0000072168

Transcript Exhibit(s)

Docket#(s): L-00000AA-01-0116-00000

Exhibit # : A7, A8, A9, A10, A11, A12, A13, A14, A15, A16, A17, A18, A19, A20, A21, A22, A23, A24, A26, A27, A28, A29, A31, A32, A33, A34, A35

A-7

La Paz County Department of Community Development
Mary Dahl, Director

Established 1983

1112 Joshua ● Suite 202 ● Parker, Arizona 85344
(928) 669-6138 ● Fax (928) 669-5503 ● TDD (928) 669-8400

EXHIBIT
A-7
admitted

November 2, 2001

Laurie A. Woodall, Chairperson
Power Plant and Transmission Line Siting Committee
Assistant Attorney General, Environmental Enforcement Section
Office of the Attorney General
1275 West Washington
Phoenix, AZ 85007

RE: Allegheny Energy Supply La Paz Generating Facility - Siting Committee Case No. 116

Dear Ms. Woodall:

This correspondence is provided as a follow-up to the Committee regarding the Certificate of Environmental Compatibility (CEC) hearing for the proposed La Paz Generating Facility held in Parker on September 4, 2001 to respond to some of the issues raised at that hearing.

One issue that was discussed is how the County might work toward encouraging compatible land uses in the vicinity of a power generating facility. As mentioned in my testimony, the County is embarking on a comprehensive planning effort in compliance with the State Growing Smarter and Growing Smarter Plus legislation. That mandate includes provisions for regulating land use and planning for transportation circulation. The County has selected a consultant to work with us to prepare this plan, which will guide land use development within the County for the next 10 years, at which time, in accordance with current legislation, the plan will either be readopted or revised and adopted. The existing and proposed zoning district classifications in the vicinity of the proposed Allegheny facility will require unique treatment within the structure of the comprehensive planning process and the final plan will ensure compatible zoning and land uses for the project area. It should be noted that consultation with all adjacent counties and, in some cases, municipalities, is a requirement of the Growing Smarter family of legislation. Our plan will include guidance on how such consultation will be carried out with Maricopa County as well as our other neighbors. We have also discussed with Allegheny its proposed CEC condition on continued consultation regarding these subjects and support that condition.

The County has been consulting closely with Allegheny on their hazardous materials handling and response obligations for the proposed facility. Their draft analysis includes a listing of anticipated hazardous materials that may be used at the site as well as other Emergency Response (ER) criteria, including an off-site consequence analysis and a discussion of the ER guidelines that may be applicable to the facility operations. Our review indicates that the draft analysis addresses the applicable portions of Title 29 of the Code of Federal Regulations (CFR)

(Employee Emergency Plans and Fire Prevention Plans, Hazardous Waste Operations and Emergency Response, and Process Safety Management of Highly Hazardous Chemicals), 40 CFR (Risk Management Planning in accordance with the Clean Air Act and Emergency Planning and Community Right-To-Know) and Arizona Revised Statutes §26-347 (Facilities Subject to Emergency Planning; Facility Emergency Response Plans). In response to a specific concern about ammonia, Allegheny has conducted an off-site consequence analysis worst-case scenario to guide in plan development, training and plan implementation in accordance with the General Duty clause of the Risk Management Plan guidelines (40 CFR Part 68). The County is satisfied that Allegheny has conducted the proper level of hazardous materials planning for the facility and we are prepared to present the draft analysis to the Local Emergency Planning Committee at its next meeting. Allegheny has indicated it will continue its close communications with the local first responders, specifically the Wenden Fire Department, Salome Fire Department and Quartzsite Fire Department

The County has had further opportunities to review the proposed offset from the Avenue 75E alignment of the transmission line and switchyard. We believe that, unless other factors make this unachievable, paralleling Avenue 75E is the preferred alternative. It provides for a single utility corridor, rather than several, thereby reducing the visual impacts, and eliminating the constraints on development that would occur if properties were bisected by power lines. It also provides available access for construction of the facility. We believe that the proposed location of the transmission line is appropriate and support pursuit by Allegheny of that alignment.

It was a pleasure to have the opportunity to provide you and the Committee with information on this most important project. We are genuinely pleased that Allegheny has chosen La Paz County for its first Arizona facility and we hope to have a long and mutually beneficial relationship with them.

Should you require additional information from me, please let me know.

Best regards,

Mary Dahl

Mary Dahl
Director
Community Development and Emergency Management

Cc: Board of Supervisors
Randall Simpson
Kevin Geraghty
Michael Grant

A-8

"Managing and conserving natural, cultural, and recreational resources"

EXHIBIT
A-8
Admitted

In reply, please refer to
SHPO-2001-2191 (7549)
adverse effect

Arizona State Parks
1300 W. Washington
Phoenix, AZ 85007

Tel & TTY: 602.542.4174
www.pr.state.az.us

800.285.3703
from (520) area code

General Fax:
602.542.4180

Director's Office Fax:
602.542.4188

October 22, 2001

Laurie A. Woodall, Chairperson, Power Plant and Transmission Line Siting Committee
Assistant Attorney General, Environmental Enforcement Section
Office of the Attorney General
1275 West Washington
Phoenix, Arizona 85007

RE: Certificate of Environmental Compatibility: The Proposed La Paz Generating Facility and Transmission Line, La Paz County, Arizona

Dear Ms. Woodall:

Thank you for having the committee's applicant (i.e., Allegheny Energy) continue to consult with this office regarding the above-mentioned state plan and associated certificate of environmental compatibility. The proposed construction plan includes a generation station, underground pipeline, transmission line, and a switchyard facility on private land and portions of Arizona State Land Department land. I have reviewed the documents submitted and offer the following comments pursuant to the State Historic Preservation Act (i.e., A.R.S. § 41-861 to 41-864) and the committee's factors to be considered (i.e., A.R.S. § 40-360.06.A.5).

As previously discussed, two historic properties were identified within the geographic area affected by the plan. Both are prehistoric archaeological sites (i.e., AZ S:7:48 and 49 ASM), and we agreed that they are eligible for inclusion in the State Register of Historic Places under Criterion D (Information Potential).

Based on the additional information submitted, a possibility exists that one or both of the archaeological sites and a suitable buffer zone may be avoided by and protected from plan-related ground-disturbing activities. If the avoidance option is implemented for both sites, a determination of no impacts (c.f., no adverse effect) would be warranted. If the avoidance option is not feasible or not chosen for one or both of the sites, then a finding of negative impacts (c.f., adverse effect) would be warranted; archaeological data recovery within the affected portion of the site or sites would be needed in this case.

We reiterate the conditions mention in our August 14, 2001 letter for the committee's consideration:

1) If Sites AZ S:7:48 and 49 (ASM) cannot be avoided by plan-related ground-disturbing activities, the applicant will continue to consult with this office, on the committee's behalf, to resolve the negative impacts. This usually entails preparing and implementing a data recovery research design and work plan.

2) If a federal agency determines that all or part of this state plan represents a federal undertaking subject to review under the National Historic Preservation Act, the applicant will participate as a consulting party, on committee's behalf, in the federal compliance

process (i.e., 36 C.F.R. 800) to reach a finding of effect and to resolve adverse effects, if any.

3) Should cultural features and/or deposits be encountered during ground-disturbing activities related to the proposed plan, the applicant will comply with A.R.S. § 41-844, which requires that work cease in the immediate area of the discovery and that the Director of the Arizona State Museum be notified promptly.

Should this project proceed, we look forward to receiving from the applicant, a letter describing the proposed avoidance and protection measures or a data recovery work plan, as appropriate. We appreciate the committee's cooperation with this office in considering the effects of state plans on cultural resources situated in Arizona. If you have any questions or concerns, please contact me at (602) 542-7137 or electronically via mbilsbarrow@pr.state.az.us.

Sincerely,

Matthew H. Bilsbarrow, RPA
Compliance Specialist/ Archaeologist
State Historic Preservation Office

cc.
Gene Rogge, URS Corporation, 7720 North 16th St, Suite 100, Phoenix, AZ 85020

EXHIBIT
A-9
admitted

La Paz Generating Facility

Application for a Certificate of Environmental Compatibility

Allegheny Energy Supply
an Allegheny Energy company

La Paz Generating Facility

Application for a Certificate of Environmental Compatibility

Testimony of Randall Simpson

Allegheny Energy Supply
an Allegheny Energy company

Environmental Conditions

State Historic Preservation Office

24. If Sites AZ S:7:48 and 49 (ASM) cannot be avoided by ground disturbing activities, the Applicant will continue to consult with the State Historic Preservation Office to resolve any negative impacts which usually entails preparing and implementing a data recovery research design and work plan.

25. If a federal agency determines that all or part of the Project represents a federal undertaking subject to review under the National Historic Preservation Act, Allegheny will participate as a consulting party in the federal compliance process (i.e., 36 C.F.R. 800) to reach a finding of effect and to resolve adverse effects, if any.

Allegheny Energy Supply
an Allegheny Energy company

Environmental Conditions

State Historic Preservation Office, *con't...*

26. Should cultural features and/or deposits be encountered during ground disturbing activities, Allegheny will comply with A.R.S. § 41-844, which requires that work cease in the immediate area of the discovery and that the Director of the Arizona State Museum be notified promptly.

27. If human remains or funerary objects are encountered during the course of any ground disturbing activities related to the development of the subject property, Applicant shall cease work and notify the Director of the Arizona State Museum in accordance with Ariz. Rev. Stat. § 41-865.

Allegheny Energy Supply
an Allegheny Energy company

Environmental Conditions
Biology

16. Allegheny will fence the generating facility and evaporation ponds to minimize effects of plant operations on terrestrial wildlife and will keep the berms surrounding the evaporation ponds clear of vegetation to limit pond attractiveness to birds.

17. Applicant will monitor the evaporation ponds, recording avian use of the ponds and water quality on a weekly basis. If a large number of birds are using the ponds, Allegheny will contact the U.S. Fish and Wildlife Service and the Arizona Game & Fish Department to discuss potential mechanisms to reduce the number of birds utilizing the ponds.

Environmental Conditions

Biology, *con't...*

18. Allegheny will continue cactus ferruginous pygmy owl surveys through the Spring of 2002, based on established protocol. If survey results are positive, the U.S. Fish and Wildlife Service and Arizona Department of Game and Fish will be contacted immediately for further consultation.

19. Allegheny will retain a qualified biologist to monitor all ground clearing/disturbing construction activities. The biological monitor will be responsible for ensuring proper actions are taken if a special status species is encountered (e.g., relocation of a Sonoran desert tortoise).

Environmental Conditions
Landscape Planning

20. Applicant will salvage mesquite, ironwood, saguaro and palo verde trees removed during project construction activities and use the vegetation for reclamation in or near its original location and/or landscaping around the plant site.

21. Applicant will retain a qualified landscape architect to develop a landscape plan for the perimeter of the generating facility. The landscape plan will use native or other low water use plant materials. The Applicant will continue to consult with La Paz County regarding the landscape plan.

Environmental Conditions
Land Use

23. The Applicant will continue to consult with La Paz County in relation to its comprehensive planning process to develop appropriate zoning and use classifications for the area surrounding the Project.

La Paz Generating Facility

Application for a Certificate of Environmental Compatibility

Testimony of Herb Verville

Allegheny Energy Supply
an Allegheny Energy company

Regulatory BACT Definition

- Section R18-2-101(19) of the Arizona Administrative Code defines BACT as “an emission limitation, including a visible emissions standard, based on the maximum degree of reduction for each pollutant listed in R18-2-101(97)(a) which would be emitted from any proposed major source or major modification, taking into account, energy, environmental, and economic impact and other costs, determined by the Director in accordance with R18-2-4069A)(4) to be achievable for such source or modification.”

Allegheny Energy Supply
an Allegheny Energy company

Regulatory BACT Definition

- Section R18-2-406(A)(4)) further states, “BACT shall be determined on a case-by-case basis and may constitute application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment, clean fuels, or innovative fuel combustion techniques, for control of such pollutant… If the Director determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof may be prescribed instead to satisfy the requirement of the application of BACT.”

Allegheny Energy Supply
an Allegheny Energy company

Breakdown of BACT Definition

- an *emissions limitation* based on the maximum degree of reduction for each air pollutant subject to regulation under the Clean Air Act that would be emitted from any proposed major source or major modification
- *determined by the Director* to be achievable for such source
- *determined on a case by case basis* taking into account energy, environmental, and economic impacts

Allegheny Energy Supply
an Allegheny Energy company

BACT Methodology – Top Down Analysis

Step 1 – Identify All Control Technologies

Step 2 – Eliminate Technically Infeasible Options

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Step 4 – Evaluate Most Effective Controls and Document Results

Step 5 – Select BACT

Allegheny Energy Supply
an Allegheny Energy company

Proposed BACT Levels for the La Paz Generating Facility

- No_x: 2.5 ppm with 10 ppm ammonia slip
- CO: 5.0 ppm
- VOC: 3.11 ppm
- PM_{10}: 0.0207 lbs/MMBtu
- SO_2: 0.0024 lbs/MMBtu

Allegheny Energy Supply
an Allegheny Energy company

La Paz Generating Facility

Application for a Certificate of Environmental Compatibility

Testimony of
David A. Carr

Allegheny Energy Supply
an Allegheny Energy company

Water Supply

- Water demand = 6,500 ac-ft/yr
- 2,319.4 acres of purchased farmland are eligible for irrigation
- No more than 30 ac-ft for any 10-year period (3 ac-ft/yr) may be pumped
- Therefore, La Paz may pump up to 6,958 ac-ft/yr
- Greater than the projected water demand of the power plant

Allegheny Energy Supply
an Allegheny Energy company

Water Supply Study

- Compiled data from publicly available sources
- Used the information to evaluate groundwater conditions
- Evaluated hydrogeologic units, aquifer thickness, depth to groundwater, groundwater flow direction, pumpage history, and groundwater quality
- Installed and tested two monitor wells on the property
- Monitor well installation report was included with the water supply report
- Power plant pumping was evaluated using a groundwater flow model developed for the Vidler recharge project

Allegheny Energy Supply
an Allegheny Energy company

Groundwater Model

- Developed by Hydrosystems for the Vidler recharge site
- Developed to assess basin-wide impacts of groundwater recharge
- Capable of assessing impacts of groundwater pumping
- Model is a 3-D, numerical model of the entire basin
- Simulates the physical dimensions and characteristics of the aquifer
- Simulates recharge, pumpage, and other sources of inflow and outflow
- Best available tool for assessing impacts of pumping from the wellfield

Allegheny Energy Supply
an Allegheny Energy company

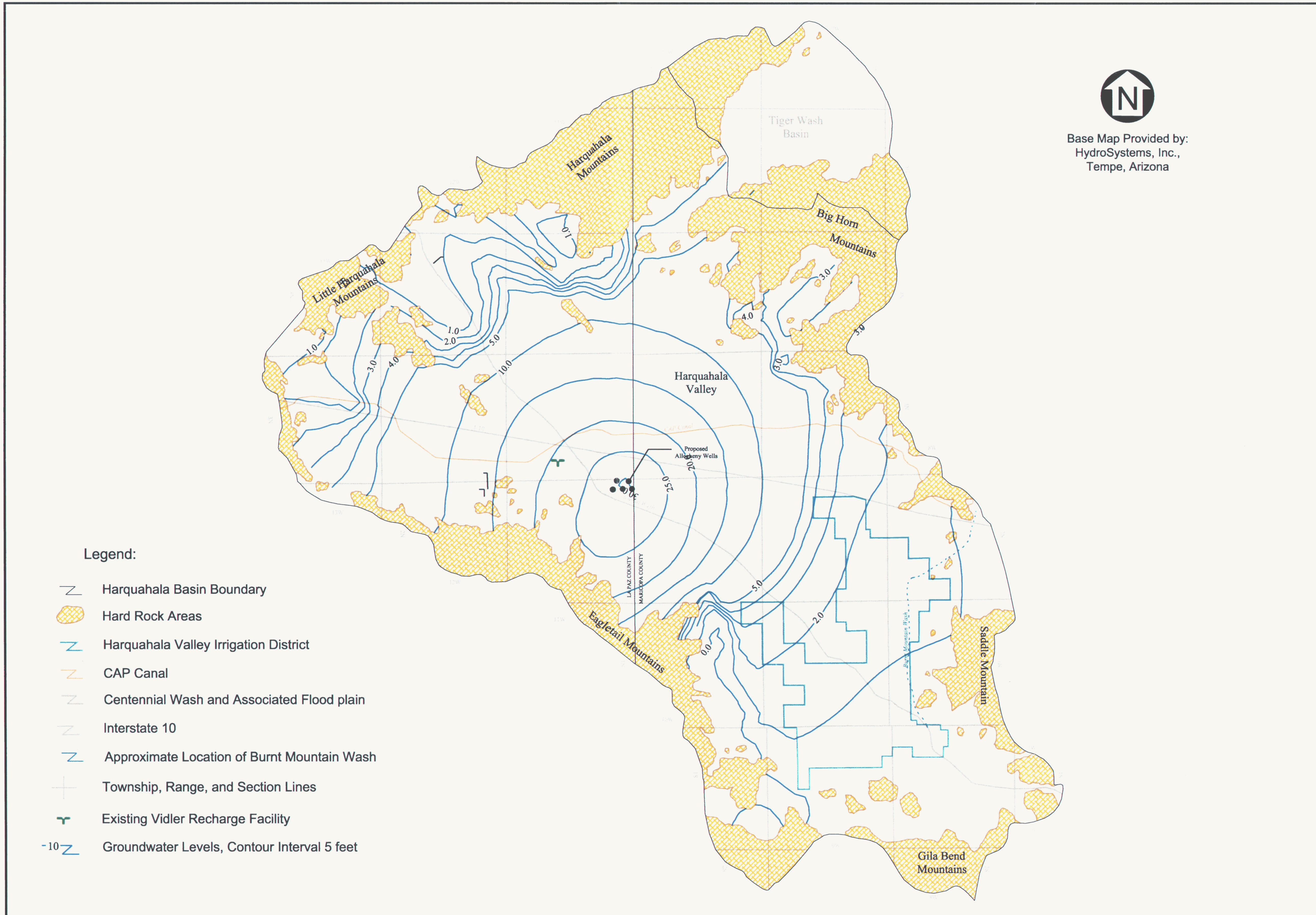
Vidler Recharge Facility

- Water Storage Permit (Jan 2001)
- Underground Storage Facility Permit (Sep 2000)
- Permitted for a maximum of 100,000 ac-ft/yr
- Water is diverted at a turnout on the CAP canal
- Directed to a series of shallow spreading basins and vadose (unsaturated) zone wells
- Allowed to infiltrate into the subsurface
- Facility is recharging 1,500 ac-ft/mo (Nov-Dec 2001, Jan 2002)
- Will begin recharging 2,200 ac-ft/mo in Feb 2002

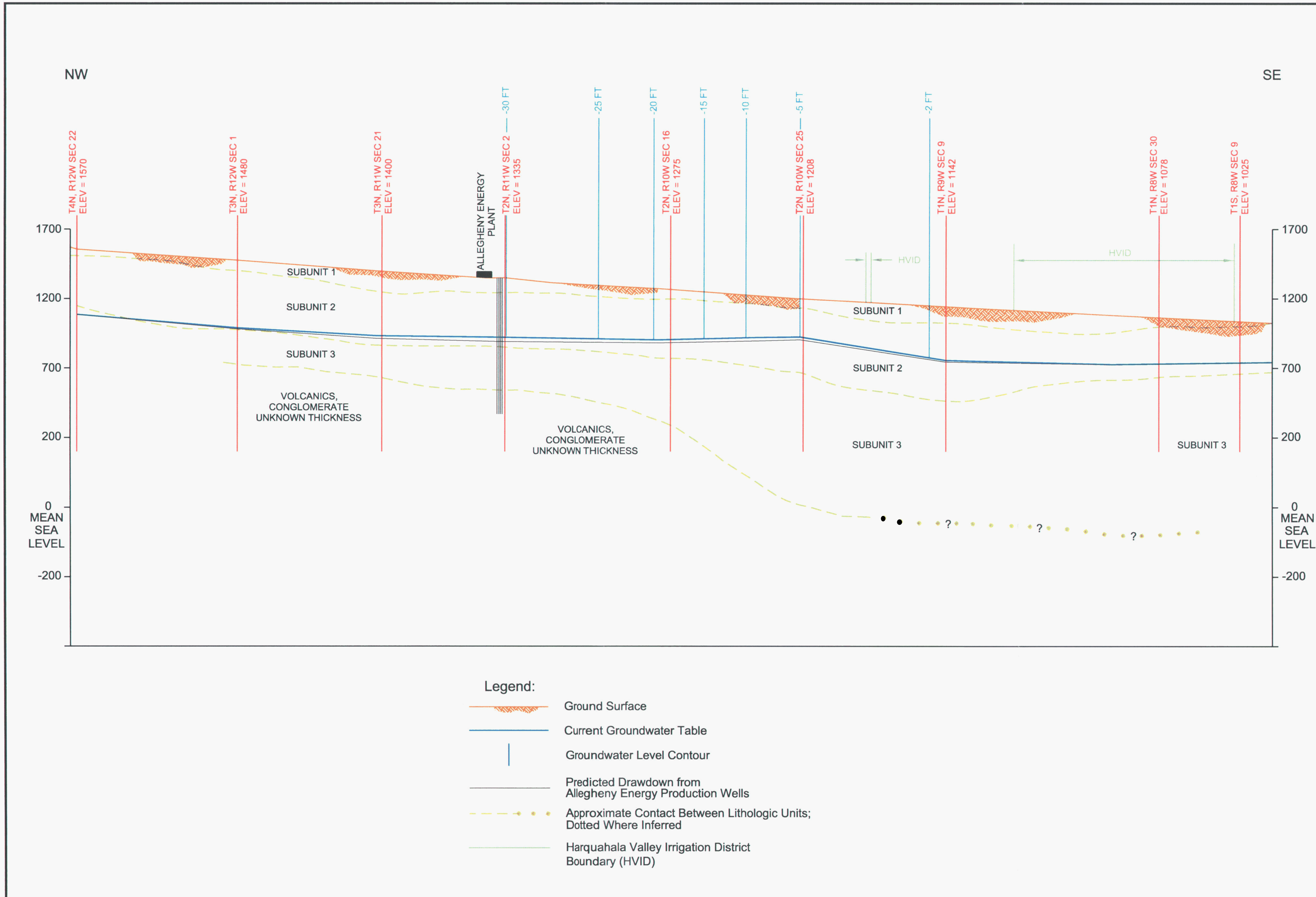
Additional Information Requested by ADWR

- Map showing the locations of the purchased farmland
- Notices of Irrigation Authority associated with these properties
- List of all wells located on the properties
- Hydrographs for wells located near the plant site
- Historical pumpage for an area that includes the plant site
- Fourth computer model run assuming 30,000 ac-ft/yr recharge from Vidler

Allegheny Energy Supply
an Allegheny Energy company



Drawdown from Allegheny Energy
Allegheny Energy Supply Company, LLC



Cross Section of Harquahala Valley
Allegheny Energy Supply Company, LLC

Conclusions of Water Supply Study

- Groundwater supply is sufficient for the projected 30-year life of the project
- Groundwater quality is suitable for electrical power generation
- Under worst-case conditions, total drawdown of 30 feet near the wellfield after 30 years of pumping
- Drawdown at the edge of the HVID is about 5 feet
- Under most likely conditions, net increase of 125 feet beneath the Vidler recharge facility, 25 feet at the wellfield

Allegheny Energy Supply
an Allegheny Energy company

Land Subsidence and Earth Fissuring

- Rogers earth fissure
- Located about 5 miles southeast of the facility site
- Discovered in 1997 after Hurricane Nora
- Believed to have opened up as a result of extreme precipitation
- Fissure was 4,400 feet in length
- Trends Northwest to Southeast
- No evidence that the fissure increased in length since 1997

Allegheny Energy Supply
an Allegheny Energy company

A-10

THE STATE OF ARIZONA
GAME AND FISH DEPARTMENT
2221 WEST GREENWAY ROAD, PHOENIX, AZ 85023-4399
(602) 942-3000 • WWW.AZGFD.COM
Yuma Office, 9140 E 28th Street, Yuma, AZ 85365-3596 (520) 342-0091

EXHIBIT
A-10
admitted

October 26, 2001

Jennifer Baker
Environmental Planner
URS
7720 North 16th Street
Phoenix, Arizona 85020

Re: Technical Report: Biological Resources La Paz Generating Facility Project, La Paz County

Dear Ms. Baker:

The Arizona Game and Fish Department (Department) has reviewed your letter dated October 16, 2001 requesting a review of the above-referenced technical report for the La Paz Generating Facility Project located in Township 3 North, Range 11 West, Section 35 (generating facility), Township 3 North Range 11 West Sections 24, 25 and 36 (500 kV transmission line and switchyard) and Township 2 North Range 10 West Sections 6, 7, 18, 19, 30 (pipeline). The following comments are provided for your consideration.

The Department notes that we were asked to provide comments on a preliminary project proposal in a letter dated April 10, 2001. At that time the proposed location for the generating facility was Township 2 North, Range 11 West, Section 1. We noted in our review letter, dated May 11, 2001, that Centennial Wash crossed through this location and that there was also a mesquite bosque on the site. We are pleased that Allegheny Power Supply Company has decided to relocate the facility away from these high-value wildlife habitats to an area consisting of creosote flats, a lower value wildlife habitat. We further note that the pipeline will be placed under the wash using directional boring. The Department supports these efforts to minimize impacts to this important wildlife habitat.

The Department notes that the location of proposed gas line, transmission line and switchyard have also been changed. The Department's Heritage Data Management System has been accessed and current records show that the special status species listed below have been documented as occurring at the new locations. We note that there was no change in the list from the previous locations.

COMMON NAME	SCIENTIFIC NAME	STATUS
Sonoran desert tortoise	*Gopherus agassizii*	SC, S², WC

STATUS DEFINITIONS

SC - **Species of Concern.** The terms **"Species of Concern"** or **"Species at Risk"** should be considered as terms-of-art that describe the entire realm of taxa whose conservation status may be of concern to the US Fish and Wildlife Service, but neither term has official status (currently all former C2 species).

S^2- **Sensitive.** Those taxa occurring on Bureau of Land Management (BLM) Field Office Lands in Arizona which are considered **"sensitive"** by the Arizona State Office of the BLM.

WC - **Wildlife of Special Concern in Arizona.** Species whose occurrence in Arizona is or may be in jeopardy, or with known or perceived threats or population declines, as described by the Department's listing of **Wildlife of Special Concern in Arizona** (WSCA, in prep.). Species included in WSCA are currently the same as those in **Threatened Native Wildlife in Arizona** (1988).

The Department notes that project biologists surveyed for tortoises and failed to find any tortoises or sign of tortoises. In addition, the proposed locations are considered marginal tortoise habitat

The Department notes that the gas pipeline route passes through an area containing ironwood (*Olneya tesota*) and palo verde (*Cercidium microphyllum*) trees and saguaro cacti (*Cereus giganteus*). We note that the mitigation plan proposes salvaging these plants when necessary. Saguaros are protected under the Arizona Native Plant Law. Therefore, the Department recommends contacting the Arizona Department of Agriculture, at the address provided below, for additional information on the Arizona Native Plant Law, and how it may apply this species.

Mr. James McGinnis
Manager, Native Plant Law
Plant Services Division
Arizona Department of Agriculture
1688 West Adams
Phoenix, Arizona 85007
Phone: 602-407-3292

In our letter dated May 11, 2001 we observed that the proposed evaporation ponds could be wildlife attractant and could have adverse impacts to wildlife. We note that the report proposes mitigation measures to minimize these potential impacts. The Department supports these measures. We note that one mitigation measure proposes to contact the Department if a large number of birds are using the ponds. The Department wishes to be contacted in such an event. However, because many of these bird species are protected under the Migratory Bird Treaty Act we also recommend contacting the U.S. Fish and Wildlife Service (Service). If there is a die-off of protected species, it is mandatory to contact the Service.

For the above stated reasons, the Department does not anticipate any significant adverse impacts to the special status species listed above, or other wildlife species, resulting from the approval of this proposed project. However we note that failure to implement the mitigation measures proposed in this report could result in adverse impacts to wildlife.

Thank you for the opportunity to review and comment on this proposed project. The Department looks forward to continuing to work with you on this project. If you have any questions, please contact me at 928-342-0091.

Sincerely,

William C Knowles

William C. Knowles
Habitat Specialist
Region IV, Yuma

cc: Russell Engel, Habitat Program Manager, Region IV
Larry Voyles, Regional Supervisor, Region IV
Bob Broscheid, Proj. Eval. Prog. Supervisor, Habitat Branch
James McGinnis, Manager, Native Plant Law ADOA

AGFD # 10-17-01 (A)

APPLIED ENVIRONMENTAL CONSULTANTS, INC.
(480) 829-0457 ◆ 2465 W. 12th Street, Suite 6 ◆ Tempe, Arizona 85281 ◆ Fax: (480) 829-8985

EXHIBIT
A-11
admitted

RESUME
HERBERT J. VERVILLE

TITLE: Senior Environmental Scientist

EXPERTISE: Source Permitting
Dispersion Modeling
Data Management
Meteorological & Ambient Monitoring

ACADEMIC
BACKGROUND: M.A. Geography, Arizona State University, 1985
B.S. Geography, Arizona State University, 1982

EXPERIENCE:

1993 - Present Senior Scientist, Applied Environmental Consultants, Inc.,

Project implementation and data analysis for air quality and meteorological related environmental projects for industry and government clients. Responsibilities include:

- Preparation of applications for new sources and changes to existing sources
- Data management for all client related projects (air quality, meteorological and emission inventory related data bases)
- Dispersion modeling analyses of instantaneous and continuous emission releases in simple and complex terrain.
- Installation and management of meteorological monitoring programs designed to collect baseline meteorological data for source permitting.
- Data analysis and report preparation for meteorological and air quality monitoring programs.

3/88-6/93 Research Specialist. Department of Geography/Office of Climatology, Arizona State University.

Primary Duties included: Development and implementation of geographic research strategies for a variety of funded projects which required technical writing of reports and proposals, computer software development, statistical manipulation of large data bases, and in-field research.

12/84-3/88 Environmental Scientist. Applied Environmental Consultants, Inc.

Duties included technical report writing following the collection, management, and analysis of data for a variety of air quality and hazardous substance related environmental projects for industrial and governmental clients. Client related projects included:

- Evaluation of the frequency of visibility impairments;
- Comparison of photographic and contrast telephotometer techniques for measuring visibility and related parameters;

- Installation and operation of air quality and meteorological monitoring stations; and

- Development and implementation of soil sampling programs to evaluate hazardous waste contamination.

6/84-12/84 Hydrologist. National Forest Service.

Assigned to slope erosion study in chaparral and pinyon-juniper vegetation communities. Responsible for site selection, surveying, mapping, and installation of erosion-runoff monitoring equipment.

9/82-6/84 Graduate Teaching/Research Assistant. Department of Geography, Arizona State University

Duties included teaching physical geography laboratory and cartography, and assisting faculty conducting research on projects ranging from mercury transport into Lake Powell to Arizona dispersion climatology.

6/80-6/81 Research Technician. Phelps Dodge Corporation.

Responsible for operation of continuous air monitoring station designed to monitor for SO2, NO2, particulates (Hi-Vol), and meteorological data (solar, visibility, precipitation, etc.).

9/72-9/74 Nike Hercules Missile Crewman. United States Army

Stationed eighteen months in West Germany. Honorable discharge. Work required a government secret classification security clearance.

PUBLICATIONS:

Brazel, A.J., McCabe, G.J. Jr., Verville, H.J., 1993. "Incident Solar Radiation Simulated by General Circulation Models for the Southwestern United States". *Climate Research*, vol. 2, 177-181.

Brazel, A.J., Verville, H.J., Lougeay, R, 1993, "Spatial-Temporal Controls on Cooling Degree Hours: an Energy Demand Parameter". *Theoretical and Applied Climatology*, vol. 47, 81-92.

Verville, H.J. (Editor), 1992. *Introductory Physical Geography Laboratory Manual, Seventh Edition*. Edina, MN: Burgess International Group, Inc.

Verville, H.J., 1985. *Channel Change, Process, and Cross-sectional Flow Distributions in an Arid-region Braided River, Agua Fria River, Arizona*. M.A. Thesis, Arizona State University.

PAPERS PRESENTED:

Verville, H.J. 1993. *Changes Between the 'Old' and 'New' Normals for Arizona*. Proceedings of the 37th Annual Meeting, Arizona-Nevada Academy of Science, University of Nevada, Las Vegas, Las Vegas, Nevada, April 1993.

Verville, H.J., Brazel, S.W., Brazel, A.J., and Calderon, S., 1992. *PRISMS Alameda station temperature observations*. Poster Session and Paper Presented at 4th Annual Arizona Weather Symposium, Phoenix, Arizona, June, 1992.

Miller, T.A., and Verville, H.J. (Seminar Presenters), 1992. *Meteorological monitoring for regulatory air quality applications*. Seminar sponsored by the Arizona Department of Environmental Quality -- Office of Air Quality, June 9, 1992.

EXHIBIT
A-12
admitted

CURRICULUM VITAE

DAVID A. CARR, R.G.

Title Associate Hydrogeologist

Expertise Hydrogeology / Groundwater Resources
Groundwater Quality / Permitting
Mine Hydrogeology
Coal Geology

Academic Background M.S., Geology, Northern Arizona University, Flagstaff, Arizona (1987)
B.S., Geosciences, University of Arizona, Tucson, Arizona (1978)

Professional Registration Registered Geologist, Arizona (1990), No. 24055
Registered Geologist, California (1992), No. 5562

Experience Mr. Carr is an associate hydrogeologist with 20 years of professional experience. He has managed and/or served as principle investigator for numerous groundwater supply and quality investigations throughout Arizona and is familiar with state and federal environmental regulations that pertain to groundwater, including the Arizona Groundwater Management Act, the Arizona Aquifer Protection Program, and the federal National Environmental Policy Act (NEPA). Mr. Carr manages a team of hydrogeologists in the URS Phoenix office.

Groundwater Resources Projects

- Senior technical reviewer for a water supply investigation for the Allegheny Energy La Paz Generating Facility, a planned 1080-megawatt, combined-cycle power plant in eastern La Paz County, Arizona. The scope of work to date has included completing an evaluation of groundwater conditions using reports and data from public and private sources, and performing a well impact assessment using an existing numerical groundwater flow model. The results of the investigation were presented in a water supply report included in the Certificate of Environmental Compatibility (CEC) application to the Arizona Corporation Commission, and in a subsequent addendum to the water supply report.

- Project manager and principal investigator for a groundwater supply investigation for the Panda Gila River Project, a planned 2000-megawatt, combined-cycle power plant near Gila Bend, Arizona. Conducted geophysical logging, zonal sampling, and aquifer testing of two existing agricultural irrigation wells. Oversaw the installation of the first groundwater production well and preparation of the report. Currently overseeing the installation of the remaining six groundwater production wells.

- Project manager and senior technical reviewer for a water supply investigation for the Toltec Power Station, a planned 2000-megawatt, combined-cycle power plant south of Eloy, Arizona. The scope of work included testing and sampling two existing agricultural irrigation wells, performing a well impact assessment, and preparing a report for inclusion in the Certificate of Environmental Compatibility (CEC) application to the Arizona Corporation Commission.

- Project manager and senior technical reviewer for a water supply investigation for the Bowie Power Station, a planned 1000-megawatt, combined-cycle power plant near Bowie, Arizona. The scope of work to date has included performing a multiple-well aquifer test of two existing agricultural irrigation wells in conjuction with ongoing irrigation, analyzing the data, and preparing the water supply report for CEC application.

- Task manager and principle investigator for a groundwater supply investigation of two alluvial basins in Arizona for APS/Pacificorp. Compiled and evaluated available groundwater data. Designed and coordinated seven 48-hour aquifer tests and used the results to obtain estimates of transmissivity and storativity. Prepared maps and cross sections to depict groundwater conditions in each basin. Performed a comparative evaluation of groundwater supply and quality in each area to select a preferred site for an electrical generating station with a water supply requirement of 5,000 acre-feet per year.

- Developed an analytical model of a groundwater production well field at Nellis Air Force Base, near Las Vegas, Nevada, to assist in siting additional production wells for the facility. Analytical modeling was performed to evaluate the impact of proposed wells on existing wells and to assess the cumulative effect of expanding groundwater production.

NEPA Projects

- Conducted the water resources assessment for the Navajo Transmission Project (NTP) EIS for Diné Power and Western Area Power Administration. The water resources assessment consisted of researching and mapping known perennial streams, springs, and flood hazards for the NTP study area, which extends across northern Arizona from northwestern New Mexico to southern Nevada, and writing the water resources assessment report.

- Technical lead responsible for preparing the groundwater section of the EIS for the Big Sandy Energy Project, a proposed power plant in northwestern Arizona. URS was retained by the BLM as a third-party consultant to prepare the EIS, which was undertaken in response to concerns over the potential impact of groundwater pumping on groundwater resources and flow in the Big Sandy River. Testified on the draft EIS before the Power Plant and Transmission Line Siting Committee of the Arizona Corporation Commission.

APP Projects

- Aquifer Protection Permit (APP) project manager for the Phelps Dodge Morenci mining district in southeastern Arizona. Served as field team leader for an extensive hydrogeologic investigation of the district. Compiled and evaluated existing groundwater data from the mining operation. Developed and managed two field investigations that included installing over 70 deep groundwater monitor wells and piezometers in bedrock, performing seven aquifer tests, and conducting a solution sampling program. Coordinated the preparation of the application document, which was submitted to ADEQ for review in March 1996. Attended numerous meetings with ADEQ to respond to technical review comments and negotiate permit conditions. The APP was signed by ADEQ in October 2000.

- APP project manager for the Phelps Dodge Dos Pobres/San Juan Project, a proposed open pit copper mining and heap leaching operation near Safford, Arizona. Responsible for project management and providing senior technical guidance. The scope of work for the project included performing a hydrogeologic field investigation; characterizing the hydrogeology of the site; characterizing material and groundwater quality; designing stormwater diversions/impoundments, heap leach pads and other facilities; meeting with the regulatory agency; and preparing the application document. The application document was submitted to ADEQ for review in October 1998. Currently responding to ADEQ comments on the permit application.

- Principle-in-charge and senior technical reviewer for an APP application addendum for the Phelps Dodge United Verde Mine near Jerome, Arizona. The addendum document was submitted to ADEQ for review in August 2000. Currently responding to ADEQ comments on the application addendum.

- APP senior technical reviewer for the Allegheny Energy La Paz Generating Facility, a planned 1080-megawatt, combined-cycle power plant in eastern La Paz County, Arizona. The scope of work includes developing a conceptual design for the evaporation ponds, and preparing an APP application for submittal to ADEQ.

- APP project manager and principal investigator for the Panda Gila River Project, a planned 2000-megawatt, combined-cycle power plant near Gila Bend, Arizona. The scope of work included developing a conceptual design for four evaporation ponds. Prepared an APP application for the evaporation ponds and submitted the application to ADEQ for review in March 2000. The APP was signed by ADEQ in October 2000.

- APP project manager and senior technical reviewer for the Duke Energy Arlington Valley Energy Facility, a planned 550-megawatt, combined-cycle power plant near Arlington, Arizona. The scope of work included developing a conceptual design for two evaporation ponds and preparing the APP application. The APP application for the evaporation ponds was submitted to ADEQ for review in February 2001.

- APP project manager and senior technical reviewer for the Toltec Power Station, a planned 2000-megawatt, combined-cycle power plant south of Eloy, Arizona. The scope of work included developing a conceptual design for the evaporation ponds and preparing the APP application. The APP application for the evaporation ponds was submitted to ADEQ for review in July 2001.

- APP project manager and principal investigator for IMSAMET of Arizona, an aluminum recycling facility located in Goodyear, Arizona. The field investigation consisted of designing and overseeing the installation of three groundwater monitor wells, and collecting and arranging for the analysis of groundwater and solution samples. The APP application was submitted to ADEQ for review in March 2001.

- Prepared an APP application addendum for the General Motors Desert Proving Ground in Mesa, Arizona. The addendum document was submitted to ADEQ for review in September 1998.

CERCLA/WQARF Investigations

- Task manager for groundwater monitoring activities at the Motorola 52nd Street Superfund site in Phoenix. Responsibilities included preparing monitoring plans, cost estimates and schedules, coordinating sampling events, and evaluating groundwater quality data.

- Task manager for an investigation of inorganic constituents in groundwater at the Motorola 52nd Street Superfund site. Responsibilities included preparing task specifications, cost estimates and schedules, coordinating staff activities, evaluating data and writing reports.

- Assisted in the development of a groundwater extraction system in fractured bedrock at the Motorola 52nd Street Southwest Parking Lot. Participated in field activities, analyzed data and prepared a comprehensive report for a multiple-well aquifer test.

- Project hydrogeologist for a groundwater contamination investigation at Reynolds Metals Company's former Phoenix Extrusion Plant site, located within the West Van Buren WQARF area in Phoenix. Primary activities included coordinating groundwater monitoring activities, meeting with the client, and preparing quarterly reports. Other activities included investigating soil contamination at the site, serving as technical representative for a PRP-led investigation of area-wide groundwater contamination, and preparing a work plan for an area-wide groundwater investigation in conjunction with other members of the PRP group.

Other Projects

- Project hydrogeologist responsible for designing groundwater intercept systems for two electrical generating stations in Arizona and New Mexico. Activities completed include designing and analyzing data from several aquifer tests, designing monitor wells, coordinating field activities, meeting with clients and writing reports.

Professional History

More than five years of experience in hydrogeology and mathematical groundwater modeling with a state agency, and more than four years of experience as a coal geologist for a mining company.

Hydrologist, Arizona Department of Water Resources, Hydrology Division, Phoenix, Arizona (1986-1991)

- Unit supervisor responsible for the direct supervision of staff participating in the development of regional, finite-difference groundwater flow models of the alluvial basins in Arizona for use in groundwater management.

- Project manager and principal investigator responsible for the development of a three-dimensional, finite-difference groundwater flow model of the Salt River Valley in central Arizona for the Phoenix Active Management Area (AMA).

- Investigated groundwater and surface water conditions within the seven sub-basins of the Phoenix AMA for the Arizona Water Resources Assessment.

- Coordinated and participated in the preparation of 25 regional groundwater quality maps of the four AMAs in Arizona.

- Served as agency technical lead for the Indian Bend Wash RI/FS and the Phoenix-Goodyear Airport RI/FS. Provided technical support for the Tucson Airport Area FS and the Motorola 52nd Street RI/FS.

- Participated in the development of a finite-difference groundwater flow/solute transport model for the Phoenix-Goodyear Airport RI/FS.

Coal geologist, Sheridan, Wyoming and Lexington, Kentucky offices of Kiewit Mining and Engineering Co., Omaha, Nebraska (1979-1983)

- Project geologist responsible for establishing an exploration office in Lexington, Kentucky to evaluate and acquire coal properties in the Appalachian Region.
- Project geologist responsible for new prospects in the Sheridan, Wyoming office. Completed preliminary drilling and evaluation of the Salt Wells prospect in southwestern Wyoming.
- Mine geologist for Big Horn Coal Co., a subsidiary surface mining operation. Planned and implemented developmental drilling programs and evaluated coal reserves.
- Staff geologist in the Sheridan, Wyoming office. Participated in exploration and developmental drilling in Wyoming and New Mexico.

Professional Training

OSHA HAZWOPER 40-Hour (1992)
OSHA HAZWOPER 8-Hour Supervisor (1992)
OSHA HAZWOPER 8-Hour Annual Refresher (Current)
MSHA 24-Hour Newly-Employed Experienced Miner (1994)
MSHA 8-Hour Annual Refresher (Current)

Professional Development

Environmental Geochemistry of Ore Deposits and Mining Activities, SARB Consulting, Inc. (1997)

Short Course on Vadose Zone Hydrology, Daniel B. Stephens and Associates (1992)

Theory and Application of Borehole Geophysics to Ground Water Problems, NWWA (1989)

Ground Water Modeling Methodology and Application, IGWMC (1986)

TARGET Mathematical Model of Groundwater Flow and Solute Transport, Dames & Moore (1986)

Professional Affiliations

National Ground Water Association, Association of Ground Water Scientists and Engineers
Arizona Hydrological Society

Citizenship

United States

Countries Worked In

United States

Language Proficiency

English, Basic Spanish, Basic Russian

Selected Publications

Carr, D.A. and Putman, F.G., 1991. Development of a three-dimensional finite-difference groundwater flow model of the Salt River Valley, Arizona in Proceedings of CONSERV 90, The National Conference and Exposition Offering Water Supply Solutions for the 1990s: National Water Well Association, pp. 1253-1254.

Carr, D.A. 1991. Facies and depositional environments of the coal-bearing upper carbonaceous member of the Wepo Formation (Upper Cretaceous), northeastern Black Mesa, Arizona, in Nations, J.D., and Eaton, J.G., editors, Stratigraphy, Depositional Environments, and Sedimentary Tectonics of the Western Margin, Cretaceous Western Interior Seaway: Geological Society of America Special Paper 260, pp. 167-188.

Corkhill, E.F., Corell, S., Hill, B.M. and Carr, D.A., 1993. A Regional Groundwater Flow Model of the Salt River Valley - Phase I, Phoenix Active Management Area, Hydrogeologic Framework and Basic Data Report: Arizona Department of Water Resources Modeling Report No. 6, 120 p.

EXHIBIT
A-13
admitted

URS

ADDENDUM TO THE WATER SUPPLY REPORT FOR THE LA PAZ GENERATING FACILITY

Prepared for
Allegheny Energy Supply Company, LLC

URS Job No. E1-00001722.03
October 1, 2001

REGISTERED GEOLOGIST
CERTIFICATE NO.
33263
KAREN J.
SCHWAB
Date Signed 10-3-01
ARIZONA U.S.A.

TABLE OF CONTENTS

REGISTERED GEOLOGIST
CERTIFICATE NO.
33268
KAREN J.
SCHWAB
Date Signed 10-3-01
ARIZONA U.S.A.

1.0 INTRODUCTION

This addendum presents additional hydrologic information in support of the Certificate of Environmental Compatibility (CEC) application for the Allegheny Energy Supply, LLC (Allegheny) La Paz Generating Facility (Project). The La Paz Generating Facility CEC application was submitted to the Arizona Power Plant and Transmission Line Siting Committee (Committee) on July 2, 2001.

Copies of the CEC application and the Water Supply Report for the La Paz Generating Facility (water supply report, URS, 2001) were provided for Mr. Dale Mason, manager of the Arizona Department of Water Resources (ADWR) modeling section in late June 2001 to review and comment on the hydrogeologic information. On August 22, 2001, staff from URS Corporation (URS) and HydroSystems, Inc., met with Mr. Mason to discuss the hydrogeologic information contained in the CEC application and the water supply report. In general, Mr. Mason approved of the information presented in the CEC application and water supply report, including the assumptions and conclusions of the groundwater flow model. However, Mr. Mason requested that Allegheny also obtain and submit the following information:

- A map showing the properties in the Harquahala Valley purchased by Allegheny
- A list of the irrigated grandfathered rights appurtenant to the purchased properties
- A list of the wells located on the Allegheny purchased property
- Hydrographs for wells located in the immediate vicinity of the proposed plant
- A chart showing historical pumpage data for the Harquahala Valley
- Historical pumpage data for Townships 2 and 3 North, Ranges 10 and 11 West
- Results of a fourth groundwater modeling scenario using a maximum of 30,000 acre-feet per year of artificial recharge.

This addendum presents discussions and accompanying tables and figures for the above information requests; it is not intended to be a stand-alone report. For details on the groundwater conditions, groundwater quality, and irrigated grandfathered rights associated with the La Paz Generating Facility, and the details of the groundwater flow model, refer to the CEC application and/or the water supply report.

2.0 BACKGROUND

2.1 PROJECT DESCRIPTION AND PROPERTY LOCATION

Allegheny is proposing to construct a 1,080 megawatt (MW), natural gas-fired, combined cycle electric generating plant in the Harquahala Valley, approximately 75 miles west of Phoenix, Arizona. The Project location is shown on Figure 1. It is estimated that the plant will require a maximum of 6,500 acre-feet per year (af/yr) water supply. Water for the plant will be supplied from the underlying aquifer, which is within the Harquahala Basin.

The power plant will be constructed on an 80-acre parcel of undeveloped desert land located approximately 0.75 mile south of Interstate 10 and on the west side of Exit 69, Avenue 75 East. Two-thirds of the Harquahala Valley lies within Maricopa County; the northwestern third, which includes the Project property, lies within La Paz County. The cadastral location of the Project property is the southern half of Section 35, Township 3 North, Range 11 West, of the Gila and Salt River baseline and meridian.

3.0 REQUESTED INFORMATON

3.1 ALLEGHENY PROPERTIES IN HARQUAHALA VALLEY

All of the properties owned by Allegheny and associated with the project lie within the Harquahala Irrigation Non-Expansion Area (INA). According to Arizona Revised Statutes (A.R.S.) § 45-437 (B), irrigation within the Harquahala INA is limited to "acres of land that were irrigated at any time during the five years preceding the date of the notice of the designation procedures to establish the INA." Until 2000, the laws governing water use within an INA did not restrict the use of groundwater or other sources of water for uses other than irrigation. In 2000, A.R.S. § 45-440 was enacted, which imposes restrictions on withdrawals of more than 100 acre feet of groundwater per year for commercial or industrial purposes. A.R.S. § 45-440 (A) requires that groundwater for such purposes be withdrawn "from land that is eligible to be irrigated pursuant to § 45-437, subsection B."

Allegheny has acquired 2,734.5 acres of farmland in the Harquahala Valley, 2,319.4 of which are eligible for irrigation as defined by A.R.S. § 45-437 (B). Allegheny intends to manage these lands so that they are not irrigated with groundwater during the period of the Project. The land may be irrigated with CAP water to maintain its existing agricultural use. Allegheny's use of groundwater for operational purposes of the Project would be in compliance with A.R.S § 45-440 (A), which provides for withdrawals of groundwater for commercial or industrial uses in an amount of 6 acre-feet in any year or a maximum of 30 acre-feet for any period of 10 consecutive years

Allegheny is in the process of purchasing the land in the southwest quarter of Section 1, Township 2 North, Range 11 West, and plans to acquire the rest of the land in Section 1 through a land exchange with the Bureau of Land Management (BLM). This property would be used for the production well field and a temporary staging area for construction equipment during construction of the plant.

Table 1 of this addendum lists the cadastral location, total number of acres and irrigable acres per property, ADWR registry number for irrigated grandfathered rights appurtenant to the properties, and wells located on the Allegheny properties. Figure 1 shows the location of the properties and associated wells on each property.

3.2 HYDROGRAPHS FROM NEARBY WELLS

Six hydrographs were constructed from six existing wells and included in the CEC application and water supply report to present an overview of water level trends throughout the basin. Five of the six wells were located in the southeastern portion of the Harquahala basin and one was located approximately two miles northwest of the La Paz Generating Plant site. All six of these wells had at least 25 years of recorded water levels.

During the August 22 meeting, Mr. Mason requested that additional hydrographs be produced for wells within the near vicinity of the Project. Figure 2 of this Addendum presents six hydrographs from wells located within 4 miles of the Project. The trend of the water levels in all six wells shows a slow but steady decrease in water levels over the past 40 years. The average rate of decline for the six wells shown in Figure 2 is 1.8 feet per year.

3.3 HISTORICAL PUMPAGE IN THE HARQUAHALA BASIN

According to D.G. Metzger (Metzger, 1957), the first successful irrigation well in the Harquahala Basin was completed in 1951. By 1954, numerous wells had been drilled and the annual groundwater pumpage increased from an estimated 1,000 af/yr in 1949 to 33,000 af/yr in 1954. Groundwater pumpage for agricultural irrigation continued to increase steadily to a maximum of 200,000 af/yr in years 1961 through 1964. Estimated pumpage for the Harquahala Basin from 1940 through 2000 is shown on Figure 3 of this Addendum.

In 1985, the Central Arizona Project (CAP) completed a canal system that conveys water from the Colorado River through the Harquahala Basin to Phoenix and Tucson. The introduction of

CAP water to the Harquahala Basin for agricultural irrigation is the major contributing factor for the decline in groundwater pumpage from 1985 to the present.

Pumpage figures from 1940 through 1984 shown on Figure 3 are estimated numbers produced by the U.S. Geological Survey (USGS) and the Arizona Public Service. Beginning in 1984, ADWR required all non-exempt well owners in an INA to report annual groundwater pumpage amounts to the agency, and hence, pumpage figures from 1985 through 2000 are reported numbers obtained from ADWR.

Due to an error in data retrieval from ADWR, the total 1999 reported groundwater pumpage for the Harquahala Basin stated in Section 2.5 of the water supply report and on page B-3-11 of the CEC, is incorrect. The correct total reported groundwater pumpage for the Harquahala Basin in 1999 was 22,887.28 ac/ft. The total reported groundwater pumpage for the year 2000 was 27,355.09 ac/ft. (The 2000 data was not available from ADWR at the time the water supply report was being compiled.)

Pumpage figures specific to Townships 2 and 3 North, Ranges 10 and 11 West are presented in the table below. Pumpage figures by township-range could only be obtained from the 1984 through 2000 ADWR data as the USGS estimated pumpage figures were for the entire basin and not broken down by township-range.

Year	Reported Groundwater Pumpage (acre-feet/year)
1984	0
1985	7,434.14
1986	2.93
1987	3,910.63
1988	0
1989	0
1990	0
1991	0
1992	0
1993	3,396.63
1994	1,680.78
1995	1,032.38
1996	4,232.34
1997	7,413.88
1998	1,282.52
1999	0
2000	5.0

The total amount of groundwater pumped from Townships 2, 3 North, Ranges 10, 11 West for the years 1984 through 2000 is 30,401.23 acre-feet, 99 percent of which was used for agricultural irrigation. A total of ten wells contributed to the above pumpage figures:

(B-02-11) 02bbb	(B-03-11) 08cab	(B-03-11) 23ccb
(B-03-11) 31cbb	(B-03-11) 34aba	(B-03-11) 34bbb
(B-03-11) 34bcc	(B-03-11) 36baa	(B-03-11) 36bbb
(B-03-11) 36cbb		

3.4 ADDITIONAL SCENARIO FOR GROUNDWATER MODEL

3.4.1 Water Level Drawdown Modeling

Water level drawdown from the proposed Project production wellfield of five wells was modeled by HydroSystems, Inc. (HydroSystems, Inc., 1999) to estimate the incremental drawdown from the wellfield for the projected 30-year life of the power plant. A discussion of the conceptual model, assumptions, specific parameters, results, and illustrated figures are presented in the CEC application and water supply report. Water level drawdown was analyzed using the modular three-dimensional finite difference groundwater flow model MODFLOW.

3.4.2 Simulated Scenarios

Three different scenarios are presented in the CEC application and water supply report to determine the impact of the pumping by the Project wellfield. Scenario 1 simulated 1997 groundwater conditions for 34 years into the future, until 2032. Scenario 1 was used as a "base case" to which the other two scenarios were compared in order to determine impacts on groundwater. Scenario 2 was a continuation of Scenario 1 with the addition of pumping from the Allegheny Energy production wells from 2002 to 2031, a 30-year time period of operation. The five Allegheny Energy production wells were simulated to be pumping at a rate of 868 gallons per minute each, a total of 7,000 af/yr. Scenario 2 acted as a "worst case," where the pumping rate was at a maximum with no attempt to mitigate the effects of the pumping.

Scenario 3 simulated the same conditions from Scenario 1 plus the pumping from the Allegheny Energy production wells (Scenario 2), but had the addition of recharge from the nearby Vidler Recharge Facility. Scenario 3 acted as a "best case" where the impacts of pumping were minimized due to the significant recharge volumes at the nearby Vidler Recharge Facility. The recharge rate from the Vidler Recharge Facility was modeled in increasing increments, beginning at 5,000 af/yr in 2002 to 70,000 af/yr in 2006 through 2031.

The results of Scenario 1 indicate that if groundwater pumping and recharge in the Harquahala basin were to continue at the current rate for the next 30 years, groundwater levels would decline between 20 to 40 feet in the vicinity of the Project and increase 50 to 70 feet in the southeastern portion of the basin. The resulting water levels in Scenario 2 indicate that the pumping from the five Allegheny production wells will create an additional 30 feet of drawdown in the immediate vicinity of the wellfield after 30 years. Wells located 3 to 5 miles from the production wellfield will experience water level declines of 20 feet in addition to the drawdown predicted in Scenario 1. For Scenario 3, the model predicts a net water level increase of 300 feet in the immediate vicinity of the Vidler Recharge Facility and a net increase of 150 to 175 feet in the area of the Allegheny wellfield. The recharge mound is projected to extend across the entire Harquahala basin, with a minimum increase of less than 25 feet in the southeastern portion of the basin.

3.4.3 Scenario 4

During the August 22, 2001 meeting with ADWR, Mr. Mason requested that the a fourth scenario be modeled, using a maximum of 30,000 af/yr of artificial recharge instead of 70,000 af/yr. All other assumptions, stresses, and parameters remained the same as used in Scenarios 1, 2, and 3.

The result of Scenario 4, in which the five Allegheny production wells would pump 7,000 af/yr for 30 years and the nearby Vidler Recharge Facility would recharge CAP water at a maximum of 30,000 af/yr, was a net water level increase of 25 feet in the immediate vicinity of the production wellfield.

The HydroSystems, Inc. modeling addendum, which presents a discussion of Scenario 4 and accompanying figures and tables, is included in Appendix A of this report.

4.0 REFERENCES

HydroSystems, Inc. 1999. Harquahala Valley, Maricopa and La Paz Counties, Numerical Ground-water Flow Model; consultant report prepared for Vidler Water Company. December, 1999.

Metzger, D.G. 1957. Geology and ground water resources of the Harquahala Plains Area, Maricopa and Yuma Counties; Arizona State Land Department, Water Resources Report 3.

URS, 2001. Water Supply Report for the La Paz Generating Facility: URS Corporation, June 2001.

TABLES

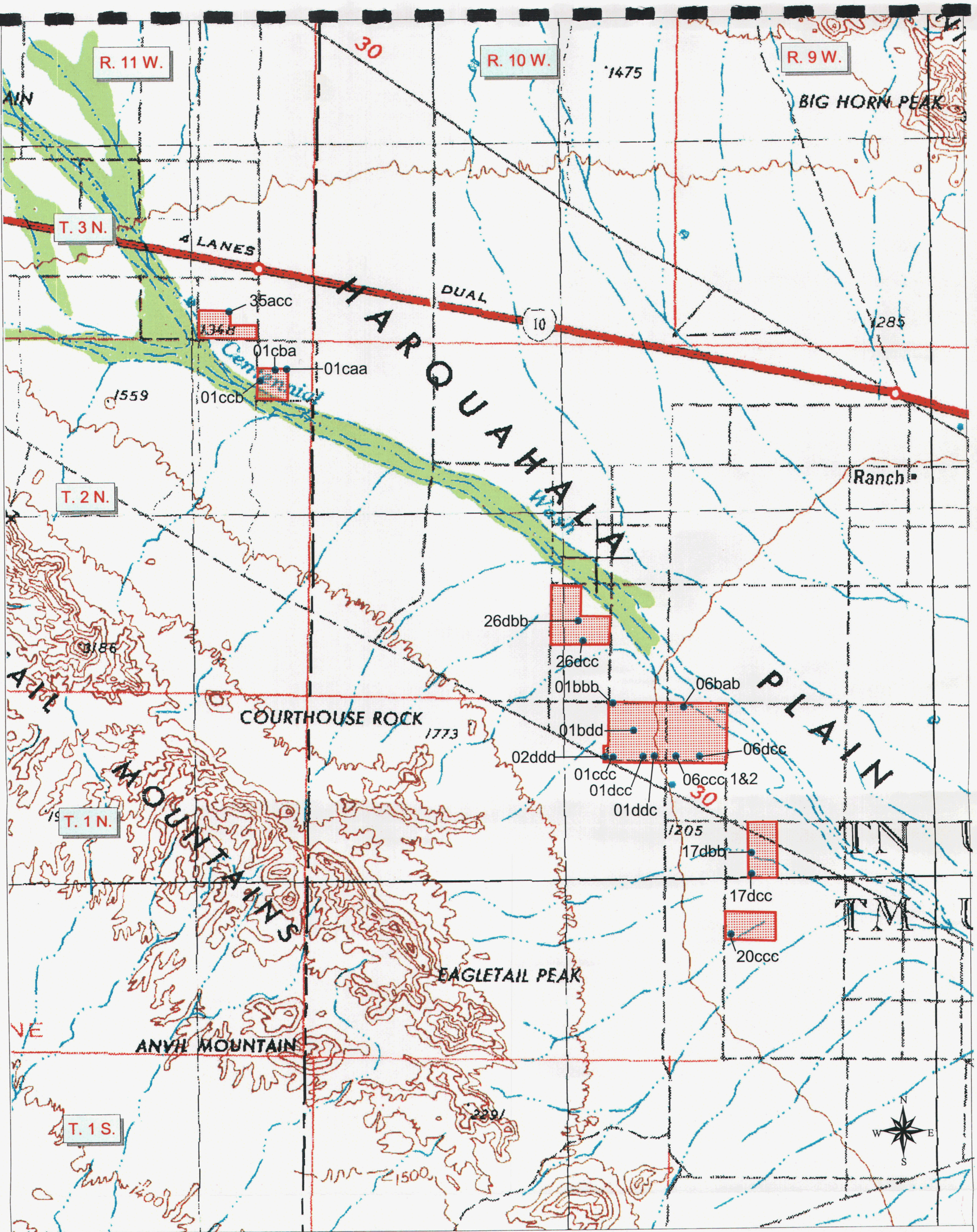
TABLE 1

ALLEGHENY PROPERTIES IN HARQUAHALA VALLEY

Township/Range	Section	Number of Acres in Parcel	Irrigation Grandfathered Right	Irrigable Acres	Wells on Property	ADWR Well Registration Number
T 1 N, R 9 W	Section 6	640	60-201040.0004	636.4	(B-01-09) 06bab (B-01-09) $06ccc_1$ (B-01-09) $06ccc_2$ (B-01-09) 06dcc	55-624942 55-624941 55-624938 55-624943
	E ½ of section 17	320	60-201184.0001	317.5	(B-01-09) 17dbb (B-01-09) 17dcc	55-627796 55-627797
	S ½ of section 20	320	60-201172.0004	305.5	(B-01-09) 20ccc	55-635436
T 1 N, R 10 W	Section 1	640	60-201040.0004	640	(B-01-10) 01bbb (B-01-10) 01bdd (B-01-10) 01ccc (B-01-10) 01dcc (B-01-10) 01ddc	55-624940 55-624939 55-624935 55-624937 55-624936
	SE 1/8 of section 2	14.5		0	(B-01-10) 02 ddd	55-556810 [1]
T 2 N, R 10 W	SW ¼ of section 25	160		0	No wells	
	E ½ of section 26	320	60-201357.0001	160	(B-02-10) 26dbb (B-02-10) 26dcc	55-607665 55-607665
T 2 N, R 11 W	SW ¼ of section 1	160	60-201125.0003	100	(B-02-11) 01caa (B-02-11) 01cba (B-02-11) 01ccb	55-579334 55-501105 55-579335
T 3 N, R 11 W [2]	S ½ of S ½ of section 35	160	60-201357.0001	160	(B-03-11) 35acc	55-564182
Totals:		**2,734.5**		**2,319.4**		

1 Owner of this well is El Paso Natural Gas.
2 Property under option to purchase.

FIGURES



Legend

Allegheny Property

Water Well (may be more than one well per 10-acre parcel)

Map Scale 1:100,000

0 3 Miles

0 10000 Feet

General Project Location In Arizona

Allegheny Properties in Harquahala Valley and Associated Wells

La Paz Generating Facility

Figure 1

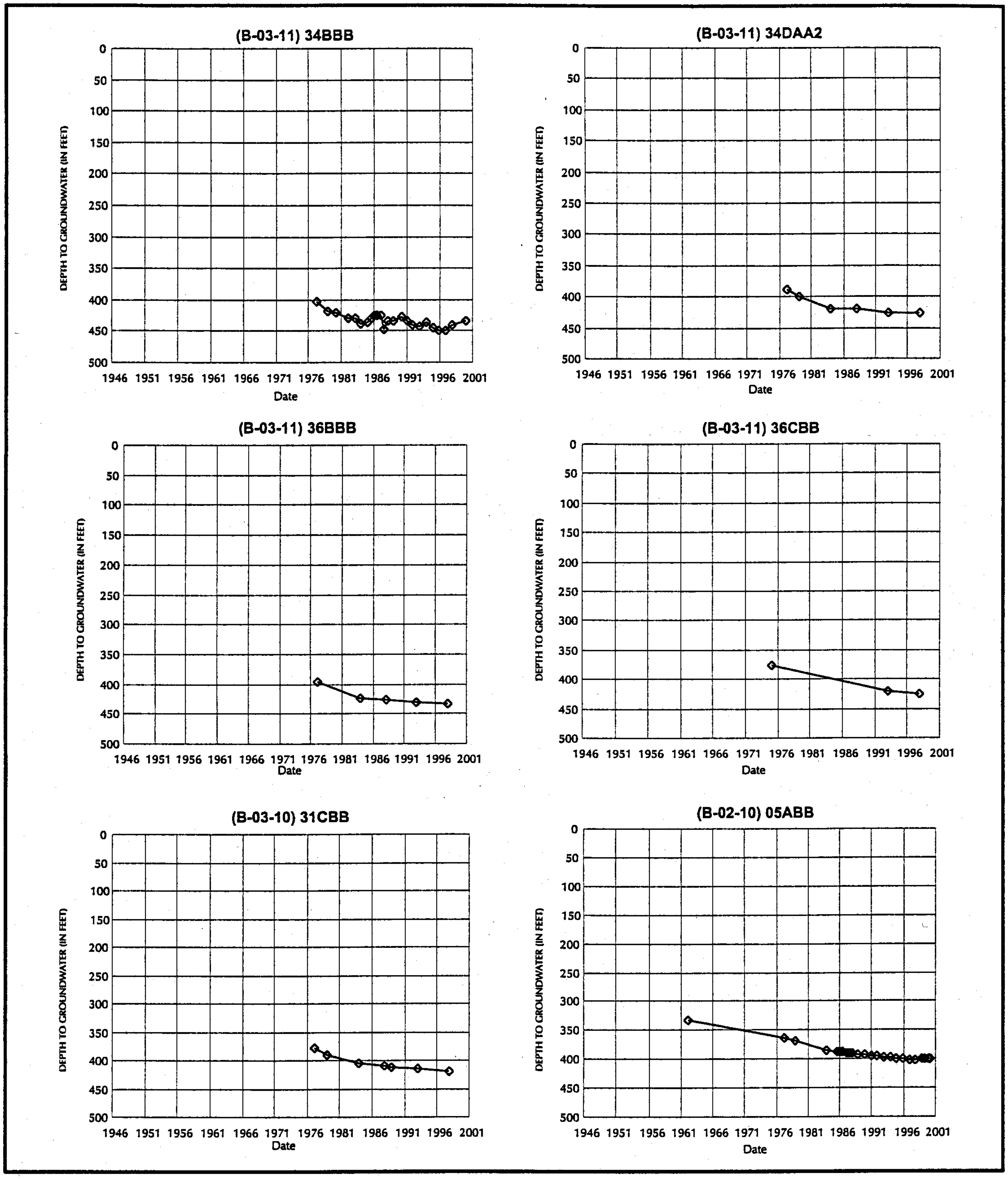
Map Revision Date: September 11, 2001

Allegheny Energy Supply
an Allegheny Energy company

URS

Sources:
USGS, Phoenix 1x2 Degree Quadrangle, Revised 1969.

x:\allegheny\e1-00001722\gis\aprs\groundwater.apr



A15046.DWG 9-13-01

HYDROGRAPHS OF SIX WELLS WITHIN 4 MILES OF THE PROJECT

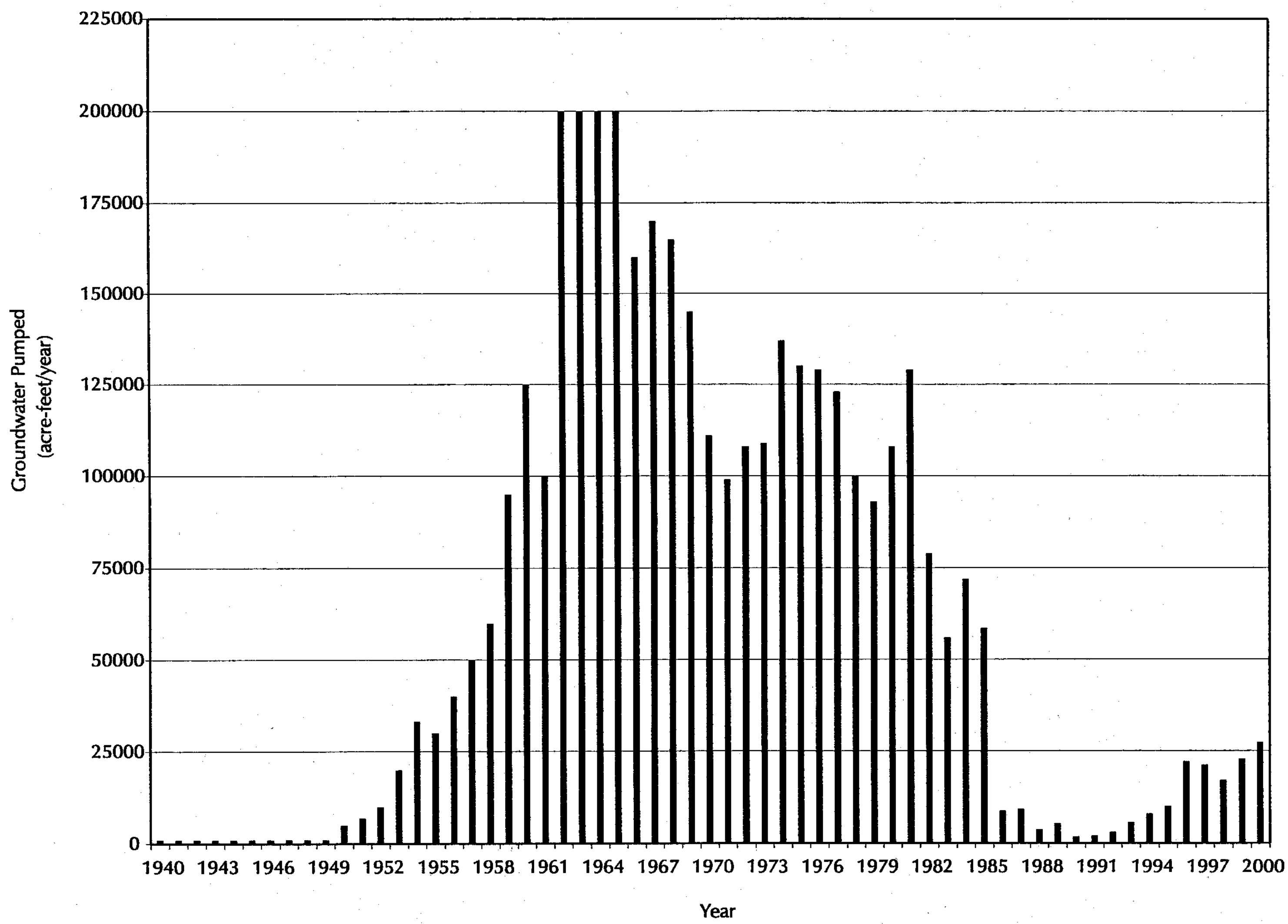
La Paz Generating Facility

URS

Figure 2

E1-00001722.03

A15047.DWG 10-19-01



HISTORICAL GROUNDWATER PUMPAGE FOR THE HARQUAHALA VALLEY

La Paz Generating Facility

URS

Figure 3

E1-00001722.03

APPENDIX A

ADDENDUM TO THE HARQUAHALA VALLEY MODELING REPORT

PREPARED BY HYDROSYSTEMS, INC.

Addendum to the

Harquahala Valley

Modeling Report

Prepared for:

Allegheny Energy Supply
McDowell Road Professional Plaza
14122 West McDowell Road – Suite 201
Goodyear, AZ 85338

Prepared by:

HydroSystems, Inc.
1220 S. Park Lane, Suite 5
Tempe, AZ 85281
Phone: 480-517-9050 fax: 480-517-9049
e-mail: info@hydrosystems-inc.com

August 29, 2001

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1.0 INTRODUCTION

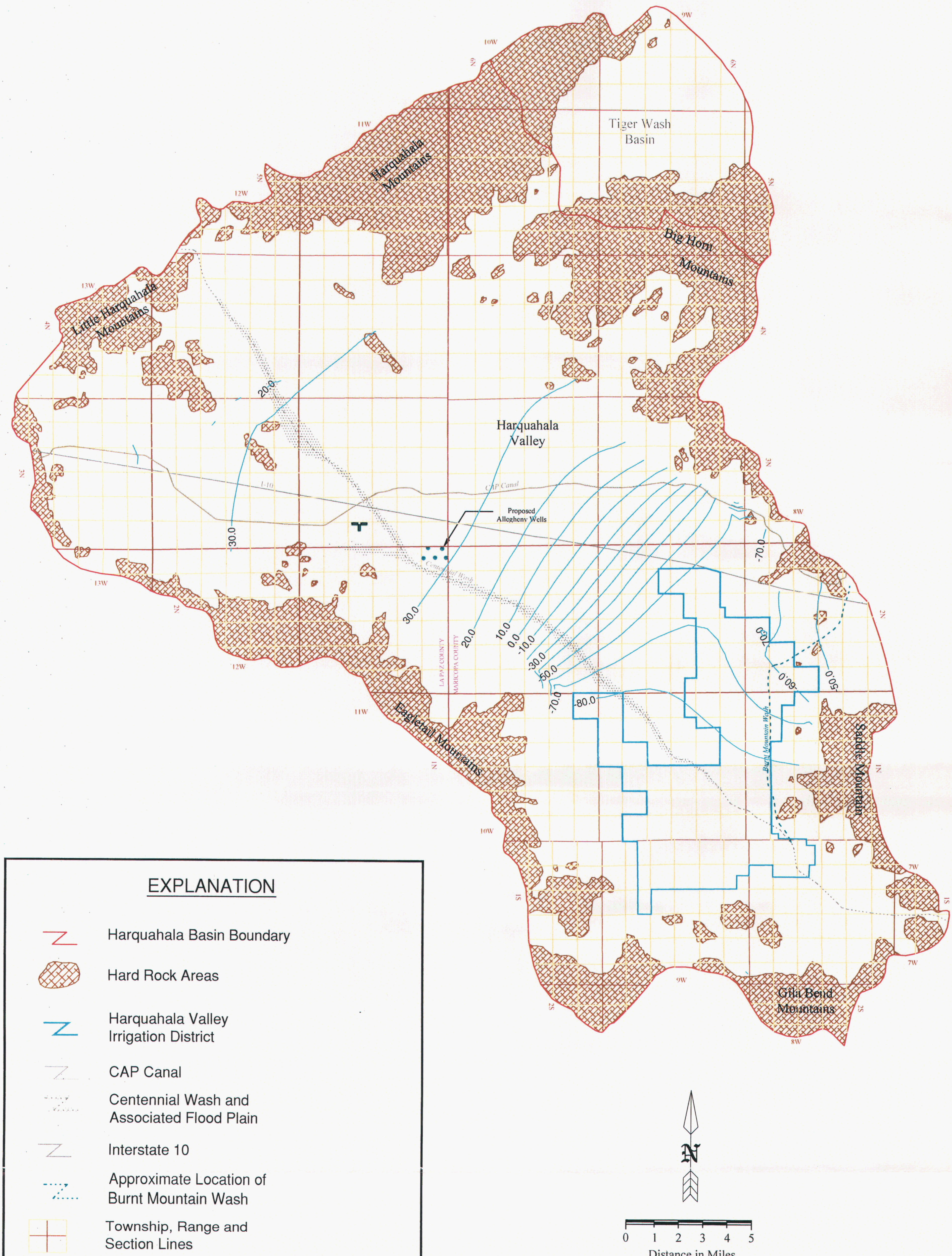
This Addendum to the Harquahala Valley Modeling Report acts as a supplemental attachment to the Harquahala Valley Modeling Report, and is not intended to be a stand alone document. However, figures and tables produced in this document are labeled independently. In order to avoid confusion between the two documents, all references to figures and tables in the Harquahala Valley Modeling Report are produced in **bold** type, and all references to figures and tables in this document are *italicized.*

Not all of the scenarios of the Harquahala Valley Modeling Report are being addressed in this addendum. One figure is being added to **Scenario 1** for clarification purposes, and Scenario 4 is being added, by way of this document, to further emphasize the impacts of the Vidler Recharge Facility on water levels in the location of the proposed Allegheny Energy Supply wells. The content of this document is in no way a revision of the findings and conclusions of the Harquahala Valley Modeling Report.

1.1 SCENARIO 1

Scenario 1 is a continuation of the transient analysis from 1997 to 2032. The purpose of **Scenario 1** is to act as a "base case" to which all other scenarios can be compared. The stresses in the model from 1997 were held constant for 34 years, from 1997 through 2031. In addition to the water levels displayed in **Figure 2** of the Harquahala Valley Modeling Report, it is important to show the change in water levels from the beginning to the end of **Scenario 1**.

For clarification purposes *Figure 1* is displayed below. *Figure 1* shows the simulated changes in water levels from 1997 to 2032, which were not displayed in the Harquahala Valley Modeling Report. Water levels in the northern portion of the basin show a decline of more than 30 feet for the 34 year simulation, while water levels in the southern portion of the basin show a rise of greater than 90 feet over the same time period. Declines in the northern portion of the basin are indicative of the continued small scale agricultural pumping in that area. The rise of the water levels in the southern portion of the basin are indicative of the aquifer's recovery from the large historical groundwater withdrawals in that area, which have recently been reduced.



EXPLANATION

- Harquahala Basin Boundary
- Hard Rock Areas
- Harquahala Valley Irrigation District
- CAP Canal
- Centennial Wash and Associated Flood Plain
- Interstate 10
- Approximate Location of Burnt Mountain Wash
- Township, Range and Section Lines
- Existing Vidler Recharge Facility
- 10 Groundwater Levels Contour Interval 10 feet

Figure 1

Scenario 1 Change in Water Levels from 1997 to 2032

HSI HydroSystems, Inc.
GARY G. SMALL M.S., P.G., C.E.I
1220 S. PARK LANE. SUITE 5 TEMPE, AZ. 85281
TELEPHONE: 480-517-9050 FAX: 480-517-9049

1.2 SCENARIO 4

Scenario 4 is a continuation of the transient analysis from 1997 through 2031 with the addition of pumping by Allegheny Energy Supply and recharge from the nearby Vidler Recharge Facility. However, unlike **Scenario 3** of the Harquahala Valley Modeling Report, the simulated recharge volumes at the Vidler Recharge facility have been reduced. This analysis takes into account the following assumptions:

- Time frame for the analysis: December 1997 through December 2031 .
- Initial heads: December 1997 model calculated heads.
- All stresses (i.e. pumping, recharge, etc.) simulated at the end of 1997 remain constant throughout the entire simulation.
- Five Allegheny Energy Supply wells added, each pumping 868 gallons per minute (gpm) beginning in 2002 and continuing through 2031.
- Additional recharge from the Vidler Recharge Facility beginning in 2002 at 5,000 acre feet per year (ac-ft/yr) and incrementally increasing to a maximum of 30,000 ac-ft/yr in 2005, and continuing through 2031.

Scenario 4 is a conservative modification to the "best case" analysis provided in **Scenario 3**, where the impacts from pumping by Allegheny Energy Supply were essentially non-existent due to the large volumes of water recharged at the nearby Vidler Recharge Facility. Just as in the **Scenario 3**, all stresses and boundary conditions at the end of 1997 remain constant through the 34 year simulation period until December 2031. Also as in **Scenario 3**, an additional 7,000 ac-ft/yr of pumping by Allegheny Energy Supply is included. However, unlike **Scenario 3**, Scenario 4 incorporates artificial recharge of up to only 30,000 ac-ft/yr at the Vidler Recharge Facility.

Consistent with **Scenarios 2 and 3**, the pumping by Allegheny Energy Supply is attributed to 5 wells, each pumping at a rate of 868 gpm for 30 years. The wells were assumed to be screened only in layer 2, thereby only withdrawing water from layer 2. The simulated pumping begins in 2002 and continues through 2031. The 5 new wells are located in Section 1 of Township 2 North and Range 11 West and are arranged within Section 1 as shown in *Figure 2* of the Harquahala Valley Modeling Report.

The Vidler Recharge Facility is located near the proposed Allegheny Energy Supply site, in Section 33 of Township 3 North and Range 11 West. The recharge facility is permitted for a maximum recharge volume of 100,000 ac-ft/yr. Although the recharge facility is permitted for 100,000 ac-ft/yr, Scenario 4 simulates an incrementally increasing recharge rate maximized at a conservatively low 30,000 ac-ft/yr. This is in essence a "worst-case" scenario for the recharge facility. The maximum simulated recharge volume of 30,000 ac-ft/yr, reached in 2005, was continued through the end of Scenario 4 (December 2031). *Table 1* displays the simulated recharge schedule for Scenario 4.

The simulated water levels in layer 1 after the 30 years of additional pumping and recharge are displayed in *Figure 2*. The impact of the Allegheny Energy Supply wells was determined by subtracting the water levels in layer 1, at the end of Scenario 4 from the water levels in layer 1 at the end of **Scenario 1** of the Harquahala Valley Modeling Report. The difference between the two water levels is the impact (or drawdown) from the Allegheny Energy Supply wells. *Figure 3* shows the drawdown in the vicinity of the Allegheny Energy Supply wells. It is important to note that the drawdown shown in *Figure 3* is negative, thus indicating a rise in water level (much like results of **Scenario 3**). Simulated water levels rise approximately 25 feet in the location of the proposed Allegheny Energy Supply's wells. The effects of pumping by Allegheny Energy Supply are still not apparent when considered with the reduced volume of water recharged at the Vidler Recharge Facility.

Table 1. Vidler Recharge Facility Proposed Recharge Schedule with Reduced Volumes

Year	Recharge Quantity (acft/yr)	Recharge Quantity (ft^3/yr)	Recharge Quantity (ft^3/day)	Recharge Rate (ft/day)	Recharge Rate (ft/s)
2002	5000	2.178E+08	596712.33	0.03395	3.9297E-07
2003	10000	4.356E+08	1193424.66	0.06791	7.8594E-07
2004	25000	1.089E+09	2983561.64	0.16976	1.9649E-06
2005	30000	2.178E+09	5967123.29	0.33953	3.9297E-06
2006	30000	3.049E+09	8353972.60	0.47534	5.5016E-06
2007	30000	3.049E+09	8353972.60	0.47534	5.5016E-06
2008	30000	3.049E+09	8353972.60	0.47534	5.5016E-06
2009	30000	3.049E+09	8353972.60	0.47534	5.5016E-06
2010	30000	3.049E+09	8353972.60	0.47534	5.5016E-06
2011	30000	3.049E+09	8353972.60	0.47534	5.5016E-06
2012	30000	3.049E+09	8353972.60	0.47534	5.5016E-06
2013	30000	3.049E+09	8353972.60	0.47534	5.5016E-06
2014	30000	3.049E+09	8353972.60	0.47534	5.5016E-06
2015	30000	3.049E+09	8353972.60	0.47534	5.5016E-06
2016	30000	3.049E+09	8353972.60	0.47534	5.5016E-06
2017	30000	3.049E+09	8353972.60	0.47534	5.5016E-06
2018	30000	3.049E+09	8353972.60	0.47534	5.5016E-06
2019	30000	3.049E+09	8353972.60	0.47534	5.5016E-06
2020	30000	3.049E+09	8353972.60	0.47534	5.5016E-06
2021	30000	3.049E+09	8353972.60	0.47534	5.5016E-06
2022	30000	3.049E+09	8353972.60	0.47534	5.5016E-06
2023	30000	3.049E+09	8353972.60	0.47534	5.5016E-06
2024	30000	3.049E+09	8353972.60	0.47534	5.5016E-06
2025	30000	3.049E+09	8353972.60	0.47534	5.5016E-06
2026	30000	3.049E+09	8353972.60	0.47534	5.5016E-06
2027	30000	3.049E+09	8353972.60	0.47534	5.5016E-06
2028	30000	3.049E+09	8353972.60	0.47534	5.5016E-06
2029	30000	3.049E+09	8353972.60	0.47534	5.5016E-06
2030	30000	3.049E+09	8353972.60	0.47534	5.5016E-06
2031	30000	3.049E+09	8353972.60	0.47534	5.5016E-06
2032	30000	3.049E+09	8353972.60	0.47534	5.5016E-06

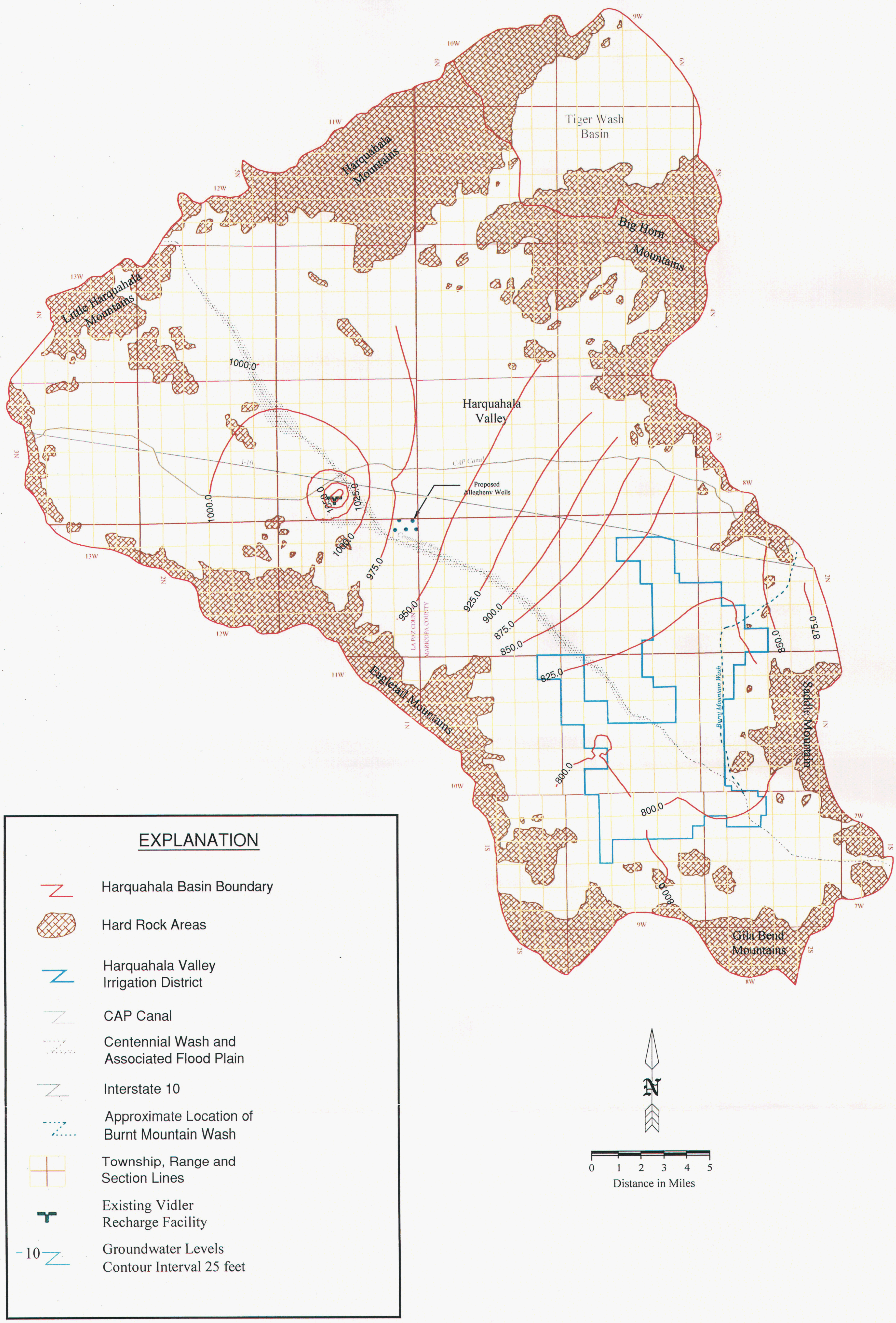


Figure 2

Scenario 4 Simulated Water Levels
December 2031 Including Allegheny Power
Company Pumping and Reduced Vidler Reecharge

HSI HydroSystems, Inc.
GARY G. SMALL M.S., P.G., C.E.I
1220 S. PARK LANE. SUITE 5 TEMPE, AZ. 85281
TELEPHONE: 480-517-9050 FAX: 480-517-9049

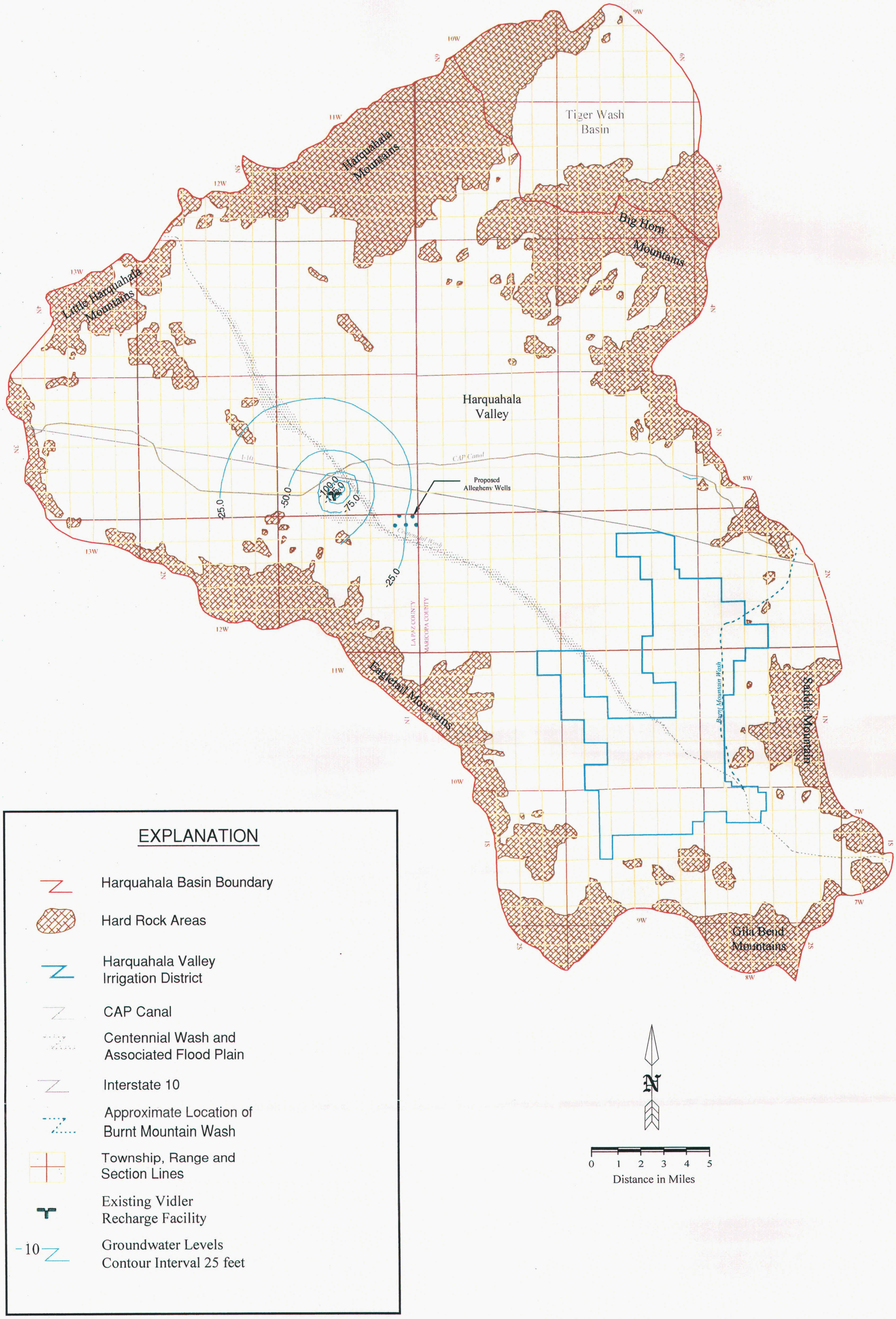


Figure 3

Scenario 4 Impact (Drawdown) of Allegheny Power Company Pumping with Reduced Vidler Recharge

HSI HydroSystems, Inc.
GARY G. SMALL M.S., P.G., C.E.I
1220 S. PARK LANE. SUITE 5 TEMPE, AZ. 85281
TELEPHONE: 480-517-9050 FAX: 480-517-9049

1.3 CONCLUSIONS

Looking at the best circumstance, because of the potentially large volume of recharge water entering the Vidler Recharge Facility, impacts of pumping from Allegheny Energy Supply wells are virtually negligible. Even when considering a significantly reduced recharge volume at the Vidler Recharge Facility (30% of the permitted volume), Allegheny Energy Supply's pumping is still negligible.

On the other hand, looking at the less ideal circumstance where recharge is not taken into account, the maximum drawdown by the Allegheny Energy Supply wells was calculated to be less than 31 feet (30.73 feet) for 30 years of operation. Combining the slow decline of water levels in the northern portion of the Harquahala Valley (less than 1 foot per year) with the drawdown caused by Allegheny Energy Supply pumping (slightly greater than 1 foot per year), the gross maximum simulated decline in water levels is approximately 2 feet per year. Over the 30 year simulation period, this drawdown is not a significant impact to the groundwater system.

EXHIBIT
A-14
admitted

BEFORE THE ARIZONA POWER PLANT AND TRANSMISSION

LINE SITING COMMITTEE

IN THE MATTER OF THE APPLICATION OF ALLEGHENY ENERGY SUPPLY COMPANY, LLC FOR A CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY FOR CONSTRUCTION OF A 1,080 MW (NOMINAL) GENERATING FACILITY IN SECTION 35, TOWNSHIP 3 NORTH, RANGE 11 WEST IN LA PAZ COUNTY, ARIZONA AND AN ASSOCIATED TRANSMISSION LINE AND SWITCHYARDS BETWEEN AND IN SECTION 35, TOWNSHIP 3 NORTH, RANGE 11 WEST AND SECTIONS 23-26, TOWNSHIP 3 NORTH, RANGE 11 WEST ALSO IN LA PAZ COUNTY, ARIZONA.	DOCKET NO. L-00000AA-01-0116 CASE NO. 116

CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY

Pursuant to notice given as provided by law, the Arizona Power Plant and Transmission Line Siting Committee (the "Committee") held public hearings in Parker and Phoenix, Arizona, on September 4, 2001, November 13, 2001 and November 14, 2001, in conformance with the requirements of Ariz. Rev. Stat. § 40-360, et. seq., for the purpose of receiving public comment and evidence and deliberating on the application of Allegheny Energy Supply Company, LLC, or its assignees ("Allegheny" or "Applicant"), for a Certificate of Environmental Compatibility ("Certificate") authorizing construction of a 1080 MW (nominal) generating facility and an associated transmission line and switchyards in La Paz County, Arizona (the "Project"), all as more particularly described and set forth in the Application (the "Application").

The following members and designees of members of the Committee were present on one or more of the hearing days:

GALLAGHER & KENNEDY, P.A.
2575 E. CAMELBACK ROAD
PHOENIX, ARIZONA 85016-9225
(602) 530-8000

Laurie Woodall	Chairman, Designee for Arizona Attorney General, Janet Napolitano
Ray Williamson	Arizona Corporation Commission
Mark McWhirter	Department of Commerce
Jeff McGuire	Appointed Member
Wayne Smith	Appointed Member
Michael Whalen	Appointed Member

Applicant was represented by Michael M. Grant and Todd C. Wiley of Gallagher & Kennedy, P.A. Arizona Corporation Commission Utilities Division Staff ("Staff") was represented by Christopher C. Kempley and Jason D. Gellman. Intervenor Arizona Unions for Reliable Energy ("Unions") was represented by James D. Vieregg of Morrison & Hecker, L.L.P. La Paz County, by its County Attorney R. Glenn Buckelew, filed a notice of limited appearance in support of the grant of Allegheny's Application.

At the conclusion of the hearing, after consideration of the Application, the evidence and the exhibits presented, the comments of the public, the legal requirements of Ariz. Rev. Stat. §§ 40-360 to 40-360.13 and in accordance with A.A.C. R14-3-213, upon motion duly made and seconded, the Committee voted to make the following findings and to grant Allegheny the following Certificate of Environmental Compatibility (Case No. 116):

The Committee finds that the record contains substantial evidence regarding the need for an adequate, economical and reliable supply of electric power and how the Project would contribute towards satisfaction of such need without causing material adverse impact to the environment.

Applicant and its assignees are granted a Certificate authorizing the construction of a 1,080 MW (nominal) electric generating plant as more particularly described in Section 4(a)(i) of the Application and an associated 500 kv transmission line and switchyards as more particularly described in Section 4(b)(i) of the Application and Exhibit G-7.

This Certificate is granted upon the following conditions:

1. Applicant and its assignees will comply with all existing applicable air and water pollution control standards and regulations, and with all existing applicable ordinances, master plans and regulations of the state of Arizona, the county of La Paz, the United States and any other governmental entities having jurisdiction, including but not limited to the following:

a. all zoning stipulations and conditions, including but not limited to any landscaping and dust control requirements and/or approvals;

b. all applicable air quality control standards, approvals, permit conditions and requirements of the Arizona Department of Environmental Quality ("ADEQ") and/or other State or Federal agencies having jurisdiction, and the Applicant shall install and operate selective catalytic reduction and catalytic oxidation technology at the level determined by the ADEQ. The Applicant shall operate the Project so as to meet a 2.5 ppm NOx emissions level, within the parameters established in the Title V and PSD air quality permits issued by ADEQ. Applicant shall install and operate catalytic oxidation technology that will produce carbon monoxide ("CO") and volatile organic compound ("VOC") emissions rates determined as current best available control technology ("BACT") by ADEQ;

c. all applicable water use and/or disposal requirements of the Arizona Department of Water Resources ("ADWR"), Section 6-503 of ADWR's Third Management Plan and the ADEQ regulations;

d. all applicable regulations and permits governing transportation, storage and handling of chemicals.

2. The authorization to construct the Project will expire five (5) years from the date the Certificate is approved by the Arizona Corporation Commission (the "Commission"), unless construction is completed to the point that the plant is capable of operating at its rated capacity by that time; provided, however, that prior to such expiration, the Applicant may request that the Commission extend this time limitation.

3. Allegheny shall provide to the Commission the system impact study and the facilities study performed by Southern California Edison regarding the Project.

4. Applicant shall provide to the Commission an interconnection agreement with the transmission provider with whom Applicant is interconnecting, within 30 days of execution of such agreement.

5. Applicant's plant interconnection must satisfy the WSCC single contingency outage criteria (N-1) without reliance on remedial action such as, but not limited to, reducing generator output, generator unit tripping or load shedding.

6. Allegheny will become and remain a member of the WSCC or its successor and file an executed copy of its WSCC Reliability Management System ("RMS") Generator Agreement with the Commission. Membership by an affiliate of Applicant satisfies this condition only if Applicant is bound by the affiliate's WSCC membership.

7. Applicant will use commercially reasonable efforts to become a member of the Southwest Reserve Sharing Group, or its successor, and if involved in the selling of wholesale power to a commercially identifiable load, thereby making its units available for reserve sharing purposes, subject to competitive pricing.

8. Subject to Federal Energy Regulatory Commission rules and tariffs and WSCC RMS requirements, Applicant shall commit to offer as ancillary services 7% of its total plant capacity to the local Control Area with which it is interconnected and to Arizona's regional ancillary service market once a Regional Transmission Organization is operational and, until such time that a Regional Transmission Organization is operational, to a regional reserve sharing pool.

9. Applicant shall offer wholesale power for sale to Arizona customers via open market, arms-length transactions.

10. In connection with the construction of the project, Applicant shall use

commercially reasonable efforts, where feasible, to give due consideration to use of qualified local and in-state contractors.

11. Applicant shall participate in good faith in the Central Arizona Transmission Study, and other state and regional transmission study forums, to identify and encourage expedient implementation of transmission enhancements, including transmission cost participation as appropriate, to reliably deliver power from the proposed plant throughout the WSCC grid in a reliable manner, and as necessary to resolve any transmission deficiencies between La Paz Power Plant and its intended market, including the Bulk EHV System, underlying 115 kV to 230 kV System, and the transmission import constraints for the Phoenix and Tucson service area; and

12. Applicant shall pursue all necessary steps to ensure a reliable supply of natural gas for the generating facility.

13. Applicant shall participate in good faith in state and regional workshops and other assessments of the interstate pipeline infrastructure.

14. Applicant shall operate the Project so that during normal operations the Project will not exceed (i) U.S. Department of Housing and Urban Development ("HUD") or Federal Transit Administration ("FTA") residential noise guidelines or (ii) Occupational Safety and Health Administration ("OSHA") Worker Safety Noise Standards.

15. Applicant will use low profile structures and stacks, non-reflective and/or neutral colors on surface materials and low intensity directive/shielded lighting fixtures to the extent feasible for the Project.

16. Allegheny will fence the generating facility and evaporation ponds to minimize effects of plant operations on terrestrial wildlife and will keep the berms surrounding

the evaporation ponds clear of vegetation to limit pond attractiveness to birds.

17. Applicant will monitor the evaporation ponds, recording avian use of the ponds and water quality on a weekly basis. If a large number of birds are using the ponds, Allegheny will contact the U.S. Fish and Wildlife Service and the Arizona Game & Fish Department to discuss potential mechanisms to reduce the number of birds utilizing the ponds.

18. Allegheny will continue cactus ferruginous pygmy owl surveys through the Spring of 2002, based on established protocol. If survey results are positive, the U.S. Fish and Wildlife Service and Arizona Department of Game and Fish will be contacted immediately for further consultation.

19. Allegheny will retain a qualified biologist to monitor all ground clearing/disturbing construction activities. The biological monitor will be responsible for ensuring proper actions are taken if a special status species is encountered (e.g., relocation of a Sonoran desert tortoise).

20. Applicant will salvage mesquite, ironwood, saguaro and palo verde trees removed during project construction activities and use the vegetation for reclamation in or near its original location and/or landscaping around the plant site.

21. Allegheny will retain a qualified landscape architect to develop a landscape plan for the perimeter of the generating facility. The landscape plan will use native or other low water use plant materials. The Applicant will continue to consult with La Paz County regarding the landscape plan.

22. From the period beginning 30 days from the date a certificate is approved by the Commission until the Project's construction is completed, Applicant shall erect and maintain at the site a sign of not less than 4 feet by 8 feet dimensions, advising:

(a) that the site has been approved for construction of a 1080 megawatt generating facility;

(b) the expected date of completion; and

(c) a phone number for public information regarding the Project.

In the event that the Project requires an extension of the term of the Certificate prior to completion of the construction, Applicant shall use reasonable means to directly notify all landowners and residents within a one-mile radius of the Project of the time and place of the proceeding in which the Commission shall consider such request for extension. Applicant shall also provide notice of such request to La Paz County.

23. The Applicant will continue to consult with La Paz County in relation to its comprehensive planning process to develop appropriate zoning and use classifications for the area surrounding the Project.

24. If Sites AZ S:7:48 and 49 (ASM) cannot be avoided by ground disturbing activities, the Applicant will continue to consult with the State Historic Preservation Office to resolve any negative impacts which usually entails preparing and implementing a data recovery research design and work plan.

25. If a federal agency determines that all or part of the Project represents a federal undertaking subject to review under the National Historic Preservation Act, Allegheny will participate as a consulting party in the federal compliance process (i.e., 36 C.F.R. 800) to reach a finding of effect and to resolve adverse effects, if any.

26. Should cultural features and/or deposits be encountered during ground disturbing activities, Allegheny will comply with A.R.S. § 41-844, which requires that work cease in the immediate area of the discovery and that the Director of the Arizona State Museum be notified promptly.

27. If human remains or funerary objects are encountered during the course of any ground disturbing activities related to the development of the subject property, Applicant shall cease work and notify the Director of the Arizona State Museum in accordance with Ariz. Rev. Stat. § 41-685.

GRANTED this ______ day of ______________, 2001.

ARIZONA POWER PLANT AND
TRANSMISSION LINE SITING COMMITTEE

By ___________________________________
Laurie Woodall, Chairwoman

12921-0004/947199 v6

EXHIBIT
A-15
admitted

WAYNE C. MICHELETTI

Wayne C. Micheletti, Inc.
977 Seminole Trail # 300
Charlottesville, Virginia 22901-2824
Off: (434) 977-8330 / Fax: (434) 977-6117
E-Mail: WCMInc@aol.com

BACKGROUND and EXPERIENCE

Wayne Micheletti has provided technical services in the area of industrial water management for more than twenty years. During that time, he has worked as a project manager for a large, diversified engineering company; initiated and coordinated research activities at a well known, nonprofit R&D institute; and most recently offered independent consulting. Because water is such an important element in so many different processes, Mr. Micheletti has worked with a wide variety of industries (including electric power, iron and steel, oil and petrochemical, plastics, tobacco, and pulp and papermaking) throughout the United States and internationally. However, the electric power industry and affiliated organizations (such as the Electric Power Research Institute, the Edison Electric Institute and the Utility Water Act Group) have always been a major client focus. He has also worked with federal and state government organizations, including EPA and DOE.

Wayne C. Micheletti, Inc.: July 1991 - Present
President. This consulting firm provides technical services related to industrial water and wastewater management on an independent basis or as part of a project team. The goal is to provide the client with the most thorough analyses of issues and the best solutions to problems in the most cost-effective and timely manner. As a result, WCM Inc. specializes in forming and managing "customized" project teams that may consist of other consultants, A/E firms, technical service organizations, and water treatment service companies which are chosen for their particular experience and unique expertise relative to the client's needs.

In the past several years, some of the projects Mr. Micheletti has been involved with include:

- Update and enhancement of EPRI PC software (*Win*SEQUIL) for predicting scaling in cooling water systems and an associated database (COOLADD) of cooling water chemical additives usage.

- Initial testing and development of a PC-based boiler cycle chemistry advisor (EPRI ChemExpert).

- Preparation of the EPRI Reference Manual for On-Line Monitoring of Water Chemistry and Corrosion (2nd Edition, 1998), and the EPRI Service Water System Corrosion and Deposition Sourcebook (1993).

- Development of guideline documents for: Closed Cooling Water Chemistry (1997); Treatment of Corrosion and Fouling in Fire Protection Systems (1998); and Flow Meter Instrumentation, Calibration and Uncertainty (1998), as a member of the EPRI Plant Support Engineering Task Group.

- Summary of U.S. water and wastewater environmental regulations for the steam-electric power industry and possible implications for evolving environmental limitations on power plants in Poland.

- Development of technical responses to proposed environmental legislation on Sections 316(a) and 316(b) of the Clean Water Act (on behalf of the Edison Electric Institute, the Utility Water Act Group, and EPRI).

- Review of environmental permit issues associated with the use of reclaimed water (treated municipal sewage effluent) as cooling system makeup at a northeastern cogeneration plant and a southern California refinery.

- Evaluation of cooling tower wood deterioration causes and development of cooling water treatment options aimed at improving and extending wood lifetime.

- Complete audit of all water/wastewater system operations and associated chemical treatment programs at a tobacco processing plant.

- Assessment of vendor bids for cooling system chemical treatment and recommendations for program implementation and performance monitoring at a plastics manufacturing facility.

- Analyses of cooling system/power plant zero discharge options.

- Formulation and assessment of options to achieve permit compliance for discharge from a cooling water evaporation pond.

He has also provided long-term support to EPRI on nontoxic biofouling control techniques, sampling and analyses for toxics in power plant process and wastewater streams (as related to the PISCES Model and Database), and EPCRA TRI (Toxics Release Inventory) reporting.

Electric Power Research Institute (EPRI): May 1983 to July 1991
Senior Project Manager. At the Institute, Mr. Micheletti guided all of EPRI's research on water quality control in balance-of-plant systems (cooling, ash handling, wastewater, and low volume waste) and for discharge compliance. He also ultimately directed any research on cooling water intake technologies and associated environmental impacts, and comanaged several projects on improving cooling tower performance.

In the area of cooling water chemistry, he directed field studies on the formation of calcium carbonate, calcium sulfate (gypsum), and silica in condensers, the development of microcomputer software for predicting scaling potential (SEQUIL), and the creation of a cooling water additives database (COOLADD). In a related activity, Mr. Micheletti managed the design, fabrication and field demonstration of a mobile test facility for evaluating chemical biocides used to control microbiological fouling. He also served as a member of EPRI's Service Water Working Group (cochair of the Water Treatment Subgroup) and the Zebra Mussel Task Group.

During this time, Mr. Micheletti conceived and managed the development of the first microcomputer code (WATERMAN) specifically designed to evaluate the complex technical and economic aspects of different approaches for integrating water use/reuse in power generating facilities. With this code, a user could create a site-specific water balance and examine the water quality and cost impacts of changes in system operating conditions, stream flows and/or new treatment processes. In associated R&D work, Mr. Micheletti also directed the preparation of a plant water management instrumentation handbook, the characterization of low volume waste streams and evaluation of waste treatment options, and the field demonstration of emerging water/wastewater treatment technologies (such as seeded reverse osmosis).

From 1984 to 1989, he was manager of all R&D in the area of power plant cooling water intake systems. In that period, EPRI published an Advanced Intake Technologies Study and an Intake Research Facilities Manual, conducted laboratory and field testing to assess the performance of behavioral barriers, and completed development of the first comprehensive industry database on power plant cooling water intake systems. Mr. Micheletti also organized and cochaired the 1987 Conference on Fish Protection at Steam and Hydroelectric Power Plants.

His research on cooling tower performance focused on the development of a rigorous numerical model of the combined heat and mass transfer phenomena in evaporative cooling systems (VERA2D) and its comparison with similar modeling efforts in the U.S. (FACTS) and France (TEFERI). This work was coordinated with full-scale, field evaluations of cooling tower fill types conducted at a specially designed EPRI Cooling Performance Test Facility in order to obtain critical verification data.

In addition, Mr. Micheletti contributed to EPRI R&D in the areas of boiler cycle chemistry, integrated environmental control (the impacts of NO_X, SO_X and particulate control on plant water and wastewater), and nuclear plant service water systems. He acted as the Institute's designated liaison with the Chemistry Committee of the Edison Electric Institute (EEI), the Low Volume Waste Committee of the Utility Solid Waste Activities Group (USWAG), and the ASME Research Committee on Water & Steam in Thermal Power Systems.

Radian Corporation: December 1976 to May 1983
Senior Engineer and Engineering Group Leader. Mr. Micheletti managed the Water Processes Group in the corporate Engineering Division. As such, his responsibilities included proposal preparation for major industrial and governmental clients, staff assignments within a matrix management organization, junior staff mentoring, overall direction of key projects (including field and laboratory studies, software development, and technology assessments), and review of specific technical reports prior to issue.

PROFESSIONAL AFFILIATIONS

- American Society of Mechanical Engineers Research Committee on Power Plant and Environmental Chemistry (formerly the EEI Chemistry Committee).

- American Society of Mechanical Engineers Research Committee on Water and Steam in Thermal Power Systems.

- National Association of Corrosion Engineers - Cross-Industry Program Coordinator. Active member of task groups and technology exchange groups for cooling systems (biocide application/misapplication; MIC; corrosion and scale control; monitoring and control; evaluation of cooling water products), boilers (chemistry; water treatment practices; lay-up/start-up), building water systems (potable, circulating and fire protection water), and nonchemical water treatment.

- EPRI liaison for the Cooling Technology Institute (CTI) Water Treatment Committee
- Water Environment Federation
- American Institute of Chemical Engineers (member of Environmental Division, and Computing and Systems Technology Division)

TECHNICAL PUBLICATIONS AND PRESENTATIONS

Mr. Micheletti has authored or coauthored more than 30 technical papers related to industrial water/wastewater management (a complete list is attached), and has chaired or cochaired many sessions at major meetings such as the American Power Conference, the International Water Conference (IWC), and NACE Corrosion Conferences. He has frequently been invited to technically review the work of others, having presented several "prepared discussions" at the IWC.

Mr. Micheletti has taught a number of courses on EPRI-developed software, workshops at UltraPure and WaterTech conferences, and educational seminars at the International Joint Power Generation Conference and the CTI Annual Conference. He has also been a guest lecturer at courses presented by others. In addition, he is an ongoing charter member of the Editorial Advisory Board for Pumps and Systems magazine and reviews books for Corrosion and Chemical Engineering Progress magazines.

EDUCATION

- Bachelor of Science in Chemical Engineering, the University of Texas at Austin
- Master of Science in Chemical Engineering, the University of Texas at Austin

PUBLICATIONS & PRESENTATIONS

J.G. Noblett, K.A. Wilde, and W.C. Micheletti, "A Computer Model of Cooling Tower Water Systems." Proceedings of the 72nd Annual Meeting of the AIChE, San Francisco, July 1978.

W. Chow, J.T. Aronson, and W.C. Micheletti. "Calculations of Cooling Water Systems: Computer Modeling of Recirculating Cooling Water Chemistry." Proceedings of the 41st Annual Meeting of the International Water Conference, Pittsburgh, October 1980.

W.C. Micheletti, P.A. Nassos, and K.T. Sherrill. "Spent Sulfuric Pickle Liquor Recovery Alternatives and By-Product Uses." Proceedings of the Symposium on Iron and Steel Pollution Abatement Technology, Philadelphia, November 1980.

W.C. Micheletti. "Determining Calcium Carbonate Scaling Potential in Complex Aqueous Systems." Proceedings of the 43rd Annual Meeting of the International Water Conference, Pittsburgh, October 1982.

J.T. Aronson, G. Miller, W. Chow, W.C. Micheletti, and R.V. Long. "Treatment of a Blend of Makeup and Recirculating Cooling Water in a Conventional Clarifier Softener System: Results of a Pilot Plant Test." Proceedings of the 43rd Annual Meeting of the International Water Conference, Pittsburgh, October 1982.

W.C. Micheletti, W. Chow, J.T. Aronson, and S.T. Litherland. "Cooling Water Treatment Field Testing for Scaling Control." Proceedigs of the American Power Conference, Chicago, April 1984.

W.C. Micheletti, W. Chow, and J.K. Laughlin. "Water Management and Reuse in Coal-Fired Power Plants: An EPRI R&D Perspective." Proceedings of Water Reuse Sysmposium III, San Diego, August 1984.

A.K. Majumdar, T. Mukerjee, J.A. Bartz, and W.C. Micheletti. "Modeling of the Heat and Mass Transfer Processes in Wet Cooling Towers." Proceedings of the ASME Winter Annual Meeting, New Orleans, December 1984.

P.A. Barker, T. Fitzsimmons, and W.C. Micheletti. "Water-Related Internal Problems in Ash Transport Systems." Proceedings of the 46th Annual Meeting of the International Water Conference, Pittsburgh, November 1985.

T.W. Trofe, M.L. Owen, and W.C. Micheletti. "Silica Removal in Lime-Soda Softeners." Proceedings of the 46th Annual Meeting of the International Water Conference, Pittsburgh, November 1985.

M. Chionis, G. Jones, W. Micheletti, and J. Tomlinson. "Wastewater Concentration by Seeded Reverse Osmosis - A Field Demonstration in the Electric Power Industry." Proceedings of the AIChE National Meeting, Boston, August 1986.

L.J. Holcombe, G.P. Behrens, and W.C. Micheletti. "Comparison of Treatment Methods for Utility Metal Cleaning Wastes." Proceedings of the AIChE National Meeting, Boston, August 1986.

D.M. Sopocy, N.M. Kass, R.J. Chiesa, and W.C. Micheletti. "Microcomputer Code for Power Plant Water Management." Proceedings of the 47th Annual Meeting of the International Water Conference, Pittsburgh, October 1986.

L.J. Holcombe, G.P. Behrens, and W.C. Micheletti. "Methods for Removal of Copper and Iron from Boiler Chemical Cleaning Wastes." Environmental Progress, Vol. 6, No. 2, May 1987, pp. 74-81.

W.C. Micheletti and L.J. Holcombe. "Management of Power Plant Low Volume Wastes." Proceedings of the International Congress on Hazardous Materials Management, Chattanooga, June 1987.

J.E. Cichanowicz and W.C. Micheletti. "Integrated Environmental Control Considerations for Improving Limestone FGD Solid Waste Characteristics." Proceedigs of the 80th Annual Air Pollution Control Association Meeting, New York City, June 1987.

S.M. Ghiaasiaan and W.C. Micheletti. "Effect of Chemical Additives on the Performance of Wet Cooling Towers." Proceedings of the Joint ASME/AIEE Power Generation Conference, Miami Beach, October 1987.

W. Micheletti. "Managing Low Volume Wastes from Fossil Fuel Fired Power Plants." Journal of the Air Pollution Control Association, Vol. 38, No. 2, February 1988, pp. 179-182.

M.C. Hess, G. Jones, W. Micheletti, and J. Tomlinson. "Waste-Water Concentration by Seeded Reverse Osmosis: A Field Demonstration in the Electric Power Industry." Environmental Progress, Vol. 7, No. 1, February 1988, pp. 7-12.

M. Stohs, D. Owens, and W. Micheletti. "Recycle/Reuse of Boiler Chemical Cleaning Wastes in Wet Limestone Flue Gas Desulfurization (FGD) Systems." Proceedings of the 81st Annual Air Pollution Control Association Meeting, Dallas, June 1988.

Y.G. Mussalli, E.P. Taft, and W.C. Micheletti. "Assessment of Developmental Needs for Advanced Intake Technologies." Journal of Hydraulic Engineering, Vol. 114, No. 6, June 1988, pp. 675-688.

D.M. Sopocy, J.A. Montanus, M.D. Rosen, W.C. Micheletti, and K. Swazas. "Using Microcomputers to Improve Power Plant Water Management," Proceedings of the 49th Annual Meeting of the International Water Conference, Pittsburgh, October 1988.

D.T. Merrill, B.D. Douglas, and W.C. Micheletti. "Using Operational Solubility Product Constants to Improve Water Softening Calculations." Proceedings of the 49th Annual Meeting of the International Water Conference, Pittsburgh, October 1988.

T.W. Trofe, R.J. Sugam, A. Pasricha and W.C. Micheletti. "Development of a Cooling Treatment Program to Protect ACB Fill in a High TDS Recirculating Cooling Water System." Proceedings of the 49th Annual Meeting of the International Water Conference, Pittsburgh, October 1988.

W. Micheletti and M. Irani. "Careful Flowmeter Selection Aids Plant Water Management." Power, January 1989, pp. 48-50.

T.A. Lott, W.C. Micheletti, and L.J. Holcombe. "Boiler Chemical Cleaning Waste Treatment and Disposal Options." Proceedings of the 50th Annual Meeting of the International Water Conference, Pittsburgh, October 1989.

W.C. Micheletti, C.D. Hardy, J.F. Garey, and B.A. Bennett. "A Portable Test Facility for Evaluating Condenser Microbiological Fouling Control Options." Proceedings of the EPRI Condenser Technology Symposium, Boston, September 1990.

B.W. Vigon, D.P. Evers and W.C. Micheletti. "Development of Standard Laboratory Protocols to Evaluate Cooling Water Additives for Scaling and Corrosion Control." Proceedings of the 51st Annual Meeting of the International Water Conference, Pittsburgh, October 1990.

W.C. Micheletti, C.D. Hardy, and J.F. Garey. "A Portable Test Facility for Evaluating Condenser Microbiological Fouling Control Options." Proceedings of the 51st Annual Meeting of the International Water Conference, Pittsburgh, October 1990.

W.C. Micheletti. "Solving Water Pumping Problems" Pumps and Systems, Vol. 1, No. 2, March 1993, pp. 14-16.

W.C. Micheletti. "Examining Pump Capacity Problems" Pumps and Systems, Vol. 2, No. 1, January 1994, pp. 12-13.

Wayne C. Micheletti. "Comprehensive Treatment Meets Service Water System Challenge" Power Engineering, Vol. 90, No. 10, October 1995, pp. 29-30.

W.C. Micheletti and B.C. Syrett. "On-Line Instrumentation for Water Chemistry and Corrosion Monitoring" Proceedings of the 5th International Conference on Cycle Chemistry in Fossil Plants, Charlotte, NC, June 1997.

W.C. Micheletti and B.C. Syrett. "On-Line Instrumentation for Water Chemistry and Corrosion Monitoring" Ultrapure Water, Vol. 15, No. 4, March 1998, pp. 63-68.

W.C. Micheletti. "Trends in the Water Treatment Services Industry: Observations and Opinions" Proceedings of the UltraPure Water Expo 2000 Executive Forum, Philadelphia, PA, April 12-13, 2000.

W.C. Micheletti and J.M. Burns. "Understanding Wet and Dry Cooling Systems" accepted for presentation at and for publication in the proceedings of the 62nd Annual Meeting of the International Water Conference, Pittsburgh, October 2001.

EXHIBIT

A-16

COMPARISON OF WET AND DRY COOLING SYSTEMS FOR COMBINED CYCLE POWER PLANTS

Final Report (Version 2.1)

November 4, 2000

Prepared by

John M. Burns, P.E.
Burns Engineering Services, Inc.
Topsfield, Massachusetts

and

Wayne C. Micheletti
Wayne C. Micheletti, Inc.
Charlottesville, Virginia

Prepared for

Hunton & Williams
Legal Counsel for
Utility Water Act Group

TABLE OF CONTENTS

GLOSSARY

Most of the technical terms used in this report are self-explanatory or are defined when first used in the text. For added clarity, however, more complete descriptions of some terms, as well as definitions of several other key terms, are presented below.

Air-Cooled Condenser - A direct, dry cooling tower comprised of finned tubes or extended surfaces wherein the turbine exhaust steam is (directly) condensed under a vacuum inside the tubes. The condenser is connected to the steam turbine via large ducts extending from the power bloc area or building. Condensate is collected by headers and piped to a hotwell near the base of the tower. The tower is generally of a mechanical draft design.

Backpressure - The pressure at the discharge of the turbine into the condenser. Operating variations from design turbine backpressure are an important indication of electricity generating efficiency; an operating backpressure greater than design means a lower generating efficiency. Since backpressure is a vacuum, it is often referenced to an absolute zero pressure scale.

Capacity Factor - The actual operating level of an electricity generating unit expressed as a percentage of the maximum possible operating level. For example, 100% represents continuous unit operation at full load. Operations at all lower loads or in modes that are not continuous are represented by percentages that are proportionally lower than a 100% factor.

Counterflow Wet Cooling Tower - A wet cooling tower in which the major direction of the airflow in the cooling zone is upward or against the downward flow of water to be cooled.

Crossflow Wet Cooling Tower - A wet cooling tower design in which the major direction of the airflow in the cooling zone is horizontal or across the downward flow of water to be cooled.

Cycles of Concentration - The number of times the chemistry of the recirculated cooling water is concentrated relative to the source water. For example, when the silica concentrations in the cooling water and the makeup water are 45 and 10, respectively, the cycles of concentration will be 4.5. The concentration is a result of evaporation in a wet cooling tower

Direct Dry Cooling Tower - A cooling tower in which the heat of condensation for the turbine exhaust steam is transferred to the atmosphere in a single step without the evaporation of water. The steam is condensed inside finned tubes and the heat of condensation is transferred directly to the surrounding atmosphere by using large diameter fans to blow ambient air over the tubes. (see Air-Cooled Condenser). (compare Indirect Dry Cooling Tower).

Dry Bulb Temperature - The temperature of ambient air as measured by a standard thermometer or other similar device.

Energy Penalty - The loss of electricity generating capacity incurred when a cooling system is unable to perform at design efficiency. The energy penalty is associated with insufficient cooling of the turbine exhaust steam and usually is manifested by an increase in steam turbine backpressure. (see Backpressure).

Evaporative Heat Transfer - A form of heat transfer in which the evaporation of a portion of water lowers the temperature of the remaining water or of the underlying surface. In a wet cooling tower, evaporative heat transfer is a result of the direct contact of ambient air with the warm water to be cooled and is provided by an exchange of the latent heat of vaporization for a small quantity of the water into the air. Evaporative heat transfer is separate from the sensible heat transfer effect, but occurs simultaneously.

Fill - The internal surface of a wet cooling tower specially designed to facilitate heat transfer by increasing air-water contact. As the water falls by gravity from the top of the tower into the basin, the fill continually exposes a large surface of the warm water to the air and extends the air-water contact time.

GW (GigaWatts) - A measure of electrical power where one gigaWatt is equal to one thousand (10^3) megaWatts or one million (10^6) kiloWatts.

Hybrid Cooling Tower - A cooling tower which combines features of both wet cooling and indirect dry cooling to address certain site-specific needs. In some cases, the wet portion of a hybrid cooling system provides supplemental cooling to compensate for the decline in performance of the dry cooling portion during periods of high ambient dry-bulb temperatures. More commonly, exit air from the dry portion of a hybrid tower is mixed with the exit air from the wet portion to reduce or eliminate the visible plume that might be produced by a traditional wet cooling tower.

Indirect Dry Cooling Tower - A cooling tower in which the heat of condensation for the turbine exhaust steam is transferred to the atmosphere in a two-step process without the evaporation of water. In the first step, the steam is condensed by cooling water in a condenser located directly beneath the turbine; in the second step, the heat absorbed by the cooling water is rejected to the surrounding atmosphere in finned-tube heat exchangers which are cooled by large diameter fans blowing air over the finned surfaces. The cooled water is then returned to the condenser to repeat the cycle. (Compare Direct Dry Cooling Tower).

Initial Temperature Difference or ITD - The difference between the turbine exhaust steam temperature and the anticipated inlet ambient air dry-bulb temperature.

Range - The temperature difference between the hot water entering and the cold water leaving a wet cooling tower.

Sensible Heat Transfer - A form of heat transfer in which a warmer body is cooled by direct contact with a colder body. In a wet cooling tower, the hot water entering the top is cooled by direct contact with the air flowing through the tower. Sensible heat transfer is separate from the evaporative heat transfer effect, but occurs simultaneously.

Terminal Temperature Difference or TTD - The difference between the turbine exhaust steam temperature and the hot cooling water temperature.

Vacuum - A system pressure that is lower than the ambient atmospheric pressure. Since gauge pressure uses ambient atmospheric pressure as a baseline, vacuum pressure is frequently reported in terms of absolute pressure, which uses zero as a reference. In power plants, equipment used to condense turbine exhaust steam operates at vacuum conditions.

Wet Bulb Temperature - The temperature of ambient air as measured by a thermometer in which the bulb is kept moistened and ventilated. The resulting measurement equates to the dynamic equilibrium temperature attained by a water surface when the rate of heat transfer to the surface by convection equals the rate of mass transfer away from the surface by evaporation. The wet bulb temperature is the lowest temperature at which evaporation can occur for specific ambient conditions (dry bulb temperature and relative humidity). The wet bulb temperature closely approximates the adiabatic saturation temperature.

Wet Cooling Tower - A cooling tower in which heated water, produced when the heat of condensation for the turbine exhaust steam is absorbed by the water in a shell-and-tube condenser, is cooled by transferring this heat to the atmosphere through: a) evaporation of some of the hot water entering the tower and b) sensible heating of ambient air flowing through the tower. After the hot water has been cooled in the tower and fresh water has been added to makeup for evaporation and system losses, the cooling water may be recirculated back to the condenser for reuse or discharged.

COMPARISON OF WET AND DRY COOLING SYSTEMS FOR COMBINED CYCLE POWER PLANTS

INTRODUCTION

Background

According to the Energy Information Administration (EIA), new combined cycle (CC) power plants will account for an additional 135 GW of electricity generating capacity in the United States over the next twenty years (2000-2020).[1] If this projection is correct, the total generating capacity for CC plants will increase to 154 GW by 2020. At that time, EIA indicates electricity generation by CC plants will be exceeded only by coal steam plants (317 GW) and combustion turbine/diesel plants (202 GW). Accordingly, the growth in CC capacity will represent 47.3% of the total new generating capacity built in the U.S. over the next twenty years. As a result, by 2020, combined cycle power plants will represent a significant portion (16%) of the projected overall U.S. electricity generating capacity as compared to the CC capacity operating in 1998 (2.6%).

Heat rejection is a natural consequence of the power generation process and water is usually used to absorb that heat. In fact, water is an essential resource in most electricity generating operations, including CC plants. But differences in the power production process mean that combined cycle plants use less water than traditional fossil and nuclear stations to generate the same amount of electricity. Even so, in locations where water availability or the potential environmental impacts of water use raise issues, design and operating alternatives that reduce overall CC plant water requirements may be important.

Since most of the water needed in a CC plant is used for cooling, water-conserving cooling alternatives could substantially reduce a plant's total water demand. Once-through cooling systems are favored in most power plants, including CC stations, because of their low capital cost and high operating performance. Yet, on a gpm/MW basis, once-through cooling systems withdraw the largest amount of water from source water bodies and require the largest intakes. The most frequently considered water-conserving alternative for new power plants is recirculated cooling systems with mechanical draft towers. In some cases, natural draft towers have been used. Direct dry cooling systems may be considered an alternative. Generally, however, dry systems are not considered to be a viable, cost-effective design choice unless there are unique circumstances and conditions associated with the either the site or the market climate for the project. Furthermore, although these alternatives differ in several ways, the most distinctive difference is that recirculated systems evaporate water for cooling while direct dry systems do not. Therefore, in this report recirculated cooling systems with mechanical draft towers are referred to as "wet" cooling and direct dry cooling systems are referred to as "dry" cooling.

Objectives and Scope

The primary objective of this study is to develop engineering and economic comparisons of wet and dry cooling systems for new combined cycle power plants. The study focus is the contiguous United States (lower 48 states) and the study period is the next twenty years (2000-2020). Study results were to include:

1. A technical discussion that identifies and explains the engineering, design and operating differences between wet and dry cooling,
2. A cost analyses that presents capital and operating costs for base case examples of both wet and dry cooling, and
3. A summary of estimated regional and national costs for new combined cycle power plants with wet and dry cooling systems.

This report summarizes the overall study efforts and presents the final study results.

OVERVIEW OF COOLING SYSTEM DESIGN AND OPERATION

The standard combined cycle power plant is defined by the "combined" two-step production of electricity using one or more gas turbines and a steam turbine. In the first step, natural gas or an appropriate liquid fuel is burned under controlled conditions and the combustion gas is used to drive a turbine; the turbine shaft is coupled to a generator which produces electricity. In the second step, the hot exhaust gas from the turbine(s) is passed through a heat recovery steam generator (HRSG) to make superheated steam; the steam is then used to drive a separate steam turbine and its generator, which produces additional electricity.

Spent exhaust steam from the steam turbine is cooled in a condenser to recover high-quality water that can be recycled to the HRSG and reused for steam production. Steam condensation in the condenser also creates a vacuum at the outlet from the steam turbine. This vacuum (monitored as turbine backpressure) allows the turbine to utilize more of the steam's energy and increases the overall efficiency of electric power generation. Lower steam temperatures in the condenser will produce a greater vacuum on the steam turbine (reflected by a lower turbine backpressure) and mean a higher generating efficiency. In this way, exhaust steam cooling directly influences power plant performance, which will be reflected in the price of electricity at the busbar.

In a CC power plant, the cooling system is designed to reject heat from the condensing steam to the environment. For wet cooling systems, water is used as the heat transfer medium between the steam and the environment. For dry cooling systems, the heat is rejected directly to the environment.

Wet Cooling Systems

All wet cooling systems use water to absorb heat via indirect contact with steam in a condenser. The condenser is a large shell-and-tube heat exchanger, with steam on the shellside and cooling water passing through the tubes. All wet cooling systems can also be divided into two types according to the manner in which the cooling water is used: once-through and recirculated.

Once-through cooling systems pump cold water from a large source (such as a river, lake or ocean) through the condenser tubes and directly to discharge, usually back into the original source waterbody at a point some distance from the initial intake. Heat absorbed by cooling water in the condenser is rejected to the environment by diffusion of that heated cooling water when it is discharged into the larger, colder body of water, and by normal surface evaporation and radiation. The large size of the makeup water body typically means little daily variation and a low temperature of the cold water pumped to the condenser. As a result, the steam turbine can be consistently operated at low design turbine backpressures for higher generating efficiencies.

Because of its relative simplicity, based on generating capacity (MW), the capital and operating costs for once-through cooling systems normally are far less than those for recirculated cooling systems with a mechanical draft tower. The major capital equipment items in a once-through cooling system are the condenser and the cooling water intake. Primary operating costs include power for the cooling water pumps, cooling water treatment chemicals (for condenser biofouling control), and labor for maintenance and repairs. But because once-through cooling water is "used" only one time, this type of wet cooling system requires a large amount of water, almost all of which (except for minor system losses) is returned to the original source at an increased temperature.

Unlike once-through systems which continuously draw fresh "cold" water from a large makeup water source, recirculated systems pump the cooling water in a recycle loop through the condenser. By doing so, recirculated systems significantly reduce the amount of intake water required to cool and condense the steam turbine exhaust. But, in order to reduce the cooling water temperature so it can be returned to the condenser as recycled "cold" water, recirculated systems must rely on some means for rejecting heat from the hot water leaving the condenser. The most common means of heat rejection is a cooling tower, although cooling ponds and spray ponds also have been used (see Figure 1).

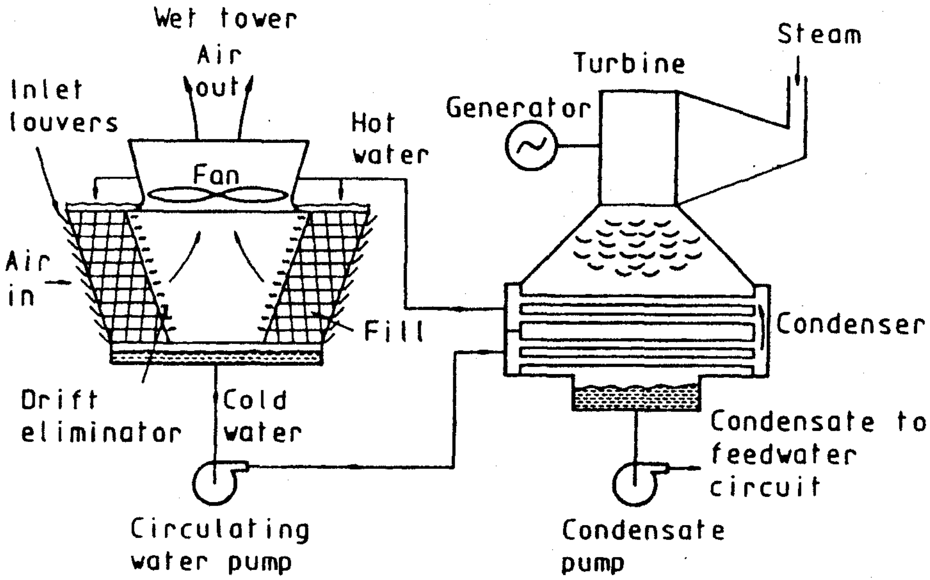


Figure 1

Recirculated Wet Cooling System with Mechanical Induced-Draft Tower[2]

A wet cooling tower is a direct-contact air-water heat exchanger. Heat absorbed by cooling water in the condenser is released to the air that passes through the cooling tower. Hot water is pumped to the top of the tower's cooling section and distributed down into a material packing called "fill" that is designed to promote the cooling effect by increasing air-water contact and extending the residence time. Two types of fill are used. In splash fill, the water falling through the tower is broken into droplets that resemble rain. In film fill, the water flows downward in thin layers (or films) along closely spaced vertical surfaces. Due to turbulent air-water contact, approximately 65-85% of the heat transfer is associated with the evaporation of a portion of the cooling water, while the remaining 15-35% is due to convective heating of the inlet air. This process lowers the temperature of the cooling water entering a tower so that it can be recirculated back to the condenser and used for cooling again. It also consumes water via evaporation that is not returned to the original makeup source waterbody.

Some water must be removed from the cooling tower collection basin to control the composition of the cold water being recirculated to the condenser. This wastewater is known as "blowdown". Evaporation in the cooling tower causes the amount of dissolved and suspended solids in the cooling loop to become concentrated, which increases the potential for scaling and corrosion in the condenser. Blowdown removes dissolved and suspended solids from the cooling loop and reduces the potential for scaling and corrosion in the condenser. Blowdown may be returned to the original source waterbody at a point some distance from the initial intake or it may be directed to either an onsite or offsite wastewater treatment facility.

Cooling tower operation affects not only the quality of the original makeup water, but the characteristics of the air passing through the tower as well. Inlet air is at ambient temperature and is usually only partially saturated (less than 100% relative humidity). Exit air from the tower is warmer (due to the sensible heat transfer from contact with the cooling water) and saturated (due to evaporation of a portion of the cooling water). Depending upon atmospheric conditions, this warmer, saturated air can produce a visible plume at the top of the cooling tower.

For all power plant cooling towers, the atmosphere (i.e., the surrounding air) is the ultimate heat sink for the thermal energy released by steam in the condenser. Thus, the atmospheric conditions are key elements in determining tower and recirculated cooling system performance. The cooling ability of a tower is measured by how close it can bring the outlet cooling water temperature to the wet-bulb temperature of the surrounding air. The lower the inlet air wet-bulb temperature (indicating colder air and/or lower humidity), the colder the tower can make the outlet cooling water temperature. As a matter of physics, the cold water temperature can never be lower than the inlet air wet-bulb temperature; in practice, the design cold water temperature of the main cooling tower sized for a power plant is usually several degrees (~8 °F) higher. For cooling towers, the difference between the anticipated inlet air wet-bulb temperature and the target cold water temperature is a design value referred to as the "cooling approach". During operation in cold weather, this design approach will increase appreciably.

Cooling towers can be broadly classified according to the air-water movement (crossflow or counterflow) and to the method of air supply (type of draft). Natural draft towers rely on the difference in density between cold ambient air and hot air inside the shell to move air through the fill section that is located near the bottom of the shell. Air flow can be enhanced if the height of the tower is increased and a hyperbolic shape is used. This design configuration is also a requirement for the structural stability of the tower in which the shell is constructed of reinforced concrete that has been cast-in-place. However, the extremely large size and associated high capital cost of the hyperbolic design limit the use of natural draft cooling towers to situations with very high heat rejection requirements and extended time periods for cost amortization. Hence, in the United States, these types of towers have been used primarily for large steam-electric power generating stations.

In utility-sized mechanical draft towers, large-diameter fans are used to move air through the fill. If the fan is located over the fill (in a stack above the hot water distribution network), the air is pulled through the fill in an "induced" draft. If the fan is located below the fill (at the base of the tower along the perimeter), the air is pushed through the fill in a "forced" draft. The mechanical, induced-draft tower is the design used most frequently today.

Capital and operating costs for recirculated cooling systems are strongly influenced by the cooling tower. The two major capital equipment items in a recirculated cooling system are the tower subsystem (including the concrete basin, the actual tower, the fans and all associated electrical/control wiring) and the condenser. Compared with once-through systems, "makeup water" flows in recirculated systems usually are much lower, determined in large part by the blowdown and evaporation from the tower. Consequently, the intake for a recirculated system is smaller and is not a large capital equipment item.

As with once-through cooling systems, key operating costs include pumping power (in this case for the recirculated cooling water pumps), fan power (for the cooling tower fans), cooling water treatment chemicals, and labor for maintenance and repairs. Typically, treatment chemical costs are higher because of the need for scale and corrosion inhibitors. Labor costs also are higher due to maintenance and repairs required for the cooling tower and fans.

Dry Cooling Systems

In theory, the term "dry cooling" implies the total absence of water. But in practice, "dry cooling" means the transfer of heat to the atmosphere without the evaporative loss of water. For example, automobiles use a type of dry cooling system to control engine temperatures. Water is circulated through the engine block to absorb heat, then through the radiator to dissipate heat, and then back to the engine block. The heat transfer from the engine to the atmosphere is said to be "indirect" because the intermediate steps of heating and cooling the water occur at two different locations and times in the cycle. The system is also said to be "dry" (or completely closed) because none of the water evaporates; makeup to the system is only required to offset minor losses, such as leaks.

Indirect dry cooling would only be considered for retrofit situations at existing power plants since a water-cooled condenser would already be in place for a once-through or recirculated cooling system. Historically, however, an indirect dry cooling system has never been used in such a case because the performance is very poor and the cost is very high. In addition, indirect dry cooling has never been used for new construction in the United States. However, it has been applied in a relatively few cases throughout the world (primarily in Eastern Europe and the Middle East) in connection with a special cooling design.

For new power plants, a direct dry cooling approach is more cost-effective. In direct dry cooling, the turbine exhaust steam is piped directly to an air-cooled, finned-tube condenser, commonly referred to as the dry cooling tower (see Figure 2). The steam exhaust duct has a large diameter and as short a length as possible to minimize pressure losses. The finned tubes on the condenser are frequently arranged in an A-frame or delta pattern to reduce the required land area. Because finned-tube condensers have a low heat transfer coefficient, they are commonly quite large. Air is typically forced across the finned tubes by fans to improve heat rejection to the atmosphere.. Since direct dry condensers rely strictly on sensible heat transfer, a large quantity of air must be supplied, requiring a correspondingly larger number of fans than would be used in a wet cooling system. The fans are installed on the cooler, inlet air side of the condenser to: a) reduce the power consumption for a given air mass flow rate, b) allow the use of less expensive materials of construction, and c) improve access and ease of maintenance.

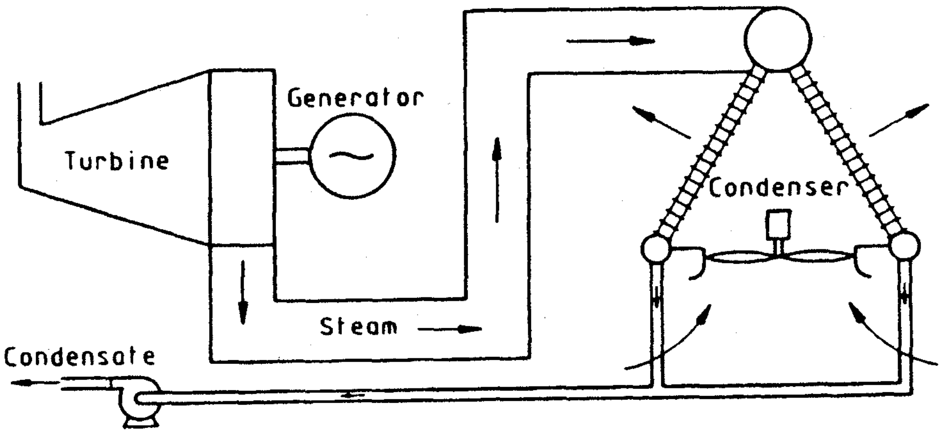


Figure 2 - Direct Air-Cooled Steam Turbine Condensing System[2]

Unfortunately, a forced-draft fan system often does not produce a uniform air flow distribution through the tower and it results in a relatively low warm air escape velocity from the top of the tube bundle. This latter characteristic can be extremely important because in a wind it increases the potential for recirculation of the hot air plume back through the tower instead of drawing in fresh ambient air.[3] Compared to wet cooling towers with the high-velocity plumes produced by induced draft fans, the low exit air velocities associated with dry towers exacerbate the recirculation problems in these systems. Therefore, anti-recirculation fences or windwalls may be required to prevent such problems.[4]

In addition, the air-cooled finned tubes are subject to freezing in the winter and are exposed to the elements (such as rain, hail, pollen and solar radiation), all of which can measurably change performance. If hail is anticipated, special screens must be installed to protect the finned surfaces from damage. Although wet cooling towers also must operate and withstand the same weather elements, they are much hardier and damage to them do not immediately and directly affect the operation of the power cycle. For instance, in a direct dry cooling tower, when one of the tubes freezes, it often splits. After thawing, the tube rupture can produce a sufficiently large air leak into the steam space that it could curtail operation. The leak also can introduce high levels of dissolved oxygen in the condensate that would increase boiler tube corrosion. Furthermore, locating and repairing the damaged tube from among thousands of tubes in a structure that is elevated off the ground by about 100 feet are difficult. In contrast, when a minor amount of ice occurs in a wet cooling tower, no equivalent impact occurs. The wet tower structure and fill are designed to be unaffected by freezing and are not directly coupled to the power cycle.

While the performance of wet cooling systems depends primarily upon the ambient wet-bulb temperature, the performance of dry cooling systems is determined by the dry-bulb temperature of the surrounding air. For dry cooling, the difference between the turbine exhaust steam temperature and the anticipated inlet air dry-bulb temperature is a key design value referred to as the "initial temperature difference" or ITD. Because ambient dry-bulb temperatures are usually higher than wet-bulb temperatures and tend to experience more dramatic daily and seasonal fluctuations, the design and operation of dry cooling systems linked to steam turbine-generators can be more problematic than for wet cooling systems. If the dry cooling system is unable to meet design heat transfer conditions in the condenser, then the turbine backpressure will increase and the plant generation will decrease. With a reasonably flexible steam turbine design, a higher backpressure and the associated decline in generating efficiency (or energy penalty) can be operationally tolerated up to a point. But as the turbine backpressure increases, at some point an alarm will warn operators that the turbine-generator is approaching limits set by the equipment manufacturer. Eventually, if steam cooling and condensation worsen, then either the steam flow to the turbine must be reduced (known as a plant derate because the amount of electricity which can be generated is reduced) or the steam-turbine generator portion of the CC plant must be temporarily shutdown.

Although the water-conserving advantage of dry cooling has increased the interest in and use of this technology (particularly at smaller facilities), the potential for incurring energy penalties due to operation at elevated turbine backpressures and/or plant derates limit its use in locations with high daily or seasonal dry-bulb temperatures. Though it is difficult to absolutely categorize a high temperature limit, when ambient temperatures exceed 90°F, the relative performance of a dry cooling system will begin to suffer appreciably.

Hybrid Cooling Systems

In some circumstances, a combination of wet and dry cooling systems may be helpful in addressing certain site-specific issues. The nature of these "hybrid" systems can vary depending upon the particular situation and objectives. Some hybrid systems are designed to compensate for the decline in performance of a dry cooling system at higher ambient dry-bulb temperatures. These hybrid systems essentially incorporate a wet-cooling component to provide supplemental cooling. But this type of wet/dry system typically has been used in situations with fairly small cooling requirements. Therefore, the technology and the associated economics for these hybrid systems remain uncertain for large-scale applications (on the order of 250 MW).

By far, the most common type of hybrid system is designed to eliminate the visible plume leaving the tower in a wet recirculated system. Hybrid plume abatement systems basically consist of an indirect dry cooling system located immediately above the cooling tower portion of a wet cooling system. Hot cooling water from the condenser is fed first to the indirect-contact, air-cooled, finned-tube heat exchangers and then to the direct-contact fill in the tower. Ambient air also is drawn through both the dry and wet segments in parallel paths. The two air streams are then mixed and exhausted from the stack of the induced-draft fan at the top of the tower. The hot, dry air from the air-cooled heat exchangers increases the temperature and decreases the relative humidity of the cooler, saturated air from the fill so that the mixture leaving the tower does not have a visible plume. Operators can control the degree of visual plume abatement by adjusting hinged damper doors along the air inlet to the dry cooling section to govern the air flow and, consequently, the volume and temperature of hot, dry air in the outlet air mixture.

Hybrid plume abatement systems are not water-conserving systems. Furthermore, these systems should not be confused with other wet/dry hybrids in which the wet portion of the cooling system is designed and operated to compensate for the reduced performance of the dry portion during periods of high ambient dry-bulb temperatures. The hybrid system described above is an option only when plume abatement for a wet cooling tower is an issue, and would be expected to result in a higher overall cost for the tower than if the system were built without plume abatement.

APPROACH AND BASIS FOR COMPARING WET AND DRY COOLING SYSTEM COSTS

Approach

A generic base-case study approach was followed to develop meaningful cost estimates for the wet and dry cooling systems of combined-cycle units. Since the cost estimating methodology included certain site-specific factors, EIA combined cycle capacity forecasts were used to identify several sites representative of anticipated growth. These same EIA data were then used to extrapolate site-specific cost estimates to regional and nationwide cost projections for the next twenty years. The four-step process involved:

1. Definition of a generic base-case CC power plant.
2. Identification of geographic areas based on anticipated new CC power plant capacity and selection of representative sites for base-case analysis.
3. Preparation of base-case capital and O&M costs for wet and dry cooling systems at each selected site.
4. Extrapolation of base-case results to develop regional and overall national cost estimates.

This approach was used for several reasons. A generic base case adequately establishes the details necessary for making reasonable and reliable cost estimates. In addition, a base case effectively fixes all parameters not directly related to the choice of cooling system, so that any comparison of cost estimates is not improperly influenced by external factors. The use of representative sites for different geographic areas enabled the study to consider the potential importance of different local parameters (such as climatic conditions). It also ensured that subsequent extrapolation of base-case results to the national level would not be improperly skewed by a single cost estimate which might unknowingly reflect a best or worst case scenario.

Base-Case CC Power Plant

The generic base case chosen for this study is a 750 MW combined cycle power plant with two 250 MW gas turbine-generators followed by one 250 MW steam turbine-generator which uses fresh water for its cooling needs. Although the typical nameplate rating for CC plants during the last decade has been somewhat smaller, the trend in capacity for plants announced and already under construction is increasing.[5, 6] For the period covered by this study (2000-2020), the 750 MW capacity adopted for the base case is consistent with this trend.

Brackish water and salt water cooling systems were not considered in this study because the number of new CC plants using either brackish water or salt water for wet cooling system makeup is expected to be relatively small compared to the number of new CC plants which will be using fresh water. However, brackish water or salt water cooling systems would be more costly than similar fresh water cooling systems. In a brackish water or salt water cooling system, the tower is slightly larger; more corrosion-resistant materials and coatings would be required; cathodic protection needs would be greater; and makeup and blowdown systems would be larger. All of these added requirements would be very site-specific and so no typical cost factor can be accurately provided. Even so, the estimated cost for a wet cooling system using either brackish water or salt water for makeup should still be appreciably lower than the cost for a dry cooling system at a new CC plant of similar size.

For cost estimating purposes, the generic base case also was assumed to use a single steam turbine design for both wet and dry cooling systems. Historically, steam turbine/condenser designs for large fossil and nuclear power plants have been optimized to reflect the type of cooling system as well as other site-specific conditions. However, as the effects of deregulation spread through the electric utility industry, plant design and construction schedules have decreased and equipment delivery times have increased. As a result, designers often rely on more flexible steam turbines which operate over a wider range of backpressures, even if it means accepting an energy penalty under certain operating conditions.[7] While some project designers may have the opportunity to consider more detailed turbine/cooling system optimizations approaches, the additional time required will have its own cost impacts in the capital market and each optimization would be highly site-specifiic. Thus, for the purposes of this analysis, the assumption has been made that a flexible steam turbine will be used in most cases.

An exhaust steam flow of 1.7 million lbm/hr for the 250 MW steam turbine was taken as representative and was considered to be the same for both the wet and dry cooling systems. Certain fixed cooling system parameters for the wet case (approach, range, and terminal temperature difference or TTD) and the dry case (initial temperature difference or ITD) were combined with site-specific design point climatic conditions (ambient wet-bulb and dry-bulb temperatures) to determine the exhaust steam temperature and its corresponding saturation pressure. Using a typical steam-turbine expansion characteristic then eliminated the necessity for a total plant cycle heat balance to estimate the performance of the cooling system. The net generation (MW) of the steam turbine was calculated from these values and a generic turbine response curve. This curve was developed specifically for the base case turbine, relying on design data from similar commercial steam turbines and the inherent capability of modern turbine designs to effectively produce generation between given inlet and exhaust steam conditions (see Appendix A).

Although condensation of exhaust steam from the steam turbine represents the predominant cooling demand in a combined cycle power plant, there are other auxiliary cooling needs that must be met as well. These auxiliary cooling loads are relatively small (typically 5% of the steam condenser heat transfer load), but critical to the overall power generation process. For example, certain auxiliary cooling heat exchangers (such as turbine lube oil coolers) require cooling water temperatures that cannot be exceeded without violating equipment manufacturer's warranty specifications.

As a result, auxiliary cooling would be different for the wet and dry cooling systems. For the wet cooling base case analyses, the design capacity of the recirculated cooling system and its direct capital cost were considered as increased by 5%. For the dry cooling base case analyses, there is no cooling water which could be used to meet auxiliary cooling needs (in direct dry cooling, the turbine exhaust steam is piped directly to an air-cooled, finned-tube condenser). Therefore, a separate indirect dry cooling system (i.e., a fan-cooled finned heat exchanger similar to but larger than an automobile radiator) was included to meet auxiliary cooling needs. In addition, to accommodate the higher cooling water temperatures occurring in an indirect dry auxiliary cooling system, key heat exchangers (such as the turbine lube oil coolers) were enlarged to provide greater heat transfer. Compared to a wet cooling system, the much greater costs for all of the extra component requirements in the indirect auxiliary system were nonetheless considered to be accounted for in the same 5% cost factor used for wet cooling systems.

Other assumptions for the wet and dry cooling systems analyses are presented in Tables 1 and 2.

Basis for CC Power Plant Capacity Projections and Base-Case Sites

Data on U.S. growth projections for combined cycle power plants were obtained from the Energy Information Administration.[1] These forecast data were developed by Electricity Marketing Module (EMM) regions on a year-by-year basis for a twenty year period (2000-2020). The detailed data are included in Appendix B. A summary of these data is presented in Table 3 by geographic groups.

The groups were made by combining physically contiguous EMM regions (each of which usually includes all or portions of several states) to establish a reasonable number of geographic areas for which generic base case examples

Table 1
Base Case Assumptions for Wet Cooling System

Parameter	Value	Basis
Cooling tower approach (difference between ambient wet-bulb temperature and cold water temperature at design conditions)	8 °F	Selected as representative of the current state-of-the-art value for counterflow towers as reflected by recent experience and engineering studies.
Cooling tower range (difference between hot and cold cooling water temperatures)	24 °F	Selected as representative of a value used in prior recirculated cooling system optimizations designed to minimize water flow.
Design ambient wet-bulb temperature	Regional mean	Depends on site location for base case evaluations. High incidence wet bulb statistics (1% of time during warm months) taken from Marley Weather Data.[8]
Wet-bulb temperature correction factor for plume recirculation	+2 °F	Plume recirculation is tower exhaust air that is reintroduced with fresh inlet air to the tower. The moisture in the plume recirculation increases the wet-bulb temperature of the inlet air and lowers tower performance.
Evaporation Rate	70% of total cooling tower heat load	Representative of computed typical mean annual average.
Cycles of Concentration	5	Consistent with cooling tower operation designed to balance water chemistry control with reduced fresh water makeup flows. [For brackish water or salt water cooling systems, the cycles of concentration would be 1.5-2.0.]
Terminal temperature difference or TTD (difference between the inlet saturation steam temperature and the hot cooling water temperature)	6 °F	Consistent with state-of-the-art values used for power plant surface steam condenser designs.
Steam exhaust moisture	~5%	Consistent with values for many combined-cycle steam turbines.
Surface steam condenser		Modern single-pass, shell-and-tube unit with carbon steel shell and tubesheet, and 22 BWG 304 stainless steel tubes. Sizing based on HEI standards for 7 ft/sec cooling water tube velocity and 85% cleanliness factor.[9]
Water Treatment Facility		Incorporated into capital costs.

could be prepared. The grouping process did consider projected CC power capacity growth. The capacity growth target for each group was 20% of the total anticipated U.S. growth. However, the physical placement of EMM regions

Table 2
Base Case Assumptions for Dry Cooling System

Parameter	Value	Basis
Initial temperature difference or ITD (difference between the steam exhaust temperature and the ambient dry-bulb temperature)	54 °F	This value includes the steam saturation temperature decrease that corresponds to the pressure loss in the exhaust duct between the steam turbine exhaust and the air-cooled condenser. Selected as representative of the current state-of-the-art value as reflected by recent experience and engineering studies.
Ambient dry-bulb temperature	Regional mean	Depends on site location for base case evaluations. High incidence dry bulb statistics (1% of time during warm months) taken from Marley Weather Data.[8]
Dry-bulb temperature correction factor for plume recirculation	+3 °F	Plume recirculation is tower exhaust air that is reintroduced with fresh inlet air to the tower. The higher temperature of the plume recirculation increases the dry-bulb temperature of the inlet air and lowers the air-cooled condenser performance.
Steam exhaust moisture	~5%	Consistent with values for many combined-cycle steam turbines.
Air-cooled, finned-tube steam condenser		Commonly used "A-frame" unit that saves site plan area, improves the forced-draft fan air distribution, and effectively accommodates the steam condensation process.
Winterization		Depends on site location for base case evaluations. Incorporated into capital costs.
Water Treatment Facility		Not included.

limited the potential for meeting this target. For example, the Mid-Atlantic Area Council (12.68 GW) could not be grouped with the Electric Reliability Council of Texas (15.13 GW), even though the combined CC power growth for these two EMM regions (27.81 GW) is 20.6% of the anticipated total (135.17 GW).

For each of the five geographic groups, a single site was selected that would provide climatic conditions and construction costs reasonably representative of all possible sites within the group. Given the extremely large geographic areas of these groups, site selection avoided extremes in climatic conditions (such as very hot and humid or very cold and dry) and construction costs (such as New York City on the high side or Omaha on the low side).

Table 3
New Combined Cycle Power Capacity (2000-2020)[1]

Electricity Marketing Module Region	New Capacity (GW)	Percent of Total New Capacity
GROUP 1 - Northeastern U.S.		
Northeast Power Coordinating Council / New England	5.20	3.85
Northeast Power Coordinating Council / New York	5.63	4.17
Mid-Atlantic Area Council	12.68	9.38
	23.51	17.40
GROUP 2 - Upper Central U.S.		
East Central Area Reliability Coordination Agreement	9.88	7.31
Mid-America Interconnected Network	4.81	3.56
Mid-Continent Area Power Pool	4.52	3.34
	19.21	14.21
GROUP 3 - Southeastern U.S.		
Southeastern Electric Reliability Council / Ex. Florida	22.38	16.56
Southeastern Electric Reliability Council / Florida	15.82	11.70
	38.20	28.26
GROUP 4 - Lower Central U.S.		
Electric Reliability Council of Texas	15.13	11.19
Southwest Power Pool	15.42	11.41
Western Systems Coordinating Council / Rocky Mtn.	4.27	3.16
	34.82	25.76
GROUP 5 - Western U.S.		
Western Systems Coordinating Council / CA-NV(south)	8.26	6.11
Western Systems Coordinating Council / Northwest	11.17	8.26
	19.43	14.37
TOTAL U.S. (Except Alaska and Hawaii)	135.17	100.00

Instead, the site selection sought locations that would reflect an average for the extremes that might be encountered at other places within the group. In addition, the site selection was group focused; that is to say, the site was intended to be representative of a specific group and, therefore, did not consider sites selected for other geographic groups. In this way, the base case results for a site could be suitably extrapolated to include anticipated CC capacity growth throughout the entire group, and summed with similarly calculated values for other groups to determine an estimated nationwide total.

The representative sites selected for each geographic group are listed in Table 4.

Table 4
Geographic Group Sites Selected for Base-Case Analyses

Geographic Group	Base-Case Site
1 - Northeastern U.S.	Albany, New York
2 - Upper Central U.S.	Madison, Wisconsin
3 - Southeastern U.S.	Atlanta, Georgia
4 - Lower Central U.S.	Amarillo, Texas
5 - Western U.S.	Sacramento, California

Base-Case Capital and O&M Cost Estimates for Wet and Dry Cooling

Installing either a wet or dry cooling system as part of a power plant requires many more activities and includes many more components than the towers themselves. Though the towers are major cost contributors, the overall capital cost of either a wet or dry cooling system is an aggregate of all the elements that comprise that cooling system.[10]

The methodology for developing the base case capital costs for the wet and dry cooling systems is illustrated by reference to Appendix D and E. The total costs were determined by the methods traditionally used by architect-engineers for utility projects. All major costs of the elements from the connection of the plant cooling system at the turbine flange outward to the cooling tower are included. Algorithms were used to estimate specific installed cooling tower costs based on past bid costs. The majority of the other cost components were individually determined using published data[11], other recent cooling system cost estimates or previous equipment quotes, along with an estimate of the quantity of materials involved or a size delineation. A description and cost for each of the major system components is included in the city cost listings (see Appendixes D and E as examples).

In addition, the following details apply to all capital cost estimates:

- Lo-noise fans were included due to the general sensitivity of most local communities to the relatively pervasive noise from cooling towers (wet and dry).

- Wiring costs were assumed to be similar to factors developed by the Marley Cooling Tower Company.[12]
- A 1% hot-weather incidence value for both wet and dry towers was selected as typical, based on design process data from the Marley Cooling Tower Company.[9]
- Construction costs were taken as the overnight type, i.e., considered to be completed so quickly that interest on the amount of a contract was negligible. By not including the interest during construction, the resulting estimated construction costs are slightly lower than normally would be incurred. These costs were commonly adjusted to a July 1999 basis using factors developed by RS Means.[11]
- The nominal construction related cost proportion was further adjusted to the particular city site in accordance with the RS Means Location Factor.[11]
- The usual project allowances included by architect-engineers for utility projects were added for management, engineering, indirect costs (such as detailed site engineering, permits, licenses, taxes, etc.) and contingencies. These latter factors added a total of 35% to the direct capital costs of the projects but are considered to be reasonable for the typical power plant cooling system installation.

Operating and maintenance (O&M) costs were based on a combination of several cost factors. For both the wet and dry cooling system, the annual maintenance costs of the entire cooling system equipment were assumed as 1% of the capital costs. This figure reflects past estimates[12] and recent experience with power plant towers, condensers, circulating water pumps and intakes. This figure also includes both labor and equipment maintenance. The cost of system auxiliary power was determined by: 1) estimating the fan power and hydraulic pump power (for wet cooling systems) requirements, and 2) adjusting these power requirements by assuming a 90% CC plant capacity factor, and 3) multiplying the adjusted power requirement by a unit cost of $25/MW-hr.

In the case of the wet cooling system, operating costs addressed a current typical makeup scenario. This assessment is usually reasonable and considered the costs of water consumption based on pumping makeup to a cooling tower basin from a cooling intake with water that is freely available from a local natural waterbody and the return of that wet cooling system blowdown to the same source without treatment. The evaluation also took into account water treatment within the plant to maintain cooling system water quality and to minimimize biofouling, corrosion, etc. This detailed aspect of the study was based on parameters listed in Table 2. But in the final analysis, the resulting costs were considered to be so small that they were not included in the overall cost estimate.

Cost Estimating Aspects Specific to Wet Cooling Systems

The wet cooling system cost has many more equipment components than the dry system; however, these components also are relatively simple. The recirculating water flow rate was estimated from the turbine heat load and the range shown in Table 2. Only counterflow towers were assumed in this analysis because they are more energy efficient, provide a better winter design, and allow a closer thermal approach.[13]

Many of the wet system major costs were assessed in algorithms by using the $/gpm rule-of-thumb. It is a pertinent and descriptive parameter because the size of the wet cooling system equipment is directly related to gpm. For example, that approach was used within this base case analysis to estimate the capital cost of the cooling tower, piping and the pumps, with two important caveats. First, as had been noted earlier, wet towers at power plants generally are designed and purchased for an approach of about 8 °F. Therefore, the cost of equivalent thermal performance demand of a counterflow tower for an 8 °F approach was assessed[14] and a wet mechanical-draft cooling tower capital cost estimate of $35/gpm was utilized. Second, it is traditional to buy power plant cooling towers as furnished and erected. With this understanding, the capital cost factor above and the estimated tower cost shown in Appendix E include installation for the base-case wet cooling system.

Based on past experiences with similar power plant wet cooling towers, the size (ground area footprint) for one cell of the base-case generic tower would be about 42 feet by 54 feet. Each cell would have a single, 30-ft diameter fan, with a fan stack height of approximately 55 feet. The total tower would consist of twelve cells in a back-to-back configuration. The complete tower structure would be about 325 feet long and 85 feet wide or roughly half the size of a football field.

The steam surface condenser size and cost were estimated from past cost data by determining the necessary heat transfer surface area. Thus, the primary installed cost parameter is a $\$/ft^2$ value with an adjustment factor to reflect the type of tubing. For this base case, 304 stainless steel tubing was chosen for the condenser because it is a reasonably high-grade material that provides suitable performance and service life at a relatively low capital cost. However, for condenser applications in more corrosive applications (such as salt water or brackish water environments), more expensive materials (e.g., titanium) would be required.

The auxiliary cooling system was assumed to be a recirculating type, separate from the main cooling tower. The direct capital costs for this system were assumed to cost 5% of the direct capital costs of the main condenser cooling system. The additional makeup water required for the auxiliary cooling system and the related operating costs were assumed to be negligible. Maintenance costs were included within the 1% capital cost factor used to estimate maintenance for the main condenser cooling system.

Cost Estimating Aspects Specific to Dry Cooling Systems

For direct dry cooling systems, capital costs cannot be estimated from the well known "$/gpm" rule-of-thumb used with wet cooling towers. This parameter is meaningless and any cost estimating approach using such a factor is irrelevant because direct dry cooling systems have no cooling water flow, only condensing steam. Because a direct dry cooling tower conveys the waste heat directly to the surrounding ambient air, other system parameters must be considered to determine an appropriately based capital cost factor.

With specific engineering relationships, the total heat transfer area of the finned surfaces on the dry cooling tower can be shown to be proportional to a particular set of turbine exhaust and ambient conditions combined with the total heat load on the tower. In addition, a large dry tower of the type that might be used at a power plant is comprised of several identical sections that could be considered as typical size fan cells. That typical fan has a characteristic by which the air-flow through the cell can be estimated. Finally, most of the construction materials used on dry towers suitable for power plants also are very similar. As a result, dry tower capital costs can be best quantified and projected from past cost data by determining the necessary heat transfer area and the number of cells required for a particular power plant application. Still, a capital cost parameter developed in this manner would only cover the cost of the manufactured equipment, which traditionally is bid only as "furnished". Therefore, the "purchased" capital cost parameter was adjusted to determine a final "erected" capital cost parameter.

Using the same heat transfer methodology described above, the characteristics for a generic base-case dry cooling tower also were determined. The site plan area was estimated to be 250 feet by 250 feet (approximately 1.4 acres) or about the same size as a football field. The structure for one of these dry towers would be about 105 feet high at the tallest point and have at least 40 fans, each 30 feet in diameter.

A direct dry cooling system has no source of cooling water to meet the auxiliary cooling demands within the plant. So an additional indirect dry cooling system must be installed to provide the needed cooling water. Consequently, for the dry cooling system base-case, a separate, smaller closed cooling water loop with heat rejection to the atmosphere by means of fan-cooled finned heat exchangers was selected to meet auxiliary cooling requirements. Such an auxiliary dry cooling system has many disadvantages, including: 1) the built-in inefficiency of an indirect system, 2) the added complexity of maintaining operation during the winter without freezing any of the thousands of water-filled tubes exposed to the atmosphere, and 3) the difficulty of achieving adequate performance for safe operation of the turbine systems during hot weather.

Despite these inherent drawbacks, which would serve to amplify the capital and operating costs, the same cost factors assumed for a simpler wet cooling system were used to develop dry cooling system cost estimates. The capital costs for the auxiliary dry system were assumed to be 5% of the main dry cooling system capital cost, and the maintenance costs were included within the 1% O&M cost estimate envelope of the main dry cooling system. Doing so ensured that the capital and O&M costs associated with auxiliary cooling in the dry cooling system base case were not overstated.

Regional and National Cost Estimates

The regional and national projections of capital costs, O&M costs and the summer peak performance shortfalls (energy penalties) for the wet and dry cooling systems were determined by combining the results of EIA 20-year forecasts for CC capacity growth with the base-case data. These separate evaluations were described previously. The number or fraction of generic 750 MW generating units was determined for a yearly projection of installed power in each of the five geographic groups.

The 1999 capital and O&M costs were inflated by 4% per year to be approximately consistent with the historical inflation index reported by RS Means for the past 20 years. To provide a uniform cost base for the results of this analysis, all costs were then brought back to 1999 (given as a calculated present worth value for July 1999) using an annual 7% discount rate. The operating and maintenance costs were projected for the next 30 years to 2030 using the same approach and factors for inflation and present worth.

The summer shortfall is defined as the aggregate loss in nominal 250-MW generation in the peak (design) summer period due to the cooling system performance loss in hot weather and the station cooling system auxiliary power demand. As has been discussed, this period is considered to occur about 30 hrs per year if the weather is normal, but could be much greater in length if the summer weather was extreme.

RESULTS

The detailed results of this study are presented in the Appendix (C-E). The key results are summarized and discussed below.

Wet and Dry Cooling System Base-Case Costs

For the base-case study (750 MW CC power plant with a 250 MW steam turbine-generator) at five different geographic sites, capital cost estimates for dry cooling systems were consistently greater than those for wet cooling systems by an average of 140% (see Table 5). Although there is appreciable capital cost variability for either the wet or the dry cooling systems between the different geographic sites, the majority of this variation reflects local construction cost factors and not climatic conditions.

Table 5
Estimated Capital and O&M Costs for 750-MW Base-Case Plant by Geographic Site

	Capital Costs ($ Millions)		Annual O&M Costs ($ Millions)	
Base-Case Sites	**Wet Cooling**	**Dry Cooling**	**Wet Cooling**	**Dry Cooling**
Group 1 - Albany, NY	25.2	60.0	0.94	1.82
Group 2 - Madison, WI	25.4	60.7	0.94	1.83
Group 3 - Atlanta, GA	23.2	56.2	0.92	1.78
Group 4 - Amarillo, TX	21.3	52.1	0.90	1.74
Group 5 - Sacramento, CA	28.0	66.0	0.96	1.88

Annual O&M costs for dry cooling systems also were uniformly greater than those for wet cooling systems by an average of 94%. To a large extent, this difference in O&M costs reflects the much larger difference in capital costs because annual maintenance costs were assumed to be 1% of the capital costs. However, the auxiliary power requirements also contributed to the overall difference in O&M costs. As shown in Table 6, the auxiliary power requirements for dry cooling systems are estimated to be 77% higher than those for wet cooling systems.

Table 6
Estimated Auxiliary Power Requirements and Energy Penalties
for Base-Case Plant by Geographic Site

Base-Case Sites	Auxiliary Power (MW)		Energy Penalty (MW)	
	Wet Cooling	**Dry Cooling**	**Wet Cooling**	**Dry Cooling**
Group 1 - Albany, NY	3.5	6.2	0.0	29.1
Group 2 - Madison, WI	3.5	6.2	0.6	30.4
Group 3 - Atlanta, GA	3.5	6.2	0.7	34.4
Group 4 - Amarillo, TX	3.5	6.2	-2.3	39.1
Group 5 - Sacramento, CA	3.5	6.2	0.0	45.2

But, a more important difference between wet and dry cooling is the predicted energy penalty (i.e., reduced plant generating capacity) for each system compared to the nominal 250 MW design rating of the steam turbine. The energy penalty is directly related to the climatic conditions of a specific site and would be expected to vary considerably throughout the United States. However, for both wet and dry cooling systems, the energy penalty normally is greatest during the hottest periods of the year. For the remainder of the year, the energy penalty should be much smaller. Unfortunately, the periods of greatest energy penalty typically coincide with the times of peak electricity consumption. As a result, any generating shortfall at that time represents a serious problem in meeting customer demand and a potentially significant revenue loss.

In addition, any energy penalty creates a need for replacement power which must be met by even more new generating capacity resulting in an increased potential for environmental impacts (such as increased air emissions). Estimating those emissions would mean projecting the costs of power production and the mix of generating capacities (coal-fired, nuclear, etc.) available at the time of anticipated demand over the next twenty years. Although such an effort was beyond the scope of this study, the importance of increased emissions produced as a direct result of the energy penalties attributed to reductions in cooling systems performance could be substantial and should not be overlooked.

Since the performance of dry cooling systems is linked to the ambient dry-bulb temperature (which can fluctuate significantly on a daily basis), dry cooling systems would be particularly sensitive to climatic variations. Even though this study selected only five sites for base-case analyses, the importance of climatic conditions at each location is evident from the range in dry cooling energy penalties (29.1 to 45.2 MW) shown in Table 6.

Furthermore, the magnitude of the energy penalty for dry cooling systems relative to wet cooling systems demonstrates the substantial economic impact that cooling system selection can have on power generation costs. Depending upon the prevailing price of replacement power, the energy penalty costs could be quite high, as shown in Figure 3. And, as replacement power costs increase, the estimated energy penalty costs for dry cooling could begin to approach the value of other elements in the anticipated annual O&M cost. On the other hand, wet cooling systems are expected to incur relatively minor energy penalty costs.

Projected Regional and National Wet and Dry Cooling System Costs

The results of regional and national projections over the next twenty years (2000-2020) for wet and dry cooling system costs are summarized in Tables 7 and 8, respectively. These projections assume that 100% of the new combined-cycle capacity will be constructed with either wet or dry cooling. While this assumption is unlikely, it enables distinct, independent analyses of the economic impacts these two cooling systems may have on the power generation industry.

As in prior base-case cost comparisons, regionally and nationally, the estimated capital and total O&M costs for dry cooling systems exceed those for wet cooling systems by about 140% and 94%, respectively. At $5.0 billion and $11.2 billion, for wet and dry systems, the total U.S. costs are not insignificant. If

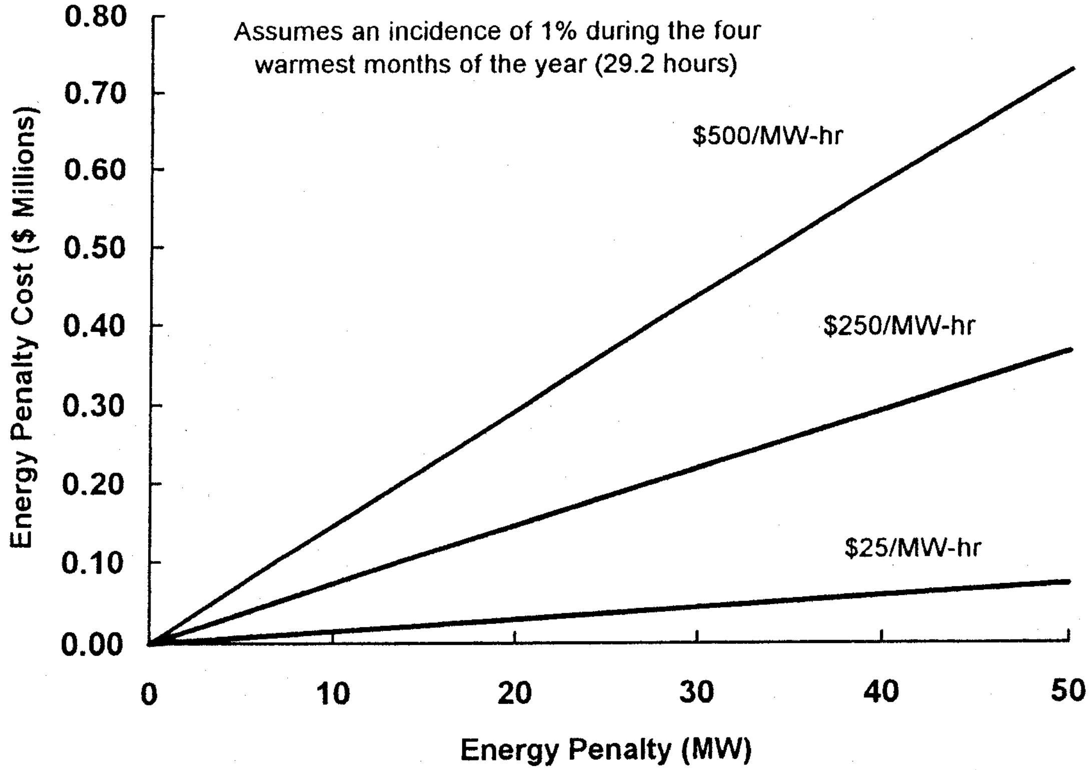


Figure 3 - Energy Penalty Costs as a Function of Replacement Power Costs

Table 7
Summary of Projected Costs for Wet Cooling Systems (2000-2020)[A]

Geographic Group	Capital Costs ($ Millions)	Total O&M Costs ($ Millions)	Total Costs ($ Millions)
1 - Northeastern U.S.	582.3	317.2	899.5
2 - Upper Central U.S.	445.1	216.7	661.8
3 - Southeastern U.S.	870.9	500.6	1,371.5
4 - Lower Central U.S.	742.5	465.5	1,208.0
5 - Western U.S.	573.3	312.6	885.9
Total U.S.	3,214.1	1,812.6	5,026.7

A - All costs are expressed in terms of July 1999 dollars where future values were escalated with a 4% annual rate and present worth values were determined with a 7% annual discount rate.

Table 8
Summary of Projected Costs for Dry Cooling Systems (2000-2020)[A]

Geographic Group	Capital Costs ($ Millions)	Total O&M Costs ($ Millions)	Total Costs ($ Millions)
1 - Northeastern U.S.	1,388.5	616.5	2,005.0
2 - Upper Central U.S.	1,064.2	422.9	1,487.1
3 - Southeastern U.S.	2,105.1	974.4	3,079.5
4 - Lower Central U.S.	1,813.3	902.9	2,716.2
5 - Western U.S.	1,348.7	608.8	1,957.5
Total U.S.	7,719.8	3,525.5	11,245.3

A - All costs are expressed in terms of July 1999 dollars where future values were escalated with a 4% annual rate and present worth values were determined with a 7% annual discount rate.

annualized at a 7% rate for the 20-year study period, the estimated national costs for wet and dry cooling systems at new CC power plants are $0.5 billion/year and over $1 billion/year, respectively.

CONCLUSIONS

Based on the results developed in this study and presented in this report, the following conclusions can be made:

1. By almost any economic measure, a dry cooling system costs about 100% more than an equivalent wet cooling system. The 140% higher capital cost is due to more expensive erected equipment. The 94% higher O&M cost is a reflection of two inherent characteristics of dry cooling: lower performance than wet cooling and greater sensitivity to climatic conditions.
2. The importance of ambient dry-bulb temperature in determining the performance of a dry cooling system means climatic conditions are important. Therefore, depending upon climatic conditions, certain locations in the country will have a higher probability of incurring larger dry cooling energy penalties.
3. Dry cooling systems are more likely to experience greater and more expensive energy penalties than wet cooling systems. The highest

probability for incurring an energy penalty will be during the warmest periods of the year when the demand and the price for electrical power will be the greatest.

4. Dry cooling systems use less water than wet cooling systems. But the unreliability of these systems during times of peak power demand, as well as the excessive capital and O&M costs make this form of water conservation less attractive than wet cooling systems.

As part of a recent rulemaking proposal, the U.S. Environmental Protection Agency prepared a document that included economic and engineering analyses of wet and dry cooling systems.[15] It was not the purpose of this study to critique the Agency's report or to compare analytical methodologies and results. During the course of this study, however, it was important to examine all of the available resources that might prove relevant. In that capacity, the Agency's report was reviewed. Based on that limited review effort and the results of this study, the following conclusions seem evident:

1. In many ways, the EPA's approach for estimating capital and O&M costs of power plant cooling systems appears to be incomplete and incorrect.
2. The amount of new electric generating capacity that will use waters of the U.S. for cooling purposes seems unreasonably low. Therefore, the amount of new capacity that might construct wet or dry cooling systems in response to the proposed rule is also unreasonably low.
3. The cost of potential energy penalties incurred by dry cooling systems has either been overlooked or ignored.
4. For each of the reasons stated above, the cooling system capital and O&M costs projected for the electric utility industry by the EPA are understated by a factor of from 10 to 100 times (one to two orders of magnitude).

However, care must be taken when making direct comparisons of the results for this study with information presented in the Agency's support document, for the following reasons:

1. This study focused only on new combined cycle power plants for the period 2000-2020. The EPA support document included all new U.S. generating capacity over the same period of time. While CC plants should represent a significant portion (135 GW) of the new generating capacity built in the U.S., the EIA projects that additional new electricity capacity will be provided by combustion turbines/diesel generators (129 GW), traditional coal-fired units (12 GW), and renewable energy sources (9 GW).[1]
2. The cooling water requirement for a combined cycle power plant (on a gpm/MW basis) will be different than those for other forms of electricity generation. For example, a traditional coal-fired power plant with a 750 MW generating capacity (identical to the base-case CC plant used in this study) would have a considerably larger cooling water requirement. Therefore, it would be incorrect to extrapolate the CC plant results from this study for comparison with the national estimates presented in the EPA support document.
3. In developing regional and national cost estimates for cooling systems, this study did not eliminate any new generating capacity from consideration based on the source of the makeup water to the cooling system. Consequently, the national cost estimates presented in this study include 180 750-MW CC plants (135 GW). In contrast, the EPA support document considers only those new generating plants that are assumed to obtain cooling system makeup water from sources designated as "waters of the United States". According to the Agency, approximately 20% of the total new generating capacity for the period 2000-2020 would obtain cooling system makeup from a designated "water of the U.S.". Therefore, the national cost estimates presented in the EPA support document includes only 24 new combined cycle power plants and 16 new coal-fired power plants over the next twenty years.

REFERENCES

1. Energy Information Administration. "Annual Energy Outlook 2000 With Projections to 2020", Report DOE/EIA-0383(2000), U.S. Department of Energy, Office of Integrated Analysis and Forecasting, Washington, DC, December 1999.
2. Kröger, Detlev G., Air-Cooled Heat Exchangers and Cooling Towers, Begell House, Inc., New York, NY, 1998.
3. Swanekamp, Robert. "Profit from Latest Experience with Air-Cooled Condensers", Power, June 1994, p. 78.
4. Kosten, H., et.al. "Operating Experience and Performance Testing of the World's Largest Air-Cooled Condenser", Proceedings of the American Power Conference, Chicago, IL, 1981.
5. Schimmoller, Brian K. "Fueling the Boom" Power Engineering, March 2000, p. 30.
6. Swanekamp, Robert "Gas Turbines, Combined-Cycles Harvest Record Orders" Power, March/April 2000, p. 30.
7. Schimmoller, Brian K. "Buddy Can You Spare a Turbine?" Power Engineering, May 2000, p. 34.
8. Cooling Tower Fundamentals and Application Principles, Engineering Weather Data, Marley Company, Overland Park, KS, 1967, p. 65.
9. Standards for Steam Surface Condensers, 9th ed. Heat Exchange Institute, 1995.
10. Burns, J.M., et.al., "The Impacts of Retrofitting Cooling Towers at a Large Power Station", Proceedings of the EPRI Cooling Tower Conference, St. Petersburg, FL, August 1994.
11. Means, R.S., Heavy Construction Cost Data - 2000, 14th ed., 1999.
12. Managing Waste Heat with the Water Cooling Tower, 2nd ed. Marley Company, Overland Park, KS, 1973.

13. Burns, J.M. and D. Brocard, "Cooling Towers" (Section 4.8 in the Handbook of Energy Systems Engineering), J. Wiley & Sons, New York, NY, 1985.

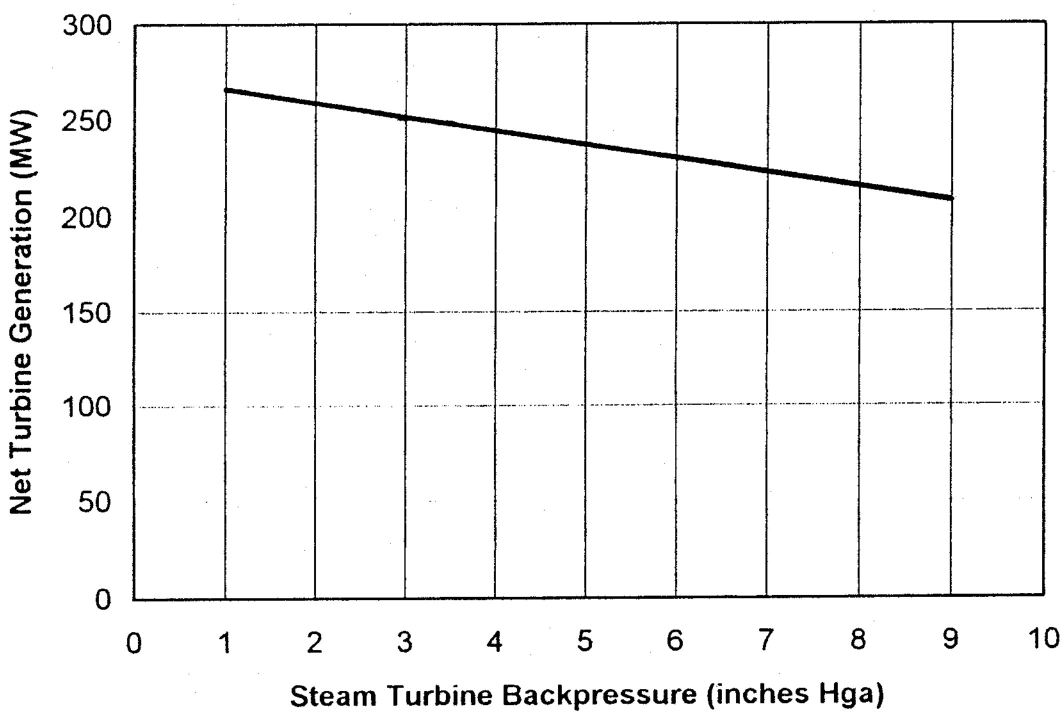
14. "Cooling Tower Performance Curves", Cooling Technology Institute, Houston, TX, 1967.

15. "Economic and Engineering Analyses of the Proposed §316(b) New Facility Rule", Report EPA-821-R-00-019, United States Environmental Protection Agency, Office of Water, Washington, DC, August 2000.

APPENDICES

Appendix A

Combined-Cycle Generic Steam Turbine Response Characteristic



Appendix B

EIA Projections of Electricity Generation by Combined Cycle Power Plants[1]

	Projected Increase in Combined Cycle Generating Capacity by EMM Region (GW)													U.S.
Year	1	2	3	4	5	6	7	8	9	10	11	12	13	Total
2000	0.00	0.13	2.08	0.00	0.00	0.00	0.26	0.05	0.35	0.44	0.35	0.20	0.00	3.86
2001	1.05	0.19	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.42	0.35	0.51	0.00	2.54
2002	0.00	1.15	0.28	0.00	0.00	0.00	0.53	0.56	0.15	1.34	1.20	0.53	0.00	5.74
2003	0.00	0.79	0.16	0.00	0.00	0.00	0.54	0.45	0.00	0.00	1.12	0.50	0.31	3.87
2004	0.00	1.02	0.00	0.00	0.45	0.00	0.58	0.99	2.27	1.08	1.91	0.92	1.74	10.96
2005	0.00	0.11	1.33	0.11	0.04	0.00	0.28	1.52	1.37	0.90	1.63	0.94	1.10	9.33
2006	0.00	1.62	0.00	0.00	0.43	0.00	0.00	1.28	1.91	0.81	1.29	0.00	1.05	8.39
2007	0.14	0.00	1.04	0.00	0.00	0.63	0.00	0.74	1.87	0.97	0.00	0.00	0.33	5.72
2008	0.00	0.70	0.00	0.00	0.33	0.00	0.00	0.87	2.25	0.93	0.05	0.35	0.83	6.31
2009	1.14	0.88	1.56	1.36	0.42	0.80	0.47	0.56	2.07	1.01	0.13	0.08	0.63	11.11
2010	0.75	0.32	0.00	0.70	0.37	0.00	0.00	0.69	1.51	0.48	0.21	0.06	0.67	5.76
2011	0.38	0.66	1.40	0.49	0.40	0.71	0.77	0.70	1.05	0.41	0.03	0.00	0.03	7.03
2012	0.36	0.15	0.60	0.21	0.29	0.68	0.81	1.19	0.99	0.31	0.08	0.00	0.05	5.72
2013	0.21	0.54	0.87	0.49	0.23	0.31	0.24	1.24	0.88	0.80	0.10	0.00	0.14	6.05
2014	0.27	0.78	0.31	0.24	0.31	0.92	0.31	1.21	1.14	0.88	0.37	0.00	0.15	6.89
2015	0.46	1.05	0.32	0.15	0.31	0.51	0.33	0.60	0.72	1.02	0.18	0.00	0.32	5.97
2016	0.76	0.84	1.27	0.10	0.42	0.90	0.00	0.84	1.22	1.09	0.37	0.04	0.19	8.04
2017	1.05	0.73	1.00	0.31	0.16	0.13	0.00	0.97	0.99	0.72	0.17	0.01	0.25	6.49
2018	0.99	0.60	1.17	0.37	0.18	0.00	0.02	0.56	0.91	0.59	0.63	0.05	0.24	6.31
2019	1.52	0.00	0.97	0.19	0.09	0.00	0.06	0.41	0.39	0.85	0.65	0.03	0.13	5.29
2020	0.80	0.42	0.75	0.09	0.09	0.04	0.00	0.39	0.34	0.37	0.35	0.05	0.10	3.79
Total	9.88	12.68	15.13	4.81	4.52	5.63	5.20	15.82	22.38	15.42	11.17	4.27	8.26	135.17

Electricity Marketing Module Region

1 - East Central Area Reliability Coordination Agreement (ECAR)
2 - Mid-Atlantic Area Council (MAAC)
3 - Electric Reliability Council of Texas (ERCOT)
4 - Mid-America Interconnected Network (MAIN)
5 - Mid-Continent Area Power Pool (MAPP)
6 - Northeast Power Coordinating Council / New York only (NPCC/NY)
7 - Northeast Power Coordinating Council / New England (NPCC/NE)
8 - Southeastern Electric Reliability Council / Florida only (SERC/FL)
9 - Southeastern Electric Reliability Council (SERC)
10 - Southwest Power Pool (SPP)
11 - Western Systems Coordinating Council / Northwest Power Pool Area (WSCC/NWP)
12 - Western Systems Coordinating Council / Rocky Mountain Power Area (WSCC/RA)
13 - Western Systems Coordinating Council / California-Southern Nevada Power (WSCC/CNV)

Appendix C

Table C-1
Projected Wet Cooling System Costs for Group 1 - Northeastern U.S

Year	New CC Plant Capacity (GW)	New 750-MW Units	Capital Cost[A] ($ Millions)	O&M Cost[A] ($ Millions)	Total Cost[A] ($ Millions)
2000	0.39	0.5	12.7	9.1	21.8
2001	0.19	0.3	6.0	4.2	10.2
2002	1.68	2.2	51.7	35.2	87.0
2003	1.33	1.8	39.8	26.5	66.3
2004	1.6	2.1	46.5	30.2	76.7
2005	0.39	0.5	11.0	7.0	18.0
2006	1.62	2.2	44.5	27.3	71.8
2007	0.63	0.8	16.8	10.0	26.9
2008	0.7	0.9	18.2	10.5	28.7
2009	2.15	2.9	54.3	30.3	84.5
2010	0.32	0.4	7.8	4.2	12.1
2011	2.14	2.9	51.0	26.4	77.4
2012	1.64	2.2	38.0	18.9	56.9
2013	1.09	1.5	24.5	11.7	36.2
2014	2.01	2.7	44.0	20.0	64.0
2015	1.89	2.5	40.2	17.3	57.5
2016	1.74	2.3	36.0	14.7	50.6
2017	0.86	1.1	17.3	6.6	23.9
2018	0.62	0.8	12.1	4.3	16.5
2019	0.06	0.1	1.1	0.4	1.5
2020	0.46	0.6	8.5	2.6	11.1
Total	23.51	31.3	582.3	317.3	899.5

A - All costs are expressed in terms of July 1999 dollars where future values were escalated with a 4% annual rate and present worth values were determined with a 7% annual discount rate.

Table C-2
Projected Wet Cooling System Costs for Group 2 - Upper Central U.S.

Year	New CC Plant Capacity (GW)	New 750-MW Units	Capital Cost[A] ($ Millions)	O&M Cost[A] ($ Millions)	Total Cost[A] ($ Millions)
2000	0.00	0.0	0.0	0.0	0.0
2001	1.05	1.4	33.6	23.2	56.8
2002	0.00	0.0	0.0	0.0	0.0
2003	0.00	0.0	0.0	0.0	0.0
2004	0.45	0.6	13.2	8.5	21.7
2005	0.15	0.2	4.3	2.7	7.0
2006	0.43	0.6	11.9	7.3	19.2
2007	0.14	0.2	3.8	2.2	6.0
2008	0.33	0.4	8.6	5.0	13.6
2009	2.92	3.9	74.3	41.2	115.5
2010	1.82	2.4	45.0	24.1	69.1
2011	1.27	1.7	30.5	15.7	46.3
2012	0.86	1.1	20.1	9.9	30.0
2013	0.93	1.2	21.1	10.0	31.1
2014	0.82	1.1	18.1	8.2	26.3
2015	0.92	1.2	19.8	8.5	28.2
2016	1.28	1.7	26.7	10.8	37.5
2017	1.52	2.0	30.8	11.7	42.6
2018	1.54	2.1	30.4	10.8	41.2
2019	1.80	2.4	34.5	11.4	45.9
2020	0.98	1.3	18.2	5.6	23.8
Total	19.21	25.6	445.1	216.7	661.8

A - All costs are expressed in terms of July 1999 dollars where future values were escalated with a 4% annual rate and present worth values were determined with a 7% annual discount rate.

Table C-3
Projected Wet Cooling System Costs for Group 3 - Southeastern U.S.

Year	New CC Plant Capacity (GW)	New 750-MW Units	Capital Cost[A] ($ Millions)	O&M Cost[A] ($ Millions)	Total Cost[A] ($ Millions)
2000	0.4	0.5	12.0	9.1	21.1
2001	0.0	0.0	0.0	0.0	0.0
2002	0.71	0.9	20.2	14.6	34.8
2003	0.45	0.6	12.4	8.8	21.2
2004	3.26	4.3	87.6	60.2	147.9
2005	2.89	3.9	75.5	50.5	126.0
2006	3.19	4.3	81.0	52.7	133.7
2007	2.61	3.5	64.4	40.7	105.1
2008	3.12	4.2	74.8	45.8	120.6
2009	2.63	3.5	61.3	36.3	97.6
2010	2.2	2.9	49.9	28.4	78.3
2011	1.75	2.3	38.5	21.2	59.7
2012	2.18	2.9	46.7	24.6	71.3
2013	2.12	2.8	44.1	22.2	66.4
2014	2.35	3.1	47.5	22.9	70.4
2015	1.32	1.8	26.0	11.9	37.8
2016	2.06	2.7	39.4	17.0	56.4
2017	1.96	2.6	36.4	14.8	51.2
2018	1.47	2.0	26.5	10.1	36.6
2019	0.8	1.1	14.0	5.0	19.0
2020	0.73	1.0	12.4	4.1	16.5
Total	38.2	50.9	870.9	500.6	1371.5

A - All costs are expressed in terms of July 1999 dollars where future values were escalated with a 4% annual rate and present worth values were determined with a 7% annual discount rate.

Table C-4
Projected Wet Cooling System Costs for Group 4 - Lower Central U.S.

Year	New CC Plant Capacity (GW)	New 750-MW Units	Capital Cost[A] ($ Millions)	O&M Cost[A] ($ Millions)	Total Cost[A] ($ Millions)
2000	2.72	3.6	75.3	60.6	135.8
2001	0.95	1.3	25.5	20.1	45.7
2002	2.15	2.9	56.2	43.3	99.5
2003	0.66	0.9	16.8	12.6	29.4
2004	2	2.7	49.4	36.2	85.6
2005	3.17	4.2	76.1	54.3	130.4
2006	0.81	1.1	18.9	13.1	32.0
2007	2.01	2.7	45.6	30.7	76.2
2008	1.28	1.7	28.2	18.4	46.6
2009	2.65	3.5	56.8	35.8	92.5
2010	0.54	0.7	11.2	6.8	18.1
2011	1.81	2.4	36.6	21.4	58.1
2012	0.91	1.2	17.9	10.1	28.0
2013	1.67	2.2	31.9	17.2	49.1
2014	1.19	1.6	22.1	11.3	33.4
2015	1.34	1.8	24.2	11.8	36.0
2016	2.4	3.2	42.1	19.4	61.5
2017	1.73	2.3	29.5	12.8	42.3
2018	1.81	2.4	30.0	12.2	42.2
2019	1.85	2.5	29.8	11.2	41.0
2020	1.17	1.6	18.3	6.4	24.7
Total	34.82	46.4	742.5	465.5	1208.0

A - All costs are expressed in terms of July 1999 dollars where future values were escalated with a 4% annual rate and present worth values were determined with a 7% annual discount rate.

Table C-5
Projected Wet Cooling System Costs for Group 5 - Western U.S.

Year	New CC Plant Capacity (GW)	New 750-MW Units	Capital Cost[A] ($ Millions)	O&M Cost[A] ($ Millions)	Total Cost[A] ($ Millions)
2000	0.35	0.5	12.7	8.4	21.1
2001	0.35	0.5	12.4	8.0	20.3
2002	1.20	1.6	41.2	25.9	67.1
2003	1.43	1.9	47.7	29.3	77.0
2004	3.65	4.9	118.3	71.0	189.3
2005	2.73	3.6	86.0	50.2	136.3
2006	2.34	3.1	71.7	40.7	112.4
2007	0.33	0.4	9.8	5.4	15.2
2008	0.88	1.2	25.5	13.6	39.1
2009	0.76	1.0	21.4	11.0	32.4
2010	0.88	1.2	24.1	12.0	36.0
2011	0.06	0.1	1.6	0.8	2.4
2012	0.13	0.2	3.4	1.5	4.9
2013	0.24	0.3	6.0	2.6	8.7
2014	0.52	0.7	12.7	5.3	18.0
2015	0.50	0.7	11.9	4.7	16.6
2016	0.56	0.7	12.9	4.9	17.8
2017	0.42	0.6	9.4	3.3	12.7
2018	0.87	1.2	18.9	6.3	25.2
2019	0.78	1.0	16.5	5.1	21.6
2020	0.45	0.6	9.3	2.6	11.9
Total	19.43	25.9	573.3	312.7	885.9

A - All costs are expressed in terms of July 1999 dollars where future values were escalated with a 4% annual rate and present worth values were determined with a 7% annual discount rate.

Table C-6
Projected Dry Cooling System Costs for Group 1 - Northeastern U.S.

Year	New CC Plant Capacity (GW)	New 750-MW Units	Capital Cost[A] ($ Millions)	O&M Cost[A] ($ Millions)	Total Cost[A] ($ Millions)
2000	0.39	0.5	30.3	17.6	47.9
2001	0.19	0.3	14.4	8.1	22.5
2002	1.68	2.2	123.4	68.5	191.8
2003	1.33	1.8	94.9	51.4	146.4
2004	1.60	2.1	111.0	58.6	169.6
2005	0.39	0.5	26.3	13.5	39.8
2006	1.62	2.2	106.2	53.1	159.3
2007	0.63	0.8	40.1	19.5	59.6
2008	0.70	0.9	43.3	20.4	63.7
2009	2.15	2.9	129.4	58.8	188.2
2010	0.32	0.4	18.7	8.2	26.9
2011	2.14	2.9	121.7	51.3	173.0
2012	1.64	2.2	90.6	36.7	127.3
2013	1.09	1.5	58.5	22.7	81.2
2014	2.01	2.7	104.9	38.8	143.7
2015	1.89	2.5	95.9	33.7	129.6
2016	1.74	2.3	85.8	28.5	114.3
2017	0.86	1.1	41.2	12.9	54.1
2018	0.62	0.8	28.9	8.4	37.3
2019	0.06	0.1	2.7	0.7	3.5
2020	0.46	0.6	20.2	5.1	25.3
Total	23.51	31.3	1388.5	616.5	2005.0

A - All costs are expressed in terms of July 1999 dollars where future values were escalated with a 4% annual rate and present worth values were determined with a 7% annual discount rate.

Table C-7
Projected Dry Cooling System Costs for Group 2 - Upper Central U.S.

Year	New CC Plant Capacity (GW)	New 750-MW Units	Capital Cost[A] ($ Millions)	O&M Cost[A] ($ Millions)	Total Cost[A] ($ Millions)
2000	0.00	0.0	0.0	0.0	0.0
2001	1.05	1.4	80.3	45.3	125.6
2002	0.00	0.0	0.0	0.0	0.0
2003	0.00	0.0	0.0	0.0	0.0
2004	0.45	0.6	31.6	16.6	48.2
2005	0.15	0.2	10.2	5.2	15.5
2006	0.43	0.6	28.5	14.2	42.7
2007	0.14	0.2	9.0	4.4	13.4
2008	0.33	0.4	20.7	9.7	30.3
2009	2.92	3.9	177.8	80.4	258.2
2010	1.82	2.4	107.7	47.0	154.7
2011	1.27	1.7	73.0	30.7	103.7
2012	0.86	1.1	48.1	19.4	67.4
2013	0.93	1.2	50.5	19.5	70.0
2014	0.82	1.1	43.3	15.9	59.2
2015	0.92	1.2	47.2	16.5	63.7
2016	1.28	1.7	63.9	21.1	85.0
2017	1.52	2.0	73.7	22.9	96.6
2018	1.54	2.1	72.6	21.1	93.7
2019	1.80	2.4	82.5	22.3	104.7
2020	0.98	1.3	43.6	10.9	54.5
Total	19.21	25.6	1064.2	422.9	1487.2

A - All costs are expressed in terms of July 1999 dollars where future values were escalated with a 4% annual rate and present worth values were determined with a 7% annual discount rate.

Table C-8
Projected Dry Cooling System Costs for Group 3 - Southeastern U.S.

Year	New CC Plant Capacity (GW)	New 750-MW Units	Capital Cost[A] ($ Millions)	O&M Cost[A] ($ Millions)	Total Cost[A] ($ Millions)
2000	0.40	0.5	29.1	17.7	46.8
2001	0.00	0.0	0.0	0.0	0.0
2002	0.71	0.9	48.8	28.4	77.2
2003	0.45	0.6	30.1	17.1	47.2
2004	3.26	4.3	211.8	117.2	329.0
2005	2.89	3.9	182.5	98.3	280.8
2006	3.19	4.3	195.8	102.6	298.4
2007	2.61	3.5	155.7	79.2	234.9
2008	3.12	4.2	180.9	89.1	270.0
2009	2.63	3.5	148.2	70.6	218.8
2010	2.20	2.9	120.5	55.4	175.9
2011	1.75	2.3	93.2	41.2	134.4
2012	2.18	2.9	112.8	47.9	160.7
2013	2.12	2.8	106.6	43.3	149.9
2014	2.35	3.1	114.9	44.5	159.4
2015	1.32	1.8	62.7	23.1	85.8
2016	2.06	2.7	95.1	33.1	128.2
2017	1.96	2.6	88.0	28.8	116.8
2018	1.47	2.0	64.1	19.6	83.8
2019	0.80	1.1	33.9	9.7	43.6
2020	0.73	1.0	30.1	7.9	38.0
Total	38.20	50.9	2105.1	974.4	3079.5

A - All costs are expressed in terms of July 1999 dollars where future values were escalated with a 4% annual rate and present worth values were determined with a 7% annual discount rate.

Table C-9
Projected Dry Cooling System Costs for Group 4 - Lower Central U.S.

Year	New CC Plant Capacity (GW)	New 750-MW Units	Capital Cost[A] ($ Millions)	O&M Cost[A] ($ Millions)	Total Cost[A] ($ Millions)
2000	2.72	3.6	183.8	117.5	301.2
2001	0.95	1.3	62.4	39.0	101.4
2002	2.15	2.9	137.2	83.9	221.1
2003	0.66	0.9	40.9	24.4	65.4
2004	2.00	2.7	120.6	70.2	190.8
2005	3.17	4.2	185.8	105.3	291.1
2006	0.81	1.1	46.1	25.4	71.6
2007	2.01	2.7	111.3	59.5	170.8
2008	1.28	1.7	68.9	35.7	104.6
2009	2.65	3.5	138.6	69.4	208.0
2010	0.54	0.7	27.5	13.3	40.7
2011	1.81	2.4	89.4	41.6	131.0
2012	0.91	1.2	43.7	19.5	63.2
2013	1.67	2.2	78.0	33.3	111.2
2014	1.19	1.6	54.0	22.0	76.0
2015	1.34	1.8	59.1	22.9	82.0
2016	2.40	3.2	102.9	37.6	140.5
2017	1.73	2.3	72.1	24.8	96.9
2018	1.81	2.4	73.3	23.6	96.9
2019	1.85	2.5	72.8	21.8	94.6
2020	1.17	1.6	44.8	12.3	57.1
Total	34.82	46.4	1813.3	902.9	2716.2

A - All costs are expressed in terms of July 1999 dollars where future values were escalated with a 4% annual rate and present worth values were determined with a 7% annual discount rate.

Table C-10
Projected Dry Cooling System Costs for Group 5 - Western U.S.

Year	New CC Plant Capacity (GW)	New 750-MW Units	Capital Cost[A] ($ Millions)	O&M Cost[A] ($ Millions)	Total Cost[A] ($ Millions)
2000	0.35	0.5	29.9	16.3	46.2
2001	0.35	0.5	29.1	15.5	44.6
2002	1.20	1.6	96.9	50.5	147.4
2003	1.43	1.9	112.2	57.1	169.3
2004	3.65	4.9	278.4	138.2	416.6
2005	2.73	3.6	202.4	97.8	300.2
2006	2.34	3.1	168.6	79.2	247.8
2007	0.33	0.4	23.1	10.5	33.7
2008	0.88	1.2	59.9	26.5	86.4
2009	0.76	1.0	50.3	21.5	71.8
2010	0.88	1.2	56.6	23.3	79.9
2011	0.06	0.1	3.8	1.5	5.2
2012	0.13	0.2	7.9	3.0	10.9
2013	0.24	0.3	14.2	5.2	19.3
2014	0.52	0.7	29.8	10.4	40.2
2015	0.50	0.7	27.9	9.2	37.1
2016	0.56	0.7	30.4	9.5	39.8
2017	0.42	0.6	22.1	6.5	28.6
2018	0.87	1.2	44.6	12.2	56.8
2019	0.78	1.0	38.8	9.9	48.7
2020	0.45	0.6	21.8	5.1	26.9
Total	19.43	25.9	1348.7	608.8	1957.5

A - All costs are expressed in terms of July 1999 dollars where future values were escalated with a 4% annual rate and present worth values were determined with a 7% annual discount rate.

Table C-11
Projected Peak Generating Capacity Reduction (MW)
For Wet Cooling Systems[A]

Year	Geographic Group 1	2	3	4	5	Total U.S. Peak Loss	Total Cost[B] ($ Millions)
2000	1.8	0.0	2.2	4.3	1.6	9.9	0.1
2001	0.9	5.7	0.0	1.5	1.6	9.7	0.1
2002	7.7	0.0	4.0	3.4	5.5	20.6	0.3
2003	6.1	0.0	2.5	1.0	6.6	16.2	0.2
2004	7.3	2.4	18.2	3.1	16.8	47.9	0.6
2005	1.8	0.8	16.2	5.0	12.5	36.3	0.4
2006	7.4	2.3	17.9	1.3	10.7	39.6	0.5
2007	2.9	0.8	14.6	3.2	1.5	22.9	0.3
2008	3.2	1.8	17.5	2.0	4.0	28.5	0.3
2009	9.9	15.8	14.7	4.2	3.5	48.0	0.5
2010	1.5	9.8	12.3	0.8	4.0	28.5	0.3
2011	9.8	6.9	9.8	2.8	0.3	29.6	0.3
2012	7.5	4.6	12.2	1.4	0.6	26.4	0.3
2013	5.0	5.0	11.9	2.6	1.1	25.6	0.3
2014	9.2	4.4	13.2	1.9	2.4	31.1	0.3
2015	8.7	5.0	7.4	2.1	2.3	25.4	0.2
2016	8.0	6.9	11.5	3.8	2.6	32.8	0.3
2017	3.9	8.2	11.0	2.7	1.9	27.8	0.2
2018	2.8	8.3	8.2	2.8	4.0	26.2	0.2
2019	0.3	9.7	4.5	2.9	3.6	21.0	0.2
2020	2.1	5.3	4.1	1.8	2.1	15.4	0.1
Total	108.0	103.9	213.8	54.7	89.2	569.6	6.1

A - Generating capacity reductions result from system energy consumption (pumps, fan motors, etc.) and from energy penalties (lower steam turbine-generator efficiency).

B - Assumes replacement power costs of $500/MW-hr; all costs are expressed in terms of July 1999 dollars where future values were escalated with a 4% annual rate and present worth values were determined with a 7% annual discount rate.

Table C-12
Projected Peak Generating Capacity Reduction (MW)
For Dry Cooling Systems[A]

Year	Geographic Group					Total U.S.	Total Cost[B]
	1	2	3	4	5	Peak Loss	($ Millions)
2000	0.0	18.3	21.7	164.3	24.0	228.3	3.2
2001	51.3	8.9	0.0	57.4	24.0	141.6	2.0
2002	0.0	78.9	38.5	129.9	82.2	329.4	4.4
2003	0.0	62.5	24.4	39.9	97.9	224.6	2.9
2004	22.0	75.2	176.7	120.8	249.9	644.5	8.2
2005	7.3	18.3	156.6	191.5	186.9	560.7	6.9
2006	21.0	76.1	172.9	48.9	160.2	479.1	5.7
2007	6.8	29.6	141.4	121.4	22.6	321.9	3.7
2008	16.1	32.9	169.1	77.3	60.2	355.7	4.0
2009	142.6	101.0	142.5	160.1	52.0	598.2	6.6
2010	88.9	15.0	119.2	32.6	60.2	316.0	3.4
2011	62.0	100.5	94.8	109.3	4.1	370.8	3.8
2012	42.0	77.0	118.1	55.0	8.9	301.1	3.0
2013	45.4	51.2	114.9	100.9	16.4	328.8	3.2
2014	40.0	94.4	127.4	71.9	35.6	369.3	3.5
2015	44.9	88.8	71.5	80.9	34.2	320.4	3.0
2016	62.5	81.7	111.6	145.0	38.3	439.2	4.0
2017	74.2	40.4	106.2	104.5	28.8	354.1	3.1
2018	75.2	29.1	79.7	109.3	59.6	352.9	3.0
2019	87.9	2.8	43.4	111.8	53.4	299.2	2.5
2020	47.9	21.6	39.6	70.7	30.8	210.5	1.7
Total	938.1	1104.5	2070.2	2103.4	1330.2	7546.5	81.9

A - Generating capacity reductions result from system energy consumption (pumps, fan motors, etc.) and from energy penalties (lower steam turbine-generator efficiency).

B - Assumes replacement power costs of $500/MW-hr; all costs are expressed in terms of July 1999 dollars where future values were escalated with a 4% annual rate and present worth values were determined with a 7% annual discount rate.

Appendix D

Example Capital Cost Calculation for Wet Cooling System (Albany, New York)

Site Specific Base Case Parameters

Ambient wet-bulb temperature (°F)	76
Cooling tower approach (°F)	8.8
Saturated steam temperature (°F)	116.8
Turbine backpressure (inches Hga)	3.16
Auxiliary power requirements (MW)	3.5
Energy penalty for lower generator performance	0.0

Item	Description	Capital Cost
1	Furnishd & Erectd FRP Wet Cooling Tower	5467000
2	Site Prep-excav,grade	32244
3	Access Road	28395
4	Concrete Basin	1271078
5	Fans- Elect wiring, controls, 4160/480 transformer	1025063
6	Painting	7890
7	Lo Noise Fans-10 dba attenuation	1640100
8	Fire & Lightning Protection	164010
9	Condenser- 304 SS tubes	6200986
10	CW pumps & motors	449306
11	El Service to CW Pump Motors-cable,mcc,etc	664973
12	Pumphouse+Crane	179722
13	Trench,bed & found.- 84 in CW Piping	193553
14	CW Piping	319475
15	Valves, Screens & Fittings	188708
16	Complete Intake	120000
17	Blowdown Facilty	30000
18	Water Treating	100000
19	Acceptance Testing	50000
20	Auxiliary Cooling Requirements	899125
	TOTAL DIRECT COSTS	18631581
21	Construction Management	1304211
22	Engineering	1490526
23	Indirects	931579
24	Allowance for Indeterm.& Contingencies	2794737
	TOTAL ESTIMATED COSTS	25152635

A - All costs are expressed in terms of July 1999 dollars; construction costs are assumed as the overnight type.

Appendix E

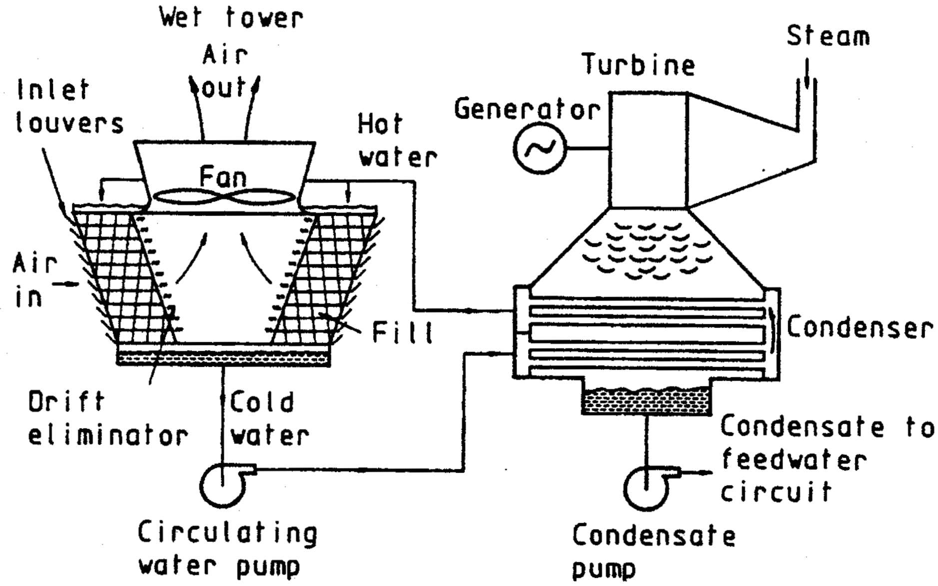
Example Capital Cost Calculation for Dry Cooling System (Albany, New York)

Site Specific Base Case Parameters

Ambient dry-bulb temperature (°F)	91
Saturated steam temperature (°F)	148
Saturated steam enthalpy (Btu/lbm)	1120
Turbine backpressure (inches Hga)	7.2
Auxiliary power requirements (MW)	6.2
Energy penalty for lower generator performance	29.1

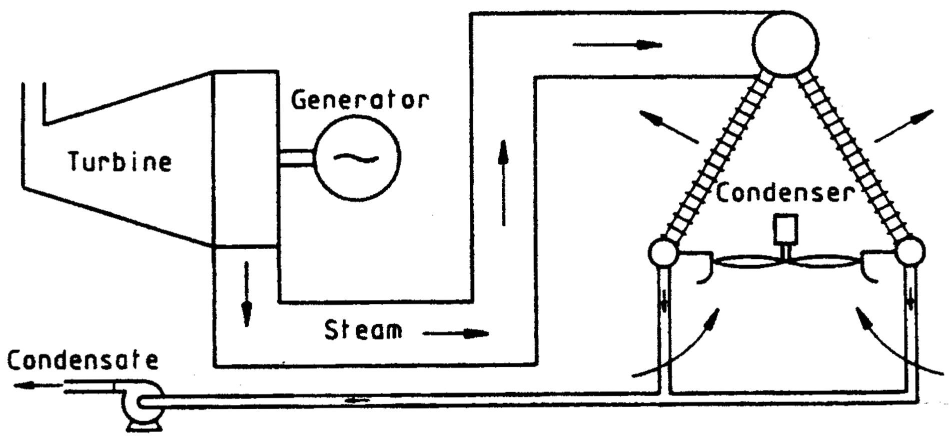
Item	Description	Cost[A]
1	Erected Dry Cooling Tower Materials	27430931
2	Site Prep-excav,grade	76878
3	Access Road	67859
4	200K Load- Spread Footing Foundation	156830
5	75 ft Columns w Base Plate, anchors,etc	665698
6	Hotwell & turbine exh support & foundatn	156830
7	Painting	42041
8	Electrical wire, circuitb, switchg,mcc,cable	3796064
9	Lo Noise Fans-10 dba attenuation	8229279
10	Finned Surface Wet-Down Cleaning System	100000
11	Control and Winter Operation	1371547
12	Fittings and valves	50000
13	Thermal Ins & Heat tracing	100000
14	Fire & Lightning Protection	822928
15	AcceptanceTests	35000
16	Auxiliary Cooling Requirements	2155094
	TOTAL DIRECT COSTS	44427092
17	Construction Management	3109896
18	Engineering	3554167
19	Indirects	2221355
20	Allowance for Indeterm.& Contingencies	6664064
	TOTAL ESTIMATED COSTS	59976574

A - All costs are expressed in terms of July 1999 dollars; construction costs are assumed as the overnight type.



Recirculated Wet Cooling System with Mechanical Induced-Draft Tower

(Source: Kröger, Detlev G., Air-Cooled Heat Exchangers and Cooling Towers, Begell House, Inc., New York, NY, 1998)



Direct Air-Cooled Steam Turbine Condensing System

(Source: Kröger, Detlev G., Air-Cooled Heat Exchangers and Cooling Towers, Begell House, Inc., New York, NY, 1998)

Daily Variation in Ambient Air Dry-Bulb and Wet-Bulb Temperatures (July 15)

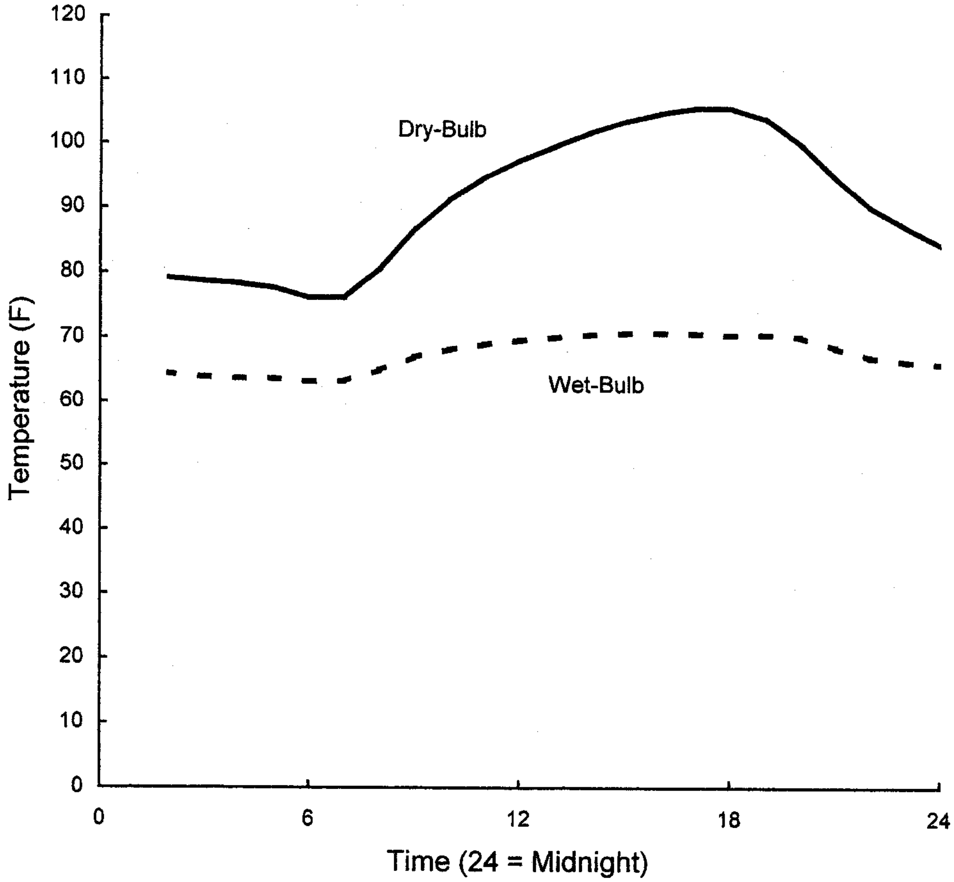


EXHIBIT
A-19
admitted

SUMMARY OF LA PAZ POWER PLANT WET & DRY COOLING DIFFERENCES

Maximum Performance Penalty	283 – 475 MW
Cooling System Capital Costs	$43.5 – 45.8 M
Physical Size	
• Footprint	1.2 vs 2.45 acres
• Height	55 vs 105 feet

A-19

November 8, 2001

Ms. Laurie Woodall
Chairperson
Arizona Power Plant and Transmission Line Siting Committee
1275 West Washington Street
Phoenix, AZ 85007

Dear Ms. Woodall:

We wish to strongly support the application for a Certificate of Environmental Compatibility by the Allegheny Energy Supply Company for the proposed La Paz Generating Plant.

Input from the citizens of La Paz County has been uniformly positive, in favor of the facility. Various members of our district have pointed out the positive financial impact of the facility on the economy of La Paz County, and have voiced no concerns regarding environmental issues. Some of them have studied the plans for the plant carefully, to assure themselves that the plant is being constructed with the environment in mind. We have heard positive support throughout La Paz County, particularly from the communities of Bouse, Salome and Wenden.

The La Paz Generating Plant will:

* Double the tax base of La Paz County
* Serve the future needs for power in Arizona
* Support the Palo Verde Nuclear Generating Facility by improving the transport capability of the existing Palo Verde-Devers 500 kV transmission line, providing voltage support between the facility and Palm Springs, California

The La Paz Generating Plant will also provide needed jobs in La Paz County, while having the potential to replace some of the smaller, less efficient, less environmentally friendly older units in the area.

We unanimously support this facility as an environmentally friendly way to enhance power production in Arizona and strengthen the economy in District 5.

Sincerely,

Herbert Guenther
CKL

Herbert R. Guenther
Arizona State Senator

Sincerely,

James Carruthers
CKL

James R. Carruthers, Ph.D.
Arizona House of Representatives

Sincerely

Robert Cannell, M.D.
CKL

Robert Cannell, M.D.
Arizona House of Representatives

Cc: Jacqueline R. Norton, Gallagher & Kennedy

EXHIBIT
Admitted
A-20

EXHIBIT
A-21
admitted

RECEIVED

2001 NOV 27 A 7:58

AZ CORP COMMISSION
DOCUMENT CONTROL

ARIZONA DEPARTMENT OF WATER RESOURCES
500 North Third Street, Phoenix, Arizona 85004
Telephone 602-417-2410
Fax 602-417-2415

JANE DEE HULL
Governor

JOSEPH C. SMITH
Director

November 21, 2001

Ms. Laurie Woodall
Chairman, Siting Committee
Office of the Attorney General
1275 West Washington
Phoenix, Arizona 85007

Re: Allegheny's Application for CEC, Docket #116 L-00000AA-01-0116

Dear ~~Madam Chairman~~ Laurie:

During the Hearing on November 14, 2001, you requested, on behalf of the Siting Committee, as to whether the Arizona Department of Water Resources (Department) has available staff and is willing to commit such staff to work on three issues with the applicant in Docket #116. The Department does not believe that this is necessary. Each issue is discussed below.

Issue #1 - Should the Applicant be required to work with the Department to perform an aquifer pump test near the site of the proposed wellfield to prove the accuracy of the model provided by Vidler Recharge? Intervenor AZURE and Committee Member Williamson proposed this question.

As stated in the November 9, 2001 Preliminary Hydrologic Review prepared by Dale Mason, Modeling Section Manager, Arizona Department of Water Resources, the Department stands by its position that the model used in this case is valid. "The numerical model was reviewed by the ADWR staff in 1999 and found to reasonably simulate the response of the regional aquifer to historic pumping stresses from 1950 to the present." (Page 3). Despite testimony of AZURE's expert witness, a well formulated and calibrated model is a good tool for predicting the behavior of particular pumping patterns or recharge activity.

Should Committee Member Williamson or any other Member of the Committee wish, the Department would be willing to conduct a generic briefing for the Committee on modeling parameters. The particulars would be from a different part of the State but would demonstrate modeling technology. The Department models many areas of the State, and is considered by most State agencies to be an expert in hydrology and modeling. I would hope that Committee Members would give deference to the Department in these matters.

Issue #2. Should subsidence monitoring be required in the area of the proposed plant and wellfield? Several Committee Members and Intervenor AZURE suggested this. In the November 9, 2001 memo from Dale Mason, the Department suggested that additional subsidence investigations be performed. Applicant testified that it performed an investigation and concluded that subsidence does not exist today in the area of the proposed plant and wellfield.

We are satisfied with the investigation performed by the Applicant, however, as suggested to the Applicant at the hearing, the Department believes that a continuing monitoring program should be put in place. The Department believes this could be as simple as requiring a periodic check (i.e. five years) of monuments and discussions with agencies with infrastructure or jurisdiction near the plant site, such as the Central Arizona Project, the Bureau of Land Management and State Lands. This information could then be conveyed to the Department and the Commission for review. Should the Applicant not prepare a condition to monitor for subsidence, the Department will be prepared to offer a condition to effect such a monitoring program.

Issue #3. Should the Applicant be required to provide mitigation for any damage that may be caused by groundwater pumping over the life of the plant? Committee Member Palmer and I suggested this, along with Intervenor AZURE.

While the Department will not commit staff to negotiate with the Applicant at this time for an agreed upon mitigation plan, the Department may be prepared at the next hearing to propose a condition for mitigation recharge. Of course, if the Applicant proposes mitigation recharge during its rebuttal case, this may not be necessary.

When the transcript is available we will review for further insight into the discussion on these issues and any other issues, which the Committee wishes to be discussed between the Department and the Applicant.

Sincerely,

Joseph C. Smith

Joseph C. Smith
Director

JCS:kd

EXHIBIT
A-22
admitted

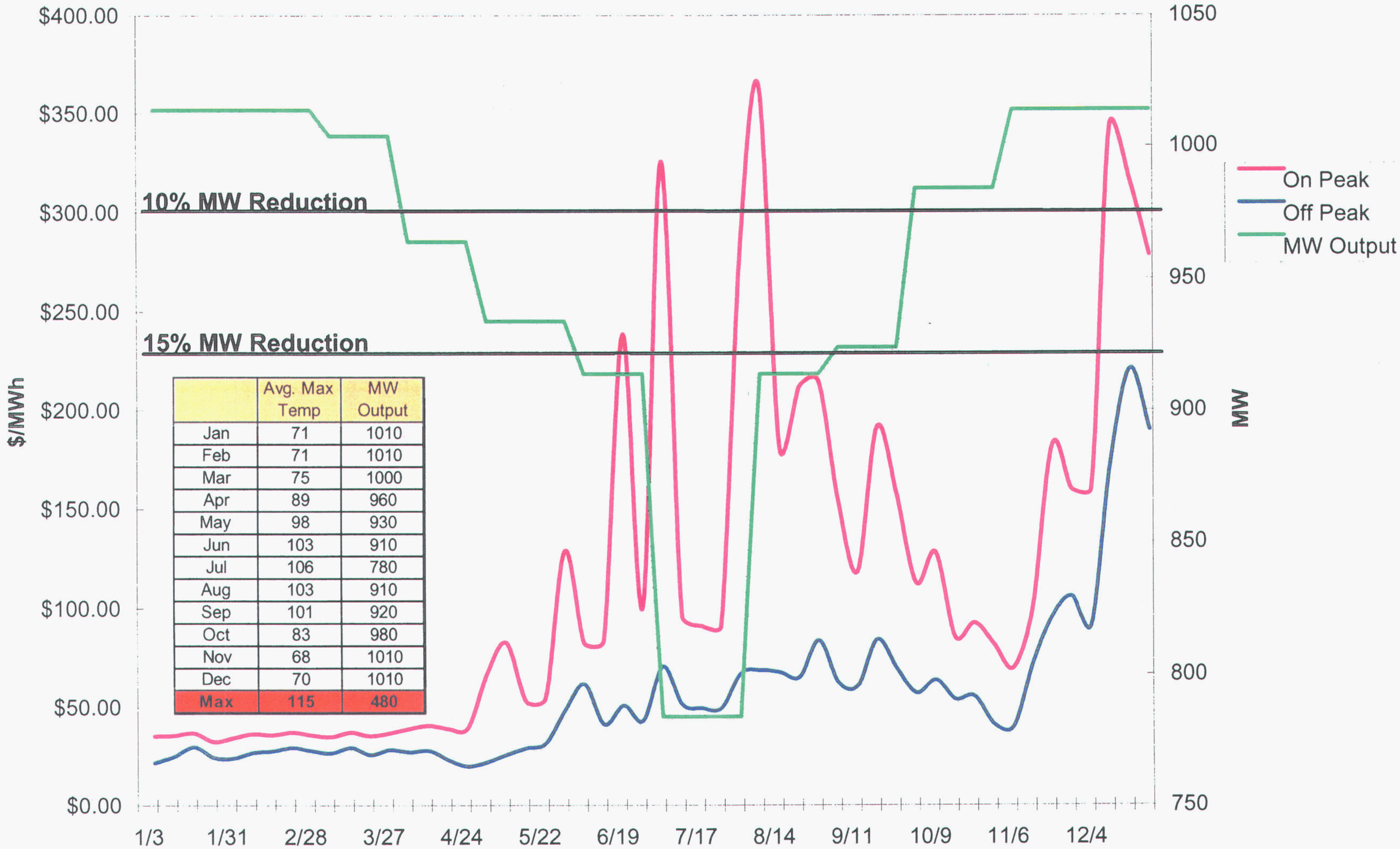
La Paz Generating Facility
Life Cycle Economic Analysis: Dry v. Wet Cooling

		Wet Cooling	Dry Cooling (10% Generation Loss)	Dry Cooling (15% Generation Loss)
Net Output	MW	1080	972	918
Heat Rate	btu/kWh	6900	7200	7200
Variable O&M Cost ($2005)	$/MWh	$1.71	$2.21	$2.21
Capital Cost	$	Base	$45,000,000	$45,000,000
Capacity Value	$/kw-yr	$72	$72	$72
Water Consumption	Ac-Ft/Yr.	5330	267	267
Net Revenue/Year	$	Base	($25,000,000)	($33,000,000)
Maximum Generation/Year	MWh	9,460,800	8,514,720	8,041,680
Average Capacity Factor	%	82%	64%	64%
Net Generation/Year after Heat Rate and O&M Effect	MWh	7,796,000	5,415,000	5,020,000
30 Yr. Economic Loss	$	Base	($750,000,000)	($990,000,000)
Equiv. Economic Cost per Ac-Ft of Water	$	Base	($4,937)	($6,517)
Increased Cost per kWh of Dry Cooling	$/kWh	Base	$0.0088	$0.0105
Annual Increased Cost of 5,000,000 MWh to AZ Customers	$	Base	($44,397,527)	($52,715,100)
Annual Increased Gas Usage for 5,000,000 MWh after Heat Rate Effect	Cu. Ft.	Base	1,500,000,000	1,500,000,000

Notes:
1. The above analysis does not include any volatility in gas or energy prices. Averages are for illustrative purposes. Actual results will vary.
2. The above analysis does not reflect any economic impact due to increased criteria air pollutants with dry cooling.
3. Wet Cooling case does not include duct firing MWs.
4. All production related values are averages of the 2005-2009 estimated values.
5. Analysis assumes constant fixed O&M and a $0.50/MWh increase in variable O&M. This represents a 39% increase in total O&M per MWh.

La Paz Generating Facility

2000 Palo Verde Weekly Pricing vs Temperature Effects on Dry Cooled Plant Output



	Avg. Max Temp	MW Output
Jan	71	1010
Feb	71	1010
Mar	75	1000
Apr	89	960
May	98	930
Jun	103	910
Jul	106	780
Aug	103	910
Sep	101	920
Oct	83	980
Nov	68	1010
Dec	70	1010
Max	115	480

A-23

La Paz Generating Facility
Black and Veatch Wet Cooling versus Dry Cooling Cost Estimate per 540MW block

EXHIBIT
A-23
admitted

TABLE 3

EQUIPMENT CAPITAL COST

	Wet Cooling	Dry Cooling
Surface Condenser	$1,182,000	N/A
Condenser Tube Cleaning System	$250,000	N/A
Air-Cooled Condenser[4]	N/A	$24,900,000
Plate and Frame Closed Cycle Cooling Water Heat Exchanger	$258,000	N/A
Air-Cooled Heat Exchanger	N/A	$2,265,000
Cooling Tower	$2,634,000	N/A
Cooling Tower Basin	$987,000	N/A
Circulating Water Pumps	$458,000	N/A
Circulating Water Piping	$2,744,000	N/A
Water Properties[5]	$4,500,000	$623,000
Water Pretreatment	$2,315,000	$1,145,000
Well Field Development (Wells, Pumps, Motors, Pipe, etc.)	$1,846,000	$510,000
Electrical Adder (extra MCC, Grounding, Switchgear, SUS, Cable and terminations, Cable Tray, Site Lighting)	Base	$3,000,000
Condensate Polishing System	Base	$980,000
Steam Duct to Condenser[6]	N/A	$2,000,000
Increased Indirect Costs	Base	$3,500,000
Total Installed Capital Cost	$17,174,000	$38,923,000
Differential Capital Cost	Base	$21,749,000

La Paz Generating Facility
Black and Veatch Wet Cooling versus Dry Cooling Cost Estimate per 540MW block

Notes:

1. All equipment pricing is given in 2001 dollars. Capital costs only without profit margins added.
2. Labor costs are based on union labor averaged at $45.00 per hour per a 6-10 schedule based on rates provided by AZURE in a proposed Project Labor Agreement
3. Cooling tower vendor offered budget pricing on 8 cell tower. Price for 10 cell based on 120% cost of 8 cell budget price.
4. Air Cooled Condenser installation cost basis used is from two duplicate in-house projects under construction. Labor rate approximately $80/hr due to higher skilled labor required.
5. Allegheny has already purchased the water properties required for wet cooling. The losses due to depressed current value of this property relative to the purchase price is not included in the cost for dry cooling.
6. Estimated number will depend on site arrangement optimization and property constraints. Dry cooling option may be difficult to fit within the limits of the current site boundary. Number is based on reasonable estimate of distances.
7. The size of the evaporation ponds is essentially unchanged for all options. Nearly all the cooling tower blowdown flow is reclaimed by the water treatment system and reused as makeup back to the tower. With the wet cooling option, flow streams such as steam cycle blowdown, flow from the CT evap coolers, etc. drain to the tower basin as makeup flow to the tower. The net effect not having the tower basin available for these "waste" streams is that the size of the flow stream to the evaporation pond is essentially unchanged for all options.

TABLE 3

EQUIPMENT CAPITAL COST

	Wet Cooling	Hybrid Cooling	Dry Cooling	Wet/Dry Parallel Cooling
Surface Condenser	$1,182,000	$1,182,000	N/A	$475,000
Condenser Tube Cleaning System	$250,000	$250,000	N/A	$157,000
Air-Cooled Condenser[4]	N/A	N/A	$24,900,000	$12,880,000
Plate and Frame Closed Cycle Cooling Water Heat Exchanger	$258,000	$258,000	N/A	$258,000
Air-Cooled Heat Exchanger	N/A	N/A	$2,265,000	NA
Cooling Tower	$2,634,000	$5,800,000	N/A	$1,235,000
Cooling Tower Basin	$987,000	$951,000	N/A	$395,000
Circulating Water Pumps	$458,000	$549,000	N/A	$279,000
Circulating Water Piping	$2,744,000	$2,744,000	N/A	$1,440,000
Water Properties[5]	$4,500,000	$4,500,000	$623,000	$3,143,000
Water Pretreatment	$2,315,000	$2,233,000	$1,145,000	$1,906,000
Well Field Development (Wells, Pumps, Motors, Pipe, etc.)	$1,846,000	$1,770,000	$510,000	$1,378,000
Electrical Adder (extra MCC, Grounding, Switchgear, SUS, Cable and terminations, Cable Tray, Site Lighting)	Base	Base	$3,000,000	$3,000,000
Condensate Polishing System	Base	Base	$980,000	$343,000
Steam Duct to Condenser[6]	N/A	N/A	$2,000,000	$2,000,000
Increased Indirect Costs	Base	Base	$3,500,000	$3,500,000

Total Installed Capital Cost	$17,174,000	$20,237,000	$38,923,000	$32,389,000
Differential Capital Cost	Base	$3,063,000	$21,749,000	$15,215,000

TABLE 6

MAXIMUM POWER OUTPUT IN KILOWATTS

89°F Ambient Temperature			
Wet	Hybrid	Dry	Wet/Dry Parallel
496,790 (unfired)	495,300 (unfired)	480,790 (unfired)	483,510 (unfired)
561,280 (fired)	559,660 (fired)	N/A	531,430 (fired)
105°F Ambient Temperature			
Wet	Hybrid	Dry	Wet/Dry Parallel
484,720 (unfired)	483,150 (unfired)	408,760 (unfired)	468,170 (unfired)
550,210 (fired)	548,630 (fired)	N/A	480,550 (fired)
110°F Ambient Temperature			
Wet	Hybrid	Dry	Wet/Dry Parallel
481,300 (unfired)	479,670 (unfired)	309,806 (unfired)	463,860 (unfired)
547,250 (fired)	545,540 (fired)	N/A	N/A

EXHIBIT
A-24
admitted

BEFORE THE ARIZONA POWER PLANT AND TRANSMISSION

LINE SITING COMMITTEE

IN THE MATTER OF THE APPLICATION OF ALLEGHENY ENERGY SUPPLY COMPANY, LLC FOR A CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY FOR CONSTRUCTION OF A 1,080 MW (NOMINAL) GENERATING FACILITY IN SECTION 35, TOWNSHIP 3 NORTH, RANGE 11 WEST IN LA PAZ COUNTY, ARIZONA AND AN ASSOCIATED TRANSMISSION LINE AND SWITCHYARDS BETWEEN AND IN SECTION 35, TOWNSHIP 3 NORTH, RANGE 11 WEST AND SECTIONS 23-26, TOWNSHIP 3 NORTH, RANGE 11 WEST ALSO IN LA PAZ COUNTY, ARIZONA.	DOCKET NO. L-00000AA-01-0116 CASE NO. 116

GALLAGHER & KENNEDY, P.A.
2575 E. CAMELBACK ROAD
PHOENIX, ARIZONA 85016-9225
(602) 530-8000

CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY

Pursuant to notice given as provided by law, the Arizona Power Plant and Transmission Line Siting Committee (the "Committee") held public hearings in Parker and Phoenix, Arizona, on September 4, 2001, November 13-14, 2001 and December 13-14, 2001, in conformance with the requirements of Ariz. Rev. Stat. § 40-360, et. seq., for the purpose of receiving public comment and evidence and deliberating on the application of Allegheny Energy Supply Company, LLC, or its assignees ("Allegheny" or "Applicant"), for a Certificate of Environmental Compatibility ("Certificate") authorizing construction of a 1080 MW (nominal) generating facility and an associated transmission line and switchyards in La Paz County, Arizona (the "Project"), all as more particularly described and set forth in the Application (the "Application").

The following members and designees of members of the Committee were present on one or more of the hearing days:

Laurie Woodall	Chairman, Designee for Arizona Attorney General, Janet Napolitano
Richard Tobin	Department of Environmental Quality
Gregg Houtz	Department of Water Resources
Ray Williamson	Arizona Corporation Commission
Mark McWhirter	Department of Commerce
Michael Palmer	Appointed Member
Jeff McGuire	Appointed Member
Wayne Smith	Appointed Member
Michael Whalen	Appointed Member

Applicant was represented by Michael M. Grant and Todd C. Wiley of Gallagher & Kennedy, P.A. Arizona Corporation Commission Utilities Division Staff ("Staff") was represented by Christopher C. Kempley and Jason D. Gellman. Intervenor Arizona Unions for Reliable Energy ("Unions") was represented by James D. Vieregg of Morrison & Hecker, L.L.P. and Mark R. Wolfe of Adams, Broadwell, Joseph & Cardozo. La Paz County, by its County Attorney R. Glenn Buckelew, filed a notice of limited appearance in support of the grant of Allegheny's Application.

At the conclusion of the hearing, after consideration of the Application, the evidence and the exhibits presented, the comments of the public, the legal requirements of Ariz. Rev. Stat. §§ 40-360 to 40-360.13 and in accordance with A.A.C. R14-3-213, upon motion duly made and seconded, the Committee voted to make the following findings and to grant Allegheny the following Certificate of Environmental Compatibility (Case No. 116):

The Committee finds that the record contains substantial evidence regarding the need for an adequate, economical and reliable supply of electric power and how the Project would contribute towards satisfaction of such need without causing material adverse impact to the environment.

Applicant and its assignees are granted a Certificate authorizing the construction of a 1,080 MW (nominal) electric generating plant as more particularly described in Section

4(a)(i) of the Application and an associated 500 kv transmission line and switchyards as more particularly described in Section 4(b)(i) of the Application and Exhibit G-7.

This Certificate is granted upon the following conditions:

1. Applicant and its assignees will comply with all existing applicable air and water pollution control standards and regulations, and with all existing applicable ordinances, master plans and regulations of the state of Arizona, the county of La Paz, the United States and any other governmental entities having jurisdiction, including but not limited to the following:

   a. all zoning stipulations and conditions, including but not limited to any landscaping and dust control requirements and/or approvals;

   b. all applicable air quality control standards, approvals, permit conditions and requirements of the Arizona Department of Environmental Quality ("ADEQ") and/or other State or Federal agencies having jurisdiction, and the Applicant shall install and operate selective catalytic reduction and catalytic oxidation technology at the level determined by the ADEQ. The Applicant shall operate the Project so as to meet a 2.5 ppm NOx emissions level, within the parameters established in the Title V and PSD air quality permits issued by ADEQ. Applicant shall install and operate catalytic oxidation technology that will produce carbon monoxide ("CO") and volatile organic compound ("VOC") emissions rates determined as current best available control technology ("BACT") by ADEQ;

   c. all applicable water use and/or disposal requirements of the Arizona Department of Water Resources ("ADWR"), Section 6-503 of ADWR's Third Management Plan and the ADEQ regulations;

   d. all applicable regulations and permits governing transportation, storage and handling of chemicals.

2. Allegheny shall construct a 100 KW solar photovoltaic array for use in conjunction with the Project's electricity use requirements. Allegheny will also participate in future solar workshops conducted by the Commission.

3. Subject to the availability of Central Arizona Project ("CAP") water and

delivery facilities, Allegheny will acquire over the next 30 years directly, through another or by contract with the Arizona Water Banking Authority ("AWBA") an aggregate amount of 30,000 acre feet of CAP water or that aggregate amount of water which may be acquired with $3 million, whichever is less. The water acquired is intended to be recharged at the Vidler Recharge Facility ("Vidler"), but may be recharged elsewhere by the Applicant or AWBA. Water recharged shall not be subject to withdrawal by Applicant. Allegheny may also meet all or a portion of its obligation hereunder by acquiring on another person or entity's behalf CAP water to be used in lieu of groundwater which would have been withdrawn and used by such person or entity. If Allegheny has used or recharged CAP water in relation to the Project's water needs, the amount of such use or recharge shall be treated as a credit against Applicant's obligation under this condition.

4. In consultation with the Arizona Department of Water Resources, Allegheny will develop a monitoring program of monument inspection and information gathering from agencies with infrastructure or jurisdiction near the plant site concerning subsidence. The data gathered pursuant to the monitoring program shall be regularly reported to the Department and Commission.

5. In the year following the commencement of groundwater withdrawals in relation to the Project, Applicant shall submit annual reports to the Arizona Department of Water Resources pursuant to A.R.S. 45-437.C.1 reporting the quantity of groundwater withdrawn and the Notice(s) of Authority appurtenant thereto.

6. Authorization to construct the facility will expire five years from the date the Certificate is approved by the Arizona Corporation Commission unless construction is completed to the point that the facility is capable of operating at its rated capacity by that time;

provided, however, that prior to such expiration the facility owner may request that the Arizona Corporation Commission extend this time limitation.

7. Applicant shall initially connect the 500 kV Plant Switchyard to the 500 kV Transmission Grid Interconnection Switchyard with a single 500 kV transmission line, but shall allocate spaces in the Plant Switchyard and shall direct SCE to allocate spaces in the Transmission Grid Interconnection Switchyard for (i) a second 500 kV Transmission line should future reliability studies indicate that such addition is necessary to maintain reliability or (ii) a second Devers/Palo Verde transmission line.

8. Applicant's plant interconnection must satisfy the Western Systems Coordinating Council's ("WSCC") single contingency outage criteria (N-1) and all applicable local utility planning criteria without reliance on remedial action such as, but not limited to, reducing generator output, reducing generator unit tripping or load shedding.

9. The Applicant's plant switchyard shall utilize a breaker and a half scheme.

10. Applicant will pay up to $25,000,000 towards upgrading transmission capacity out of the Palo Verde hub in relation to the Devers Palo Verde, North Gila and Palo Verde Westwing lines for delivery to Arizona markets. This may be done in one of two ways. Applicant may either apply such funding for upgrades to the existing Devers to Palo Verde 500 kV and/or other transmission lines and switchyard facilities, as set forth in Southern California Edison's (SCE's) La Paz system impact study and facilities study, or apply such funding towards the building of new transmission lines out of Palo Verde. If the former option is chosen, Applicant will contact SCE to determine the earliest opportunity for the transmission line to be upgraded and Applicant will use commercially reasonable efforts to assure that such upgrades are completed before this plant commences commercial operation.

11. Prior to construction of any facilities, Allegheny shall provide to the Commission the system impact study and the facilities study performed by Southern California Edison regarding the La Paz project. To the extent that these studies do not provide the following information, Allegheny shall provide the Commission additional technical study evidence that sufficient transmission capacity exists to accommodate the full output of the Project and that the full output of the Project will not compromise the reliable operation of the interconnected transmission system. The SCE studies or additional supplemental technical study shall include a power flow and stability analysis report showing the effect of the full output of the Project on the planned Arizona electric transmission system and shall document physical flow capability for the full output of the plant to its intended market. In addition, Allegheny must provide the Commission with updates of the information required in this condition not more than one year and not less than three months prior to commercial operation of the full output of the plant.

12. Prior to construction of any Project transmission facilities, Applicant shall provide the Commission with copies of the transmission interconnection and transmission service agreement(s) it ultimately enters into with SCE or any transmission provider(s) with whom it is interconnecting, within 30 days of execution of such agreement(s).

13. Applicant will become and remain a member of WSCC, or its successor, and file an executed copy of its WSCC Reliability Management System (RMS) Generator Agreement with the Commission. Membership by an affiliate of Applicant satisfies this condition only if Applicant is bound by the affiliate's WSCC membership.

14. Applicant shall apply to become and, if accepted, thereafter remain a member of the Southwest Reserve Sharing Group or its successor, thereby making its units

available for reserve sharing purposes, subject to competitive pricing.

15. Applicant shall offer for Ancillary Services, in order to comply with WSCC RMS requirements, a total of up to 10% of its total plant capacity to (A) the local Control Area with which it is interconnected and (B) Arizona's regional ancillary service market, (i) once a Regional Transmission Organization (RTO) is declared operational by FERC order, and (ii) until such time that an RTO is so declared, to a regional reserve sharing pool.

16. Within 30 days of the Commission decision authorizing construction of this project, Applicant shall erect and maintain at the site a sign of not less than 4 feet by 8 feet dimensions, advising:

a. That the site has been approved for the construction of a 1,080 MW (nominal) generating facility;

b. The expected date of completion of the facility; and

c. Phone number for public information regarding the project.

In the event that the Project requests an extension of the term of the certificate prior to completion of the construction, Applicant shall use reasonable means to directly notify all landowners and residents within one-mile radius of the project of the time and place of the proceeding in which the Commission shall consider such request for extension. Applicant shall also provide notice of such extension to La Paz County.

17. Applicant shall first offer wholesale power purchase opportunities to credit-worthy Arizona load-serving entities and to credit-worthy marketers providing service to those Arizona load-serving entities.

18. Pursuant to applicable Federal Energy Regulatory Commission ("FERC") regulations, Applicant shall not knowingly withhold its capacity from the market for reasons other

than a forced outage or pre-announced planned outage. Allegheny shall not be required to operate its Project at a loss.

19. In connection with the construction of the project, Applicant shall use commercially reasonable efforts, where feasible, to give due consideration to use of qualified Arizona contractors.

20. Applicant shall continue to participate in good faith in state and regional transmission study forums to identify and encourage expedient implementation of transmission enhancements, including transmission cost participation as appropriate, to reliably deliver power from the Project throughout the WSCC grid in a reliable manner.

21. Applicant shall participate in good faith in state and regional workshops and other assessments of the interstate pipeline infrastructure.

22. Applicant shall pursue all necessary steps to ensure a reliable supply and delivery of natural gas for the Project.

23. Within five days of Commission approval of this CEC, Applicant shall request in writing that El Paso Natural Gas Company ("El Paso") provide Applicant with a written report describing the operational integrity of El Paso's Southern System facilities from mileposts 660-670. Such request shall include:

a. A request for information regarding inspection, replacement and/or repairs performed on this segment of El Paso's pipeline facilities since 1996 and those planned through 2006; and

b. An assessment of subsidence impacts on the integrity of this segment of pipeline over its full cycle, together with any mitigation steps taken to date or planned in the future.

Applicant shall file El Paso's response under this docket with the Commission's Docket Control. Should El Paso not respond within thirty (30) days, Applicant shall docket a copy of Applicant's request with an advisory of El Paso's failure to respond. In either event, Applicant's responsibility hereunder shall terminate once it has filed El Paso's response or Applicant's advisory of El Paso's failure to respond.

24. Applicant shall operate the Project so that during normal operations the Project will not exceed (i) U.S. Department of Housing and Urban Development ("HUD") or Federal Transit Administration ("FTA") residential noise guidelines or (ii) Occupational Safety and Health Administration ("OSHA") Worker Safety Noise Standards.

25. Applicant will use low profile structures and stacks, non-reflective and/or neutral colors on surface materials and low intensity directive/shielded lighting fixtures to the extent feasible for the Project.

26. Allegheny will fence the generating facility and evaporation ponds to minimize effects of plant operations on terrestrial wildlife and will keep the berms surrounding the evaporation ponds clear of vegetation to limit pond attractiveness to birds.

27. In consultation with the Arizona Game & Fish Department, Applicant will develop a monitoring and reporting plan for the evaporation ponds. The plan will include the type and frequency of monitoring and reporting to the Game & Fish Department and the U.S. Fish and Wildlife Service.

28. Allegheny will continue cactus ferruginous pygmy owl surveys through the Spring of 2002, based on established protocol. If survey results are positive, the U.S. Fish and Wildlife Service and Arizona Department of Game and Fish will be contacted immediately for further consultation.

29. Allegheny will retain a qualified biologist to monitor all ground clearing/disturbing construction activities. The biological monitor will be responsible for ensuring proper actions are taken if a special status species is encountered (e.g., relocation of a Sonoran desert tortoise).

30. Applicant will salvage mesquite, ironwood, saguaro and palo verde trees removed during project construction activities and use the vegetation for reclamation in or near its original location and/or landscaping around the plant site.

31. Allegheny will retain an Arizona registered landscape architect to develop a landscape plan for the perimeter of the generating facility. The landscape plan will use native or other low water use plant materials. The Applicant will continue to consult with La Paz County regarding the landscape plan.

32. Allegheny will use a directional drilling process to bore under Centennial Wash in constructing the gas pipeline to minimize potential impacts to the mesquite bosque associated with the wash.

33. The Applicant will continue to consult with La Paz County in relation to its comprehensive planning process to develop appropriate zoning and use classifications for the area surrounding the Project.

34. Allegheny will use its best efforts to avoid the two identified cultural resource sites. If Sites AZ S:7:48 and 49 (ASM) cannot be avoided by ground disturbing activities, the Applicant will continue to consult with the State Historic Preservation Office to resolve any negative impacts which usually entails preparing and implementing a data recovery research design and work plan.

35. If a federal agency determines that all or part of the Project represents a

federal undertaking subject to review under the National Historic Preservation Act, Allegheny will participate as a consulting party in the federal compliance process (i.e., 36 C.F.R. 800) to reach a finding of effect and to resolve adverse effects, if any.

36. Should cultural features and/or deposits be encountered during ground disturbing activities, Allegheny will comply with A.R.S. § 41-844, which requires that work cease in the immediate area of the discovery and that the Director of the Arizona State Museum be notified promptly.

37. If human remains or funerary objects are encountered during the course of any ground disturbing activities related to the development of the subject property, Applicant shall cease work and notify the Director of the Arizona State Museum in accordance with Ariz. Rev. Stat. § 41-865.

38. Allegheny will retain a qualified archaeologist to monitor ground clearing/disturbing construction activities and to appropriately instruct workers on detection and avoidance of cultural resource sites.

GRANTED this ______ day of ______________, 2001.

ARIZONA POWER PLANT AND
TRANSMISSION LINE SITING COMMITTEE

By ________________________________
Laurie Woodall, Chairwoman

12921-0004/947199 v6

EXHIBIT
A-26
admitted

AIR-COOLED HEAT EXCHANGERS

AND

COOLING TOWERS

Thermal-flow performance evaluation and design

Detlev G Kröger

Department of Mechanical Engineering
University of Stellenbosch
Private Bag X1, Matieland, 7602
South Africa

Fax: Int. +27-21-808 4958
E-mail: dgk@maties.sun.ac.za

1998

The cover: Temperature distribution in the plume above an air-cooled heat exchanger. With permission from dr. W.A.Schreüder.

requirements and waste water include the use of wet-cooling systems designed to operate with high cycles of concentrating dissolved solids in the circulating water, the use of various types of dry-cooling systems which make no consumptive use of water, and the use of various types of cooling tower systems which combine dry- and wet-cooling technology.

General studies to determine the comparative economics of alternative heat rejection systems should not fail to consider all of the potential advantages offered by the use of water conserving systems. For example, dry-cooled or dry/wet-cooled plants need not be located at the same site as the base case wet-cooled plant with which they are being compared and should take into account the siting flexibility afforded by the use of the water conserving systems. Fuel cost savings resulting from locating a coal-fired plant at the mine mouth where there may not be enough water available to permit the use of wet-cooling could be substantially greater than the accompanying increase in transmission costs. Further, the use of a water conserving heat rejection system could permit expansion of existing generating facilities at a site without sufficient water to serve additional wet-cooled capacity, thereby taking advantage of existing support and service facilities and rights-of-way. Even with an adequate water supply at a given site, the use of a water conserving system could, in some cases, reduce indirect project costs and lead times by reducing environmental study, public hearing, and permit requirements. Other factors, including the changes in micro climate, corrosion of equipment, piping and structural steel, emission of chemicals, poor visibility and freezing of ground or road surfaces located near cooling towers plumes as well as potential health hazards [86CR1, 97CU1] (legionnaires' disease) in poorly maintained systems, cannot be ignored in practice. The impact of all these factors on the comparative economics of alternative heat rejection systems will depend upon the unique circumstances of each particular application.

For the foreseeable future, wet-cooling towers are expected to remain the economical choice, in most cases, where an adequate supply of suitable make-up water is available at a reasonable cost. Decreasing water availability and increasing water costs and more stringent environmental and water use and accessibility regulations will, however, make a water conserving heat rejection system a practical and economical choice for more power plant [77SU1, 94KO1] and other applications [59MA1], especially if the effectiveness of such systems can be improved [80MC1].

EXHIBIT
A-27
admitted

Understanding Wet and Dry Cooling Systems

WAYNE C. MICHELETTI, Wayne C. Micheletti, Inc., Charlottesville, VA
JOHN M. BURNS, P.E., Burns Engineering Services, Inc., Topsfield, MA

IWC-01-38

Keywords: cooling towers, dry cooling, combined-cycle power plants

Summary: Evaporative cooling towers, an integral part of most industrial operations, typically represent the single largest demand for plant makeup water and can be a major source of discharge wastewater. As a result, in new industrial facilities, dry cooling systems recently have been receiving increasing attention as an alternative to cooling towers. Evaluating new cooling system options requires a solid understanding of not only the readily apparent design and operating differences, but also the subtle, yet equally important, performance and cost implications.

BACKGROUND

The need to control elevated temperatures in a variety of industrial processes makes the choice of cooling medium and system an important operating and economic decision. Historically, water has been the cooling medium of choice because it was readily available, relatively inexpensive and reusable up to a point. For more than twenty years, evaporative systems (i.e., cooling towers) have been the predominant means for using water to cool process equipment.

Nowhere is this more apparent than in the steam-electric power industry, where large amounts of water are needed to condense turbine exhaust steam. In fact, the USEPA estimates that 92.4% of all industrial cooling water is used in steam-electric power generation.[1] This trend will very likely continue. Over the next twenty years, the Energy Information Administration projects that the nation's electric generating capacity will increase by 217 GW.[2] Most (62%) of this new capacity will be produced by combined-cycle (CC) power plants, all of which will need cooling for the steam-electric generation portion.

Growing competition from municipal and agricultural users has decreased the amounts and increased the prices of good quality water resources available to industrial users. At the same time, environmental regulations on the blowdown discharged from cooling towers have become much more stringent. Because dry (air-cooled) systems consume no water, generate no blowdown and create no visible plume, they may be seen as an economically and environmentally attractive alternative to wet cooling systems in new industrial facilities.

But when considering cooling options for new facilities, there are some important similarities and differences between wet and dry systems that should be fully understood before making a selection. Differences in heat transfer are particularly important because of the associated influences on the performance and costs of these systems.

CHARACTERISTICS OF WET AND DRY COOLING SYSTEMS

Industrial cooling systems are designed to transfer heat from one or more process operations to the surrounding atmosphere. For steam-turbine generators, this "waste" heat is produced when the turbine exhaust steam is condensed to recover high-purity water for recycle to the boiler. Steam condensation also creates a vacuum at the turbine outlet. This vacuum (monitored as turbine backpressure) allows the turbine to utilize more of the steam's energy and increases the overall efficiency of electric power generation. Lower steam temperatures in the condenser will produce a greater vacuum on the steam turbine (reflected by a lower turbine backpressure) and mean a better generating efficiency and higher total plant generation capability. In this way, the cooling system directly influences power plant performance.

All wet cooling systems use water to absorb heat via indirect contact with steam in a condenser. The condenser is a large shell-and-tube heat exchanger, with steam on the shellside and cooling water passing through the tubes. For systems with cooling towers, the water is pumped in a loop through the condenser to the tower and back to the condenser (see Figure 1). Because of this recycle circuit, this type of cooling system is frequently referred to as "closed-loop" or as "recirculated".

Heat absorbed by cooling water in the condenser is released to the air that passes through the cooling tower.

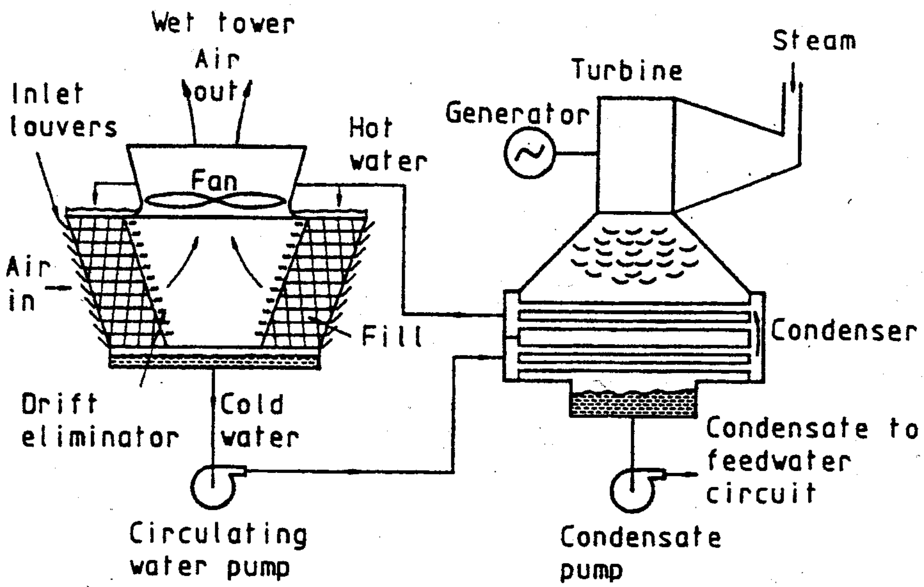


FIGURE 1
WET COOLING SYSTEM WITH MECHANICAL INDUCED-DRAFT TOWER[3]

Due to intimate direct air-water contact in the cooling tower fill,approximately 65-85% of this heat rejection is associated with the evaporation of a portion of the cooling water; the remaining 15-35% is due to simultaneous sensible heating of the inlet air. This process lowers the temperature of the water passing through the tower so that it can be recirculated back to the condenser and used for cooling again.

Because the surrounding air is the ultimate heat sink for the thermal energy released in the cooling tower, the atmospheric conditions are key elements in determining cooling system design and performance. The cooling ability of a tower is measured by how close it can bring the outlet cooling water temperature to the wet-bulb temperature of the surrounding air. The lower the inlet air wet-bulb temperature (indicating colder air and/or lower humidity), the colder the tower can make the outlet cooling water temperature. As a matter of physics, the cold water temperature can never be lower than the inlet air wet-bulb temperature.

When designing wet cooling towers, this difference between the anticipated inlet air wet-bulb temperature and the target cold water temperature is a value known as the "cooling approach". The approach for most wet cooling towers at high design-point wet-bulb temperatures is usually between 5 and 10 °F. A lower approach can be achieved by building and operating a larger tower. But doing so will increase the cooling tower capital and O&M costs. So, for power plant cooling towers, the design approach is generally about 8 °F. During operation in cold weather, this design approach can be expected to increase considerably due to atmospheric conditions.

Although the term "dry cooling" implies the total absence of water, it really means the transfer of heat to the atmosphere without the evaporative loss of water. For example, automobiles use a type of dry cooling system to control engine temperatures. Water is circulated through the engine block to absorb the heat of combustion, then through the radiator to dissipate that thermal energy by sensible heat transfer with the surrounding air, and finally back to the engine block. The system is said to be "dry" (or completely closed) because none of the water evaporates and makeup is only required to offset minor losses, such as leaks.

The automobile example is also said to be "indirect" because water is used as a medium for transferring the thermal energy from the heat source (the engine) to the heat sink (the atmosphere). Conceptually, an indirect, dry tower would seem to be a likely alternative to the standard wet cooling tower. However, the extremely poor thermal

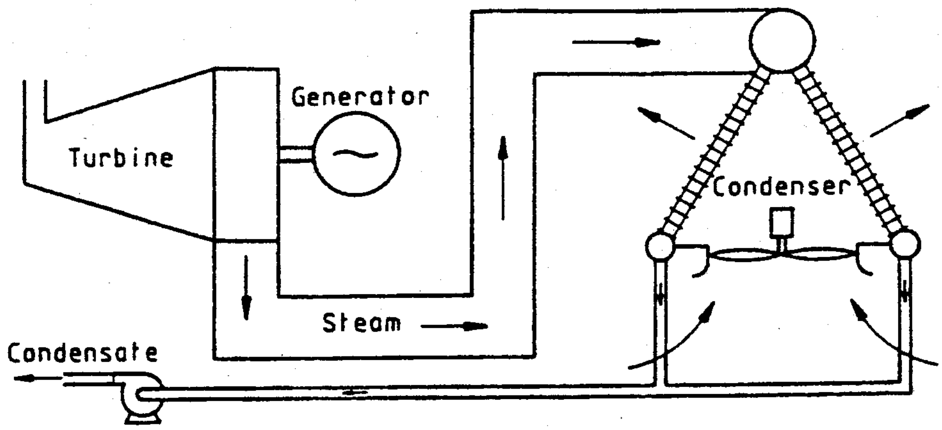


FIGURE 2
DRY COOLING SYSTEM WITH DIRECT AIR-COOLED CONDENSER (ACC)[3]

performance and very high cost have been factors that have precluded the selection of indirect dry cooling as a viable system design for new power plants in the United States. This particular cooling approach has been limited to a few special cases, primarily in Eastern Europe and the Middle East.

Instead, for new power plants, a "direct" dry cooling system is more applicable. In direct dry cooling, the turbine exhaust steam is piped directly to a finned-tube, air-cooled condenser (ACC), also referred to as the dry cooling tower (see Figure 2). The steam exhaust duct has a large diameter and as short a length as possible to minimize pressure losses. Because finned-tube, air-cooled condensers have a low heat transfer coefficient, they are commonly quite large. To reduce the required land area, the finned tubes on the ACC are frequently arranged in an A-frame or delta pattern. Air is forced across the finned tubes by fans to improve heat rejection to the atmosphere. The A-frame design also provides an improved fan air-flow coverage to the entire tube bundle.

Since an ACC relies strictly on sensible heat transfer, a large quantity of air must be supplied, requiring a correspondly larger number of fans than would be used in a wet cooling tower. Forced-draft fans are installed on the cooler, inlet air side of the condenser to: a) reduce the power consumption for the necessary air mass flow rate, b) allow the use of less expensive materials of construction, and c) improve access and ease of maintenance. Unfortunately, a forced-draft fan system often does not produce a uniform air flow distribution through the dry tower, resulting in a relatively low warm-air escape velocity from the top of the tube bundle. In a wind, this low velocity can be extremely important because it increases the potential for recirculation of the hot plume back through the tower instead of drawing in fresh ambient air.[4] Compared to wet cooling towers with the high-velocity plumes produced by induced-draft fans, the low exit air velocities associated with dry towers exacerbate recirculation in these systems. Therefore, anti-recirculation fences or windwalls may be required to prevent such problems.[5]

While the performance of wet cooling systems depends primarily upon the ambient wet-bulb temperature and is determined by the design approach, the performance of dry cooling systems depends upon the ambient dry-bulb temperature and is determined by a design value referred to as the "initial temperature difference" or ITD. For dry cooling, the ITD is the difference between the turbine exhaust steam temperature and the anticipated inlet air dry-bulb temperature. Reported design ITD values range from 25 to 55 °F. And just as the design approach for wet cooling systems can be reduced by increasing the tower size, a lower design ITD for dry cooling systems can be achieved by building and operating a larger ACC. However, the capital and O&M costs for an ACC are more sensitive to size than for a wet cooling tower. Therefore, when the heat rejection is substantial (as in the case of power plants), economics dictate that the size of the ACC be minimized, resulting in a larger design ITD.

Because ambient dry-bulb temperatures are usually higher than wet-bulb temperatures and tend to experience more dramatic daily and seasonal variations, the design and operation of dry cooling systems linked to steam turbine-generators can be more problematic than for wet cooling systems. If the dry cooling system is unable to meet design heat transfer conditions in the condenser, then the turbine backpressure will increase and the plant's power generation efficiency will decrease. With a reasonably flexible steam turbine design, a higher backpressure and the associated decline in generating efficiency (or energy penalty) can be operationally tolerated up to a point. But as the turbine backpressure increases, eventually an alarm will warn operators that the turbine-generator is approaching limits set by the equipment manufacturer. If steam cooling and condensation worsen, then the steam flow to the turbine must be reduced (known as a plant derate because the amount of electricity which can be generated by the entire plant is reduced). Though it is difficult to absolutely categorize a high-temperature limit, when ambient dry-bulb temperatures exceed 90 °F, the relative performance of a dry cooling system will usually begin to suffer appreciably.

HYBRID COOLING SYSTEMS

In some circumstances, a combination of wet and dry cooling systems has been helpful in addressing certain site-specific issues. The nature of these "hybrid" systems can vary significantly depending upon the particular situation and objectives. Some hybrid systems are designed to compensate for the decline in performance of a dry cooling system at higher ambient dry-bulb temperatures. These hybrid systems essentially incorporate a wet-cooling component with a surface condenser in a parallel steam path to provide supplemental evaporative cooling when needed. This type of wet/dry system is currently not in widespread use and typically has been limited to situations with small cooling requirements.

By far, the most common type of hybrid system is designed to eliminate the visible plume leaving the tower of a wet cooling system. Hybrid plume-abatement systems basically consist of an indirect dry cooling system located immediately above the cooling tower portion of a wet cooling system. Hot cooling water from the condenser is fed first to indirect-contact, finned-tube, air-cooled heat exchangers and then to the direct-contact fill in the wet tower. When operating in the plume-abatment mode, ambient air is drawn through both the dry and wet segments in parallel paths. The two air streams are then mixed and exhausted from the stack of the induced-draft fan at the top of the tower. The hot, dry air from the air-cooled heat exchangers increases the temperature and decreases the relative humidity of the cooler, saturated air from the fill in the wet tower so that the final mixture does not have a visible plume. Operators can control the degree of visual plume abatement by adjusting hinged damper doors along the air inlet to the dry cooling section to govern the air flow and, consequently, the volume, temperature and relative humidity of hot, dry air in the outlet mixture. Hybrid plume abatement systems are not water-conserving systems.

EVALUATING COOLING SYSTEM OPTIONS

When considering cooling system options for a new facility, any number of site-specific factors can influence the evaluation and selection process. But, in general, the key environmental factors will most likely be:

- Water availability and quality
- Wastewater discharge limitations
- Meteorological conditions
- Drift and plume aesthetics
- Fish protection
- Worker and community health and safety
- Noise

The primary economic factors are:

- Water availability and quality
- Wastewater discharge treatment
- Geographic location (as related to land availability and cost, and construction cost)
- System performance over variable operating conditions

Based on these lists, dry cooling systems offer several obvious advantages. There are no makeup water requirements or wastewater discharge concerns. Aquatic impacts and drift or plume problems are nonexistent. And any health or safety issues related to waterborne contaminants and pathogens or water treatment chemicals are eliminated.

But the extensive design and operating experience with wet cooling systems in a broad range of industrial applications cannot be ignored. This history has established wet cooling towers as the low-cost, closed-loop standard for stable performance over variable operating conditions at virtually any site throughout the U.S. and the world. And given the evolving competitive market in the U.S. electric power industry, the major emphasis will undoubtedly be on cost and performance at new power generation facilities. With this in mind, a generic base-case combined-cycle plant was studied to compare the cost and performance characteristics of wet and dry cooling systems at five different U.S. sites (Albany, NY; Atlanta, GA; Madison, WI; Amarillo, TX and Sacramento, CA).

BASE CASE PARAMETERS

The generic base case selected for study was a 750-MW combined-cycle power plant with two 250-MW gas turbine-generators followed by one 250-MW steam turbine-generator. Since exhaust steam condensation from the single steam turbine represents the largest cooling demand, only this portion of the plant is considered in the detailed analysis. The smaller auxiliary cooling loads were estimated to add 5% to the overall capital costs of both the wet and dry cooling systems.

To further simplify the analyses, a single steam turbine design was assumed for both wet and dry cooling systems. In the past, steam turbine/condenser designs for large fossil and nuclear power plants have been optimized to reflect the type of cooling system, as well as other site-specific conditions. However, more recently, designers have been relying on more flexible steam turbines which operate over a wider range of backpressures, even if it means accepting an energy penalty under certain conditions. An exhaust steam flow of 1.7 million lbm/hr (at 5% moisture) was assumed as representative for a 250-MW steam-turbine designed to operate at 2.5 in Hga.

The base-case cooling tower is a mechanical-draft, counterflow design with a concrete basin and FRP support structure. The fill is a modern, low-clog plastic film fill. The total tower would consist of twelve cells in a back-to-back configuration. The area of each cell would be about 42 feet by 54 feet, so that the overall footprint of the tower would be 325 feet long and 85 feet wide. The maximum height of the tower (measured at the top of the fan stack) would be about 55 feet. Each cell would have a single, 30-ft diameter, low-noise, induced-draft fan.

The condenser is a modern, single-pass, shell-and-tube design with carbon steel shell, waterbox, tubesheet and supports, and 22 BWG 304 stainless steel tubes. The overall size was determined using Heat Exchange Institute (HEI) steam surface condenser standards for a cooling water velocity of 7 ft/sec and an 85% cleanliness factor.

The air-cooled condenser (dry cooling tower) was made of carbon steel finned tubing arranged in the "A-frame" configuration with an exhaust steam manifold at the top and condensate collection lines at the bottom on either side. The ACC footprint was estimated to be 250 feet by 250 feet (1.4 acres). The maximum ACC height (at the top of the A-frame) would be about 105 feet. A total of forty 30-ft diameter, low-noise, forced-draft fans would be required.

Other base case design details for the wet and dry cooling systems are summarized in Table 1.

TABLE 1
BASE-CASE COOLING SYSTEM DESIGN SPECIFICS

Wet Cooling System	
Cooling tower approach	8 °F
Cooling tower range	24 °F
Ambient wet-bulb temperature	Regional Mean
Wet-bulb temperature recirculation	+ 2 °F
Evaporation (% of total heat load)	70
Cycles of concentration	5
Condenser terminal temp. difference	6 °F
Dry Cooling System	
Initial temperature difference (ITD)	54 °
Ambient dry-bulb temperature	Regional Mean
Dry-bulb temperature recirculation	+ 3 °F

ESTIMATED CAPITAL AND O&M COSTS

Capital costs for both wet and dry cooling systems were developed using estimating methods commonly employed by architect-engineers for large utility projects, and included all system elements beginning at the turbine exhaust flange. Algorithms based on prior bid costs were used to estimate specific installed cooling tower costs. The majority of the other cost components were individually determined using published data[6] and other recent cooling system cost estimates or previous equipment quotes, in combination with an assessment of the quantity of materials involved or a size delineation. In addition, the following details also apply to all capital cost estimates.

- Low-noise fans (with 10 dba attenuation) were included due to the general sensitivity of most communities to the relatively pervasive noise from cooling towers (wet and dry).
- A 1% hot-weather incidence value was selected as typical for both wet and dry cooling towers.[7]
- Wiring costs[8] and local construction costs[6] were based on factors specifically developed for this purpose.
- The usual project allowances for indirect costs such as management, engineering, and contingencies were included.
- All costs were adjusted to a July 1999 basis using standard factors.[6]

Table 2 is an itemized comparison of the resulting capital cost estimates for wet and dry cooling systems at one location.

TABLE 2
ITEMIZED CAPITAL COST ESTIMATES FOR WET AND DRY COOLING SYSTEMS
(Albany, NY $Million, July 1999)

	Wet Cooling	Dry Cooling
Cooling Tower	6.64	28.06
Fans	2.58	11.64
Condenser	6.05	
Auxiliary Cooling	0.89	2.13
System Miscellaneous	2.19	1.58
General Miscellaneous	0.28	1.02
Total Direct Costs	18.63	44.43
Indirect Factors	6.52	15.55
Total Costs	25.15	59.98

Wet cooling tower costs include the tower and basin; dry cooling tower costs include the ACC, steam duct, foundation and support structure. System miscellaneous costs include the cooling water intake and cooling water pumps and piping (for the wet system), and a tube wet-down/cleaning system, special controls, insulation and heat tracing (for the dry system). General miscellaneous costs include site preparation, access roads, fire/lightening protection, painting and acceptance testing (for both systems).

Table 3 is a comparison of the total estimated capital costs at all five locations.

TABLE 3
TOTAL CAPITAL COST ESTIMATES FOR WET AND DRY COOLING SYSTEMS
($Million, July 1999)

	Wet Cooling	Dry Cooling
Albany, NY	25.2	60.0
Atlanta, GA	23.2	56.2
Madison, WI	25.4	60.7
Amarillo, TX	21.3	52.1
Sacramento, CA	28.0	66.0

For the base-case example (250-MW steam turbine at a new 750-MW combined-cycle power plant), the total estimated capital costs for a dry cooling system were consistently greater than those for a wet cooling system by an average of 140% at all five sites studied. The higher costs can be attributed to the larger, more expensive ACC and the increased number of fans. Although there was appreciable capital cost variability for either the wet or the dry cooling systems between the different sites, the majority of this variation reflects local construction cost factors and not climatic conditions.

Operating and maintenance (O&M) costs were based on a combination of several cost factors. For both wet and dry systems, the annual labor and materials maintenance costs for all cooling system components were assumed to be 1% of the capital costs. This figure reflects past estimates[8], as well as recent experience with power plant towers, condensers, circulating water pumps and intakes. The cost of system auxiliary power was determined by: 1) estimating the power requirements (fans for dry systems and fans and pumps for wet systems), 2) adjusting these power requirements by assuming a 90% CC plant capacity factor, and 3) multiplying the adjusted power requirement by a unit cost of $25/MW-hr.

A comparison of the estimated annual O&M costs at all five locations is presented in Table 4.

TABLE 4
ANNUAL ESTIMATED O&M COSTS FOR WET AND DRY COOLING SYSTEMS
($Million, July 1999)

	Wet Cooling	Dry Cooling
Albany, NY	0.94	1.82
Atlanta, GA	0.92	1.78
Madison, WI	0.94	1.83
Amarillo, TX	0.90	1.74
Sacramento, CA	0.96	1.88

The largest proportion of the estimated annual O&M costs is for system auxiliary power: 70-75% for wet systems and 65-70% for dry systems. For wet systems, this power cost is split almost evenly between pumps and fans. For dry systems, the power cost is associated entirely with fans.

An important annual cost not included in these estimated O&M costs is the potential energy penalty (i.e., the reduced plant generating capacity) for each system. The energy penalty is directly related to the climatic conditions of a specific site and would be expected to vary considerably throughout the country. However, for both wet and dry cooling systems, the energy penalty normally is greatest during the hottest periods of the year (usually assumed to be only 1% of the time during the four warmest months or 29.2 hours/year). For the remainder of the year, the energy penalty should be much smaller. Unfortunately, the periods of greatest energy penalty typically coincide with the times of peak electricity consumption. Therefore, any generating shortfall at that time represents a serious problem in meeting customer demand and a potentially significant revenue loss.

Since the performance of dry cooling systems is linked to the ambient dry-bulb temperature (which can fluctuate significantly on a daily basis), dry cooling systems are particularly sensitive to climatic variations. This influence can be seen in Table 5 which shows the maximum energy penalties estimated for both wet and dry cooling systems compared to the base 250-MW capacity.

The magnitude of the maximum energy penalty for dry cooling systems relative to wet cooling systems demonstrates the substantial economic impact that cooling system selection can have on power generation costs. Depending upon the prevailing price of replacement power, the maximum energy penalty costs could be quite high, as shown in Figure 3. And, as replacement power costs increase, the estimated maximum energy penalty costs for dry cooling could begin to approach the value of other elements in the anticipated annual O&M cost. On the other hand, wet cooling systems are expected to incur relatively minor energy penalty costs.

TABLE 5
ESTIMATED MAXIMUM ENERGY PENALTY FOR WET AND DRY COOLING SYSTEMS (MW)

	Wet Cooling	Dry Cooling
Albany, NY	0.0	29.1
Atlanta, GA	0.7	30.4
Madison, WI	0.6	34.4
Amarillo, TX	- 2.3	39.1
Sacramento, CA	0.0	45.2

CONCLUSIONS

Selecting a cooling system for a new industrial facilty means balancing a number of site-specific constraints. Dry cooling systems offer some environmentally attractive

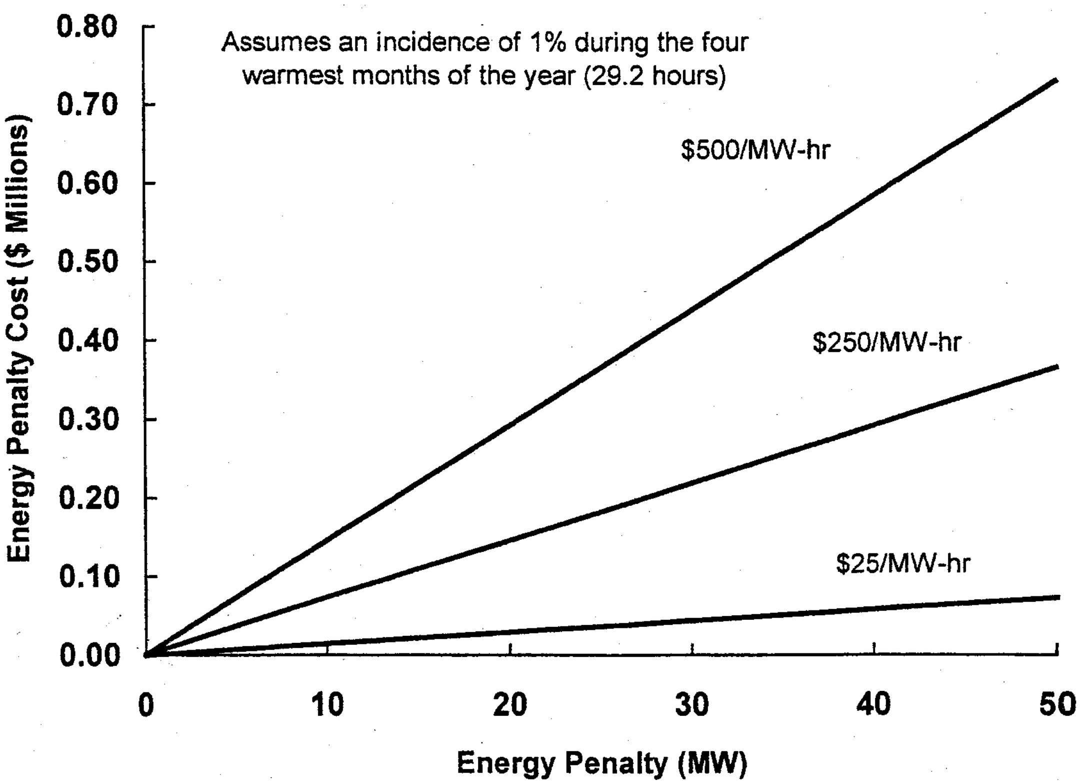


FIGURE 3
ENERGY PENALTY COSTS AS A FUNCTION OF REPLACEMENT POWER COSTS

advantages, particularly if new facility permitting may be a concern. However, these advantages have a large price when compared with the economics and performance of wet cooling systems. For example, an evaluation of wet and dry cooling systems for a 250-MW steam turbine-generator at a new 750-MW combined-cycle power plant shows that:

- The estimated capital cost for a dry cooling system is 140% greater than for a wet cooling system,
- The estimated annual O&M cost for a dry cooling system is 94% greater than for a wet cooling system,
- The performance of dry cooling systems (which are directly related to the ambient dry-bulb temperature) is more sensitive to climatic conditions and more likely to vary over wider ranges on both a daily and seasonal basis than the performance of wet cooling systems (which are directly related to the ambient wet-bulb temperature), and
- The decline in system performance (calculated as the maximum energy penalty) for dry cooling could range from 29-45 MW, depending upon local climatic conditions; for wet cooling, the maximum energy penalty is negligible.

Therefore, by almost any economic measure, wet cooling would generally be the preferred cooling system option for a new industrial facility. Dry cooling systems are most likely to be selected only in limited special situations with very unique constraints that make wet cooling systems technically impractical or environmentally unacceptable.

ACKNOWLEDGEMENT

Much of the information presented in this paper was developed as part of a study sponsored by the Utility Water Act Group (UWAG) in November, 2000.[9]

REFERENCES

1. "Economic and Engineering Analyses of the Proposed §316(b) New Facility Rule", Report EPA-821-R-00-019, Office of Water, U. S. Environmental Protection Agency, Washington, DC, August 2000.
2. "Annual Energy Outlook 2000 With Projections to 2020", Report DOE/EIA-0383(2000), Energy Information Administration, U.S. Department of Energy, Office of Integrated Analysis and Forecasting, Washinton, DC, December 1999.
3. Kröger, Detlev G., Air-Cooled Heat Exchangers and Cooling Towers, Begell House, Inc., New York, NY, 1998.
4. Swanekamp, Robert. "Profit from Latest Experience with Air-Cooled Condensers", Power, June 1994, p. 78.
5. Kosten, H., et.al., "Operating Experience and Performance Testing of the World's Largest Air-Cooled Condenser", Proceedings of the American Power Conference, Chicago, IL, 1981.
6. Means, R.S., Heavy Construction Cost Data - 2000, (14th edition), 1999.
7. Cooling Tower Fundamentals and Application Principles, Engineering Weather Data, Marley Company, Overland Park, KS, 1967, p. 65.
8. Managing Waste Heat with the Water Cooling Tower, (2nd edition), Marley Company, Overland Park, KS, 1973.
9. "Comparison of Wet and Dry Cooling Systems for Combined Cycle Power Plants", Utility Water Act Group, Washington, DC, November 4, 2000.

La Paz Generating Facility

Application for a Certificate of Environmental Compatibility

January 15 and 16, 2002
Exhibit A-28

EXHIBIT
A-28
admitted

Allegheny Energy Supply
an Allegheny Energy company

La Paz Generating Facility

Application for a Certificate of Environmental Compatibility

Testimony of Donald L. Mundy

Allegheny Energy Supply
an Allegheny Energy company

Unique Power System Benefits to Arizona from the Project

- Commitment of up to $25 million in transmission upgrades to the Arizona Transmission Grid
- Commitment of an additional $2.5 million and proportional sharing of additional upgrade costs at the Palo Verde Hub.
- Increased merchant power supply
- Commitment to reserve sharing
- Commitment of up to 10% of the plant for ancillary services
- Increased Palo Verde - Devers transmission reliability with new Project interconnection switchyard
- Provision for development of new local power grid near the Project
- Provision for future interconnection and expansion of other regional transmission lines to the Project

Plant Retirement Opportunities in Arizona as a Result of the Allegheny Project

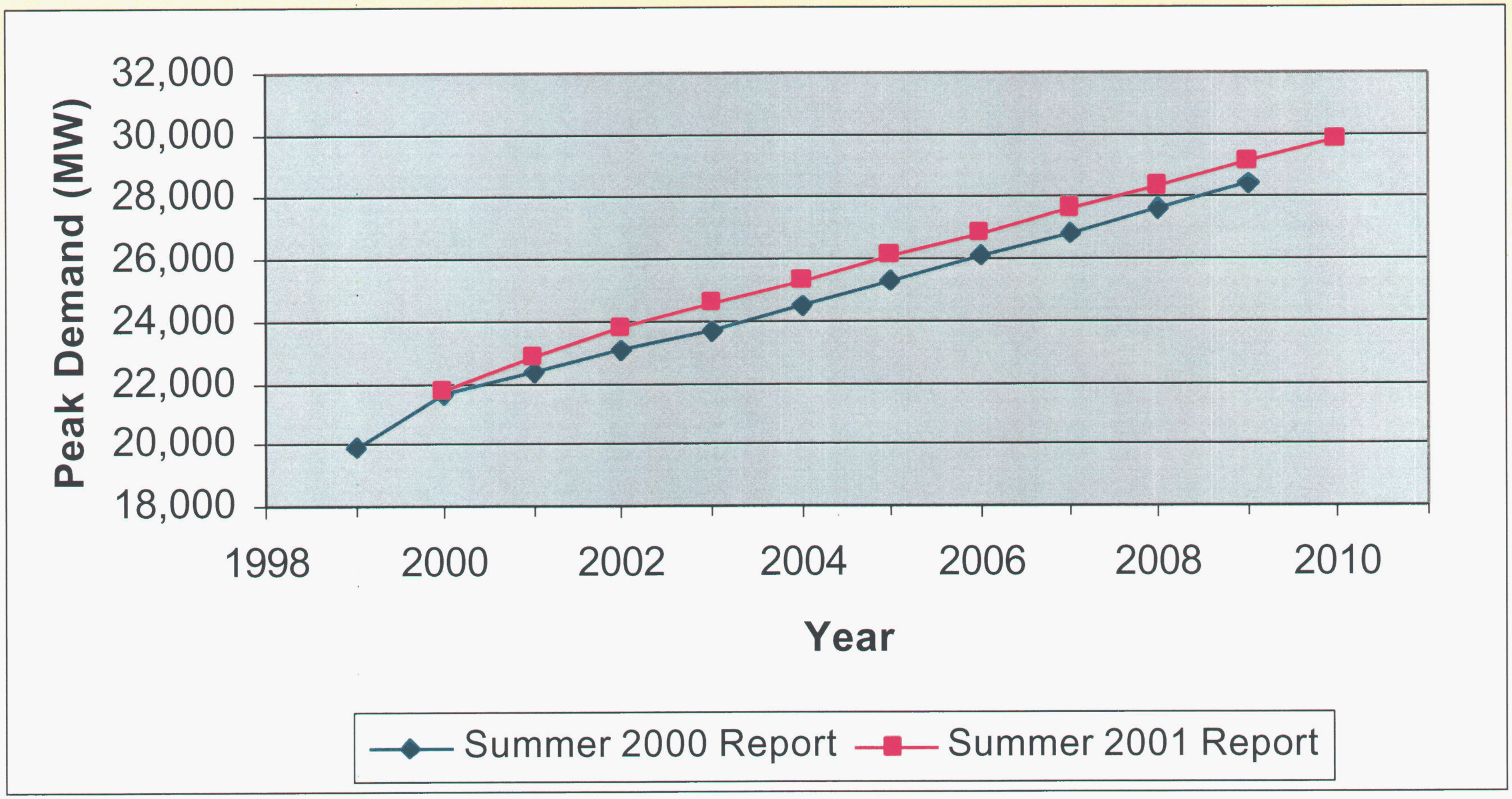
- In 2004/5 (planned commercial operation of the Project) about 6,000 MW of the Arizona generating plants will be over 30 years old.
- The natural gas fuel consumption necessary to produce electric energy in a typical Arizona generating plant constructed in the 1960s and 1970s is from 50% to 100% <u>greater</u> than the fuel consumption of the Allegheny Project. In other words, the Allegheny Project is much more fuel efficient than the older facilities, which translates into lower costs to the consumer.
- The Allegheny Project will use technologies and control systems that will produce much lower emissions than units constructed 20 plus years ago.
- The Allegheny Project together with other similar plants under construction (about 5,700 MW) will allow Arizona to keep up with forecast load growth and reserve margin needs and also retire 30 plus-year-old, less efficient and less environmentally friendly units, thus broadly improving the power supply situation.

Allegheny Energy Supply
an Allegheny Energy company

Updated Regional Power System Forecasts

- New WSCC data (**10-Year Coordinated Plan Summary 2001 - 2010)** dated August 2001, was officially adopted by NERC on October 16, 2001 and released on October 26, 2001.
- Relevant data are based on the Arizona, New Mexico and Southern Nevada Region.
- Arizona represents about 65% of the region on a MW load basis.
- New load growth forecasts indicate higher values. In 2005 the new predicted growth in the region is 829 MW higher than the previous forecast.
- New regional reserve margins have shifted to generally lower values in the period. In 2005 the forecast margin is 24% less than was previously forecast.
- The following graphs indicate the regional values in comparative form.

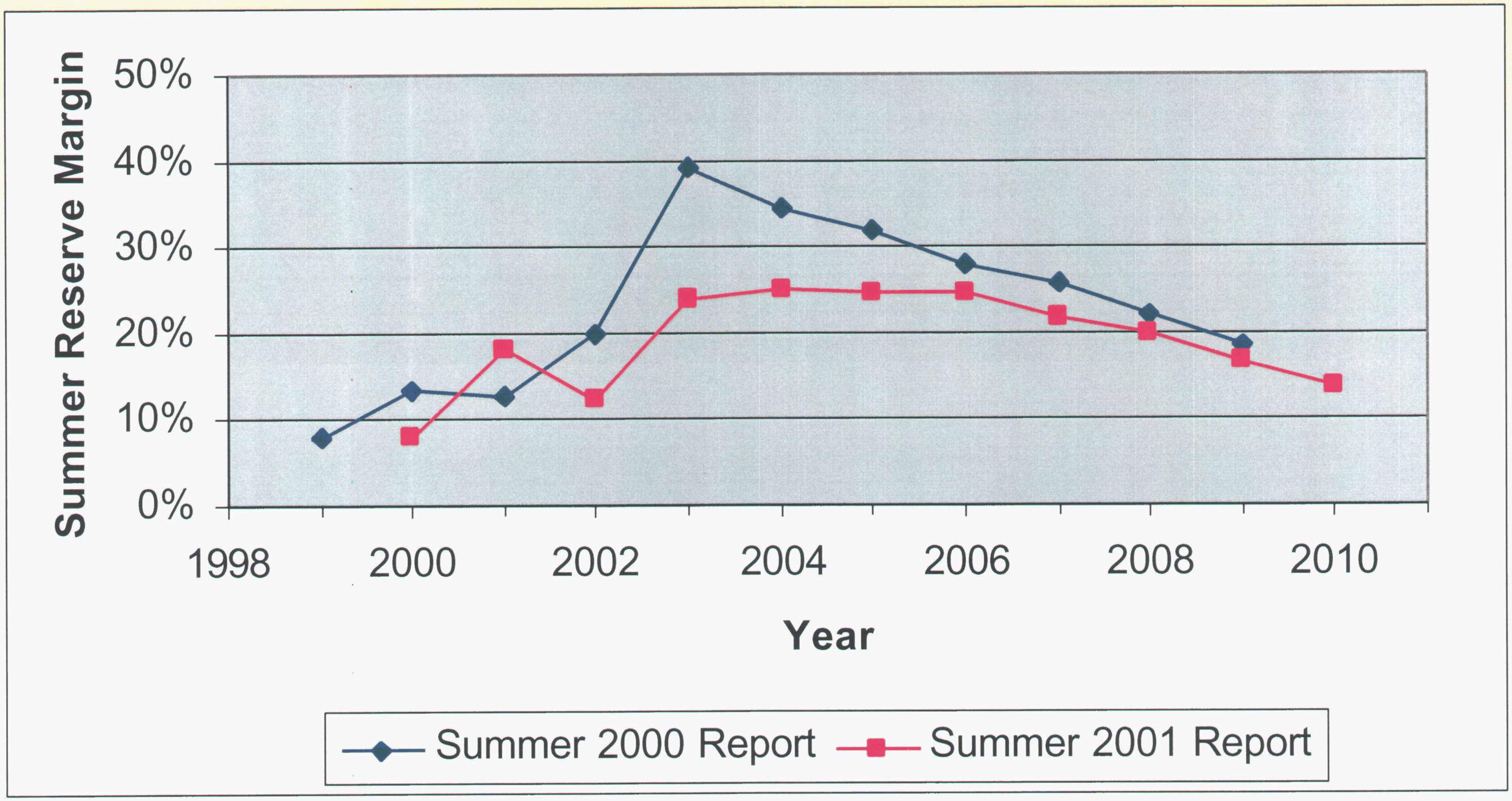
AZ/NM/SNV Regional Load Forecast Comparison



WSCC 10 - Year Coordinated Plan Summary 2001-2010, August 2001 and 2000-2009, October 2000

Allegheny Energy Supply
an Allegheny Energy company

AZ/NM/SNV Regional Load Reserve Margin Comparison

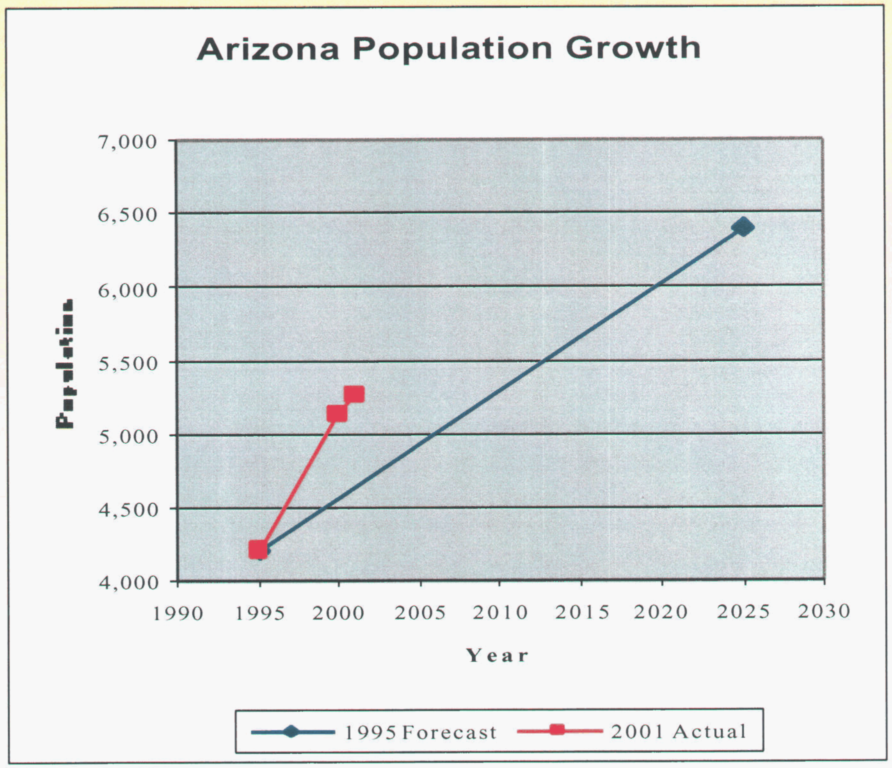


WSCC 10 - Year Coordinated Plan Summary 2001-2010, August 2001 and 2000-2009, October 2000

Allegheny Energy Supply
an Allegheny Energy company

Increased Power Demand from Population Growth

- **Arizona's population growth**
  - twice the national average growth from 1995 to 2025
  - fourth fastest growing state
  - growth in 2001 projected to be 2.7% above 2000 levels



"The official [2000] population count, 5,130,632, was nearly 1.5 million more than in 1990, surprising even experts who have experienced Arizona's dramatic growth firsthand." – *THE ARIZONA REPUBLIC, December 2001*

Allegheny Energy Supply
an Allegheny Energy company

The Status and Certainty of Projects is constantly changing

- "Energy companies are scaling back construction of new power plants to cope with low wholesale electricity prices and market jitters over high levels of corporate debt. New data show that some 18% of all announced projects already are effectively dead, nearly double the attrition rate a year ago."

  THE WALL STREET JOURNAL, Friday, January 04, 2002

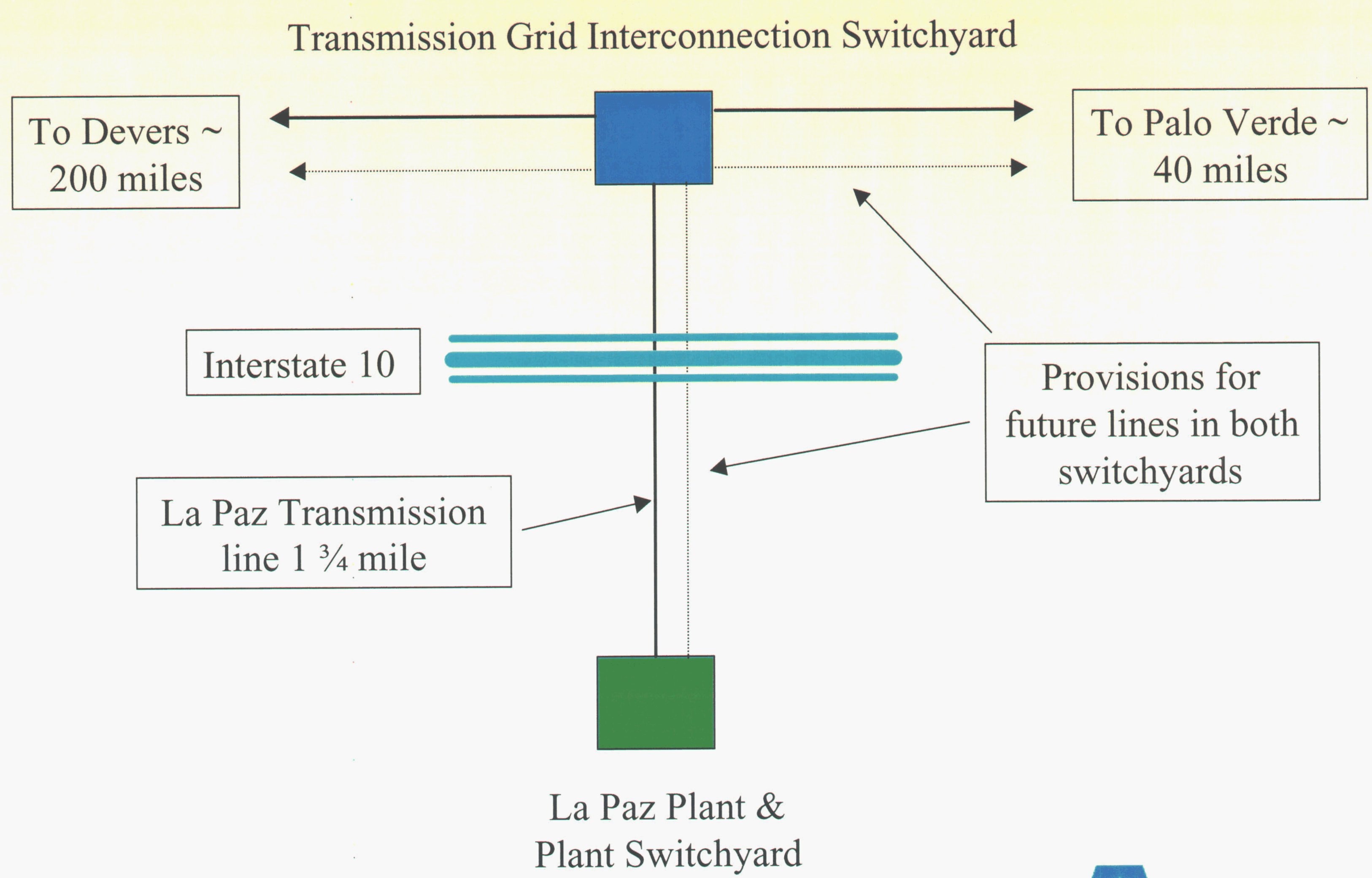
- From various discussions at the December 2001 PowerGen Conference:
  - Panda - Gila River - Will not move forward as planned with the second 1,000 MW block - will stop at foundations.
  - Springerville 3&4 (TEP) - May be cancelled or significantly delayed.
  - Reliant - Signal Peak may not proceed ahead at all due to interconnection issues.
  - Montezuma - Likely to be cancelled.
  - Big Sandy 1-2 (Caithness) - Temporarily dead.
  - Red Hawk 3&4 - Possible conversion to simple cycle.

Allegheny Energy Supply
an Allegheny Energy company

Comments on the Marcus Testimony

- "To the extent that the La Paz project output will be contractually sold outside of Arizona, it will make no contribution to Arizona reliability." Consider that Allegheny has transmission rights from California for sales into Arizona and has sold 1 million MW-hours to Arizona utilities over the last 30 months. Further, any plant built and running in a region increases reliability in that region.
- Several references were made to projects under development or under construction within the AZ/NM/SNV region without references or names. In some cases the reference did not match the values quoted. Also, a California Energy Commission prospect list is used based on news releases, announced developments, filings, etc. as a source for Arizona plants.
- The precise need for more power and more efficient power is uncertain. In the past, utilities took risks, often at consumer expense, in an attempt to precisely meet growth with new projects. But in a competitive market, the consumer is not at risk so long as an ample supply is present.
- Ample supply is key to a robust competitive market and it will to some extent control itself by slowing or not building some projects as merchants watch the market. Not all projects or phases of projects will be built as planned or ever.

Project Grid Interconnection Diagram



Allegheny Energy Supply
an Allegheny Energy company

Groups and Utilities that will review the Project Interconnection to the Grid

As part of the interconnection process, numerous studies and agreements are prepared, discussed and reviewed by those parties having a stakeholder interest in the Grid.

- Arizona Corporation Commission and Staff
- Southern California Edison, Interconnecting Transmission Owner
- California Independent System Operator, Interconnection Transmission Operator
- Federal Energy Regulatory Commission, Interconnection Agreement Regulator
- Western Systems Coordinating Council, NERC Reliability Group
- Western Arizona Transmission System (WATS), Reliability Group
- Palo Verde Engineering & Operations Group, Reliability Group
- Nuclear Regulatory Commission, Connections at/near Nuclear facilities
- Southwest Regional Transmission Association, Reliability Group
- Western Regional Transmission Association, Reliability Group
- Arizona Public Service, Specialty Studies

Allegheny Energy Supply
an Allegheny Energy company

Summary of Power System Benefits to Arizona from the Project

- Increased merchant power supply, and meeting new growth
- Providing opportunity to retire more costly and less environmentally friendly plants
- Commitment of up to $25 million in transmission upgrades to the Arizona Transmission Grid, and $2.5 million more at the Palo Verde Hub.
- Commitment to reserve sharing
- Commitment of up to 10% of the plant for ancillary services
- Increased Palo Verde - Devers transmission reliability with new Project interconnection switchyard
- Provision for development of new local power grid near the Project
- Provision for future interconnection and expansion of other regional transmission lines to the Project

Allegheny Energy Supply
an Allegheny Energy company

I-22

EXHIBIT
A-29
admitted

ALLEGHENY ENERGY SUPPLY COMPANY
ALLEGHENY POWER PROJECT

INTERCONNECTION STUDY

SYSTEM IMPACT STUDY

October 19, 2001

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL℠ Company

Prepared by
Jorge Chacon
(Consultant)

Southern California Edison Company

EXECUTIVE SUMMARY

Southern California Edison Company (SCE) performed and delivered a system impact study as requested by Allegheny Energy Supply (Allegheny) for interconnection of a new generation plant with a total capacity of 1290 MW to SCE's Devers-Palo Verde 500-kV transmission line. The CAISO requested SCE to perform additional studies to address issues regarding the maximum Southern California Import Transfer (SCIT) levels assumed in the studies. In addition, Allegheny has submitted revised machine models and has lowered the interconnection request from 1290 MW down to 1260 MW with a proposed in-service date for the project is June 1, 2004.

The purpose of a System Impact Study is to determine the adequacy of SCE's transmission system to accommodate all or part of the requested capacity and to address issues raised by the CAISO on the first study dated July 14, 2000. This study will identify the extent of any congestion and determine if there are any negative impacts to reliability. New facilities or upgrades will be recommended to maintain system reliability in accordance with the California Independent System Operator's (CAISO) Reliability Criteria.

The results of the System Impact study will be used as the basis to determine project cost allocation for facility upgrades in the Facilities Study. ***The study accuracy and the results for the assessment of the system adequacy are contingent on the accuracy of the technical data provided by the customer as shown in Figure 1 and Appendix B.*** Any changes to the attached data could void the study results.

The study was performed for two system conditions: (a) 2004 heavy summer load forecast (once-in-ten-year heat wave assumption) with minimal internal eastern area generation and high East-of-River / West-of- River (EOR/WOR) power flow, and (b) 2005 heavy spring load forecast (65% of 2005 heavy summer) with minimal eastern area generation and high EOR/WOR power flow.

The study includes a power flow (steady state and post-transient) analysis, transient stability analysis, and short-circuit duty analysis.

CONCLUSIONS

Studies identified that the existing facilities are inadequate to accommodate the Allegheny Power project. The Allegheny-Devers and Palo Verde-North Gila 500-kV transmission lines are loaded in excess of their respective nameplate rating as limited by series capacitors. Congestion may be used as a means to manage the base case overloads shown below. Generation scheduled within SCIT can be re-dispatched from EOR/WOR to Midway-Vincent. This will maintain the SCIT level at 13,200 MW while reducing the loading on the Allegheny-Devers and Palo Verde-North Gila 500-kV transmission lines. The Allegheny Power project will be required to schedule according to the SCIT nomogram and will have an adverse effect on the amount of existing EOR and WOR generation that can be schedule for import.

Case	SCIT Level	Allegheny-Devers 500-kV	Palo Verde-N. Gila 500-kV
Without Allegheny (Palo Verde-Devers 500kV)	13,238 - HS 12,458 – SP	97% 83%	99% 84%
With Allegheny Displacing Palo Verde Area Generation	13,242 - HS 12,458 – SP	107% 95%	96% 80%
With Allegheny Displacing Navajo Area Generation	13,201 - HS 12,470 – SP	118% 104%	104% 87%
With Allegheny Displacing Mohave Area Generation	13,245 - HS 12,427 – SP	126% 110%	110% 92%
With Allegheny Displacing Arizona Generation (Scaled)	13,241 - HS 12,470 - SP	112% 104%	100% 87%

In addition to the base case overloads, the Allegheny Power project increases the loading on both of these transmission lines under single contingency conditions as shown below.

Transmission Line Outage	Palo Verde-N. Gila 500-kV	Allegheny-Devers 500-kV
Transmission Line Overload	**Allegheny-Devers 500-kV**	**Palo Verde-N. Gila 500-kV**
Without Allegheny (Palo Verde-Devers 500kV)	130% (HS) 105% (SP)	137% (HS) 126% (SP)
With Allegheny Displacing Palo Verde Area Generation	140% (HS) 115% (SP)	137% (HS) 126% (SP)
With Allegheny Displacing Navajo Area Generation	154% (HS) 134% (SP)	149% (HS) 126% (SP)
With Allegheny Displacing Mohave Area Generation	165% (HS) 122% (SP)	162% (HS) 127% (SP)
With Allegheny Displacing Arizona Generation (Scaled)	146% (HS) 122% (SP)	142% (HS) 116% (SP)

A Facilities Study will be required to determine the facilities and upgrades required to interconnect the proposed Allegheny Power 1260 MW project. The study should:

1. Determine and develop cost for 500-kV upgrades required to mitigate all base case overloads identified.

2. Review circuit breakers at the four 500-kV, eleven 230-kV, and three 115-kV substation locations to determine need for breaker replacement and cost allocation as a result of the original Allegheny request.

3. Review circuit breakers at one 500-kV substation location to determine need for breaker replacement and cost allocation as a result of the revised Allegheny request.

4. Perform Single-phase-to-ground short-circuit duty analysis.

5. Determine and develop cost for facilities required to interconnect the proposed project by looping in the Devers-Palo Verde 500-kV transmission line: switchyard facilities, circuit breakers, relay protection, and metering.

6. Reevaluate single and double contingency cases to determine congestion requirements and need for remedial action schemes assuming upgrades in place to mitigate base case overloads.

7. Determine and develop the cost for the 500-kV and 230-kV upgrades necessary to mitigate remaining bulk contingency overloads.

8. Reevaluate short-circuit duty to account for the impacts resulting from system upgrades required to mitigate base case overloads.

9. Determine new operating procedures or modify existing operating procedures for this project. The facility study should address the scope of the procedures that may be needed, however, actual operating procedures and studies to support those procedures will not be developed until the Interconnection Facility Agreement (IFA) is executed.

CONTENTS

CONTENTS

ALLEGHENY ENERGY SUPPLY COMPANY
ALLEGHENY POWER PROJECT

SYSTEM IMPACT STUDY

October 19, 2001

INTRODUCTION

Southern California Edison Company (SCE) performed and delivered a system impact study as requested by Allegheny Energy Supply (Allegheny) for interconnection of a new generation plant with a total capacity of 1290 MW to SCE's Devers-Palo Verde 500-kV transmission line. The CAISO requested SCE to perform additional studies to address issues regarding the maximum Southern California Import Transfer (SCIT) levels assumed in the studies. In addition, Allegheny has submitted revised machine models and has lowered the interconnection request from 1290 MW down to 1260 MW with a proposed in-service date for the project is June 1, 2004.

The purpose of a System Impact Study is to determine the adequacy of SCE's transmission system to accommodate all or part of the requested capacity and to address issues raised by the CAISO on the first study dated July 14, 2000. This study will identify the extent of any congestion and determine if there are any negative impacts to reliability. New facilities or upgrades will be recommended to maintain system reliability in accordance with the California Independent System Operator's (CAISO) Reliability Criteria.

The results of the System Impact study will be used as the basis to determine project cost allocation for facility upgrades in the Facilities Study. ***The study accuracy and the results for the assessment of the system adequacy are contingent on the accuracy of the technical data provided by the customer as shown in Figure 1 and Appendix B.*** Any changes to the attached data could void the study results.

The study was performed for two system conditions: (a) 2004 heavy summer load forecast (once-in-ten-year heat wave assumption) with minimal internal eastern area generation and high East-of-River / West-of- River (EOR/WOR) power flow, and (b) 2005 heavy spring load forecast (65% of 2005 heavy summer) with minimal eastern area generation and high EOR/WOR power flow.

The following sections provide detailed study conditions and assumptions and present the results of Power Flow (steady state and post transient), Transient Stability, and Short-Circuit Duty assessments.

STUDY CONDITIONS AND ASSUMPTIONS

A. Planning Criteria

The study was conducted by applying the California Independent System Operator (CAISO) Reliability Criteria. More specifically, the main criteria applicable to this study are as follows:

Load Flow Assessment

The following contingencies are considered for transmission or subtransmission lines and 500/230 kV transformer banks ("AA-Banks"):

Assuming the largest unit (San Onofre Unit 2 or 3) initially off and then:

- Single Contingencies (N-1 Line or N-1 AA-Bank)

Assuming both San Onofre Units 2 and 3 in service and then:

- Single Contingencies (N-1 Line or N-1 AA-Bank)
- Double Contingencies (N-2 Two Lines, N-1 Line and N-1 AA-Bank) (Outages of two AA-Banks are beyond the Planning Criteria)

The following loading criteria are used:

Transmission Lines	Base Case	Limiting Component Normal Rating
	N-1	Limiting Component A-Rating
	N-2	Limiting Component B-Rating
500-230kV Transformer Banks	Base Case	Normal Loading Limit
	Long-Term & Short-Term	As defined by SCE Operating Bulletin

System upgrades or remedial action schemes are recommended only for base case overloads, single contingency overloads in excess of the short-term emergency rating, and common mode failure double contingencies in excess of the short-term emergency rating.

Stability Assessment

The Transmission System is to remain stable under a three-phase-to-ground fault at the most critical locations, normally cleared, with the loss of one or two transmission lines and during the most critical single-phase-to-ground fault with delayed clearing. Maximum acceptable first swing voltage drops are 25% under single contingencies and 30% under double contingencies. In addition, first swing voltage swings are not to exceed 20% for more than 20 cycles under single contingency and no more than 20% for 40 cycles under double contingency conditions as defined by the WSCC Planning Criteria.

Post Transient Assessment

The maximum voltage deviations allowed under contingency conditions in the post transient time frame are:

- 7 percent under N-1 assuming one San Onofre generating unit off
- 10 percent under N-2 assuming both San Onofre generating units on

Congestion Assessment

The following principles, outlined below, were used for interconnecting generation into the SCE transmission system, which fall under CAISO jurisdiction (these principles may be subject to change for future interconnection projects).

- Sufficient capacity shall be maintained to accommodate all Must Run and Regulatory Must-Take generation resources with all facilities in service

- Sufficient capacity shall be maintained to accommodate the total output of any one generation resource which is not classified as Must-Run

- The CAISO protocol on congestion management shall apply when two or more generation resource which are not classified as Must-Run or Regulatory Must-Take exceeds the available capacity of the system

- Dispatch of the Allegheny Power project will be done within the defined SCIT nomogram.

The following guideline were included in the System Impact Study to cover the congestion issues:

a). Under Base Case (all transmission facilities in service), without the proposed Project, the system was evaluated with all existing interconnected generation and all generation requests in the area that have a queue position ahead of this request. It should be noted that the interconnection requests in the Palo Verde area totaling 8,000 MW were not included in this study assessment.

b). Under Base Case, the total output of the proposed project was added and the system was reevaluated for the following four scenarios:

   - Allegheny displacing generation in the Palo Verde area (simulated by reducing one Palo Verde generation unit by 1,260 MW).

   - Allegheny displacing generation in the Mohave area (simulated by reducing Mohave generation by 1,260 MW).

- Allegheny displacing generation in the Navajo area (simulated by reducing Navajo generation by 1,260 MW).

- Allegheny displacing generation throughout the Arizona area (simulated by scaling Arizona generation down by 1,260 MW).

No facilities must be over the limiting component normal loading limit. If the normal loading limits of some facilities in a) are exceeded, the overload is an existing overload caused by a project in queue ahead of proposed project. The proposed project may be subjected to potential upgrade cost sharing and/or participation of any proposed remedial action schemes if the proposed project aggravates the overload. If the normal loading limits of some facilities in b) are exceeded but were not exceeded in a), reduce the generation from the proposed project until the overload is mitigated in order to identify total available capacity.

The results of these studies should be able to identify:

a). If there is capacity available to accommodate the proposed project without the need for system upgrades.

b). If congestion exists in the area.

c). An estimate of the amount of congestion in the area.

d). If the project impacts SCIT, West-of-River, or East-of-River power flows.

B. Allegheny Energy Company – Allegheny Power Project

Figure 1 shows the one-line diagram of the proposed Allegheny Energy Company Power Project. A summary of the total plant output is as follows:

Proposed Allegheny Power Project

4 Gas Units (G1-G3)	190 MW (each)
2 Steam Units (ST)	265 MW
Total Auxiliary Load	30 MW
Net Plant Output	1,260 MW

The interconnection of the proposed generating facilities to the CAISO controlled system is looping the Devers-Palo Verde 500-kV transmission line.

The dynamic data for the new generating combustion turbine using the GE PSLF models, as provided by Allegheny, is shown in Appendix B.

C. System Conditions

To simulate the SCE transmission system for analysis, the study used the same databases that were used to conduct the CAISO Controlled Transmission 2002-2006 Assessment. Load flow studies considered the existing system arrangement without the SDGE proposed Rainbow-Valley 500-kV transmission project while short-circuit duty analysis included the Rainbow-Valley 500-kV project. This assumption was made since accurate models for the Rainbow-Valley Unified Power Flow Controller (UPFC) are not available at this time. General Electric Power System Energy Consulting is working on developing these models.

The bulk power study considered scenarios that evaluated maximum EOR/WOR[1] imports and maximum generation from Qualified Facilities. Pump loads in the eastern area (MWD pumps) were assumed on for both heavy summer and light spring conditions. These conditions were evaluated to identify worst scenarios that would stress the SCE 500-kV transmission system network and SCE 230-kV Eastern area. In addition, the study considered two system load conditions: 2004 heavy summer and 2005 light spring. The summer peak load forecast was based on the SCE's 2000 Transmission Substation Transformer Capacity Assessment, and reflects a one-in-ten-year heat wave assumption. The 2001-2005 heavy summer load forecast is shown in Tables 1-1. The 2005 light spring load forecast assumed 65% of heavy summer load forecast as shown in Table 1-2.

D. Load Flow Study

Load flow studies were conducted under 2004 heavy summer and 2005 light spring conditions. Further description of the case assumptions follows:

a). 2004 Heavy Summer without the Allegheny Power project, Case 1

2004 heavy summer load with minimal internal generation in SCE's eastern area electrical system and maximum EOR/WOR power flow. Generation included: Year 2000 reliability must-run and all regulatory must-take. Generation patterns were maximized in the LA Basin to fully stress the Palo Verde-North Gila and Palo Verde-Devers 500-kV transmission lines in order to identify extent of potential congestion on the bulk power system with the addition of the proposed project.

b). 2004 Heavy Summer with the Allegheny Power project, Case 2

Case 1 modified to include the Allegheny Power project with power displaced in the Palo Verde area (East-of-River).

c). 2004 Heavy Summer with the Allegheny Power project, Case 3

[1] Maximizing EOR/WOR flow increases Arizona imports to Southern California.

Case 1 modified to include the Allegheny Power project with power displaced in the Mohave area (West-of-River).

d). 2004 Heavy Summer with the Allegheny Power project, Case 4

Case 1 modified to include the Allegheny Power project with power displaced in the Navajo area (East-of-River).

e). 2004 Heavy Summer with the Allegheny Power project, Case 5

Case 1 modified to include the Allegheny Power project with power displaced throughout the Arizona area.

f). 2005 Light Spring without the Allegheny Power project, Case 6

2005 light spring load with minimal internal generation in SCE's eastern area electrical system and maximum EOR/WOR power flow. Generation included: Year 2000 reliability must-run and all regulatory must-take. Generation patterns were maximized in the LA Basin to fully stress the Palo Verde-North Gila and Palo Verde-Devers 500-kV transmission lines in order to identify extent of potential congestion on the bulk power system with the addition of the proposed project.

g). 2005 Light Spring with the Allegheny Power project, Case 7

Case 6 modified to include the Allegheny Power project with power displaced in the Palo Verde area (East-of-River).

h). 2005 Light Spring with the Allegheny Power project, Case 8

Case 6 modified to include the Allegheny Power project with power displaced in the Mohave area (West-of-River).

i). 2005 Light Spring with the Allegheny Power project, Case 9

Case 6 modified to include the Allegheny Power project with power displaced in the Navajo area (East-of-River).

j). 2005 Light Spring with the Allegheny Power project, Case 10

Case 6 modified to include the Allegheny Power project with power displaced throughout the Arizona area.

2004 HEAVY SUMMER SCIT, EAST-OF-RIVER, AND WEST-OF-RIVER FLOWS SCE AREA TOTAL GENERATION, IMPORT, LOAD AND LOSSES (MW)					
	Case 1	Case 2	Case 3	Case 4	Case 5
SCIT	13,238	13,242	13,245	13,201	13,241
EOR	5,471	4,245	4,186	5,342	4,283
WOR	6,486	6,504	6,489	6,400	6,528
Generation	15,650	16,910	16,915	15,657	16,910
Import*	6,580	5,320	5,319	6,580	5,320
Load	21,703	21,703	21,703	21,703	21,703
Losses	526	525	531	534	527

*Arizona Imports were reduced with the addition of the proposed project since the project is assumed to be in the SCE service territory.

2005 LIGHT SPRING SCIT, EAST-OF-RIVER, AND WEST-OF-RIVER FLOWS SCE AREA TOTAL GENERATION, IMPORT, LOAD AND LOSSES (MW)					
	Case 6	Case 7	Case 8	Case 9	Case 10
SCIT	12,458	12,458	12,470	12,427	12,470
EOR	5,580	4,344	4,323	5,509	4,323
WOR	8,312	8,323	8,324	8,247	8,324
Generation	8,418	9,680	9,686	8,427	9,686
Import*	6,200	4,940	4,940	6,200	4,940
Load	14,303	14,303	14,303	14,303	14,303
Losses	315	317	323	324	323

*Arizona Imports were reduced with the addition of the proposed project since the project is assumed to be in the SCE service territory.

The two tables above identify the SCE area system demand and resources as well as the Southern California Import conditions modeled. As can be seen, SCIT levels were maintained in all cases studied. EOR flows are decreased for those cases where Allegheny displaces Arizona area generation at Palo Verde, Navajo, or throughout the entire Arizona system. In addition, SCE imports are reduced and SCE generation is increased in the cases where the Allegheny Power project displaces Arizona area generation since the project is assumed to be within the SCE service territory.

It should be noted that although the studies assumed 65% bulk system spring loads, lower levels during actual operation of the system may exist that would subject the proposed project to additional congestion management not identified in this study.

Simulations

For each of the ten cases, load flow simulations of the bulk power system were conducted for the base case, single contingencies and double contingencies for lines and 500-230 kV transformer banks to determine impacts to the SCE system as well as neighboring bulk transmission systems.

E. Transient Stability Study

Stability studies were conducted for the contingencies listed in Table 4. These contingencies were identified in the following two studies:

1. in the CAISO Controlled Transmission 2001-2005 Assessment with 4-cycle 3-phase faults on the most critical 500-kV buses cleared by opening one or two transmission lines.

2. in this System Impact Study with

    a. 4-cycle 3-phase faults on the Perkins 500-kV bus cleared by opening two 500-kV transmission lines.

    b. 4-cycle 3-phase faults on the Allegheny 500-kV bus cleared by opening one 500-kV transmission line.

    c. 15-cycle single-phase-ground faults with delayed clearing on the Valley 500-kV bus cleared by opening the Valley-Serrano 500-kV transmission lines.

The same Allegheny Power project cases used for power flow studies were also used for the stability study. For each of the ten cases, a total of 10 critical contingencies were evaluated for stability.

F. Post Transient Study

The power flow study voltage results were used as a screen to identify those contingencies that may require additional post transient voltage studies. Contingencies identified in the power flow to have a voltage drop in excess of 5% for single and double contingencies were selected for post-transient simulation.

G. Short Circuit Duty Study

To determine the impact of the proposed Allegheny Power project on short circuit duties at buses in the SCE bulk transmission system, the study calculated the maximum symmetrical three-phase-to-ground and single-phase-to-ground short circuit duties at the most critical 230-kV and 500-kV buses.

The study used a 2004 heavy summer scenario with all generators in service. Bus locations where changes in symmetrical three-phase-to-ground and single-phase-to-ground duties are identified for further review in the Facilities Study if the fault duty contribution attributed to the proposed Allegheny Power project is greater than 0.1 KA and the duty is in excess of 60% minimum breaker nameplate rating at that location.

The study also considered the following major transmission upgrades based on the current plans for the projects identified in the CAISO Controlled Transmission 2000-2005 Assessment:

- Rainbow-Valley 500kV project
- Mira Loma #4 AA-Bank (proposed for 2003)

In addition, market generation projects in queue ahead of the proposed Allegheny Power project were added to the short-circuit duty study regardless of their proposed on-line date.

STUDY RESULTS

A. Load Flow Study

1) Base Case

With the addition of the Allegheny Power project, the study identified that the PaloVerde-Devers 500-kV and PaloVerde-North Gila 500-kV transmission lines load in excess of their respective normal rating as limited by the series capacitors and summarized in the table below.

Case	SCIT Level	Allegheny-Devers 500-kV	Palo Verde-N. Gila 500-kV
Without Allegheny (Palo Verde-Devers 500kV)	13,238 - HS 12,458 - SP	97% 83%	99% 84%
With Allegheny Displacing Palo Verde Area Generation	13,242 - HS 12,458 - SP	107% 95%	96% 80%
With Allegheny Displacing Navajo Area Generation	13,201 - HS 12,470 - SP	118% 104%	104% 87%
With Allegheny Displacing Mohave Area Generation	13,245 - HS 12,427 - SP	126% 110%	110% 92%
With Allegheny Displacing Arizona Generation (Scaled)	13,241 - HS 12,470 - SP	112% 104%	100% 87%

SCIT levels were maintained at the at the year 2000 maximum of approximately 13,200 MW as indicated in SCE's 2001-2005 CAISO Assessment. In the original study, the CAISO commented that SCIT should be maintained to the maximum allowable SCIT level as defined by the SCIT nomogram and requested studies to be reevaluated with SCIT limits maintained at approximately 13,200 MW. These base cases should serve to satisfy this request.

As can be seen, all four scenarios resulted in loading the Allegheny-Devers 500-kV transmission line in excess of the normal rating as limited by the series capacitors. The worst overload, 126%, was observed when the Allegheny project displaces generation in the SCE Mohave area. Displacing generation in the Palo Verde area results in a lower overload of 107% while displacing generation in the Navajo area results in an overload of 118%.

Three of the four scenarios resulted in loading the Palo Verde-North Gila 500-kV transmission line in excess of the normal rating under heavy summer conditions as limited by the series capacitor. Since the series capacitor is bypassed in all cases, the overloads identified impacting the series capacitor do not exist in this case.

It is unclear which generation displacement will occur during real operation of the project. For this reason, the fourth case was developed which spread the generation reduction throughout the Arizona area. This case resulted in loading the Allegheny-Devers 500-kV transmission line up to 112% with the addition of the Allegheny Power project.

Power Flow Plots 1a-HS, 1b-HS, 1c-HS, 1d-HS and 1e-HS in Appendix A illustrate the Heavy Summer power flow base cases without the proposed project and all four generation displacement scenarios studied with the addition of the proposed project.

Power Flow Plots 1a-LS, 1b-LS, 1c-LS, 1d-LS and 1e-LS in Appendix A illustrate the Light Spring power flow base cases without the proposed project and all four generation displacement scenarios studied with the addition of the proposed project

Reduction of the project size does not result in eliminating the overload since the starting base case loading is already at maximum. Congestion management may be used as a means to mitigate the base case overloads identified. Generation scheduled within SCIT can be re-dispatched from EOR/WOR to Midway-Vincent. This will maintain the SCIT level at 13,200 MW while reducing the loading on the Allegheny-Devers and Palo Verde-North Gila 500-kV transmission lines.

2) <u>Single Contingencies</u>

The study focused primarily on identifying overloads on the Arizona-California Tie-lines and transmission line overloads within the SCE service territory. The study did not address the power flow impacts of the project on the neighboring utilities with the exception of the Palo Verde-North Gila 500-kV line. A review of all 500-kV single line outage conditions possible in Arizona identified that the worst loadings on the Arizona to California transmission lines are seen under outage of the Allegheny-Devers or PaloVerde-North Gila 500-kV lines. Upgrades or mitigation measures required to mitigate overloads seen under these two contingencies should also solve the overloads seen under all other system single contingency conditions.

Transmission Line Outage	**Palo Verde-N. Gila 500-kV**	**Allegheny-Devers 500-kV**
Transmission Line Overload	**Allegheny-Devers 500-kV**	**Palo Verde-N. Gila 500-kV**
Without Allegheny (Palo Verde-Devers 500kV)	130% (HS) 105% (LS)	137% (HS) 126% (LS)
With Allegheny Displacing Palo Verde Area Generation	140% (HS) 115% (LS)	137% (HS) 126% (LS)
With Allegheny Displacing Navajo Area Generation	154% (HS) 134% (LS)	149% (HS) 126% (LS)
With Allegheny Displacing Mohave Area Generation	165% (HS) 122% (LS)	162% (HS) 127% (LS)
With Allegheny Displacing Arizona Generation (Scaled)	146% (HS) 122% (LS)	142% (HS) 116% (LS)

Power Flow Plots 2a-HS, 2b-HS, 2c-HS, 2d-HS and 2e-HS in Appendix A illustrate the Heavy Summer power flow following single contingency of the Palo Verde-North Gila 500-kV transmission line for cases without the proposed project and all four generation displacement scenarios studied with the addition of the proposed project

Power Flow Plots 3a-HS, 3b-HS, 3c-HS, 3d-HS and 3e-HS in Appendix A illustrate the Heavy Summer power flow following single contingency of the Allegheny-Devers 500kV transmission line for cases without the proposed project and all four generation displacement scenarios studied with the addition of the proposed project

Power Flow Plots 2a-LS, 2b-LS, 2c-LS, 2d-LS and 2e-LS in Appendix A illustrate the Light Spring power flow following single contingency of the Palo Verde-North Gila 500-kV transmission line for cases without the proposed project and all four generation displacement scenarios studied with the addition of the proposed project

Power Flow Plots 3a-LS, 3b-LS, 3c-LS, 3d-LS and 3e-LS in Appendix A illustrate the Light Spring power flow following single contingency of the Allegheny-Devers 500kV transmission line for cases without the proposed project and all four generation displacement scenarios studied with the addition of the proposed project

No likely double contingency overloads where identified with the addition of the proposed project.

B. Transient Stability Study

The results of the stability studies are summarized in Tables 3-1 and 3-2. Simultaneous outage of the Lugo-Mira Loma No. 1 & 2 500-kV transmission lines results in violation of the WSCC first swing voltage criteria under Heavy Summer conditions. It was found that the first swing is in excess of 40%, which exceeds the maximum 30% WSCC criteria. This condition has been identified as a new problem in the 2002-2006 CAISO Annual Assessment and will be addressed as part of the CAISO Annual Planning Assessment.

With the addition of the Allegheny project, the voltage swings are not aggravated and therefore the revised Allegheny project does not adversely impact system stability.

C. Post Transient Voltage Study

The steady state load flow study was used as an initial screening method for voltage deviation violations. Post transient voltage study identified no criteria violations. The percent voltage change did not exceed 5% for N-1 and 10% for N-2. The proposed Allegheny Power project does not adversely affect post transient voltage.

D. Short Circuit Duty Study

The results of the maximum symmetrical three-phase-to-ground short circuit duties for the original Allegheny (1290 MW) and revised Allegheny (1260 MW) request at the critical buses in the SCE transmission system are summarized in Table 5-1 and Table 5-2. Single-phase-to-ground short-circuit duties will be provided in the completed Facilities Study report.

The study results indicate that the original Allegheny Power project increases short-circuit duties at four 500-kV, eleven 230-kV and three 115-kV SCE substation locations by more than 0.1 KA where the duty is at least 60% of the breaker's rating. In addition, changes to the machine data parameters resulted in an additional increase of short-circuit duty at one of the four 500-kV substation locations impacted by the original project request. The following summarizes the impacts associated with the proposed Allegheny Power project on short-circuit duties:

a). At the Allegheny 500-kV substation bus, the short circuit duty was found to be 20.6 kA for the original request. The revised request was found to have a duty of 20.9 kA prior to the revision (reflects additional projects in queue added between the original request and the revised request) and 21.3 kA after the revision indicating an increase of 0.4 kA.

b). Breakers at the four 500-kV, eleven 230-kV, and three 115-kV substation locations, which are listed in Table 5-1, will be reviewed by Engineering to determine need for breaker replacement as a result of the original project request. Criteria used to determine need for breaker review focused on an increase in duty greater than 0.1 KA and the breaker duty exceeding 60% of the KA rating

c). Breakers at one 500-kV substation locations, which is listed in Table 5-2, will be reviewed by Engineering to determine need for breaker replacement as a result of the revised project request.

CONCLUSIONS

Studies identified that the existing facilities are inadequate to accommodate the Allegheny Power project. The Allegheny-Devers and Palo Verde-North Gila 500-kV transmission lines are loaded in excess of their respective nameplate rating as limited by series capacitors. Congestion may be used as a means to manage the base case overloads shown below. Generation scheduled within SCIT can be re-dispatched from EOR/WOR to Midway-Vincent. This will maintain the SCIT level at 13,200 MW while reducing the loading on the Allegheny-Devers and Palo Verde-North Gila 500-kV transmission lines. The Allegheny Power project will be required to schedule according to the SCIT nomogram and will have an adverse effect on the amount of existing EOR and WOR generation that can be schedule for import.

Case	SCIT Level	Allegheny-Devers 500-kV	Palo Verde-N. Gila 500-kV
Without Allegheny (Palo Verde-Devers 500kV)	13,238 - HS 12,458 - LS	97% 83%	99% 84%
With Allegheny Displacing Palo Verde Area Generation	13,242 - HS 12,458 - LS	107% 95%	96% 80%
With Allegheny Displacing Navajo Area Generation	13,201 - HS 12,470 - LS	118% 104%	104% 87%
With Allegheny Displacing Mohave Area Generation	13,245 - HS 12,427 - LS	126% 110%	110% 92%
With Allegheny Displacing Arizona Generation (Scaled)	13,241 - HS 12,470 - LS	112% 104%	100% 87%

In addition to the base case overloads, the Allegheny Power project increases the loading on both of these transmission lines under single contingency conditions as shown below.

Transmission Line Outage	**Palo Verde-N. Gila 500-kV**	**Allegheny-Devers 500-kV**
Transmission Line Overload	**Allegheny-Devers 500-kV**	**Palo Verde-N. Gila 500-kV**
Without Allegheny (Palo Verde-Devers 500kV)	130% (HS) 105% (LS)	137% (HS) 126% (LS)
With Allegheny Displacing Palo Verde Area Generation	140% (HS) 115% (LS)	137% (HS) 126% (LS)
With Allegheny Displacing Navajo Area Generation	154% (HS) 134% (LS)	149% (HS) 126% (LS)
With Allegheny Displacing Mohave Area Generation	165% (HS) 122% (LS)	162% (HS) 127% (LS)
With Allegheny Displacing Arizona Generation (Scaled)	146% (HS) 122% (LS)	142% (HS) 116% (LS)

A Facilities Study will be required to determine the facilities and upgrades required to interconnect the proposed Allegheny Power 1260 MW project. The study should:

1. Determine and develop cost for 500-kV upgrades required to mitigate all base case overloads identified.

2. Review circuit breakers at the four 500-kV, eleven 230-kV, and three 115-kV substation locations to determine need for breaker replacement and cost allocation as a result of the original Allegheny request.

3. Review circuit breakers at one 500-kV substation location to determine need for breaker replacement and cost allocation as a result of the revised Allegheny request.

4. Perform Single-phase-to-ground short-circuit duty analysis.

5. Determine and develop cost for facilities required to interconnect the proposed project by looping in the Devers-Palo Verde 500-kV transmission line: switchyard facilities, circuit breakers, relay protection, and metering.

6. Reevaluate single and double contingency cases to determine congestion requirements and need for remedial action schemes assuming upgrades in place to mitigate base case overloads.

7. Determine and develop the cost for the 500-kV and 230-kV upgrades necessary to mitigate remaining bulk contingency overloads.

8. Reevaluate short-circuit duty to account for the impacts resulting from system upgrades required to mitigate base case overloads.

9. Determine new operating procedures or modify existing operating procedures for this project. The facility study should address the scope of the procedures that may be needed, however, actual operating procedures and studies to support those procedures will not be developed until the Interconnection Facility Agreement (IFA) is executed.

TABLES

TABLE 1-1

2001-2005 HEAVY SUMMER LOAD FORECAST

TRANSMISSION SUBSTATION	2001	2002	2003	2004	2005
ALAMITOS	173	175	175	176	175
AMERON	58	58	58	58	58
ANTELOPE	471	489	499	510	518
BAILEY	63	63	63	62	62
BARRE	697	710	720	732	738
BLYTHE	51	51	51	51	50
CAMINO	1	1	1	1	1
CENTER	478	470	469	470	467
CHEVMAIN	100	100	100	100	100
CHINO	596	618	634	651	664
CIMA	1	1	1	1	1
DEL AMO	512	515	516	519	518
DEVERS / MIRAGE	770	801	822	844	861
EAGLE MT.	2	2	2	2	2
EAGLE ROCK	216	219	219	220	219
ELLIS	623	634	642	651	656
EL NIDO	317	311	313	317	318
ETIWANDA	374	373	381	388	393
GOLETA	274	280	282	284	285
GOULD	115	117	117	118	118
HINSON	363	354	354	355	354
JOHANNA	432	429	433	438	441
KRAMER	244	248	251	254	257
LA CIENEGA	463	464	471	480	485
LA FRESA	567	562	563	566	564
LAGUNA BELL	564	561	565	569	570
LEWIS	626	641	647	657	661
LIGHTHIPE	491	484	485	486	485
MESA	616	624	625	627	626
MIRA LOMA	469	485	498	512	522
MOORPARK	747	766	781	798	809
OLINDA	372	377	377	378	377
PADUA	649	678	698	718	734
RECTOR	560	581	595	609	619
RIO HONDO	675	683	696	710	719
SAN BERDO	453	468	483	499	511
SANTA CLARA	466	479	486	493	497
SANTIAGO	896	929	955	982	1003
SAUGUS	606	623	632	642	647
SPRINGVILLE	165	169	170	172	172
VALLEY	1008	998	1026	1055	1078
VESTAL	140	144	145	147	148
VICTOR	448	456	463	473	481
VILLA PARK	726	739	748	759	764
VISTA 66KV	717	733	745	759	767
VISTA 115KV	398	405	412	419	424
WALNUT	666	679	690	701	708
TOTALS	20,419	20,747	21,059	21,413	21,627

TABLE 1-2

2001-2005 LIGHT SPRING LOAD FORECAST

TRANSMISSION SUBSTATION	2001	2002	2003	2004	2005
ALAMITOS	112	114	114	114	114
AMERON	58	58	58	58	58
ANTELOPE	306	318	324	332	337
BAILEY	41	41	41	40	40
BARRE	453	462	468	476	480
BLYTHE	33	33	33	33	33
CAMINO	1	1	1	1	1
CENTER	311	306	305	306	304
CHEVMAIN	100	100	100	100	100
CHINO	387	402	412	423	432
CIMA	1	1	1	1	1
DEL AMO	333	335	335	337	337
DEVERS / MIRAGE	501	521	534	549	560
EAGLE MT.	1	1	1	1	1
EAGLE ROCK	140	142	142	143	142
ELLIS	405	412	417	423	426
EL NIDO	206	202	203	206	207
ETIWANDA	243	242	248	252	255
GOLETA	178	182	183	185	185
GOULD	75	76	76	77	77
HINSON	236	230	230	231	230
JOHANNA	281	279	281	285	287
KRAMER	159	161	163	165	167
LA CIENEGA	301	302	306	312	315
LA FRESA	369	365	366	368	367
LAGUNA BELL	367	365	367	370	371
LEWIS	407	417	421	427	430
LIGHTHIPE	319	315	315	316	315
MESA	400	406	406	408	407
MIRA LOMA	305	315	324	333	339
MOORPARK	486	498	508	519	526
OLINDA	242	245	245	246	245
PADUA	422	441	454	467	477
RECTOR	364	378	387	396	402
RIO HONDO	439	444	452	462	467
SAN BERDO	294	304	314	324	332
SANTA CLARA	303	311	316	320	323
SANTIAGO	582	604	621	638	652
SAUGUS	394	405	411	417	421
SPRINGVILLE	107	110	111	112	112
VALLEY	655	649	667	686	701
VESTAL	91	94	94	96	96
VICTOR	291	296	301	307	313
VILLA PARK	472	480	486	493	497
VISTA 66KV	466	476	484	493	499
VISTA 115KV	259	263	268	272	276
WALNUT	433	441	449	456	460
TOTALS	13,328	13,541	13,744	13,974	14,113

TABLE 2
ALLEGHENY POWER PROJECT

2004 HEAVY SUMMER & 2005 HEAVY SPRING POWER FLOW STUDY RESULTS

BASE CASE

Case	SCIT Level	Allegheny-Devers 500-kV	Palo Verde-N. Gila 500-kV
Without Allegheny (Palo Verde-Devers 500kV)	13,238 - HS 12,458 – SP	97% 83%	99% 84%
With Allegheny Displacing Palo Verde Area Generation	13,242 - HS 12,458 – SP	107% 95%	96% 80%
With Allegheny Displacing Navajo Area Generation	13,201 - HS 12,470 – SP	118% 104%	104% 87%
With Allegheny Displacing Mohave Area Generation	13,245 - HS 12,427 – SP	126% 110%	110% 92%
With Allegheny Displacing Arizona Generation (Scaled)	13,241 - HS 12,470 - SP	112% 104%	100% 87%

TABLE 2
ALLEGHENY POWER PROJECT
2004 HEAVY SUMMER & 2005 HEAVY SPRING
POWER FLOW STUDY RESULTS

SINGLE CONTINGENCY

Transmission Line Outage	**Palo Verde-N. Gila 500-kV**	**Allegheny-Devers 500-kV**
Transmission Line Overload	**Allegheny-Devers 500-kV**	**Palo Verde-N. Gila 500-kV**
Without Allegheny (Palo Verde-Devers 500kV)	130% (HS) 105% (SP)	137% (HS) 126% (SP)
With Allegheny Displacing Palo Verde Area Generation	140% (HS) 115% (SP)	137% (HS) 126% (SP)
With Allegheny Displacing Navajo Area Generation	154% (HS) 134% (SP)	149% (HS) 126% (SP)
With Allegheny Displacing Mohave Area Generation	165% (HS) 122% (SP)	162% (HS) 127% (SP)
With Allegheny Displacing Arizona Generation (Scaled)	146% (HS) 122% (SP)	142% (HS) 116% (SP)

TABLE 3-1
ALLEGHENY POWER PROJECT

2004 HEAVY SUMMER
SYSTEM TRANSIENT STABILITY STUDY RESULTS

CASE	FAULT LOCATION	FAULT TYPE	DURATION	CONTINGENCY	PRE PROJECT	DISPLACE PALOVERDE	DISPLACE NAVAJO	DISPLACE MOHAVE	DISPLACE ARIZONA
1	Devers 500-kV	3-Phase	4-Cycle	Devers-Valley 500-kV	Stable	Stable	Stable	Stable	Stable
2	Lugo 500-kV	3-Phase	4-Cycle	Lugo-Mohave No.1 500-kV	Stable	Stable	Stable	Stable	Stable
3	Lugo 500-kV	3-Phase	4-Cycle	Lugo-El Dorado 500-kV	Stable	Stable	Stable	Stable	Stable
4	Allegheny 500-kV	3-Phase	4-Cycle	Allegheny-Devers 500-kV	Stable	Stable	Stable	Stable	Stable
5	Allegheny 500-kV	3-Phase	4-Cycle	Allegheny-Palo Verde 500-kV	Stable	Stable	Stable	Stable	Stable
6	Palo Verde 500-kV	3-Phase	4-Cycle	Palo Verde-North Gila 500-kV	Stable	Stable	Stable	Stable	Stable
7	Lugo 500-kV	3-Phase	4-Cycle	Lugo-Mira Loma No. 2 500-kV Lugo-Mira Loma No. 3 500-kV	1st Swing Violation	1st Swing Violation	1st Swing Violation	1st Swing Violation	1st Swing Violation
8	Palo Verde 500-kV	3-Phase	4-Cycle	Palo Verde-Westwing No. 1 500-kV Palo Verde-Westwing No.2 500-kV	Stable	Stable	Stable	Stable	Stable
9	Perkins 500-kV	3-Phase	4-Cycle	Palo Verde-Westwing No. 1 500-kV Palo Verde-Westwing No.2 500-kV Perkins-Meade 500-kV	Stable	Stable	Stable	Stable	Stable
10	No Fault			Palo Verde Unit 2 Palo Verde Unit 3	Stable	Stable	Stable	Stable	Stable
1-SLG	Devers 500-kV	Single-Phase-to-Ground	15-Cycle	Devers-Valley 500-kV	Stable	Stable	Stable	Stable	Stable

TABLE 3-2
ALLEGHENY POWER PROJECT

2005 HEAVY SPRING
SYSTEM TRANSIENT STABILITY STUDY RESULTS

CASE	FAULT LOCATION	FAULT TYPE	DURATION	CONTINGENCY	PRE PROJECT	DISPLACE PALOVERDE	DISPLACE NAVAJO	DISPLACE MOHAVE	DISPLACE ARIZONA
1	Devers 500-kV	3-Phase	4-Cycle	Devers-Valley 500-kV	Stable	Stable	Stable	Stable	Stable
2	Lugo 500-kV	3-Phase	4-Cycle	Lugo-Mohave No.1 500-kV	Stable	Stable	Stable	Stable	Stable
3	Lugo 500-kV	3-Phase	4-Cycle	Lugo-El Dorado 500-kV	Stable	Stable	Stable	Stable	Stable
4	Allegheny 500-kV	3-Phase	4-Cycle	Allegheny-Devers 500-kV	Stable	Stable	Stable	Stable	Stable
5	Allegheny 500-kV	3-Phase	4-Cycle	Allegheny-Palo Verde 500-kV	Stable	Stable	Stable	Stable	Stable
6	Palo Verde 500-kV	3-Phase	4-Cycle	Palo Verde-North Gila 500-kV	Stable	Stable	Stable	Stable	Stable
7	Lugo 500-kV	3-Phase	4-Cycle	Lugo-Mira Loma No. 2 500-kV Lugo-Mira Loma No. 3 500-kV	Stable	Stable	Stable	Stable	Stable
8	Palo Verde 500-kV	3-Phase	4-Cycle	Palo Verde-Westwing No. 1 500-kV Palo Verde-Westwing No.2 500-kV	Stable	Stable	Stable	Stable	Stable
9	Perkins 500-kV	3-Phase	4-Cycle	Palo Verde-Westwing No. 1 500-kV Palo Verde-Westwing No.2 500-kV Perkins-Meade 500-kV	Stable	Stable	Stable	Stable	Stable
10	No Fault			Palo Verde Unit 2 Palo Verde Unit 3	Stable	Stable	Stable	Stable	Stable
1-SLG	Devers 500-kV	Single-Phase-to-Ground	15-Cycle	Devers-Valley 500-kV	Stable	Stable	Stable	Stable	Stable

TABLE 4
ALLEGHENY POWER PROJECT

2004 HEAVY SUMMER
POST-TRANSIENT VOLTAGE STUDY RESULTS

CASE	LOCATION	CONTINGENCY	PRE PROJECT	DISPLACE PALOVERDE	DISPLACE NAVAJO	DISPLACE MOHAVE	DISPLACE ARIZONA
1	DEVERS 500-KV	Palo Verde-North Gila 500-kV	Within Limit	Within Limit	Within Limit	Within Limit	Within Limit
2	MIGUEL 500-KV	Allegheny-Devers 500-kV	Within Limit	Within Limit	Within Limit	Within Limit	Within Limit
3	VALLEY 500-KV	Serrano-Valley 500-kV	Within Limit	Within Limit	Within Limit	Within Limit	Within Limit

TABLE 5-1
SHORT-CIRCUIT DUTY
(3-PHASE)

ALLEGHENY POWER PROJECT - ORIGINAL PROJECT REQUEST (1290 MW)

SCE SUBSTATIONS	KV	Off X / R	Off KA	On X / R	On KA	INCREASE
-------500kV Stations-------						
ELDORADO	500	18.4	35.1	18.3	35.2	0.1
LUGO	500	21.1	40.6	21.1	40.7	0.1
MIRA LOMA	500	24.6	30.8	24.5	30.9	0.1
SERRANO	500	23.2	26.3	23.2	26.4	0.1
-------230kV Stations-------						
BARRE	230	17.8	48.1	17.8	48.2	0.1
CHINO	230	16.7	46.8	16.7	46.9	0.1
DEVERS	230	13.3	23.4	13.3	23.6	0.2
EL DORADO	230	17.6	48.6	17.6	48.7	0.1
ELLIS	230	17.9	41.1	17.9	41.2	0.1
ETIWANDA	230	22.6	44.2	22.6	44.3	0.1
LEWIS	230	19.5	42.5	19.5	42.6	0.1
MIRA LOMA EAST	230	24.2	62.0	24.2	62.1	0.1
MIRA LOMA WEST	230	24.2	62.0	24.2	62.1	0.1
PADUA	230	14.9	18.9	14.9	19.0	0.1
SAN BERNARDINO	230	17.3	33.4	17.3	33.5	0.1
-------115kV Stations-------						
DEVERS	115	26.6	18.0	26.8	18.1	0.1
FARRELL	115	7.6	9.3	7.6	9.4	0.1
THORNHIL	115	8.0	9.9	8.0	10.0	0.1
-----NON-SCE Stations-----						
TOLLING	230	18.5	50.7	18.4	50.8	0.1
-------Project Site-------						
ALLEGHNY	500			19.9	20.6	20.6

TABLE 5-2
SHORT-CIRCUIT DUTY
(3-PHASE)

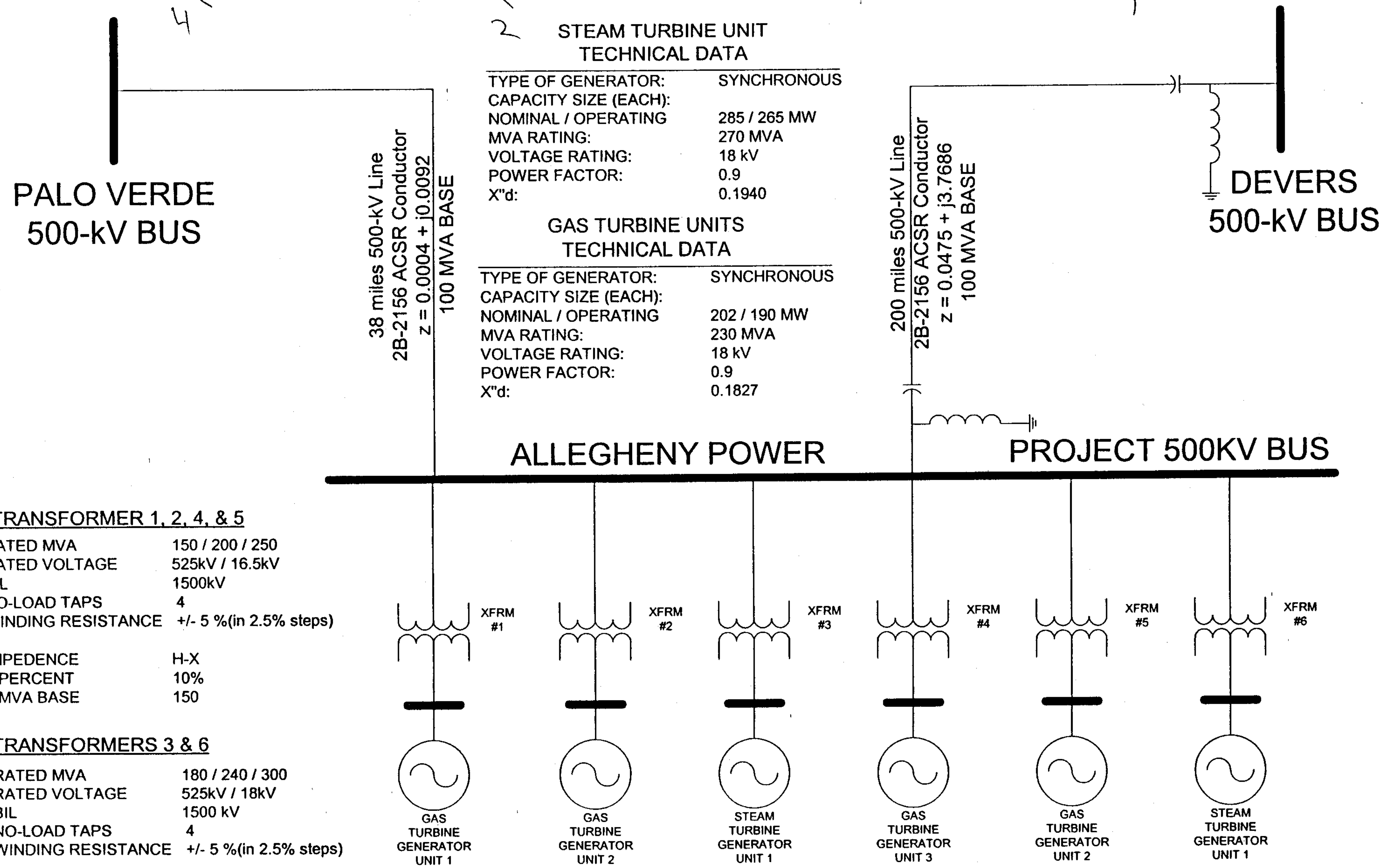
ADDITIONAL SHORT-CIRCUIT DUTY CONTRIBUTION
ALLEGHENY POWER PROJECT - REVISED PROJECT REQUEST (1260 MW)

		Off		**On**		
SCE SUBSTATIONS	KV	X / R	KA	X / R	KA	INCREASE
-------500kV Stations-------						
ELDORADO	500	18.3	35.4	18.3	35.5	0.1
-------Project Site-------						
ALLEGHNY	500	19.8	20.9	20.1	21.3	0.4

FIGURES

1600 MVa at transformers @ .8pf = 1280 Mw

FIGURE 2 - ALLEGHENY REVISED PROJECT DATA
~~THREE~~ 4 CTs AND ~~THREE~~ 2 STs FOR TOTAL OUTPUT OF 12~~6~~90 MW



STEAM TURBINE UNIT TECHNICAL DATA

TYPE OF GENERATOR:	SYNCHRONOUS
CAPACITY SIZE (EACH):	
NOMINAL / OPERATING	285 / 265 MW
MVA RATING:	270 MVA
VOLTAGE RATING:	18 kV
POWER FACTOR:	0.9
X"d:	0.1940

GAS TURBINE UNITS TECHNICAL DATA

TYPE OF GENERATOR:	SYNCHRONOUS
CAPACITY SIZE (EACH):	
NOMINAL / OPERATING	202 / 190 MW
MVA RATING:	230 MVA
VOLTAGE RATING:	18 kV
POWER FACTOR:	0.9
X"d:	0.1827

TRANSFORMER 1, 2, 4, & 5

RATED MVA	150 / 200 / 250
RATED VOLTAGE	525kV / 16.5kV
BIL	1500kV
NO-LOAD TAPS	4
WINDING RESISTANCE	+/- 5 %(in 2.5% steps)
IMPEDENCE	H-X
PERCENT	10%
MVA BASE	150

TRANSFORMERS 3 & 6

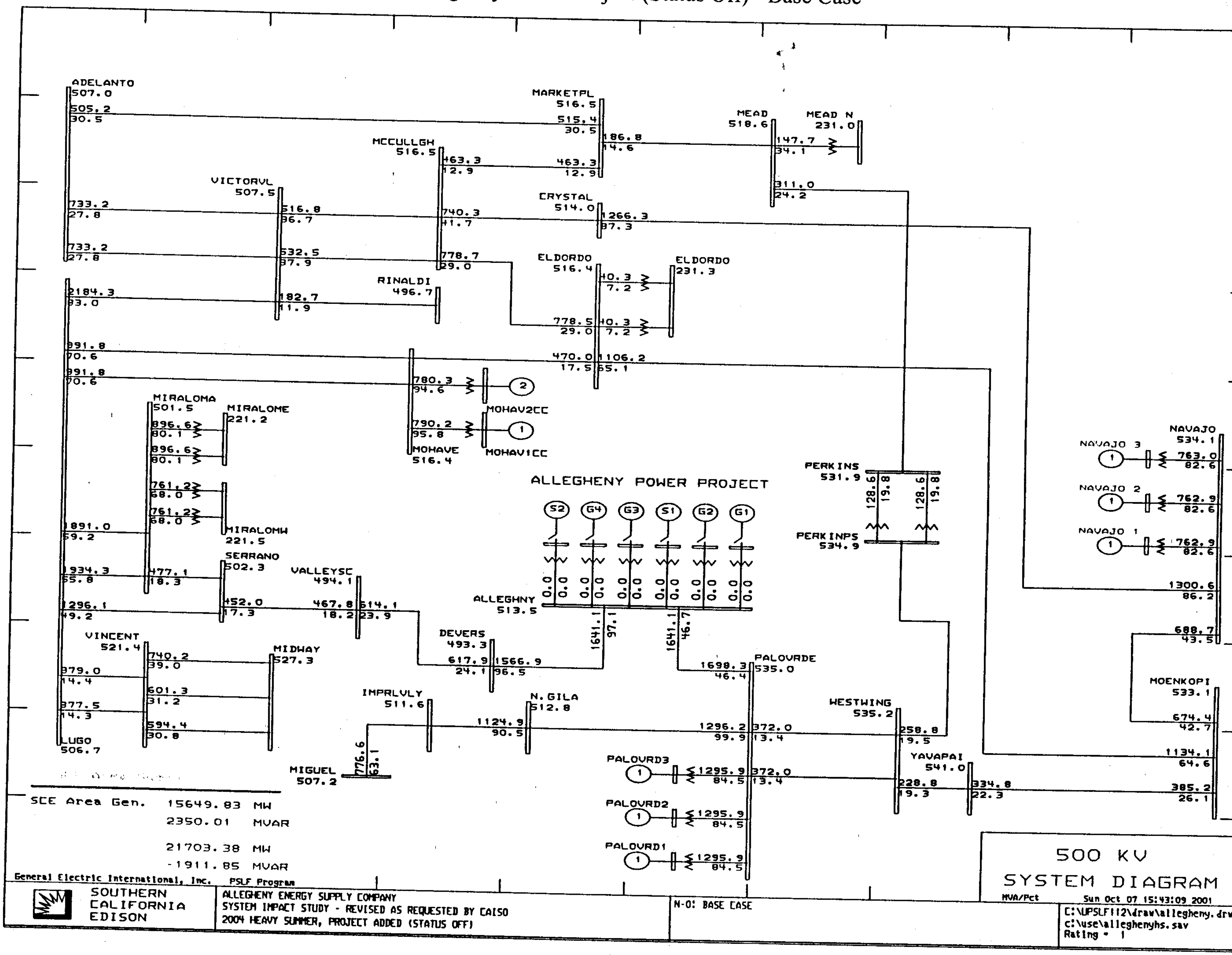
RATED MVA	180 / 240 / 300
RATED VOLTAGE	525kV / 18kV
BIL	1500 kV
NO-LOAD TAPS	4
WINDING RESISTANCE	+/- 5 %(in 2.5% steps)
IMPEDENCE	H-X
PERCENT	10%
MVA BASE	180

APPENDIX A

LOAD FLOW PLOTS

Plot Allegheny1aHS

Allegheny Power Project (Status Off) - Base Case

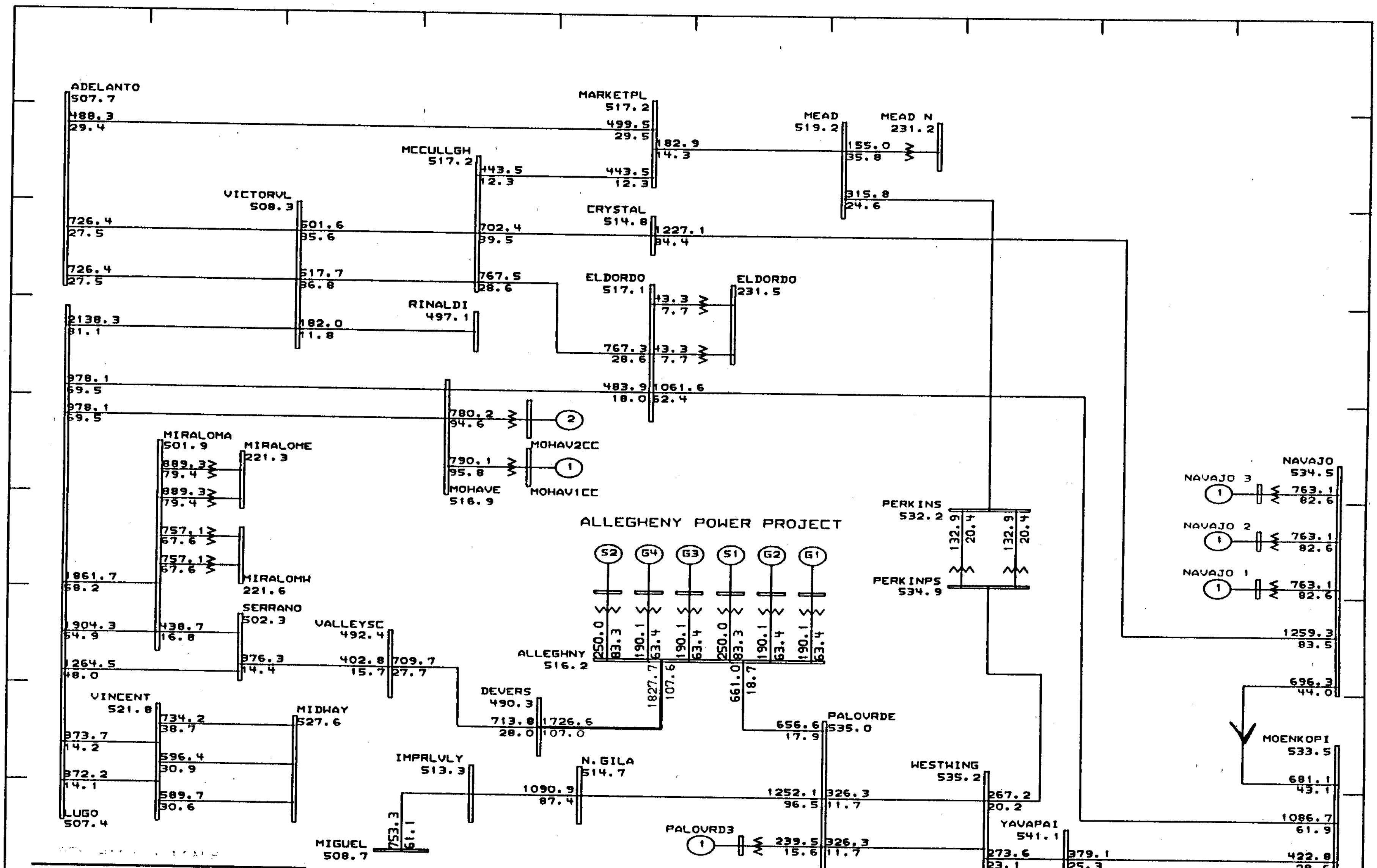


2289

Navajo = 2289
Mohave = 1570
PVerde = 3888

Plot Allegheny1bHS

Allegheny Power Project Displacing Palo Verde Area Generation - Base Case



SCE Area Gen. 16907.87 MW
2479.46 MVAR

21703.38 MW
-1911.85 MVAR

General Electric International, Inc. PSLF Program

SOUTHERN CALIFORNIA EDISON

ALLEGHENY ENERGY SUPPLY COMPANY
SYSTEM IMPACT STUDY - REVISED AS REQUESTED BY CAISO
2004 HEAVY SUMMER, PROJECT DISPLACING PALOVERDE AREA GEN

N-0: BASE CASE

500 KV
SYSTEM DIAGRAM

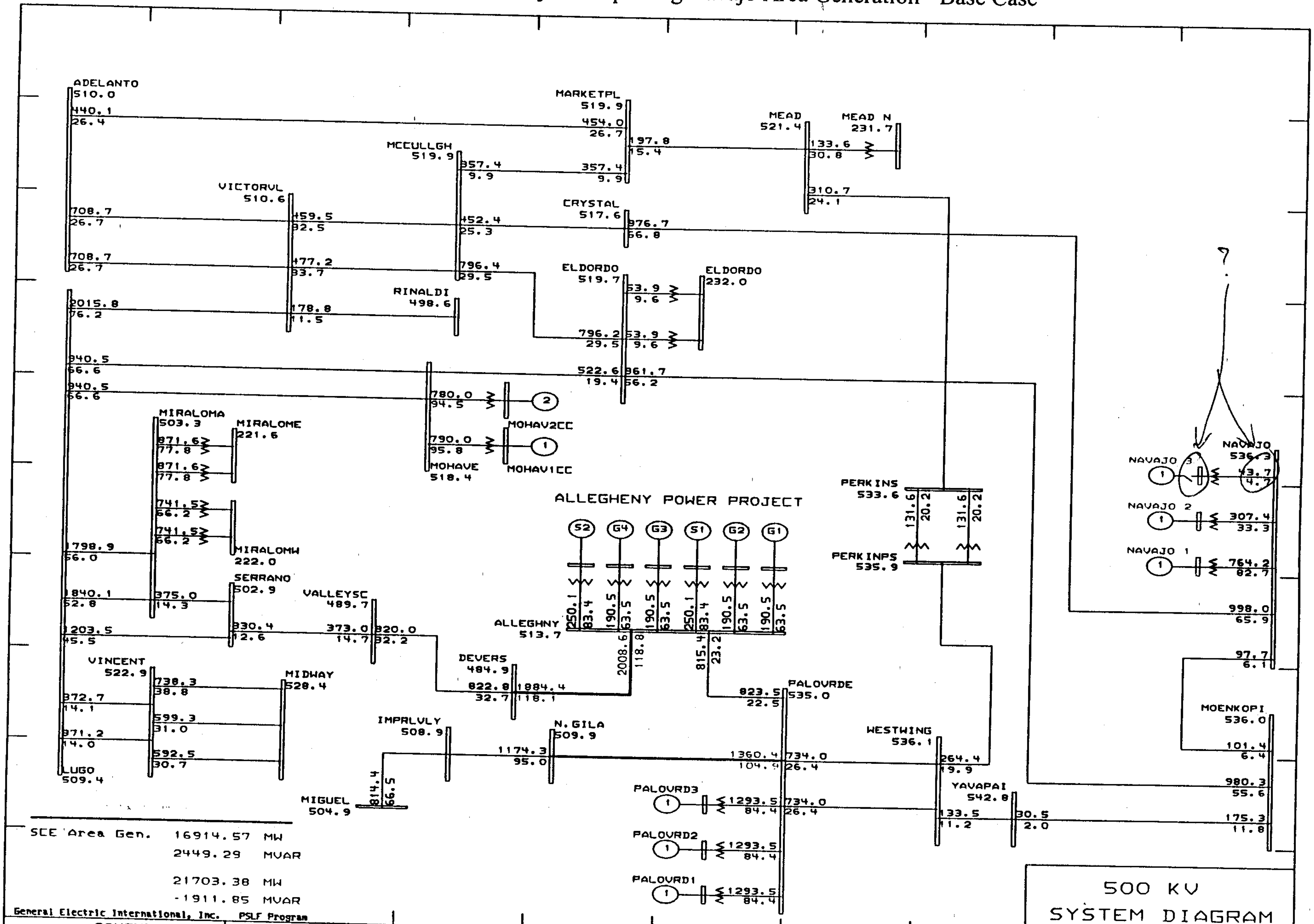
MVA/Pct

Sun Oct 07 15:47:16 2001
C:\UPSLF112\draw\allegheny.drw
c:\wse\alleghenyhs.sav
Rating = 1

Navajo ≈ 2289, Mohave = 1570, PV ≈ 2812, w/Δ of 1076 MW; Allegheny ≈ 1260

Plot Allegheny1cHS

Allegheny Power Project Displacing Navajo Area Generation - Base Case



General Electric International, Inc. PSLF Program

SOUTHERN CALIFORNIA EDISON

ALLEGHENY ENERGY SUPPLY COMPANY
SYSTEM IMPACT STUDY - REVISED AS REQUESTED BY CAISO
2004 HEAVY SUMMER, PROJECT DISPLACING NAVAJO AREA GEN

N-0: BASE CASE

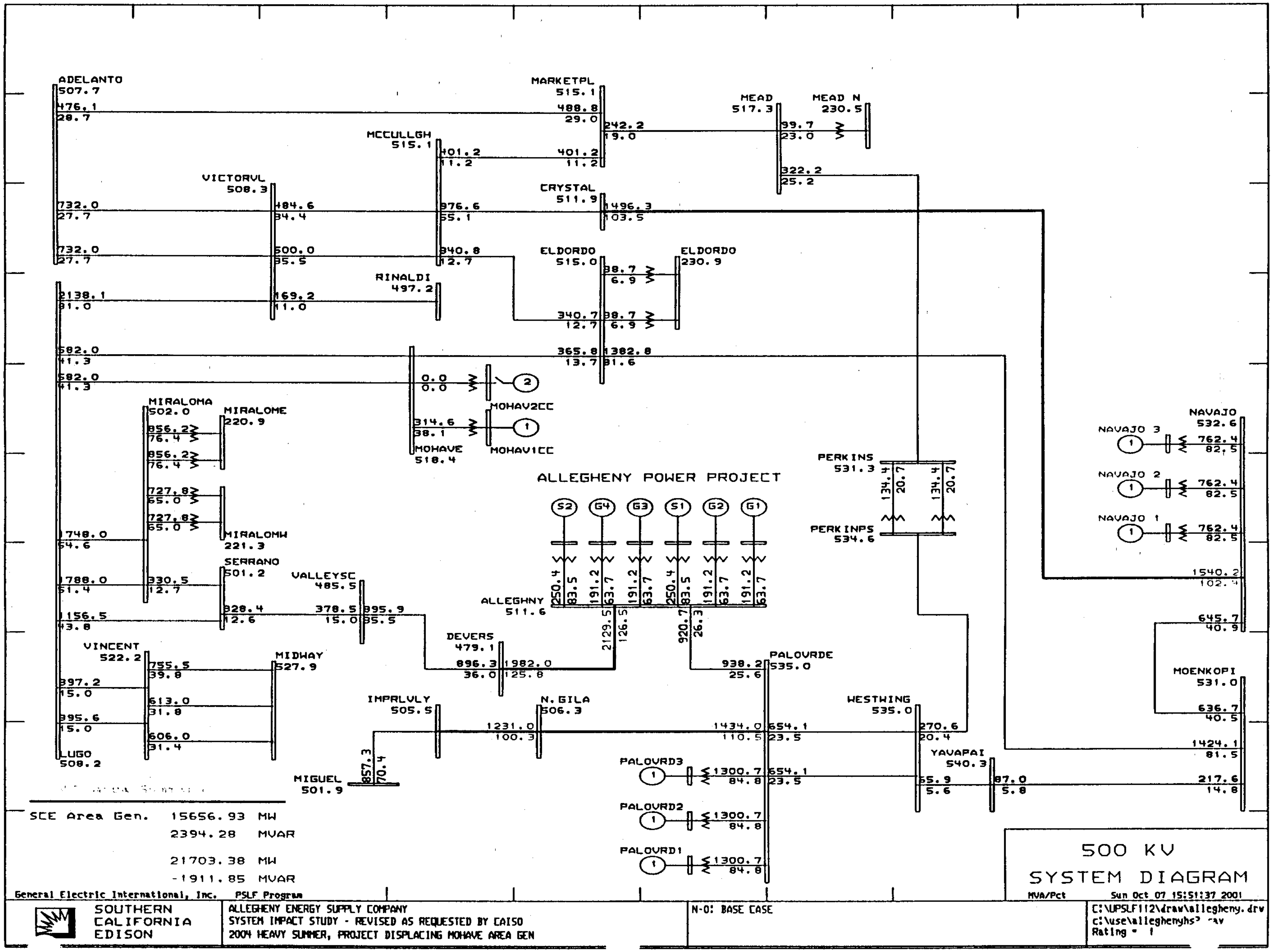
500 KV
SYSTEM DIAGRAM
MVA/Pct
Sun Oct 07 15:49:51 2001
C:\UPSLF112\draw\allegheny.drw
c:\use\alleghenyhs?.sav
Rating = 1

PV Δ = -7 MW
-1124 M

Allegheny = 1260 MW

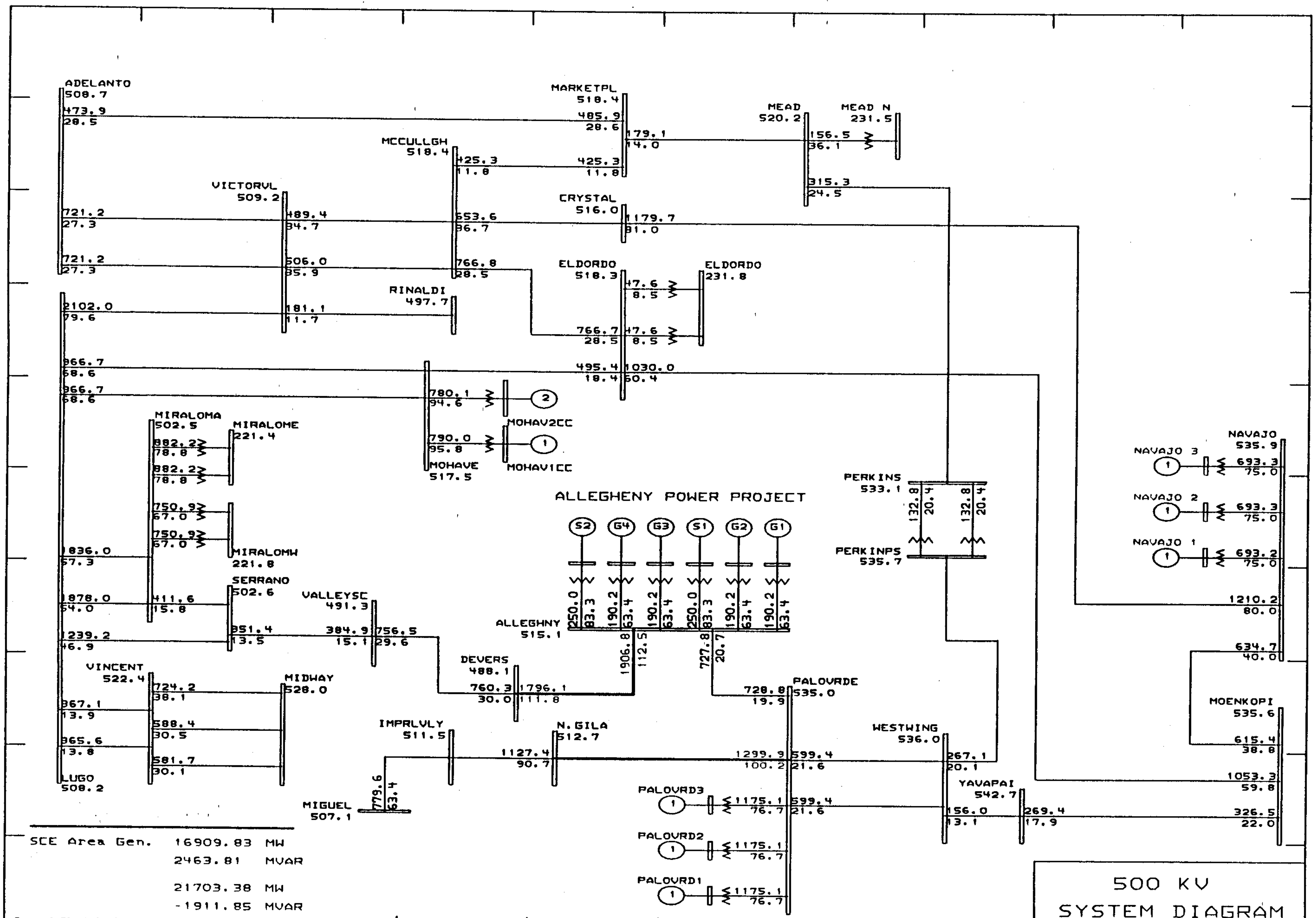
Plot Allegheny1dHS

Allegheny Power Project Displacing Mohave Area Generation - Base Case



Plot Allegheny1eHS

Allegheny Power Project Displacing Arizona Generation - Base Case



500 KV

SYSTEM DIAGRAM

MVA/Pct Sun Oct 07 15:52:08 2001

General Electric International, Inc. PSLF Program

SOUTHERN CALIFORNIA EDISON

ALLEGHENY ENERGY SUPPLY COMPANY
SYSTEM IMPACT STUDY - REVISED AS REQUESTED BY CAISO
2004 HEAVY SUMMER, PROJECT DISPLACING ARIZONA GENERATION (SCALED DO...

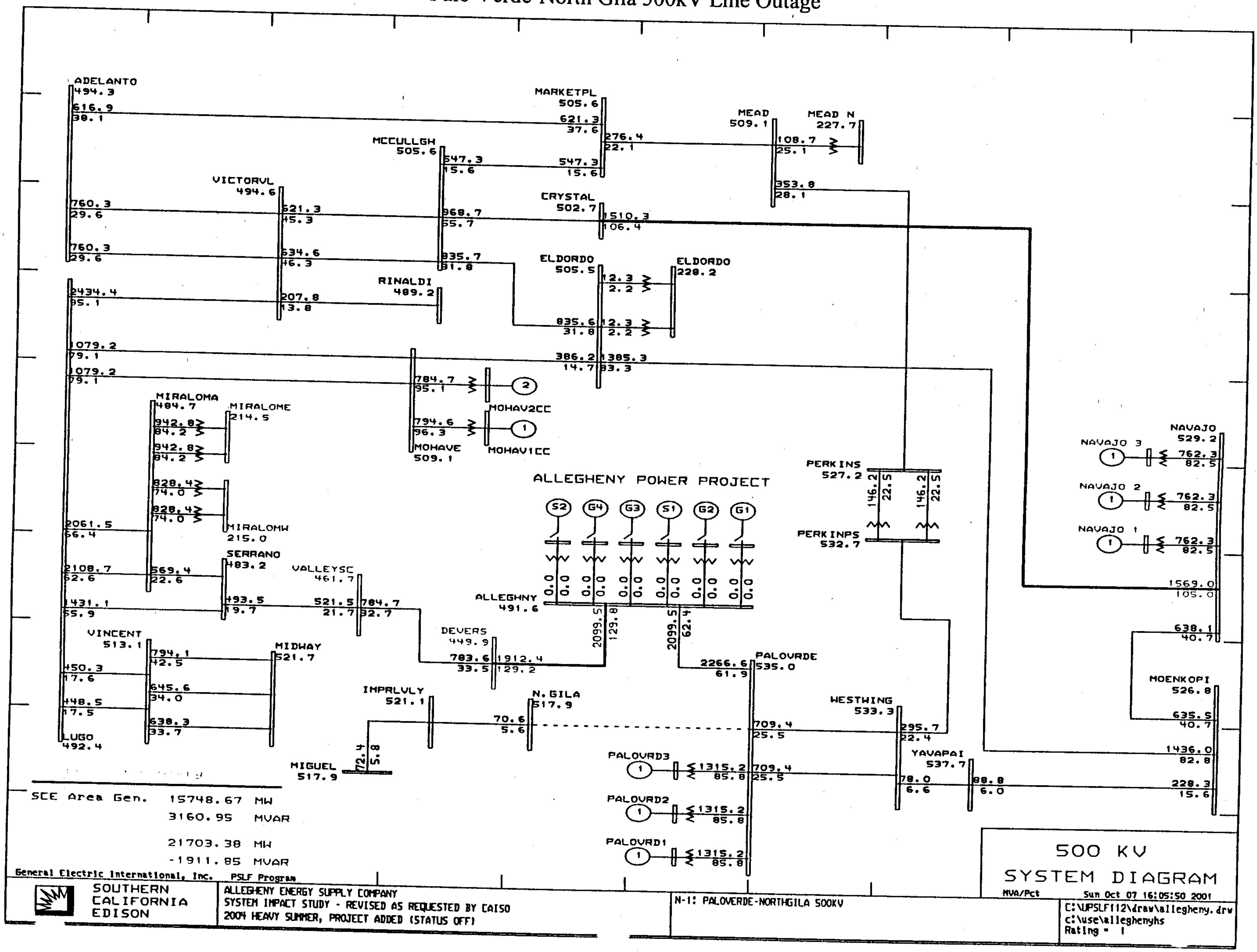
N-0: BASE CASE

C:\UPSLF112\draw\allegheny.drw
c:\use\alleghenyhs4.sav
Rating = 1

Plot Allegheny2aHS

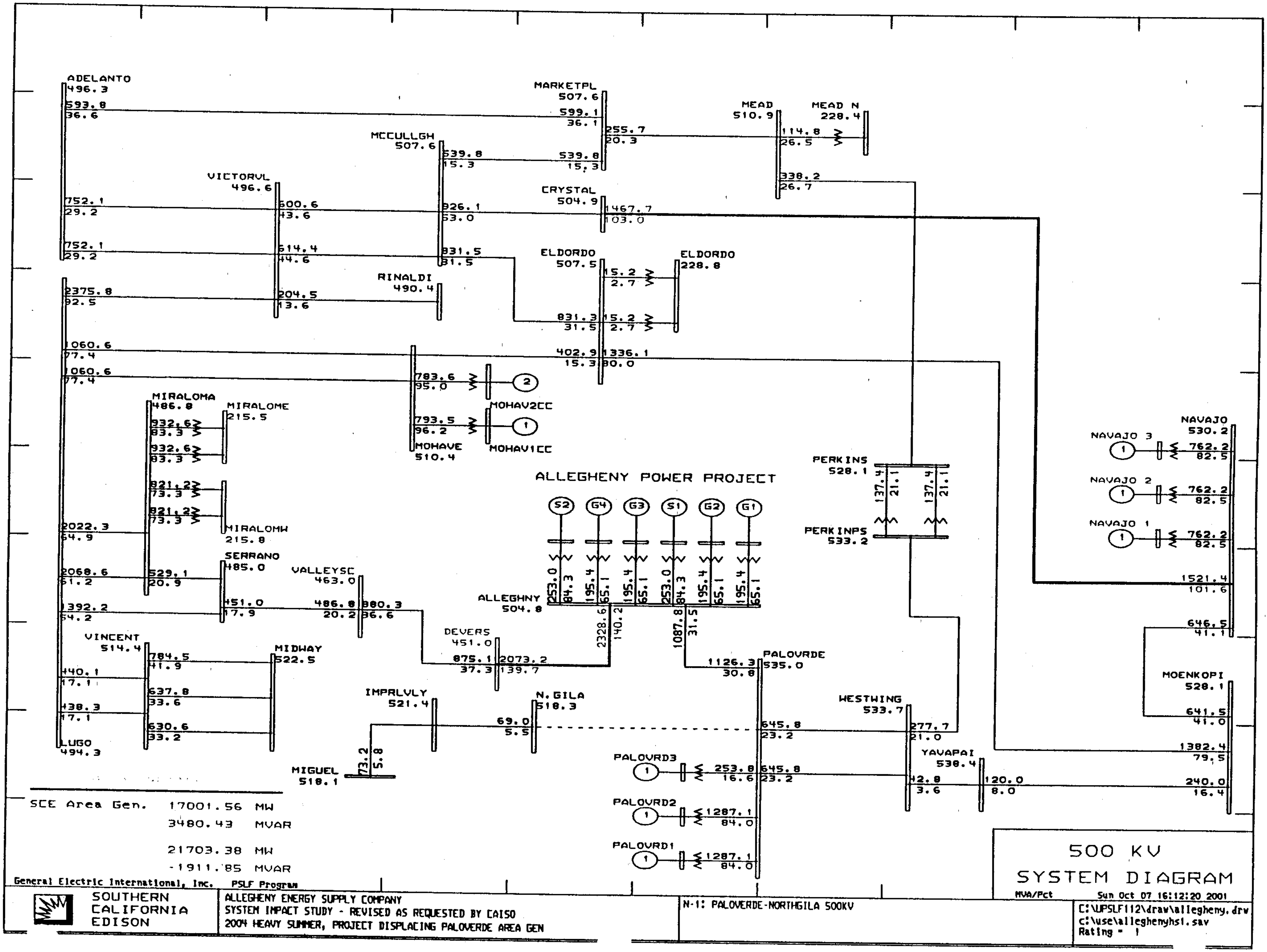
Allegheny Power Project (Status Off)

Palo Verde-North Gila 500kV Line Outage



Plot Allegheny2bHS

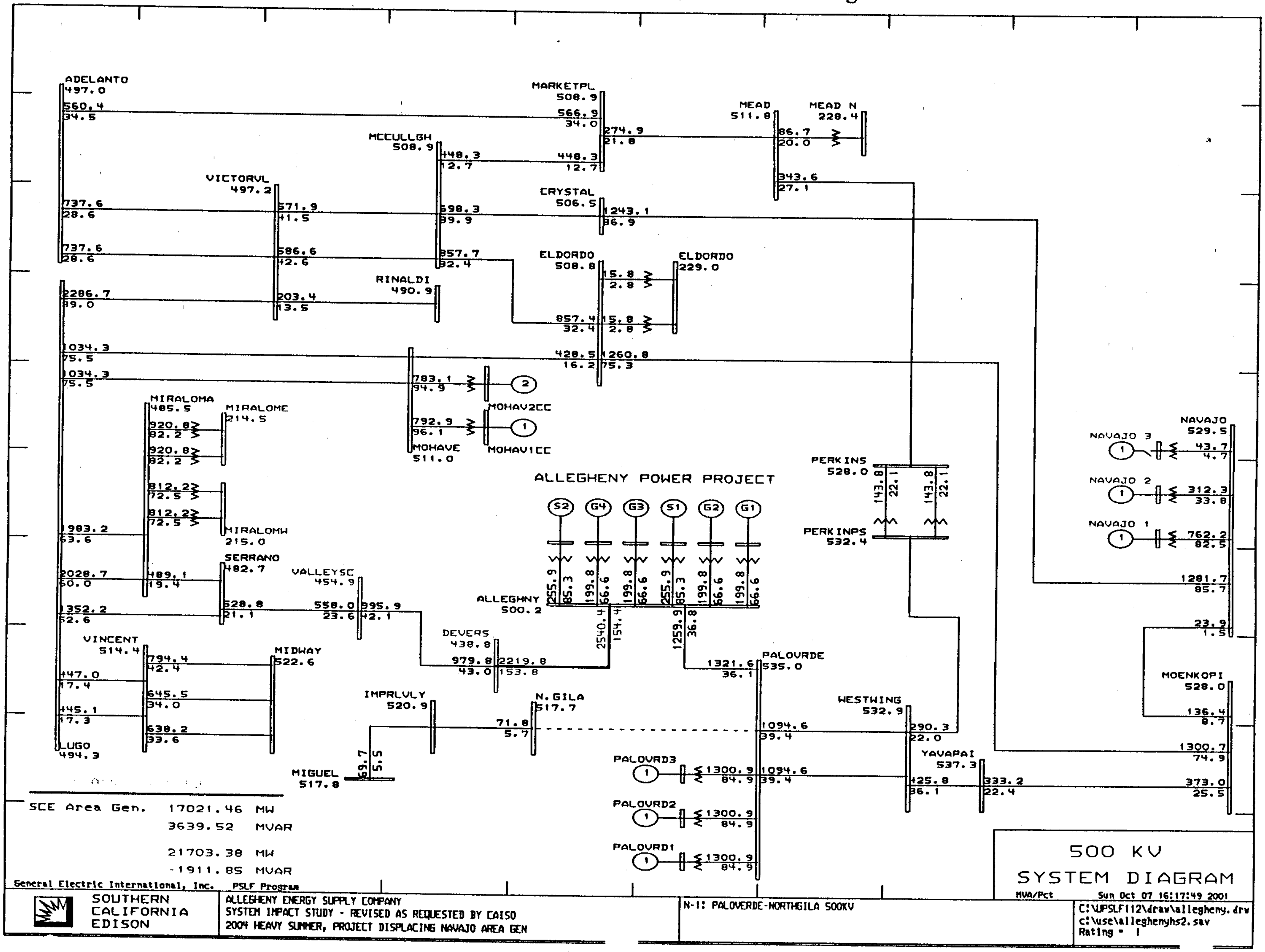
Allegheny Power Project Displacing Palo Verde Area Generation
Palo Verde-North Gila 500kV Line Outage



Plot Allegheny2cHS

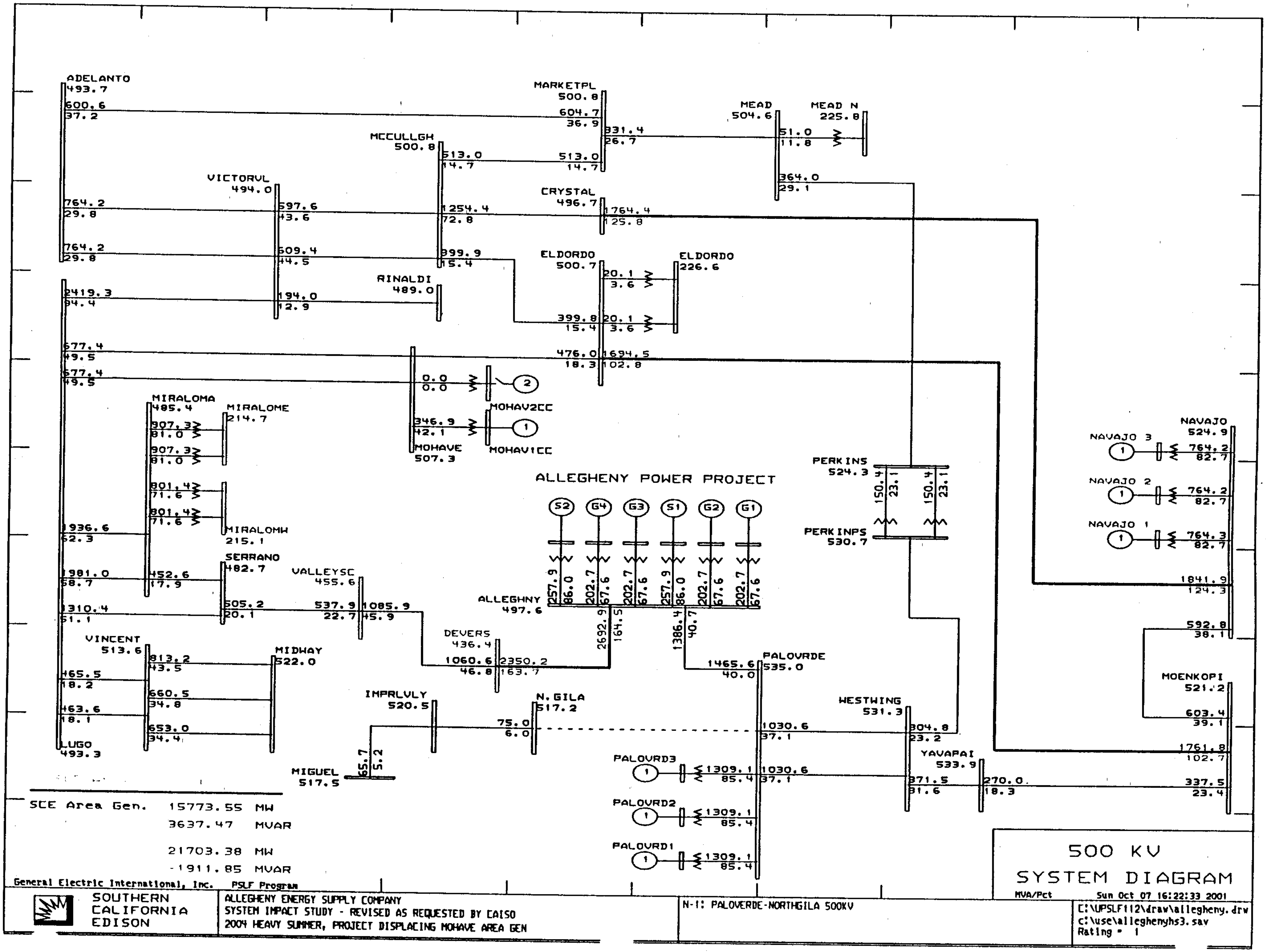
Allegheny Power Project Displacing Navajo Area Generation

Palo Verde-North Gila 500kV Line Outage



Plot Allegheny2dHS

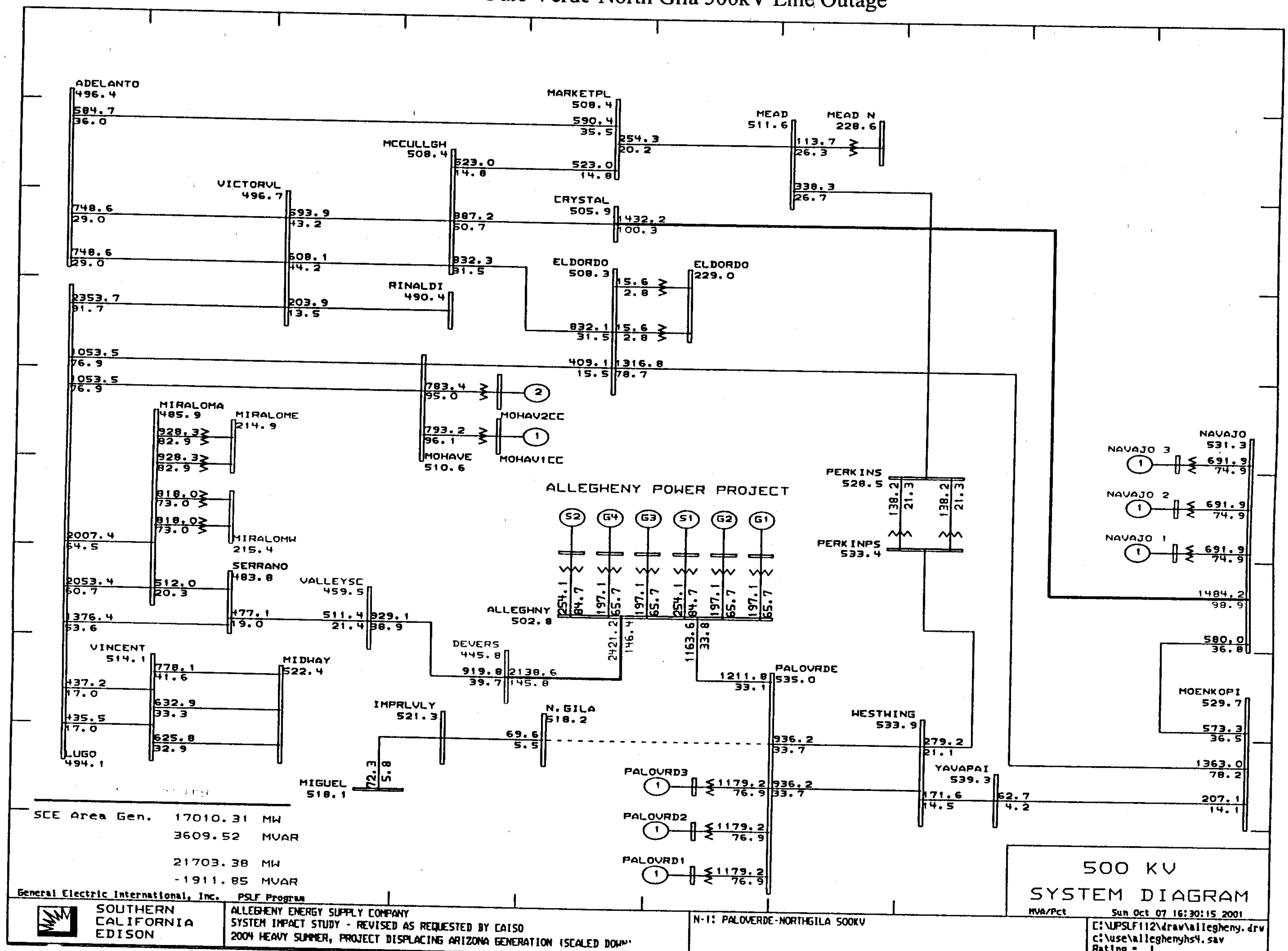
Allegheny Power Project Displacing Mohave Area Generation
Palo Verde-North Gila 500kV Line Outage



Plot Allegheny2eHS

Allegheny Power Project Displacing Arizona Generation

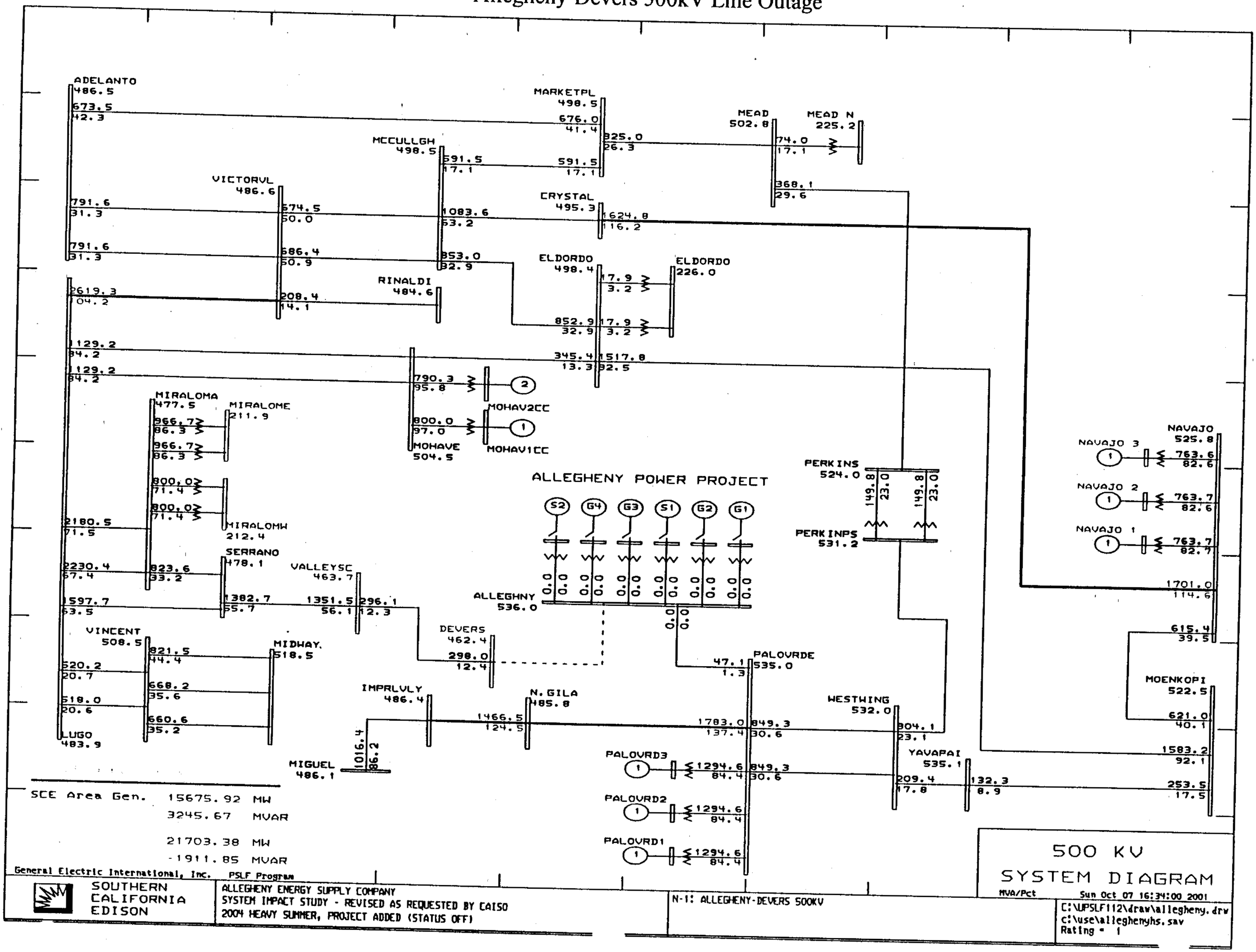
Palo Verde-North Gila 500kV Line Outage



Plot Allegheny3aHS

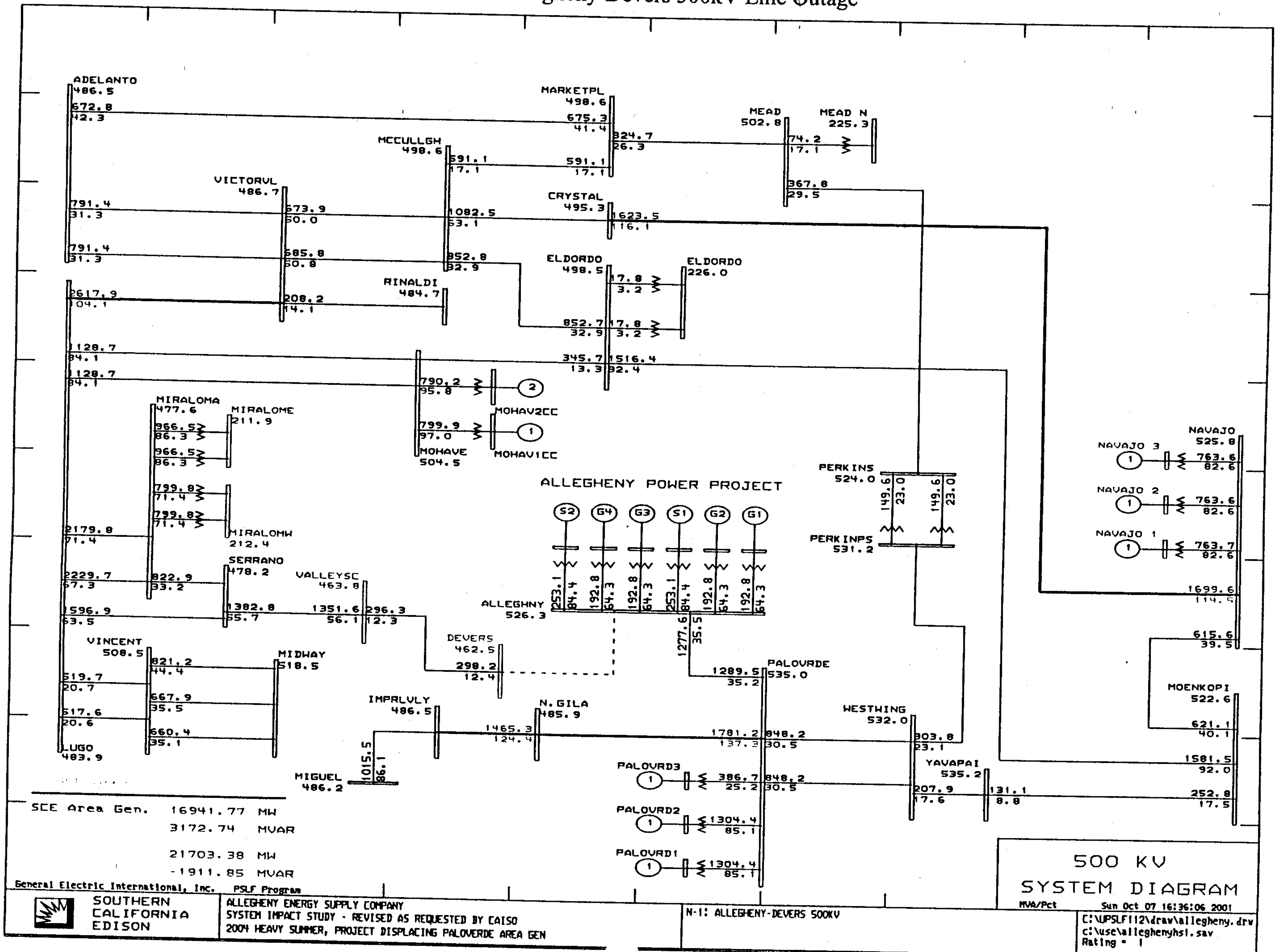
Allegheny Power Project (Status Off)

Allegheny-Devers 500kV Line Outage



Plot Allegheny3bHS

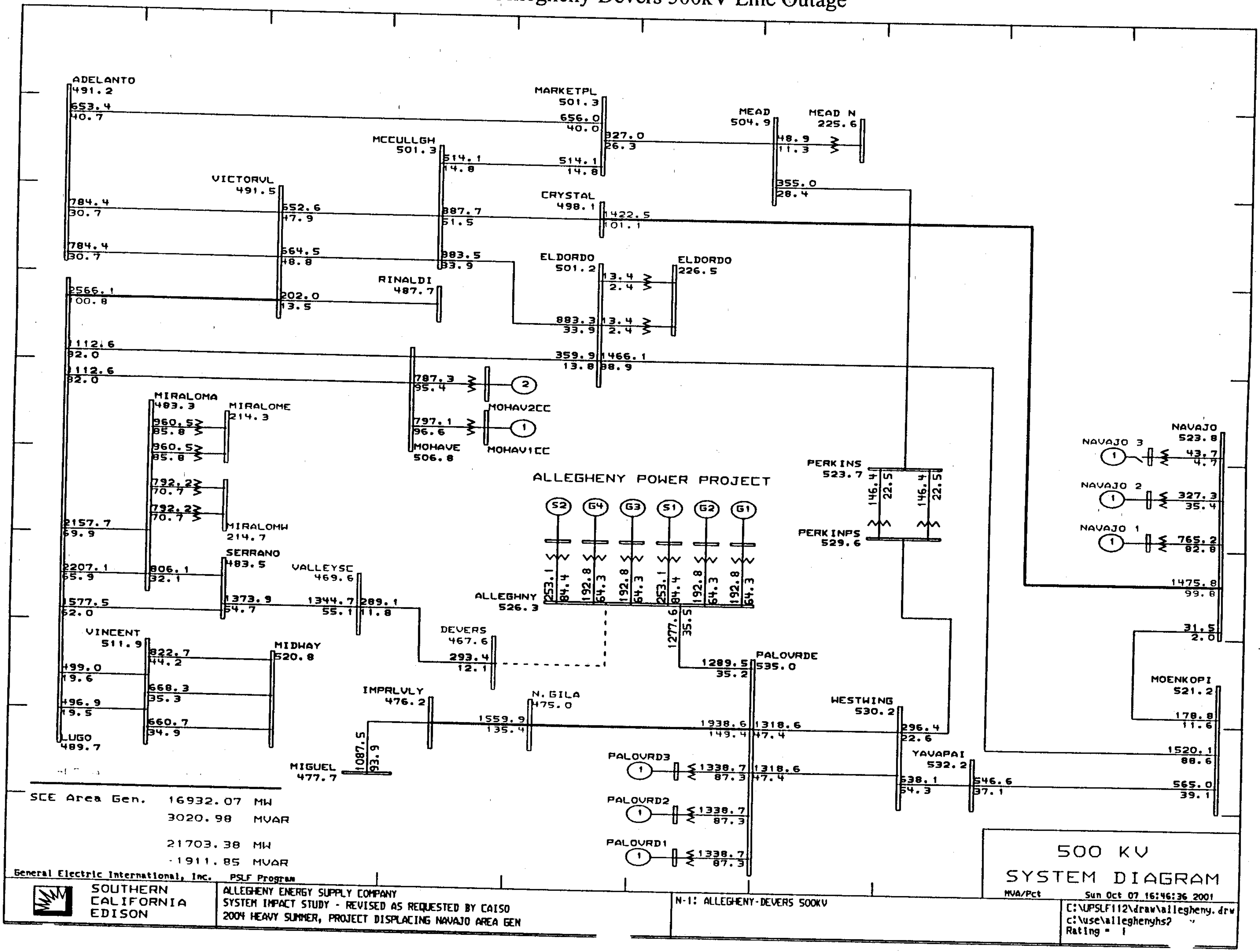
Allegheny Power Project Displacing Palo Verde Area Generation
Allegheny-Devers 500kV Line Outage



Plot Allegheny3cHS

Allegheny Power Project Displacing Navajo Area Generation

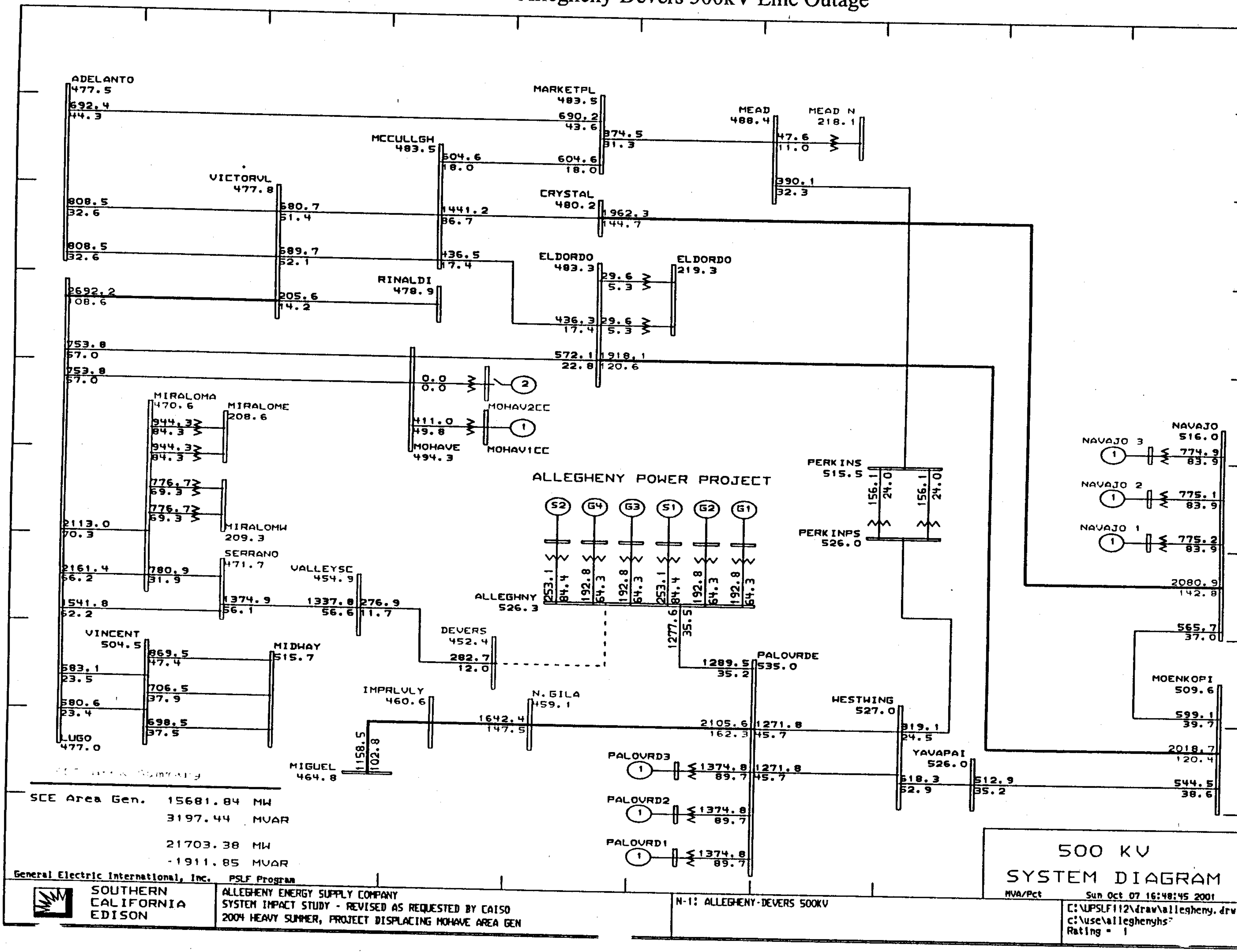
Allegheny-Devers 500kV Line Outage



Plot Allegheny3dHS

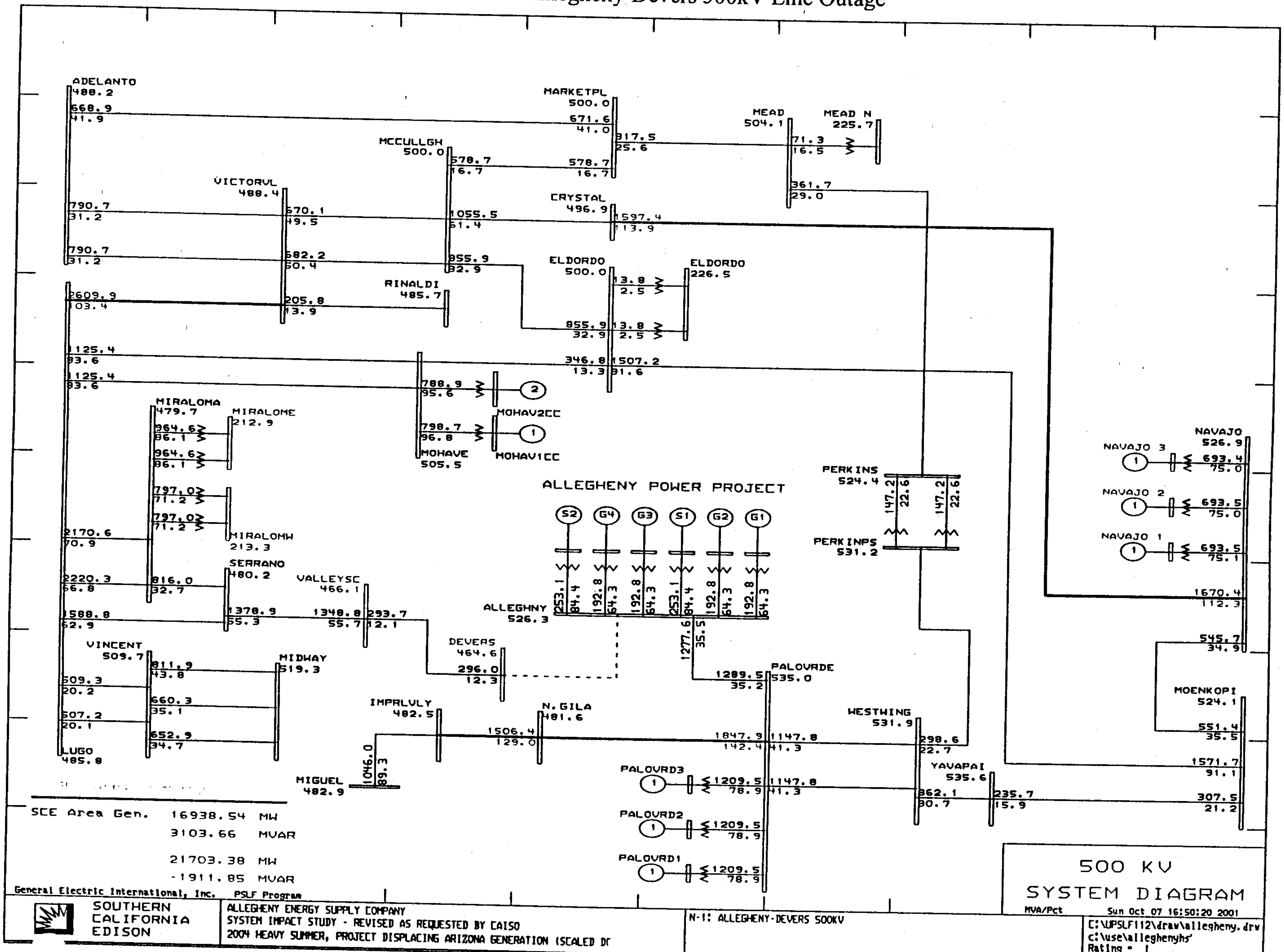
Allegheny Power Project Displacing Mohave Area Generation

Allegheny-Devers 500kV Line Outage



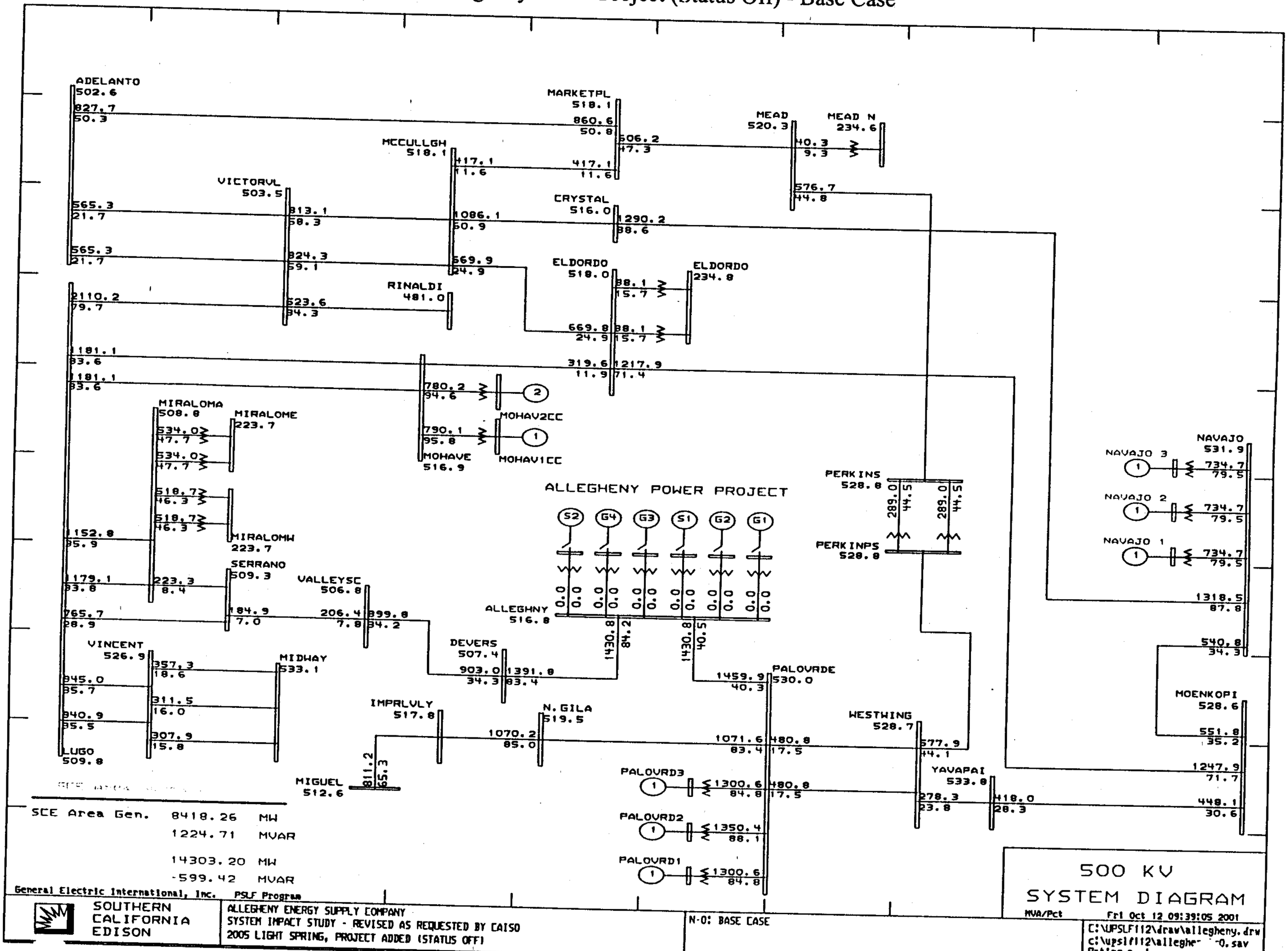
Plot Allegheny3eHS

Allegheny Power Project Displacing Arizona Generation
Allegheny-Devers 500kV Line Outage



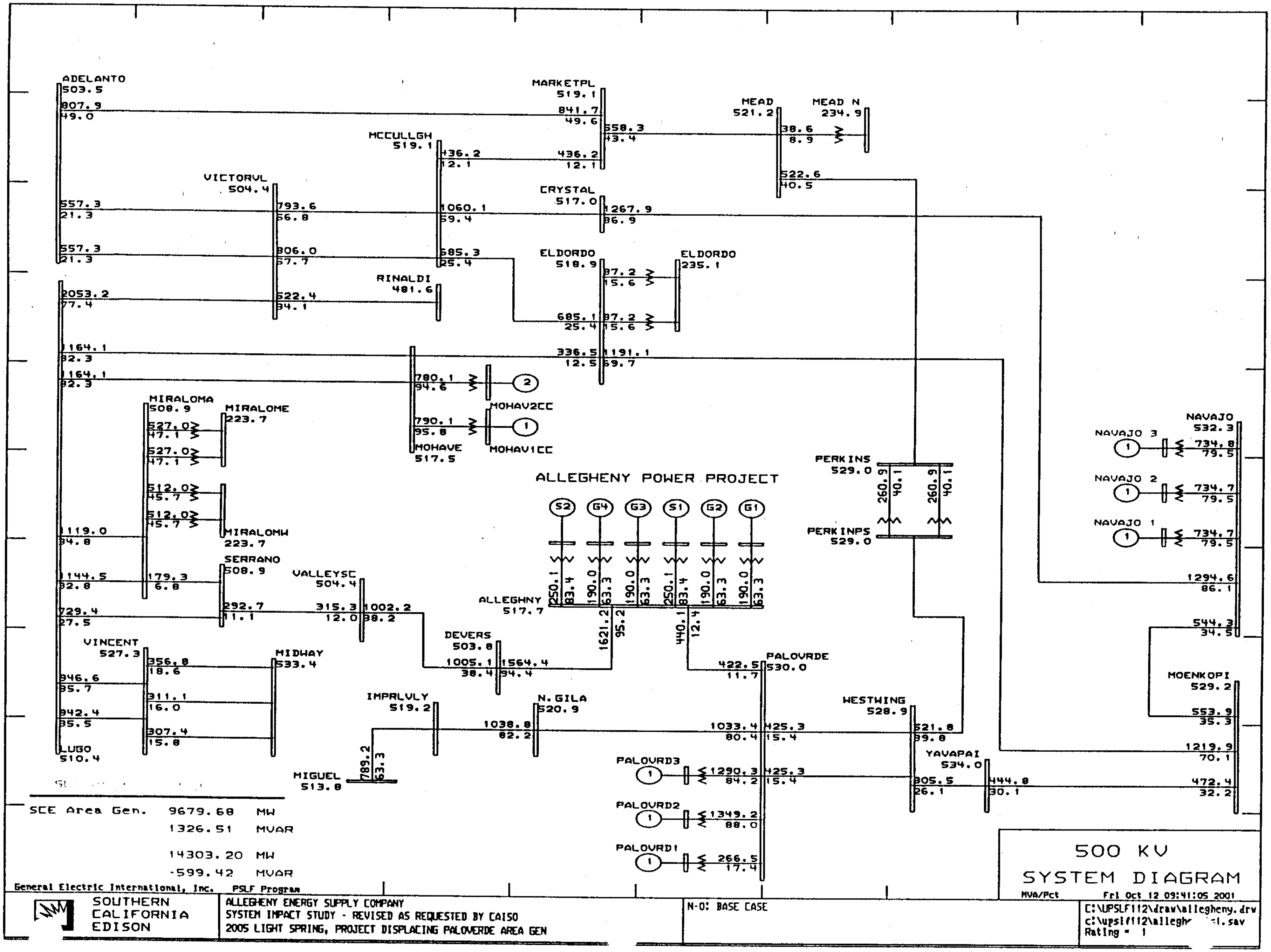
Plot Allegheny1aSP

Allegheny Power Project (Status Off) - Base Case



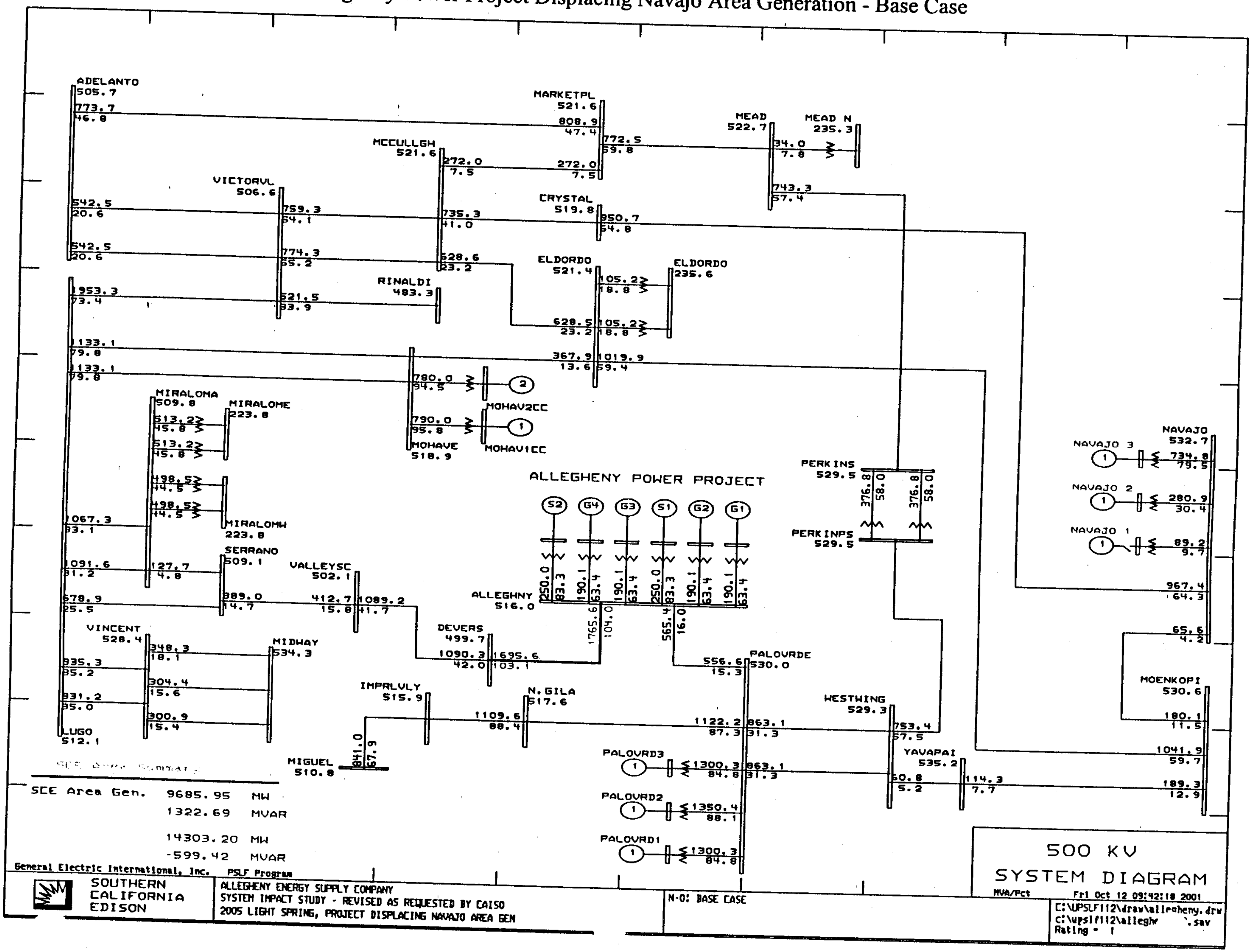
Plot Allegheny1bSP

Allegheny Power Project Displacing Palo Verde Area Generation – Base Case



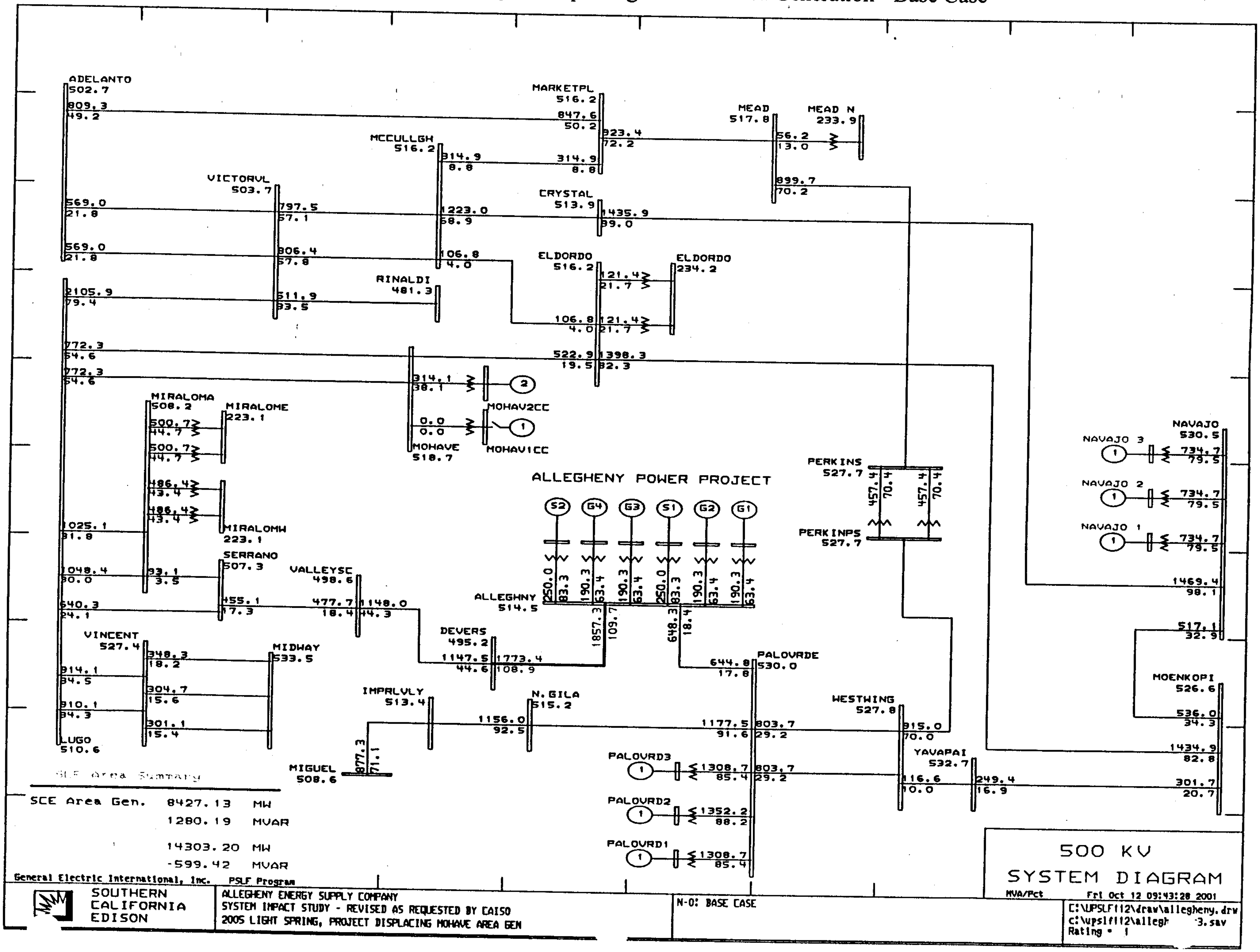
Plot Allegheny1cSP

Allegheny Power Project Displacing Navajo Area Generation - Base Case



Plot Allegheny1dSP

Allegheny Power Project Displacing Mohave Area Generation - Base Case



Plot Allegheny1eSP

Allegheny Power Project Displacing Arizona Area Generation - Base Case

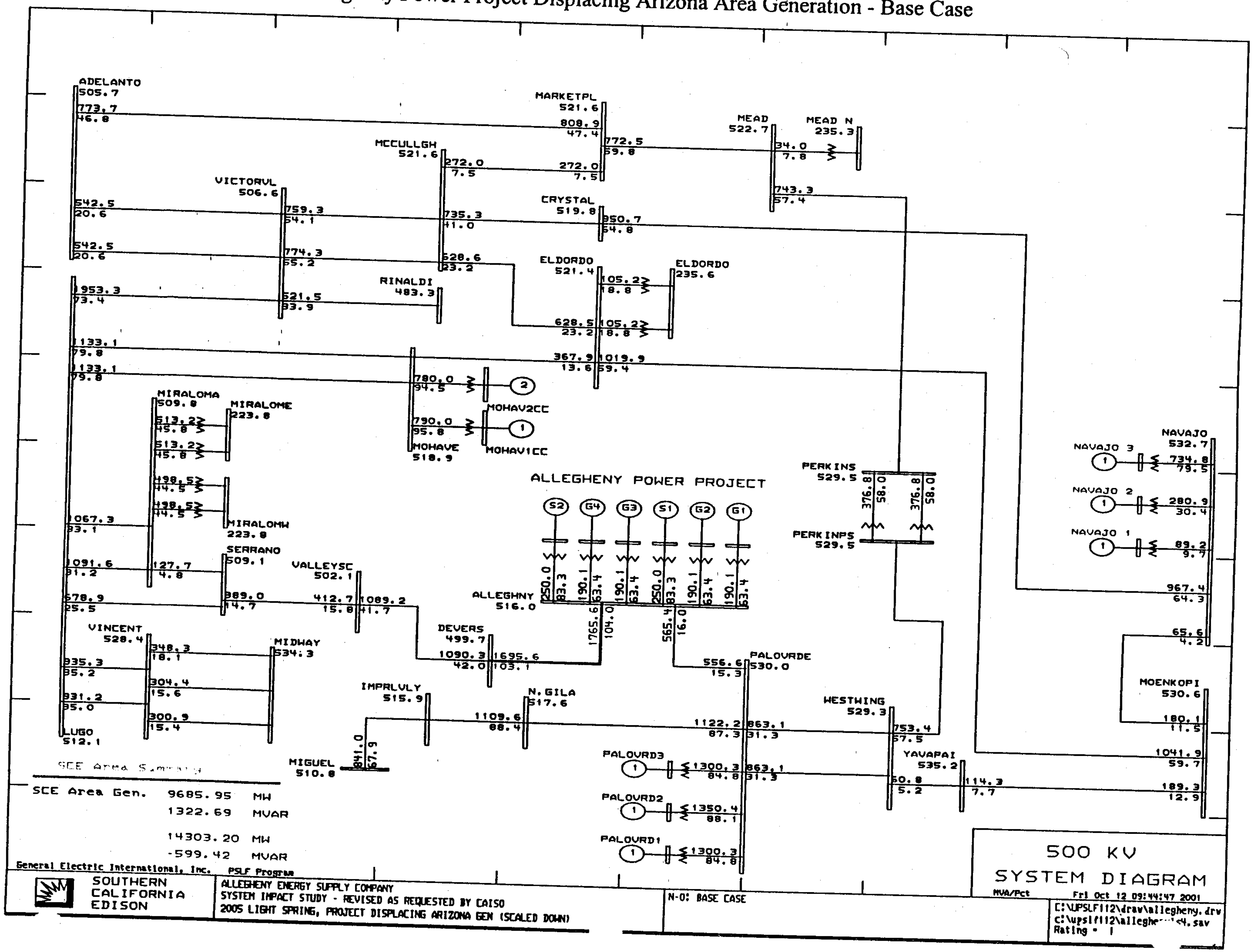


EXHIBIT
A-30
admitted

This visual simulation was prepared using conceptual engineering data. The appearance of the facilities is subject to change based upon final engineering.

Visual Simulation

Wet Cooled Alternative

La Paz Generating Facility

Exhibit A-30

Allegheny Energy Supply
an Allegheny Energy company

URS

This visual simulation was prepared using conceptual engineering data. The appearance of the facilities is subject to change based upon final engineering.

URS

Visual Simulation

Dry Cooled Alternative

La Paz Generating Facility

Exhibit A-30

Allegheny Energy Supply
an Allegheny Energy company

This visual simulation was prepared using conceptual engineering data. The appearance of the facilities is subject to change based upon final engineering.

Visual Simulation

Wet/Dry Cooled Alternative

La Paz Generating Facility

Exhibit A-30

Allegheny Energy Supply
an Allegheny Energy company

URS

A-31

THE STATE OF ARIZONA
GAME AND FISH DEPARTMENT
2221 WEST GREENWAY ROAD, PHOENIX, AZ 85023-4399
(602) 942-3000 • WWW.AZGFD.COM

EXHIBIT
A-31
admitted

RECEIVED
ATTY GENL'S OFFICE
DEC 14 2001

RECEIVED
2001 DEC 18 P 3:
AZ CORP COMMISSION
DOCUMENT CONTROL

December 14, 2001

Ms. Laurie A. Woodall, Chairman
Power Plant and Transmission Line Siting Committee
Office of the Attorney General
1275 West Washington
Phoenix, Arizona 85007

L-00000AA-01-0116

Re: Allegheny Energy Supply Company- La Paz Generating Facility

Dear Ms. Woodall:

The purpose of this letter is to provide additional management recommendations for evaporative ponds associated with the La Paz Generating Facility and natural gas-fired generating facilities in Arizona.

At your request, the Arizona Game and Fish Department (Department) reviewed Dr. Terrill's testimony regarding an evaluation of potential impacts to wildlife resources as a result of power plants in Arizona. The Department stated in our letter, dated December 10, 2001, that we do not disagree with that review, and that we believe evaporative ponds have the potential to adversely impact wildlife resources. For that reason, we believe monitoring water quality and wildlife use should be an important aspect of avoiding potential adverse impacts to wildlife. Monitoring should be designed to identify potential impacts, and then develop appropriate contingency actions or long-term mitigation measures. Since migratory birds are protected under the Migratory Bird Treaty Act, the Department and U.S. Fish and Wildlife Service should be included in the design and implementation of monitoring, research and contingency plans. If monitoring identifies any potential negative impacts, we recommend that the following contingency plans be established to address these problems.

Avoidance
Preventing wildlife from utilizing the evaporation ponds could be accomplished through measures such as fencing, netting, enclosing, harassing, or removing the water.

Improving Conditions
Improving water quality in the evaporation ponds can be accomplished through adding fresh water, removing toxins, or removing contaminated food sources (e.g., aquatic plants and brine shrimp)

The Department has been working with Allegheny Energy Supply Company to identify potential measures (fencing and vegetation control) that we believe will reduce wildlife use of the ponds.

b

Ms. Laurie A. Woodall
December 14, 2001December 14, 2001
2

In addition, the applicant has proposed to monitor water quality and wildlife use. The Department will continue to work with Allegheny Energy Supply Company to develop contingency plans that minimize potential adverse impacts to wildlife. Please contact me at (602) 789-3602 if you have any questions regarding this letter or the Department's involvement in this project.

Sincerely,

John Kennedy
Habitat Branch Chief

JK:BDB:bb

cc: Bob Broscheid, Project Evaluation Program Supervisor
Russ Engel, Habitat Program Manager, Region IV, Yuma

EXHIBIT

A-32

admitted

GALLAGHER & KENNEDY, P.A.
2575 E. CAMELBACK ROAD
PHOENIX, ARIZONA 85016-9225
(602) 530-8000

BEFORE THE ARIZONA POWER PLANT AND TRANSMISSION

LINE SITING COMMITTEE

IN THE MATTER OF THE APPLICATION OF ALLEGHENY ENERGY SUPPLY COMPANY, LLC FOR A CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY FOR CONSTRUCTION OF A 1,080 MW (NOMINAL) GENERATING FACILITY IN SECTION 35, TOWNSHIP 3 NORTH, RANGE 11 WEST IN LA PAZ COUNTY, ARIZONA AND AN ASSOCIATED TRANSMISSION LINE AND SWITCHYARDS BETWEEN AND IN SECTION 35, TOWNSHIP 3 NORTH, RANGE 11 WEST AND SECTIONS 23-26, TOWNSHIP 3 NORTH, RANGE 11 WEST ALSO IN LA PAZ COUNTY, ARIZONA.	DOCKET NO. L-00000AA-01-0116 CASE NO. 116

CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY

Pursuant to notice given as provided by law, the Arizona Power Plant and Transmission Line Siting Committee (the "Committee") held public hearings in Parker and Phoenix, Arizona, on September 4, 2001, November 13-14, 2001, December 13-14, 2001, and January 15-16, 2002, in conformance with the requirements of Ariz. Rev. Stat. § 40-360, et. seq., for the purpose of receiving public comment and evidence and deliberating on the application of Allegheny Energy Supply Company, LLC, or its assignees ("Allegheny" or "Applicant"), for a Certificate of Environmental Compatibility ("Certificate") authorizing construction of a 1080 MW (nominal) generating facility and an associated transmission line and switchyards in La Paz County, Arizona (the "Project"), all as more particularly described and set forth in the Application (the "Application").

The following members and designees of members of the Committee were present on one or more of the hearing days:

Laurie Woodall	Chairman, Designee for Arizona Attorney General, Janet Napolitano
Richard Tobin	Department of Environmental Quality
Gregg Houtz	Department of Water Resources
Ray Williamson	Arizona Corporation Commission
Mark McWhirter	Department of Commerce
Michael Palmer	Appointed Member
Jeff McGuire	Appointed Member
Wayne Smith	Appointed Member
Sandie Smith	Appointed Member
Michael Whalen	Appointed Member

Applicant was represented by Michael M. Grant and Todd C. Wiley of Gallagher & Kennedy, P.A. Arizona Corporation Commission Utilities Division Staff ("Staff") was represented by Christopher C. Kempley and Jason D. Gellman. Intervenor Arizona Unions for Reliable Energy ("Unions") was represented by James D. Vieregg of Morrison & Hecker, L.L.P. and Mark R. Wolfe of Adams, Broadwell, Joseph & Cardozo. La Paz County, by its County Attorney R. Glenn Buckelew, filed a notice of limited appearance in support of the grant of Allegheny's Application.

At the conclusion of the hearing, after consideration of the Application, the evidence and the exhibits presented, the comments of the public, the legal requirements of Ariz. Rev. Stat. §§ 40-360 to 40-360.13 and in accordance with A.A.C. R14-3-213, upon motion duly made and seconded, the Committee voted to make the following findings and to grant Allegheny the following Certificate of Environmental Compatibility (Case No. 116):

The Committee finds that the record contains substantial evidence regarding the need for an adequate, economical and reliable supply of electric power and how the Project would contribute towards satisfaction of such need without causing material adverse impact to the environment.

Applicant and its assignees are granted a Certificate authorizing the construction of a 1,080 MW (nominal) electric generating plant as more particularly described in Section 4(a)(i) of the Application and an associated 500 kv transmission line and switchyards as more particularly described in Section 4(b)(i) of the Application and Exhibit G-7. In addition to the Avenue 75 East alignment, Applicant also is granted two alternative routes for the associated 500 kv transmission line and interconnection switchyard to and along the section lines one mile east and one mile west of Avenue 75 East to the point of interconnection with the Devers-Palo Verde transmission line. Applicant shall use its best efforts to construct the associated 500 kv transmission line along either of those alternative routes.

This Certificate is granted upon the following conditions:

1. Applicant and its assignees will comply with all existing applicable air and water pollution control standards and regulations, and with all existing applicable ordinances, master plans and regulations of the state of Arizona, the county of La Paz, the United States and any other governmental entities having jurisdiction, including but not limited to the following:

a. all zoning stipulations and conditions, including but not limited to any landscaping and dust control requirements and/or approvals;

b. all applicable air quality control standards, approvals, permit conditions and requirements of the Arizona Department of Environmental Quality ("ADEQ") and/or other State or Federal agencies having jurisdiction, and the Applicant shall install and operate selective catalytic reduction and catalytic oxidation technology at the level determined by the ADEQ. The Applicant shall operate the Project so as to meet a 2.5 ppm NOx emissions level, within the parameters established in the Title V and PSD air quality permits issued by ADEQ. Applicant shall install and operate catalytic oxidation technology that will produce carbon monoxide ("CO") and volatile organic compound ("VOC") emission rates determined as current best available control technology ("BACT") by ADEQ;

c. all applicable water use and/or disposal requirements of the Arizona Department of Water Resources ("ADWR"), Section 6-503 of ADWR's Third Management Plan and the applicable

ADEQ water use and discharge regulations;

d. all applicable regulations and permits governing transportation, storage and handling of petroleum products and chemicals.

2. Allegheny shall construct a 100 KW solar photovoltaic array for use in conjunction with the Project's electricity use requirements. Allegheny will also participate in future solar workshops conducted by the Commission.

3. Subject to the availability of Central Arizona Project ("CAP") water and delivery facilities, Allegheny will acquire over the next 30 years directly, through another or by contract with the Arizona Water Banking Authority ("AWBA") an aggregate amount of 30,000 acre feet of CAP water or that aggregate amount of water which may be acquired with $3 million, whichever is less. The water acquired is intended to be recharged at the Vidler Recharge Facility ("Vidler"), but may be recharged elsewhere by the Applicant or AWBA. Water recharged shall not be subject to withdrawal by Applicant. Allegheny may also meet all or a portion of its obligation hereunder by acquiring on another person or entity's behalf CAP water to be used in lieu of groundwater which would have been withdrawn and used by such person or entity. If Allegheny has used or recharged CAP water in relation to the Project's water needs, the amount of such use or recharge shall be treated as a credit against Applicant's obligation under this condition.

4. Applicant may withdraw groundwater for electrical generation and related uses in amounts as specified in A.R.S. § 45-440.

5. In consultation with the Arizona Department of Water Resources, Allegheny will develop a monitoring program of monument inspection and information gathering from agencies with infrastructure or jurisdiction near the plant site concerning subsidence. The data gathered pursuant to the monitoring program shall be regularly reported to

the Department and Commission.

6. In the year following the commencement of groundwater withdrawals in relation to the Project, Applicant shall submit annual reports to the Arizona Department of Water Resources pursuant to A.R.S. 45-437.C.1 reporting the quantity of groundwater withdrawn and the Notice(s) of Authority appurtenant thereto.

7. Authorization to construct the facility will expire five years from the date the Certificate is approved by the Arizona Corporation Commission unless construction is completed to the point that the facility is capable of operating at its rated capacity by that time; provided, however, that prior to such expiration the facility owner may request that the Arizona Corporation Commission extend this time limitation.

8. Applicant shall initially connect the 500 kV Plant Switchyard to the 500 kV Transmission Grid Interconnection Switchyard with a single 500 kV transmission line, but shall allocate spaces in the Plant Switchyard and shall direct SCE to allocate spaces in the Transmission Grid Interconnection Switchyard for (i) a second 500 kV Transmission line should future reliability studies indicate that such addition is necessary to maintain reliability or (ii) a second Devers/Palo Verde transmission line.

9. Applicant's plant interconnection must satisfy the Western Systems Coordinating Council's ("WSCC") single contingency outage criteria (N-1) and all applicable local utility planning criteria without reliance on remedial action such as, but not limited to, reducing generator output, reducing generator unit tripping or load shedding.

10. The Applicant's plant switchyard shall utilize a breaker and a half scheme.

11. Prior to construction of any facilities, Allegheny shall provide to the Commission the system impact study and the facilities study performed by Southern California

Edison regarding delivery of the full output of the Project to its intended markets (the "SCE Technical Studies"). The SCE Technical Studies shall be prepared in accordance with the rules and regulations governing such interconnections as established by the Transmission System Owner and Operator, in this case the Palo Verde-Devers Transmission Line owned by SCE and operated by CAISO. The SCE Technical Studies shall include a power flow and stability analysis report and shall identify transmission system upgrades or capacity improvements such that the Project will not compromise the reliable operation of the interconnected transmission system in accordance with SCE, CAISO and WSCC requirements. Applicant shall make all arrangements necessary with SCE and CAISO to implement the necessary transmission system upgrades or capacity improvements as documented in the final interconnection agreements. Applicant shall provide the Commission with copies of the transmission interconnection and transmission service agreement(s) it ultimately enters into with SCE or any transmission provider(s) with whom it is interconnecting, within 30 days of execution of such agreement(s). Prior to commencing operation of the Project, transmission facilities improvements, as identified in the SCE Technical studies, shall have been completed.

12. Applicant anticipates that the transmission system upgrades or capacity improvements that will be identified and required in the SCE Technical studies and the final interconnection agreement(s) may cost up to $25,000,000 and will result in substantial transmission capacity increases out of the Palo Verde hub. However, in the event that these transmission capacity increases at the Palo Verde hub are not equivalent to 1080 MW, Applicant will work with the Commission Staff and Transmission Owners to determine the best method for making up to an additional $2,500,000 contribution towards additional upgrading of the transmission capacity out of the Palo Verde hub. Applicant will use commercially reasonable

efforts to assure that such additional upgrades are completed before the Project commences commercial operation.

13. Applicant will become and remain a member of WSCC, or its successor, and file an executed copy of its WSCC Reliability Management System (RMS) Generator Agreement with the Commission. Membership by an affiliate of Applicant satisfies this condition only if Applicant is bound by the affiliate's WSCC membership.

14. Applicant shall apply to become and, if accepted, thereafter remain a member of the Southwest Reserve Sharing Group or its successor, thereby making its units available for reserve sharing purposes, subject to competitive pricing.

15. Applicant shall offer for Ancillary Services, in order to comply with WSCC RMS requirements, a total of up to 10% of its total plant capacity to (A) the local Control Area with which it is interconnected and (B) Arizona's regional ancillary service market, (i) once a Regional Transmission Organization (RTO) is declared operational by FERC order, and (ii) until such time that an RTO is so declared, to a regional reserve sharing pool.

16. Within 30 days of the Commission decision authorizing construction of this project, Applicant shall erect and maintain at the site a sign of not less than 4 feet by 8 feet dimensions, advising:

a. That the site has been approved for the construction of a 1,080 MW (nominal) generating facility;

b. The expected date of completion of the facility; and

c. Phone number for public information regarding the project.

In the event that the Project requests an extension of the term of the certificate prior to completion of the construction, Applicant shall use reasonable means to directly notify all landowners and residents within a one-mile radius of the Project of the time and place of the proceeding in which the Commission shall consider such request for extension. Applicant shall also provide notice of such extension to La Paz County.

17. Applicant shall first offer wholesale power purchase opportunities to credit-worthy Arizona load-serving entities and to credit-worthy marketers providing service to those Arizona load-serving entities.

18. Pursuant to applicable Federal Energy Regulatory Commission ("FERC") regulations, Applicant shall not knowingly withhold its capacity from the market for reasons other than a forced outage or pre-announced planned outage. Allegheny shall not be required to operate its Project at a loss.

19. In connection with the construction of the project, Applicant shall use commercially reasonable efforts, where feasible, to give due consideration to use of qualified Arizona contractors. In addition, Allegheny shall encourage the hiring of qualified local employees in connection with construction and operation of the Project.

20. Applicant shall continue to participate in good faith in state and regional transmission study forums to identify and encourage expedient implementation of transmission enhancements, including transmission cost participation as appropriate, to reliably deliver power from the Project throughout the WSCC grid in a reliable manner.

21. Applicant shall participate in good faith in state and regional workshops and other assessments of the interstate pipeline infrastructure.

22. Applicant shall pursue all necessary steps to ensure a reliable supply and delivery of natural gas for the Project.

23. Within five days of Commission approval of this CEC, Applicant shall

request in writing that El Paso Natural Gas Company ("El Paso") provide Applicant with a written report describing the operational integrity of El Paso's Southern System facilities from mileposts 660-670. Such request shall include:

a. A request for information regarding inspection, replacement and/or repairs performed on this segment of El Paso's pipeline facilities since 1996 and those planned through 2006; and

b. An assessment of subsidence impacts on the integrity of this segment of pipeline over its full cycle, together with any mitigation steps taken to date or planned in the future.

Applicant shall file El Paso's response under this docket with the Commission's Docket Control. Should El Paso not respond within thirty (30) days, Applicant shall docket a copy of Applicant's request with an advisory of El Paso's failure to respond. In either event, Applicant's responsibility hereunder shall terminate once it has filed El Paso's response or Applicant's advisory of El Paso's failure to respond.

24. Applicant shall operate the Project so that during normal operations the Project will not exceed (i) U.S. Department of Housing and Urban Development ("HUD") or Federal Transit Administration ("FTA") residential noise guidelines or (ii) Occupational Safety and Health Administration ("OSHA") Worker Safety Noise Standards.

25. Applicant will use low profile structures and stacks, non-reflective and/or neutral colors on surface materials and low intensity directive/shielded lighting fixtures to the extent feasible for the Project. Applicant shall use monopoles for the associated 500 kv transmission line to the point of interconnection with the Devers-Palo Verde transmission line.

26. Allegheny will fence the generating facility and evaporation ponds to

minimize effects of plant operations on terrestrial wildlife and will keep the berms surrounding the evaporation ponds clear of vegetation to limit pond attractiveness to birds.

27. In consultation with the Arizona Game & Fish Department, Applicant will develop a monitoring and reporting plan for the evaporation ponds. The plan will include the type and frequency of monitoring and reporting to the Game & Fish Department and the U.S. Fish and Wildlife Service. Should any issues arise as a result of the monitoring and reporting plan, Applicant shall work with the United States Fish and Wildlife Service and the Arizona Game and Fish Department to develop screening or other methods to protect wildlife from harm at the Project's evaporation ponds.

28. Allegheny will continue cactus ferruginous pygmy owl surveys through the Spring of 2002, based on established protocol. If survey results are positive, the U.S. Fish and Wildlife Service and Arizona Department of Game and Fish will be contacted immediately for further consultation.

29. Allegheny will retain a qualified biologist to monitor all ground clearing/disturbing construction activities. The biological monitor will be responsible for ensuring proper actions are taken if a special status species is encountered (e.g., relocation of a Sonoran desert tortoise).

30. Applicant will salvage mesquite, ironwood, saguaro and palo verde trees removed during project construction activities and use the vegetation for reclamation in or near its original location and/or landscaping around the plant site.

31. Allegheny will retain an Arizona registered landscape architect to develop a landscape plan for the perimeter of the generating facility. The landscape plan will use native or other low water use plant materials. The Applicant will continue to consult with La Paz

County regarding the landscape plan.

32. Allegheny will use a directional drilling process to bore under Centennial Wash in constructing the gas pipeline to minimize potential impacts to the mesquite bosque associated with the wash.

33. The Applicant will continue to consult with La Paz County in relation to its comprehensive planning process to develop appropriate zoning and use classifications for the area surrounding the Project.

34. Allegheny will use its best efforts to avoid the two identified cultural resource sites. If Sites AZ S:7:48 and 49 (ASM) cannot be avoided by ground disturbing activities, the Applicant will continue to consult with the State Historic Preservation Office to resolve any negative impacts which usually entails preparing and implementing a data recovery research design and work plan.

35. If a federal agency determines that all or part of the Project represents a federal undertaking subject to review under the National Historic Preservation Act, Allegheny will participate as a consulting party in the federal compliance process (i.e., 36 C.F.R. 800) to reach a finding of effect and to resolve adverse effects, if any.

36. Should cultural features and/or deposits be encountered during ground disturbing activities, Allegheny will comply with A.R.S. § 41-844, which requires that work cease in the immediate area of the discovery and that the Director of the Arizona State Museum be notified promptly.

37. If human remains or funerary objects are encountered during the course of any ground disturbing activities related to the development of the subject property, Applicant shall cease work and notify the Director of the Arizona State Museum in accordance with Ariz.

Rev. Stat. § 41-865.

38. Allegheny will retain a qualified archaeologist to monitor ground clearing/disturbing construction activities and to appropriately instruct workers on detection and avoidance of cultural resource sites.

39. Applicant shall prepare a plan for shutdown, decommissioning and cleanup of the plant site which shall be filed with the Commission's Docket Control within one year of beginning construction. In that regard, the Committee recommends that Applicant work with La Paz County and/or any other local governing body with jurisdiction over the plant site to ensure that such plan is reasonable, and is followed or amended as necessary.

GRANTED this ______ day of _____________, 2002.

ARIZONA POWER PLANT AND
TRANSMISSION LINE SITING COMMITTEE

By ________________________________
Laurie Woodall, Chairwoman

12921-0004/947199 v8

EXHIBIT
A-33
admitted

11. Prior to construction of any facilities, Allegheny shall provide to the Commission the system impact study and the facilities study performed by Southern California Edison regarding delivery of the full output of the Project to its intended markets (the "SCE Technical Studies"). The SCE Technical Studies shall be prepared in accordance with the rules and regulations governing such interconnections as established by the Transmission System Owner and Operator, in this case the Palo Verde-Devers Transmission Line owned by SCE and operated by CAISO. The SCE Technical Studies shall include a power flow and stability analysis report and shall identify transmission system upgrades or capacity improvements such that the Project will not compromise the reliable operation of the interconnected transmission system in accordance with SCE, CAISO and WSCC requirements. Applicant shall make all arrangements necessary with SCE and CAISO to implement the necessary transmission system upgrades or capacity improvements as documented in the final interconnection agreements. Applicant shall provide the Commission with copies of the transmission interconnection and transmission service agreement(s) it ultimately enters into with SCE or any transmission provider(s) with whom it is interconnecting, within 30 days of execution of such agreement(s). Prior to commencing operation of the Project, transmission facilities improvements, as identified in the SCE Technical studies, shall have been completed.

12. Applicant anticipates that the transmission system upgrades or capacity improvements that will be identified and required in the SCE Technical Studies and the final interconnection agreement(s) may cost up to $25,000,000 and will result in transmission capacity increases out of the Palo Verde Hub. However, in the event that these transmission capacity increases at the Palo Verde Hub are not equivalent to 1080 MW, pursuant to Federal Energy Regulatory Commission orders or regulations concerning interconnection and transmission service, Applicant will work with the Commission Staff, Transmission Owners and power plant operators interconnected at the Palo Verde Hub to determine the best method for making additional necessary upgrades at the Palo Verde Hub to accommodate interconnected generation. Applicant shall contribute the sum of $2,500,000 or its pro rata share of the cost of such necessary upgrades in relation to other power plant operators interconnected at the Palo Verde Hub, whichever is greater. Applicant will use commercially reasonable efforts to assure that such additional upgrades are completed before the Project commences commercial operation.

EXHIBIT
A-34
admitted

BEFORE THE ARIZONA POWER PLANT AND TRANSMISSION

LINE SITING COMMITTEE

IN THE MATTER OF THE APPLICATION OF ALLEGHENY ENERGY SUPPLY COMPANY, LLC FOR A CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY FOR CONSTRUCTION OF A 1,080 MW (NOMINAL) GENERATING FACILITY IN SECTION 35, TOWNSHIP 3 NORTH, RANGE 11 WEST IN LA PAZ COUNTY, ARIZONA AND AN ASSOCIATED TRANSMISSION LINE AND SWITCHYARDS BETWEEN AND IN SECTION 35, TOWNSHIP 3 NORTH, RANGE 11 WEST AND SECTIONS 23-26, TOWNSHIP 3 NORTH, RANGE 11 WEST ALSO IN LA PAZ COUNTY, ARIZONA.	DOCKET NO. L-00000AA-01-0116 CASE NO. 116

GALLAGHER & KENNEDY, P.A.
2575 E. CAMELBACK ROAD
PHOENIX, ARIZONA 85016-9225
(602) 530-8000

CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY

Pursuant to notice given as provided by law, the Arizona Power Plant and Transmission Line Siting Committee (the "Committee") held public hearings in Parker and Phoenix, Arizona, on September 4, 2001, November 13-14, 2001, December 13-14, 2001, and January 15-16, 2002, in conformance with the requirements of Ariz. Rev. Stat. § 40-360, et. seq., for the purpose of receiving public comment and evidence and deliberating on the application of Allegheny Energy Supply Company, LLC, or its assignees ("Allegheny" or "Applicant"), for a Certificate of Environmental Compatibility ("Certificate") authorizing construction of a 1080 MW (nominal) generating facility and an associated transmission line and switchyards in La Paz County, Arizona (the "Project"), all as more particularly described and set forth in the Application (the "Application").

The following members and designees of members of the Committee were present on one or more of the hearing days:

Laurie Woodall	Chairman, Designee for Arizona Attorney General, Janet Napolitano
Richard Tobin	Department of Environmental Quality
Gregg Houtz	Department of Water Resources
Ray Williamson	Arizona Corporation Commission
Mark McWhirter	Department of Commerce
Jeff McGuire	Appointed Member
Michael Palmer	Appointed Member
Wayne Smith	Appointed Member
Sandie Smith	Appointed Member
Margaret Trujillo	Appointed Member
Michael Whalen	Appointed Member

Applicant was represented by Michael M. Grant and Todd C. Wiley of Gallagher & Kennedy, P.A. Arizona Corporation Commission Utilities Division Staff ("Staff") was represented by Christopher C. Kempley and Jason D. Gellman. Intervenor Arizona Unions for Reliable Energy ("Unions") was represented by James D. Vieregg of Morrison & Hecker, L.L.P. and Mark R. Wolfe of Adams, Broadwell, Joseph & Cardozo. La Paz County, by its County Attorney R. Glenn Buckelew, filed a notice of limited appearance in support of the grant of Allegheny's Application.

At the conclusion of the hearing, after consideration of the Application, the evidence and the exhibits presented, the comments of the public, the legal requirements of Ariz. Rev. Stat. §§ 40-360 to 40-360.13 and in accordance with A.A.C. R14-3-213, upon motion duly made and seconded, the Committee voted to make the following findings and to grant Allegheny the following Certificate of Environmental Compatibility (Case No. 116):

The Committee finds that the record contains substantial evidence regarding the need for an adequate, economical and reliable supply of electric power and how the Project would contribute towards satisfaction of such need without causing material adverse impact to the environment.

Applicant and its assignees are granted a Certificate authorizing the construction of a 1,080 MW (nominal) electric generating plant as more particularly described in Section 4(a)(i) of the Application and an associated 500 kv transmission line and switchyards as more particularly described in Section 4(b)(i) of the Application and Exhibit G-7. In addition to the Avenue 75 East alignment, Applicant also is granted two alternative routes for the associated 500 kv transmission line and interconnection switchyard to and along the section lines one mile east and one mile west of Avenue 75 East to the point of interconnection with the Devers-Palo Verde transmission line. Applicant shall use its best efforts to construct the associated 500 kv transmission line along either of those alternative routes.

This Certificate is granted upon the following conditions:

1. Applicant and its assignees will comply with all existing applicable air and water pollution control standards and regulations, and with all existing applicable ordinances, master plans and regulations of the state of Arizona, the county of La Paz, the United States and any other governmental entities having jurisdiction, including but not limited to the following:

a. all zoning stipulations and conditions, including but not limited to any landscaping and dust control requirements and/or approvals;

b. all applicable air quality control standards, approvals, permit conditions and requirements of the Arizona Department of Environmental Quality ("ADEQ") and/or other State or Federal agencies having jurisdiction, and the Applicant shall install and operate selective catalytic reduction and catalytic oxidation technology at the level determined by the ADEQ. The Applicant shall operate the Project so as to meet a 2.5 ppm NOx emissions level, within the parameters established in the Title V and PSD air quality permits issued by ADEQ. Applicant shall install and operate catalytic oxidation technology that will produce carbon monoxide ("CO") and volatile organic compound ("VOC") emission rates determined as current best available control technology ("BACT") by ADEQ;

c. all applicable water use and/or disposal requirements of the Arizona Department of Water Resources ("ADWR"), and Section 6-503 of ADWR's Third Management Plan;

d. all applicable ADEQ water use and discharge regulations;

e. all applicable regulations and permits governing transportation, storage and handling of petroleum products and chemicals.

2. Allegheny shall construct a 100 KW solar photovoltaic array for use in conjunction with the Project's electricity use requirements. Allegheny will also participate in future solar workshops conducted by the Commission.

3. Subject to the availability of Central Arizona Project ("CAP") water and delivery facilities, Allegheny will acquire over the next 30 years directly, through another or by contract with the Arizona Water Banking Authority ("AWBA") an aggregate amount of 30,000 acre feet of CAP water or that aggregate amount of water which may be acquired with $3 million, whichever is less. However, at least one-half of the obligation shall be expended or acquired within the first ten (10) years. The water acquired is intended to be recharged at the Vidler Recharge Facility ("Vidler"), but may be recharged elsewhere by the Applicant or AWBA. Applicant shall use its best efforts to recharge or acquire "in lieu" water as described herein in the Harquahala INA. Water recharged shall be subject to annual extinguishment by Applicant. Allegheny may also meet all or a portion of its obligation hereunder by acquiring on another person or entity's behalf CAP water to be used in lieu of groundwater which would have been withdrawn and used by such person or entity. If Allegheny has used or recharged CAP water in relation to the Project's water needs, the amount of such use or recharge shall be treated as a credit against Applicant's obligation under this condition.

4. Applicant may withdraw groundwater for electrical generation and related uses in amounts as specified in A.R.S. § 45-440.

5. Prior to the commencement of groundwater withdrawals and in consultation with the Arizona Department of Water Resources, Allegheny will develop a

monitoring program of monument inspection and information gathering from agencies with infrastructure or jurisdiction near the plant site concerning subsidence. The data gathered pursuant to the monitoring program shall be regularly reported to the Department and Commission.

6. In the year following the commencement of groundwater withdrawals in relation to the Project, Applicant shall submit annual reports to the Arizona Department of Water Resources pursuant to A.R.S. 45-437.C.1 reporting the quantity of groundwater withdrawn and the Notice(s) of Authority appurtenant thereto.

7. Authorization to construct the facility will expire five years from the date the Certificate is approved by the Arizona Corporation Commission unless construction is completed to the point that the facility is capable of operating at its rated capacity by that time; provided, however, that prior to such expiration the facility owner may request that the Arizona Corporation Commission extend this time limitation.

8. Applicant shall initially connect the 500 kV Plant Switchyard to the 500 kV Transmission Grid Interconnection Switchyard with a single 500 kV transmission line, but shall allocate spaces in the Plant Switchyard and shall direct SCE to allocate spaces in the Transmission Grid Interconnection Switchyard for (i) a second 500 kV Transmission line should future reliability studies indicate that such addition is necessary to maintain reliability or (ii) a second Devers/Palo Verde transmission line.

9. Applicant's plant interconnection must satisfy the Western Systems Coordinating Council's ("WSCC") single contingency outage criteria (N-1) and all applicable local utility planning criteria without reliance on remedial action such as, but not limited to, reducing generator output, reducing generator unit tripping or load shedding.

10. The Applicant's plant switchyard shall utilize a breaker and a half scheme.

11. Prior to construction of any facilities, Allegheny shall provide to the Commission the system impact study and the facilities study performed by Southern California Edison regarding delivery of the full output of the Project to its intended markets (the "SCE Technical Studies"). The SCE Technical Studies shall be prepared in accordance with the rules and regulations governing such interconnections as established by the Transmission System Owner and Operator, in this case the Palo Verde-Devers Transmission Line owned by SCE and operated by CAISO. The SCE Technical Studies shall include a power flow and stability analysis report and shall identify transmission system upgrades or capacity improvements such that the Project will not compromise the reliable operation of the interconnected transmission system in accordance with SCE, CAISO and WSCC requirements. Applicant shall make all arrangements necessary with SCE and CAISO to implement the necessary transmission system upgrades or capacity improvements as documented in the final interconnection agreements. Applicant shall provide the Commission with copies of the transmission interconnection and transmission service agreement(s) it ultimately enters into with SCE or any transmission provider(s) with whom it is interconnecting, within 30 days of execution of such agreement(s). Prior to commencing operation of the Project, transmission facilities improvements, as identified in the SCE Technical studies, shall have been completed.

12. Applicant anticipates that the transmission system upgrades or capacity improvements that will be identified and required in the SCE Technical Studies and the final interconnection agreement(s) will result in transmission capacity increases out of the Palo Verde Hub. However, in the event that these transmission capacity increases at the Palo Verde Hub are not equivalent to 1080 MW, pursuant to Federal Energy Regulatory Commission orders or

regulations concerning interconnection and transmission service, Applicant will work with the Commission Staff, Transmission Owners and power plant operators interconnected at the Palo Verde Hub to determine the best method for making additional necessary upgrades at the Palo Verde Hub to accommodate interconnected generation. Applicant shall contribute its share of the cost, as directed by FERC or governing RTO, if applicable, of such necessary upgrades. Applicant will use commercially reasonable efforts to assure that such additional upgrades are completed before the Project commences commercial operation.

13. Applicant will become and remain a member of WSCC, or its successor, and file an executed copy of its WSCC Reliability Management System (RMS) Generator Agreement with the Commission. Membership by an affiliate of Applicant satisfies this condition only if Applicant is bound by the affiliate's WSCC membership.

14. Applicant shall apply to become and, if accepted, thereafter remain a member of the Southwest Reserve Sharing Group or its successor, thereby making its units available for reserve sharing purposes, subject to competitive pricing.

15. Applicant shall offer for Ancillary Services, in order to comply with WSCC RMS requirements, a total of up to 10% of its total plant capacity to (A) the local Control Area with which it is interconnected and (B) Arizona's regional ancillary service market, (i) once a Regional Transmission Organization (RTO) is declared operational by FERC order, and (ii) until such time that an RTO is so declared, to a regional reserve sharing pool.

16. Within 30 days of the Commission decision authorizing construction of this project, Applicant shall erect and maintain at the site a sign of not less than 4 feet by 8 feet dimensions, advising:

a. That the site has been approved for the construction of a 1,080 MW (nominal) generating facility;

b. The expected date of completion of the facility; and

c. Phone number for public information regarding the project.

In the event that the Project requests an extension of the term of the certificate prior to completion of the construction, Applicant shall use reasonable means to directly notify all landowners and residents within a one-mile radius of the Project of the time and place of the proceeding in which the Commission shall consider such request for extension. Applicant shall also provide notice of such extension to La Paz County.

17. Applicant shall first offer wholesale power purchase opportunities to credit-worthy Arizona load-serving entities and to credit-worthy marketers providing service to those Arizona load-serving entities.

18. Pursuant to applicable Federal Energy Regulatory Commission ("FERC") regulations, Applicant shall not knowingly withhold its capacity from the market for reasons other than a forced outage or pre-announced planned outage. Allegheny shall not be required to operate its Project at a loss.

19. In connection with the construction of the project, Applicant shall use commercially reasonable efforts, where feasible, to give due consideration to use of qualified Arizona contractors. In addition, Allegheny shall encourage the hiring of qualified local employees in connection with construction and operation of the Project.

20. Applicant shall continue to participate in good faith in state and regional transmission study forums to identify and encourage expedient implementation of transmission enhancements, including transmission cost participation as appropriate, to reliably deliver power from the Project throughout the WSCC grid in a reliable manner.

21. Applicant shall participate in good faith in state and regional workshops and other assessments of the interstate pipeline infrastructure.

22. Applicant shall pursue all necessary steps to ensure a reliable supply and delivery of natural gas for the Project.

23. Within five days of Commission approval of this CEC, Applicant shall request in writing that El Paso Natural Gas Company ("El Paso") provide Applicant with a written report describing the operational integrity of El Paso's Southern System facilities from mileposts 628-670.39. Such request shall include:

a. A request for information regarding inspection, replacement and/or repairs performed on this segment of El Paso's pipeline facilities since 1996 and those planned through 2006; and

b. An assessment of subsidence impacts on the integrity of this segment of pipeline over its full cycle, together with any mitigation steps taken to date or planned in the future.

Applicant shall file El Paso's response under this docket with the Commission's Docket Control. Should El Paso not respond within thirty (30) days, Applicant shall docket a copy of Applicant's request with an advisory of El Paso's failure to respond. In either event, Applicant's responsibility hereunder shall terminate once it has filed El Paso's response or Applicant's advisory of El Paso's failure to respond.

24. Applicant shall operate the Project so that during normal operations the Project will not exceed (i) U.S. Department of Housing and Urban Development ("HUD") or Federal Transit Administration ("FTA") residential noise guidelines or (ii) Occupational Safety and Health Administration ("OSHA") Worker Safety Noise Standards.

25. Applicant will use low profile structures and stacks, non-reflective and/or neutral colors on surface materials and low intensity directive/shielded lighting fixtures to the extent feasible for the Project. Applicant shall use monopoles for the associated 500 kv transmission line to the point of interconnection with the Devers-Palo Verde transmission line.

26. Allegheny will fence the generating facility and evaporation ponds to minimize effects of plant operations on terrestrial wildlife and will keep the berms surrounding the evaporation ponds clear of vegetation to limit pond attractiveness to birds.

27. In consultation with the Arizona Game & Fish Department, Applicant will develop a monitoring and reporting plan for the evaporation ponds. The plan will include the type and frequency of monitoring and reporting to the Game & Fish Department and the U.S. Fish and Wildlife Service. Should any issues arise as a result of the monitoring and reporting plan, Applicant shall work with the United States Fish and Wildlife Service and the Arizona Game and Fish Department to develop screening or other methods to protect wildlife from harm at the Project's evaporation ponds.

28. Allegheny will continue cactus ferruginous pygmy owl surveys through the Spring of 2002, based on established protocol. If survey results are positive, the U.S. Fish and Wildlife Service and Arizona Department of Game and Fish will be contacted immediately for further consultation.

29. Allegheny will retain a qualified biologist to monitor all ground clearing/disturbing construction activities. The biological monitor will be responsible for ensuring proper actions are taken if a special status species is encountered (e.g., relocation of a Sonoran desert tortoise).

30. Applicant will salvage mesquite, ironwood, saguaro and palo verde trees

removed during project construction activities and use the vegetation for reclamation in or near its original location and/or landscaping around the plant site.

31. Allegheny will retain an Arizona registered landscape architect to develop a landscape plan for the perimeter of the generating facility. The landscape plan will use native or other low water use plant materials. The Applicant will continue to consult with La Paz County regarding the landscape plan.

32. Allegheny will use a directional drilling process to bore under Centennial Wash in constructing the gas pipeline to minimize potential impacts to the mesquite bosque associated with the wash.

33. The Applicant will continue to consult with La Paz County in relation to its comprehensive planning process to develop appropriate zoning and use classifications for the area surrounding the Project.

34. Allegheny will use its best efforts to avoid the two identified cultural resource sites. If Sites AZ S:7:48 and 49 (ASM) cannot be avoided by ground disturbing activities, the Applicant will continue to consult with the State Historic Preservation Office to resolve any negative impacts which usually entails preparing and implementing a data recovery research design and work plan.

35. If a federal agency determines that all or part of the Project represents a federal undertaking subject to review under the National Historic Preservation Act, Allegheny will participate as a consulting party in the federal compliance process (i.e., 36 C.F.R. 800) to reach a finding of effect and to resolve adverse effects, if any.

36. Should cultural features and/or deposits be encountered during ground disturbing activities, Allegheny will comply with A.R.S. § 41-844, which requires that work

cease in the immediate area of the discovery and that the Director of the Arizona State Museum be notified promptly.

37. If human remains or funerary objects are encountered during the course of any ground disturbing activities related to the development of the subject property, Applicant shall cease work and notify the Director of the Arizona State Museum in accordance with Ariz. Rev. Stat. § 41-865.

38. Allegheny will retain a qualified archaeologist to monitor ground clearing/disturbing construction activities and to appropriately instruct workers on detection and avoidance of cultural resource sites.

39. Applicant shall prepare a plan for shutdown, decommissioning and cleanup of the plant site which shall be filed with the Commission's Docket Control within one year of beginning construction. In that regard, the Committee recommends that Applicant work with La Paz County and/or any other local governing body with jurisdiction over the plant site to ensure that such plan is reasonable, and is followed or amended as necessary.

40. The Applicant, its successor(s) or assign(s) shall submit a self-certification letter annually listing which conditions contained in the CEC have been met. Each letter shall be submitted to the Utilities Division Director on August 1, beginning in 2002, describing conditions which have been met as of June 30. Attached to each certification letter shall be documentation explaining, in detail, how compliance with each condition was achieved. Copies of each letter, along with the corresponding documentation shall also be submitted to the Arizona Attorney General and the Directors of the Department of Water Resources and Department of Commerce Energy Office.

GRANTED this ______ day of ______________, 2002.

ARIZONA POWER PLANT AND
TRANSMISSION LINE SITING COMMITTEE

By ________________________________
Laurie Woodall, Chairwoman

12921-0004/947199 v10

EXHIBIT

A-35

admitted

California Environmental Protection Agency

AIR RESOURCES BOARD

Guidance for Power Plant Siting and Best Available Control Technology

As Approved by the Air Resources Board on July 22, 1999

Stationary Source Division

Issued September 1999

State of California
California Environmental Protection Agency
Air Resources Board

Guidance for Power Plant Siting and Best Available Control Technology

July 22, 1999

Prepared by
Project Assessment Branch
Stationary Source Division

Principal Authors

Grant Chin
Christopher Gallenstein
Robert Giorgis
Stephanie Nakao
Judy Yee

Michael Tollstrup, Manager
Project Support Section

Beverly Werner, Manager
Regulatory Assistance Section

Raymond Menebroker, Chief
Project Assessment Branch

ACKNOWLEDGMENTS

Contributing Air Resources Board Staff

John DaMassa

Greg Harris

Reviewed by

D. Aron Livingston, Legal Counsel	Office of Legal Affairs Executive Office
Peter Venturini, Chief	Stationary Source Division

Table of Contents

Appendices

Appendix A: CALIFORNIA ENERGY COMMISSION CURRENT AND FUTURE SITING CASES

Appendix B: GUIDANCE ON THE PROCEDURE FOR MAKING A BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION

Appendix C: SUPPORTING MATERIAL FOR BACT REVIEW FOR LARGE GAS TURBINES USED IN ELECTRIC POWER PRODUCTION

Appendix D: MANUFACTURER EMISSION GUARANTEES FOR NO_X AND AMMONIA SLIP

List of Tables

PREFACE

At a public meeting held on July 22, 1999, the Air Resources Board ("ARB" or "Board") approved the proposed Guidance for Power Plant Siting and Best Available Control Technology (Guidance), which was originally available on June 23, 1999. The Board adopted Resolution 99-31, approving the Guidance. Specific textual amendments to the Guidance discussed at the Board meeting, have been incorporated into this final version of the Guidance document. The changes made to the Guidance are summarized below.

Sections of the Guidance were modified to clarify that continuous emission monitors (CEMs) are not required for volatile organic compounds (VOC) and ammonia (NH_3).

Sections of the Guidance were modified to provide greater flexibility in the recommended frequency of source testing and the monitoring mechanisms to demonstrate compliance with emission limits.

Sections of the Guidance were modified to clarify that ammonia is not a federal hazardous air pollutant or a State-identified toxic air contaminant; however, it is listed under the Air Toxics "Hot Spots" Program due to acute and chronic non-cancer health effects.

Sections of the Guidance were modified to clarify that references to best available control technology (BACT) are intended to address "California BACT," which is equivalent to federal lowest achievable emission rate (LAER).

Sections of the Guidance were modified to clarify that the effectiveness of catalytic systems on the level of oxides of nitrogen (NO_X) emission control is dependent on turbine exhaust gas temperature. Because simple-cycle power plant configurations do not recover heat from the turbine exhaust gas, the temperature may be a consideration in evaluating the applicability of the recommended NO_X BACT emission level for simple-cycle power plants.

Sections of the Guidance related to BACT for particulate matter of 10 microns or less (PM_{10}) and oxides of sulfur (SO_X) were modified to clarify that the natural gas supply does not have to be provided by a Public Utilities Commission (PUC)-regulated utility.

Sections of the Guidance were modified to provide greater flexibility regarding the use of facility-wide emission limits, as long as adequate monitoring is specified.

Staff intends to periodically evaluate the need for modifications to the Guidance for the purpose of modifying recommended BACT emission levels, to make other related modifications, and to incorporate changes in policy. Staff will report back to the Board with these modifications and updates to the Guidance as appropriate. A copy of Resolution 99-31 is attached.

I.

EXECUTIVE SUMMARY

1. INTRODUCTION

In 1996, the Legislature passed a law which deregulated the electric utility industry in California to create a competitive, "open," market system for serving the electricity needs of homes, businesses, industry, and farms (Assembly Bill 1890, Statutes of 1996, Chapter 854). In response, there has been a statewide increase in proposed new power plant construction projects and anticipated projects over the next few years.[1] These power plant projects will need to comply with the requirements of various air pollution control programs. One major program entitled "New Source Review (NSR)" has requirements for emission control, best available control technology (BACT) or lowest achievable emission rate (LAER), and emission offsets. The Air Resources Board's (ARB) guidance set forth in this document will assist local air pollution control districts and air quality management districts (districts) in making permitting decisions as the districts participate in California's consolidated approval process for major power plants. Applicants will also find the information in this document useful in developing their proposed projects.

The State Energy Conservation Commission, more commonly known as the California Energy Commission (CEC), has the exclusive authority for licensing major power plant projects which replaces district authority to construct permits. Other State and local agencies participate in the process to ensure that the projects will comply with applicable laws, ordinances, regulations, and standards. In California, new or modified sources that will emit air pollutants typically must meet certain emission control requirements and obtain preconstruction and operating permits from the district. The district prepares an engineering analysis and places conditions in the permits to ensure that the source will comply with the requirements of federal, State, and local air pollution regulations. For major power plants under the CEC's jurisdiction, the district's engineering analysis and proposed conditions for the preconstruction permit are submitted to the CEC as a Determination of Compliance

[1]Appendix A contains the California Energy Commission list of current and future siting cases: 35 projects which range in size from 120 to 1,500 megawatts (MW). The total aggregated electric generating capacity of these projects is in excess of 22,000 MW.

(DOC). However, the district issues and enforces the power plants' operating permits.

This guidance is intended to provide California districts with the information they need to ensure that new power plants employ the best available control technology, and are constructed and operated in away that eliminates or minimizes adverse air quality impacts. The proposed power plants are larger than, and are expected to be operated differently than existing power plants approved in past years. The differences will present new challenges for districts as they review proposed projects to determine whether or not the projects can comply with applicable requirements. This guidance is intended to promote general consistency in the districts' permitting decisions.

This document presents guidance along with some background information on the power plant siting process in California. Chapter I, Executive Summary, provides an introduction, background, and a recommendation. In Chapter II, staff provides background information including brief descriptions of the CEC power plant siting process, applicable air pollution control permit requirements, and the roles of the districts and the ARB. In Chapter III, guidance is provided on air pollution control technology (BACT) for large gas turbines used in electric power production. Guidance on emissions offsets, ambient air quality impact analysis, health risk assessment and management, and other considerations are provided in Chapter IV, Chapter V, Chapter VI, and Chapter VII, respectively. Several appendices are included to provide more detailed or technical information. Air pollution control technology continues to advance at a quick pace. Because of this, staff intends to periodically update this guidance with addendums, that reflect the advancing state of control technology.

B. BACKGROUND

This section briefly discusses the content of this document in question-and-answer format. The reader is directed to subsequent chapters for more detailed discussions.

1. What is the purpose of this guidance document?

The purpose of this document is to set forth guidance to assist districts in making permitting decisions as the districts participate in the CEC's power plant siting process. It will also provide all affected parties an understanding of ARB staff's position in its review of such permitting decisions. This guidance is intended to provide California districts with the information they need to ensure that new power plants employ the best available control technology, and are constructed and operated in a way that eliminates or minimizes adverse air quality impacts. Applicants will also find this guidance useful when developing and planning a proposed power plant project.

2. How has deregulation of the electric utility industry in California affected power plant construction?

Over the next few years, the open market created by the deregulation of the electric utility industry is expected to result in an increase in new power plant construction. Currently, over 22,000 megawatts (MW) in new generating capacity is being considered (based on the 35 current and future projects known to the CEC listed in Appendix A). The majority of the projects are large; individual projects have proposed electric generating capacity in the range of 500 to 1,000 MW. The projects propose to produce electricity using large stationary combustion turbines fueled with natural gas and equipped with state-of-the-art air pollution control technologies. In the 1997 California Energy Plan, the CEC projects that the total statewide peak electricity demand is expected to reach 68,100 MW by the year 2015. The difference in the projected peak demand and in-State installed capacity of 53,700 MW, as of August 1998, is approximately 14,400 MW. The CEC has stated that as much as 6,700 MW of new capacity will be needed between the years 2000 and 2007. These differences are the minimums to meet long-term reserve requirements of the system. In a competitive electricity market, additional new generation resources, beyond the minimum requirements, could compete with existing resources or provide ancillary services. Generation options could include out-of-state generation and transmission, demand-side management, and distributed generation. The 35 projects being proposed, or anticipated, to date would provide an additional 22,000 MW, if they are all constructed; some power plant proposals may never move beyond exploratory discussions.

3. How will the new power plants differ from plants built before the deregulation of the electric utility industry?

The new power plants will operate in the competitive market with more equipment startups and shutdowns and will operate at various power loads; these power plants are commonly referred to as "merchant power plants" that operate in "merchant mode." Equipment startups and shutdowns will account for a greater proportion of emissions from these new plants, than traditional plants. In general, oxides of nitrogen (NO_X) emissions from the new units will be approximately 0.1 pounds per megawatt-hour (lb/MW-hr) less than emissions from existing power plants. For example, NO_X emissions from an existing gas-fired utility boiler typically would be 0.15 lb/MW-hr as compared to a new gas turbine power plant emitting at 0.05 lb/MW-hr.

4. What are the expected air pollution impacts from the new power plants?

As mentioned, most of the proposed power plants will consist of large stationary combustion turbines. The operation of the turbines with natural gas as fuel and state-of-the art controls is expected to result in some of the lowest emission concentrations achieved to date for this source category. However, despite the benefit of lower emission concentrations, the merchant operation and the large size of the combustion turbines is expected to result in substantial emissions. The emissions are likely to exceed New Source Review (NSR) permitting regulation thresholds for emission offsets for NO_X and carbon monoxide (CO). The larger projects may also exceed the offset thresholds for particulate matter of ten microns or less (PM_{10}), oxides of sulfur (SO_X), and volatile organic compounds (VOC). Unless adequately mitigated as part of the new source review process, these emissions have the potential to negatively impact ambient air quality.

5. What is the process for approving power plant construction?

California has a consolidated approval process for the siting of major power plants. The CEC has the exclusive authority to approve the construction and operation of power plants that use thermal energy and have an electric generating capacity of 50 MW or larger. The CEC's authority supercedes that of all other State and local agencies. The CEC, however, solicits other local, State, and federal agencies' participation in the power plant siting process to ensure that the construction and operation of power plants will comply with applicable local, State, and federal requirements. The CEC siting process additionally provides full opportunity for public participation.

6. What areas are covered by this guidance?

This guidance document addresses the following five specific areas:

- best available control technology (BACT) - staff's review of recent BACT determinations for large gas turbines used in electric power production and staff's guidelines;

- emission offsets - how to assure that emission offsets provided by the project will be sufficient in quantity and type to provide an air quality benefit, with specific guidance on interpollutant and interbasin offset trading;

- ambient air quality impact analysis - the purpose of an ambient air quality impact analysis and procedures for performing the analysis, if required;

- health risk assessment - the purpose of a health risk assessment for a toxic air contaminant and procedures for performing the analysis, if required; and

- other permitting considerations - identifies the numerous issues that are difficult to address in a permit, including emission limits, equipment startup and shutdown, source testing and monitoring, fuel sulfur content, and ammonia slip with the utilization of selective catalytic reduction (SCR) control technology.

7. How was this guidance developed?

Consistent with ARB's oversight responsibility for air pollution control programs in California, staff drafted the proposed guidance document and provided it to interested parties for review and comment. On February 24, 1999, staff held a scoping meeting to discuss the BACT component of this guidance. Staff also held public workshops on May 21 and 25, 1999, to discuss the areas covered by the guidance document and on July 6, 1999, to receive comments on the proposed guidance document. Attendees at the workshops included district representatives, CEC staff, electric utilities representatives, equipment manufacturers, and environmental group representatives. Staff has also had numerous conversations with interested parties.

3. RECOMMENDATION

The Board endorses the use of this guidance document by local districts and staff in reviewing and siting major power plants in California. The salient points are as follows:

1. Best Available Control Technology for Large Gas Turbines Used in Electric Power Production

Health and Safety Code Section 42300 authorizes delegation of stationary source permitting authority from the State to local air districts. Each district has its own set of definitions and rules. As a result, the definition of BACT and, where used, LAER can vary by district.

Federal BACT is defined in Section 169(3) of the federal Clean Air Act. It states that the 'term "best available control technology" means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques,...'

Federal LAER is defined in Section 171(3) of the federal Clean Air Act. It states that the 'The term "lowest achievable emission rate" means for any source, that rate of emissions which reflects --(A) the most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or (B) the most stringent emission limitation which is achieved in practice by such class or category of source, whichever is more stringent.'

Most BACT definitions in California are consistent with the federal LAER definition and are often referred to as "California BACT." One should take note not to confuse "California

BACT" with the less restrictive federal BACT. In the context of this guidance, references to BACT specifically refer to "California BACT."

BACT guidelines for NO_X, CO, VOC, PM_{10}, and SO_X emissions are summarized in Tables I-1 and I-2 for simple-cycle power plant configurations and combined-cycle power and cogeneration power plant configurations, respectively. BACT requirements will change if operational data or advances in technology demonstrate that lower levels have been achieved or are achievable at a reasonable cost. Given the regional nature of ozone and PM_{10} precursor pollutants (NO_X and VOC for ozone, and SO_X for PM_{10}), the BACT levels in Tables I-1 and I-2 apply in both attainment and nonattainment areas. Because CO is a localized pollutant and generally attributed to mobile sources, the area attainment status could be considered in establishing BACT to the extent allowed in district rules and regulations. However, factors that may affect the district's BACT determination include, but are not limited to, use of aeroderived versus industrial frame gas turbine for simple-cycle power plant configuration, and the use and function of the gas turbine. When selective catalytic reduction is the control method for NO_X emissions, districts should consider establishing health protective ammonia slip levels at or below 5 ppmvd at 15 percent oxygen in light of the fact that control equipment vendors have openly guaranteed single-digit levels for ammonia slip.[2]

The basis for the BACT emission levels in Table I-1 for simple-cycle power plant configurations is as follows:

- for NO_X, the most stringent BACT required and achieved in practice in three consecutive annual source tests;
- for CO, the most stringent BACT required and achieved in practice in three consecutive annual source tests; and
- for VOC, within the range of the most stringent BACT required and based on levels achieved in practice in three consecutive annual source tests.

It should be noted that as exhaust gas temperatures increase, performance and reliability of control systems for reducing NO_X emissions may diminish and should be considered in determining BACT for NO_X emissions from simple-cycle power plants.

[2]Ammonia slip guarantees from several selective catalytic reduction vendors are included in Appendix D.

Table I-1: Summary of BACT for the Control of Emissions from Stationary Gas Turbines Used for Simple-Cycle Power Plant Configurations

NO_X	CO	VOC	PM_{10}	SO_X
5 ppmvd @ 15% O_2, 3-hour rolling average	6 ppmvd @ 15% O_2, 3-hour rolling average	2 ppmvd @ 15% O_2, 3-hour rolling average OR 0.0027 pounds per MMBtu (based on higher heating value)	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf (no more than 0.55 ppmvd @ 15% O_2)

Table I-2: Summary of BACT for the Control of Emissions from Stationary Gas Turbines Used for Combined-Cycle and Cogeneration Power Plant Configurations

NO_X	CO	VOC	PM_{10}	SO_X
2.5 ppmvd @ 15% O_2, 1-hour rolling average OR 2.0 ppmvd @ 15% O_2, 3-hour rolling average	6 ppmvd @ 15% O_2, 3-hour rolling average	2 ppmvd @ 15% O_2, 1-hour rolling average OR 0.0027 pounds per MMBtu (based on higher heating value)	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf (no more than 0.55 ppmvd @ 15% O_2)

The basis for the BACT emission levels in Table I-2 for combined-cycle and cogeneration power plant configurations is as follows:

- for NO_X, the most stringent emission level deemed BACT by the South Coast Air Quality Management District, recognized as demonstrated in practice by the United States Environmental Protection Agency (U.S. EPA), and the most stringent BACT level proposed for six major power plant projects either approved or currently under review;

- for CO, a reasonable level of emissions based on previous BACT requirements, emission levels achieved in practice, and BACT levels proposed for major power plants currently under review, with the understanding that flexibility in adjusting the BACT emission level is given to sources in CO attainment areas and where allowed by district rules; and

- for VOC, within the range of the most stringent BACT required and based on levels achieved in practice by similar power plants.

The basis for the BACT emission levels for PM_{10} and SO_X in Tables I-1 and I-2 for both simple-cycle power plant configurations and combined-cycle and cogeneration power plant configurations is the type of fuel combusted and levels of fuel sulfur found in natural gas readily available from California utilities.

2. Emission Offsets

Emission reductions used as offsets need to be specifically identified and quantified in accordance with applicable requirements of district emission reduction credit banking programs and State and federal law. To the extent allowed by applicable programs and law, the emission reduction may be a different type of pollutant than the emission increase (i.e., interpollutant emission offsets) or originate outside the air basin of the proposed project's location (i.e., interbasin emission offsets). Interpollutant or interbasin emission offsets should be allowed only after the applicant has surrendered any applicant-held emission reduction credit certificates and has demonstrated that additional emission reductions are not available onsite. However, the use of interpollutant and interbasin emission offsets must not prevent or interfere with the attainment or maintenance of any applicable ambient air quality standard.

1. Offset Package Milestones

Consistent with CEC power plant siting regulations and procedures, an emission offset package should be complete and secured by the following milestones in the permitting process:

- a complete offset package identified and quantified at the time of submission of the Application for Certification (AFC),

- letters of intent signed by the time the district provides public notice for the preliminary Determination of Compliance (DOC),

- option contracts signed by the time of issuance of the final DOC, and

- offsets secured and in place prior to operation of the power plant. (However, some emission trades may include emission reductions that are contemporaneous; that is, occurring within a designated period ending shortly after commencement of operation.)

2. Interpollutant and Interbasin Emissions Offset Ratios

Minimum interpollutant emissions offset ratios and interbasin emission offset ratios are summarized in Tables I-3 and I-4. The interpollutant offset ratios in Table I-3 are based on recent and past assessments of interpollutant relationships; staff is in the process of developing offset ratios specific to air basins through the utilization of a photochemical grid model (where available) and a gridded emission inventory for the ozone attainment year. The interbasin pollutant offset ratios in Table I-4 were derived by staff after surveying district regulatory requirements for the distance offset ratios established in district rules and regulations for use within their respective air basins. However, other methods for determining emission offset ratios may be allowed, consistent with district rules and State law, on a case-by-case basis when justified by the particular circumstances for the proposed project.

The overall emission offset ratios should be determined by combining, unless otherwise specified in district rules, the interpollutant emission offset ratio and the interbasin emission offset ratio, as applicable, and all other applicable district discount or distance ratios; this is a critical requirement when an offset ratio is independent of other ratios in its protection of air quality. With the inherent uncertainties associated with the determination of offset ratios, combining the applicable offset ratios will help ensure that sufficient emission offsets have been obtained to provide an air quality benefit.

Table I-3: Minimum Interpollutant Offset Ratios

Offsetting Pollutants	Minimum Interpollutant Offset Ratio
Ozone Precursors (NO_X and VOC)	Basin specific and no less than 1.0:1
$PM_{2.5}$, PM_{10}, and Precursors (NO_X, VOC, and SO_X)[3]	1.0:1

[3]Due to a lawsuit and the U. S. EPA's implementation schedule for the federal standard, there are no current requirements for $PM_{2.5}$ offsets.

Table I-4: Minimum Interbasin Offset Ratios

Distance Between Project and Offsetting Source	Minimum Interbasin Offset Ratio
Within 50 miles	2.0:1
Over 50 miles	Increase the 2.0:1 by 1.0 for every 25 miles increase beyond 50 miles

3. Ambient Air Quality Analysis

Any evaluation of air quality impacts from a new power plant should be conducted with a model approved by the U.S. EPA and the ARB. A modeling protocol should be prepared and shared with the appropriate regulatory agencies. The protocol should describe the model(s) to be used, how the model will be applied, the types and sources of input data, the assumptions used, and the type of results or outputs. Any modeling conducted for evaluating ozone impacts associated with the proposed use of interpollutant offsets should employ available gridded emission inventories and urban airshed models where available and used in the most recent version of the State Implementation Plan. A protocol will greatly facilitate review of the proposed modeling approach and minimize subsequent technical disagreements. An ARB guidance document, "Technical Guidance Document: Photochemical Modeling, April 1992," is available.

4. Health Risk Assessment

Any health risk assessment for a large power plant project should be conducted consistent with established district policies, or regulations, on health risk assessment for making risk management decisions. When applicable policies or regulations are not in place, health risk should be assessed according to guidance established by the Office of Environmental Health Hazard Assessment (OEHHA) pursuant to Section 44360.b.2. of the Health and Safety Code. Risk management decisions should be consistent with the ARB's "Risk Management Guidelines for New and Modified Sources of Toxic Air Pollutants, July 1993." Risk assessments prepared for recent proposed power plant projects report that the increase in lifetime cancer risk is less than one in a million.

5. Other Permitting Considerations

Recommendations are provided for adequately addressing the following issues in a power plant permit: emission limits, startup and shutdown of equipment, source testing and monitoring, fuel sulfur content, and ammonia slip.

1. Emission Limits

Permit conditions specifying the emission limits should be expressed in the same form as the underlying regulatory requirement. For example, if a BACT requirement is expressed as an emission concentration measured at a given averaging time and exhaust gas oxygen content, the permit condition implementing the requirement should utilize the same parameters.

2. Equipment Startup and Shutdown

A district should address all phases of plant operations in BACT decisions and assure that controls are required and used where feasible to minimize power plant emissions; permit emission limits should be written to apply to turbine emissions for all potential loads. Emissions generated during equipment startup and shutdown should be regulated by a separate set of limitations to optimize emission control; to regulate these emissions, permit conditions should limit and require record keeping of the number of daily and annual startups and shutdowns. The power plant operator should be required to have a district-approved plan to minimize emissions from equipment startup and shutdown.

3. Source Testing and Monitoring

ARB's goal is to assure initial and ongoing compliance of each power plant with BACT and other emission limits specified in permit conditions. Compliance with BACT and other emission limits is most easily verified through continuous emission monitors (CEMs) and annual source testing, using certified methods that meet district, State, and federal protocols.

4. Fuel Sulfur Content

The permit should include conditions to address SO_X emission levels and to require that the levels be determined using the upper limit of the sulfur content specified in the natural gas supplier's contract.

5. Ammonia Slip

The permit should include conditions to minimize the amount of ammonia slip to a health protective level when selective catalytic reduction is used as a control method; districts should consider establishing ammonia slip levels at or below 5 ppmvd at 15 percent oxygen.

II.

POWER PLANT SITING IN CALIFORNIA

1. OVERVIEW

The California Energy Commission (CEC) has been given authority under State law for a consolidated approval process for the siting of major power plants that use thermal energy.[4] This process allows a project applicant to submit a single application for all necessary State and local approvals. This siting process is intended to avoid duplication, provide a timely review, and provide analysis of all aspects of a proposed project, including need, environmental impact, safety, efficiency, and reliability. The siting process fully satisfies California Environmental Quality Act (CEQA; Sections 21000-21177 of the Public Resources Code) requirements by integrating CEQA's purposes and objectives to assure that all potential impacts of a major project are reviewed.

The CEC has the exclusive authority to approve the construction and operation of power plants that will use thermal energy and have electric generating capacities of 50 megawatts (MW) or larger.[5] The CEC's authority supercedes that of all other State and local agencies, particularly in regards to requirements for permits, and federal agencies to the extent provided by federal law. However, the CEC solicits other public agencies' participation in the power plant siting process to ensure that the construction and operation of power plants will comply with applicable local, State, and federal requirements. For example, the CEC siting process incorporates the local air pollution control and air quality management district's (district) preconstruction permitting program entitled "New Source Review (NSR)." As with non-power plant projects, the district

---

[4]Sources of thermal energy include natural gas, synthetic gas, methanol, oil, coal, other fossil fuel, nuclear power, geothermal, biomass, and the sun.

[5]Proposed facilities between 50 to 100 MW may qualify for a Small Power Plant Exemption (SPPE) from the CEC. Exempt projects and projects under 50 MW are subject to the authority of local agencies, including any necessary permits.

independently evaluates the power plant project, prepares permit conditions (e.g., design, operation, and other) to address applicable air quality requirements, and provides public notice and comment opportunity. After the power plant is constructed, the district issues an operating permit and conducts normal enforcement activities to ensure compliance of the power plant with applicable air quality rules and regulations.

The remainder of this chapter briefly describes the CEC power plant siting process, the air pollution regulatory programs applicable to power plants, the role of local air districts, and the role of the Air Resources Board (ARB).

B. BRIEF DESCRIPTION OF THE CALIFORNIA ENERGY COMMISSION 'S POWER PLANT SITING PROCESS

As provided by the 1974 Warren-Alquist Act (Section 25000 *et. seq.* of the Public Resources Code), the CEC's siting responsibilities consist of a statewide planning analysis, a two-phase site approval process, and a compliance monitoring function. A brief description of the overall siting process and identification of the participants is provided below. For more details, consult these CEC documents, "Power Plant Siting," and "Participating in the Siting Process: Practice and Procedure Guide, Second Edition," and siting regulations, "Rules of Practice and Procedures" and "Power Plant Certification Regulations" (Title 20, Division 2, of the California Code of Regulations). Information on current power plant applications is available at the CEC's website.[6]

The Notice of Intention to file an Application for Certification (NOI) is the first of a two-part power plant siting process; the Application for Certification (AFC) is the second phase. Participants are the full decision-making body of the CEC (the Commission), a Commission committee to act as administrative judges, the Hearing Advisor, CEC staff acting as an independent objective party, the Public Advisor, the applicant, the public, other public agencies, and intervenors.[7] All NOIs and AFCs undergo a review process consisting of the following six phases: prefiling, data adequacy, discovery, analysis, hearings, and decision. The NOI phase has a review period of nine months for geothermal projects and 12 months for non-geothermal and

[6] http://www.energy.ca.gov

[7] A public member or agency must apply to become an intervenor. An intervenor is a formal party to the proceedings with certain responsibilities and certain rights not granted to other public members or agencies.

transmission line projects. An AFC exempt from the NOI phase, or an AFC filed within one year of the NOI decision, has a review period of 12 months from its acceptance for filing; otherwise, the AFC phase has a review period of 18 months.

The NOI phase is traditionally used to determine the need for the proposed power plant, site acceptability and suitability, and alternatives to a proposed project. An affirmative NOI decision represents an approval of the proposal in concept. The consideration of a specific site, technology and equipment occurs in the AFC phase. With the deregulation of the electric utility industry, applicants are seeking, and receiving, exemptions from the NOI phase. On May 12, 1999, the CEC announced that it has amended its policies and procedures to allow any proponent for a natural gas-fired merchant power plant project to file an AFC without applying for an NOI exemption.

In the AFC phase, the design, construction, operation, and closure of the power plant is closely examined in relation to applicable laws, ordinances, rules, and standards. Adverse environmental effects are identified and mitigation measures established. The need for the facility is determined, or reconfirmed, if preceded by an NOI. The AFC process ensures that the proposed power plants are safe, reliable, environmentally sound, and comply with all applicable requirements.

C. MAJOR AIR POLLUTION REGULATORY PROGRAMS APPLICABLE TO POWER PLANTS

All proposed power plants must be constructed and operated in compliance with applicable federal, State, and local air pollution requirements and this compliance must be provided for as one aspect of the CEC siting process. The new, or modified, power plant is subject to the requirements of several programs established by the federal Clean Air Act; where applicable, the district incorporates the requirements of these programs into its rules and regulations. Additional district rules and regulations implementing measures or programs specified in the State Implementation Plan, the California Clean Air Act (CCAA) of 1988 (Statutes of 1988, chapter 1568), and the district's local air quality plan are also applicable to the power plants.

For power plant projects, the air pollution control program of primary concern is entitled "New Source Review (NSR)." California's NSR permit program is derived from the State Health and Safety Code and the federal Clean Air Act. Each of the districts in California has adopted its own NSR rules and regulations to regulate the construction of new, and modifications to, industrial sources which will emit air pollutants. The control requirements are pollutant specific and depend on an area's attainment status for the ambient air quality standards; a district may have an attainment designation for some pollutants and a nonattainment designation for other pollutants. Each district uses the term, "best available control technology (BACT)" exclusively when referring to the emission control requirements of their New Source Review permitting programs. With a few exceptions, the district definitions of BACT are based on federal lowest achievable emission rate (LAER) rather than federal BACT.[8] For this reason, BACT definitions in California are often referred to as "California BACT." In addition, larger sources are required to mitigate any remaining emissions after the installation of controls by supplying offsets. Offsets are emission reductions at the project location or at another location. Offsets are needed to mitigate the adverse air quality impacts from the expected increase in emissions from the project.

There is also a federal program for new source performance standards (NSPSs); the NSPSs are regulations adopted by the United States Environmental Protection Agency (U.S. EPA) that define emission limits, testing, monitoring, and record keeping for certain categories of sources or processes (Sections 111 and 129 of the federal Clean Air Act; Title 40 Code of Federal Regulations (40 CFR) Part 60). The NSPS for gas turbines at power plants is contained in Subpart GG of 40 CFR Part 60. The federal program for national emission standards for hazardous air pollutants (NESHAP) is applicable to new and existing sources emitting over ten tons per year (TPY) of one hazardous air pollutant (HAP) or 25 TPY of a combination of HAPs (Section 112 of the federal Clean Air Act; 40 CFR Part 61 and 63); a NESHAP may include a requirement for maximum achievable control technology (MACT). However, electric utility steam generating units are temporarily exempt from MACT requirements by Section 112(n)(1)(A) of the federal Clean Air Act. A proposed power plant is also subject to the monitoring and reporting requirements of Title IV (Acid Rain) of the federal Clean Air Act. An operating power plant will be required to meet the permit requirements of Title V (Major Source Operating Permits) of the federal Clean Air Act. The requirements of Title IV and Title V are implemented through federal regulations in 40 CFR Parts 72-78 and Parts 70-71, respectively, and applicable district regulations.

A power plant project may also be subject to requirements and control measures contained in the State Implementation Plan and local air quality plans. Some districts have rules or policies for reviewing new sources of toxic air contaminants which may include emission control and mitigation requirements at certain health risk levels. A new power plant is subject to the "New Facility Operator Requirement" of the Air Toxics "Hot Spots" Information and Assessment Act of 1987 pursuant to Section 44344.5 of Health and Safety Code. The Air Toxics "Hots Spot" Act (Section 44360 *et seq.* of the Health and Safety Code) established a statewide program for the inventory of air toxics emissions from individual facilities as well as, in certain cases, requirements for risk assessment and public notification of potential health risk.

---

[8]In certain districts with attainment, or unclassified, designations for the ambient air quality standards, the BACT definition may be more similar to the less stringent federal requirement which is termed "best available control technology (BACT)". The more stringent federal requirement is termed "lowest achievable emission rate (LAER)" and is required when an area is nonattainment for a standard.

4. LOCAL AIR DISTRICT'S ROLE IN THE POWER PLANT SITING PROCESS

For power plants with 50 MW or greater capacity, the districts' traditional permitting responsibility to control emissions from non-vehicular sources (stationary sources) is incorporated into the CEC's power plant siting process. The CEC's power plant siting regulations specifically provide for the district's participation in the process. The district has the primary responsibility within the AFC process for determining a project's compliance with its NSR permitting regulations and other applicable air pollution control regulations. Each district's regulations may vary depending on the air quality conditions in the district and the district's policies and strategies for attaining or maintaining compliance with the federal and State ambient air quality standards. The district's analysis and recommendations are provided to the CEC in a document known as a Determination of Compliance (DOC).[9]

The district's participation begins early in the process with the review of the application for completeness. The district will also determine if more specific information is needed to assess the acceptability of the project and independently evaluate the project and prepare a preliminary DOC. The preliminary DOC documents the configuration of the power plant, its component sources (equipment), emissions, applicable regulations, and contains an air quality impact assessment. The preliminary DOC additionally contains design, operation, and other conditions needed to ensure compliance with applicable air quality regulations. The district will provide a public notice and comment period for the preliminary DOC. CEC staff recommends that the preliminary DOC be completed within 120 days of the date the CEC finds that the AFC is data adequate; CEC staff will include the preliminary DOC in the CEC's Preliminary Staff Assessment. A final DOC must be provided to the CEC within 180 days of the data adequacy finding for inclusion in the CEC's Final Staff Assessment.

At CEC hearings, the district may be called on to testify on its analysis and recommended conditions in the DOC. If the district has become an intervenor in the siting process, the district may independently provide unrestricted testimony and question other participants. When a project is approved, the CEC decision will contain air quality conditions of certification. In most cases, the conditions will reflect the requirements set forth by the district in its DOC. Additional conditions (e.g., mitigation related to CEQA) may be included at the recommendation of CEC staff. After the power plant is constructed, the CEC compliance monitoring process accommodates district issuance of an operating permit. Via this mechanism, the district can conduct normal enforcement activities to ensure compliance of the power plant with applicable air quality rules and regulations.

---

[9]The DOC is functionally equivalent to both the engineering analysis and preconstruction permit, the Authority to Construct, that the district would typically prepare for applications under its jurisdiction.

5. AIR RESOURCES BOARD'S ROLE IN THE POWER PLANT SITING PROCESS

The ARB is the State agency charged with coordinating efforts to attain and maintain federal and State ambient air quality standards and comply with requirements of the federal Clean Air Act (42 U.S.C., Section. 7401, et seq.).[10] The ARB is empowered to do such acts as may be necessary for the proper execution of these powers and duties. State regulations permit, and in some cases require, that the ARB participate in the CEC siting process to help ensure that power plant will be constructed and operated in compliance with all applicable laws, ordinances, regulations, and standards.

The ARB is typically an informal participant in the power plant siting process; however, the ARB also has the option of applying to be a formal participant, an intervenor. Consistent with the ARB's overall responsibilities, staff follows each power plant siting proceeding. Staff will attend many of the workshops and hearings and generally function as a sounding board and resource to the district and CEC staff. Staff will also provide comments to the CEC on the district's preliminary and final DOC, as necessary, to reflect the policies outlined in this guidance. If requested, staff can provide the district and the CEC with technical assistance.

[10]The ARB also has the primary responsibility for control of air pollution from vehicular sources.

III.

BEST AVAILABLE CONTROL TECHNOLOGY FOR LARGE GAS TURBINES USED IN ELECTRIC POWER PRODUCTION

A. SUMMARY OF BACT ANALYSIS

This chapter summarizes Air Resources Board (ARB) staff's analysis of best available control technology (BACT) for stationary natural gas-fired turbines (herein referred to as "gas turbines") having a power rating of 50 megawatts (MW) or greater and used for electric power production. General guidance for performing a BACT evaluation is contained in Appendix B. The summary information in this chapter covers control methods for oxides of nitrogen (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), particulate matter of ten microns or less (PM_{10}), and oxides of sulfur (SO_X) emissions. These control methods include both combustion and add-on control technologies.

In most air pollution control and air quality management district (district) permitting rules, BACT is defined as the most stringent limitation or control technique:

1) which has been achieved in practice,

2) is contained in any State Implementation Plan (SIP) approved by the United States Environmental Protection Agency (U.S. EPA), or

3) any other emission control technique, determined by the Air Pollution Control Officer to be technologically feasible and cost effective.

Staff BACT guidelines are summarized in Tables III-1 and III-2. Different requirements apply to gas turbines used in simple-cycle than apply to combined-cycle and cogeneration power plant configurations. The BACT emission levels in the tables should be considered contemporaneous with the publishing of ARB's guidance. BACT requirements will change if operational data or advances in technology demonstrate that lower levels have been achieved or are achievable at a reasonable cost. These emission levels should be used as a starting point in case-by-case analyses. Conditions specific to each gas turbine application may be considered in adjustment of the recommended BACT emission levels. Factors that may affect the BACT determination include, but are not limited to:

- area attainment status,
- gas turbine exhaust gas temperature for simple-cycle power plant configuration (for example, use of aeroderived versus industrial frame gas turbine), and
- use and function of gas turbine.

It is the responsibility of the permitting agency to make its own BACT determination for the class and category of gas turbine application. The BACT emission levels are intended to apply to the emission concentrations as exhausted from the stacks. Summaries of information and findings utilized in assessing BACT for gas turbine emissions follow the tables. Supporting material is presented in Appendix C.

Table III-1: Summary of BACT for the Control of Emissions from Stationary Gas Turbines Used for Simple-Cycle Power Plant Configurations

NO_X	CO	VOC	PM_{10}	SO_X
5 ppmvd @ 15% O_2, 3-hour rolling average	6 ppmvd @ 15% O_2, 3-hour rolling average	2 ppmvd @ 15% O_2, 3-hour rolling average OR 0.0027 pounds per MMBtu (based on higher heating value)	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf (no more than 0.55 ppmvd @ 15% O_2)

Table III-2: Summary of BACT for the Control of Emissions from Stationary Gas Turbines Used for Combined-Cycle and Cogeneration Power Plant Configurations

NO_X	CO	VOC	PM_{10}	SO_X
2.5 ppmvd @ 15% O_2, 1-hour rolling average OR 2.0 ppmvd @ 15% O_2, 3-hour rolling average	6 ppmvd @ 15% O_2, 3-hour rolling average	2 ppmvd @ 15% O_2, 1-hour rolling average OR 0.0027 pounds per MMBtu (based on higher heating value)	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf (no more than 0.55 ppmvd @ 15% O_2)

B. SUMMARY OF INFORMATION AND FINDINGS

For the purposes of recommending BACT for gas turbines, staff considered the controls for each pollutant and corresponding emission levels in the context of:

- current SIP control measures,
- emission limits and control techniques required as BACT,
- emission levels achieved in practice, and
- more stringent control techniques which are technologically and economically feasible but are not yet achieved in practice.

The BACT emission levels discussed in the following sections apply to those emissions occurring during normal operations and should not be construed as being required during startup and shutdown periods. Factors which should be taken into consideration when limiting emissions from startup and shutdown are discussed at the end of this section.

1. Control of NO_X Emissions

a. Current SIP Control Measures

There are several control measures in approved SIPs that apply to the control of NO_X emissions from gas turbines. These control measures were adopted by local districts to reduce emissions from existing gas turbines. The most stringent of these control measures have been adopted in California with NO_X emission standards based, for the most part, on size, annual operating hours, and control systems employed. The most stringent NO_X requirements are 25 parts per million by volume dry (ppmvd) at 15 percent oxygen averaged over 15 consecutive minutes for gas turbines from 0.3 to under 2.9 MW, 9 ppmvd at 15 percent oxygen averaged over 15 consecutive minutes for gas turbines rated 2.9 to 10 MW, and 9 ppmvd at 15 percent oxygen averaged over 15 consecutive minutes for gas turbines of at least 10 MW employing selective catalytic reduction. The control measures are applicable to stationary gas turbines (greater than 0.3 MW in size) and provide limited exemptions from the NO_X standards for certain units.[11] These control measures have been adopted to comply with air quality goals of the California Clean Air Act of 1988 and meet a level of stringency referred to as Best Available Retrofit Control Technology (BARCT). BARCT can be more stringent than similar control measures required for the Federal Clean Air Act, which are referred to as Reasonably Available Control Technology (RACT).

[11]Exemptions are generally provided for laboratory units, units used only for firefighting or flood control, emergency standby units, units under 4 MW with limited annual hours of operation, and during startup and shutdown. Exemptions do not preempt the units from all rule requirements. The exemptions primarily apply to requirements for emission limits.

b. Control Techniques Required as BACT

The efficiency of some NO_X control techniques is affected by exhaust temperature. This is especially true of catalytic control techniques. Efficiencies of these controls techniques may be reduced at hot or cold temperatures. For example, high temperatures associated with uncooled exhaust may cause sintering of a catalyst. Conversely, catalysts normally require a minimum temperature before they become chemically active. Flue gas temperatures associated with simple-cycle gas turbines are higher than those of gas turbines used in combined-cycle and cogeneration operations. In the latter, exhaust heat is removed with a heat recovery steam generator (HRSG) resulting in a decrease in flue gas temperatures from the gas turbine (e.g., 1050 °F) to the stack (e.g., 350 °F). On the other hand, simple-cycle gas turbines can have exhaust temperatures ranging up to and around 1100 °F, which vary only slightly from the gas turbine to the stack. Catalysts used for selective catalytic reduction are not as efficient in controlling NO_X at the higher temperatures associated with uncooled exhaust. As a result, gas turbine emissions from combined-cycle and cogeneration operations can be controlled with more efficiency.

The most stringent BACT limit for a simple-cycle gas turbine was specified in the preconstruction permit issued for Carson Energy Group in Sacramento County, California. The permit establishes a limit of 5 ppmvd NO_X at 15 percent oxygen averaged over 3 hours with ammonia slip limited to 20 ppmvd at 15 percent oxygen. The determination was made for a 42 MW General Electric LM6000 gas turbine with water injection and selective catalytic reduction. This turbine has been in operation since 1995.

The most stringent BACT limit for a combined-cycle gas turbine was specified in a preconstruction permit issued for the Sutter Power Plant near Yuba City, California. The permit establishes a limit of 2.5 ppmvd NO_X at 15 percent oxygen averaged over 1 hour with ammonia slip limited to 10 ppmvd at 15 percent oxygen. This determination was for a Westinghouse 501F gas turbine nominally rated at 170 MW with dry low-NO_X combustors and selective catalytic reduction. There are other major combined-cycle and cogeneration power plant projects currently going through the California Energy Commission's (CEC) siting process that are proposing a BACT limit of 2.5 ppmvd NO_X at 15 percent oxygen averaged over 1 hour. These projects are the High Desert Power Plant, the La Paloma Generating Company, Sunrise Cogeneration, Delta Energy Center, and Metcalf Energy Center. Therefore, to date, one project has been permitted and five projects are in the siting process at this NO_X levels.

The most stringent BACT limit for an operating combined-cycle gas turbine is 3 ppmvd NO_X at 15 percent oxygen averaged over 3 hours with the ammonia slip limited to 10 ppmvd at 15 percent oxygen. This emission level was achieved on a 102 MW combined-cycle Siemens V84.2 gas turbine at Sacramento Power Authority (Campbell Soup) in Sacramento County, California. The gas turbine is equipped with dry low-NO_X combustors and selective catalytic reduction. This unit has been operating since October 1997.

c. Emission Levels Achieved in Practice

Three consecutive years of source testing on a simple-cycle gas turbine at Carson Energy Group in Sacramento County, California, indicate emissions vary from approximately 3.95 to 4.72 ppmvd NO_X at 15 percent oxygen averaged over 3 hours. The 42 MW power plant consists of a General Electric LM6000 gas turbine with water injection and selective catalytic reduction. This gas turbine has been in operation since 1995.

Measurement with continuous emission monitors (CEMs) at Federal Cogeneration in Los Angeles County, California, indicates that an emission level of 2.0 ppmvd NO_X at 15 percent oxygen averaged over 15 minutes was achieved. This facility consists of a 32 MW combined-cycle General Electric LM2500 gas turbine. The gas turbine utilizes water injection in conjunction with an after treatment catalyst system called SCONOx. Initially, six months of CEMs data from June to December 1997 were examined by both the U.S. EPA and the South Coast Air Quality Management District (SCAQMD). Upon reviewing this data, the U.S. EPA deemed 2.0 ppmvd NO_X at 15 percent oxygen with a 3-hour averaging time as demonstrated in practice. This finding was presented in a March 23, 1998, letter from U.S. EPA to Robert Danziger of Goal Line Environmental Technologies. The SCAQMD subsequently determined BACT as 2.5 ppmvd at 15 percent oxygen with 1-hour averaging. In correspondence dated June 10, 1998, the U.S. EPA recognized 2.0 ppmvd and 2.5 ppmvd NO_X at 15 percent oxygen with 3- and 1-hour averaging times, respectively, as levels that would represent BACT.

Subsequent to the evaluations by both U.S. EPA and SCAQMD, ARB staff independently verified the performance claims of SCONOx for the seven month period from June 1, 1997 to December 31, 1997 by reviewing CEMs data. Staff's assessment was done through ARB's Equipment and Process Certification Program. Staff verified that the SCONOx system demonstrated emissions of 2.0 ppmvd NO_X at 15 percent oxygen over a 3-hour average with zero ammonia emissions.

d. More Stringent Control Techniques

There are three basic types of NO_X emission controls employed on gas turbines: wet controls using water or steam injection to reduce combustion temperatures for NO_X control, dry controls using advanced combustor design to suppress NO_X formation, and post-combustion controls to reduce NO_X formed in the turbine. While each type of control results in a particular level of NO_X emissions, the potential for reducing NO_X emissions down to single-digit values and fractions thereof has been achieved using controls in combination to reduce NO_X. Common NO_X control combinations currently in use include water or steam injection with selective catalytic reduction, dry low-NO_X combustors with selective catalytic reduction, and water injection with SCONOx. Gas turbine installations equipped with supplemental firing from duct burners generally reduce NO_X emissions using burner combustion controls such as low-NO_X burners. The combination of duct burner, gas turbine combustion, and add-on controls has the potential to reduce NO_X emissions to levels more stringent than what has currently been achieved in practice.

Staff has identified a number of power plant projects with proposed emissions below the achieved in practice level of 2.5 ppmvd NO_X at 15 percent oxygen averaged over 1 hour. One of these projects is for the Sunlaw Energy Corporation which is proposing to meet an emission rate of 1 ppmvd NO_X at 15 percent oxygen averaged over 1 hour for an 840 MW combined-cycle natural gas-fired power plant in Los Angeles County, California. The NO_X emission level is proposed to be achieved using SCONOx. There are no ammonia emissions from the SCONOx technology. This project represents a refining of the SCONOx control technology which is already recognized as achieved in practice at 2.0 ppmvd NO_X at 15 percent oxygen averaged over 3 hours. The Application for Certification (AFC) is tentatively scheduled to be filed with the CEC in September 1999. Two projects in Massachusetts, ANP Bellingham and ANP Blackstone, have been conditionally approved with emissions of 2.0 ppmvd NO_X at 15 percent oxygen averaged over 1 hour and 3.5 ppmvd NO_X at 15 percent oxygen averaged over 1 hour during power augmentation with steam injection. Both power plants will consist of two 180 MW ABB GT-24 gas turbines. The NO_X emission levels are proposed to be achieved using selective catalytic reduction. Ammonia slip will be limited to 2.0 ppmvd at 15 percent oxygen averaged over 1 hour. Another Massachusetts project in the proposed stage is the 360 MW Island End Cogeneration. Proposed emission levels are also 2.0 ppmvd NO_X at 15 percent oxygen and 2.0 ppmvd ammonia at 15 percent oxygen averaged over 1 hour using selective catalytic reduction.

Emission levels from 1.33 to 4.04 ppmvd NO_X at 15 percent oxygen averaged over 15 minutes measured with a CEMs have been achieved at Silicon Valley Power in Santa Clara, California, utilizing the XONON technology. XONON is a flameless catalytic system integrated into the combustor to lower temperature. This facility consists of a 1.5 MW simple-cycle Kawasaki M1A-13A gas turbine. Once this technology is scaled-up, it may represent the most efficient combustion control for NO_X available for gas turbines. There is not yet sufficient operating experience to ensure reliable performance on large gas turbines. General Electric is currently working with Catalytica Combustion Systems (manufacturer of XONON) to implement the technology on a larger scale.

Coen Company submitted a proposal in February 1999 to ARB's Innovative Clean Air Technology (ICAT) Program to develop and demonstrate a low-NO_X duct burner for cogeneration gas turbine applications. The burner is expected to reduce NO_X emissions below 5 ppmvd at 15 percent oxygen. The project will utilize advanced fuel and air mixing strategies, stability enhancements, and control system design to achieve the target NO_X levels. Use of the new low-NO_X duct burner technology in conjunction with XONON has the potential to match BACT emission levels without the need for add-on control systems such as selective catalytic reduction. Projected date of commercial availability is 2001 to 2002.

e. Concerns Regarding NO_X Emission Measurement

NO_X emissions from gas-turbine power plants employing advanced combustor design and post-combustion controls have been reduced to levels of approximately 2 to 3 ppmvd at 15 percent oxygen. The American Society of Mechanical Engineers (ASME) Codes and Standards Committee B133 is directing an investigation due to its concern that current measurement technologies are not able to produce the precision required for monitoring and testing at the low NO_X levels being identified as BACT. Findings for the first phase of the investigation are detailed in the January 11, 1999, final report "Low NO_X Measurement: Gas Turbine Plants" which investigated the present capabilities available for measuring low NO_X concentrations.

In a letter dated April 28, 1998, the ASME B133 Committee submitted comments to SCAQMD as a result of findings detailed in the January 11, 1999, final report. The letter addressed SCAQMD's proposal to deem 2.5 ppmvd NO_X at 15 percent oxygen BACT for gas turbines based on operating data from the 32 MW Federal Cogeneration plant in Vernon, California. Issues of concern included deficiencies in test protocol, the effect of NO_X removal by water vapor from steam injection, bias induced by permeation and absorption of NO in polymeric tubing, noncompliance of the test procedure used to develop the NO_X levels, and uncertainty of CEM~~S~~s measurement by ±6 ppmvd NO_X.

The SCAQMD issued a response to the ASME concerns in correspondence of May 26, 1998, from Dr. Anupom Ganguli of SCAQMD to Mr. Steve Weinman of ASME. In the letter, the SCAQMD disagreed with the conclusions of ASME and responded in rebuttal to each of the issues mentioned. The SCAQMD ultimately concluded that low NO_X levels can be consistently and accurately measured with the use of currently available measurement technology with a likely accuracy of ±1 ppmvd NO_X. ARB staff are currently investigating the issue of accuracy with regard to current NO_X measurement methods. These methods may need to be revised to assure accuracy at the 2.5 ppmvd level and below.

f. Concerns Regarding Am monia Emissions

Selective catalytic reduction uses ammonia as a reducing agent in controlling NO_X emissions from gas turbines. The portion of the unreacted ammonia passing through the catalyst and emitted from the stack is called ammonia slip. Currently, ammonia is not regulated by district new source review rules. New source review rules regulate criteria pollutants and their regulatory precursors. Although ammonia is recognized to contribute to ambient PM_{10} concentrations, it is not listed in any California new source review rule as a precursor to PM_{10}. As a result districts have regulated ammonia slip since the mid-1980's under nuisance and toxic air contaminant rules. The only exception is in the South Coast Air Quality Management District, where ammonia is specifically regulated under a new source review rule.

Ammonia is not a federal hazardous air pollutant or a State identified toxic air contaminant. However, due to acute and chronic non-cancer health effects, ammonia is potentially regulated under district risk management programs. Such programs may include toxic new source review rules/policies and the requirements of the Air Toxics "Hot Spots" Program (Section 44360 *et seq.* of the Health and Safety Code). Ammonia is listed under the "Hot Spots" Program, and therefore, sources are required to report the quantity of ammonia they routinely release into the air.

Ambient particulate matter of 2.5 microns or less ($PM_{2.5}$) is composed of a mixture of particles directly emitted into the air and particles formed in air from the chemical transformation of gaseous pollutants (secondary particles). Principle types of secondary particles are ammonium sulfate and ammonium nitrate formed in air from gaseous emissions of SO_X and NO_X, reacting with ammonia. Studies conducted in the South Coast Air Basin by Glen Cass of Caltech have indicated that ammonia is a primary component in secondary particulate matter. As a result, districts should consider the impact of ammonia slip on meeting and maintaining PM_{10} and $PM_{2.5}$ standards. Where a significant impact is identified, districts should revise their respective new source review rules to regulate ammonia as a precursor to both $PM_{2.5}$ and PM_{10}.

Gas turbines using selective catalytic reduction typically have been limited to 10 ppmvd ammonia slip at 15 percent oxygen; however levels as low as 2 ppmvd at 15 percent oxygen have been proposed and guaranteed by control equipment vendors. In addition, Massachusetts and Rhode Island have established ammonia slip LAER levels of 2 ppmvd. To date, Massachusetts has permitted two large gas turbine power plants using selective catalytic reduction with 2 ppmvd ammonia slip limits. Given the potential for health impacts and increases in PM_{10} and $PM_{2.5}$, districts should ensure that ammonia emissions are minimized from projects using selective catalytic reduction. Staff recommends that districts consider establishing ammonia slip levels below 5 ppmvd at 15 percent oxygen in light of the fact that control equipment vendors have openly guaranteed single-digit levels for ammonia slip.[12]

g. BACT Recommendation

The most stringent NO_X BACT for a simple-cycle gas turbine was required in the preconstruction permit for Carson Energy Group in Sacramento County, California, at 5 ppmvd NO_X at 15 percent oxygen averaged over 3 hours. The determination was made for a 42 MW General Electric LM6000 simple-cycle gas turbine equipped with selective catalytic reduction. Since 1995, the gas turbine has demonstrated compliance with the NO_X emission limit in three consecutive years of source testing. Considering that the Carson Energy Group represents the most stringent NO_X BACT which has been achieved in practice, staff recommends BACT for NO_X emissions from simple-cycle gas turbines is 5 ppmvd at 15 percent oxygen averaged over 3 hours. It should be noted that as exhaust gas temperatures increase, performance and reliability

[12] Ammonia slip guarantees from several selective catalytic reduction vendors are included in Appendix D.

of control systems for reducing NO_X may diminish and should be considered in determining BACT for NO_X emissions from simple-cycle power plants. For example, the turbine at Carson Energy Group is an aeroderivative gas turbine, which can have lower exhaust gas temperatures than a larger industrial frame gas turbine.

The most stringent BACT limit for a combined-cycle/cogeneration gas turbine was required in the preconstruction permit issued for the Sutter Power Plant near Yuba City, California. This determination was for a Westinghouse 501F gas turbine nominally rated at 170 MW. It requires 2.5 ppmvd NO_X at 15 percent oxygen using 1-hour averaging, achieved using dry low-NO_X burners and selective catalytic reduction.

Emission levels of 2.0 ppmvd NO_X at 15 percent oxygen using 15-minute averages measured with CEMs were achieved at 32 MW Federal Cogeneration in Los Angeles, California, utilizing water injection in conjunction with SCONOx. Six months of CEMs data were examined by both the U.S. EPA and SCAQMD. Upon evaluation, U.S. EPA subsequently deemed 2.0 ppmvd at 15 percent oxygen with a 3-hour averaging time as demonstrated in practice. U.S. EPA acknowledged that future combined-cycle gas turbine projects subject to LAER must recognize the 2.0 ppmvd limit. The SCAQMD subsequently determined BACT as 2.5 ppmvd at 15 percent oxygen with 1-hour averaging.[13] U.S. EPA correspondence of June 10, 1998, subsequent to this determination recognized 2.0 ppmvd and 2.5 ppmvd at 15 percent oxygen with 3- and 1-hour averaging times, respectively, as levels that would represent BACT.

In light of the U.S. EPA and SCAQMD determinations, staff recommends BACT for NO_X emissions from combined-cycle and cogeneration gas turbines be 2.5 ppmvd at 15 percent oxygen averaged over 1 hour. In addition to the Sutter Power Plant, this NO_X BACT level is being proposed for five other large combined-cycle and cogeneration power plant projects currently going through the CEC siting process.

2. Control of CO Emissions

a. Current SIP Control Measures

Historically, two forms of CO emission controls have been used on gas turbines. Combustion controls were used in the mid-1980's to achieve emission levels down to 10 ppmvd CO at 15 percent oxygen. In the late 1980's, oxidation catalysts were used on larger gas turbine cogeneration units. Oxidation catalysts can achieve 80 to 90 percent control of CO emissions. Although oxidation catalysts have been used on simple-cycle gas turbines, the use of oxidation catalysts have been largely limited to cogeneration and combined-cycle gas turbines. High temperature oxidation catalysts are available. Simple-cycle gas turbines with lower flue-gas temperatures have been controlled with high temperature oxidation catalysts.

---

[13] NO_X emission averaging time is not included in the BACT summary; however SCAQMD staff report clarifies the averaging time as 1 hour.

Currently, only two areas are designated nonattainment for the California CO ambient air quality standards: Los Angeles County and the city of Calexico in Imperial County. The only area of California designated nonattainment for the national CO ambient air quality standard is the South Coast Air Basin. CO violations arise primarily from concentrated motor vehicle emissions. As a result, districts have not historically instituted control measures that have applied specifically to the regulation of CO emissions from gas turbines. The only California district with a CO emissions limit for gas turbines is the San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD). SJVUAPCD Rule 4703 limits CO emissions from gas turbines to 25 to 250 ppmvd at 15 percent oxygen averaged over 3 hours, depending on turbine design and use. The control measure is applicable to stationary gas turbines rated at and greater than 0.3 MW.

b. Control Techniques Required as BACT

The most stringent BACT limit for a simple-cycle gas turbine was specified in the preconstruction permit issued for Carson Energy Group in Sacramento County, California. The permit established a CO limit of 5.93 pounds per hour (lb/hr) (equivalent to approximately 5.97 ppmvd at 15 percent oxygen averaged over 3 hours). The determination was made for a 42 MW General Electric LM6000 gas turbine using an oxidation catalyst. This turbine has been in operation since 1995.

The most stringent BACT limit for a combined-cycle gas turbine was specified in a preconstruction permit issued for Newark Bay Cogeneration Partnership in Newark, New Jersey. The permit established a limit of 1.8 ppmvd CO at 15 percent oxygen averaged over 1 hour. This determination applied to a 640 MMBtu/hr Westinghouse CW251/B-12 gas turbine using an oxidation catalyst. The facility is located in a CO nonattainment area.

c. Emission Levels Achieved in Practice

Three consecutive years of source testing at Carson Energy Group in Sacramento County, California, indicate CO emissions vary from 0.07 to 0.29 lb/hr (approximately 0.06 to 0.26 ppmvd CO at 15 percent oxygen). The 42 MW simple-cycle power plant consists of a General Electric LM6000 gas turbine with an oxidation catalyst. This gas turbine has been in operation since 1995.

Two consecutive years of source testing at Crockett Cogeneration in Crockett, California, indicate CO emissions of 1.11 and 2.02 ppmvd CO at 15 percent oxygen. The 240 MW combined-cycle power plant consists of a General Electric Frame 7FA gas turbine with an oxidation catalyst. In addition, two consecutive years of source testing at Sacramento Power Authority (Campbell Soup) in Sacramento County, California, indicate CO emissions of 0.50 and 1.89 lb/hr (approximately 0.16 and 0.62 ppmvd CO at 15 percent oxygen). The 102 MW combined-cycle power plant consists of a Siemens V84.2 gas turbine with an oxidation catalyst.

SCONOx supplier, Goal Line Environmental Technologies, claims SCONOx can achieve

2.0 ppmvd CO at 15 percent oxygen averaged over 1 hour. Goal Line bases this claim upon CEMs data from 32 MW Federal Cogeneration in Los Angeles County, California. The power plant consists of a General Electric LM2500 combined-cycle gas turbine.

d. More Stringent Control Techniques

Source testing at Newark Bay Cogeneration Partnership indicated compliance with a permitted emission limit of 1.8 ppmvd CO at 15 percent oxygen through use of an oxidation catalyst. The facility is a 136 MW cogeneration plant with two 640 MMBtu/hr gas turbines located in Newark, New Jersey. However, source testing is not required on an annual basis, so staff cannot determine whether the level has been demonstrated as "achieved in practice."

e. BACT Recommendation

The most stringent CO BACT for a simple-cycle gas turbine was required in the preconstruction permit for Carson Energy Group in Sacramento County, California, at approximately 6 ppmvd CO at 15 percent oxygen averaged over 3 hours. The determination was made for a 42 MW General Electric LM6000 simple-cycle gas turbine equipped with an oxidation catalyst. Since 1995, the gas turbine has demonstrated compliance with the CO emission limit in three consecutive years of source testing. Considering that the Carson Energy Group represents the most stringent CO BACT which has been achieved in practice, staff recommends BACT for CO emissions from simple-cycle gas turbines is 6 ppmvd at 15 percent oxygen averaged over 3 hours.

With regard to a recommendation for combined-cycle and cogeneration power plants, the most stringent BACT limit for a combined-cycle gas turbine of the size of merchant power plant currently in review with the CEC, was specified in a preconstruction permit issued for Sutter Power Plant near Yuba City, California. The permit established a limit of 4.0 ppmvd CO at 15 percent oxygen averaged over 24 hours. This determination applied to a nominally rated 170 MW Westinghouse 501F gas turbine using an oxidation catalyst. A similar BACT requirement is proposed for Pittsburg District Energy Facility in Pittsburg, California, at 6.0 ppmvd CO at 15 percent oxygen averaged over 3 hours. Although the CO emission concentration is higher than that for Sutter Power Plant, staff believes the shorter averaging time represents a BACT level which is more accommodating in determining compliance with emission limits. Therefore, considering available data, staff recommends a BACT emission level of 6.0 ppmvd CO at 15 percent oxygen averaged over 3 hours.

The levels recommended for BACT are for CO nonattainment areas. New source review rules require BACT for CO emissions even though most of California is designated attainment for the CO ambient air quality standards. CO standard violations, however, are associated with concentrations of mobile source emissions. Therefore, staff will recognize the need for some flexibility in establishing CO emission controls from new gas turbines in CO attainment areas, where allowed by district rules.

3. Control of VOC Emissions

a. Current SIP Control Measures

Staff is not aware of any existing control measures designed specifically to limit VOC emissions from gas turbines.

b. Control Techniques Required as BACT

Similar to CO emissions, VOC emissions can be abated with combustion controls and oxidation catalysts. Due to low VOC emission concentrations, the control of VOC emissions from gas-fired turbines was relatively unimportant to regulators compared to emissions of NO_X and CO. As a result, initial control of VOC emissions experienced with oxidation catalysts were more coincidental than intentional since the oxidation catalysts were initially utilized to control CO emissions. Oxidation catalysts can be designed for control efficiencies of 40 and 50 percent for VOC emissions from gas turbines.

The most stringent BACT limit for a simple-cycle gas turbine was specified in the preconstruction permit for Carolina Power & Light in Goldsboro, North Carolina. The permit established a limit of 0.0015 lb VOC/MMBtu (equivalent to approximately 1.11 ppmvd VOC as methane at 15 percent oxygen). The determination was for a 1,907.6 MMBtu/hr General Electric 7231 FA gas turbine using combustion controls while firing on natural gas.

The most stringent BACT limit for a combined-cycle gas turbine is proposed for the High Desert Power Plant in San Bernardino County, California. Emissions will be limited to 1.0 ppmvd VOC as methane at 15 percent oxygen averaged over 1 hour. The determination is for a 700 to 750 MW power plant using an oxidation catalyst.

c. Emission Levels Achieved in Practice

Three consecutive years of source testing at Carson Energy Group in Sacramento County, California, indicate VOC emissions vary from 0.39 to 1.21 lb/hr (approximately 0.64 to 1.98 ppmvd VOC as methane at 15 percent oxygen). The 42 MW simple-cycle power plant consists of a General Electric LM6000 gas turbine with an oxidation catalyst. This gas turbine has been in operation since 1995.

Two years of source testing at Crockett Cogeneration in Crockett, California, indicate VOC emissions vary from 0.007 to 0.085 ppmvd precursor organic compound (POC) as methane at 15 percent oxygen over a 1-hour average. The 249 MW plant consists of a combined-cycle General Electric Frame 7FA combustion gas turbine with an oxidation catalyst. The 0.007 ppmvd VOC level corresponds to the sensitivity threshold of the source test method. Bay Area Air Quality Management District (BAAQMD) staff indicates a more appropriate characterization of the measured value is less than 1 ppmvd at 15 percent oxygen.[14]

d. More Stringent Control Techniques

Staff is not aware of any additional technologically feasible control techniques, existing or under development, designed to limit VOC emissions from gas turbines.

e. BACT Recommendation

Based on VOC emission levels required for simple-cycle gas turbines, the most stringent BACT requirements are in the range of 1 to 2 ppmvd VOC at 15 percent oxygen. Source tests at Carson Energy Group demonstrate VOC emission levels of no more than 2 ppmvd at 15 percent oxygen can be met on a consistent basis. Therefore, staff recommends a BACT emission level for VOC from simple-cycle gas turbines of 2 ppmvd at 15 percent oxygen averaged over 3 hours.

The most stringent VOC BACT requirements for combined-cycle and cogeneration gas turbines have been in the range of 1 to 2 ppmvd VOC at 15 percent oxygen for power plants equipped with oxidation catalysts. Staff recognizes that accuracy of some test methods performed for VOC emissions is uncertain, but available source tests at Crockett Cogeneration and other gas turbine power plants consistently give emission results of no greater than 2.0 ppmvd VOC at 15 percent oxygen averaged over 1 hour with use of an oxidation catalyst. Based on these findings, staff recommends a BACT level of 2.0 ppmvd VOC at 15 percent oxygen averaged over 1 hour (or equivalent limit of 0.0027 lb VOC/MMBtu, higher heating value).

4. Control of PM_{10} Emissions

a. Current SIP Control Measures

Staff is not aware of any control measures designed specifically to limit PM_{10} emissions from gas turbines.

---

[14]Personal communications with Ken Lim of the Bay Area Air Quality Management District.

b. Control Techniques Required as BACT

PM_{10} emissions are partially dependent on fuel sulfur and nitrogen content. Natural gas has negligible amounts of fuel-bound nitrogen. As a result, there should be negligible nitrate production from any fuel-bound nitrogen. The production of thermally-induced nitrates and the organic fraction of PM_{10} can best be abated through the use of combustion controls. On new gas turbines with state of the art combustion design, PM_{10} emissions are most effectively reduced through use of fuels with both lower sulfur content and low ash content.

There are no add-on control technologies that can feasibly reduce PM_{10} emissions in gas turbine exhaust. As a result, the lowest PM_{10} emissions are achieved through combustion of low-sulfur natural gas along with combustion design that minimizes NO_X and unburned hydrocarbons. Applicants have the ability to select a low-sulfur fuel, such as natural gas; however, only the gas supplier has the ability to limit fuel sulfur content below PUC-regulated levels.[15] Natural gas utility companies have the ability to specify fuel sulfur content in purchase contracts with gas suppliers. Two major California natural gas utility companies, Pacific Gas & Electric and Southern California Gas, use purchase contracts that specify levels no higher than 1 grain of total sulfur per 100 standard cubic feet (1 gr S/100 scf).

An example of a recent PM_{10} BACT limit on a large combined-cycle gas turbine was applied to the Sutter Power Plant. A PM_{10} limit of 11.5 lb/hr averaged over 24 hours assuming a fuel sulfur content of 0.7 gr S/100 scf and a 10 percent conversion of fuel sulfur to sulfate emissions. Staff's calculations indicate that this limit is equal to an emission concentration of 0.0013 grains per dry standard cubic feet of exhaust gas (gr/dscf) at 3 percent carbon dioxide (CO_2). This determination applied to a Westinghouse 501F gas turbine nominally rated at 170 MW. In this case, the applicant presumed fuel sulfur content is below the 1 gr S/100 scf specified in the local gas utility company purchase contracts.

c. Emission Levels Achieved in Practice

Two consecutive annual source tests at Carson Energy Group in Sacramento County, California, indicate PM_{10} emissions of 0.63 and 0.882 lb/hr (approximately 0.00025 and 0.00035 gr/dscf at 3 percent CO_2) assuming a fuel sulfur content of 1 gr S/100 scf and 6.5 percent conversion of fuel sulfur to sulfate emissions. The results were obtained on a 450 MMBtu/hr General Electric LM6000 simple-cycle gas turbine.

---

[15]Under California Public Utilities Commission General Order 58-8, the total sulfur of gas supplied by any gas utility for domestic, commercial, or industrial purposes is limited to 5 grains of total sulfur per 100 standard cubic feet.

Two consecutive annual source tests at Sacramento Power Authority (Campbell Soup) in Sacramento County, California, indicate PM_{10} emissions of 1.93 and 2.98 lb/hr (approximately 0.00027 and 0.00042 gr/dscf at 3 percent CO_2) assuming a fuel sulfur content of 1 gr S/100 scf and 6.5 percent conversion of fuel sulfur to sulfate emissions. The results were obtained on a 102 MW combined-cycle Siemens V84.2 gas turbine.

d. More Stringent Control Techniques

Staff is not aware of any additional technologically feasible control techniques, existing or under development, to reduce PM_{10} emissions from gas turbines.

5. BACT Recommendation

The lowest PM_{10} emissions from gas turbines are achieved through combustion of low-sulfur natural gas along with combustion design that minimizes NO_X and unburned hydrocarbons. Applicants have the ability to select a low-sulfur fuel, such as natural gas; however, only the gas supplier has the ability to limit fuel sulfur content below Public Utilities_Commission (PUC)-regulated levels.[16] Natural gas utility companies have the ability to specify fuel sulfur content in purchase contracts with gas suppliers. Two major California natural gas utility companies, i.e., Pacific Gas & Electric and Southern California Gas, use purchase contracts that specify levels no higher than 1 gr S/100 scf. Staff believe this represents a limiting circumstance in the maximum emission level of the sulfate portion of PM_{10}.

Considering the above, the default PM_{10} BACT requirement for combined-cycle gas turbines is natural gas containing no more than 1 gr S/100 scf. In addition, staff believes that appropriate combustion controls and low sulfur fuel are essential components of a PM_{10} BACT determination for a gas turbine. Any emission limit required for BACT should correspond with a fuel gas sulfur content of 1 gr S/100 scf. Furthermore, there are "housekeeping measures" that can prevent emissions from the lube oil vent, including a lube oil vent coalescer and an associated opacity limit of 5 percent. These latter provisions were required at Badger Creek Limited on a 457.8 MMBtu/hr General Electric LM-5000 gas turbine cogeneration unit with a 48.5 MW capacity.

[16]Under California Public Utilities Commission General Order 58-8, the total sulfur of gas supplied by any gas utility for domestic, commercial, or industrial purposes is limited to 5 grains of total sulfur per 100 standard cubic feet.

5. Control of SO_X Emissions

a. Current SIP Control Measures

Several California districts have SIP control measures limiting sulfur compounds (as sulfur dioxide) from fossil fuel-burning equipment used generally for the production of useful heat or power.[17] The most stringent of these limits restrict sulfur dioxide emissions to no more than 200 pounds per hour. This level of emissions is not approached with gaseous fuel combustion.

b. Control Techniques Required as BACT

SO_X emissions are highly dependent on fuel sulfur content. As a result, the lowest emissions are achieved through the combustion of fuels with the lowest sulfur. Entities regulated by the PUC in California have purchase contracts with an effective maximum total sulfur content for natural gas of 1 gr S/100 scf (equivalent to approximately 17 ppmv sulfur). The most stringent BACT required for a simple-cycle, combined-cycle, or cogeneration gas turbine is firing of low-sulfur natural gas. Natural gas should not contain more than 1 gr S/100 scf if delivered by a California gas utility regulated by the PUC.

The Sutter Power Plant in Sutter County, California, was issued a preconstruction permit for a 170 MW Westinghouse 501F combined-cycle gas turbine. The BACT determination limited SO_2 emissions to no more than 1.0 ppmvd at 15 percent oxygen using 24-hour averaging. This emission level is proposed to be achieved using PUC pipeline quality natural gas for all combustion operations. Staff's calculations indicate that 1.0 ppmvd at 15 percent oxygen is achievable at fuel sulfur contents below 1.8 gr S/100 scf for gaseous fuels assuming full conversion of fuel sulfur to sulfur dioxide.

c. Emission Levels Achieved in Practice

Staff is not aware of any source tests for SO_X conducted on gas turbines that burn natural gas. It appears that source testing is generally not required for gas turbines that burn natural gas exclusively. Because natural gas supplied by a California gas utility regulated by the PUC should not contain more than 1 gr S/100 scf, this represents a limiting factor in SO_X emissions.

d. More Stringent Controls Techniques

SCOSOx is a catalytic sulfur removal system that works in conjunction with the SCONOx system to remove sulfur compounds from combustion exhaust streams. It is nearly identical to

[17]Such rules may only apply to cogeneration and combined-cycle units. Others may apply more generally and may cover simple-cycle gas turbines.

the SCONOx catalyst for NO_X removal except that it favors sulfur compound absorption and is installed upstream of the SCONOx catalyst. SCOSOx was installed in early 1999 at the Genetics Institute in Andover, Massachusetts in conjunction with SCONOx. The 5 MW cogeneration plant consists of a 65 MMBtu/hr Solar Taurus Model 60 gas turbine with auxiliary-fired HRSG. The SCOSOx system was installed as a "guard bed" for the SCONOx system to enhance the control effectiveness of the NO_X catalyst. In this case, no attempt was made to determine SO_X removal. Therefore, there is no opportunity to assess any SO_X emissions reductions associated with SCOSOx at this time. Goal Line Environmental Technologies is now supplying the SCOSOx catalyst automatically with the SCONOx technology.

5. BACT Recommendation

SO_X emissions result from the oxidation of fuel sulfur during combustion. Staff is unaware of combustion or add-on controls feasible for controlling SO_X emissions from gas turbines. Therefore, staff recommends a SO_X BACT limit equivalent to emissions caused by combusting gaseous fuel with a sulfur content of 1 gr S/100 scf. Based on mass balance calculations and assuming no fuel sulfur conversion to sulfate, a gas turbine firing on natural gas with this level of sulfur content will emit a maximum 0.55 ppmvd at 15 percent oxygen. The district determination may also wish to require as BACT compliance with a fuel sulfur content limit, especially if the content limit is below purchase specification used by the gas utility. In addition, staff suggests that a an emission concentration limit corresponding to the assumed fuel sulfur content, i.e., 0.55 ppmvd at 15 percent oxygen or lower, may be appropriate.

6. Considerations in Controlling Emissions from Startup and Shutdown

Due to deregulation of the electric utility industry in California, many new power plants will be operating under merchant mode. Recent applications for power plant certifications indicate these plants will operate under varying loads with numerous startups and shutdowns to handle changing electricity demands. Gas turbines generally have higher emissions during periods of startup and shutdown. In fact, startup and shutdown emission may substantially contribute to the total project emissions. Therefore, the BACT decision should consider control of emissions during such periods of operation.

Gas turbines are designed to run online near rated capacity. Optimal combustion in a gas turbine tends to occur at full load. In addition, emission control systems, especially those dependent on feedback systems, operate best at steady-state. In this post deregulation period, gas ~~turbines~~ power plants may spend a significant amount of time in other modes of operation. Derated operation can be associated with less efficient combustion. Startup, shutdown, and load changes will cause variations of flue gas flows and temperature. Periods of disequilibrium may be frequent and long. For example, cold startups for combined cycle units may require up to four hours.

To the extent possible, emissions should be controlled where possible, including during startups and shutdowns. Emission control systems should operate when circumstances allow and use of bypass stacks should be minimized. For example, if flue gas temperatures are within the effective temperature window of the catalytic control system, emission control systems should be in service, and emissions controlled to the maximum extent allowed by circumstances. Also, startup and shutdown should be minimized with permit conditions limiting their duration. Definitions of startup and shutdown should be well delineated with precise definitions that include markers that clearly distinguish the onset and conclusion of such events. Districts may want to limit startup and shutdown emissions where it is possible to enforce such limits.

Commenters have also suggested other more specific ways of reducing startup and shutdown emissions. They include the following:

- using an auxiliary boiler or other source of steam turbine sealing steam to reduce startup times,

- using a stack dampener to maintain high temperatures in the HRSG during shutdown, thereby allowing a hot or warm startup instead of a cold startup,

- early injection of ammonia into the selective catalytic reduction unit,

- using alternatives to the widely used low-NO_X combustor technology (These include XONON, which can achieve 3 ppmvd NO_X at 15 percent oxygen and will soon be offered and guaranteed on General Electric gas turbines), and

- investigate ways to more quickly heat catalysts to operation temperature.

At a minimum, districts should require applicants to submit a plan for district approval, to minimize emissions during equipment startups and shutdowns.

IV.

EMISSION OFFSETS

A. OVERVIEW

Air pollution control and air quality management district (district) new source review (NSR) rules and regulations employ both best available control technology (BACT) and emission offset requirements to reduce the impact on air quality from new or modified stationary sources. If emission increases are above certain specified levels, district NSR rules require the application of BACT. If the emission increases after the installation of BACT are still above specified levels, then emission offsets may be required. Emission offsets are emission reductions at the project location, or at a nearby location, to compensate for the expected increases in emissions from the project. An overall air quality benefit is expected if the offsets (emission reductions) are greater than the emission increases from the project (i.e., if the emission offset ratio is greater than 1.0:1) and the emission increases are not expected to result in a new violation, or add to an existing violation, of ambient air quality standards within the impact area of the power plant.

Even though state-of-the-art controls, as discussed in the previous chapter, will drive emission concentrations to some of the lowest levels ever achieved for stationary combustion turbines, the proposed power plants, because of their size, will still emit substantial quantities of pollutants. Emissions from the proposed power plants are expected to exceed specified levels for emission offsets for oxides of nitrogen (NO_X) and carbon monoxide (CO); however, most areas in California have been designated attainment with the federal and State CO standards and do not require CO offsets. In CO nonattainment areas, most projects will avoid CO offset requirements due to a common provision in many districts' NSR rules and regulations; offsets will not be required if modeling demonstrates that there is not a violation of the air quality standard at the proposed project site and that the emission increase will not cause or contribute to a violation of the standard. In addition, the larger-sized projects may also exceed offset thresholds for particulate matter of ten microns or less (PM_{10}), oxides of sulfur (SO_X), and volatile organic compounds (VOC).

B. GENERAL GUIDANCE

Emission reductions used as offsets should be specifically identified and quantified in accordance with applicable requirements of district emission reduction credit banking programs and State and federal law. Emission offsets must be real, quantifiable, surplus, permanent, and enforceable. Emission reductions which are real are those that have actually occurred, not those that could have been emitted but were not. Quantifiable means that the amount of emission reduction can be determined with reasonable certainty. Surplus reductions are those reductions which are not encumbered by any local, State, or federal law, regulation, order, or requirement. Permanent means that the benefits of the emission reduction do not diminish or disappear over time. Reductions which can be checked and verified by field inspection or source testing are enforceable.

The generation of emission reductions from sources not required to have permits must be consistent with the requirements of Section 40714.5 of the Health and Safety Code and applicable district rules and regulations and meet emission banking criteria otherwise required for sources with permits. Emission reductions from mobile sources[18] or area stationary sources should be banked and transferred under an interchangeable credits rule adopted by the district and approved by the Air Resources Board (ARB). To the extent allowed by a district's rules and regulations and State law, the emission reductions may be a different type pollutant than the emission increase (i.e., interpollutant emission offsets) or originate outside the air basin of the proposed project's location (i.e., interbasin emission offsets).

1. Completeness of Emission Offset Package

An application should contain a complete emission offset package and include sufficient emission information to verify the type and quantity of required ~~emissions~~ offsets.

a. Emission Information

Emission offset requirements are calculated using detailed emissions information. Therefore, emission estimates and supporting information for all proposed operating scenarios of the power plant, including alternative operating scenarios, should be submitted to the California Energy Commission (CEC) in the Application for Certification (AFC). The emission estimates and supporting information should meet the following criteria:

- be clearly depicted,
- be supported by equipment-specific data with sources of information referenced,
- be sufficient to verify each step of the emission calculations, and
- reflect the worst-case potential impact on ambient air quality with the worst-case

[18] ARB has established guidance for the generation of emission reductions from mobile sources in a document entitled, "Mobile Source Emission Reduction Credits: Guidelines for the Generation and Use of Mobile Source Emission Reduction Credits, February 1996."

operating scenario identified for each pollutant emitted.

b. Emission Offset Requirements

The quantity of emission offsets should be calculated in accordance with district requirements, including any applicable offset ratios. Offset ratios normally increase with increasing distance between the project site and the source of the emission reductions. Where district rules do not address such ratios, an appropriate ratio can be established provided technical justification can show that the use of the ratio will not have a negative impact on air quality.

The district's preliminary determination of compliance (DOC) regarding the application should evaluate whether, or not, the applicant's emissions offset package is complete and has made the following demonstrations:

- the amount of emission offsets required has been calculated in accordance with district requirements;
- any emission reductions provided that have not been banked in accordance with district regulations are real, quantifiable, surplus, permanent, and enforceable and based on worst-case operating scenarios;
- emission reductions not banked by the date of preliminary DOC issuance have undergone any adjustments required by district rules and regulations including adjustments for BACT, Best Available Retrofit Control Technology (BARCT), and Reasonably Achievable Control Technology (RACT); and
- the applicant has demonstrated (through letters of intent, option-to-purchase contracts, or the equivalent) intent and ability to secure, in a timely manner, any emissions offsets from sources not under the applicant's direct control.

2. Milestones for Securing the Required Emission Offsets

The emission offsets package should be complete and secured by the following milestones in the permit process:

- a complete offset package identified and quantified at the time of submission of the Application for Certification (AFC),
- letters of intent signed by the time the district provides public notice for the preliminary DOC,
- option contracts signed by the time of issuance of the final DOC, and

- offsets secured and in place prior to operation of the power plant (However, some emission trades may include emission reductions that are contemporaneous; that is, occurring within a designated period ending shortly after commencement of operation.).

Any significant changes in the offsets package after the preliminary DOC is issued should be subject to additional public notice to ensure that a full and completed public process occurs.

3. INTERPOLLUTANT EMISSION OFFSETS AND INTERBASIN EMISSION OFFSETS

1. Overall Guidance Perspective

Staff recommends that interpollutant or interbasin emission offsets be allowed only after the applicant has surrendered any applicant-held emission reduction credit (ERC) certificates, and has demonstrated that additional emission reductions are not available onsite or near the source.

In this document, staff is providing guidance for determining emission offset ratios for interpollutant emissions offsets and interbasin emission offsets. Staff recommends the interpollutant emissions offset ratios and interbasin emission offset ratios as summarized in Tables IV-1 and IV-2, respectively. The minimum interpollutant offset ratios in Table IV-1 are based on recent and past staff assessments of interpollutant relationships; staff is in the process of developing offset ratios specific to air basins through the utilization of a photochemical grid model (where available) and a gridded emission inventory for the ozone attainment year. Where district rules and regulations do not specifically establish interbasin offset ratios, staff recommends the interbasin pollutant offset ratios specified in Table IV-2. The minimum interbasin pollutant offset ratios in Table IV-2 were derived by staff after surveying district regulatory requirements for distance offset ratios established in district rules and regulations for use within their respective air basins. However, staff recommends that other methods for determining emission offset ratios be allowed, consistent with district rules and regulations and State law, on a case-by-case basis when justified by the particular circumstances for the proposed project.

Overall emission offset ratios should be determined by combining, unless otherwise specified in district rules and regulations, the interpollutant emission offset ratio and the interbasin emission offset ratio, as applicable, and all other applicable district discount or distance ratios; this is a critical requirement when an offset ratio is independent of other ratios in its protection of air quality. With the inherent uncertainties associated with the determination of the offset ratios, combining the applicable offset ratios will help ensure that sufficient emission offsets are provided to provide an air quality benefit.

Table IV-1: Minimum Interpollutant Offset Ratios

Offsetting Pollutants	Minimum Interpollutant Offset Ratio
Ozone Precursors (NO_X and VOC)	Basin specific and less than 1.0:1
$PM_{2.5}$, PM_{10}, and Precursors (NO_X, VOC, and SO_X)[19]	1.0:1

Table IV-2: Minimum Interbasin Offset Ratios

Distance Between Project and Offsetting Source	Minimum Interbasin Offset Ratio
Within 50 miles	2.0:1
Over 50 miles	Increase the 2.0:1 by 1.0 for every 25 miles increase beyond 50 miles

2. Specific Guidance on Interpollutant Emission Offsets

Where emission reductions of the same type of pollutant are not available, some districts' rules and regulations may allow the use of interpollutant offsets. The use of interpollutant emission offsets should be allowed only under the following circumstances:

- the applicant demonstrates that emission reduction credits of the same type of pollutant as the emission increase are not available onsite,
- the applicant has used any applicant-held ERC certificates, and
- the use of interpollutant emission offsets does not prevent or interfere with the

[19]Due to a lawsuit and the United States Environmental Protection Agency's (U. S. EPA) implementation schedule for the federal standard, there are no current requirements for $PM_{2.5}$ offsets.

attainment or maintenance of any applicable ambient air quality standard, consistent with Section 42301 of the Health and Safety Code.

1. Ozone Precursors (NO_X and VOC)

As summarized in Table IV-1, staff recommends that interpollutant emission offsets of ozone precursors (NO_X and VOC) be allowed if the offsets required are calculated with an interpollutant offset ratio that is a minimum ratio of 1.0:1 and specific for the air basin in which the project is proposed. Staff is in the process of developing ratios for air basins throughout the State. To the extent offsets are calculated with ratios specified in district rules and regulations or developed by ARB staff, the technical assessment of the applicant's emission offset package can be minimized. In lieu of ARB ratios, the applicant can make a case-by-case determination of the interpollutant offset ratio if the ratio can be technically justified in a manner approved by the district, ARB, and the U.S. EPA; this ratio cannot be less than 1.0:1.

Staff is in the process of developing interpollutant offset ratios specific to an air basin utilizing a photochemical grid model (where available) and a gridded emission inventory for the ozone attainment year.[20] If the applicant chooses to do a case-by-case determination of an interpollutant offset ratio utilizing a photochemical model, the modeling protocol should be consistent with the following criteria:

- ARB's 1992 guidance document, "Technical Guidance Document: Photochemical Modeling;"
- use of the projected attainment emissions inventory from the latest approved air quality plan as a starting point; and
- use of the most up-to-date VOC speciation profiles, which can be obtained from ARB staff.

Prior to carrying out any analyses, the applicant would need to discuss the use of new emission inventories and updated VOC speciation profiles with appropriate regulatory agencies. The ARB maintains a library of VOC speciation profiles for different source types which are documented in the ARB's 1991 speciation manual, "Identification of Volatile Organic Compound Species Profiles," and updates to this information.

---

[20]This is the year in which the federal ozone standard is projected to be attained in the latest local air quality plan. The attainment date for the 1-hour ozone standard varies based on an area's severity of pollution.

b. $PM_{2.5}$, PM_{10}, and Precursors (NO_X, VOC, and SO_X)[21]

As summarized in Table IV-1, staff recommends that the interpollutant emission offsets for particulate matter of 2.5 microns or less ($PM_{2.5}$), particulate matter of 10 microns or less (PM_{10}), and precursors (NO_X, VOC, and SO_X) be allowed at a minimum interpollutant offset ratio of 1.0:1. However, interpollutant offsets cannot be used where the offsetting pollutant contributes to the violation of another standard. For example, NO_X increases cannot be offset with PM_{10} reductions in an ozone nonattainment area and, upon implementation of requirements, $PM_{2.5}$ increases cannot be offset with PM_{10} reductions in a $PM_{2.5}$ nonattainment area. Also, the interpollutant offset ratio minimum of 1.0:1 may not hold true for $PM_{2.5}$ in all areas. A minimum 1.0:1 ratio can be used in areas that do not have a $PM_{2.5}$ air quality problem; where a problem exists, a minimum ratio of 1.0:1 can be used until sufficient data becomes available for the ARB, or other regulatory agencies, to reevaluate the minimum ratio or determine appropriate ratios.

3. Specific Guidance on Interbasin Emission Offsets

Interbasin emission offsets should be allowed only for ozone precursors (NO_X and VOC) and PM_{10} precursors (NO_X, VOC, and SO_X) under the following circumstances:

- the use of the interbasin emission offsets meets the following minimum requirements of Section 40709.6 of the Health and Safety Code:
  - the stationary source to which the emission reductions are credited is located in

[21] In response to a recent lawsuit, the U.S. Court of Appeals for the District of Columbia has invited comment on the federal $PM_{2.5}$ standard, which could range from retention to removal of the standard. If the standard is retained, requirements for $PM_{2.5}$ offsets are not anticipated until after a district receives a non-attainment designation and has prepared the required implementation plan; this will be after the year 2006 according to the U.S. EPA's implementation schedule.

an upwind district that is classified as being a worse nonattainment status than the downwind district,
- the ARB has established that there is an emission transport relationship between the two districts and an overwhelming impact on the downwind district accepting the offsets,[22]
- the downwind district accepting the offsets has adopted a rule to discount the emission reduction credits from the upwind stationary source, and
- the interbasin emission offsets transaction has been approved by both districts;

- the applicant demonstrates that emission reductions are not available onsite;

- the applicant has used any applicant-held ERC certificates; and

- the interbasin offset ratio is combined, unless otherwise specified in district rules and regulations, with any other applicable ratios.

Where district rules and regulations have not specified interbasin offset ratios, staff recommends the ratios summarized in Table IV-2. The minimum interbasin offset ratios provided by staff are based on a survey of district distance offset ratios and have been established at a sufficiently high level to account for uncertainties, where staff would expect an air quality benefit. If consistent with district requirements, staff recommends a minimum interbasin emission offset ratio of 2.0:1 for sources within 50 miles. When the distance between sources is greater than 50 miles, staff recommends that the minimum interbasin offset ratios be increased by one for each additional 25 miles distance between the sources; for example, when the distance between two sources is 100 miles, the recommended minimum interbasin offset ratio is 4.0:1.

Staff's ratios are not intended to prevent an applicant or a district from developing other interbasin offset ratios based on a detailed technical analysis. It should also be noted that staff's

[22]Transport couples are designated with one or more transport characterizations (i.e., overwhelming, insignificant, or inconsequential). Where a transport couple is identified with more than one transport characterization and one of which is an overwhelming designation, the transport characterization can be considered overwhelming for the purpose of this interbasin emission offset guidance. The current list of designations can be found in the ARB publication entitled "Second Triennial Review of the Assessment of Impacts of Transported Pollutants on Ozone Concentrations in California."

interbasin emission offset ratios are distance ratios; if district offset requirements already include an equally protective distance offset ratio, additional discounting of the offsets for distance between sources may not be necessary.

V.

AMBIENT AIR QUALITY IMPACT ANALYSIS

1. OVERVIEW

One of the primary concerns in siting a new project, especially a large power plant, is its impact on air quality. The benchmarks of acceptable air quality are normally State and federal ambient air quality standards. Section 42301(a) of the Health and Safety Code requires district permit systems to ensure new permits will not be issued for emission units (sources) that will prevent or interfere with the attainment or maintenance of any applicable air quality standard. For this reason, air quality impacts should be evaluated for each State and national ambient air quality standard potentially impacted by emissions from a project. Another concern may be the project's potential to cause a significant degradation of air quality. This latter concern is addressed by Part C of Title I of the federal Clean Air Act (Prevention of Significant Deterioration) and the California Environmental Quality Act.

Air quality models are the primary tools for relating emissions to air quality impacts. Models, in turn, require acceptable input data for emissions, surface topography, meteorological parameters, receptor configurations, baseline air quality, and initial and boundary conditions for each modeling scenario. Since the quality and reliability of model outputs can never be any better than the inputs, quality control of the input data is an important concern.

2. MODEL SELECTION AND PROCEDURES

The baseline air quality and anticipated emission behavior of the project must be characterized before structuring the air quality impact analysis. The baseline air quality may be characterized as representative background air quality, or it may be represented as a particular air quality scenario associated with worst-case air quality experienced at some point in the past. It is also important that any modeled emission scenario is appropriate for evaluating the project's future compliance with the given regulatory requirement (e.g., assessment of long-term health impacts). Project emission rates used for air quality impact modeling should clearly depict and reflect worst-case conditions for any operating scenario requiring evaluation.

Any evaluation of air quality impacts from a new power plant should be conducted with models approved by the U.S. Environmental Protection Agency (U.S. EPA) and the ARB. Models should be appropriate for the pollutants and scenarios to which an air quality impact analysis is applied. The measurement parameters for assessing air quality impacts should consider the applicable state and national ambient air quality standards, for all relevant averaging times. Any air quality models used should be readily available to the public in source code format ("public domain") and should have no restrictions regarding modifications to the model. In addition, the model(s) should have undergone peer review, undergone one or more model performance evaluations, and be properly documented.

ARB strongly recommends that a modeling protocol be prepared and shared with the appropriate regulatory agencies. The protocol should describe the model(s) to be used, how the model will be applied, the types and sources of input data, the assumptions used, and the type of results or outputs. A protocol will greatly facilitate review of the proposed modeling approach and minimize subsequent technical disagreements. An ARB guidance document, "Technical Guidance Document: Photochemical Modeling, April 1992;" is available.

The proposed modeling grid should be sufficient to address all relevant source-receptor relationships. The resolution of the grid and area of coverage should be documented in the modeling protocol. For photochemical pollutant modeling, nested grids (a fine resolution grid near a source embedded within a larger grid) may be used provided they are properly documented and justified in the modeling protocol. For inert pollutant modeling, a fine grid nested within a coarse grid is appropriate to determine the point of maximum pollutant concentration. If sources have significant effective plume rise (e.g., 50 meters or more), a minimum fine grid resolution of 100 meters is required to estimate the point of maximum pollutant concentration. For emissions with an effective plume height closer to the ground, a finer grid resolution may be required.

Prior to investing resources in a refined analysis, a screening analysis may be employed using worst-case assumptions to determine if there will be a potential air quality problem. If a screening analysis indicates a potential air quality problem, a refined analysis is needed. Refined analyses utilize better models and data to provide an improved estimate of air quality impacts.

All aspects of an air quality impact analysis should be thoroughly documented prior to submission for regulatory review. Documentation should address all assumptions and procedures, and provide the following information:

- the state of current air quality in the project impact area;
- the selection of modeled scenarios;
- the selection of air quality models;
- characteristics of the modeling grid;
- emission inputs, including any temporal or spatial apportionment;
- meteorological input data, including data quality and representativeness;

- air pollutant concentration input data, including data quality and representativeness;

- air pollutant concentration output data and any other model outputs, including interpretive limitations associated with procedural assumptions, input data, or theoretical basis of the model; and

- all model input files, including the model source code, should be available on computer ready media (e.g., CD-ROM or diskette) and made available, if requested.

3. MODEL INPUT DATA CRITERIA AND QUALITY

In a broad sense, there are three categories of environmental data inputs into a model, i.e., terrain elevation, meteorological, and air quality data. The simplest category to address is terrain elevation data. Terrain elevation data used should be consistent with the grid resolution(s) chosen. The U.S. Geological Survey is a standard source for terrain data.

Any meteorological data used should comply with the requirements for data collection and quality assurance described in U.S. EPA's "Quality Assurance Handbook for Air Pollution Measurement Systems: Volume IV, Meteorological Measurements, 1989," and supplemented by U.S. EPA's "On-Site Meteorological Program Guidance for Regulatory Modeling Applications, 1995." For photochemical modeling, the meteorological data should be specific to the modeled episode. For inert modeling, the U.S. EPA recommends five years of representative meteorological data when estimating concentrations with an air quality model. In this case, the most recent readily available consecutive five-year period should be used. There may be conditions where no data are representative of the facility. In such conditions, either a screening evaluation should be performed or a meteorological collection program should be established to gather a minimum of one year of site-specific meteorological data.

All air quality input data for the model should be both spatially and temporally representative of the area for which it is applied. The representativeness of the data used should be described in the modeling protocol. Background values used for inert modeling should be based on pollutant concentration measurements. The measurements and assumptions used to determine background concentrations should be described in the modeling protocol. Boundary and initial conditions should be based on specific observations for the episode undergoing photochemical modeling, or reasonable assumptions based upon available meteorological and air quality measurements for inert modeling.

4. GUIDANCE FOR MODELING SECONDARY POLLUTANT IMPACTS

When modeling NO_X emissions impacts on ambient NO_2 concentrations, a tiered approach is normally used to estimate NO_2 concentrations for a source. Under the first tier, 100 percent conversion of NO_X to NO_2 is assumed. In successive tiers, it is recommended that the Ozone Limiting Method (OLM) as specified in the U.S. EPA Modeling Guidelines be used; it assumes ten percent of plume NO_X and 100 percent conversion of remaining NO_X as a function of ozone availability. A more refined approach is to conduct hour-by-hour simulations using hourly values of ozone, NO_2, and NO_X emissions.

For sources with ammonia emissions, districts may want to consider the impacts of ammonia on secondary particulate matter emissions from the project and on ambient PM_{10} concentrations.

VI.

HEALTH RISK ASSESSMENT

A. OVERVIEW

A health risk assessment is an evaluation of the potential for adverse health effects that can result from public exposure to emissions of toxic substances. The information provided in the health risk assessment, if required, can be used to decide if or how a project should proceed. Applicants for large power plant projects have typically been required to submit risk assessments to satisfy California Environmental Quality Act (CEQA) review requirements for potential impacts. Applicants may also use the risk assessments, and associated emission assessments, to satisfy the new facility operator requirement of the Air Toxics "Hot Spots" Program in Section 44344.5 of the Health and Safety Code. Risk assessments prepared for recent proposed power plant projects report that the increase in lifetime cancer risk is less than one in a million.

Some air pollution control and air quality management districts (districts) may have regulations, or established policies, on health risk assessments for making risk management decisions; some examples of such districts include the South Coast Air Quality Management District and Monterey Bay Unified Air Pollution Control District, which both have regulations that specifically identify the type of projects for which health risk assessments must be submitted. Other districts have relied upon the authority provided by Section 41700 of the Health and Safety Code to manage health risk impacts. When applicable policies or regulations are not in place, staff recommends that health risk be assessed according to guidance established by the Office of Environmental Health Hazard Assessment (OEHHA) pursuant to Section 44360.b.2 of the Health and Safety Code. Staff also recommends that the district make decisions consistent with the Air Resources Board's (ARB) "Risk Management Guidelines for New and Modified Sources of Toxic Air Pollutants, July 1993."

2. HEALTH RISK ASSESSMENT

A health risk assessment should address three categories of health impacts from all pathways of exposure, if appropriate: acute health effects from inhalation only, chronic non-cancer health effects, and cancer risks from multiple exposure paths. Acute health effects generally result from short-term exposure to high concentrations of pollutants. Chronic non-cancer health effects, such as lead intoxication affecting the nervous system, and cancer risks may result from long-term exposure to relatively low concentrations of pollutants.

Important steps to take when evaluating health impacts include determining the emissions of toxic substances from a project, characterizing the environmental fate of the toxic substances, and assessing the public's exposure to the toxic substances. In the final step of a health risk assessment, health impacts are characterized by combining the output from an air dispersion model with pollutant specific unit risk factors (for cancer effects) or reference exposure levels (for acute and chronic non-cancer effects).[23]

1. Emissions of Toxic Substances from a Project

The health risk assessment should identify the toxic substances of concern and the quantities that may be emitted from the power plant. The assessment may need to focus on certain criteria air pollutants [24] and different toxic substances for each of the three categories of health effects to be evaluated. The toxic substances of concern may also vary from one project to another because of differences in the basic equipment and emission controls that are proposed. According to information obtained through the Air Toxics "Hot Spots" Program, the criteria air pollutants and toxic substances identified in Table VI-1 should be addressed, at a minimum, when assessing the health risk associated with power plants equipped with combustion turbines that will be fueled with natural gas.

After the toxic substances of concern are identified, the quantity of emissions from the power plant must be estimated. Emission estimates may be developed from the information reported to the Air Toxics "Hot Spots" Program; however, it should be noted that this information does not focus on criteria air pollutants. An ARB guidance report, "Emission Inventory Criteria and Guidelines for the Air Toxics 'Hot Spots' Program, May 15, 1997," is available. Alternatively, emission factors based on source tests conducted on similar facilities may be used to estimate the quantity of toxic substances that will be emitted from a proposed power plant. Ideally, the emission factors would be derived from a source test of the same model turbine equipped with similar combustion devices and air pollution control equipment, and operated in the same manner as the proposed power plant.

In general, all emission estimates should reflect the operation of the power plant at maximum capacity and steady-state operation. However, emission estimates should be developed for all anticipated modes of operation that would result in worst-case impacts for the specific

[23]Reference Exposure Levels and Unit Risk Factors may be obtained from the Office of Environmental Health Hazard Assessment (OEHHA).

[24]The term "criteria air pollutants" is used here to refer pollutants such as oxides of nitrogen (NO_X) and carbon monoxide (CO) for which there are ambient air quality standards.

health effects being evaluated. For example, emission estimates developed to evaluate acute health effects should be based upon predictable process upsets. An assessment of acute health effects should include, at a minimum, the impacts from equipment startup, equipment shutdown, and any other situations where the air pollution equipment may be by-passed or operated well below typical operating efficiency. For assessment of non-cancer and cancer health effects, the emission estimates should reflect the expected long-term operation of the power plant which would include emissions from steady-state operation, emissions during periods of process upsets, and emissions from the startup and shutdown of equipment.

Table VI-1: Pollutants To Evaluate For Health Impacts

Acute Health Effects	
Ammonia (w/ SCR only)	Formaldehyde
Carbon Monoxide	Oxides of Nitrogen
Chronic Non-Cancer Health Effects	
Acrolein	Ammonia (w/ SCR only)
Benzene	Formaldehyde
Naphthalene	Nitrogen dioxide
Phenol	Propylene
Toluene	Xylenes
Cancer Risks	
Acetaldehyde	Benzene
Formaldehyde	

2. Characterizing Environmental Fate

The applicant will need to characterize the extent to which a power plant's toxic emissions will impact the surrounding environment. Air dispersion models should be used to predict the ambient air concentrations of the toxic substances emitted by a power plant. It is necessary to determine the highest emission concentrations, where they will occur, and the ground-level concentrations of the toxic substances at other points of interest (e.g, nearby schools and residences). The assessment must identify the exposure media. The common routes by which humans can be exposed to toxic substances are breathing ambient air, contact by touching a contaminated object, and eating or drinking items contaminated by the substance. Staff recommends that the applicant prepare a protocol detailing how the air dispersion modeling will be performed; the protocol should be reviewed and approved by appropriate regulatory agencies.

Only air dispersion models approved by the ARB and the United States Environmental Protection Agency (U.S. EPA) should be used.

3. Exposure Assessment

The estimated emission concentrations and identified exposure media are used to establish exposure levels. The applicant must determine the relationship between the exposure levels and incidence of adverse health effects. Algorithms and default values to determine this relationship can be obtained from OEHHA. The applicant may also provide a refined risk assessment based upon data that are more representative of the operations and the conditions unique to the location of the proposed power plant. When a refined risk assessment is prepared, the methods used and assumptions made must be documented and justified.

4. **Risk Characterization**

In the final step of a risk assessment, the output from the air dispersion modeling is combined with pollutant specific factors called unit risk factors (for cancer effects) or reference exposure levels, for acute and non-cancer health effects. Combining this information will provide an estimate of the potential cancer risk (chances per million) and potential non-cancer impacts expressed as a hazard index. Districts, ARB or OEHHA should be contacted for the most current reference exposure levels. Any potential increases in cancer risk or non-cancer health impacts should be reviewed in context with district risk management policies. According to California Energy Commission staff, typical results from screening analyses performed so far for proposed new power plants are less than one in a million cancer risk and less than one for the ratio of project exposure levels to reference exposure levels for acute and chronic health effects.

VII.

OTHER PERMITTING CONSIDERATIONS

1. OVERVIEW

Power plant permitting in California remains a complex process despite the consolidated California Energy Commission (CEC) power plant siting process, as a major power plant may be subject to myriad of federal, State and local requirements. Complete and enforceable permit conditions governing the design, operation, and maintenance of the proposed power plants serve as valuable compliance tools. This guidance is not intended to be comprehensive. Based on staff's review of recent applications for power plant projects, staff has identified a number of issues that are often difficult to adequately address in a permit. While some general guidance is provided, staff's guidance focuses on the following areas: emission limits, equipment startup and shutdown, source testing and monitoring, fuel sulfur content, and ammonia slip.

2. GENERAL PERMITTING CONSIDERATIONS

In California, the local air pollution control or air quality management district (district) is responsible for drafting and enforcing the permit conditions needed to ensure that the power plant will comply with local, State, and federal requirements. Permit conditions should be clearly identified as being applicable to an emission unit or the entire facility. When a requirement is applicable on an emission unit basis, it is important to have permit conditions that adequately address the construction or operation of the affected emission unit. Each permit should contain enforceable conditions to adequately address the following areas:

- all assumptions and specifications used in the engineering analysis regarding design, operation, performance, and emission limitations used in the technical analysis to establish any emission rate or concentration, or operating parameter;

- any parameter used to evaluate air quality impacts through air quality modeling, such as stack height;

- the applicant's responsibilities for source testing, emission monitoring, data recording, and reporting; and
- any specific requirements contained in district rules and regulations and State and federal law.

This guidance does not address requirements of Title IV (the Acid Rain Provisions) and Title V (the federal operating permit program) in the 1990 federal Clean Air Act Amendments. Staff recommends that a district consult its own regulations, the federal Title IV and Title V regulations (Title 40 Code of Federal Regulations (40 CFR) Parts 72 through 77 and Part 70, respectively) for the applicable requirements, and any applicable guidance prepared by the United States Environmental Protection Agency (U.S. EPA).

3. SPECIFIC PERMITTING CONSIDERATIONS

As mentioned previously, this guidance is not entirely comprehensive. The guidance presented here focuses on certain requirements or areas that are often difficult to address in a permit. It is provided to promote consistent and adequate treatment of emission limits, equipment startup and shutdown, source testing and monitoring, fuel sulfur content, and ammonia slip from selective catalytic reduction of oxides of nitrogen (NO_X).

1. Emission Limits

In general, a power plant will be required to comply with emission limits that are derived from prohibitory rules, new source performance standards, control technology requirements (i.e., best available control technology or BACT), and/or mitigation requirements. Permit conditions specifying the emission limits should be expressed in the same form as the underlying regulatory requirement. For example, if a BACT requirement is expressed as an emission concentration measured at a given averaging time and flue gas oxygen content, the permit condition implementing the requirement should utilize the same parameters (i.e., a surrogate hourly or daily limit would not be appropriate in this case). Furthermore, a BACT decision is specific to an individual emission unit or process and should be implemented with permit conditions that are applicable to the affected emission unit, not the facility as a whole. Emission limits implementing control technology requirements should be stated, to the extent feasible, as unit-specific and short-term (i.e., hourly or daily) limits and be enforceable using direct measurement methods.

Emission limits derived from new source review (NSR) and prevention of significant deterioration (PSD) requirements typically need to address both short-term and annual emissions. For example, an air quality impact analysis depends on precise quantification of emissions to model worst-case impacts. When the analysis utilizes less than the potential to emit,[25] the

[25]Potential to Emit is defined as the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design only if the limitation or the effect it would have on emissions is enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source. (as defined in the 40 CFR 51.165)

emission assumption should be enforceable through an emission limit in the permit; otherwise, the air quality impacts may be underestimated. If short-term emission limits are not evaluated in the ambient air quality impact analysis, then predicted short-term emission limits should be evaluated using the emission levels corresponding to the potential to emit and included in the permit conditions.

While emission offset requirements are typically based on facility-wide emissions, an emission limit on the facility as a whole, or an emission cap, may not be the most appropriate implementation tool; facility-wide emission caps are more difficult to enforce, especially if determination of emissions requires evaluation of extensive records and complex calculations. Ideally, permit conditions should limit annual emissions from each emission unit at the facility. Although combination of the individual emission limits provides the best assurance that the facility will be operated in accordance with the assumptions relied upon when the emission offset requirements were determined, emission caps may be considered to allow greater operational flexibility as long as adequate monitoring is specified.

2. Equipment Startup and Shutdown

With deregulation of the electric utility industry in California, the proposed power plants may need to operate with varying loads and numerous equipment startups and shutdowns. Power plants operated in this manner are known as "merchant plants" that operate in "merchant mode." Combustion turbines and control equipment do not operate at optimum performance during startup and shutdown due to the changing loads and temperatures. When compared to continuous online operation, merchant mode operation can contribute substantially to the total annual emissions. As a result, ultimate control of emissions can only be achieved by minimizing the emissions during these periods of equipment startup and shutdown. Minimizing emissions is possible by addressing all phases of operation in the BACT decisions and assuring that controls are required and used where feasible. Permit emission limits should be enforceable and written to apply to turbine emissions for all potential loads. Emissions generated during startup and shutdown periods should be regulated by a separate set of limitations to optimize emission control.

To regulate these emissions, permit conditions should require~~d~~ that the power plant operator have a district-approved plan to minimize emissions from equipment startup and shutdown. Permit conditions should limit and require recordkeeping of the number of daily and annual startups and shutdowns. If the turbines are equipped with continuous emission monitors (CEMs), CEMs should be capable of providing duration and quantity of emissions associated with each type of startup and shutdown (cold, warm, hot). When CEMs are not present for a particular pollutant, the permit should be conditioned so that emission projections and limits associated with each type of startup/shutdown are confirmed or enforced, respectively, with source testing where possible. Ideally, permit conditions should require that testing be conducted to establish these emissions prior to commencement of operation, and at least annually thereafter.

3. Source Testing and Monitoring

ARB's goal is to assure that facilities are in compliance with BACT and other emission limits specified in permit conditions. Compliance with BACT an.d other emission limits is most easily verified through CEMs and annual source testing. All source tests should use certified methods that meet the federal, State, and district protocols. A list of approved source test methods is available from the U.S. EPA's website, or the ARB's website.[26] If CEMs are required, source testing should include Relative Accuracy Test Audits (RATA). When CEMs are not used, the district should establish an alternate emission monitoring system to ensure ongoing compliance; an initial source test should establish the relationship between emissions and surrogate parameters which typically include fuel flow rate, flue gas flow rates, flue gas temperature, fuel British thermal unit (Btu) content, revolutions per minute (RPM), load, electrical energy produced, ambient air temperature and pressure, injection rates (if applicable) and other operating parameters. Annual source testing may be used to verify BACT and other emission limits, RATA testing of CEMs and verification of the alternative emission monitoring system, if applicable.

The permit should contain conditions to address the following requirements for source testing:

- pollutants to be tested, operating parameters, frequency of source testing, applicable test methods, parameters to monitor and relationship to emissions, duration of tests, and averaging times;

- for any requirement for CEMs, RATA, quality assurance (QA), and quality control (QC) requirements and procedures;

- for an alternate emission monitoring system, establishment and annual verification of the relationship of emissions to surrogate parameters;

Monitoring should be conducted to verify continual compliance with emission limits. Where feasible, CEMs should be used for measuring NO_X, carbon monoxide (CO), and flue gas oxygen content (O_2). Volatile organic compounds (VOC) can be monitored through correlation with CO CEMs data. Oxides of sulfur (SO_X) emissions can be verified through monitoring of fuel sulfur content. Annual source testing or surrogate parameters are appropriate to determine compliance with the emission limit for particulate matter of ten microns or less (PM_{10}). _Ammonia (NH_3) can be monitored through tracking of NH_3 injection rate and mass balance calculation; compliance with limits during periods between source testing should be monitored with surrogate parameters that limit potential emissions or correlate with emissions. Staff recommends the following list of monitoring methods in descending order of reliability:

---

[26]The source test methods are approved for Title V compliance monitoring.

- continuous emission monitoring (CEMs),
- source testing along with an alternate emission monitoring system, and
- annual source testing alone.

Concerns have been raised concerning the accuracy of current stationary source test and CEMs methods for measuring gaseous emission levels in the ranges recommended as BACT. ARB staff are currently investigating this low emission level measurement issue and may, if necessary, develop recommendations to ensure accurate and reproducible results in measuring emissions from new power plants.

4. Fuel Sulfur Content

The combustion of fuels containing sulfur results in the emission of SO_X. The quantity of SO_X emitted is directly proportional to the sulfur content of the fuel. SO_X emission levels can be conservatively estimated from the sulfur content of the fuel with mass balance calculations. The SO_X emission levels can be minimized with the use of natural gas as fuel. In determining SO_X emission levels, the calculations should be made with the upper limit of the sulfur content that is specified in the natural gas supplier's contract.

The permit should include the following conditions to address SO_X emission levels:

- a maximum sulfur content (the upper sulfur content limit of the natural gas supplier) and
- monthly monitoring of fuel sulfur content and record keeping requirements (the gas supplier's sulfur content records are acceptable compliance parameters for monitoring of sulfur content.).

5. Ammonia Slip

If selective catalytic reduction is the specified control technology, ammonia will be utilized to convert NO_X to molecular nitrogen (N_2). In converting NO_X to N_2, there is typically some ammonia that does not react and is released out of the stack; this is called ammonia slip. As the health risk assessment of ammonia emissions relies on the ammonia emission levels, permit conditions limiting the ammonia slip are necessary to be health protective.

The permit should include the following conditions to address ammonia slip:

- an emission concentration limit for ammonia, in parts per million volume (ppmv) with a specified averaging time, along with a limit on the ammonia injection rate;[27]

- monitoring and record keeping requirements;

- a requirement for appropriate calibration procedures to verify ammonia emission levels; and

- a requirement to monitor ammonia emission levels directly or to monitor ammonia injection rates as a surrogate parameter (Correlations between ammonia slip and ammonia injection rate may be established by mass balance analysis or source testing).

[27]As previously stated in Chapter III., staff recommends that districts consider establishing ammonia slip levels at or below 5 ppmvd at 15 percent oxygen in light of the fact that control equipment vendors have openly guaranteed single-digit levels for ammonia slip.

APPENDICES

Appendix A:

CALIFORNIA ENERGY COMMISSION
CURRENT AND FUTURE SITING CASES

	Project	Applicant	Size (MW)	Cap. Cost	Location	Filing Date 1/
1	High Desert (97-AFC-1)	Inland & Constellation	720	$350+ million	Victorville, San Bernardino Co.	Jun. 30, 1997
2	Sutter Power (97-AFC-2)	Calpine	500	$300 million	Yuba City area, Sutter County	Dec. 15, 1997
3	Pittsburg (98-AFC-1)	Enron	500	$300 million	Pittsburg, Contra Costa County	Jun. 15, 1998
4	La Paloma (98-AFC-2)	U.S. Generating Co.	1,043	$500 million	McKittrick, Kern County	Aug. 12, 1998
5	Delta Energy (98-AFC-3)	Calpine & Bechtel	880	$400+ million	Pittsburg, Contra Costa Co.	Dec. 18, 1998
6	Sunrise Cogen (98-AFC-4)	Texaco Global Gas & Pwr	320	$250 million	Fellows, Kern County	Dec. 21, 1998
7	Elk Hills (99-AFC-1)	Sempra & Oxy	500	$250 million	Elk Hills, Kern Co.	Feb. 24, 1999
8	Three Mountain (99-AFC-2)	Ogden Power Pacific	500	$300 million	Burney, Shasta Co.	March 3, 1999
9	Metcalf (99-AFC-3)	Calpine & Bechtel	600	$300 million	Santa Clara Co.	April 30,1999
10	Moss Land Repwr (99-AFC-4)	Duke Energy	1,206	$500 million	Moss Landing, Monterey Co	May 7, 1999
11	Morro Bay Repower 2/	Duke Energy	530	$250 million	Morro Bay, San Luis Obispo Co.	July 1999
12	Otay Mesa 2/	U.S. Generating Co.	1,050	$500 million	Otay Mesa, San Diego Co.	July 1999
13	Midway-Sunset 2/	ARCO Western Energy	500	$300 million	Kern Co.	July 1999
14	Combined Cycle 3/		500	$300 million	Imperial. Co.	July 1999
15	Antelope Valley 2/	AES	1000	$500 million	California City, Kern Co.	July 1999
16	Combined Cycle 3/		1000	$500 million	Los Angeles Co.	Aug. 1999
17	Combined Cycle 3/		1000	$500 million	Orange Co.	Aug. 1999
18	Newark 2/	Calpine & Bechtel	600	$300 million	Alameda Co.	Aug. 1999
19	Blythe Energy 2/	Summit Energy Group	400	$250 million	Blythe, Riverside Co.	Aug. 1999
20	South City 2/	AES	550	$300 million	So. San Francisco, San Mateo Co.	Aug. 1999
21	Long Beach 2/	Enron	500	$300 million	Long Beach, LA Co.	Aug. 1999
22	Sunlaw 2/	Sunlaw Cogen Partners I	800	$450 million	Vernon, LA Co.	Sep. 1999
23	Pastoria 2/	Tejon Ranch	960	$300 million	Kern County	Oct. 1999
24	Combined Cycle 3/		500?	$300 million?	San Bernardino Co.	Nov. 1999
25	Combined Cycle 3/		120	$75 million	San Bernardino Co.	Feb. 2000
26	Combined Cycle 3/		500?	$300 million?	Los Angeles Co.	Mar. 2000
27	Combined Cycle 3/		500?	$300 million?	San Bernardino Co.	May 2000
28	Combined Cycle 3/		500	$300 million	San Bernardino County	May 2000
29	Combined Cycle 3/		400	$250 million	Kern County	June 2000
30	Combined Cycle 3/		400	$250 million	Kern County	June 2000
32	Combined Cycle 3/		500	$300 million	Yuba County	Sept. 2000
31	Combined Cycle 3/		500	$300 million	S.F. Bay Area	Dec. 2000
33	Combined Cycle 3/		500	$300 million	S.F. Bay Area	Dec. 2000
34	Combined Cycle 3/		500	$300 million	San Diego County	June 2001
35	Combined Cycle 3/		1500	$700 million	San Diego County	Dec. 2001

Notes:
1/Staff's expected filing date.

2/Project has been publicly announced.
3/Project is not publicly disclosed; working with potential applicant.

Source: California Energy Commission Staff. Revised 5/12/99

Appendix B:

GUIDANCE ON THE PROCEDURE FOR MAKING A BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION

1. OVERVIEW

Federal regulations found in Parts 51 and 52 of Title 40 Code of Federal Regulations (40 CFR Parts 51 and 52) specify that one of two levels of emission control will apply to a new, or modified, stationary source of criteria pollutants subject to major source permitting requirements. The control requirements are pollutant specific and depend on an area's attainment status for the ambient air quality standards; a district may have an attainment designation for some pollutants and a nonattainment designation for other pollutants. The more stringent federal requirement is termed "lowest achievable emission rate (LAER)" and is required when an area is nonattainment for a standard; the less stringent federal requirement is termed "best available control technology (BACT)" and is required when an area is in attainment, or has an "unclassified" designation, for a standard. However, local air pollution control and air quality management districts (districts) in California use the term, "best available control technology (BACT)" exclusively when referring to the emission control requirements of their New Source Review (NSR) permitting programs. With a few exceptions, the district definitions of BACT are based on the more stringent of the two federal emission control requirements.[1]

Unless otherwise indicated, the use of the term "best available control technology (BACT)" in this document will refer to the emission control requirements in California as defined in a district's NSR permitting program regulation, often referred to as "California_BACT." With some variation, the districts' BACT definitions generally share the following elements/provisions:

- BACT is determined for a given "class or category of source;"

- BACT is generally specified as the most stringent emission level of these three alternative minimum requirements:
  - the most effective control achieved in practice,
  - the most stringent emission control contained in any approved State Implementation Plan (SIP),
  - any more stringent emission control technique found by the district to be both technologically feasible and cost effective; and

---

[1]In certain districts with attainment, or unclassified, designations for the ambient air quality standards, the BACT definition may be more similar to the less stringent federal requirement.

- BACT emission limits must not be less stringent than a New Source Performance Standard (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP) or any other applicable federal, State, or district requirement.

As part of the NSR process, the district must review an applicant's proposed BACT for the project's emission sources. The BACT determination must be consistent with the district's BACT definition and is a demonstration that the emission source will be constructed, or modified, in such a manner that its operation will release the least amount of air pollutants possible. District permitting programs and the California Energy Commission power plant siting process provide opportunity for the Air Resources Board (ARB), United States Environmental Protection Agency (U.S. EPA), and public interest groups to provide input in the BACT decision process.

Following is a discussion of the generalized procedure for making a BACT determination.[2] A summary of a technical review of previous BACT determinations for power plant combustion turbines using natural gas is contained in Chapter III of ARB's "Guidance for Power Plant Siting and Best Available Control Technology." The technical review which is the basis for the Chapter III summary is contained in Appendix C. The technical review examines, in detail, the various control equipment and performance that have been achieved in practice or are technologically feasible.

B. DESCRIPTION OF A GENERALIZED PROCEDURE FOR DETERMINING BEST AVAILABLE CONTROL TECHNOLOGY

BACT determinations typically involve a methodical analysis of the applicable district's BACT definition, and past and recent BACT determinations. In this section, the generalized procedure is described for determining BACT. This generalized procedure reflects the common elements/provisions of district BACT definitions and consists of the following steps:
1) establishment of the "class or category of source," 2) determination of "achieved in practice levels," 3) evaluation of control measures and implementing rules and regulations contained in State Implementation Plans (SIPs), 4) identification of control technologies that are more

---

[2]This procedure does not provide for the consideration of economic, energy, and environmental impacts; however, district BACT definitions based on the less stringent federal Best Available Control Technology definition found in Section 169(3) of Part C of Title I of the federal Clean Air Act provide for the consideration of economic, energy, and environmental impacts.

stringent than what has been "achieved in practice," and 5) the determination of BACT.

As the requirement for BACT is pollutant specific, the following generalized procedure should be repeated for each pollutant for which a proposed project's emissions will exceed BACT requirement thresholds. Also, when evaluating the information collected during each step of the generalized procedure, it may be necessary in some cases to reconsider the conclusions made at a previous step (i.e., one may need to repeat previous steps). For example, the "class or category of source" established in step one may be found to be overly broad, or narrow, after evaluation of information collected in latter steps.

Step 1. Establishing the "Class or Category of Source"

The effort to determine BACT begins with the establishment of the "class or category of source." The "class or category of source" establishes the scope of evaluations for the subsequent steps involving evaluations of control requirements. BACT determinations should be consistent within a "class or category of source."

"Class or category of source" provides the scope of what other basic equipment (or sources) will be used as comparables. The term "class or category of source" is not explicitly defined in federal, State, or district rules and regulations. As a practical matter, a power plant's basic equipment, processes, and energy sources (fuel) should be considered when establishing "class or category of source." Equipment or processes of similar type or function are typically placed together in a "class or category of source." Different makes (manufacturers) or models of the same type of basic equipment (e.g., a combustion turbine) generally should not be a consideration in establishing "class or category of source." However, the function and capacity of the basic equipment may be a consideration. It is noteworthy that the U.S. EPA has a technology transfer policy that broadens a "class or category of source" to include any sources with similar exhaust gas streams that could be controlled by the same or similar technology or any similar, but not necessarily identical, processes (e.g., similar coating operations).[3]

The establishment of an appropriate "class or category of source" is an important step; an appropriate selection will promote consistent BACT decisions that will help ensure that only the cleanest projects are approved. When the "class or category of source" that is otherwise applicable for a proposed project appears to be overly broad, the applicant has the burden of providing a demonstration to justify a narrower "class or category of source." For example, gas turbines may be considered a "class or category of source." Alternatively, one may want to

---

[3]August 29, 1998, U.S. EPA Memorandum entitled, "Transfer of Technology in Determining Lowest Achievable Emission Rate (LAER)," from John Calcagni, Director of Air Quality Management Division, to David Kee, Director of Air and Radiation Division, Region V.

consider gas turbines fired on natural gas and gas turbines fired on oil as two different "classes or categories of source." Commonly, the "class or category of source" may have been restricted to account for differences in technological feasibility and performance of control equipment due to the size of the basic emitting equipment. In this case, the applicant would need to demonstrate to the district that there are changes in control efficiency, lack of demonstrated use, inability to obtain financing, or restrictive conditions of vendor guarantees or warranties, etc. that make the control technology infeasible. ARB staff does not consider lack of vendor guarantees or warranties alone to be sufficient justification for altering a "class or category of source" determination.

Step 2. Establishing the "Achieved In Practice" Emission Control Level

This step identifies what emission limitation or control technology is the most stringent control level that has been achieved in practice for a relevant "class or category of source." This step involves a review of past, and recent, performance of controls on other equipment units in the same "class or category of source." The emission levels achieved with the various controls are compared and ranked to determine which control is the most stringent. Emission concentrations, normalized emissions rates (e.g., lb per Btu) and/or technology-specific requirements should be used to compare the performance of the required controls. Averaging times for emission measurement may be a factor in comparing the emission levels.

There are several sources of information on past BACT determinations. BACT determinations are cataloged in the clearinghouses maintained by the California Air Pollution Officers Association (CAPCOA) and the U.S. EPA.[4] In California, several districts, including the South Coast Air Quality Management District (SCAQMD) and the San Joaquin Valley Unified Air Pollution Control District, have BACT guidance documents. However, the SCAQMD intends to discontinue use of its guidance document and begin maintaining its own clearinghouse.

Step 3. Rules Or Regulations Contained In Any Approved State Implementation Plan

[4]The CAPCOA and U. S. EPA RACT/BACT/LAER clearinghouses are available on the Internet at www.arb.ca.gov/bact/bact.htm and at mapsweb.rtpnc.epa.gov/RBLCWEB/b102.htm, respectively.

Typically, a BACT emission limitation must be at least as stringent as any control measure that is contained in any approved State Implementation Plan (SIP) that is applicable to the "class or category of source." For example, a district may have a rule specifically limiting emissions from stationary gas turbines, or more general rules restricting opacity or fuel sulfur content from any emission source required to obtain a permit. The BACT emission limitation should not be less stringent or cause a violation of any of these applicable SIP-approved rules and regulations. Therefore, this step involves evaluation of the rules and regulations of all California districts as well as the rules and regulations of other states that may apply to emission sources within the same "class or category of source." Rules and regulations for California districts are available from the ARB website. Rules and regulations for other states can be found at the U.S. EPA's RACT/BACT/LAER Clearinghouse website, individual state websites, or by contacting each state directly.[5]

Step 4. Control Technologies More Stringent Than Tho se Achieved In Practice

Most districts in California are required to consider more stringent control technologies than those that are achieved in practice. The more stringent controls must be both technologically feasible and cost effective. Where more than one such control exists, staff suggests that the U.S. EPA's "top-down," decision-making procedures be used to rank the controls.[6] Staff recommends that the district rank technologically feasible controls by stringency of emission control after making the following determinations or demonstrations:

- determine the technologies that are technologically achievable using data from prototype testing, utilization with another "class or category of source," or limited operation not meeting achieved in practice criteria;
- determine the economic feasibility of each of the technologies identified above with a cost-effectiveness analysis;
- determine if the cost effectiveness is within the cost effectiveness limits of current BACT requirements or predetermined cost-effectiveness criteria established by the district; and

[5] A listing of state air quality office contact information is available on the U.S. EPA website at www.epa.gov/ttn/uatw/saq_offices.htm.

[6] See previous footnote 3.

- rank the cost-effective control technologies from the most to least stringent.

Step 5. Making The BACT Decision

In the final step of the generalized procedure, a BACT decision is made. The BACT decision must be consistent with the provisions of the district's BACT definition including the requirement that the BACT emission limit must not be less stringent than an applicable NSPS or NESHAP. In most cases, the BACT decision will be based on the most stringent emission level of the following three alternative minimum requirements identified in earlier steps:

- the most effective control achieved in practice identified (See Step 2.),
- the most stringent emission control contained in any approved SIP (See Step 3.), or

- any more stringent emission control technique found by the district to be both technologically feasible and cost effective (See Step 4.).