bidding strategy of other players.

SCE and DRA do not model strategic bidding to estimate benefits of DPV2 due to its mitigation of market power. In its opening brief, SCE takes the position that modeling of strategic bidding should be optional and that the Commission should not require a specific methodology, since the applicant in a

CPCN proceeding has the burden of proof. In prepared testimony, SCE viewed efforts to model market power with skepticism:

> Modeling of market power is an unbounded problem because one can't rely on anything factual. The reduction in market power is a positive benefit, but the absolute value of the benefit can't be quantified. (Ex. 9 at 7.)

Global Energy agrees with the CAISO that it would be desirable to reflect bidding strategies in an analysis of the economic benefits of transmission projects if cost-based studies do not show that a project will bring net benefits. In its view, however, the CAISO's approach to bidding strategies must be refined and undergo further testing before it can be accepted. Global Energy cites concerns by the CAISO Market Surveillance Committee that further work is needed, as well as its own concerns about the lack of data from the entire WECC market, possible misspecification of the econometric model, and a poor R-squared measure of model accuracy.

BAMx agrees with the price-cost and bid-cost markup methodology used by the CAISO and recommends that the Commission adopt it.

b) Discussion

No party in this proceeding has disputed that transmission expansions can mitigate generator market power. However, the difficulty lies in quantifying the value of that reduced market power in terms of reduced energy prices. The evidence in this proceeding demonstrates that attempts to quantify the benefits of market power mitigation are extremely complex, and that it is difficult to confirm the extent to which they produce reliable results. Consequently, we are not persuaded that an applicant should be required to forecast the proposed transmission project's impact on strategic bidding

behavior and market prices. The CAISO suggests a threshold market power study requirement if cost-based benefit-cost ratios are below 1.5; we are not convinced of the value of such a threshold. As SCE reminds us, the applicant has the burden of demonstrating need for its proposed project. We believe that the applicant should be allowed to determine whether to include information regarding market power mitigation benefits to meet this responsibility.

There is general agreement that the forecasting of bidding strategies is a very complex undertaking. The CAISO Market Surveillance Committee has noted the difficulty of modeling such behavior:

> The interaction of transmission constraints and market prices is an extremely complicated process that is difficult to model. Over the last decade there has been quite a bit of research into methods for modeling imperfect competition in electricity networks and several approaches have been developed. Unfortunately, the process of vetting and empirically testing these approaches has just begun. (Att. 17 to Ex. 13 at 7-8.)

While the CAISO has made significant strides in developing a dynamic bidding strategy algorithm in an attempt to quantify the benefit of market power reduction, we have several concerns about the CAISO methodology as submitted in this proceeding. An initial observation is that the methodology has not been thoroughly vetted. The only applications to date of the CAISO's dynamic bidding strategy methodology are the Path 26 and DPV2 studies submitted in this proceeding, with the CAISO making several refinements when it undertook the DPV2 study. The CAISO is not aware that any other entity has engaged in such an undertaking, and acknowledges that "much research and development remains to be done in this area" and that

further enhancements of its market price methodology are "both important and necessary."

We question the consequences of the CAISO's use of historical data to predict generator bidding behavior in the anticipated LMP-based market. Because the LMP market design has not yet been implemented in the CAISO control area, the CAISO has no experience with an LMP-based market to inform its analysis. Both the CAISO and the CAISO Market Surveillance Committee recognize that this is a potential shortcoming of the CAISO's approach to modeling bidding strategies. Additionally, the combination of the market power mitigation measures in the LMP market design and the large portions of supply that will be under contract as a result of the Commission's resource adequacy and long term procurement requirements will tend to reduce the ability of producers to exercise market power. The CAISO's historically based strategic bidding algorithm does not reflect these fundamental changes in market design or their effect in reducing the extent to which new transmission projects may mitigate market power.

Another concern is that the reasonableness of the CAISO's use of derived market-wide price-cost markups to approximate individual generators' bid-cost markups has not been established. The CAISO Market Surveillance Committee has opined that it is very difficult to estimate econometrically unit or even firm-specific bid mark-ups. The CAISO had only limited information on bidding behavior of suppliers, since it relied upon information provided by the CAISO's real-time markets, which account for only a very small portion of wholesale energy sales in the CAISO control area (less than 5% in 2003). The CAISO acknowledges that some calibrations may be needed when price-bid

markups are used as a proxy for bid-cost markups, but did not undertake such an effort in its evaluation of DPV2.

Similarly, the CAISO has not established the predictive ability of its chosen regression specification. As Global Energy noted, the R-squared value of 0.46 for the CAISO's chosen equation provides only limited assurance in this regard. The CAISO chose its regression equation based on a qualitative comparison of the predictive ability of three candidate equations using five days of historical market data from July 2003. We would like to see a more rigorous analysis of the predictive ability of bidding strategies submitted in support of a proposed transmission project.

Global Energy describes that, while SCE and DRA did not use this capability in their DPV2 analyses, its transportation model contains a method for modeling bidding strategies and market power. Global Energy states that in D.03-02-069 the Commission reviewed and accepted the Henwood analysis of the effects of market power as part of its evaluation of the Miguel-Mission and Imperial Valley upgrades. Global Energy asks the Commission to find that its methodology for modeling market power continues to be reasonable.

The record in this proceeding is insufficient for us to pass judgment on Global Energy's methodology for modeling bidding strategies and market power. In D.03-02-069 the Commission found the Henwood analysis of the Miguel-Mission and Imperial Valley projects to be reasonable. The Commission did not address the reliability of the market power (then called the scarcity premium) component of the Henwood analysis, commenting only that the scarcity premium came into play during very few hours. In this proceeding, Global Energy provided only a brief description of its approach to modeling

bidding strategies and market power, characterizing it as a rational behavior-based approach. Lacking a detailed record in this proceeding regarding the Global Energy modeling of bidding strategies and market power or whether Global Energy has modified its approach since its evaluation of Miguel-Mission, we cannot make findings at this time regarding the acceptability of Global Energy's methodology.

In summary, market power mitigation can be an important benefit of transmission projects, but a benefit that may be difficult to quantify reliably. Any party submitting an economic evaluation in a transmission CPCN proceeding that includes impacts of the proposed project to lessen market power should include a complete description of its bidding strategy methodology and steps taken to validate its predictive ability in anticipated market conditions. The party should also submit a comparable economic analysis that does not model strategic bidding or market power mitigation benefits, so that the Commission can evaluate both the manner in which the market power mitigation analysis is performed and its effect on the economic justification for the project.

3. Other Modeling Assumptions and Simplifications

The parties' efforts to model the economic impacts of the Path 26 and DPV2 transmission projects, while perhaps the most complex ever presented for a transmission project, entail numerous assumptions and simplifications. In some instances, simplifications are necessary due to modeling limitations. Other modeling choices may be made because of resource or time constraints.

Parties that submit economic evaluations in CPCN proceedings should identify significant assumptions and simplifications, the reasons for those choices, and the biases and possible effects on their study results. While it may

not be possible to quantify the effects of many assumptions and simplifications, the parties should provide as much information as possible, both quantitative and qualitative, about the likely magnitude and direction of such effects.

As mentioned above, parties should address the impacts of modeling choices that affect power flows and congestion revenues, as well as generation unit commitment and dispatch. We describe here several other assumptions and simplifications made in DPV2 evaluations about which concerns have been raised in this proceeding, and which by their nature also appear likely to be at issue in other CPCN proceedings.

a) Contracts and Ownership of New Generation Facilities

In system simulations performed for their DPV2 evaluations, SCE and the CAISO assume that all energy is bought and sold at spot market prices. DRA is concerned that this modeling simplification tends to overestimate consumer surplus benefits, because it credits the transmission project with price reductions for all energy sold. DRA points out that, in reality, much of the utilities' energy needs is met by power contracts or cost-of-service generation whose costs to ratepayers are either partially or entirely insensitive to market prices and immune to exercise of market power.

SCE and the CAISO justify their use of this modeling choice because of difficulties in predicting future contract terms. They downplay possible impacts of this simplification on the basis that, in the long run, contract prices should track expectations regarding the market price, subject to risk considerations. They also state that, to the extent that consumer surplus benefits may be overstated due to use of spot market prices, there may be offsetting

impacts in the generator and transmission surplus calculations that may mitigate or even eliminate the purported overstatement.

As a related concern, DRA criticizes SCE's analysis of DPV2 in that it assumes that no new generating units will be owned by CAISO utilities or controlled by CAISO utilities under a power purchase contract. DRA contends that SCE's assumption biases the results because it underestimates the reduction in URG producer surplus due to the new transmission project and, thus, overestimates the benefits of the transmission project to CAISO ratepayers. DRA notes that PG&E is currently proposing to complete construction of the Contra Costa 8 unit[9] and that PG&E issued two Requests for Offers in 2005 that sought turnkey bids that would enable PG&E to take ownership of additional new resources. DRA also believes that, given the Commission's physical resource adequacy requirement, the utilities will enter new power contracts in the future that give them control over specific generating units, including such units' revenues. DRA comments that the municipal utilities that are CAISO PTOs also are likely to own or control new generating unit revenue streams in the future.

We agree with DRA that such aspects of economic evaluations should be reviewed with particular care. While the need for modeling simplifications is understandable, the effect of such simplifications on the ability to forecast system operations reliably under anticipated market conditions must be addressed. In all economic evaluations submitted in CPCN proceedings, parties should identify their modeling assumptions about bilateral contracts and

[9] In D.06-06-035, the Commission granted PG&E a CPCN for the Contra Costa 8 facility.

ownership of new generation, and should address possible impacts of such assumptions on study results.

b) Number of Years Studied and Extrapolation of Results

In its TEAM approach, the CAISO states that at least two years of system operations must be evaluated. The CAISO would require that the two years studied be at least five years apart. The CAISO conducted its analysis of DPV2 for 2008 and 2013. Although SCE expects DPV2 to become operational in 2009, the CAISO used 2008 for its first year of analysis, and 2013 as the second year because those were the two years for which the CAISO was able to obtain a representation of the network and associated data from SSG-WI.

Using forecasted 2013 energy benefits, the CAISO assumed a 1% real (adjusted for inflation) escalation rate for energy benefits after 2013. The CAISO performed sensitivity calculations which indicated the change in levelized energy benefits if a negative 1% real escalation rate or a positive 3% real escalation rate is assumed instead.

SCE performed production simulations for a study period beginning with DPV2's proposed operating date of June 1, 2009 through 2014, and forecasted that benefits would continue with zero real growth beyond 2014.

We agree with the CAISO that at least two years should be modeled, with the years chosen several years apart. We prefer, however, that analyses also simulate the intervening years, particularly if there are significant system changes, e.g., large transmission or generation additions or retirements, during those years. DRA notes that 61% of the present-value benefits that SCE projected due to DPV2 occur during the four and a half years it modeled. We agree that there would be limited value to undertaking detailed simulations

much beyond five years of initial operation, due both to increasing uncertainty regarding market conditions as time progresses and to the fact that energy benefits during the later years will be increasingly discounted in present-value benefit calculations.

Any party submitting an economic analysis in a transmission CPCN proceeding should justify the number and choice of years to be simulated. It should also explain and justify the method for estimating benefits for years for which simulations are not undertaken, including any years before and those years after the last year simulated. The party should also provide sensitivity analyses such as those the CAISO submitted for the effects of different assumptions about benefits in years that are not simulated.

c) Time Period Studied Each Year

The CAISO would require chronological modeling in which at least 12 weeks per year and at least 168 hours per week would be simulated. It recommends that the entire year (8,760 hours) be simulated, as it did for DPV2. The SCE analysis of DPV2 simulated a typical week each month, and every fourth hour in each of the typical weeks, to reduce simulation times. DRA submits that SCE's approach tends to overestimate a transmission project's value, because it causes the appearance that outages occurring during the simulated week last the entire month.

In an economic evaluation, the party should identify the number of hours studied each year and, if the entire year is not simulated, should address any impact the choice not to simulate all hours may have on study results.

We note that a party with resource or time constraints may make trade-offs in how it undertakes an economic evaluation. The CAISO stated that it views additional sensitivity cases to be more important than simulations of

multiple sequential years. At the same time, in evaluating DPV2 it chose to study all hours of the year. SCE chose to limit the number of hours studied, but performed a stochastic analysis with 100 simulations of four and a half years of system operations. Resource constraints may affect other choices as well, such as whether to use a network model or a transportation model. Each party submitting economic evaluations should address the extent to which resource or time constraints affected its study design choices, including but not limited to the type of model used, the number of years and the number of hours per year studied, and the number of scenarios or stochastic iterations performed. Each party should address the basis for any resulting trade-offs it made among such study attributes. This will allow the Commission to better understand the parties' showings.

4. Uncertainty Analysis

Because of the long-lived nature of the investment, economic evaluations of proposed transmission projects require judgments and assumptions about system and market conditions for many years into the future and even the best forecasts are inherently uncertain in this respect. As a result, it is essential that economic evaluations consider how uncertainty about future system and market conditions affects the likelihood that a project's forecasted benefits will be realized.

The impact of risk and uncertainty on economic benefits associated with transmission expansions can be assessed using deterministic, scenario, and/or stochastic approaches. A deterministic analysis would rely on a system simulation using expected forecasts of critical parameters that would affect the magnitude of benefits to be obtained due to the project. Factors such as system load, fuel prices, and hydrological conditions may be critical parameters in

economic analyses of transmission projects. A scenario analysis would undertake multiple simulations using predetermined combinations of forecasted values for such key variables and, if relative probabilities are assigned to the individual scenarios, would allow calculation of probability-weighted expected benefits. In contrast, a stochastic analysis would develop probability distributions for the key parameters such as fuel prices and would then perform repeated system simulations using values for the key parameters chosen by randomly sampling the values from the probability distributions. Such a stochastic analysis is often referred to as a Monte Carlo analysis.

We agree with the CAISO that it would be overly prescriptive and counterproductive to mandate the methodology to be used in performing uncertainty evaluations. As the parties' sensitivity analyses for DPV2 demonstrate, whether scenario or stochastic sensitivity studies are appropriate may depend to some extent on the type of system modeling tool that is chosen, e.g., a network model or a transportation model. It is appropriate, however, to provide certain guidance regarding the types of uncertainty that should be considered and the scope of the showing that we expect.

The CAISO would require sensitivity analyses only if the Societal benefit-cost ratio for a proposed project under what the applicant considers to be base case conditions is less than 1.5. We are not comfortable with use of such a threshold. As the DPV2 analyses demonstrate, benefit projections can vary widely based on relatively minor variations in key parameters and modeling conventions. We require that any applicant requesting a CPCN for a transmission project justified wholly or partly on the basis of economic benefits submit an uncertainty analysis consistent with the guidelines we adopt today.

While using very different approaches, SCE and the CAISO provided probabilistic economic analyses of DPV2. SCE performed 100 stochastic simulations varying hydro conditions, natural gas prices, and demand conditions according to assigned probability distribution functions for each variable. In contrast, the CAISO analyzed 17 market-based scenarios which, in addition to load, gas price, and hydro variations, also considered that merchant generators alternatively exhibited low, base case (derived from the regression analysis described in Section V.B.2), or high levels of market power in their bidding strategies. SCE and the CAISO each used its results to calculate probability-weighted expected future benefits of DPV2.

While we will address the results of the parties' economic analyses of DPV2 in a later order in A.05-04-015, it is clear that such probabilistic studies are very helpful in understanding the potential effects of uncertainty on large transmission investments. Recognizing that probabilistic studies may be expensive, we require that any applicant proposing a transmission project expected to cost more than $100 million and justified at least in part on the basis of expected economic benefits provide a probabilistic analysis of the effects of uncertainty on the expected benefits of the project. Such an analysis should consider a reasonable range of possible variations in key parameters that may affect economic benefits significantly. We do not specify the parameters that should be considered or the type of probabilistic analysis, e.g., scenario or stochastic, that should be undertaken. However, the inputs and corresponding results of individual cases (whether stochastically or manually derived) should be provided as part of the submitted economic evaluation.

Contingency events may affect the cost-effectiveness of a transmission project in either a positive or negative manner, but it is difficult to

assign a probability to them. Transmission projects may provide insurance value for high-risk contingency events. At the same time, there may be downside risk that unexpected market developments may render a transmission investment uneconomic. For DPV2, the CAISO analyzed eight market-based contingency scenarios representing extreme or unlikely transmission and generation events. DRA likewise analyzed eight sensitivity scenarios having no assigned probabilities, including extended outages of the Palo Verde nuclear units, no differential between Arizona and southern California natural gas prices, the addition of a 1,000 MW solar installation that interconnects at the proposed Midpoint substation on the DPV2 line, a delay in the retirement of California generators, alternate assumptions about capacity expansions in Arizona, extended outages of the San Onofre nuclear units, higher natural gas prices, and construction of 1,250 MW of combined cycle plants instead of DPV2.

Parties presenting uncertainty analyses should address a reasonable range of contingency events. Parties should address both contingency events whose possible economic consequences may be quantified (providing both the inputs and corresponding results for each such contingency event analyzed) and those whose consequences may be addressed only in a qualitative fashion. We do not specify the contingency events that should be considered, since they are likely to vary depending on the transmission project under consideration.

DRA is concerned that model complexity poses a major barrier to understanding parties' analyses. DRA recommends that the Commission direct applicants to submit a deterministic reference case and specified sensitivity cases to illustrate the impact of changes in major variables on project valuation. For similar reasons, the CAISO proposed in its prepared testimony that all parties submitting economic evaluations of a transmission project be required to analyze

at least one cost-based reference case using the SSG-WI database, to facilitate comparison of different parties' analyses and help identify the cause of differing results.

As DRA and the CAISO suggest, establishment of reference cases would assist the Commission's evaluation and comparison of parties' economic analyses. We have found DRA's reference cases particularly helpful in understanding differences between its and SCE's evaluations of DPV2.

We require that each party submitting an economic evaluation provide at least one cost-based (that is, without strategic bidding) deterministic reference case, subject to the following guidance, in order to facilitate understanding of its chosen methodologies and comparison with other parties' showings. The applicant should use its baseline resource plan and assumptions about the system outside its service territory from procurement or other recent Commission proceedings, as described in Section V.E, and what it views as most likely forecasts of key variables such as fuel prices, demand, and hydro conditions. The applicant should provide a detailed description of its reference case and should provide access to its database (as is required by §§ 1821 and 1822 and Rules 10.3 and 10.4). Other parties should submit a cost-based deterministic reference case that mirrors the resources and other key assumptions in the applicant's reference case to the extent feasible, consistent with that party's chosen model and methodologies. Any party that models strategic bidding should also submit a market-based reference case that varies from its cost-based reference case only in its inclusion of strategic bidding, so that the effects of its modeling of market power mitigation benefits are clearly delineated. We encourage parties to submit additional reference cases, for example, to help

illuminate differences among parties' positions on modeling issues and input assumptions.

We decline to require use of the SSG-WI database in the parties' reference cases, because of the need to maintain consistency with resource plans used in other Commission proceedings. There are also concerns about compatibility of the SSG-WI database with non-network models and its maintenance and accessibility following its recent transfer to the WECC. We are willing, however, to revisit the use of SSG-WI data in future CPCN or other relevant proceedings.

DRA proposes that applicants be required to submit a tipping point analysis, such as DRA provided for DPV2. DRA notes that there may be a small number of pivotal factors in which slight changes can drive the economics of the project from positive to negative. DRA recommends that parties be required to identify clearly which parameters, assumptions, or relationships most affect their conclusions. Once tipping point factors are determined, DRA recommends that the next step would determine the tipping point value (or "knife edge") for each factor, above (or below) which the proposed project would not be economically beneficial.

Regarding DPV2, DRA identified four variables as tipping points: modeling conventions, the natural gas price differential between Arizona and California generators, the on-line status of the Palo Verde nuclear units, and the wholesale cost of natural gas. Due to time constraints, DRA was not able to perform a "knife edge" analysis for these variables.

We agree that there is value in understanding the critical factors in a party's economic evaluation. As DRA suggests, we require that each party identify which parameters, assumptions, or relationships most affect the

conclusions in its economic evaluation. We encourage but do not require an explicit tipping point analysis such as DRA submitted for DPV2.

In addition to near-term uncertainty, DRA emphasizes that the farther a forecast extends into the future, the more likely it is to be wrong, particularly given the potential for major paradigm shifts in the production, distribution, and consumption of electricity. DRA proposes an Uncertainty Margin methodology as a way to quantify the robustness of benefit-cost calculations to forecast risk. The requirement adopted in Section V.B.3.b that parties indicate the effect of different escalation rates for energy benefits after the last year simulated has much the same effect and so we do not adopt DRA's proposal for a separate Uncertainty Margin analysis.

C. Other Quantifiable Economic Benefits and Costs

In addition to expected energy benefits and project costs, other potential economic benefits and costs of a proposed project may be identified and quantified. The CAISO recommends, but would not require, that economic benefits in addition to energy benefits be quantified and included in a benefit-cost analysis, to the extent feasible. It states that proponents should have flexibility to offer credible methodologies for determination of such benefits.

Parties have identified the following non-energy attributes that may have economic benefits or costs that may be quantified and thus included in an economic assessment:

- Reductions in operating costs,
- Changes in system losses,
- Environmental benefits or costs,
- Capacity benefits,

- Capital and other costs or benefits resulting from resource substitution, and
- Increased transmission revenues from CAISO wheeling service and Existing Transmission Contracts.

To the extent parties estimated the value of these benefits attributable to DPV2, we will assess those estimates in our later decision in A.05-04-015.

In its economic evaluation, an applicant should identify and, if possible, quantify the economic impacts of any attributes of its proposed transmission project or its operation that may increase societal costs or have other detrimental effects. The importance of quantifying non-energy economic benefits depends, to some extent, on whether identified energy benefits provide sufficient justification for the proposed project. We encourage parties, however, to provide such information so that we may consider as fully as possible all important attributes of the proposed project. If a party quantifies non-energy benefits and costs, the party should report separately the amount of each such attribute of the proposed project. Parties may include these factors in their uncertainty analyses, to the extent appropriate.

The cost of a proposed transmission project is an integral component of any economic evaluation. Each party should specify the level of project costs (including capital and operating and maintenance costs) assumed in its economic evaluation, and how a change in project costs would affect cost-effectiveness results. In particular, any party presenting benefit-cost analyses should specify, through a formula if appropriate, how a change in project costs would change any benefit-cost ratios or other benefit-cost results in its economic evaluation. Additionally, to the extent an applicant learns its evaluation relies upon estimated costs that have become outdated by more than 5%, the applicant shall

update its economic evaluation to reflect that change in estimated costs of the project and shall explain the impacts of that change on the evaluation.

In its opening brief, BAMx argues that the Commission should develop the long-term cost of entry for new capacity for various regions within California. We do not address the BAMx proposal because, in addition its untimeliness, this proceeding is not an appropriate place for its consideration.

D. Non-monetized Considerations

In order to allow full consideration of a proposed transmission project, the applicant should apprise the Commission of any detrimental aspects of the project whose economic impacts cannot be quantified. We encourage parties to also address any economic benefits that may be difficult to measure. As examples, parties have identified the following considerations that may be relevant to a proposed transmission project and whose benefits or costs may not be quantifiable:

- Access to renewable resources,
- Non-monetized environmental impacts,
- Fuel diversity benefits,
- Reliability impacts,
- Enhanced system operational flexibility,
- Mitigation of market power, to the extent not quantified,
- Potential for increased reserve resource sharing, and
- Job creation or losses.

The Commission will consider such non-monetized aspects of the proposed project, along with other relevant factors, in assessing an applicant's CPCN request.

E. Resource Plans and Alternatives to a Proposed Project

The applicant's resource plan and assumptions about transmission and generation resources in other portions of the study area are important components of the economic evaluation of a proposed transmission project. An economic assessment should take into account other potential changes to the system that may accompany construction of the proposed project. It should also consider alternative resources that could be added or implemented in lieu of the proposed transmission project.

In its economic analysis of DPV2, SCE used the system database it maintains for the Commission's long term procurement proceedings, with updated forecasts for loads, natural gas prices, and available hydro generation. SCE describes that, for inclusion in its baseline resource plan, construction of other transmission projects should be fairly certain, with entities sponsoring the new transmission taking affirmative steps toward construction such as entering projects in the WECC rating process, making monetary investments like purchasing land or major facilities, or applying for necessary regulatory permits necessary to construct.

SCE's criteria for inclusion of a generation project include that it must either be substantially constructed and have financing completed, or be an investor-owned or municipal utility project. SCE's baseline resource plan included increased energy efficiency and demand response, as well as renewables to meet or exceed the State's 20% RPS goal. SCE removed generation based on published retirement dates, if a plant reaches a life of 55 years, if retirement is planned due to air quality restrictions, or if retirement is consistent with Commission planning assumptions. SCE suggests that developing the DPV transmission corridor could attract new generation development east of the

Devers substation and that DPV2's benefits could increase due to the increased access to new generation. However, SCE did not model or quantify this purported benefit.

SCE describes that it evaluated several potential transmission projects that could increase transmission import capability into California. The identified projects were screened using rough estimates of project costs and deterministic production simulations before the DPV2 project was chosen.

In its DPV2 analysis, the CAISO modeled the transmission and generation system using the SSG-WI database, modified after lengthy discussions with SCE to improve its representation of the SCE system. The CAISO describes that it also added generation resources to the SSG-WI database to reflect estimated RPS goals in each state, and added new gas-fired generation, primarily combined cycle plants, in each of the WECC areas as needed to maintain at least a 15% planning reserve margin.

The CAISO describes its intent to plan the transmission grid taking into account the profitability of generation additions in various locations. The CAISO explains that, in this way, it will influence generation decision making, rather than accounting for generation additions after the fact. Under this approach, the CAISO would model the profitability of new generation and would optimize generation additions for "with upgrade" and "without upgrade" cases. The CAISO states that it would attribute to the proposed transmission upgrades the benefits and costs of resources alternatives that are economic in the "with upgrade" case but not viable in the "without upgrade" case. However, the CAISO did not optimize generation additions in its economic evaluation of DPV2. Instead, the CAISO used the same resource plan for its "with DPV2" and "without DPV2" simulations.

The CAISO's view is that both additional generation in southern California and inter-regional transmission upgrades should be pursued. Thus, it did not evaluate new generation projects in southern California as an alternative to DPV2.

DRA based its economic evaluation of DPV2 on SCE's resource plan assumptions, with certain modifications. DRA notes one difference between the baseline resource plans developed by SCE and the CAISO: the CAISO included a series capacitor upgrade sponsored by the Salt River Project, whereas SCE did not. DRA expects that inclusion of that upgrade in SCE's (and therefore DRA's) analysis would reduce the indicated economic benefits of DPV2. However, DRA did not opine on whether SCE should have included that upgrade in its baseline resource plan. DRA explored several other sensitivity scenarios modeling possible changes to SCE's resource plan.

The importance of well-developed and clearly justified baseline resource plans is not unique to CPCN proceedings. In order to allow consistency among Commission proceedings, the applicant in a CPCN proceeding should use a baseline resource plan and assumptions about the system outside its service territory that are consistent with its resource plan and system assumptions used in procurement or other recent Commission proceedings. In its showing, the applicant should identify clearly and explain any changes to its baseline resource plan or to prior assumptions about transmission and generation resources in other parts of the study area. The applicant should also specify the criteria it used to determine the inclusion, exclusion, and retirements of generation, transmission, and other resources, and also the sources and justification for its assumptions about the system outside its service area. Other parties presenting economic evaluations of the proposed transmission project

should highlight any differences between resource and other input assumptions they utilize and those submitted by the applicant, and should address how the differences may affect the results of their analyses.

The Commission will examine the utilities' resource plans and their modeling of the system outside their service areas on an on-going basis as needed in CPCN and other relevant proceedings. We believe that it would be helpful to develop clear and consistent criteria regarding what resources should be included in or excluded from baseline resource plans, for use in CPCN and other Commission proceedings. Limited criteria have evolved in prior CPCN proceedings for when a pending generation facility should be included in the baseline resource plan, but the treatment of pending transmission upgrades has been addressed primarily on a case-by-case basis. Lacking a well-developed record on this matter, we hesitate to adopt specific criteria at this time. We plan to explore this matter further in the future.

Finally, we agree with the parties that the availability and cost of feasible alternatives should be evaluated as part of the economic evaluation of a proposed project, but that the exact approach should not be dictated at this time. Depending on the proposed project, alternatives to be examined may include other transmission projects or configurations, central station or distributed generation, renewable generation, demand-side options, and/or operating procedures or additional remedial action schemes. Each party submitting an economic evaluation in a transmission CPCN proceeding should identify alternatives it considered, the bases for its choices, and the results of its alternatives analysis.

VI. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with § 311(d) and Rule 77.1 (now Rule 14.2) of the Commission Rules of Practice and Procedure. The CAISO, DRA, and BAMx filed comments on the proposed decision. SCE, SDG&E, and Global Energy filed reply comments taking issue with certain aspects of the CAISO and BAMx comments.

In its comments on the proposed decision, DRA fully supports the proposed decision and recommends its adoption. DRA comments that adoption of the proposed decision should aid the goal of streamlining major transmission proceedings. It comments that, as an added benefit, the principles and minimum requirements for the economic evaluation of transmission projects in certification proceedings should "spill over" into other resource planning and procurement proceedings and that the statewide planning process should be well served with adoption of the proposed decision.

The CAISO takes issue with the proposed decision's provision allowing a CPCN applicant to choose the type of system model to use in its economic assessment of the proposed transmission project. The CAISO reiterates its position that, because transportation models do not represent physical flows on the transmission system accurately, outcomes of transportation models are unreliable. We are unpersuaded by the CAISO's arguments that benchmarking efforts can never be sufficient to allow reliance on economic evaluations based on the use of transportation models. However, we have clarified the discussion regarding the showing that a party in a CPCN proceeding must make regarding the adequacy of the system modeling efforts that underlie its economic evaluation of a proposed transmission project.

The CAISO requests, if the Commission intends to rely on D.03-02-069 as a justification for the continued acceptance of transportation models, that the Commission reopen the record to evaluate the accuracy of the modeling effort using a transportation model to assess the economic benefits of the Miguel-Mission and Imperial Valley upgrades. Our determination in today's decision that a CPCN applicant should not be required to use a specific type of system model results from our assessment of the parties' showings in this proceeding, and is not based on the earlier findings in D.03-02-069. There is no need to reopen the record regarding the economic evaluations of the Miguel-Mission and Imperial Valley upgrades undertaken in I.00-11-001.

BAMx reiterates its position, stated for the first time in its opening brief, that the Commission should develop the long-term cost of entry for new capacity for various regions within California. We see no reason to modify the proposed decision in this regard.

BAMx also urges the Commission to keep I.05-06-041 open to examine the application of the adopted principles in the context of intra-zonal projects, such as SDG&E's pending application for a CPCN for the Sunrise Powerlink transmission project (A.05-12-014). However, continuation of this investigation is not needed to ensure the proper application in CPCN proceedings of the principles and guidance adopted in today's decision. Consistent with the provisions of § 1701.5, this investigation should be closed at this time.

VII. Comments on Alternate Proposed Decision

The alternate proposed decision of President Michael R. Peevey was mailed to the parties on October 10, 2006 in accordance with Pub. Util. Code § 311(e) and Rule 14.1 of the Commission Rules of Practice and Procedure.

Comments on the alternate proposed decision were filed on _____ and reply comments were filed on _____.

VIII. Assignment of Proceeding

Dian M. Grueneich is the Assigned Commissioner and Charlotte F. TerKeurst is the assigned ALJ in this proceeding.

Findings of Fact

1. The CAISO's work in developing its TEAM approach has advanced the state of the art in economic evaluations of transmission projects.

2. The state of the art in economic evaluations of transmission projects continues to evolve, with continuing developments in system modeling capabilities and computer advances.

3. It is reasonable for the Commission to adopt general principles and provide guidance to establish a framework and minimum requirements for economic evaluations to be submitted in CPCN proceedings for proposed transmission projects.

4. The Commission should retain the ability to assess the adequacy of the applicant's showing regarding its baseline resource plan and alternatives to a proposed transmission project, and to maintain consistency among proceedings in which the Commission assesses alternative means of meeting California's energy needs.

5. It is reasonable to allow the Assigned Commissioner or assigned ALJ in a CPCN proceeding for a proposed transmission project to modify application of the minimum requirements for economic evaluations adopted in this decision with good cause shown, taking case-specific conditions into account.

6. It is reasonable for the Commission to assess the applicability of the principles and guidance adopted in this decision in the context of individual CPCN applications, as the need arises.

7. Provided certain safeguards to protect the public interest are met, as set forth in this decision, it is reasonable to grant a rebuttable presumption in a CPCN proceeding to an economic evaluation approved by the CAISO Board.

8. The grant of a rebuttable presumption should apply only to the economic evaluation of a proposed transmission project and should not impact the environmental analysis or other factors that the Commission must consider in evaluating a request for a CPCN.

9. The rebuttable presumption granted in this decision will not apply to CPCN applications filed with the Commission prior to the effective date of this decision unless the economic analysis complies with the safeguards and requirements of this decision and the assigned commissioner of a pending transmission proceeding issues a ruling that explicitly elects to apply it to that application.

10. In economic evaluations of proposed transmission projects, there are three general categories of costs and benefits: (1) the change in total production costs, or energy benefits, (2) changes in other quantifiable economic costs and benefits not included in production cost analyses, and (3) factors whose economic effects cannot be monetized.

11. In evaluating a proposed transmission project, the distribution of potential benefits and costs among geographic areas and among various types of market participants can be assessed.

12. The WECC or Societal benefit-cost perspective takes into consideration all market participants in the WECC area, including consumers (or their load

serving entities), producers, and transmission owners or holders of transmission rights.

13. The Modified Societal benefit-cost perspective includes only the portion of producer profits derived from competitive prices, and excludes additional producer net revenue obtained through the exercise of market power.

14. The CAISO Ratepayer benefit-cost perspective includes the benefits and costs that would accrue to CAISO consumers, utility-retained generation, and transmission owners on the CAISO-controlled grid.

15. It is reasonable to use the CAISO's standardized benefit-cost methodology, as described in this decision, to measure the economic benefits of a proposed transmission project.

16. The perspective of CAISO ratepayers is of primary importance in the Commission's evaluation of a proposed transmission project, because it reflects the effects on customers of the utilities within our jurisdiction.

17. A transmission expansion may improve the import capability over a transmission path and allow access to additional sources of power, thus reducing producers' ability to exercise market power and lowering production costs, to the benefit of consumers.

18. For economic evaluations that include estimates of producers' strategic bidding behavior, the Modified Societal perspective is the appropriate perspective to use in evaluating societal benefits of the proposed transmission project.

19. Use of discount rates equal to the utilities' weighted cost of capital will facilitate consistent comparison of proposed transmission projects and alternative energy investments.

20. The energy benefits due to a proposed transmission project consist of the net changes in consumer costs, producer net income, and congestion revenues flowing to transmission owners or holders of transmission rights. The sum of these changes equals the change in energy production costs.

21. It is reasonable to use the CAISO's energy benefits framework for the computation of energy benefits of a proposed transmission project, as described in this decision.

22. Both network models and transportation models have advantages and disadvantages.

23. It is reasonable to allow the applicant to choose the type of system model to use in its showing of need for a proposed transmission project.

24. The modeling of the benefits of market power mitigation is a complex undertaking, and it is difficult to confirm the extent to which such forecasts produce reliable results.

25. It is reasonable to allow the applicant to determine whether to include information regarding market power mitigation benefits as part of its showing of need for a proposed transmission project.

26. It is reasonable to require that parties identify significant assumptions and simplifications in their modeling of the economic impacts of proposed transmission projects, the reasons for those choices, and possible effects on study results.

27. It is reasonable to require that, in economic evaluations of proposed transmission projects, system operations be modeled for at least two years, with the years chosen several years apart.

28. It is reasonable to require that, in its economic evaluation of a proposed transmission project, each party address the extent to which resource or time

constraints affected its economic study design choices and the basis for any resulting trade-offs it made among study attributes.

29. Evaluations of proposed transmission projects require judgments and assumptions about system and market assumptions for many years into the future and even the best forecasts are inherently uncertain in this regard.

30. It is reasonable to require that an applicant address how uncertainty about future system and market conditions affects the likelihood that the proposed transmission project's forecasted economic benefits will be realized, taking into account a reasonable range of possible variations in key study parameters and contingency events.

31. It is reasonable to require that an applicant proposing a transmission project expected to cost more than $100 million provide a probabilistic analysis of the effects of uncertainty on the expected benefits of the project.

32. It is reasonable to require that each party submitting an economic evaluation in a transmission CPCN proceeding provide at least one cost-based deterministic reference case, with the applicant using its baseline resource plan and other parties mirroring the resources and other key assumptions in the applicant's reference case to the extent feasible.

33. It is reasonable to require that a party that models the effects on strategic bidding of a proposed transmission project submit a market-based reference case that varies from its cost-based reference case only in its forecast of strategic bidding.

34. It is reasonable to require that each party identify the parameters, assumptions, or relationships that most affect the conclusions in its economic evaluation of a proposed transmission project.

35. It is reasonable to require that the applicant identify any attributes of its proposed transmission project that may increase societal costs or have other detrimental effects and, if possible, quantify the potential effects.

36. It is reasonable to require that each party specify the level of project costs it assumed in its economic evaluation of a proposed transmission project, and how a change in project costs would affect its cost-effectiveness results.

37. The importance of identifying and quantifying non-energy economic benefits of a proposed transmission project depends, to some extent, on whether identified energy benefits provide sufficient justification for the project.

38. It is reasonable to require that, in its economic evaluation of a proposed transmission project, the applicant use a baseline resource plan and assumptions about the system outside the applicant's service territory that are consistent with its resource plan and system assumptions used in procurement or other recent Commission proceedings, with identification and explanation of any differences.

39. It is reasonable to require that, in their economic evaluations of a proposed transmission project, parties other than the applicant identify and justify any differences between the resource plan and other input assumptions they utilize and those submitted by the applicant.

40. It is reasonable to evaluate the availability and cost of feasible alternatives as part of the economic evaluation of a proposed transmission project.

41. It is reasonable to require that each party identify alternatives to the proposed transmission project that it considered, the bases for its choices, and the results of its alternatives analysis.

42. It is reasonable to adopt the Principles and Minimum Requirements for the Economic Evaluation of Proposed Transmission Projects appended as Attachment A, with the further guidance provided in this decision, for use in

CPCN proceedings in which the applicant proposes a transmission project wholly or partly on the basis of expected economic benefits.

Conclusions of Law

1. The Principles and Minimum Requirements for the Economic Evaluation of Proposed Transmission Projects appended as Appendix A should be adopted, with the further guidance provided in this decision, for use in CPCN proceedings in which the applicant proposes a transmission project wholly or partly on the basis of expected economic benefits.

2. The Assigned Commissioner or assigned ALJ in a CPCN proceeding should be allowed to modify application of the minimum requirements for economic evaluations adopted in this decision with good cause shown, taking case-specific conditions into account.

3. In order to rebut the presumption created by a CAISO Board-approved economic evaluation in support of a proposed transmission project, parties opposing the proposed project in a CPCN proceeding should bear the burden of demonstrating either (1) that the CAISO Board-approved economic evaluation does not comply with the principles and minimum requirements of this decision or (2) that the project is not cost-effective.

4. A CAISO determination of economic value should not be a prerequisite to obtaining a CPCN and an applicant should retain the right to rely upon its own economic evaluation.

5. This order should be effective today so that the adopted principles and minimum requirements can be applied to transmission projects that the Respondents may propose.

6. This proceeding should be closed.

ORDER

IT IS ORDERED that:

1. We adopt the Principles and Minimum Requirements for the Economic Evaluation of Proposed Transmission Projects (Principles and Minimum Requirements) appended as Attachment A, with the further guidance provided in this decision, for use in certificate of public convenience and necessity (CPCN) proceedings in which the applicant proposes a transmission project wholly or partly on the basis of expected economic benefits.

2. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each submit an economic evaluation consistent with the Principles and Minimum Requirements and the further guidance provided in this decision, as part of its showing in any proceeding in which it requests a CPCN for a transmission project proposed wholly or partly on the basis of expected economic benefits.

3. Non-applicant parties in CPCN proceedings considering a transmission project proposed wholly or partly on the basis of expected economic benefits may submit economic evaluations that are consistent with the Principles and Minimum Requirements and the further guidance provided in this decision.

4. The Assigned Commissioner or assigned Administrative Law Judge in a CPCN proceeding considering a transmission project proposed wholly or partly on the basis of expected economic benefits may modify application of the minimum requirements for economic evaluations adopted in this order with good cause shown, taking case-specific conditions into account.

5. If the California Independent System Operator (CAISO) Board makes the explicit findings regarding an economic evaluation of a proposed transmission

project as set forth in this decision, the evaluation shall be granted a rebuttable presumption.

6. If material facts relied upon in a CAISO Board-approved economic evaluation are inaccurate or become outdated, the applicant shall submit additional information and shall provide an explanation of the additional information's impact on the assumptions and conclusions contained in the economic evaluation.

7. Investigation 05-06-041 is closed.

This order is effective today.

Dated _____, at San Francisco, California.

ATTACHMENT A
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PRINCIPLES AND MINIMUM REQUIREMENTS FOR THE ECONOMIC EVALUATION OF PROPOSED TRANSMISSION PROJECTS

PRINCIPLES:

1. Benefits Framework

The CAISO's standardized benefit-cost methodology, as described in this decision, shall be used to measure the economic benefits of proposed transmission projects. The perspective of CAISO ratepayers is of primary importance in a CPCN proceeding because it reflects the effects on customers of the utilities within the Commission's jurisdiction.

The discount rate to be used in evaluating the benefits of a proposed transmission project shall be the applicant's weighted cost of capital adopted most recently by the Commission.

Economic assessments of proposed transmission projects shall consider three categories of costs and benefits: (a) the change in total production costs, or energy benefits; (b) changes in other quantifiable economic costs and benefits not included in the production cost analysis; and (c) factors whose effects cannot be monetized.

2. Energy Benefits

The CAISO's framework, as described in this decision, for the computation of potential energy benefits of a proposed transmission project shall be used. The change in production costs, or the energy benefits, has three components: the change in consumer costs, the change in producers' profits, and the change in congestion revenues flowing to transmission owners or holders of transmission rights.

Parties shall assess energy benefits using an established, credible, and commercially-available production cost modeling tool. Computer modeling access requirements of Public Utilities Code Sections 1821 and 1822 shall be met consistent with Rules 10.3, 10.4, and 1.2 of the Commission Rules of Practice and Procedure.

PRINCIPLES AND MINIMUM REQUIREMENTS FOR THE ECONOMIC EVALUATION OF PROPOSED TRANSMISSION PROJECTS

The applicant may decide whether to include market power mitigation benefits as part of its demonstration of need for a proposed transmission project.

Parties shall model system operations for at least two years, with the years chosen several years apart. The Commission prefers that parties also model system operations during the intervening years, particularly if there are significant system changes, e.g., large transmission or generation additions or retirements, during those years.

3. Other Economic Benefits and Costs

In addition to energy benefits, other economic effects of a proposed transmission project may be considered, including economic effects that may not be quantifiable. The applicant shall identify in its economic evaluation any attributes of the proposed transmission project that may increase societal costs in some manner. Additionally, to the extent an applicant learns its evaluation relies upon estimated costs that have become outdated by more than 5%, the applicant shall update its economic evaluation to reflect that change in estimated costs of the project and shall explain the impacts of that change on the evaluation.

4. Uncertainty Analysis

Economic evaluations shall consider how uncertainty about future system and market conditions affects the likelihood that a proposed transmission project's forecasted benefits will be realized.

5. Resource Plans and Other Input Assumptions

Economic evaluations of proposed transmission projects shall use baseline resource plans and assumptions about the system outside the applicant's service territory that are consistent with resource plans and system assumptions used in procurement or other recent Commission proceedings, updated as appropriate. Potential changes to the system that may result from or accompany construction of the proposed project shall be taken into account.

PRINCIPLES AND MINIMUM REQUIREMENTS FOR THE ECONOMIC EVALUATION OF PROPOSED TRANSMISSION PROJECTS

6. Alternative Resource Options

Economic evaluations shall consider feasible resource alternatives to the proposed transmission project. Depending on the transmission project, these alternatives may include, but are not limited to, other transmission projects or configurations, central station or distributed generation, demand-side options, operating procedures, and/or additional remedial action schemes.

REQUIREMENTS:

1. Benefits Framework

Each party that submits an economic evaluation in a transmission CPCN proceeding shall report benefits from, at a minimum, the CAISO Ratepayer perspective and the Societal perspective.

If a party quantifies and attributes benefits based on mitigation of market power, the party shall report benefit-cost results using both the Societal and Modified Societal perspectives.

2. Energy Benefits

Parties shall report separately the three components of their energy benefit calculations, that is, the changes in consumer surplus, producer surplus, and transmission surplus (congestion revenues). This level of detail shall be provided for each benefit perspective reported, i.e., the Societal, Modified Societal, CAISO Ratepayer, and any other benefit perspectives reported.

If a party attributes benefits based on mitigation of market power, the party shall include a complete description of its bidding strategy methodology and steps taken to validate its predictive ability in anticipated market conditions. The

party shall also submit a comparable economic analysis that does not include strategic bidding or market power mitigation benefits.

Each party shall identify and justify significant assumptions and simplifications in its economic analysis, and shall provide information about the likely effects of the assumptions and simplifications. In particular, each party shall address its treatment of the following modeling issues:

- Modeling of power flows, constraints and congestion charges within both the CAISO control area and all other areas included in system simulations.
- Modeling of generation unit commitment and dispatch.
- Modeling of bilateral contracts and assumptions about future contracts.
- Assumptions about ownership of new generation facilities.
- Number and choice of years studied, the method for estimating benefits for years not studied, and the number of hours per year for which system operations are simulated. The party shall provide a sensitivity analysis addressing the effect on benefit-cost results of different assumptions about energy benefits in years that are not simulated.

3. Other Benefits and Costs

The applicant shall identify any attributes of its proposed transmission project that may increase societal costs or have other detrimental effects and, if possible, quantify the potential effects. In addition to energy benefits, parties are encouraged to identify other beneficial economic aspects of the transmission project. Parties may include these factors in their uncertainty analyses, to the extent appropriate.

If a party quantifies changes in non-energy economic benefits or costs, the party shall identify separately the economic value of each of those benefits or costs.

Each party shall specify the level of project costs (including capital and operation and maintenance costs) it assumed in its economic evaluation, and shall specify, through a formula if appropriate, how a change in project costs would change any benefit-cost ratios or other numerical benefit-cost results in its economic evaluation.

4. Uncertainty Analysis

The applicant shall submit an uncertainty analysis that considers a reasonable range of possible variations in key study parameters and contingency events. For any proposed transmission project expected to cost more than $100 million, the applicant's uncertainty analysis shall include a probabilistic and/or scenario evaluation.

Each party that submits an economic evaluation shall provide the inputs and corresponding results for each deterministic case, individual probability case (whether stochastically or manually derived), and each contingency event whose possible economic consequences are quantified.

Each party that submits an economic evaluation shall provide a cost-based (that is, without strategic bidding) deterministic reference case. The applicant shall use its baseline resource plan and assumptions about the system outside its service territory from procurement or other recent Commission proceedings, modified as appropriate. Other parties shall mirror resource and other key assumptions in the applicant's reference case to the extent feasible. Any party that models strategic bidding shall submit a market-based reference case that varies from its cost-based reference case only in its forecast of strategic bidding.

Each party shall identify the parameters in its economic analysis whose realized values are most likely to affect the cost-effectiveness of the transmission project under consideration.

5. Resource Plans and Other Input Assumptions

PRINCIPLES AND MINIMUM REQUIREMENTS FOR THE ECONOMIC EVALUATION OF PROPOSED TRANSMISSION PROJECTS

The applicant shall use a baseline resource plan and assumptions about the system outside its service territory that are consistent with its resource plan and system assumptions used in procurement or other recent Commission proceedings, with identification and explanation of any differences. The applicant shall consider any potential changes to the system that may result from or accompany construction of the proposed project.

The applicant shall specify the criteria it used to determine the inclusion, exclusion, and retirements of generation, transmission, and other resources in its baseline resource plan, and also the source and justification for its assumptions about the system outside its service area.

Other parties shall identify and justify any differences between the resource plans and other input assumptions they utilize and those submitted by the applicant, and shall address how the differences may affect the results of their analysis.

6. Alternative Resource Options

Each party shall identify the resource alternatives to a proposed transmission plan that it considered, the bases for its choices, and the results of its alternatives analysis.

7. General

If the CAISO has determined that a proposed transmission project is needed, the applicant shall present the CAISO's economic evaluation and may use the CAISO assessment to help meet its burden of proof.

Each party shall address the extent to which resource or time constraints affected its study design choices, including but not limited to the type of model used, the number of years and the number of hours per year studied, and the number of scenarios or stochastic iterations performed. Each party shall address the basis for any resulting trade-offs it made among such study attributes.

PRINCIPLES AND MINIMUM REQUIREMENTS FOR THE ECONOMIC EVALUATION OF PROPOSED TRANSMISSION PROJECTS

(END OF ATTACHMENT A)

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INFORMATION REGARDING SERVICE

I have provided notification of filing to the electronic mail addresses on the attached service list.

Upon confirmation of this document's acceptance for filing, I will cause a Notice of Availability of the filed document to be served upon the service list to this proceeding by U.S. mail. The service list I will use to serve the Notice of Availability of the filed document, attached as Attachment B, is current as of today's date.

Dated October 10, 2006, at San Francisco, California.

/s/ TERESITA C. GALLARDO
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UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY

National Electric Transmission Congestion Study

COMMENTS OF
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The Public Utilities Commission of the State of California ("CPUC") hereby provides its comments pursuant to the Department of Energy's ("DOE") August 2006 National Electric Transmission Congestion Study (hereinafter, "the DOE Study").

The CPUC has previously commented on DOE's February 2006 Notice of Inquiry ("NOI"), *Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors* ("NIETCs"), and actively participated in the March 2006 Technical Conference in Chicago that addressed the substance of the NOI. The CPUC filed additional comments, in April 2006, following up on certain key topics that were addressed at the Chicago Technical Conference.

Section 1221 of the Energy Policy Act ("EPAct")[1] of 2005 directed the Secretary of Energy to conduct a nationwide study of electric transmission congestion by August 8, 2006. Based upon this study, comments thereon, and considerations that include economics, reliability, fuel diversity, national energy policy and national security, the Secretary may designate "any geographical area experiencing electric energy transmission capacity constraints or congestion that adversely affects customers" as a NIETC. The DOE Study is to be updated every three years.

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INTRODUCTION

The DOE Study finds that three classes of congestion merit further federal

[1] Section 216(a) of the Federal Power Act.

attention: Critical Congestion Areas, Congestion Areas of Concern and Conditional Constraint Areas. One of the two Critical Congestion Areas identified in the DOE Study is located, at least in significant measure, in California. One of the four Congestion Areas of Concern identified in the DOE Study, namely, the San Francisco Bay Area, is located in California. Finally, one of the Conditional Congestion Areas identified in the DOE Study as being of principal interest to DOE is also located in California. This area, shown as "Renewables" in the area north of Los Angeles on Figures ES-4 and 5-5, and described as "new wind development in Southern California" on page 49 of the DOE Study, is the Tehachapi wind resource area. In addition, the Montana - Wyoming Conditional Constraint Area, has implications for "mega" transmission projects being proposed for delivering power from interior western coal- and wind-rich areas to the west coast and Arizona, with California viewed as a major destination.

Because of these identifications, the CPUC, and the State of California more generally, have serious concerns about the prospect of any NIETC designations resulting from this Study. Any NIETC designations arising from DOE's findings could substantially impact California's energy planning process and could ultimately impose large costs on Californians. Moreover, depriving the stakeholders of the opportunity to work out mutually acceptable arrangements for paying for such massive projects, which the designation of a NIETC would effectively do, will raise profound, and possibly irresolvable, disputes about the allocation of the enormous costs of these projects.

Indeed, the designation of a NIETC in connection with any large, multi-state projects is more likely to delay project siting, because of the ensuing litigation and conflict resulting from the interference with the delicate negotiations among many parties that a NIETC designation would cause, than to accelerate it, which is the ostensible legislative purpose behind EPAct Section 1221.

The following comments will summarize the CPUC's understanding of the DOE Study's principal findings regarding Southern California and the San Francisco Bay Area, discuss further considerations regarding transmission planning in California and the West and its relationship to congestion and potential NIETC designations, and provide some more general recommendations for how DOE might best proceed with this initiative.

However, in view of the prominence of California in each of the three classes of congestion identified in DOE's Study, it is apparent to us that DOE considers transmission congestion in our state to be sufficiently of concern that DOE is, or soon will be, considering the designation of one or more NIETCs in California. Accordingly, the main purpose of these comments is to urge DOE not to designate any NIETCs in or into California at this time. The reasons why DOE should not take any such precipitous action, which will be elaborated in more detail below, are as follows:

- California is already making significant progress to plan for and site needed new transmission, especially in the Southern California area. Assuming

that most of these projects are ultimately approved, the reasons for which DOE identified "Southern California" as a Critical Congestion Area will no longer apply, such that there would be no legal or factual justification for the designation of <u>any</u> NIETCs in Southern California. Accordingly, DOE should not designate any NIETCs in Southern California until all of the current regulatory processes have reached their conclusion.

- There is even less need for DOE to take action to address its interest in the Conditional Congestion Area associated with wind development in Southern California, because the California stakeholders are already far along the road to addressing and resolving this issue, which arises purely from forward-looking state policy initiatives that are more advanced than the renewable energy and energy diversity/independence objectives rightly supported in the DOE Study.
- DOE's identification of the San Francisco Bay Area as a Congestion Area of Concern is based on various filed comments and other, unattributed information, which is largely out-of-date, misleading or of limited relevance. This identification also appears to ignore recent transmission upgrades in the Bay Area, as well as other transmission upgrades that have already been approved but are not yet built, as well as planned generator additions and replacements that will reduce congestion within the region.

DOE should accordingly not take any action to designate any NIETCs into or within the Bay Area.

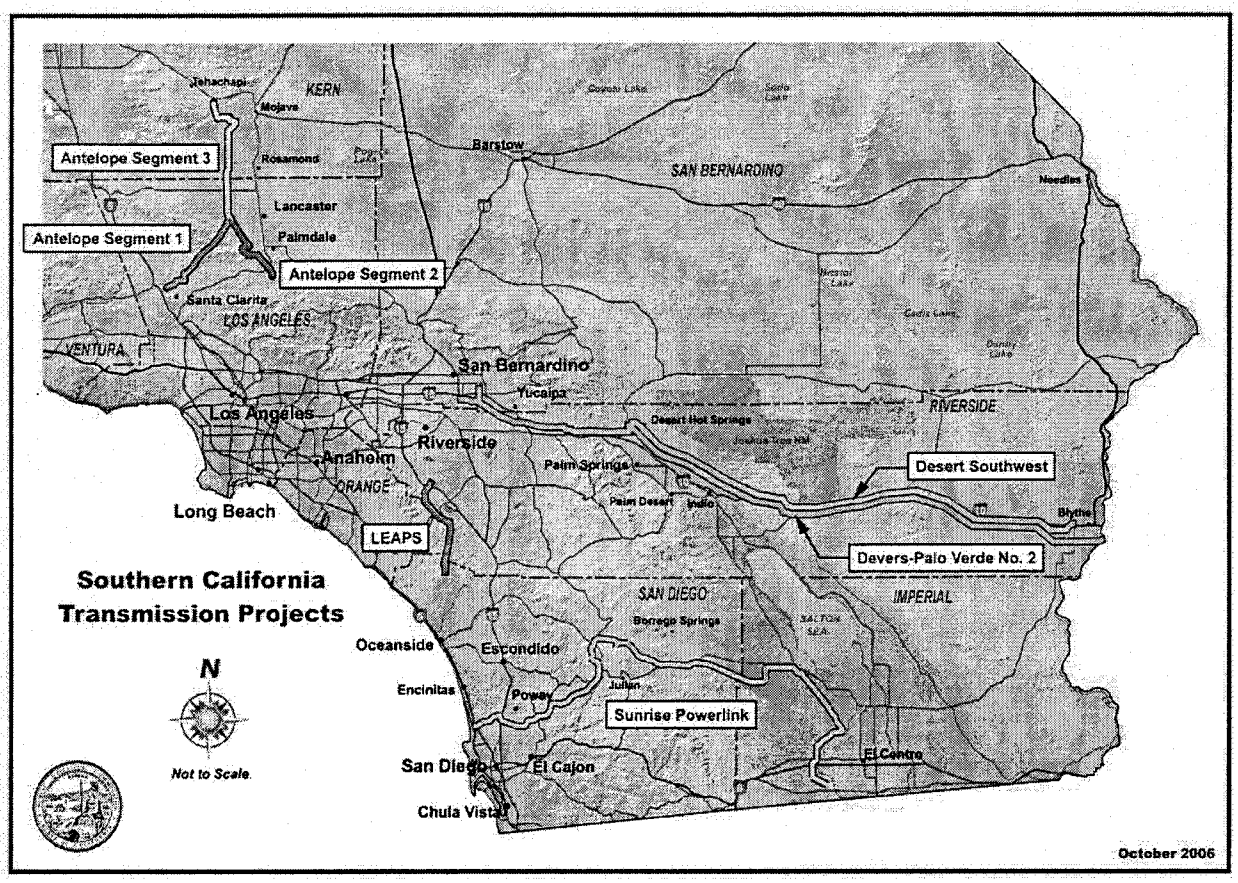
- Because of the existence, and the increasing sophistication, of the regional transmission planning process in the Western Interconnection, and the preliminary nature of planning for transmission "mega projects" across the West, DOE should not, at this time, designate any NIETCs relating to any of the other Conditional Constraint Areas that DOE has identified in the West.
- Although these comments demonstrate that there is no reason for DOE to designate any NIETCs in or into California at this time, there is something that DOE can do, right now, to assure that additional transmission that will be needed in California in the future can be sited in a rational and efficient manner. Specifically, DOE can incorporate into the EPAct Section 368 study that is currently under way the existing and new transmission corridors in the Angeles and Cleveland National Forests that are discussed below. Also, DOE can support efforts by the California Independent System Operator ("CAISO"), the CPUC, and California stakeholders to obtain approval by the Federal Energy Regulatory Commission of more forward-looking and efficient means of funding transmission to access remote, location-dependent resources of the types discussed at considerable

length in the DOE Study.

DISCUSSION

A. SOUTHERN CALIFORNIA

California is already making significant progress to site needed new transmission, especially in the Southern California area. There are currently six separate transmission projects that are currently under active regulatory review, and final decisions on three of these six projects are expected within the next three months. The map below illustrates these various projects.



The Devers-Palo Verde No. 2 Project ("D-PV2"), the Sunrise Powerlink Project ("Sunrise") and Antelope Segments 1, 2 and 3 are all currently under review before the CPUC.

Devers-Palo Verde No. 2. The 500 kV D-PV2 project is in the final stages of permitting at the CPUC. The project application was filed at the CPUC in April 2005 and the project is currently undergoing environmental review. The final environmental document is expected to be published in October 2006 and a Commission decision is

anticipated in December 2006. The project is also currently undergoing hearings by the Arizona Siting Committee.[2]

Sunrise Powerlink Transmission Project. Sunrise is a proposed 500 kV line from Imperial County into San Diego that has been analyzed and approved by the California Independent System Operator ("CAISO") and is in the midst of permitting at the CPUC.[3] A partial project application was filed at the CPUC in December 2005, and an amended Proponents Environmental Assessment ("PEA") was filed in August 2006. The project is currently undergoing environmental scoping review. The expected date for the issuance of final environmental reviews and a Commission decision is the fourth quarter of 2007 or early in the first quarter of 2008.

Tehachapi Transmission Project. The Tehachapi project currently is being permitted in four phases. The first phase consists of two applications, one for Antelope Segment 1 and another for Antelope Segments 2 and 3, both of which were filed in December 2004. The application on Segments 2 and 3 was initially incomplete and was amended in September 2005.[4] The Segment 1 application (Antelope-Pardee 500 kV line)

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2 The D-PV2 application is being reviewed in CPUC Docket No. A.05-04-015. The link to this docket on the CPUC's website is: http://www.cpuc.ca.gov/proceedings/A0504015.htm.

3 The Sunrise application is being reviewed in CPUC Docket No. A.06-08-10. The link to this docket on the CPUC's website is: http://www.cpuc.ca.gov/proceedings/A0608010.htm.

4 Antelope Segment 1 is being reviewed in CPUC in Docket A.04-12-007, and Segments 2 and 3 are being reviewed in CPUC in Docket A.04-12-008. The links to these dockets on the CPUC's

is in the final stages of review at the CPUC. The draft environmental document has been issued, and the

website are: http://www.cpuc.ca.gov/proceedings/A0412007.htm, and http://www.cpuc.ca.gov/proceedings/A0412008.htm.

public comment period just ended in early October. The final environmental document is expected be issued in early November 2006, with a Commission decision expected before the end of this year. The amended application for Segments 2 and 3 was filed at the end of September 2005 and deemed complete in November 2005. An environmental document is currently out for public review. The comment period will close in mid-October 2006. The final environmental document should be issued in December 2006, with a Commission decision expected in January 2007. There will be two more permitting phases for the Tehachapi Project. The next project application is scheduled to be filed with the CPUC in March 2007. This application should include a 500 kV substation as a connection point for the Tehachapi Wind Farm projects. The estimated date for approval for this project by the CPUC's Commissioners is mid 2008. The final application should be filed in June 2007 and includes the rest of the transmission build-out for the Tehachapi area. This application will require environmental review both by the state and by federal agencies. The estimated date for approval of this application by the CPUC's Commissioners is late 2008. When added to Tehachapi transmission projects already before the CPUC, this will accommodate up to 2,200 MW of wind generation. There is one additional phase of work on the Tehachapi project that will not require any filings with the CPUC, as it only involves extending the capabilities of facilities to be previously installed, by changing out some equipment in existing substations from 230 kV to 500 kV and increasing the operating voltage for certain of the

new transmission lines to 500 kV. These modifications will add an additional 2,300 MW of transmission capacity for the wind resources from the Tehachapi area, for a total of 4,500 MW of wind export capability.

The Desert Southwest Project ("DSP") is being sponsored by a number of municipal utilities and is not subject to CPUC jurisdiction. The CPUC understands that if both D-PV2 and DSP are approved, only one of these projects will proceed, as they follow essentially the same route and would eliminate the same existing congestion.

Finally, the Lake Elsinore Advanced Pumped Storage ("LEAPS") project, because it is a hydroelectric project, is currently undergoing review at the Federal Energy Regulatory Commission ("FERC"), although it will also require approval by the CAISO (and possibly other state agencies) in order to be built. This project includes a key 500 kV transmission link that will substantially enhance the flexibility of importing power into Southern California load centers.

Once the currently on-going regulatory processes that are addressing all of these proposed new projects are completed -- within the reasonably near future -- and assuming that most of these projects are ultimately approved, the reasons for which DOE identified Southern California as a Critical Congestion Area will no longer apply, such that there would be no legal or factual justification for the designation of <u>any</u> NIETCs in Southern California. Moreover, as the following comments show, the DOE Study apparently exaggerated the significance of congestion into Southern California, such that DOE's

identification of Southern California as a Critical Congestion Area appears to be premature and overly pessimistic.

DOE should accordingly take a "wait and see" attitude, and not designate any NIETCs in Southern California until all of the current regulatory processes have reached their conclusion, and until DOE takes a more careful look at the data on which they based their initial identification of congestion in Southern California as being "critical."

The CPUC's Understanding of the DOE Study Findings

The DOE Study identified "Southern California" as one of two nationwide Critical Congestion Areas. Apparently, the term, "Southern California," refers primarily to transmission paths from Arizona into Southern Nevada and Southern California. This terminology and physical scope are of consequence, as is discussed below. Page 17 of the DOE Study states that information on congestion in the Western Interconnection was received in two forms: a review of "over 35" documents from a variety of sources, and examination of archived data collected by the Western Electricity Coordinating Council ("WECC"), including data on hourly lines flows. Beyond this, the DOE Study clearly indicates that findings also rely significantly on simulations of generator dispatch and power flows, while noting that "given the uncertainties and complexities of these simulations, the relative rankings of constrained paths are more significant that the

absolute values estimated for any specific path."[5] The DOE Study's discussion of the rationale for identifying particular Congestion Areas also appears to indicate significant emphasis on comments filed by interested parties.

Summary tables submitted to DOE by the Western Congestion Assessment Task Force ("WCATF")[6] identify "Arizona to California" as a congestion area based on "Task 1 Studies" consisting of a review of various existing studies, and also based on simulations for 2008, but not based on historical data for 1999-2002, and not based on simulations for 2015. The DOE Study concludes that transmission paths from Arizona into Southern Nevada and Southern California experience congestion "based on current or near-term conditions,"[7] although transmission data for 1999-2002 did not actually show high congestion in this area, particularly compared to other major paths in the Western Interconnection.[8]

"Task 1 studies" submitted by WCATF, which indicated this to be a congestion area, included Path 49 (East of River) upgrade studies focused on autumn 2006 conditions and the California Energy Commission's ("CEC") Strategic Transmission

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5 DOE Study, page 14.

6 *See,* Table 3, Comprehensive Summary List/ Western Interconnection Identified Congestion Areas, WCATF Study, page 20.

7 From DOE Study, Figure 4-1, which, we understand, was not reviewed by WCATF in its final form.

8 *See,* DOE Study, Figure 4-2.

Investment Plan, which did not conduct original analyses, but reviewed "publicly available information from project proponents and other sources"[9] and concluded that congestion in this area (Arizona to California) was significant and that three proposed projects in this area would represent good investments, namely, D-PV2, Sunrise (Imperial to San Diego) and Imperial County area upgrade projects.

However, in another submitted study, "Western Interconnection 2006 Path Utilization Study," which was based on physical flow data over the Western Interconnection during 1999-2005, Arizona-to-Southern California was not among those areas found to be experiencing "heavy path usage".[10]

The WCATF Simulation for year 2015 assumed completion of several planned transmission projects in Arizona, Southern Nevada and Southern California that would mitigate congestion, including: D-PV2, Sunrise, and another 500 kV line from Imperial County to Los Angeles, which has been proposed by a non-jurisdictional utility. WCATF's submittal to DOE recommended that the areas where these new lines are located "should be considered constraint areas until the facilities are operational."

9 *See,* information provided in item 11 of the Summary Templates for Existing and New Projects/Studies (DOE Tasks 1 and 3) submitted to DOE by the WCATF, May 8, 2006.

10 *See,* Item 13 in template information provided to DOE by the WCATF for the Western Interconnection 2006 Path Utilization Study (template item 13, "Congestion Identified").

However, in Section 5.3 of the DOE Study, considerations cited in finding "Southern California" to be a Critical Congestion Area include the large population and growing electricity demand, the economic importance of the area, CAISO documents indicating that contingencies could cause Southern California to be short on local generation, submitted comments from the CEC citing portions of the CEC's Strategic Transmission Investment Plan finding four Southern California transmission projects to be needed in the near term, and comments submitted by San Diego Gas & Electric Company ("SDG&E") which state that San Diego faces reliability concerns and which also quote from a CEC report stating that San Diego's transmission problems are acute.

We would also note that while the DOE Study identifies a congestion area as "Southern California," this is a misnomer, which has more than semantic implications. First, electricity transmission from the desert southwest into Southern California is an interstate concern, involving infrastructure capabilities and development in Southern California, Southern Nevada, and extending almost half way across Arizona. Also, within California, it extends beyond the CAISO control area or CPUC jurisdictional utilities' territories, into the neighboring Imperial Irrigation District and also includes existing and proposed transmission facilities of the Los Angeles Department of Water and Power.

Year 2008 simulations are cited in the DOE Study as indicating the high economic significance of congestion from Arizona into Southern Nevada and Southern California. In fact, the highest simulated congestion costs (calculated line-specific congestion rents)

occur on lines from Arizona into Southern Nevada. The D-PV2 Project, in final stages of permitting at the CPUC, extends well into Arizona, and the important "EOR 9000+" transmission upgrade deals with lines from Arizona into Southern Nevada. Also, SDG&E's proposed Sunrise Project requires complementary transmission upgrades outside of the CAISO control area. DOE should accordingly recognize and reflect in its terminology the fact that future transmission congestion seen to threaten Southern California is an interstate transmission issue involving facilities and processes across several states and transmission systems. It is no coincidence that the title of EPAct § 1221 reads "Siting of ***Interstate*** [emphasis added] Transmission Facilities." Only if and when the interstate processes break down should DOE consider designated a NIETC, with its threat of federal preemption of state siting authority, from the desert southwest into Southern California.

It is appropriate and constructive for DOE to call attention to present and future challenges regarding transmission adequacy from the desert southwest into Southern California. However this situation is being addressed on an ongoing and focused basis, regionally by WECC and sub-regionally by the Southwest Transmission Expansion Planning ("STEP") process, as well as by CAISO and CPUC transmission planning and permitting processes. As noted above, D-PV2 and Sunrise are under active consideration by the CPUC, and several transmission upgrades have already been implemented or

approved.[11]

While recognizing current efforts by the CAISO and the CPUC to identify and permit transmission solutions and urging continued cooperative analysis and planning, and despite the fact that the WCATF Study, which was presumably the technical basis for the DOE Study does not support this finding, the DOE Study nonetheless finds "Southern California" to be a Critical Congestion Area when taking into account the area's economic and strategic significance plus the value of supply diversity and skepticism about siting future generation in Southern California.

The CPUC questions DOE's basis for this identification and respectfully suggests that the following discussion on transmission planning in California and the West should alleviate some of the skepticism that may have played a role in this identification.

Transmission Planning in California

Within California, the CAISO works closely with its Participating Transmission Owners ("PTOs"), the CPUC, the CEC and its other stakeholders to proactively identify needed, cost effective transmission solutions through an open, non-discriminatory

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11 "Short-term upgrades" approved by the CAISO Board in 2004 (capacitors, phase shifter, dynamic voltage support, transformer addition) for the southern part of the Arizona-Southern California interface are largely now in place to significantly alleviate congestion in this area, and when fully completed by next summer will add just over 500 MW to Arizona-to-California transfer capability. The "EOR 9000+" project now in the final path rating process at WECC will add 1250 MW to Arizona-to-Southern California transfer capability via series capacitors on lines into Southern Nevada from Arizona. Originally considered less certain, this project was excluded from the WCATF's simulations for 2008 and 2015, and will have a substantial impact on any projected congestion.

planning process. Over the five-year period between 2000 through 2004, the CAISO authorized 237 transmission project upgrades representing $2.4 billion of infrastructure investment. $1.8 billion of transmission projects were completed during that time period.

In general, the CAISO oversees the transmission expansion planning process within the CAISO control area in order to establish the reliability and economic need of proposed new projects. Transmission expansion plans are developed through a collaborative process that includes PTOs, the State, and other stakeholders. The PTOs perform the majority of the technical analyses for their respective systems and jointly participate in development of longer-term assessments. The CAISO reviews and approves PTO plans and assessments based on applicable planning standards and criteria, and technical and economic feasibility. A new economic test, the Transmission Economic Assessment Methodology ("TEAM") has been developed to provide a common methodology to evaluate the economic need of transmission upgrades based on local and regional benefits, market power, and uncertainty of a wide range of future system conditions, operational feasibility, and the comparison of valid alternatives. A proposed decision of the CPUC, which is expected to be considered for adoption by the CPUC's Commissioners next month, would give a rebuttable presumption in CPUC proceedings on applications for a Certificate of Public Convenience and Necessity

("CPCN")[12] to a CAISO determination that a given proposed project is needed.[13]

The CAISO's coordinated grid planning process involves review of proposed system upgrades and expansions to ensure efficient use of the system and enhance operating flexibility. Currently, the CAISO's Comprehensive Grid Expansion Plan is developed from the following inputs:

a. Proposed generation projects identified through interconnection requests;

b. The CAISO Controlled Grid Plan that includes needs identified by PTO's through the PTOs' Annual Transmission Plans. (The PTOs' Annual Transmission Plans describe proposed facility additions covering a 10-year planning horizon);

c. Needs identified by the CAISO or Market Participants or through stakeholder or policy-driven processes, such as those associated with transmission upgrades necessary to accommodate new renewable energy resources; and

d. The availability of Reliability Must Run Generation, Local Area Reliability Service, and Resource Adequacy resources.

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12 This is the name of the permit that the CPUC issues when it approves a major new project, such as a new transmission line.

13 This Proposed Decision can be found at the CPUC's website at the following link: http://www.cpuc.ca.gov/EFILE/ALT/60624.htm.

The CAISO has the authority to mandate system upgrades required for reliability deficiencies. The CPUC also has the authority to require an upgrade or expansion of PTO facilities to meet regulatory obligations.

California is currently working to develop statewide transmission planning efforts that will include non-CAISO participants. Toward this end, the CAISO, the CPUC and other stakeholders in California have already begun the work of creating a California-wide sub-regional transmission planning group. We are optimistic that all key transmission systems in California, including those of the large, unregulated municipal utilities that do not participate in the CAISO, will soon be joining in a collaborative state-wide process, with the full support of the WECC, to identify transmission upgrades that will be needed state-wide in order to meet future needs.

B. TEHACHAPI WIND RESOURCE AREA

California's legislatively mandated Renewable Portfolio Standard ("RPS") explicitly recognizes the need for new transmission facilities to facilitate the achievement of RPS goals.[14] Soon after the adoption of the RPS, the CPUC took the initiative to commence a planning process to identify the transmission needed to access 4,000+

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[14] California's Renewable Portfolio Standard Program was enacted in 2002 and is set forth at California Public Utilities ("P.U.") Code section 399.11, *et seq*. With respect to transmission issues associated with the development of renewable resources, see, in particular, P.U. Code section 399.25.

megawatts of wind energy in the Tehachapi Region of California by convening a Study Group incorporating all interested stakeholders.

Early in this process, several initial transmission upgrades were identified and submitted to the CAISO for approval. Thereupon, the CPUC ordered the Southern California Edison Company ("SCE") to file a permit application for these upgrades, which were designated Antelope Segments 1, 2 and 3. SCE duly complied, and these applications are currently before the CPUC. The environmental review of these projects is nearing its completion, and we expect that the CPUC's Commissioners will be able to issue a decision on these applications before the end of this year for Segment 1 and very early next year on Segments 2 and 3.

After the completion of the extensive, multi-year stakeholder process, the Tehachapi Study Group developed a set of proposals for the rest of the transmission upgrades that would allow the full potential wind energy output of the Tehachapi Region to be fully deliverable to load within the state. The results of this effort were turned over to the CAISO for final analysis this past spring.[15] Working with SCE, the Pacific Gas & Electric Company ("PG&E") and other stakeholders over the past 6 months, the CAISO has modified the configuration of the Tehachapi Study Group proposals in order to provide the needed transmission to access the Tehachapi wind resource in the most

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15 The Final Report of the Tehachapi Study Group can be found at http://www.cpuc.ca.gov/Published/Graphics/48819.PDF.

reliable and cost-effective manner possible. The CPUC fully expects the CAISO to approve the final configuration of the needed new Tehachapi transmission before the end of this year. Once the CAISO has approved this final configuration, SCE is committed to submitting applications to the CPUC during 2007 for the necessary permits to build all of the transmission necessary to bring full complement of Tehachapi wind resources to load.

At the same time that the Tehachapi study process was being conducted under the auspices of the CPUC, another study process intended to identify transmission needed to accommodate new renewable resources in the Imperial Valley area of Southeastern California was undertaken under the auspices of the CEC.[16] The results of this work performed by the Imperial Valley Study Group were also turned over to the CAISO for final approval. SDG&E's Sunrise project, which is also currently under permit review at the CPUC, is, in part, an outgrowth of this Imperial Valley study process.

In addition, another California transmission project, the LEAPS project in Riverside County, has the potential to assist the state in meeting its RPS goals by providing energy storage and a key 500 kV transmission link. As noted above, the LEAPS project is currently undergoing review at FERC, although it will also require approval by the CAISO (and possibly other state agencies) in order to be built.

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16 The CEC, rather than the CPUC, was ultimately responsible for preparing the report of Imperial Valley Study Group, because several of the key stakeholders in the development of the Imperial Valley's renewable resources (*i.e.*, the Los Angeles Department of Water and Power and the Imperial Irrigation District) are unregulated municipal utilities that are outside the CPUC's jurisdiction.

Given this set of major proposed transmission projects in Southern California, all geared, at least in part, to advance the state's RPS, the CAISO has undertaken an integrated review of the proposed Sunrise, Tehachapi and LEAPS transmission projects in order to identify which of these projects will optimally advance the state's RPS goals while also providing for grid reliability and good value for ratepayers. Work on this Southern California-wide transmission planning effort is currently ongoing and is intended to result in the ultimate approval by the CAISO of a set of economically viable projects that will allow significant quantities of renewable resources to become fully deliverable to load. The CPUC is hopeful that the CAISO will complete its work on this Southern California plan before the end of this year.

The work of the CPUC, the CAISO and other stakeholders on the Tehachapi and Imperial Valley Study Groups, and now on the Southern California transmission plan, is an outstanding example of how state policy can appropriately, effectively and beneficially impact the transmission planning process and of how state agencies can take a proactive role in this process.

There is accordingly no need for DOE to take any action to address transmission needs associated with wind development in Southern California, because the California stakeholders are already far along the road to addressing and resolving the issue. The Tehachapi transmission project has been created to support aggressive state renewable energy and energy diversity goals of the type lauded by the DOE Study. This effort

would be harmed, not aided, by the threat of overlaying preemptive federal siting authority on a transmission development process that clearly falls within the authority of the state, the CAISO and the CPUC-jurisdictional electric utilities. Rather than the possible threat of federal preemption, what is needed here is enhanced federal understanding and support of the state processes and efforts, particularly through enhanced federal cooperation in the areas of cost recovery and siting.

Coordinating and expediting the permitting of such projects by federal agencies, such as the Forest Service and the Bureau of Land Management, through whose lands the projects pass, would be very helpful in contexts such as Tehachapi. Similarly, it would be useful if DOE were to provide to the states, without the need or request for any NIETC designations, the same degree of federal agency permitting coordination and urgency that FERC proposes to require to support its own, new siting role as addressed in its Notice of Proposed Rulemaking in Docket No. RM06-12-000.[17]

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[17] In this NOPR, FERC sets forth proposed backstop transmission siting rules that would be applicable to proposed projects located in any DOE-designated NIETCs pursuant to EPAct Section 1221 if states have not completed action on the proposed project within a year.

C. THE SAN FRANCISCO BAY AREA

The CPUC's Understanding of the DOE Study Findings

Information submitted to DOE by the WCATF regarding the analysis of historical power flow data and simulations for years 2008 and 2015 did not indicate congestion problems in the San Francisco Bay Area. Rather, in support of finding this area to be a "Congestion Area of Concern", the DOE Study cites three Bay Area cities' (Bay Area Municipal Transmission Group or "BAMx") comments regarding the high reliance on reliability-must-run ("RMR") generation in the Bay Area, as well as unattributed comments regarding "numerous large outages, including those of 1998, 2003 and 2005" experienced by San Francisco, and regarding San Jose's "high loads served with little local generation, heavy dependence on two substations, and a 115 kV system." The DOE Study concludes: "no broad suite of solutions has been proposed and approved to address these problems. Until this objective is met, the Department will view the Bay Area as a Congestion Area of Concern."

The only information provided to DOE by the WCATF that addresses congestion issues in the San Francisco Bay Area appears to be the CEC's Strategic Transmission Investment Plan, which, "relied upon the analysis performed by the San Francisco Stakeholder Group"[18] regarding reliability benefits of the proposed Trans-Bay DC Cable,

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[18] California Energy Commission, Strategic Transmission Investment Plan, in Western Congestion Assessment Study Summary Templates provided by WCATF to DOE, May 8, 2006.

and concluded that this project represents a worthwhile near term investment. The CEC also submitted corresponding comments directly to DOE. Key cited benefits of this project included eliminating the need for RMR contracts for the aging Hunters Point and Potrero power plants in San Francisco, and also helping enable the retirement of these plants.[19]

Comments and Recommendations

It is true that the San Francisco Bay Area, especially San Francisco and the upper peninsula, presents power delivery challenges in terms of maintaining reliability under certain contingencies. This situation arises from the geography and demography of the region, and has long been recognized and grappled with by the CPUC, the CAISO, the CEC, Northern California utilities and other stakeholders. The solution has been recognized as a combination of new generation, transmission upgrades and demand side measures. This represents a broad, and broadly agreed on, suite of solutions.

While the Bay Area does provide an electricity delivery challenge, some of the information cited by the Congestion Study as well as other information submitted to DOE in support of a NIETC designation, is simply out of date or of limited relevance. For example, the "numerous large outages, including those of 1998, 2003 and 2005," cited as experienced by San Francisco, apparently refer, in the cases of 2003 and 2005, to events that were in fact caused by substation fires in the 115 kV system that moves power

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[19] *Id.*

within the urban area (unless the 2005 outage instead refers to the storm-related outage in December). The 1998 event represents a large outage caused by a major technician error leading to a ground fault at a 230 kV/115 kV substation, followed by sub-optimal responses. The above outage events were essentially driven by internal problems needing attention, not by a shortfall of power imports from outside of the area.

A table submitted by BAMx to DOE[20] was taken from a CEC report and shows high "shortage risks" for San Francisco. This table depicts results of a probabilistic study based on 300 Monte Carlo simulations addressing the summer peak period of 2003. This study time frame predates approval of the major Jefferson-Martin transmission project by the CAISO and the CPUC. The Jefferson-Martin project added 400 MW of import capability into San Francisco and is presently in service. Combined with other transmission upgrades, this has allowed the aging Hunters Point Power Plant in San Francisco to not merely be taken off RMR status, but to be retired, which occurred several months ago.

It is important to recognize reliability risks, but it is equally important not to overstate them. Besides being out of date, the table submitted by BAMx depicts

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20 Attachment to "Comments of the Bay Area Municipal Transmission Group on Department of Energy's (DOE) Notice of Inquiry on Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridor" (March 3, 2006). The attachment is titled "Comments of the Bay Area Cities on Department of Energy's (DOE) Notice of Inquiry and Opportunity to Comment on Designation of National Interest Electric Transmission Bottlenecks (NIETB)" (September 17, 2004).

percentage "risks" that do not represent simulated risk of outage, but rather simulated risk of falling below a 7% operating reserve margin.

The unattributed statement that San Jose is dependent on a 115 kV system is at best misleading. Power is imported to the borders of the Bay Area over 500 kV lines from the Central Valley and the coastal Moss Landing Power plant, is moved further into the urban area including San Francisco and San Jose over 230 kV lines, and then is transmitted across the urban area over 115 kV lines. It would thus be more realistic to say that San Jose and the Bay Area depend significantly on 500 kV, 230 kV and 115 kV systems

Besides the Jefferson-Martin 230 kV line, numerous Bay Area transmission upgrades at the 60 kV, 115 kV and 230 kV levels have been completed in recent years. Furthermore, PG&E lists[21] the following planned Bay Area transmission projects that have reliability and/or RMR reduction benefits, and that have already been approved by the CAISO:

- ✓ Potrero-Hunters Point underground 115 kV cable (in San Francisco), in-service earlier this year
- ✓ Dumbarton-Newark 115 kV re-conductoring (in-service estimate 12/2006)
- ✓ Jefferson substation, second 230/60V transformer (in-service estimate 12/2006)
- ✓ Bair-Belmont 115 kV re-conductoring (in-service estimate 5/2007)

[21] 2006 Electric Transmission Reliability Assessment Study Report, final, September 7, 2006

- ✓ Ravenswood substation, 230 kV shunt capacitors (in-service estimate 12/2007)
- ✓ Martin-Hunters Point 115 kV underground cable (estimate in-service 12/2007)
- ✓ Metcalf-Moss Landing 230 kV re-conductoring (in-service estimate 12/2007)
- ✓ Vaca-Dixon 2nd 500/230 kV transformer (in-service estimate 12/2007)
- ✓ Metcalf-El Patio 115 kV re-conductoring (in-service estimate 5/2008)
- ✓ Newark-Fremont 115 kV re-conductoring (in-service estimate 5/2008)
- ✓ Trans-Bay Cable (400 MW capacity DC cable from Pittsburg to San Francisco, in-service estimate 2010)
- ✓ *Contra Costa - Las Positas 230 kV re-conductor (in-service estimate 5/2010)
- ✓ Oakland 115 kV underground cable (in-service estimate 5/2010
- ✓ Metcalf-Evergreen, re-conductor both 115 kV lines (in-service estimate 5/2012)
- ✓ Metcalf-Pierce, Swift-Metcalf, and Newark-Dixon Landing, re-conductor 115 kV lines (in-service estimate 5/2012)

These transmission upgrades address reliability and RMR reduction needs looking out several years, for the San Franscisco/Upper Peninsula area and for the broader Bay Area, including the three BAMx municipals submitting comments to DOE. PG&E has also proposed other upgrades not yet approved by the CAISO, including several 230 kV

re-conductorings and, ultimately, 500 kV facilities extending further into the Bay Area. The Trans-Bay Cable project supported in CEC comments was reviewed and approved by the CAISO, is undergoing environmental permitting outside of the CPUC.

The three Northern California municipal utilities submitting comments to FERC in support of a NIETC are the only load serving entities in the region that are not members of the CAISO, and, thus, represent holes in the independent, open access transmission system operating and planning process managed by the CAISO.

The ongoing solution to the San Francisco Bay Area's electric reliability challenges will include a mixture of local generation, transmission and demand side measures. Besides the transmission measures discussed above, a 600 MW natural gas-fired plant on the east side of the bay has been approved by the CEC and is estimated to be completed in 2010, and a 145-MW simple cycle peaking (reliability) plant in San Francisco was just approved by the CEC on October 3, 2006 and is expected to be in service in October of 2007.[22] Prudent planning will likely always require a certain amount of generation within the Bay Area itself, some of it in San Francisco, regardless of transmission objectives. However, construction of new plants will reduce the economic and environmental costs of this generation.

There is currently one remaining generating plant of substantial size in San

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22 *See,* http://www.energy.ca.gov/sitingcases/all_projects.html.

Francisco itself, and this plant is unlikely to be fully replaced by transmission alone. Thus, the CEC Presiding Member's Proposed Decision of August 26, 2006 regarding approval of the new 145 MW power plant within San Francisco finds " a combination of both generation and transmission – are necessary to preserve electrical reliability in San Francisco…no evidence of record credibly challenges this fact."[23] In contrast to some claims to the contrary, that Proposed Decision also states that the proposed Trans-Bay Cable "would fail to make closing aging in-city generation potentially possible."[24]

In conclusion, the San Francisco Bay Area's electric reliability presents a complex

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23 San Francisco Electric Reliability Project, Application for Certification (AFC-04-1), Presiding Member's Proposed Decision, August 2006, Page 15.

24 *Op cit.*, page 21.

ongoing challenge driven by geography, demography and economics. It is reasonable for DOE to seek more information, which the CPUC encourages. However, unlike the other congestion areas identified and discussed in the DOE Study, the San Francisco Bay Area apparently was not evaluated via any systematic quantitative analyses. DOE accordingly needs to consider either: (1) developing such a foundation if it wishes to assess this area in greater depth going forward, or (2) concluding that congestion issues within the San Francisco Bay Area are of too localized a nature for the NIETC process to be useful.

Based on the foregoing, the CPUC strongly urges DOE to conclude that the designation of a NIETC would be inappropriate and ineffective, especially in light of the ongoing pursuit of generation, transmission (AC and DC, land and water) and demand side solutions involving California energy agencies, local government and other stakeholders. This pursuit represents the crafting of the "broad suite of solutions" that DOE calls for in its Study.

D. OTHER CONDITIONAL CONSTRAINT AREAS IN THE WEST

The DOE Study notes that parts of the West are rich in coal and wind resources, that scenarios for accessing these resources have been explored by the Western Governors' Association's ("WGA") Clean and Diversified Energy Initiative, and that several large interstate transmission projects have in fact been proposed. The Study also notes the existence of additional generation resources further upstream in Canada, and concludes that "under a diverse range of generation futures, the Western Interconnection

needs large additions to its transmission network" to deliver the output of diverse and distant resources to load.

The CPUC generally agrees with the above observations, believes that such west-wide transmission issues require attention, and appreciates DOE's and FERC's engagement. However, it would be premature to even consider designating one or more NIETCs having preemptive federal siting, until *all* of the following have occurred:

- The locations and magnitudes of generation resource development are more fully established, including sufficient demonstration of commercial interest;
- There are also clear indications of willing buyers (and their locations) for the output of such generation resources;
- There are at least minimally credible feasibility-level demonstrations of cost effectiveness and cost allocation for would-be transmission projects;
- State and regional processes for developing this transmission are already receiving full cooperation from federal agencies such as regarding cost recovery and permitting on federal lands; and
- Notwithstanding the foregoing points, state and regional processes show clear evidence of being unable to address the transmission needs in a timely manner.

It is clear that these conditions do not currently exist, although they could conceivably develop. Moreover, in view of the abundance of effective, large-scale transmission planning and development that is already taking place in the Western Interconnection, DOE should not take any actions following on the publication of the DOE Study that might undermine or seek to trump these efforts. It is, first of all, up to

the states and the regions to solve their transmission planning and siting problems. Federal agencies should not intervene on the state or regional level unless and until there is a demonstrated need for them to do so.

Notwithstanding this considerable progress that is being made to enhance Interconnection-wide transmission planning in the West, and the existence of the major, interstate project proposals that are based on the outcome of regional and sub-regional planning in the Western Interconnection, a number of Conditional Constraint Areas are identified in DOE's Study as being of interest to DOE, in particular, the Montana-Wyoming Conditional Constraint Area, from which energy from coal and wind resources could be wheeled to Arizona and California. Because of the existence of our regional planning process and the effective collaboration we have had so far in the Western Interconnection, DOE should not, at this time, designate any NIETCs relating to these Conditional Constraint Areas. Rather, DOE should follow the process that the stakeholders in the Western Interconnection are conducting with respect to these large, multi-state projects.

Once it has been shown that any of these projects is both technically and, more importantly, financially feasible, then DOE can begin to keep closer tabs on the process in order to ascertain whether reasonable progress is being made moving the project to reality. It is only when DOE can show that a technically feasible project with realistic financing expectations is being unreasonably held up that DOE should consider

designating any NIETCs with regard to that project.

DOE must recognize, especially with respect to these large, multi-state projects associated with Conditional Constraint Areas, that the process will work best if the varied and numerous stakeholders who must all reach agreement in order for the project to move forward are given the opportunity to reach a consensus voluntarily, and without the undue pressure that the designation of a NIETC would bring to bear. Indeed, in such cases, it is likely that the designation of a NIETC is more likely to delay the project than to move it along.

Meanwhile, we encourage DOE to recognize and support the transmission planning and development efforts taking place in the West, which are summarized below.

Regional Planning in the Western Interconnection

Within the Western Interconnection, WECC (and its predecessor, the Western States Coordinating Council) has maintained a formal coordinated planning process for over ten years. The Seams Steering Group – Western Interconnection ("SSG-WI") was formed in the later 1990's to address physical and market interface issues across the sub-regions and (actual and potential) RTOs in the West, including congestion and its costs under different load and resource scenarios, using a comprehensive database and production cost modeling. The functions of SSG-WI have recently been handed over to WECC, and the SSG-WI database is currently being maintained by WECC and is freely

available to any transmission developer that seeks to build a project in the Western Interconnection.

In addition, in recent years, under the aegis of SSG-WI, sub-regional transmission planning organizations have formed and been active across the West. These include: the STEP, already mentioned above, the Northwest Transmission Assessment Committee ("NTAC"), the Southwest Area Transmission ("SWAT") study, the Colorado Coordinated Planning Group ("CCPG"), and the Rocky Mountain Area Transmission Study ("RMATS"). Furthermore, as DOE well knows, WECC, via WCATF and with support from the CPUC staff, helped to prepare the Western Interconnection portion of the congestion studies that went into the preparation of the DOE Study.

However, in order to allow for more coordinated planning to occur, this past April, the WECC Board formally approved a Transmission Expansion Planning Policy Committee ("TEPPC").[25] TEPPC will oversee the interconnection-wide planning process on a collaborative basis that will allow for the consolidated needs of all of the system operators in the Western Interconnection to be considered in the transmission planning process. The work to be performed under TEPPC will consider long-term regional needs for new transmission beyond reliability and congestion relief. Through

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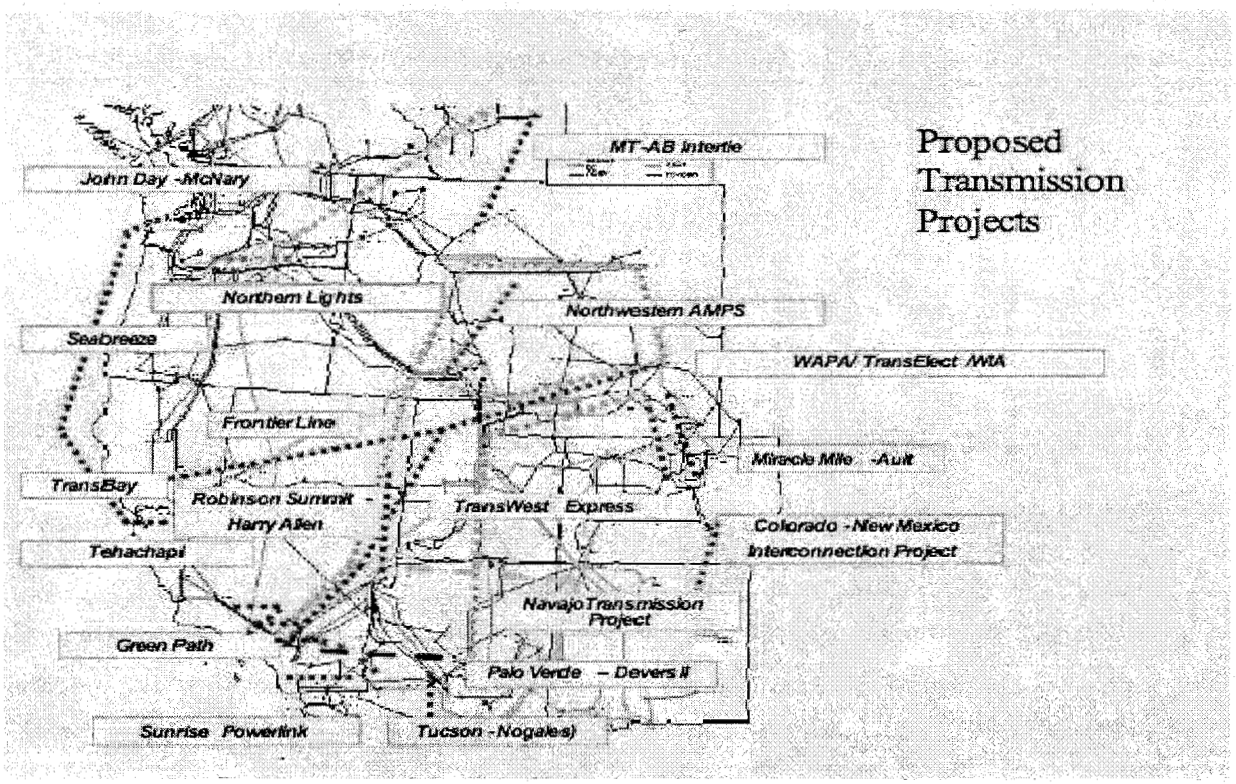
[25] TEPPC's three main functions include: (1) overseeing database management, (2) providing policy and management of the planning process, and (3) guiding the analyses and modeling for Western Interconnection economic transmission expansion planning. These functions compliment but do not replace the responsibilities of WECC members and stakeholders to develop and implement specific expansion projects.

the TEPPC, WECC is expanding its scope to take over and extend SSG-WI's role in "economic" transmission planning. Moreover, a key objective of the TEPPC will be to work toward the use of consistent and transparent input assumptions and robust methodologies that allow for the effective comparison of the results of the various transmission planning exercises that will be conducted throughout the Western Interconnection. This expanded role has the support of the industry, the states, and key regional organizations such as the WGA, the Western Interstate Energy Board ("WIEB") and the Committee on Regional Electric Power Cooperation ("CREPC").

While the TEPPC assumes its role in West-wide economic transmission planning, on-going transmission planning and evaluation activity in the West has already resulted in specific proposals for major new transmission projects that are currently under review at the state level. For example, the WCATF study identified projected congestion both east and west of the Colorado River. Two proposed transmission projects that would alleviate this congestion, D-PV2 and Sunrise, which are discussed in more detail above, were reviewed and approved through the sub-regional STEP process and are currently under active review by the CPUC. In addition to these California-specific projects, experience in the Western Interconnection shows that open transmission planning can lead to proposed projects and ultimately steel in the ground. For example, the sub-regional transmission planning processes have already resulted in the permitting and

development of several projects in Arizona, as well as the identification of numerous other potential transmission proposals in the Western Interconnection, including several large multi-state projects:



California participates closely in WECC, in sub-regional planning groups, and in regional energy organizations such as WGA, WIEB and CREPC. Transmission planning in California reflects and balances diverse goals and reflects collaboration among various organizations and stakeholders, extending to relevant sub-regional organizations (*e.g.*, STEP for Southern California and desert southwest transmission planning).

Thus, on-going transmission planning activities in California and across the

Western Interconnection have been developed through a careful, collaborative process, and are addressing a range of key, interdependent issues including reliability, congestion, competitiveness and diversity of supply, state policy objectives, resource adequacy, local area needs, stakeholder interests, balancing of wires and non-wires alternatives, and both permitting and funding challenges. Effective organizations and organizational relationships have been developed painstakingly over time, and we are making substantial progress. The evidence of this progress includes the activities of WECC, the sub-regional groups, west-wide organizations, and individual states, as well as the major transmission projects in various stages of planning and development.

E. THE SECTION 368 PROCESS

In addition to the process under Section 1221 of EPAct that led to the preparation of DOE's Study, DOE is currently carrying out a complementary process under EPAct Section 368, under which DOE is working with other federal agencies and the states to identify potential energy corridors on federal lands in the West that will be the subject of a Programmatic Environmental Impact Statement ("PEIS") to be completed late next year. DOE representatives have stated publicly that the Section 1221 process and the Section 368 process are "closely related."

Although the foregoing comments demonstrate that there is no reason for DOE to designate any NIETCs in or into California at this time, there is something that DOE can do, right now, to assure that additional transmission that will be needed in California in

the future can be sited in a rational and efficient manner. Specifically, DOE can incorporate into the EPAct Section 368 study that is currently under way certain existing and new transmission corridors in the Angeles and Cleveland National Forests.

The CPUC is a cooperating agency in the preparation of this PEIS for energy corridors under Section 368, and, since October 2005, the CPUC has been actively working with the California Interagency Working Group ("CIWG"), which consists of a number of state and federal agencies, on this project. Based on recent experience, and on preliminary long-term transmission plans for Southern California that we are aware of, we have determined that Section 368 corridor designation is necessary in the Tehachapi area (in Kern County), in the area known as "south of Vincent" in Los Angeles County, both in the Angeles National Forest, and also for the Valley-Serrano transmission corridor in the Cleveland National Forest. Each of these areas is currently designated as a "utility corridor" in the land management plans prepared by the Angeles and Cleveland National Forests, respectively. Planning currently under way could result in proposals to upgrade existing transmission in these areas to 500 kV lines. In addition, we have determined that it is appropriate to designate a new energy corridor in the southwest portion of the Cleveland National Forest (in San Diego County), to facilitate development of the Sunrise transmission project.

The CIWG's consensus-based approach has resulted in a strong package of corridor designation proposals. However, the consensus-based approach has been unable

to satisfactorily resolve disagreements when they have arisen. The Forest Service has to date not supported Section 368 designation for the areas discussed above, in part due to the existing utility corridor designations in its land management plans, which the Forest Service has argued render Section 368 designation unnecessary.

However, recent issues arising in the permitting process for the Antelope Segment 1 Project (which is proposed to built along an existing utility corridor in the Angeles National Forest), raises concerns that the designation of an existing "utility corridor" in a Forest Plan may not provide adequate certainty for planning future transmission upgrades for renewable resource development, grid reliability, and/or congestion.

A principal benefit of Section 368 corridor designation is to require federal agencies to conform their land management plans to the corridor designation. Such modifications to the Angeles and Cleveland land management plans would significantly reduce the uncertainty of transmission line siting in those areas. Since national forest lands surround the largest load area in California, *i.e.*, Los Angeles, Section 368 designations in existing utility corridors would help to ensure the ability to serve a growing population, likely with less environmental and societal impacts on the residents of California than would result from developing new corridors. Moreover, a Section 368 corridor designation in the southern Cleveland would provide a potential alternative route to a transmission line currently proposed to run through California's largest state park.

Given California's increasing population and energy demands, and its associated needs for renewable resource development and to solve reliability and congestion issues, the CPUC strongly recommends that the following Section 368 energy corridors are needed and are consistent with Section 368 (d) of the 2005 Energy Policy Act:

Existing Energy Corridors

- Midway – Vincent – Reliability, congestion, and Tehachapi renewable access (Angeles National Forest)
- Antelope – Pardee – Tehachapi renewable access (Angeles National Forest)
- Vincent – Rio Hondo – Tehachapi renewable access and congestion (Angeles National Forest)
- Vincent – Gould – Tehachapi renewable access and congestion (Angeles National Forest)
- Serrano – Valley – Congestion, reliability, and grid enhancement from Arizona via Devers-Palo Verde and Devers- Valley into urban growth area of Orange County (Cleveland National Forest)

New Energy Corridor

- Southern Cleveland National Forest – Access to Salton Sea geothermal and solar resources

We would accordingly urge DOE, as we have done in previous correspondence, to include in the Section 368 Study that is currently under way the existing and new corridors in the Angeles and Cleveland National Forests noted above.

CONCLUSION

For the foregoing reasons, as it moves forward to implement its Congestion Study,

DOE should take into account the concerns of the CPUC, and, specifically, in recognition of the significant progress currently being made to site needed new transmission in the state, and of the progress being made to develop Interconnection-wide transmission planning in the West, DOE should not designate any NIETCs in or into California at this time. However, DOE can take steps now to assure that additional transmission, which will be needed in California in the future, can be sited in a rational and efficient manner by incorporating into the Section 368 Study that is currently under way the existing and new corridors in the Angeles and Cleveland National Forests that are discussed above

October 9, 2006

Respectfully submitted,

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PART 1 OF 2
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To review Part 2 please see:

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