Conf-811250--

GEOTHERMAL ENERGY: THE INSTITUTIONAL MAZE AND ITS CHANGING STRUCTURE

Presented

December 1 - 2, 1981

Sheraton Hotel, Newport Beach, CA

CONF-811250--

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Sponsored by:

Geothermal Resources Council
P.O. Box 98
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GEOTHERMAL ENERGY: THE INSTITUTIONAL MAZE AND ITS CHANGING STRUCTURE

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DEPARTMENT of the INTERIOR
news release

OFFICE OF THE SECRETARY

For Release October 26, 1981 Reed (202) 343-5717

INTERIOR MOVES TO INCREASE GEOTHERMAL LEASING

Actions aimed at freeing-up the Federal geothermal leasing program have been ordered by Interior Secretary James Watt. "Clean energy from largely untapped and virtually renewable geothermal resources on America's public lands should be encouraged, not thwarted, by Government policy," Secretary Watt said.

Actions ordered by the Secretary include setting time limits for processing noncompetitive lease applications, holding competitive lease sales for all unleased known geothermal resource areas (KGRA's), and implementing a simultaneous leasing procedure to allow relinquished leases to be reoffered. The Secretary reaffirmed that there would be no geothermal leasing within a National Park. He said strict monitoring procedures would be conducted on any geothermal leasing proposals for which the Department of the Interior may have responsibility.

The directive by Secretary Watt complements geothermal leasing legislation introduced by Congressmen Marriott and Santini in H.R. 4067, and similar legislation introduced by Senators Warner and McClure, S. 1516. Of particular importance in the legislation is a provision to increase the present State acreage limit from 20,480 to 51,200 acres. About 50 geothermal lessees are at the current acreage limit. Increasing the limit would likely bring $40 to $60 million in bonuses over the next year and a half to the U.S. Treasury (with even larger revenues coming from royalties) and spur efforts to bring on this alternate energy resource.

In the Secretarial memorandum to the Directors of the Bureau of Land Management, the U.S. Geological Survey (USGS) and the National Park Service, Watt pointed out that Interior's geothermal leasing program has now been in operation for over seven years.

"Although approximately 1750 noncompetitive leases have been issued during that time, over 2000 lease applications are still pending," Watt said. "Less than one-half of those Federal lands designated as known geothermal resource areas have been offered at competitive lease sales."

The Interior Secretary also noted that about one-third of all leases issued have been relinquished and have yet to be reoffered. "Such backlogs," Watt noted, "are unacceptable at a time when this Department is committed to increasing domestic energy production. In addition, we must be fully protective of thermal features in our National Parks. It is important that we apply special protections to existing environmental standards to ensure protection of national treasures, such as Old Faithful. I firmly believe that a dramatic acceleration in the geothermal leasing program is possible, consistent with all legal mandates."

(more)

The specific actions ordered by Secretary Watt include:

-- processing of all pending noncompetitive lease applications within 12 months, new applications to be processed within 90 days;

-- unleased KGRA parcels to receive necessary environmental reviews and offered at competitive lease sales within 12 months, with priority review for declassification of parcels receiving no bids;

-- BLM to finalize rulemaking to allow reoffering of relinquished leases, followed by implementation of an active simultaneous leasing program as soon as the regulations are made final;

-- use of relevant information contained in existing environmental reviews or land use plans, to the maximum extent possible, in preparing pre-lease environmental reviews;

-- allowing carefully limited geophysical exploration operations in accordance with Congressional authority in areas under study for possible wilderness designations with proper safeguards to prevent impairing of suitability of such lands for inclusion in the wilderness system;

-- a closer working relationship between BLM and USGS to implement the foregoing measures, and to the extent possible, to make the Agriculture Department's U.S. Forest Service a full partner in future agreements and procedures;

-- a directive to BLM to consult with the National Park Service on protective measures and with the USGS on monitoring procedures prior to offering lands for lease outside Yellowstone and Lassen National Parks; and a requirement that USGS monitor all development on Federal lands in the vicinity of other National Parks containing geothermal features.

Watt said that the benefits to the public could be substantial in terms of both energy produced and revenues received while fully protecting our National Parks.

x x x

Geothermal Resources Council
bjh/11/17/81

GEOTHERMAL ENERGY: THE INSTITUTIONAL MAZE
AND ITS CHANGING STRUCTURE

1-2, December 1981

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GEOTHERMAL ENERGY:
THE INSTITUTIONAL MAZE AND ITS CHANGING STRUCTURE

1-2 December 1981
Sheraton Newport Hotel, Newport Beach, CA

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THE HOT CONNECTION

GEOTHERMAL RESOURCES COUNCIL, LOS ANGELES SECTION NEWSLETTER

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GERRY MORELLI Vice President, Membership
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555 S. Flower Street - NO. 5154
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DECEMBER 9, 1981
L.A. SECTION LUNCHEON MEETING

GUEST SPEAKER FOR THE MEETING WILL BE CHESTER BUDD SPEAKING ON THE TOPIC OF "UNION OIL'S GEOTHERMAL ACTIVITIES IN THE PHILIPPINES"

Please be sure to fill out your reservation form on page 4 to confirm your attendance and lunch.
See page 3 for directions to meeting place.

LUNCHEON SPEAKERS HAVE BEEN EXCELLENT!

BEN HOLT ON GEOTHERMAL IN CHINA, AND ROBERT REX ON THE HISTORY OF GEOTHERMAL ENERGY IN THE IMPERIAL VALLEY, HAVE ESTABLISHED A FORMAT OF ORAL AND VISUAL PRESENTATIONS THAT ARE BOTH HIGHLY INFORMATIVE AND INTERESTING. YOUR BOARD OF DIRECTORS IS SEEKING OUT THE HIGHEST QUALITY PRESENTATIONS FOR OUR BI-MONTHLY MEETINGS. SUGGESTIONS FOR FUTURE SPEAKERS OR TOPICS OF INTEREST ARE WELCOME. CALL TOM SPARKS (213) 572-2612.

CHESTER F. BUDD, JR.

Chester Budd is Manager of Foreign Operations for the Geothermal Division of Union Oil and until a year ago was Vice President and General Manager of Philippine Geothermal, Inc. (a wholly owned subsidiary of the Union Oil Company of California). He has been affiliated with Union Oil since 1968. Mr. Budd is a graduate of the Colorado School of Mines and holds a Petroleum Engineer degree. He presently holds membership in the GRC and the Society of Petroleum Engineers of AIME.

SPECIAL DECEMBER 9 AGENDA ITEM

FORMATION OF A GEOTHERMAL INDUSTRY TRADE ASSOCIATION BEGINS

ATTEND THIS IMPORTANT MEETING FOR DETAILS

MESSAGE FROM L.A. SECTION PRESIDENT JAMES R. STITES

As we reported at our last meeting, the consensus of respondees to the questionnaire regarding formation of a trade association was favorable. I think that we would all agree that the geothermal industry does not have a strong cohesive voice in Washington or Sacramento and that such a voice is necessary.

During a discussion at the GRC meeting in Houston last month, it was agreed that a need exists to establish a trade association separate and apart from our GRC organization. Since we will be discussing this at our next meeting, your attendance and participation is important. We look forward to your comments and support as we undertake a careful review.

REPORT FROM L.A. SECTION MEMBERSHIP CHAIRMAN GERRY MORELLI

Our paid membership has reached another new high! Starting with 29 interested attendees at our organizational meeting held on June 2, 1981, we grew to 136 paid members by August 25 and presently stand at over 210.

This may be the first issue of the "Hot Connection" reaching those of you located outside of the Los Angeles area. We are responding to interest shown by GRC members from your area. You are very welcome to join our section and/or attend our future meetings.

LOGO DESIGN

Our L.A. Section logo was designed by Casey Carter of Republic Geothermal.

ANNOUNCEMENT

The GRC Board of Directors at the October annual meeting in Houston elected our own James R. Stites to join their board as a director. Congratulations Jim ! ! !

INTERNATIONAL GEOTHERMAL BUSINESS OPPORTUNITIES

Cooperative trade missions begin to stimulate business development

The newly organizing geothermal industry trade association, in conjunction with the GRC/LA Section and private companies is arranging for geothermal trade exhibits at international conferences.

How can YOUR company reap the benefits of international exposure at very low cost? A revolving system of trade mission sponsorships (allowing maximum exposure and opportunity to all sectors of the geothermal industry) will be available on a first come, first reserved order of participation. Each sponsor (company) contributes a sponsorship fee in addition to producing and shipping their own catalogs or brochures to the event location care of the trade mission exhibit. The trade mission representative travels to the event, sets up the geothermal exhibit, displays the sponsors' names, disseminates the sponsors' literature, obtains registrants/attendees lists, and makes contacts with governments, interested companies, and the international news media. Upon return, a report to the sponsors will be produced sharing contacts, inquiries, and leads. This sharing of trade mission expenses allows very low cost participation and representation to the sponsoring companies.

To participate in international conferences call: (213) 945-3661 ext. 312 or (805) 482-6288.

SEE BULLETIN BOARD FOR UPCOMING EVENTS!!!

THE BULLETIN BOARD

INTERNATIONAL GEOTHERMAL BUSINESS OPPORTUNITIES

UPCOMING EVENTS

Florida - December '81: Fourth Miami International Conference on Alternative Energy Sources.

West Germany - April '82: Hanover Fair '82 (the world's largest industrial trade show).

Florence, Italy - May '82: International Conference on Geothermal Energy.

To participate in any of these international conferences, call (213) 945-3661 ext. 312 or (805) 482-6288.

FINAL NOTICE - SUBMISSIONS

IF YOU ARE INVOLVED IN ANY ASPECT OF GEOTHERMAL ENERGY

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- BUSINESS AND PROFESSIONAL ADVERTISING
- TECHNICAL REPORTS, AUTHOR'S ARTICLES

GEOTHERMAL WORLD DIRECTORY 1982

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(805) 482-6288   5762 FIREBIRD COURT
MISSION OAKS, CAMARILLO, CA 93010

HAVE A NICE THANKSGIVING!

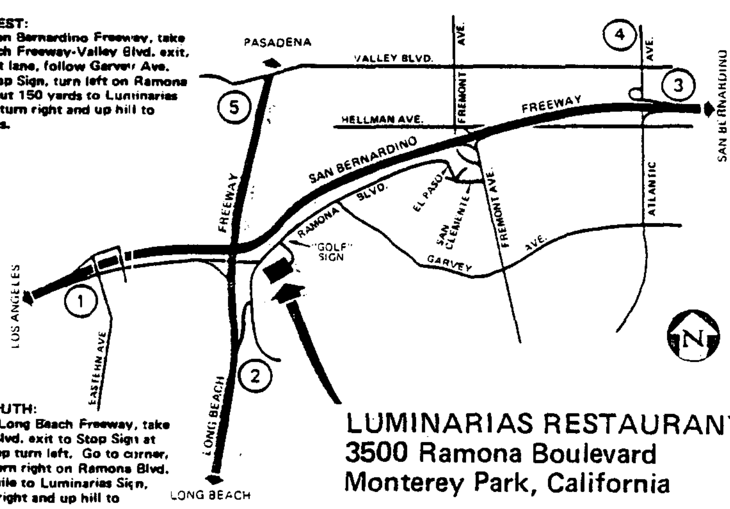
MEET OUR NEW SECRETARY/ TREASURER

RONALD R. SPOEHEL

A Corporate Finance Officer with Bank of America in the Los Angeles Energy Section, Ron has primary responsibility for B of A's activities in the geothermal industry replacing Jeffery Weinress who has left sunny Southern California for San Francisco. Ron's prior position with B of A was in the Project Finance Group where he was involved in domestic and international geothermal and oil and gas project financing. Ron holds a B.S. in Economics, M.S. in Engineering, and an M.B.A. from the University of Pennsylvania. In addition to his GRC loyalties, Ron is a member of the Society of Petroleum Engineers.

G.R.C. LOS ANGELES SECTION LUNCHEON MEETING PLACE

1 **FROM WEST:**
East on San Bernardino Freeway, take Long Beach Freeway-Valley Blvd. exit, stay in left lane, follow Garvey Ave. sign to Stop Sign, turn left on Ramona Blvd., about 150 yards to Luminarias Sign then turn right and up hill to Luminarias.



LUMINARIAS RESTAURANT
3500 Ramona Boulevard
Monterey Park, California

2 **FROM SOUTH:**
North on Long Beach Freeway, take Ramona Blvd. exit to Stop Sign at top of ramp turn left. Go to corner, at signal turn right on Ramona Blvd. about ¼ mile to Luminarias Sign, then turn right and up hill to Luminarias.

3 **FROM EAST:**
West on San Bernardino Freeway take Atlantic Blvd. exit, then south on Atlantic about ½ mile to Garvey Ave., right on Garvey about 1 mile to Ramona, left about ¼ mile to Luminarias Sign, then turn left and up hill to Luminarias.

4 **FROM NORTH:**
South on Atlantic Blvd. to Garvey Ave., right on Garvey about 1 mile to Ramona Blvd., left about ¼ mile to Luminarias Sign, then turn left and up hill to Luminarias.

5 **FROM NORTH:**
South on Long Beach Freeway, take San Bernardino Freeway to Fremont, right to San Clemente to Ramona to Luminarias Sign then turn left and up hill to Luminarias.

LUNCHEON TIME: 12:00 NOON

Please fill in and return the following:

Name: ______________________________

Title: ______________________________

Company: ______________________________

Address: ______________________________

Phone: (___) ____________________

JOIN THE LARGEST AND FASTEST GROWING G.R.C. SECTION SERVING THE SOUTHERN CALIFORNIA GEOTHERMAL COMMUNITY THE YEAR AROUND

RESERVATION CONFIRMATION

☐ I will be attending the DEC. 9, 1981 L.A. Section luncheon meeting.

** THE COST OF LUNCH WILL BE $10.00 PER PERSON AND MUST BE RESERVED AND PREPAID WITH THIS FORM. **

MEMBERSHIP, L.A. SECTION

☐ My check for membership in the Geothermal Resources Council, Los Angeles Section ($5.00 per annum) is enclosed.

☐ My check for membership ($5.00 per annum) is enclosed but I am unable to attend the DEC. 9, 1981 luncheon meeting - - please place me on your mailing list for the bimonthly "HOT CONNECTION" newsletter.

Please make checks payable to Geothermal Resources Council, Los Angeles Section and mail all remittances to:

Mr. Ronald Spoehel
555 S. Flower Street - No. 5154
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BRING A GUEST!
PASS THIS NEWSLETTER ON TO YOUR ASSOCIATES

CUT HERE

GEOTHERMAL RESOURCES COUNCIL
LOS ANGELES SECTION

c/o Ronald Spoehel
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DATES TO REMEMBER

DEC. 1 & 2
GEOTHERMAL ENERGY: The Institutional Maze
Newport Beach, California

DEC. 3 & 4
LEGAL ASPECTS OF GEOTHERMAL DEVELOPMENT
Newport Beach, California

DEC. 9
L.A. SECTION MEETING
Monterey Park, California

JAN. 11 - 13, 1982
GEOTHERMAL ENERGY CONFERENCE
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FIRST ANNOUNCEMENT

FOURTH SYMPOSIUM ON THE CERRO PRIETO GEOTHERMAL FIELD, BAJA CALIFORNIA, MEXICO, SPONSORED BY THE COMISION FEDERAL DE ELECTRICIDAD OF MEXICO AND THE UNITED STATES DEPARTMENT OF ENERGY.

A final symposium summarizing the five years of cooperative activities at the Cerro Prieto Geothermal Field between the Comisión Federal de Electricidad of Mexico and the United States Department of Energy will be held at the Guadalajara Sheraton, Guadalajara, Mexico, August 10-12, 1982. Field trips to the La Primavera and Los Azufres geothermal fields are tentatively planned for August 9 and 13, respectively.

Invited papers by participants in the project will cover results on the geology, geophysics, geochemistry, subsidence, and reservoir engineering aspects of the Cerro Prieto field. Interested American and foreign engineers and scientists are encouraged to attend.

For further information, please contact Ing. Alfredo Mañón, Coordinadora Ejecutiva de Cerro Prieto, C.F.E., P.O. Box 248, Calexico, California, 92231, or Rubén Zelwer, University of California, Lawrence Berkeley Laboratory, Earth Sciences Division, Berkeley, California, 94720; (415) 486-5560; FTS 451-5560.

GEOTHERMAL ENERGY: THE INSTITUTIONAL MAZE AND ITS CHANGING STRUCTURE

1-2 December 1981

Sheraton Newport Hotel, Newport Beach, CA

Schedule and Program

Monday, 30 November

5:30 pm - 7:30 pm	REGISTRATION & CHECK-IN/CASH BAR RECEPTION

Tuesday, 1 December

7:30 am - 8:40 am	REGISTRATION AND CHECK-IN
	David C. Russell, U.S. Department of the Interior Conference Moderator
8:40 am - 8:50 am	WELCOME AND ANNOUNCEMENTS David N. Anderson - Geothermal Resources Council
8:50 am - 9:00 am	INTRODUCTION David C. Russell, U.S. Department of the Interior
9:00 am - 9:45 am	GEOTHERMAL RESOURCES AND THE NEW ADMINISTRATION David C. Russell, U.S. Department of the Interior
9:45 am - 9:55 am	Discussion
9:55 am -10:10 am	COFFEE BREAK
10:10 am -10:55 am	STREAMLINING INTERNAL ADMINISTRATIVE PROCEDURES FOR GEOTHERMAL DEVELOPMENT AT THE U.S. GEOLOGICAL SURVEY, U.S. BUREAU OF LAND MANAGEMENT AND U.S. FOREST SERVICE William Isherwood, U.S. Geological Survey
10:55 am -11:05 am	Discussion
11:05 am -11:50 am	PENDING CHANGES IN GEOTHERMAL REGULATIONS: Geothermal Steam Act, Clean Air Act, Cultural Resources Act, FLIPMA, EPA Regulations, etc. John J. McNamara, J-M Energy Consultants
11:50 am -12:00 pm	Discussion
12:00 am - 1:30 pm	HOSTED LUNCHEON

1:30 pm - 2:15 pm	PENDING CHANGES IN THE REGULATION OF SOLID WASTE DISPOSAL AND UNDERGROUND INJECTION: Impact of State Programs in Lieu of Federal Programs Gary D. Knight, U.S. Synthetic Fuels Corporation
2:15 pm - 2:25 pm	Discussion
2:25 pm - 3:10 pm	CURRENT AND PENDING FEDERAL LEGISLATION: ITS EFFECT ON GEOTHERMAL DEVELOPMENT Richard Bliss, Wood Enterprises, Inc.
3:10 pm - 3:20 pm	Discussion
3:20 pm - 3:35 pm	COFFEE BREAK
3:35 pm - 4:20 pm	CURRENT AND PENDING TAX LEGISLATION: ITS IMPACT ON GEOTHERMAL DEVELOPMENT Richard Bliss, Wood Enterprises, Inc.
4:20 pm - 4:30 pm	Discussion
4:30 pm - 5:15 pm	PURPA (PUBLIC UTILITY REGULATORY POLICIES ACT): ITS IMPACT ON GEOTHERMAL POWER PLANT DEVELOPMENT John Nimmons, Earl Warren Legal Institute
5:15 pm - 5:25 pm	Discussion
6:00 pm - 7:30 pm	HOSTED RECEPTION

Wednesday, 2 December

Thomas A. Ladd, Naval Facility Engineering Command
Conference Moderator

8:00 am - 8:45 am	DISTRICT HEATING PROJECTS: Legal, regulatory and public relations problems and proposed solutions Diana King, Consultant
8:45 am - 8:55 am	Discussion
8:55 am - 9:40 am	IMPLICATIONS OF THE CALIFORNIA PUBLIC UTILITIES COMMISSION'S DECISION ON THE PROPOSED SOUTHERN CALIFORNIA EDISION/CHEVRON RESOURCES POWER PLANT AT HEBER, CALIFORNIA. Dr. Priscilla C. Grew, Commissioner, California Public Utilities Commission
9:40 am - 9:50 am	Discussion
9:50 am -10:05 am	COFFEE BREAK
10:05 am -10:50 am	COSTS OF GEOTHERMAL ENERGY AND COMPETING FORMS OF ENERGY: Oil, Gas, Coal, Nuclear, Solar, Oil Shale, Tar Sands, etc. S. J. Nola - Southern California Edison
10:50 am -11:00 am	Discussion

SPECIAL SESSION: GEOTHERMAL DEVELOPMENT ON MILITARY LANDS

11:00 am -11:45 am	OPPORTUNITIES FOR INDUSTRY IN THE DEVELOPMENT OF GEOTHERMAL ENERGY AT U.S. MILITARY INSTALLATIONS Carl Austin, U.S. Navy, Naval Weapons Center
11:45 am -11:55 am	Discussion
11:55 am - 1:30 pm	LUNCH BREAK
1:30 pm - 2:15 pm	SPECIAL REQUIREMENTS AND PROCEDURES FOR GEOTHERMAL DEVELOPMENT ON NAVY LANDS Carl Austin, U.S. Navy, Naval Weapons Center
2:15 pm - 2:25 pm	Discussion
2:25 pm - 3:10 pm	HOW TO DEAL WITH THE DEPARTMENT OF DEFENSE: Contracts, Leases, and Special Requirements. Thomas A. Ladd, Naval Facility Engineering Command
3:10 pm - 3:20 pm	Discussion
3:20 pm - 3:35 pm	COFFEE BREAK
3:35 pm - 4:20 pm	U.S. NAVY CONTRACT REGULATIONS FROM A DEVELOPER'S POINT OF VIEW David M. Roney, California Energy, Inc.
4:20 pm - 4:30 pm	Discussion
4:30 pm	CONFERENCE ADJOURNS

ATTITUDES OF THE REAGAN ADMINISTRATION TOWARD GEOTHERMAL DEVELOPMENT

by

David C. Russell
Deputy Assistant Secretary
Land and Water Resources
U.S. Department of the Interior

It's a pleasure to be here today and discuss with members of the Geothermal Resources Council attitudes of the Reagan Administration toward the leasing and development of geothermal resources in the United States.

Geothermal resources in the United States are located almost entirely in the Western States. The highest potential areas include The Geysers (80 miles north of San Francisco), the Imperial Valley (southern California), the Cascade Range (Washington, Oregon and Northern California), and central Utah; although Idaho, Nevada and New Mexico also have substantial potential.

The United States Geological Survey evaluates the Nation's geothermal resources in two classification categories. The first are known geothermal resources areas (KGRA) which have high potential for commercial production of either electrical or thermal energy. The second are prospective geothermal resources which have lesser potential but still may contain comercially valuable resources.

Presented by David C. Russell at the Geothermal Resources Council's Conference in Newport Beach, California, December 1, 1981.

The quantity of geothermal resources in Federal lands is, however, largely unknown although most authorities are in agreement that the potential for localized energy applications is substantial. The Department of Energy previously estimated, based on its own and USGS information, that geothermal energy production from all lands could exceed 125,000 megawatts by 2020. That would be the equivalent to approximately five million barrels of oil per day. The 1990 and 2000 projections are 10,000 and 38,000 megawatts respectively.

More than one-half of our geothermal resource potential occurs in Federal lands. Therefore, to the extent that lands are made available to exploration and development, Federal lands could contribute substantially to the future of geothermal energy in the United States.

The Bureau's geothermal leasing program began in 1974 -- four years after passage of the Geothermal Steam Act of 1970. In accordance with regulations appearing at 43 CFR 3200, lands within a known geothermal resources area (KGRA) are leased through competitive bidding. Lands not within a KGRA are leased to the first qualified applicant. Rentals for competitive leases are $2/acre/year noncompetitive leases are assessed $1/acre/year. All leases include specific diligent expenditure requirements which, if not met, subject the lease to termination.

As an incentive to exceed the minimum required expenditure, lessees are entitled to a refund of a special escalating rental, provided sufficient exploration has occurred. All leases are for 10 years, with five year extensions possible for drilling on the expiration date. Leases can be renewed for longer terms if there is production. Royalties are initially fixed at 10 percent of the value of production, but can be increased to 22-1/2 percent.

As of November 30, 1981, approximately 3.6 million acres (2000 leases) had been leased noncompetitively, and 700,000 acres (400 leases) had been leased competitively. Sales of competitive leases have earned the public almost $50 million, while annual rentals received are presently $3.5 million per year. In addition, a number of Federal leases are already providing steam for powerplants sited on private lands in California, and a major (110 MW) powerplant is nearing completion on public lands at the Geysers.

Royalties on production were only about $.5 million in FY 80, but increased to almost $2 million in FY 81 and they are expected to increase dramatically throughout the next two decades. In particular, some 25 leases in Nevada, Utah and Southern California have already been found to be producible and are awaiting construction of powerplants or other types of utilization facilities. Development plans to date have involved primarily electrical generation, but interest is growing in crop drying, greenhousing, and gasohol production.

The Bureau of Land Management has internally established a goal of leasing at least 20 million acres for geothermal development by 1990. This would include approximately 3.8 million acres already leased. The remaining 1.5 million KGRA acres that have not yet been offered (some will not be available for leasing), the 4.5 million acres currently under noncompetitive lease application (to be processed entirely by mid-1983), and approximately 1.5 million noncompetitive each year after 1983. This latter figure represents the Bureau's projection of anticipated industry interest in Federal lands.

Annual revenues from rentals and royalties are expected to increase from the $3.5 million received in FY 80 to a range of $46 to 70 million in 1990. In addition, competitive lease sales may earn the public between $40 - 120 million in bonus bids. Energy production by 1990 could approach 2000 megawatts, the equivalent of over 25 million barrels of oil per year.

All of these projections reflect the Administration's understanding of what the future of geothermal energy in this country can be.

This Administration, through Secretary James Watt, is committed to fostering the development of this clean, virtually renewable alternate energy resource. The Secretary has ordered a major overhaul of the Department's geothermal leasing and permitting program. Initiatives undertaken are:

Regulatory Reform

As part of a government wide program to reduce regulation of the private sector, the geothermal regulations appearing at 43 CFR 3200 (BLM leasing rules) have been reviewed to identify those provisions that are unnecessary, burdensome or counterproductive. Proposed regulation as they will soon appear in the Federal Register include:

1. Deleting the requirement for exhaustive prelease environmental reviews. This will allow the Bureau to use both "phased environmental reviews" and the "categorical exclusion" option, thereby greatly reducing the time needed to process lease applications.

2. Eliminating the requirement for an annual report from lessees demonstrating compliance with lease terms.

3. Allowing joint bonding for oil and gas and geothermal operations.

4. Deleting the requirement for a prelease plan of exploration or development.

5. Revising escalating rental provisions to allow for a waiver of these rentals rather than a refund.

6. Deleting the provisions that required lease applications, filed in excess of the lease acreage limitation, to be rejected.

7. Amending the powerplant licensing provisions to include licensing of nonelectrical utilization facilities.

A separate rulemaking pending since November 1979 is being made final and will soon appear in the Federal Register. That regulation will provide procedures under which the BLM will conduct a simultaneous geothermal leasing program similar to that used in the oil and gas program. Over 600 former leases involving over one million acres of land can now be reoffered. These simultaneous parcel offerings will be held in each BLM State office and will commence in April.

Administrative Actions

Secretary Watt, on September 9, 1981, ordered immediate acceleration of the Department's geothermal program. Noting that extensive backlogs existed, Secretary Watt Directed BLM and GS to process all pending lease applications within 90 days of receipt. In addition, all unleased KGRA acreage will be offered at competitive lease sales by the end of FY 82. Parcels receiving no bids will be reviewed for reclassification out of KGRA status on a priority basis.

Accordingly, BLM and GS streamlining includes efforts to:

1. Develop a Memorandum of Understanding (MOU) between BLM, GS and the Forest Service. This MOU will include specific agency response times for all government actions necessary to issue leases and approve exploration and developemnt of projects. The response times apply equally to BLM and FS field offices.

2. Revise Environmental Review Procedures. This involves adoption of phased environmental review and categorical exclusion by both BLM and FS offices.

3. Reduce the Use of Special Stipulations. A separate BLM/FS/GS MOU will be issued which should dramatically reduce the number of special stipulations being attached to leases.

4. Establish a Schedule for Leasing. Previous leasing schedules have been established, but never met. A new schedule is being originated jointly by BLM and FS field offices and revised as necessary by respective Washington Offices to assure elimination of backlogs. Under the Secretary's new Management by Objectives System, all BLM State Directors are being held accountable for meeting the leasing goals contained in the schedule.

Support Legislation

The Department is on record for not only supporting the goals of current House and Senate bills to amend the Geothermal Steam Act of 1970, but for urging enactment. Of particular importance in pending legislation is a proposed increase in the acreage limitation from 20,480 acres per State to 51,200 acres with a second increase possible to 115,200 acres in 1985. The Department has spent considerable time working with House and Senate staff to resolve other issues in the various bills to enable to encourage acreage limitation increases to go forward. We are especially concerned that if the limitation is not increased soon, lessees will be unable to absorb all of the leases that will be offered this year.

I hope that these comments have provided some insight as to the attitude of this Administration to geothermal energy. In closing, I wish to express my personal commitment to assisting the geothermal industry in developing geothermal energy in this country to its full potential.

Thank you.

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IN REPLY REFER TO:
3200 (520)

United States Department of the Interior

BUREAU OF LAND MANAGEMENT
WASHINGTON, D.C. 20240

November 5, 1981

Instruction Memorandum No. 82 - 64
Expires 9/30/82

To: All Field Officials

From: Director

Subject: Environmental Reviews in the Geothermal Leasing Program

By Instruction Memorandum No. 80-198, dated January 6, 1980, all offices were provided guidance on the use of phased environmental review for geothermal leasing. The purpose of this memorandum is to clarify the concept of phased environmental review and to make its use mandatory for all geothermal leasing of lands administered by the Bureau of Land Management.

General

The Government faces an apparent dilemma with respect to geothermal leasing in that leases are ordinarily issued without knowing the nature or extent or possible uses of the geothermal resource. Without such knowledge, decisions on lease issuance must necessarily be made without full knowledge of what the consequent impacts might be. Yet, leasing does convey the right, conditioned on subsequent approvals, to explore for, develop, and use geothermal resources. How then can leasing decisions be made in a timely and responsible manner when the impacts that could result are largely unknown? The answer is through the use of phased environmental review, a form of "tiering" as defined by the Council on Environmental Quality at 40 CFR 1508.28.

The concept of phased environmental review is based on the fact that the overall environmental review and decision process within the geothermal program consists of a number of distinct steps. At each step, the government is afforded an opportunity to conduct necessary environmental reviews to evaluate impacts that are reasonably predictable prior to making decisions that would affect the environment. First, there is the pre-lease review which leads to a decision that commits the government to allowing development consistent with applicable laws, regulations, and the standard and special terms of the lease. Subsequently, there are environmental reviews prior to approval of specific exploration, development or production operations. The overall environmental review is, therefore, completed in steps. By recognizing this fact and by taking full advantage of the tiering concept, unnecessary, unrealistic, and costly analyses can be avoided.

Pre-lease Reviews

The primary purpose of the pre-lease environmental review is to generally address the compatibility of geothermal activities on the lands being considered for leasing. If some known and highly important land use program or critical resource appears to have a higher value to the public than the opportunity to explore for and develop geothermal resources, and the program or resource cannot be adequately protected by the standard lease terms or by additional special stipulations, the lands should not be leased. However, considering (1) the small percentage of a leased area likely to be developed, (2) the flexibility for siting of operations, (3) the degree of environmental controls available, and (4) the high value of developable geothermal energy resources—lands should rarely be found to be incompatible with geothermal activities. While there may be incompatibility for small areas within a leasehold (administrative sites, stream channels, recreation sites, cultural resources, etc.), it is not necessary to extensively inventory such resources and uses prior to lease issuance, and it is normally not necessary to develop special stipulations to protect such areas. The regulations and standard lease terms already provide protection for these areas.

Accordingly, the pre-lease review should be concise and general, relying primarily on relevant information in existing land use plans, existing resource inventories, or other environmental source documents. The review should recognize that a decision to lease could lead to development and the use of a percentage of the land for electric generation and/or direct thermal use facilities. However, it is ordinarily useless and inefficient to attempt to address in detail the impacts of those activities on specific resources such as wildlife, water, recreation, etc. While impacts on such resources are a real possibility, they are related to specific sites and operations, and are best reviewed when specific operations are proposed. Controls or mitigating measures necessary to prevent unacceptable environmental impacts can be applied at that time. The types of impacts that should be addressed in the pre-lease review are those involving the general impact of geothermal exploration, development, and production on the broad management program and purposes of the lands being considered for leasing.

Post-lease Reviews

Subsequent to lease issuance all surface disturbing activities on a geothermal leasehold are subject to appropriate reviews prior to approval. These activities may include initial exploration, deep exploration drilling, development drilling, and construction of utilization facilities. The U.S. Geological Survey is the lead agency for reviewing and approving such activities, but the surface management agency must also grant approval.

To develop necessary stipulations and reach decisions on post-lease activities, the environmental reviews should primarily assess the specific activity proposed and the impacts of the activity. Since definite proposals and sites are known, the reviews should include appropriate detail on impacts to specific resources. However, they should still be limited to the level of detail necessary to make an informed decision on the immediate proposal. Future activities should be anticipated and briefly considered, but it is not necessary to address them in detail. For example, when considering a deep exploration well proposal, the review should ordinarily not attempt to anticipate the details of future development which might result. Subsequent proposed activities will be subject to review and approval on their own merits.

Summary

The design of the geothermal program is such that the government can save costs and time by minimizing environmental reviews prior to lease issuance and relying instead, primarily, on post-lease reviews to protect the environment. The issuance of a geothermal lease conveys the right to develop and use geothermal resources conditioned on government approval of each proposal made in the exercise of those rights. The government's approval authority includes the right to modify or reject specific proposals based on incompatibility with lease terms, special stipulations, regulations, or laws. Proper conduct of the program requires that all parties are aware that this approval authority exists, and that it may be necessary to restrict the extent or modify the location of exploration, development, or production operations on a leasehold. While this awareness can be obtained from a close reading of the lease form and regulations, there is an advantage in the clear statement of the authority in a conspicuous place. Therefore, the enclosed Lease Notice shall be made a part of all future geothermal leases for BLM-administered lands. Also, each pre-lease environmental review shall contain the enclosed Explanation of the Environmental Review Process.

Gerald E. Petty
Associate Director
Acting

2 Enclosures:
Encl. 1 - Lease Notice
Encl. 2 - Explanation of Environmental Review Process

Lease Notice

The lessee in accepting this lease understands that the surface management agency has reviewed existing information and planning documents and, except as otherwise noted in attached special stipulations, knows of no reason why normal development cannot proceed on the leased lands. However, specific development activities could not be considered prior to lease issuance since the nature and extent of the geothermal resource were not known and specific operations have not been proposed. The lessee is hereby made aware that, consistent with 30 CFR 270.12, all post-lease operations will be subject to appropriate environmental review and may be limited or denied, but only if unmitigatable and unacceptable impacts on other land uses or resources would result.

Explanation of Environmental Review Process

This review has evaluated the proposed leasing action in regard to general aspects of potential operations and their compatibility with broad land use programs or critical resources for the area considered for leasing. Details of possible future activities have not been evaluated because of lack of knowledge of the extent and nature of the geothermal resource and the type and scale of activity that might be proposed. Any lease issued will establish rights to explore for, develop, and use geothermal resources on the lands leased. However, specific activities will not be approved which would cause unmitigatable and unacceptable impacts on other land uses or resources. All activities will be subject to appropriate subsequent evaluations and approvals by the government. The role of the government in such approvals will be to assure that site-specific proposals are consistent with the standard and special terms of the lease, and applicable regulations and laws. Reasonable precautions will be taken to prevent or mitigate adverse impacts on other important resources and values.

United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

SEP 9 [illegible]

Memorandum

To: Director, Bureau of Land Management
Acting Director, Geological Survey
Director, National Park Service

Through: Assistant Secretary, Land and Water Resources
Assistant Secretary, Energy and Minerals
Assistant Secretary, Fish and Wildlife and Parks

From: The Secretary

Subject: Expediting Geothermal Leasing Program

The Department's geothermal leasing program has now been in operation for over seven years. Although approximately 1,750 noncompetitive leases have been issued during that time, over 2,000 lease applications are still pending. In addition, less than one-half of those Federal lands designated as known geothermal resource areas (KGRA) have been offered at competitive lease sales. Also, about one-third of all leases issued have been relinquished and have yet to be reoffered. Such backlogs are unacceptable at a time when the Nation is attempting to assess and develop its alternate energy resources, so as to increase domestic energy production, augment gains made by energy conservation, and further reduce imports of foreign oil. Increased leasing, exploration and production, however, must be accompanied by increased measures to protect environmental resources and unique geothermal features, particularly those in our national parks. It is important that we add special protections to existing environmental standards and insure protection of national treasures, such as Old Faithful.

I firmly believe that a dramatic acceleration in the geothermal leasing program is possible, consistent with all legal mandates. The benefits to the public can be substantial in terms of both revenues received and energy produced. Accordingly, you are to take all action necessary to implement promptly the following.

1. Noncompetitive Lease Applications

   It is expected that all pending noncompetitive lease applications will be fully processed within 12 months. Once the current backlog is eliminated, all new applications should be routinely processed in 90 days or less.

2. Competitive Lease Sales

All unleased KGRA parcels are to receive necessary environmental reviews and, if appropriate, to be offered at competitive lease sales within 12 months. A review for possible reclassification of parcels receiving no bids is to receive high priority.

3. Reoffering of Leases

The BLM is to transmit promptly to the Federal Register final regulations to allow reoffering of relinquished, cancelled, expired or terminated leases. An active simultaneous leasing program is to be implemented as soon as the regulations are final.

4. Environmental Reviews

Compliance with the National Environmental Policy Act is to be achieved at the appropriate points in the leasing, exploration and development process. To expedite reviews and reduce duplication of effort, to the maximum extent possible all prelease environmental analyses are to rely on relevant information in existing environmental reviews or land use plans. When actual development plans are submitted, environmental reviews and supporting resource inventories are to be directed at, and limited to, identifying impacts that are reasonably certain to occur; impacts that are hypothetical or insignificant may be noted but should not be discussed in detail.

In addition, BLM is to prepare proposed regulatory changes providing that, whenever possible, for noncompetitive geothermal leases, compliance with NEPA is to be accomplished primarily at the time plans for operation are received, rather than at the time the leases are issued. This proposal is to be forwarded within 30 days to the Assistant Secretry for Policy, Budget and Administration for publication in the Federal Register and is to address the following justifications for the proposed changes, among others:

(1) Impacts on the land occur, not at the time a lease is issued (this is an exercise in paperwork), but after plans of operations are received. (2) Operating experience over the past seven years has shown that, in most cases where noncompetitive geothermal leases are issued, plans for operations are never received--either because initial geophysical and other assessments reveal that geothermal potential is lower than originally thought, or because current technologies and the economics of evaluating, developing and marketing a geothermal resource are found to be inadequate to justify further investments.

It is thus in the public interest not to spend time and money preparing detailed environmental studies for areas that never go beyond lease issuance stage. (3) Special stipulations to protect environmental values can be appended to operating permits. These can be drafted to address concerns and values that are unique to the specific area being considered for operations and may exclude: (a) areas determined to be particularly sensitive; (b) activities or means of access determined to pose unnecessary risks of environmental harm or to have unnecessary impacts which could be avoided; and (c) activities or means of access for which less impairing alternatives are reasonably available, considering economic, technical and safety factors.

5. Wilderness Study Areas (WSA)

It is essential that the nature and extent of geothermal resources in wilderness study areas be understood in sufficient detail that the Department, Congress and American public can make informed choices concerning conflicting resource values and the potential effects of wilderness designation, in terms of energy opportunities foregone. Therefore, geophysical exploration operations, conducted in accordance with reasonable environmental and reclamation stipulations, are to be permitted in WSAs and will be considered as not impairing the suitability of such lands for inclusion in the Wilderness System. Permanent roads should not be permitted; if road construction, grading operations or access on skids is necessary, these activities are to be controlled through stipulations, to minimize impacts, provide for reclamation and insure that permanent impairment does not result. This approach will enable the Department to protect environmental values and preserve wilderness characteristics and options, while developing adequate data on which to base fully informed land use decisions.

6. Cooperative Agreements and Interagency Relations

The BLM and GS are to review existing cooperative agreements and procedures to ensure that the above measures will be implemented at minimal or no increase in agency budgets. Emphasis should be placed on reducing paperwork, eliminating unnecessary steps and specifying agency response times. To the extent possible, the Forest Service should be made a full partner in any revised agreements and proceedings.

7. National Park Protections

Special protections for nationally significant thermal features are required for Yellowstone and Lassen National Parks. The BLM, in coordination with the Forest Service where appropriate, is to consult with the National Park Service on protective measures and with the USGS on monitoring procedures prior to offering lands for lease outside Yellowstone and Lassen National Parks. The GS is to require monitoring of the effects that development and production will have on the hydrologic regime of lands adjacent to the National Park System, to insure that geothermal values within the parks are fully protected.

James G. Watt

STREAMLINING INTERNAL ADMINISTRATIVE PROCEDURES FOR GEOTHERMAL DEVELOPMENT AT THE U.S. GEOLOGICAL SURVEY, U.S. BUREAU OF LAND MANAGEMENT AND THE U.S. FOREST SERVICE

by

William Isherwood and Buford Holt

This paper briefly discusses the roles of the three principal agencies for lease issuance and administration and the highlights of recent changes in Federal requirements for submittal of plans and reports by operators. We include a summary of the details of a new Memorandum of Understanding (MOU) which governs inter-agency coordination between the Geological Survey (GS), the Bureau of Land Management (BLM), and the Forest Service (FS), the major actors in the Federal lease program.

This new MOU's basic contribution to streamlining is to delete some steps, specify new paperwork procedures that speed processing and set deadlines for rejection of permit applications. Additional inter-agency streamlining measures will include adoption of standard lease stipulations to eliminate the delays caused by inter-agency negotiation over the wording of stipulations on a lease-by-lease basis.

The BLM and possibly the Forest Service will go to the use of phased environmental reviews, under which pre-lease reviews look only for show-stoppers roughly at the scale of quarter sections. Detailed environmental reviews for the sites proposed for specific operations follow the reciept of a post-lease Plan of Operation (POO). The BLM is also revising its regulation to 1) eliminate the requirement for a pre-lease Plan of Operation in conjunction with each lease application, 2) adjust fees and requirements for utilization facility siting to accommodate uses other than power plants, and 3) speed the leasing of lands which were previously leased but have been relinquished or terminated.

The GS is excluding whole categories of operations from detailed environmental documentation and using only brief forms and notes, known as Categorical Exclusion Reviews (CER's) to document the absence of problems. Only if the potential exists for significant problems is an environmental assessment (EA) prepared. The GS is also emphasizing the reclassification of lands with regard to competitive versus noncompetitive leasing status. The GS has eliminated the requirements for an Annual Report of Environmental Compliance and for annual reports of Diligent Exploration Expenditures (DEE) when none have been made. The GS has also reworded the requirement for environmental baseline data collection to give explicit authority for scaling the scope of the baseline effort to the anticipated impacts. Explicit authority was also given for the prolongation of elements of the baseline studies into monitoring programs as necessary.

The GS is considering additional changes, such as, 1) elimination of DEE requirements, 2) turning over its power plant permitting authority to state and local governments, and 3) making post- rather than pre-lease economic evaluations for competitively leased lands. However, for now, the specifics of post-lease submittals by the lessee or the lessee's designated operator are essentially unchanged from the detailed accounts given in the Geothermal Resources Operational Orders. The changes being the previously mentioned deletions of pre-lease POO's, DEE reports of non-expenditures, and Annual Reports of Compliance.

Other streamlining steps come from the mandated time frames and procedures specified by the new inter-agency MOU. This MOU specifies that prior to a competitive lease sale the BLM will:

1. Request its District Offices to submit recommendations on lease issuance at least 120 days prior to the scheduled sale date. If Forest lands are involved, the BLM will request receipt of consent and special terms for lease issuance be provided at least 120 days prior to the scheduled sale date.
2. Coordinate with, and assist if requested, the FS in environmental reviews to ensure that a single review is applicable to both BLM and FS actions in the leasing decision.
3. Provide the GS a description of lands that are to be offered for lease at least 90 days prior to the scheduled lease sale date, requesting concurrence on any proposed special stipulations, and requesting recommendations on rental and royalty rates, parceling and economic valuations of tracts to be offered. BLM's request is to note whether mineral reserved lands (MRL) are involved and, if readily known, identify the surface owner.

The GS is required to:

1. Provide data and advice to BLM or FS in preparing their environmental reviews, if requested, including informal review of special stipulations as they are developed.
2. Respond to BLM's request for concurrence on proposed special stipulations, and provide recommendations on rental and royalty rates and parcelling at least 60 days prior to the scheduled lease sale date.

For non-competitive leases, the BLM and FS will cooperate as follows. Upon receipt of a lease application, BLM is to:

1. Provide the GS a copy of the serial register page; and request recommendations on lease issuance from BLM District Offices or, if Forest lands are involved, denial or consent with special terms for lease issuance from FS, be submitted within 45 days.
2. Coordinate environmental reviews with FS to ensure a single review is applicable to both BLM and FS actions for the leasing decision.
3. Provide GS a description of lands to be offered for lease, requesting KGRA clearlisting, and concurrence on any proposed special stipulations. BLM's request is to note whether mineral reserved lands (MRL) are involved and, if readily known, identify the surface owner.
4. Request final concurrence from GS and, if Forest lands are involved, FS prior to offering the lease.

The GS is to:

1. Provide data and advice to BLM and FS in preparing their environmental reviews, if requested, including informal review of special stipulations.
2. Respond to BLM's request for KGRA clearlisting, and review of special stipulations within 10 working days.

The Forest Service is now committed to cooperate in meeting these deadlines.

For pre-lease Exploration Permits, the surface managing agency (SMA, usually BLM or FS) is to:

1. Request GS District Office to review and make recommendations for all exploration permits involving a deep (greater than 500') temperature gradient holes.

2. Provide GS copies of all approved permits. The GS is to provide recommendations to BLM or FS within 10 working days of request and assist BLM or FS in monitoring operations, if requested.

Upon reciept of a Plan of Operations (POO), the GS will:

1. Forward a copy to the SMA after deleting proprietary data.
2. Request additional information from the operator deemed necessary by BLM, FS, or GS and schedule a joint on-site inspection of interested and involved parties if necessary. The on-site inspection is to be held within 20 working days after the request, weather permitting.
3. Determine the intensity and scope of and prepare the environmental review after consultation with the SMA.
4. Prepare and sign a joint approval letter for the POE or POO containing conditions of approval mutually agreeable to both GS and the SMA.

The SMA is to:

1. Notify GS within 5 working days of receipt of a POE or POO if additional information is needed from the operator or if a joint inspection is necessary.
2. Provide recommendations and special requirements for approval to GS, including information on how the operator can obtain any necessary access permits across Federally administered surface, within 10 working days of receipt of an acceptable POE or POO or within 10 working days of the joint on-site inspection;

   or

   Provide GS a new deadline for response describing the events that necessitate additional time for review. If formal consultation with the U.S. Fish and Wildlife Service (FWS) is necessary under Section 7 of the Endangered Species Act of 1973, as amended, the consultation will be initiated by BLM or FS on behalf of GS, and BLM or FS will request FWS to provide a biological opinion within 45 days. BLM or FS will also ensure, on behalf of GS, compliance with Section 106 of the Historic Preservation Act of 1966, as amended.
3. Assist GS in preparing its environmental review, as necessary.
4. Sign and return the joint approval letter within 5 working days of receipt.

Upon reciept of a an application for a Geothermal Drilling Permit (GDP), Geothermal Exploration Permit (GEP), or other operation under an Approved POE or POO, the GS will:

1. Approve applications for GDP's, GEP's or other permits for operations included in an approved POE or POO after informally coordinating any minor changes with SMA, and determining that lease compliance and protection bonds have been approved.
2. Provide BLM or FS a copy of any approved GDP's, GEP's or other permits including any attached conditions of approval, and indicating the intended compliance inspection program with respect to surface concerns.
3. Notify BLM or FS prior to commencement of all surface disturbing operations.
4. Ensure that operations are conducted in accordance with the approved GDP, GEP or other permits, involving BLM or FS assistance as necessary.

The SMA is to:

1. Inform GS if additional surface disturbing compliance inspections are deemed necessary at specific stages of approved operations.
2. Assist GS in monitoring of new surface disturbing operations, as necessary.

3. In cases of emergency, where serious environmental damage appears imminent and a GS representative is not available, issue a stop order to the operator and immediately notify GS.

For operations not included in a POE or POO, minor changes to a POE or POO will ordinarily be coordinated informally by the GS with BLM or FS. Proposed modifications involving substantial new surface disturbance will be processed as revisions to a POE or POO.

Upon reciept of an application for a Utilization Facility License, the BLM will:

1. Forward a copy to GS and, if Forest lands are involved, to FS.
2. Coordinate with GS and, if Forest lands are involved, FS regarding the environmental review.
3. Approve the utilization facility license for Forest lands only with the written concurrence of FS.
4. Coordinate compliance inspections with GS.

The FS will coordinate with BLM and GS with respect to environmental review and compliance inspections. The GS will similarly coordinate with BLM and FS.

This MOU provides a new and better cooperative framework for the participating Federal Agencies. The time frames in this document are designed to make expeditious leasing and permiting possible. In particular, goals include 1) elimination of the entire backlog of lease applications and unoffered KGRA lands, 2) processing new lease applications within 90 days, 3) processing exploration permits within 30 days, and 4) processing development permits within 120 days. We recognize that state, local, and other legal constraints may sometimes prevent meeting these goals, but the Federal government will now provide a system which will not further delay geothermal development.

MAZE Sect #2

Exhibit 3. APPLICATIONS AND REPRESENTATIVE PROCESSING TIMES FCR VARIOUS GEOTHERMAL ACTIVITIES

ACTIVITY	MUST BE ADDRESSED IN						ACTIVITY AUTHORIZED BY				PROCESS TIME	REFERENCE PAGE(S)
	POE	PBDC	POD	POI	POU	PFP	GEP	GDP	GUP	SN		
Casual Use							Advance notice required for expenditures to qualify as diligent exploration expenditures					
Aerial Surveys												
Geologic Mapping											None	16
Surveying												
Water Sampling												
Exploration Operations												
Areal Geopyhsical Surveys							x				30 days maximum	16-17
Temperature Gradient Hole Drilling and Coring (max. 3000 feet)							x					
Exploration Drilling and Testing											30 days maximum	
Geotechnical Site Study												16-17
With trenching or road construction							x					
No trenching or road construction							x					16-17
Well Pad and Access Road Construction	x							x		x	3-6 months	3-4, 17-21, Exh. 1
Exploratory Well Drilling	x							x				
Well Testing												
Additional surface disturbance	x									x	3 months maximum	3-4, 21-22
No additional surface disturbance										x	15 days maximum	21-22
Development												
Geotechnical Site Study											30 days maximum	6-8, 16-17
With trenching or road construction			x				x					
No trenching or road construction							x					16-17
Well Pad and Access Road Construction			x	x				x		x		6-11, 17-22, Exh. 1
Injection Well Drilling				x				x			4-6 months	8-11, 17-21, Exh. 1
Production Well Drilling			x					x				6-8, 17-21, Exh. 1
Pipeline Construction			x							x		6-8, 21-22
Well Testing (production and injection)												
Additional surface disturbance			x	x						x	3 months maximum	3, 6-11, 21-22
No additional surface disturbance										x	15 days maximum	21-22
Injection facilities construction				x						x		8-11, 21-22
Production facilities construction			x							x	2-6 months	6-8, 21-22
Later construction on same site										x		21-22
Alteration										x	15 days maximum	
Production and Utilization												
Geotechnical Site Study											30 days maximum	11-14, 16-17
With trenching or road construction					x		x					
No trenching or road construction							x					16-17
Site Construction					x				x	x		11-14, 21-24
Facility Construction					x				x	x	3-18 months	11-14, 21-24
Power Transmission Line Construction					x				x	x		
Facility Operation					x				x			11-14, 23-24
Production						x					45 days	14-15
Injection or Disposal (incl. byproducts)				x							4-6 months	8-11
Environmental Data Collection												
Baseline Data Collection (pre-development operations - one year minimum)		x									45 days maximum	5-6
Environmental Monitoring (post development operations)					x	x						11-5
Miscellaneous Activities												
Abandonment											15-30 days	11-14, 21-22
Utilization facility					x					x		
Well								x		x	7 days	17-22
Changes to Approved Plans or Permits										x		
Subsequent Well Operations												
Acidize										x	7 days	21-22
Casing changes										x		
Convert to injection well										x		
Deepen								x			7-15 days	17-21
Directionally drill								x			1-15 days	
Fracture test										x		
Perforate										x	7 days	21-22
Plug back								x				17-21
Redrill								x			7-15 days	17-21
Repair										x		21-22

KEY - POE=Plan of Exploration, PBDC=Plan of Baseline Data Collection, POD=Plan of Development, POU=Plan of Utilization, PFP=Plan for Production, GEP=Geothermal Exploration Permit, GDP=Geothermal Drilling Permit, GUP=Geothermal Utilization Permit, SN=Geothermal Sundry Notice.

Note: Where more than one Plan or Permit is checked off, the acitivity may be addressed in either Plan and authorized by either Permit.

Many of the itemized activities are processed together under one Plan rather than individually. Processing times shown are those for the entire Plan, and are based on submittal of a complete application. Processing of the Plans of Development, Injection or Disposal, and Utilization may be done concurrently, and submittal of these Plans togther is encouraged.

J. M. Energy Consultants, Inc.   John J. McNamara

LEGAL AND INSTITUTIONAL OVERVIEW:

BY LAND AND AIR - THE STRUGGLE CONTINUES

A. By Land:

On October 26, 1981, more than a decade after passage of the Geothermal Steam Act, Interior Secretary James Watt issued a press release which noted that he had taken administrative action to "Expedite the Geothermal Leasing Program." In a Secretarial Memorandum to BLM, USGS and the National Park Service, Watt had directed an increase in the laggard pace of the program.

He pointed out that over 2,000 noncompetitive lease applications were still pending while only 1,750 had been issued since passage of the Steam Act. Similarly, over half of the designated KGRA (Known Geothermal Resource Area) acreage had never been offered for bid and much of what had been offered went with no takers but had not been subsequently reclassified.

Watt therefore directed BLM to clean up the "backlog" within a year and process new applications within ninety (90) days. KGRA lands are to be offered within twelve (12) months as well, or reclassified. In addition, pre-lease environmental reviews are to be limited, with full NEPA compliance to take place at the time when Plans of Operation are filed by the lessees.

Watt also called for geophysical operations in BLM wilderness study areas and prior monitoring by USGS and Park Service before offering leases outside of Yellowstone or Lassen National Parks. But he did not foreclose such leasing.

Secretary Watt's actions, and the pending passage of the "Geothermal Steam Act of 1981" (H.R. 4067 (Santini to Marriott) and S. 1516 (McClure)) auger well for the future development of geothermal resources on the Federal lands. The legislation in question would toughen the test for KGRA designation, and significantly increase lessee acreage limits. Operative leases and those containing a producible well would also be exempted from the limits. The veto power of several non-Interior agencies over geothermal leasing of their lands would be reduced to consultation except for agency-acquired lands. "Exploration and testing" would be allowed in both Forest Service and BLM wilderness study areas, although Watt's memo would seem to indicate that this will not mean any deep well tests. While the House bill's "Burton Amendment" would create a no-leasing buffer zone around Yellowstone and Lassen, the likely outcome in Conference will probably be closer to Watt's more discretionary configuration.

In addition to Watt's pro-developmental leadership and the positive aspects of the legislation, several other encouraging administrative actions have surfaced this year. USGS has issued a policy directive eliminating the need for the creation of most Environmental Assessments (EAs) when each staged Plan of Operation (POO) submitted by a geothermal lessee. A ministerial Negative Declaration will be substituted instead, unless certain specific problems appear likely to arise.

The U.S. Forest Service, the other major Federal land manager, has long been criticized for tis endlessly negative responses to geothermal lease applications within National Forests. Recently, however, no less than four (4) such decisions, all in the Service's Pacific Northwest Region (Oregon and Washington), have been reversed, with large amounts of acreage available for leasing, and "No Surface Occupancy" (NSO) or "No Leasing" alternatives dramatically reduced.

Beyond all this encouraging movement, however, lie some large problem areas. Secretary Watt is already under intense fire and may eventually give way. Thus, all gains, whether administrative or legislative, need to be quickly consolidated against certain counter-attack. Secondly, other land use-impacting statutes present hurdles that may be more onerous than those in the Steam Act or its administration.

B. <u>By Air</u>:

The Clean Air Act is up for reauthorization this year and the policy debate has, unfortunately, become polarized from the opening bell. From a geothermal perspective, the allowance of state ambient standards which are in addition to or in excess EPA's own needs to be rectified, as does the present law's application of PSD to non-criteria pollutants such as hydrogen sulfide (H_2S). Both the new "visibility" regulations and the "air quality related values" portion of PSD seem to be scarily vague and unsupportable scientifically. However both seem to be unchallenged in most Reagan- and EPA-backed positions. Finally, the proliferation of "golden rules" for measurement - "B.A.C.T.", "R.A.C.T.", "L.A.E.R.", etc., might be replaced by flat emissions limits such as in "New Source Performance Standards" (N.S.P.S.) which allow a plant owner freedom to choose the most cost-effective method for achieving the required level, rather than selecting it for him.

OUTLINE OF
Speech by

Gary D. Knight
U.S. Synthetic Fuels Corporation

Before the
Geothermal Resources Council
Newport Beach, CA
December 1, 1981

"PENDING CHANGES IN THE REGULATION OF SOLID WASTE DISPOSAL AND UNDERGROUND INJECTION: Impact of State Programs in Lieu of Federal Programs

I. Resource Conservation and Recovery Act

A. History
1. 1976 Act
2. 1980 Amendments

B. Regulations
1. Open dumps (Subtitle D)
2. Hazardous Waste (Subtitle C)
a. Definitions
b. Mining exemption
c. Litigation

C. Mining Study
a. Intent
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3. Impact on regulations

E. State response
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II. Safe Drinking Water Act

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1. 1974 Act
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Outline
Speech by Gary Knight

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B. Underground injection regulations

1. June 24, 1980 regulations
2. Industry litigation
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C. EPA Budgetary picture

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D. State response

1. State regulations
2. Future plans

III. Consolidated permits

1. Impact on RCRA regs
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4. Prospective outcome

IV. Wrap-up

B 3

SPEECH BY

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Impact of State Programs in Lieu of Federal Programs"

Good afternoon, ladies and gentlemen. It is a pleasure to be here with you this afternoon. Thank you for that kind introduction. I'm usually introduced as the "latest dope from Washington!"

But seriously, the subject of my talk concerns the regulatory maze posed by the regulatory regimes emanating from the Resource Conservation and Recovery Act and the Underground Injection Control regulations pursuant to the Safe Drinking Water Act. As you know, there is a regulatory reform mood alive and well in Washington these days, and I've been told that at a recent cabinet meeting the attendees were visited by God Himself. He chose three persons in the room at random to each ask a single question. Secretary Haig was first, and he asked: "Lord will we achieve peace in the Middle East?" Whereupon, God said: "Yes, but not in your lifetime." Next, Secretary Weinberger asked, "God, will we achieve strategic arms reductions along with the Soviets?" God responded, "Yes, but not in your lifetime." Finally, Vice President Bush, who heads the President's regulatory reform task force asked, "Lord, will we ever achieve real regulatory reform?" To which God responded, "Yes, but not in <u>my</u> lifetime!"

So, if you already didn't know, we really have our jobs cut out for us.

Let's begin by discussing the Resource Conservation and Recovery Act, or RCRA, as it is usually called. RCRA was passed in 1976 after a two-year effort by primarily, Senator Jennings Randolph of West Virginia who then chaired the Senate Public Works Committee. He is considered the "father of solid waste" in the Senate and is the benefactor of RCRA's successor legislation, the Solid Waste Disposal Act of 1965 and the Resource Recovery Act of 1970. The purpose of these ancestor laws was to begin a federal role in solid waste management and resource recovery. Their impact, however, was minimal and during the environmental decade of the '70's Congress attempted to fashion a bill that would increase the outflow of federal monies to states and localities and to coordinate solid waste planning on more of a regional level. The resource recovery plants of the early '70's had trouble working on a commercial scale, and Senator Randolph fashioned his bill to help increase the utilization of this "trash to energy" technology. In fact, 10% of the authorizations from RCRA were to go into the funding of expert teams to travel around and consult with municipalities to help them develop a sound waste disposal system to suit their needs.

I worked on the development of RCRA for over two years in my role as the head of environmental affairs at the U.S. Chamber of Commerce. Let me tell you that the inclusion of Subtitle C, dealing with hazardous wastes was not a foregone conclusion. Noone knew the extent of the nation's hazardous waste problem back then. I failed to get industry technicians alarmed enough at the possible cost and regulatory implications of the inclusion of such a program in this bill. They perceived it simply as another "trash bill" of Senator Randolph's. However, environmental groups and zealous Hill staffers included Subtitle C in the weekend drafting session to write a compromise to the House and Senate-passed versions, which was adopted without debate on the respective floors the following week. The rest, as we all know, is history--as tardy and drawn-out as the regulatory scheme has been.

In 1979, EPA sought to even further strengthen RCRA's requirements, especially with regards to hazardous waste. They struck the 10% funding for the resource recovery teams; they asked for a new Assistant Administrator for solid waste; they sought increased penalties for violations;they sought authority to allow private contractors and EPA officials to inspect privately-owned sites; they wanted tougher imminent hazard provisions; they sought a "reckless endangerment" provision to make it easier to prosecute firms needlessly exposing employees or the public to possibly dangerous substances; and they wanted strict penalties for destroying records or for failure to keep records. Basically, they achieved all these legislative goals.

Industry, on the other hand wanted Congress to include separate levels of control for new, as opposed to existing disposal sites, as exists in the air and water acts. They also wanted water settling ponds and surface impoundments, constructed pursuant to the NPDES water permit system, exempted from RCRA. Finally, they wanted to narrow the definition of "solid waste". The major concern of the mining industry here was to narrow the definition to eliminate the "recycling and reuse" of materials from coverage under the hazardous wastes provisions. As you will see, industry was only marginally successful in having these provisions adopted, and many are still being debated and negotiated in the on-going regulatory process.

RCRA contains a Subtitle D, which governs the control of disposal of nonhazardous wastes. The primary objective of this subtitle was to eventually list all "open dumps", defined as any disposal site which does not contain hazardous materials, which is not a federal or state-licensed "sanitary landfill." All dumps so listed must be closed or upgraded within five years of their inclusion on the published list.

With respect to the issue of conern to the geothermal, as well as most industries, we find the labryinth known as Subtitle C--Hazardous Waste Management. The objective of this subjtitle is to establish a "cradle to grave" regulatory scheme to control all wastes defined as hazardous to human health or the environment. "Hazardous Waste" is defined as "a solid waste, or combination of solid wastes, which because of its quantity, concentration or physical, chemical or infectious characteristics may -- 1. cause, or significantly contribute to an increase in mortality or an increase in serious irreversible, or incapacitating reversible illness; or 2. pose a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported or disposed of, or otherwise managed."

Under this program, EPA can set minimum standards for the creation of a regulatory program and issue operating permits; however, a state can create and carry-out its own program if EPA approves.

Section 3001 of Subtitle C of RCRA is the key to this regulatory scheme. The law contains three ways to designate a waste as hazardous, which triggers the regulatory program: 1) a governor may petition EPA for the identification or listing of a material as hazardous; 2) by Section 7004(a) a citizen may so petition; or 3) EPA can develop criteria for identifying and listing, whereupon it must then set regulations for control of that material. Identification and listing regulations were finally published May 19, 1980 and have been amended several times since.

Included in these regulations was EPA's determination that a hazardous waste is a solid waste that is 1) listed as hazardous; 2) a mixture of solid waste and one or more listed waste, or 3) exhibits any of the hazardous waste characteristics identified. EPA has steadfastly refused to include a"degree of hazard" determination despite strong industry, academic and even environmental testimony that this would be the fairest method to determine the required degree of control. EPA has insisted that such a program would be impossible to implement in terms of staff and money and would be an open invitation to court challenge due to the continuous subjective judgements which would have to be made.

Four characteristics of a hazardous waste have been established by EPA: 1) ignitability, 2) corrosivity; 3) reactivity; and 4) EP toxicity; a groundwater contaminiation test involving the subjecting of a "representative sample" of waste to an acetic acid leaching medium with a pH of 5, and then testing the extract. An extract which reveals contaminants in concentrations equal to or greater than 100 times the National Interim Primary Drinking Water Standards is deemed hazardous.

EPA has also listed three types of lists: 1) non-specific sources (such as degreasing solvents), 2) specific sources (for example, certain settlement sludges from industrial processes) and 3) discarded commercial chemical products.

Before I delve into a report on the progress of recent devélopments, let me remind you all that Subtitle C also includes an exempt ion for small generators--those producing or accumulating less than 1000 kilograms per month (although smaller quantities are permitted for certain substances). This exemption, promulgated under regulations published on November 19, 1980, is calculated on a site-by-site basis and includes an exclusion from the calculation for wastes destined for recycling though not for certain sludges.

Subtitle C also has seaparate regulatory schemes and permits for generators, transporters, and operators of treatment, storage and disposal sites--all connected with a mandatory manifest system to ensure that no hazardous wastes "slip through this 'cradle-to-grave' system".

The 1980 amendments to RCRA provided temporary special treatment for certain categories of wastes in Section 7002(p) .In the 1976 law, the study was in Section 7002(f), and actually, the 7002(f) study is what is being conducted. These include drilling fluids, produced waters, and other wastes associated with exploration, development and production of crude oil or natural gas or geothermal energy, and the foregoing are not subject to the subtitle C regulations until a 24-month period during which study must be made concerning the appropriateness of including them. Parenthetically, a concurrent 6-month study is required to be conducted on the extraction, beneficiation, and processing of ores and minerals, including phosphate rock and overburden from the mining of uranium ore and cement kiln dust. While these studies are going on, firms handling utility wastes, mining wastes and cement kiln dust may be required to take certain actions with respect to sites and facilities that will be closed during the study phase. Some people have assumed that their activities will continue be exempted from Subtitle C due to these studies, but it would be unwise to make that assumption. Rather, a familiarity with RCRA's requirements and close study of on-going developments are advised.

Several industries have brought suit as a result of the provisions of EPA's May 19, 1980 hazardous waste regulations as well as the Agency's promulgation of regulations the same date to establish a consolidated permit program to supposedly simplify industry's compliance burden with permit requirements under RCRA, the Clean Air Act, the Clean Water Act and the Underground Injection Control Program. The former case, called Shell Oil v. EPA by the lawyers, includes over 25 key issues of concern to industry.

Some of these are:

1) Revision of definition of "solid waste" and management scheme for regulation of reuse or recycling activities.A broad exclusion may be given from waste status for most material being reused if within the same process or operation.

2) Criteria for listing and also for delisting of substances.

3) Failure of EPA to include a "degree of hazard" system.

4) Adequacy of the extraction procedure.

5) Short term generator storage, subsequent to which EPA has circulated a draft rule which would permit the accumulation of up to 200 kilogram of hazardous waste at "satellite" areas for 10 days without the need to comply with the 90-day accumultion standards.

6) Groundwater monitoring requirements, including a) statistical issues, b) elimination of certain parameters from required analyses, and c) reductions in frequency of sampling and unumber of replicate analyses.

7) Surface Impoundments, including acceptible neutralization techniques, design standards, etc.

8) Regulation of mixtures; whereas, EPA promulgated a prohibition of mixing waste waters with any listed chemical, 1 part per million of listed wastes is now allowed under the proposed settlement.

9) Interpretation of exemption for drilling muds and brines.

10) Underground injection well regulation.

Many of the points of concern raised by industry in the above litigation have been resolved through negotiation. Others have been made moot by the November 1980 amendments to RCRA. The remaining points will, obviously, be played out in court. I can only advise you to read the trade publications to keep on top of the day-to-day developments. I must add that many of these issues will be revisited during the development of amendments to the Water Act next year.

As I have said, the 1980 amendments to RCRA included the provision for a study of mining wastes to preceed the establishment of regulations affecting mining wastes. EPA had conducted a preliminary study of those wastes pursuatn to a study required under the 1976 Act. It hired one firm which began the study and was then forced to withdraw by the Agency. EPA then hired Pedco, out of Cincinnati to conduct the study. After approximately 18 months of conducting preliminary samplings and analyses, Pedco has now narrowed its studies down to a representative sampling of mining sites. To my knowledge none of these concern the geothermal industry.

Since August of this year, Pedco has been to and installed monitoring wells at six of the eight sites which they have narrowed their study down to. The last two should be monitored as of next week, and Pedco fully expects to make its report to EPA in sufficient time for the Agency to send its report to Congress by the end of October, 1983 as required in the statute. Unfortunately, it is much too early to speculate on the outcome of this study of mining and milling wastes, and while it is clear that the geothermal industry's practices are not now being studied, the final outcome subsequent to the recommendations of the ongoing study will have implications as to how the geothermal industry's wastes will be addressed by the Agency.

It would be instructive at this point to look briefly at the state of EPA's budget with respect to the implementation of RCRA. In a document accompanying EPA Administrator Anne Gorsuch's testimony before Rep. John Dingell's oversight subcommittee on November 18, 1981, the following budget cuts in the RCRA program for FY 82 are noted:

1. A $5.25 million reduction for development of hazardous waste regulations, guidelines and policies to implement a reduction to reflect: 1) a stretched-out development of technical manuals; 2) a more explicit workplan for Regulatory Impact Analyses, eliminating some of the need for formerly planned benefit/impact analysis; 3) a postponement of sleected activities and industry investigations leading to new hazardous waste listings, new industry-specific regulations, and the encouragement of resource recovery as a hazardous waste management alternative; and 4) less EPA implementation guidance to States as they become increasingly independent in operating hazardous waste programs.

2. A $868,800 cut in regulatory strategy implementation funds for hazardous waste management representing a significant loss of contract funds for the regional offices. EPA and state personnel will have to assume the responsibility for doing inspections on generators and transporters. The increased workload will translate into decreased inspections of such facilities. A large portion of the contract would have funded technical a-sistance in writing land disposal permits.

3. A $106,300 reduction in hazardous waste enforcement. $60 thousand of this will be to technical support for potential subtitle C judicial actions. The remainder is a reduction in funds for the Dallas regional office to train state and local officials.

4. A $24,700 cut in hazardous waste permit enforcement eliminating all contractrual assistance in developing new hazardous waste permits.

Further, OMB has announced its intentions to reduce by 36% ($700 million) by FY 84, including an elimination of over 6000 personnel. Included in this proposal is a 65% cut in hazardous waste program funds, as opposed to the Agency's plans to cut an additional 10% in this area.

With respect to personnel, there are no breakdowns available publicly on an office-by-office or program-by-program basis. However, the proposed FY 83 overall personnel figure of 8,953 represents a 15% reduction. Environmental groups have complained,however, that when one compares the proposed figures with the actual personnel onboard in FY 81, the changes would actually represent a reduction of 27% over two years, with further cuts to the 6,000 level in FY 84.

These budgetary and personnel reductions are included to give you an idea of the reduced role of EPA in implementing and enforcing the Congressionally-mandated regulatory programs. These include the RCRA programs which are only now getting off the ground. Since it is highly doubtful that Congress will change the RCRA program anytime soon -- and it is clear the program will not be reduced by Congress since its chief watchdog, Jim Florio returns to head his subcommittee after barely losing the New Jersey Governor's race -- the states will have to pick up the load.

As many of you in this room know well, California has long been a leader in environmental regulation on the state level. The solid and hazardous waste area is no exception. Your state just passed Senate Bill 618 which updated California's hazardous waste regulatory program. The California Mining Association valiantly attempted to have mining wastes exempted from the regulatory scheme similar to the scheme I and others had included in the federal bill. They unfortunately did not succeed. However, I am told that what they did get was not too bad and the prospects apparently look good that industry negotiations with the state Department of Health Services. The Association is reviewing the recommendations of the Department with respect to the proposed changes to the regulations, and there appears to be a good possibility that they will be successful in having included a category of "other wastes" to accurately reflect the high-volume, low-toxicity nature of these wastes.

In conclusion, the implementation of RCRA especially as it impacts your ability to easily and inexpensively deal with "make-up water" containing various materials which might be included on the EPA hazardous list will continue to impact the growth, development and cost picture of the geothermal industry.

Moving along to the Underground Injection Program, let me remind you how the Safe Drinking Water Act of 1974 was first passed. Congress for several years had resisted efforts of environmental groups to coerce it into passage of a statute to regulate the nation's drinking water supplies. Partly this was due to the fact that many such systems are owned by small local governments with little money and less wherewithall to implement complex regulatory schemes. However, late in 1974 EPA released a half-baked study that showed that the drinking water in New Orleans and several other cities contained vast amounts of carcinogenic trihalomethanes. The fact that the chlorine used to help purify the water is broken down to form some of these chemicals and the fact that many of the supposed contaminants counted were merely diatoms, were not uncovered until years later. The desired effect on Congress was achieved, and the Act was rushed into effect.

The Act was later amended in 1980 to address problems raised by municipalities, industry and environmental groups concerning the pracicalities of implementation.

The Clean Water Act, of course, is the primary statutory vehicle for cleaning up the nation's waters defined as "waters of the United States." However, underground acquifiers are not included in this definition. EPA has decided to use RCRA on an interim basis until the Underground Injection Control (UIC) program under the SDWA comes into effect, and for above-ground parts of hazardous waste injection facilities.

Part C of this Act provides for the states or EPA to implement permit programs and/or detailed regulations to govern sub-surface implacement by well injection. EPA promulgated regulations on June 24, 1980, which sets out the program. The permitting aspects of the program are governed by the UIC portions of the already-mentioned consolidated permit regulations promulgated on May 19, 1980. EPA has informed all states that they should be developing their own programs (assume "primacy"); meanwhile, EPA is using RCRA to govern injection operations that are above-ground.

Several definitions in the SDWA are quite broad:

"Endangerment" by a contaminant injected underground occurs "if the presence of such contaminant may result in a public water system not complying with any national primary drinking water regulation or may otherwise adversely affect the health of persons."

"Underground sources of drinking water" includes both currently used and potential drinking water sources. Even some acquifiers currently containing undrinkable water may not be excluded, and given the Congressional debate, aquifers with fewer than 10,000 parts per million of total dissolved solids be included.

"Well injection" is defined as the "subsurface implacement of fluids through a bored, drilled or driven well; or through a dug well, where the depth is greater than the largest surface dimension and the principal function of the well is the subsurface implacement of fluids."

EPA has created an arbitrary classification system which serves as the major guideline for determining the degree of regulation pertaining to each and every specific well:

Class I: All disposal wells that inject below all underground sources of drinking water in the area; and hazardous waste injection wells other than Class IV wells.

Class II: Wells that inject fluid for oil or gas recovery, and for storage of liquid hydrocarbons at standard temperature and pressure.

Class III: Wells which inject for extraction of minerals or energy.

Class IV: Wells that inject hazardous waste or radioactive wastes into or above underground sources of drinking water. These must be inventoried and states must implement an enforcement strategy such that they will be closed within 3 years of the effective date of the program with new ones prohibited.

CLASS V: ALL OTHER INJECTION WELLS

Class I wells are subjected to permits and regulatory restrictions persuant to the consolidated permit program. Class II wells were to be permitted; however, the amendments passed in December, 1980 allowed the states to continue existing systems of regulating injections in connection with oil and gas operations if they effectively prevent injection which endangers drinking water supplies.

On June 24, 1980 EPA published final rules pursuant to the Act which regulated most geothermal wells as Class 3. Subsequently, the regulations were challenged in court by the American Mining Congress on behalf of a number of its member companies. AMC's arguments were, among other issues, that since there is no chemical differnece between brines utilized for the generation of electricity and those used for direct use purposes, and since geothermal utilization merely extracts heat and does not significantly chemically alter brines, then all geothermal reinjection wells should be in Class 5. This is especially true since most Class 3 wells involved chemically treating water to mine minerals, like for example, sulfur and potash. These processes, it was argued, have virtually nothing in common with geothermal processes.

AMC made these arguments even though there was no geothermal company pressing for challenge, since there were virtually no commercial reinjection wells in operation. However, a quick examination of the regulations pertaining to Class 3 wells quickly revealed to AMC and its outside counsel that this inclusion of geothermal operations could become a major expense item in a geothermal operation and could indeed render future such operations totally uneconomic in certain cases.

Operators of Class III wells must comply with tough construction, operating and monitoring requirements specifically applicable to those wells. The most important of these is that the well be properly cased, cemented and operated, according to specified factors, in order to prevent the migration of fluids into or between underground sources of drinking water.

Similarly, Class V well operators have to get the required permits and comply with construction and operating requirements as imposed. EPA has thus far required only that the owners or operators of Class V wells notify the program director of the existence of such wells and that they submit an inventory of such wells. No construction or operation requirements have yet been imposed; such requirements await the completion of the inventory and the promulgation of regulations by the states.

EPA and AMC agreed to a settlement stipulation to the aforementioned lawsuit on July 23, 1981, requiring EPA to publish new changes to the UIC program in the form of a proposed regulation and accompanying changes to the preamble language. This publication occurred on October 1, 1981, with comments due by November 6.

The proposed amendments provided significant relief to the AMC litigants by resolving a number of extremely important issues including:

1) Reclassification from Class III to Class V of geothermal wells and wells used for in situ recovery of coal, lignite, tar sands and oil shale. This action would remove these wells from technical requirements pending further study and assessment.

2) Revision of the definition of "underground source of drinking water" to more closely conform to the statutory language, and provision for increased flexibility in exempting aquifers of water containing between 3,000 and 10,000 micrograms per liter of total dissolved solids.

3) Replacement of the "no migration" standard with an "adequate protection" standard with respect to the plugging and abandonment of Class III operations.

4) Provision for greater flexibility concerning the notice which an operator must give the state about construction, operation, conversion, plugging or abandonment of wells.

5) Provision for the demonstration of mechanical integrity of Class III wells through cementing records.

6) Provision for increased flexibility in the evidence required to demonstrate financial responsibility.

7) Elimination of certain reporting and monitoring requirements which are

unnecessary to the protection of underground sources of drinking water.

8) Protection against the unnecessary disclosure of proprietary information in monitoring reports.

Clearly, progress has been made for both the mining and geothermal industries with these proposed changes. It is unclear at this point what comments have been received by the Agency that might affect its changing its mind on any of the above points. However, the outlook is good at this point that most, if not all, will be published in close to their present form sometime early in 1982.

EPA's drinking water program is also the subject of deep cuts. In FY 82, a little more than one million has been reduced for contracts to support revisions to the primary drinking water regulations and support for regulations development will be reduced. In addition, a reduction will be incurred in the Office of Drinking Water's management support for underground injection control and public water system programs.

Secondly, $232,500 has been cut for contract funds used in support of training for state and local water treatment operators. Some of this contract money has been earmarked for training in geochemistry and subsurface waste disposal and water treatment technology specifically for groundwater.

Finally, over $1.2 million was cut to develop a program to provide training and technical assistance for small rural systems in 29 states.

These cuts will be violently opposed by Rep. Toby Moffett of Connecticut who chairs the Environment, Energy and Natural Resources oversight subcommittee of the House Government Operations Committee. Since he is running for the Senate next year, he cannot afford to sit back and let the high-profile need for an enhanced "national groundwater program" be gutted due to budget cuts. It will be quite interesting to watch and certainly will have a tremendous impact on EPA's ability to effectively carry out this second new regulatory program which so affects your industry.

Finally, with a peek into the future, let's look briefly at EPA's FY 83 budget. Here we find that the office of driking water has had its research and development budget slashed 19%, the largest decrease of any office's R & D budget. EPA says that UIC regulations will be reviewed in 1983 "upon the accumulation of experience, with the purpose of improving provisions and deleting requirements that have proved unnecessary." EPA said it anticipates a "rapid rate of delegation to the states" for the UIC program, since 40 states and territories would have primacy by the end of 1982, leaving EPA responsible for the program in 17 areas. EPA added "in 1983, we propose to start characterization of the subsurface contamination problem and development of practical approaches for assessing the hazard and scope of contamination."

While the FY 83 budget for groundwater protection will remain at the FY 82 level of $3.8 million, it proposes to increase its state program resource assistance budget in this area by 5% to $6.9 million. In the UIC enforcement area, the Agency plans to fund its headquarters with 6 people and $233,000 and its regions with 19 people and $594,000. It says this is the "minimum" level necessary "to support underground injection control programs until (they) develop further." EPA explains that the regional enforcement program will concentrate on enforcing the federal UIC program for 12 non-primacy states and issuing UIC permits "for wells in non-primacy jurisdictions."

So, as in RCRA, you in California are faced with the situation of a declining federal role but a state with the resources and ability to step right in and enforce the program. With the only commercially operating geothermal wells in the nation, you also have the most experience and perhaps have solved all the engineering and practical problems that others will later face.

I wish you the best of luck in the creation of this new and exciting industry, and I would like to thank the Geothermal Resources Council for inviting me to appear before you today. If we who are on your side in Washington can do anything to make your life easier--statutory or regulation-wise--please do not hesitate to let us know.

FEDERAL LEGISLATION AFFECTING GEOTHERMAL DEVELOPMENT

by

Richard W. Bliss
Westwood Geothermal Corporation

Perhaps more than any other segment of the energy industry, geothermal is dependent on Federal statutes and policy for its stimulation and survival. Access to the resource, markets, financing (both through tax incentives and government guarantee programs) and costs of production (because of environmental laws, depletion allowances, royalties) are largely in the hands of Uncle Sam.

Federal leasing statutes probably have a more immediate effect on the development of the geothermal industry than all other Federal statutes combined. This is so because most of the resource is in the Western states, and most of the land in the Western states is Federally-owned. Without access to Federal land, there will be no large scale geothermal industry. In fact, by comparison with other energy resources, geothermal will never hold center ring. However, it could add at least 20,000 pollution free megawatts to our electric generation mix, and has even greater potential for direct heat uses.

In order to appreciate the need for amending existing Federal legislation, it is important to review the existing law. It is not my intention here to relate section-by-section applicable Federal leasing law, but rather to highlight the critical points.

The Geothermal Steam Act of 1970 (30 U.S.C. 1001)

After initial successes in generating electricity from the unique dry steam geothermal resources found in an area north of San Francisco known as the Geysers, had been commercially demonstrated by the private sector, the Geological Survey identified a number of areas on Federal land in the West where heat from the earth's interior comes into contact with large underground aquifers at relatively shallow depths (from less than 1000 feet to about 8000 feet), thus having the potential for being utilized directly, for space heating and industrial processing, and indirectly for the generation of electricity. In order to provide a statutory framework for development of this resource, the original "Steam Act" was passed in 1970.

Under the Act, and its implementing regulations, Federal lands, not otherwise restricted, where temperatures and water volumes were estimated to be large enough and reasonably well defined, were classified as known geothermal resource areas (or KGRAs), and may, when offered, be leased from the Department of the Interior (Bureau of Land Management) under a competitive bidding system. KGRAs are classified on the basis of "geology, nearby discoveries, competitive interests, or other indicia, which would engender a belief in men who are experienced in the subject matter that the prospects for extraction of geothermal steam or associated geothermal resources are good enough to warrant expenditures of money for that purpose." Non-KGRA lands may be leased non-competitively for $1/acre. The Act also sets the primary lease term at 10 years, with royalty adjustment at 20-year intervals, beginning 35 years after first production. Individual leases are limited to "reasonably compact areas" not more than 2560 acres. The Act also limits leaseholds in any one state, to any one company (or individual), to 20,480, with authority granted to the Secretary of the Interior to increase this to 51,200 in 1985.

<u>Earlier Efforts to Amend the Geothermal Steam Act</u>

At the time this Act was passed, there was truly a dearth of information regarding the amount of viable geothermal resources that exists, or the technology necessary to exploit the resource. The only operating information available was from The Geysers (dry steam -- which is not comparable to the wet steam/hot water resource available in most other areas of the United States), and in a few overseas areas, notably New Zealand, Iceland, and Italy. The relative abundance of cheap fossil fuels made geothermal development relatively unattractive.

Even after the oil embargo of 1973-74, which was the dawn of the "energy crisis" as a major league issue, development was slow. In January, 1979, the Streamlining Task Force of the Interagency Geothermal Coordinating Council filed a report outlining reasons for the relatively slow interest in geothermal and making a number of recommendations for changes in Federal and policy statutes. Although a number of lease sales had taken place, and a substantial amount of acreage leased, no commercial power plants were under development or even seriously contemplated. The report noted a number of institutional barriers to geothermal development, including "competitive interest" KGRAs, limited acreage availability and excessive delays in lease and permit issuance by the government.

The findings and recommendations of that report were in a large part responsible for the introduction early in the 96th Congress of an Omnibus Geothermal bill which included improvements in the leasing system, and increased funding for a number of DOE programs (for example, loan guarantees) intended to stimulate the industry's growth.

The "omnibus" bill was split in the 96th Congress, with the DOE incentives program portion becoming Title VI of the Energy Security Act (the Synthetic Fuels Corporation Act, P.L. 96-294) and the leasing provisions being considered as separate legislation. There were several leasing bills introduced in both the House and the Senate, differing in detail, but having in common significant improvements in making Federal land available for geothermal development. Unfortunately, none of these bills survived the political struggles of 1980.

Public Utilities Regulatory Policies Act (PURPA)

While all of this was going on, other significant legislative events had taken place. The Public Utility Regulatory Policies Act (P.L. 95-617) signed on November 9, 1978, included in sections 202 and 203, provisions, the effect of which is to require both investor-owned and "publicly-owned" utilities to interconnect with and "wheel" (or transmit electricity) for small power producers. This can have the effect of encouraging widespread electric power wholesaling and allows non-utilities to generate and transmit power to markets, not necessarily in the local utilities' marketing area. Section 210 of PURPA, among other things, requires that utilities buy and sell power from small power producers (including geothermal) at reasonable rates. The primary criterion for determining the value to a utility of purchased power became "avoided cost", or roughly what it would cost the utility to generate that increment of power. Presto, there was a market for your geothermal-generated electricity.

As you may know, PURPA, including section 210, has been found unconstitutional by a U.S. District Court in Mississippi (FERC v. State of Mississippi, et al). This case is now on appeal to the U.S. Supreme Court (No. 80-1749). The essential issue is whether the Federal government can dictate that the states promulgate standards intended to have a certain effect on retail rates for electricity and standards for purchasing from and selling to small power producers, when the Federal government is not prepared to assume this responsibility in the absence of state action. The jurisdiction of the Federal government to act in the area of regulation of electric utilities is not questioned.

Specifically, the issue concerning us is whether the Federal government can require the states to promulgate regulations implementing section 210. If section 210 of PURPA is found to be unconstitutional by the Supreme Court, absence of a new constitutionally "pure" Federal statute having the same effect, could be a severe blow to the independent electric generation segment of the geothermal industry.

Section 210 of PURPA also permitted FERC to exempt power plants up to 30 megawatts from the Federal Power Act, the Utility Holding Company Act, and state laws respecting rates. This exemption was increased to 80 megawatts by Title III of P.L. 96-294. Most companies interested in geothermal development for electric generation would consider exemption from regulation as a utility as an absolute prerequisite to entering the actual power generating end of the business, as opposed to supplying the resource to a plant owned by a regulated utility.

Pending Federal Leasing Legislation

Early this year, the Geothermal Industry Group in Washington submitted to the Department of the Interior, as well as key Congressional Members and staff, a draft bill incorporating many of the features of the leasing legislation considered in the 96th Congress. Originally it was contemplated that the Reagan Administration would submit a bill to the Congress aimed at correcting the deficiencies in the leasing system. However, because of objections by the Office of Management and Budget, particularly with regard to competitive versus non-competitive leasing systems (OMB is concerned about the revenue impact), a true Administration bill was not introduced. However, the Department of the Interior, did consult with key Congressional Members and staff regarding the elements that should be in a bill and did provide a drafting service regarding key provisions.

Based on input from the Geothermal Industry Group, the Department of the Interior and Congressional staff, H.R. 4067 was introduced on June 26, 1981 by Congressmen Santini and Marriott, and is currently pending before the Mines and Mining Subcommittee of the House Interior Committee. Although a hearing was held on July 29 on the bill, the inability of the Administration to take a position caused the subcommittee to defer action on the bill and momentum was lost.

Meanwhile, the identical bill (with the exception that it does not contain a "parks provision") was introduced by Senators Warner and McClure in the Senate as S. 1516 on July 23, 1981. Other priorities initially caused Senate Energy Committee action on the bill to be deferred, although a hearing was finally held on October 27. The real difficulty, however, is the protection of national parks issue discussed below.

The salient points of these bills are:

1) Changes the definition of "known geothermal resource area" to delete KGRA designations because of competitive interest in leases.

2) Affords "point man" protection by allowing first applicant on non-KGRA lands, who develops data upon which subsequent KGRA designation results, to meet high bid in competitive sales.

3) Expands the per company - per state acreage limitation from 20,400 to 51,200 immediately, with a possible further administrative extention per state to 115,000, by the Secretary of the Interior after hearings in 1985.

4) Returns to non-competitive status, KGRA leases offered for sale and upon which no bids are received.

5) Extends the lease renewal period from 10 to 20 years.

6) Provides for administrative extention for up to 10 years where substantial investment has been made in a reservoir and commercial production is not possible because of administrative delays or demonstrated marginal economics.

7) The House bill establishes a fifteen mile wide buffer zone around Yellowstone National Park (except areas within the Island Park Caldera in Idaho) - and a one mile buffer zone around Lassen National Park.

Protection of Thermal Features of National Parks

We are all familiar with the world's most famous geyser, Old Faithful in Yellowstone, which is truly a natural national treasure. The same natural conditions that result in geothermal reservoirs amenable to commercial development is responsible for Old Faithful, as well as numerous other geysers, thermal springs, hot pools, and other surface manifestations of subterranean hot water aquifers. The West is literally covered with such phenomena although none approaches the beauty and uniqueness found in Yellowstone National Park.

I doubt there is any responsible geothermal developer who would chose to exploit truly unique thermal features such as those found in Yellowstone. In any case, it has long been the contention of most of us involved in the industry, as well as most officials in the Administration and on Capitol Hill who have responsibility for regulating geothermal development on Federal lands, that existing statutes, including the Geothermal Steam Act itself, afford full protection for features such as Old Faithful. There are also those who feel that, although existing law grants discretionary authority not to lease, or not to issue permits for development in areas where such features could be threatened, that more protection is needed. It is felt by some that protection should be taken out of the hands of Federal officials and some measure of iron-clad statutory protection afforded certain thermal features, such as those found in Yellowstone, while throwing the burden to show that "Nationally significant thermal features" found on certain Federal lands will not be damaged by geothermal development.

In the 96th Congress, two of the four "serious" geothermal leasing bills contained provisions protecting the thermal features of National parks. One bill also restricted development affecting thermal features of National monuments. It was originally estimated that only five National parks were affected. Subsequently the National Park Service produced a list of 26 National parks requiring protection of thermal features, and recommended that the Secretary have discretion to add to the list.

As you may know, there is a tremendous difference between National parks and National monuments. For one thing, in a beautiful state like California it seems that every other tree is a National monument. If the protection scheme included creating a buffer zone around every thermal feature, within which development would be prohibited or restricted, huge areas of the West would be unavailable for geothermal development. This of course raises the question of what is a "national significant thermal feature"? It could be argued that every hot spring, or steam vent is unique and therefore nationally significant. If this were accepted as the case, much of our best geothermal prospects would simply be out of reach.

Surface manifestations such as thermal springs and steam vents have been responsible for much of the early discovery work in geothermal. These are simply areas where an underground geothermal aquifer has reached the surface, usually along a fault. What better places to explore for commercial geothermal prospects than those where you know a geothermal aquifer exists?

In any event, controversy over this issue is what has caused the geothermal leasing bill to be in a state of limbo.

The industry position is simple. It is generally agreed that existing statutes protect Old Faithful and other unique thermal features. However, it is recognized that there are potent forces in the Congress who feel it necessary and desirable to afford an extra measure of statutory protection in order to thwart any damaging development which might be permitted by insensitive administrators. It is also recognized that the issue often boils down to simplistic terms such as, are you for or against protection of National parks? Politically it is very bad to be against protecting National parks. Hence, the reality is that some measure of extra statutory protection for parks probably must be accepted in order to get a geothermal leasing bill passed.

Any effort to split off the "parks issue" as a separate matter is not likely to succeed. The industry is willing to accept a reasonable parks protection provision. However, inclusion of National monuments is unacceptable.

Three National parks are generally singled out for special attention with respect to such protection: Yellowstone, Lassen, and Mount Ranier. The industry has suggested that a buffer zone of five miles be placed around Yellowstone within which geothermal development could be restricted or prohibited unless a showing could be made that no damage to any of the thermal features of the park would occur through development. The Department of the Interior has increased this recommended buffer zone to 15 miles. Even a five mile zone would place the closest possible development some 20 to 30 miles from Old Faithful. Nevertheless, with the limited operating experience in geothermal, plus the uniqueness of each hydro-thermal system, "proving" that development would not affect thermal features could be difficult indeed.

What starts out as a very broad issue in Washington frequently narrows down to relatively parochial interests, and that is exactly what has happened in the parks situation. Right outside Yellowstone's boundaries in Idaho is an area known as the Island Park Calder. It is one of only two major KGRAs in the State of Idaho and may have substantial potential for geothermal development, although to my knowledge no major developer has shown any great interest in the area to date.

Senator McClure of Idaho, for years and still a champion of geothermal energy, and Chairman of the Senate Energy Committee, has a great interest in avoiding unnecessary restrictions of geothermal potential in his state. At the same time, Senator Wallop of Wyoming also on the Energy Committee, understandably wants assurances that development on the periphery of Yellowstone will not damage its thermal features. Meanwhile in the House of Representatives, Congressman Cheney of Wyoming, who obviously has an interest in protecting Yellowstone, is attempting to work out compromise language on parks protection with Congressman Seiberling, Chairman of the Public Lands and National Parks Subcommittee of the House Interior and Insular Affairs Committee. A field hearing has been scheduled for Casper, Wyoming on the issue on December 12.

The Clausen Amendment

Another controversial issue regarding the leasing bill is the so called "Clausen amendment". In essence, the Clausen amendment would compensate certain owners of fee surface estates, where the Federal government reserved the mineral rights to the land. This issue resulted primarily from lands which were homesteaded in California (although there are similar lands in other states), many years ago. The surface owners, some of whom are absentee landlords and some of whom raise stock, contend that they always knew the geothermal resource (primarily around The Geysers area) was there, but thought that it was "water". Because of a court decision declaring geothermal to be a "mineral", it became subject to the jurisdiction and leasing authority of the Federal government. The land owners claim that they have a right to royalties from development of this resource *per se*, and also because of surface disturbance which may be caused by geothermal development.

The opposing point of view is that (1) they knew, or should have known, that mineral development was always possible on the land and held the land subject to that risk and (2) they are simply looking for a windfall. I suppose your view on this issue depends on whether or not you own land similarly situated.

The consensus in the industry seems to be that the claims of the land owners are not especially meritorious. There is greater concern that allowing surface estate owners to collect a royalty by special legislation would set a terrible precedent which may be carried over to the leasing of other minerals on Federal land. Clausen is lobbying very hard in both the House Interior Committee, and Senate Energy Committee for his amendment. Although he claims to have substantial support, there will almost certainly be substantial opposition and it is difficult to say at this point whether his amendment will be adopted.

Federal Tax Incentives for Geothermal

When the program for today was established by the Program Committee about two months ago, it appeared that some significant changes in tax law applicable to geothermal would be recommended by the Administration. For reasons I shall discuss in a moment, these changes have not materialized. However, I think it still would be useful to review the tax incentives situation as it exists. My comments on the tax situation are offered only as generalities, since the applicability of the various features of the tax code to a particular project depends on how the deal is structured, how equipment is classified, and a host of variables, each of which must be examined in the light of the tax code to determine specific effects.

During the energy independence exuberance of the Carter Administration, offered as part of the five part National Energy Plan, was the Energy Tax Act of 1978. This Act, P.L. 95-618, included among its features a special 10% investment credit for certain alternative energy property including solar, wind, photovoltaics, biomass and geothermal. In the Windfall Profit Tax Act, P.L. 96-223, which became law on April 2, 1980, the geothermal credit was extended to 15%, higher than any other renewable energy resource. When added to the "regular" 10% investment credit, a total of 25% investment credit is available for the purchase of "geothermal equipment". This credit expires on December 31, 1985.

In general terms, if you embark on a project involving the purchase of $10 million in eligible equipment, $2.5 million in tax credits will be generated. Under an amendment to the tax code contained in the Economic Recovery Tax Act of 1981, the credits are available even though up to 75% of the total amount of the project is borrowed, and only 25% actual "risk" equity. Hence, with $2.5 million in cash equity, $2.5 million in tax credits can be generated. These credits can be carried forward up to 7 years, or used to recover taxes paid up to 3 years prior to the taxable year in question.

During a recent round of budget cutting, the Office of Management and Budget (OMB), had recommended to the Department of the Treasury, that the elimination or reduction of special investment credit for alternative energy property be examined. The mere suggestion of the elimination of these credits had a decidedly chilling effect on investments in renewable energy, including geothermal. Industry frustration was obvious. Just at a time when tax incentives were beginning to have an effect, they would be eliminated.

It appears that neither OMB nor Treasury was prepared for the wrath of the Congress that descended upon them on this issue. Resolutions were introduced in both the House and Senate and signed by a majority of both bodies opposing reductions in alternative energy credits. We haven't heard much about this proposal in the past month, and it appears to be dead. The Department of the Treasury has all sorts of curious ways of determining the revenue loss incurred as a result of various tax incentives. How the revenue loss is determined for something like geothermal is difficult to imagine since the investment resulting in the credit would not be made in many cases were the credit not available. I assume that they assume that the investment would be made in an alternative area where the credit is not available, hence the taxes would be paid.

When IRS proposed regulations implementing the geothermal portion of the Energy Tax Act (September 19, 1980), "geothermal equipment" eligible for the credit was very narrowly construed to the point where the credit was almost worthless except for electric generating equipment, and even there confusion abounded. The IRS definition would have required "geothermal equipment" to be exclusively designed for use by a geothermal resource, and then only if the resource met certain criteria. As you know, geothermal equipment is often the same as equipment utilizing any hot water resource (regardless of what heated the water) and most of it is not unique.

After receiving comments from the industry, and holding a public hearing on the matter at which several geothermal companies testified, IRS broadened the definition considerably to include virtually all equipment utilizing the resource (46 F.R. 7287; January 23, 1981). The IRS did not go so far as to adopt my recommended "but for" test. This would define as "geothermal equipment", all equipment at a plant site, including any structures, "but for" development of that geothermal resource, would not be there. I still think that this broadened interpretation is worth fighting for.

Also worthy of mention is the accelerated cost recovery system (ACRS) implemented under the Economic Recovery Act of 1981, which allows geothermal equipment (except "public utility equipment") to be depreciated over a 5-year period, with an option for a 12 or 25-year period. As you may know, "public utility equipment", owned by <u>regulated</u> utilities is ineligible for the special 15% geothermal tax credit. Senator Matsunaga (D-Hawaii) has introduced a bill (S. 1517) to remove this restriction, although no action has yet been taken.

Amendments to the IRS code in the recent past also extended to geothermal exploration the same depletion allowance afforded small oil producers (to be maintained at 15%) and the deductibility of intangible drilling costs.

<u>Our Federal Legislative Future</u>

Although as I mentioned it is possible that the leasing bill will be enacted this year, it more likely will be carried over to next year. It is difficult to imagine how a piece of legislation so essential to development of an all-American, pollution free, viable energy resource can become embroiled in such political controversy. The really sad part is that there is no controversy over the most essential feature of this bill, which is to increase the acreage limitation immediately. Most companies interested in geothermal development have already reached their acreage limitation in a number of states. Even though the Department of the Interior, to its credit, is expediting its leasing schedule, many companies cannot participate in the bidding until the acreage limitation is increased. Nevertheless, with next year being an election year, if the bill is not acted on early in the session, it may be lost for yet another year.

One of our greatest problems is that the industry is not really yet an "industry", although, we have in Washington a "Geothermal Industry Group", a group of companies involved in developing geothermal, which operates on an ad hoc basis. To date, I think the "Group" has been very effective, considering the political realities of this issue. However, once the industry matures, certainly a more permanent organization to represent the industry's needs in Washington is necessary. The GRC fulfills an essential, but different function as a forum for the exchange of technical and other information among those involved in geothermal development. I understand that a group is now organizing in Los Angeles with a view toward filling the "Federal relations" role.

Many companies involved in geothermal do have individual representation in Washington. However, there is so much going on in the Congress and in various government agencies having regulatory authority over differing aspects of the industry, it is impossible for individuals to keep up. For example, when the IRS regs implementing the Energy Tax Act were proposed, only three or four companies having interest in geothermal testified at the hearing held on these regulations, even though the outcome of the rulemaking proceeding could have meant millions of dollars in tax credit availability to any given geothermal project. When EPA originally proposed regulations implementing the Safe Drinking Water Act, no comments were received from the geothermal industry regarding the classification of reinjection wells for geothermal power plant projects as Class III wells, which are heavily regulated. (This classification has been changed to Class V.)

These developments do not reflect lack of interest on the part of companies involved in geothermal. Rather it reflects lack of organization to respond to such initiatives.

Conclusion

Today the situation for geothermal is that we have relatively favorable tax treatment, access to markets, a rapidly developing body of technological expertise in geothermal utilization technology, an operating flash plant in Northern Mexico (25 miles south of the United States border generating 180 megawatts from geothermal), plenty of good prospect areas in the United States on which to drill, a demand for power in many Western States, and still no serious development of the industry.

There are many reasons, with the acreage limitation probably being the single most important. But in addition, it appears that there are several other serious problems:

1) Most utilities today have great difficulty in raising capital with which to pursue geothermal exploration and development.

2) Utilities do not qualify for the additional investment tax credits for geothermal equipment.

3) Many prime geothermal prospect areas are in very remote locations making exploration difficult, and limiting markets.

4) Most major geothermal developers at present are in the oil business. Geothermal exploration through the "well stage" is easy to relate to, even though it is technically very different. Generating electricity and dealing with a heavily regulated, "natural monopoly" type industry is unfamiliar territory.

5) Even though many utilities may need the power, they have, or at least argue that they have, a low avoided cost, making the risks inherent in geothermal development for power production difficult to justify. A single well can cost over $2 million. Since it is a site specific resource and, unlike oil or gas, cannot be moved more than a couple of miles, a good return on capital must offset these risks.

6) How much is it worth? Unlike virtually every other energy resource, geothermal has no readily ascertainable value. Although PURPA talks about purchasing <u>power</u> at "avoided cost", it doesn't (and shouldn't), give us a clue as to what the hot water and steam flowing or being pumped from the ground is worth. Is it worth the cost of development plus a healthy rate of return? Should all geothermal R&D in a particular field be figured into the cost of the first commercially produced wells? Should it be valued at its equivalent BTU content with the world price of oil? Should it be sold at what the traffic will bear?

As the industry matures, precedents will be set, familiarity will grow and the answers to these difficult questions will seem obvious.

It has been a pleasure to have the opportunity to be here today to discuss these issues. Notwithstanding the problems I mentioned confronting the geothermal industry, I am very confident that we are approaching the dawn of rapid and large scale development in which I hope you will all have the opportunity to participate.

FEDERAL GEOTHERMAL LEASING BILLS - 97th CONGRESS

BILL/SPONSOR	DESCRIPTION	HISTORY	STATUS
H.R. 4067, Santini (D-NV) (co-sponsor: Marriott (R-UT)	A bill to amend the Geothermal Steam Act of 1970, to expedite exploration and development of geothermal resources. Increases acreage limitation per state to 51,200 immediately (possibly to 115,200 acres in 1985); eliminates competitive interest KGRA's; extends lease renewals from 10 to 20 years; forgives diligence on units upon commercial production with commitment to utilize; protects thermal features of national parks.	Introduced 6/26/81 and referred to House Committee on Interior and Insular Affairs. Subcommittee (Mines & Mining) hearing held 7/29/81. Additional hearing scheduled for 12/1/81.	Appears to have broad support within the Administration, both Houses of Congress and geothermal industry. Very likely to be enacte into law this year or next year. Controversy over parks language hopefully to be resolved in near future.
S. 1516, Warner (R-VA); co-sponsor: McClure (R-ID)	A bill to amend the Geothermal Steam Act of 1970. Same description as above bill, H.R. 4067, except no parks provision.	Introduced 7/23/81 and referred to Senate Energy & Natural Resources Committee. Subcommittee (Energy & Mineral Resources) hearing held 10/27/81. Field hearing scheduled for 12/12/81 in Casper, Wyoming.	Appears to have broad support within the Administration, both Houses of Congress and geothermal industry. Negotiations underway re a provision to protect significant thermal features of national parks. Likely to become law.
S. 669, Jackson (D-WA)	"Geothermal Steam Act Amendments of 1981"-- similar to 96th Congress S. 1388 -- increases acreage limitation to 51,200 acres, also sets aside 10% of acreage leased in year, for "public bodies" (electric co-ops) and specifies that Secretary shall attempt to lease 10% of lands in year on non-cash bonus basis.	Introduced and referred to Senate Committee on Energy & Natural Resources 3/10/81. Hearing 10/27/81 (joint hearing with S. 1516).	Some Members of Congress who supported the 96th Congress geothermal bill introduced by Sen. Churc (S. 1388) may support this bill, since it is similar. S. 1516 is major markup vehicle.

SECTION 6

CANCELLED

PURPA BENEFITS FOR GEOTHERMAL POWER PRODUCERS: ASSURED MARKETS AND REGULATORY EXEMPTIONS

by

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I. INTRODUCTION

This paper reviews important economic and regulatory benefits now available to independent geothermal power producers under Title II of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), and discusses the extension of certain of these benefits to utility-owned geothermal facilities under recent regulations implementing the 1980 Energy Security Act's amendments to PURPA.

Title II's basic purpose is to foster competition in electric generation by encouraging independent, non-utility producers to undertake generation from non-conventional sources and to increase fuel efficiency through cogeneration. The circumstances leading to Title II's enactment and the nature of the benefits it provides have been summarized by the Federal Energy Regulatory Commission ("FERC") as follows:

> Prior to the enactment of PURPA, a cogenerator or small power producer seeking to establish interconnected operation with a utility faced three major obstacles. First, a utility was not generally willing to purchase the electric output or was not willing to pay an appropriate rate. Secondly, some utilities charged discriminatorily high rates for back-up service to cogenerators and small power producers. Thirdly, a cogenerator or small power producer which provided electricity to a utility's grid ran the risk of being considered an electric utility and thus being subjected to extensive State and Federal regulation.

> Sections 201 and 210 of PURPA are designed to remove these obstacles. Each electric utility is required under section 210 to offer to purchase available electric energy from cogeneration and small power production facilities which obtain qualifying status under section 201 of PURPA, and to provide back-up power and other services to such facilities on a non-discriminatory basis. For such purchases, electric utilities are required to pay rates which are just and reasonable to the ratepayers of the utility, which are in the public interest, and which do not discriminate against cogenerators and small power producers. Section 210(e) of PURPA provides that the Commission can exempt qualifying facilities from State regulation regarding utility rates and financial organization, [and] from Federal regulation under the Federal Power Act ...and...the Public Utility Holding Company Act. (45 Fed. Reg. 17959, March 20, 1980; emphasis added.)

Translation into practice of PURPA's broad mandate for power purchases and sales and regulatory exemptions has been primarily the responsibility of FERC, through federal rulemaking proceedings, and secondarily the responsibility of state public utility commissions and non-regulated (municipal and cooperative) utilities, through state rulemaking proceedings implementing FERC regulations and through administrative oversight of utility activities. FERC's rulemaking, now virtually completed, has resulted in comprehensive regulations defining the boundaries within which state regulatory commissions, utilities and independent power producers must operate. State implementation efforts are not as far along: many states have published final regulations and power purchase price schedules, but some have not, and relatively few actual transactions between utilities and others have so far occurred under PURPA. The following discussion summarizes basic elements of the overall federal regulatory scheme which the states must honor, and which should be of substantial interest to prospective geothermal power producers wherever they are located.

II. ELIGIBILITY FOR BENEFITS

Title II's benefits are available to two types of facilities: "small power production facilities" and "cogeneration facilities." Section 201 of the statute, as amended, defines a small power production facility ("SPPF") as one which produces up to 80 MW of electricity using biomass, waste, renewable resources or geothermal as its primary energy source. It defines a cogeneration facility ("CGF") as one which produces electricity *and* other useful energy (including steam or heat) for "industrial, commercial, heating, or cooling purposes," without regard to the size of the facility or the type of fuel used. Under these definitions, a geothermal facility might be considered either a SPPF or a CGF, depending upon its size and the form of its energy output.

As originally enacted in 1978, PURPA benefits were afforded only to "qualifying" SPPs or CGFs. "Qualifying" facilities were those meeting specified fuel use, efficiency and reliability standards, and owned by a person "not primarily engaged in the generation or sale of electric power" other than from such facilities. (PURPA §§201, 210.) FERC has defined the latter requirement to mean that *not more than a 50% interest in the facility may be owned by an electric utility or utilities, electric utility holding company or companies, their subsidiaries or combinations thereof*. (18 CFR §§292.101(b)(1), 292.206.)

This utility ownership limitation continues to apply to all non-geothermal small power production and cogeneration facilities. However, as to geothermal facilities, PURPA amendments contained in §643 of the 1980 Energy Security Act ("ESA") omitted the "qualifying" requirement as a condition of eligibility for PURPA's regulatory exemptions, and FERC has suggested that the ESA's legislative history may warrant administrative elimination of the requirement in connection with PURPA's power purchase provisions as well. (See *Notice of Proposed Rulemaking* issued Nov. 6, 1980 in RM81-2, pp. 5-8.) This means that electric utility ownership of geothermal facilities will not preclude eligibility for some, or perhaps for any, of PURPA's substantive benefits discussed below.

III. UTILITY POWER PURCHASES AND SALES

PURPA's most far-reaching benefits for geothermal power producers and cogenerators are those designed to overcome traditional utility reluctance to purchase or transmit independently generated power. First, the Act authorizes FERC to order the physical connection of geothermal power facilities with utility transmission facilities, and to require related actions which may be necessary to make such connections effective. (PURPA §§202, 210.) Second, it empowers FERC to order electric utilities to provide transmission services to geothermal power producers. (PURPA §203.) Third and most important, PURPA directs FERC to prescribe rules requiring electric utilities to purchase electric energy from, and to sell backup, supplemental and maintenance power to, qualifying small power and cogeneration facilities. (PURPA §210(a).)

The electric utility power purchase requirement is at the heart of PURPA. It virtually ensures that independent geothermal power producers will have a market for as much of their electric output as they might choose to sell, and that the prices paid for this output will often be substantially higher than they might have been without PURPA. To ensure a market, PURPA and FERC rules require electric utilities to purchase *all* the electric output offered by qualifying facilities with which the utility is interconnected (except during system emergencies and unusual lightloading situations), and to interconnect with such facilities where necessary to accomplish such purchases. (18 CFR §§292.303(a), (c) and 292.304(f).)

To ensure prices above those which independent producers might otherwise have commanded, PURPA provides for purchase rates based on the "incremental cost to the electric utility of alternative electric energy," defined to mean

> the cost to the electric utility of the electric energy which, but for the purchase from such co-generator or small power producer, such utility would generate or purchase from another source. (PURPA §210(b),(d).)

In place of this unwieldy statutory definition, FERC regulations substitute the shorthand term "avoided costs" - i.e., the costs which the purchasing utility would otherwise incur to generate equivalent power itself or to purchase it from some other generating source.

This basic pricing standard is designed to allow qualifying facilities to benefit from the fact that a utility's incremental or marginal costs -- hence the prices payable to independent power producers -- generally will represent its highest unit costs. Most electric utilities operate on the principle of "economic dispatch," which dictates that among various types of units comprising their generating mix, those with the highest operating costs (e.g., gas turbines for peaking) are brought into service last and taken out of service first as load shifts occur. This means that, at any given moment, a purchase from a qualifying facility can substitute for energy costs (including fuel and O & M costs) associated with the highest-cost units the utility would otherwise be operating. Similarly, in the long run, most electric utilities expect to meet projected demand growth by adding generating capacity or purchasing power at costs far higher than those associated with comparable capacity or purchase contracts already in place. To the extent that assured purchases of reliable power from independent producers would defer or displace such capacity additions or purchases, they likewise would result in the avoidance of marginal costs and in payments to such producers substantially higher than the utility's average embedded system costs which, without PURPA, would place a ceiling on prices paid for independently produced power.

In order to decide whether particular prospective geothermal power facilities present attractive business opportunities under PURPA, potential investors need to be able to determine or at least to estimate rates for purchases based on the costs which the participating electric utility will avoid by reason of purchases from the proposed facility. PURPA and FERC regulations recognize this need and provide for it in several ways.

To begin with, they provide that each qualifying facility shall have the option to provide energy "as available" (i.e., non-firm energy provided when the facility chooses) or "pursuant to a legally enforceable obligation" (i.e., firm energy or capacity provided when the purchasing utility requires it.) For non-firm energy, the rates for purchases are to be based on the utility's avoided costs calculated <u>at the time of delivery</u>. For firm energy or capacity, rates are to be based, at the supplier's option, either on avoided costs calculated at the time of delivery *or* on avoided costs calculated <u>at the time the obligation is incurred</u>. (18 CFR §292.304(d); see also §292.304(b)(5).) Although this option (where available) necessarily will be based on estimates and forecasts, it will result in a contract price fixed at the outset and therefore useful in providing the rate-of-return certainty needed by many potential investors.

Whether rates are to be based on avoided costs estimated in advance or calculated at the time of delivery, there must be some mechanism for identifying these costs. Accordingly, FERC regulations require the electric utilities themselves to make available to state regulatory commissions and to the public detailed data from which their avoided energy and capacity costs can be derived. Such data, which is subject to utility commission review, must include among other things the utility's own estimates of avoided energy costs during peak and off-peak periods, its plans for capacity additions, and their estimated costs. (18 CFR §292.302.)

Avoidable energy and capacity costs differ widely among different utilities in different regions, depending on such factors as the type and age of generating equipment used, variations in peak demand patterns and in anticipated demand growth, the availability and cost of conventional fuel sources and the length of proposed supply contracts. Moreover, avoided cost estimates for any particular utility can vary substantially over short periods of time, primarily as a function of changing conventional fuel prices. Thus, avoided cost data furnished by utilities at a given point in time does not necessarily represent the utility's actual rate for purchases from qualifying facilities, but is intended to provide a starting point for arriving at such a rate through negotiations between the utility and the prospective supplier. In this connection, it is worth stressing that the rate provisions discussed here govern supplier/utility transactions only where the qualifying facility so chooses: <u>nothing in the ACT or FERC regulations precludes negotiated agreements between the parties whose terms depart from what the regulations might otherwise require</u>. (18 CFR §292.301(b).) The intent is to allow independent producers to retain flexibility in dealing with electric utilities, while greatly strengthening their bargaining position by providing clear legal rights and protections as a basis for negotiations. (As to the implications of extending avoided cost purchase benefits to utility-owned facilities, a prospect which FERC has raised but not resolved, see *Notice of Proposed Rulemaking* cited above, at pages 12, et seq.)

IV. REGULATORY EXEMPTIONS

In keeping with PURPA's overall intent to encourage cogeneration and small power production, §210(e) of the statute, as amended by the 1980 ESA, directs FERC to prescribe rules exempting "qualifying" small power producers and cogenerators in general, and "geothermal small power production facilities of not more than 80MW capacity" in particular, from the major burdens of federal and state utility regulation. The rationale for these exemptions appears from the Conference Report accompanying the 1978 legislation:

> The conferees wish to make clear that cogeneration is to be encouraged under this section and therefore the examination of the level of rates which should apply to the purchase by the utility of the cogenerator's or small power producer's power should not be burdened by the same examination as are utility rate applications .... The establishment of utility type regulation over them would act as a significant disincentive to firms interested in cogeneration and small power production. (Conference Report No. 95-1750 (to accompany H.R. 4018), October 10, 1978; p. 98.)

PURPA §210(e) generally limits FERC's exemption authority to "qualifying" (i.e., non-utility-owned) small power production and cogeneration facilities. To the extent that geothermal power projects meet this criterion, FERC's present rules governing qualifying facilities in general also govern geothermal facilities. These rules provide exemptions from most provisions of the Federal Power Act (the basic federal utility regulatory legislation), including those reflecting federal rate and securities regulation ordinarily attendant on public utility status; from the federal Public Utility Holding Company

Act; and from state laws and regulations respecting electric utility rates and financial and organizational matters. (18 CFR §§292.601, .602.)

However, as noted earlier, the 1980 Energy Security Act amendments to PURPA §210(e) did not limit FERC's exemption authority to "qualifying" facilities in the case of geothermal. FERC therefore has assumed the authority to exempt from regulation non-qualifying, utility-owned geothermal facilities as well as qualifying facilities. It has already done so with respect to the Public Utility Holding Company Act and is considering similar action as to the Federal Power Act and state utility regulation. (See Final Rule issued as Order No. 135 in RM81-2 on March 23, 1981, and *Notice of Proposed Rulemaking* cited above.)

Although PURPA §210(e) is not explicit on the point, FERC interprets its exemption authority as to state regulation in general to extend only to regulation of wholesale sales, and not to retail sales over which FERC itself has no jurisdiction.[1] Retail sales of electricity and, in some states, of steam and/or hot water, are subject to regulation by state utility commissions. Thus, although geothermal power facilities may be exempt from most federal and state regulation as to any sales of electricity for resale which they might make to electric utilities under the avoided cost scheme described earlier, exemptions for retail sales of electricity or heat to non-utility purchasers would be a matter of state law.[2] As the Conference Report quoted earlier indicated, and as this author has explained elsewhere in the direct heating context,[3] the prospect of state utility regulation may remain a serious disincentive to retail sales. However, PURPA's wholesale power purchase requirements, avoided cost incentives and regulatory exemptions go far toward encouraging geothermal power production, and should be considered important elements in future project planning.

REFERENCES

1. Personal communication from FERC staff member Mr. Michael Kessler, March 20, 1981; cf. PURPA §210(a), expressly limiting FERC's authority to prescribe rules governing power sales for purposes other than resale.

2. FERC has taken the position that it has no authority to exempt cogenerators from state regulation as steam utilities. See FERC Staff Discussion, 44 Fed. Reg. 38865, note 5 (July 3, 1979). For detailed discussion of the jurisdiction of Western state utility commissions over geothermal steam or hot water distribution, see Nimmons, *Overview of State Public Utility Regulation Impact on Geothermal Direct Heat Applications* and *State-by-State Analysis of Public Utility Laws Affecting Geothermal Direct Heat Applications* (Earl Warren Legal Institute Energy Studies Project, April and June 1979).

3. See Nimmons, *Utility Policy and Geothermal Heating: Toward Rational Regulation* (Earl Warren Legal Institute Energy Studies Project, December 1980).

Financing. Clearly, financing capability is one of the major considerations in structuring a district heating system. No matter how great the interest, if you can't raise the money, you're not going to be able to build the system. While federal funding has played the major role in the first-generation geothermal DH projects now underway, commercial financing is becoming more available and will have an important effect on how future projects are structured.

At the resource confirmation stage, federal funding has been crucial for the public projects because there is no way that exploration could have been financed out of local revenues, particularly in small, depressed communities such as Susanville. In fact, significant municipal expenditures for resource confirmation will always be generally considered inappropriate because of the level of risk.

Some state funding for resource confirmation may be available to fill the gap left by the shrinking of DOE programs. For the most part, however, private capital will probably be needed, and tax incentives such as intangible drilling cost deductions, percentage depletion and energy investment credits, make geothermal projects attractive for private investors. Private funding can be provided in various ways. A geothermal resource company may confirm and develop a resource to supply its own or an independent distribution system. For publicly-initiated projects, one option is for a city or community group to form a joint venture with a specially created drilling partnership. In Boise, such a partnership was put together by a local investment banker with no previous geothermal experience, who found local investors to finance resource development for the city's distribution system. This partnership will continue to produce and sell hot water to the city under a 30-year contract. Another option is a joint venture for resource confirmation with an energy developer, who may in turn find limited partners to invest in the project. This kind of arrangement was put together for the Litchfield project, with provision for a buyout of the system by the City at the earliest possible date.

It must be kept in mind that as a consequence of using private investment for resource confirmation, the price of heat to the ultimate consumer will have to cover a return on this investment that is commensurate with the risk involved.

Construction of the hot water distribution systems for the current projects has also been largely federally funded. In addition to DOE funds, grants have been awarded by EDA, HUD and FmHA for municipal district heating projects. Some programs of these agencies may continue to be available for supplementary funding, but future systems will probably have to look primarily to nongovernment sources for basic financing.

Tax-exempt bonds are the most attractive vehicle for financing pipeline construction because they offer long-term capital at the lowest cost. Both public or private entities may have the power to use tax-exempt bond financing, depending on applicable laws and local circumstances, and the structure of a DH project may often be adapted to take advantage of the bonding opportunities available in a particular community.

A private system may be able to utilize tax-exempt industrial development revenue bonds — IDBs — but only if the laws of that state authorize local or state agencies to issue bonds for such a project and approval can be obtained from the agency. A city or public district may be able to issue G.O. or revenue bonds — assuming that it has statutory authority, and that debt limits and voter approval requirements can be met.

Even if bonds can legally be issued, there remains the job of finding a market for them. A recent development is that the investment community is becoming interested in DH. Several of the nongeothermal projects I mentioned earlier have had the participation of national investment banking houses from their early planning stages. In some cases, investment houses are even competing for the opportunity to underwrite DH bond issues.

Investment bankers have stiff requirements, however, for the projects they underwrite. Where revenue bonds are backed only by revenues from the new DH project itself, the bankers want to assure that the payments of principal and interest on the bonds will be met. Ironclad guarantees such as take-or-pay contracts — agreements from customers to pay regardless of whether any heat is delivered — are the ideal security, but understandably these are difficult to obtain.

The experience of the Litchfield project, which is the first geothermal DH project to get a commitment from the financial community to purchase revenue bonds, and of several nongeothermal DH projects, shows that it is possible to put together a package of guarantees which will assure that the bondholders will be paid.

First of all, clear legal authority is required to prevent the threat of legal challenge which could hold up the project. Second, supply guarantees are needed to assure a reliable heat source at a predictable price. Third, construction and performance guarantees go into the package. And fourth, market guarantees. I'll discuss legal authority in a moment. For geothermal DH projects, the most important elements will be guarantees of the heat supply and a secured market. Because geothermal utilization is so new and reservoir life predictions are untested, some outside guarantee of the heat supply will probably be needed. Reservoir insurance for the Litchfield project will be provided by a large national insurance company to guarantee that the requirements of the customer contract will be met.

Long-term contracts with creditworthy customers are the best market guarantees. In Litchfield a contract negotiated with the State of California to supply the state prison provides good security. Where there are many smaller customers rather than a single or few large customers, providing market guarantees will be more difficult. Private residential and commercial customers do not offer such good security because they are less likely to be there for the full 20- or 30-year term of the bonds. Obtaining long-term commitments from such customers is also more difficult. This may be a reason to structure a DH system serving such customers as a user association, so that the customers who have the ultimate obligation to repay the bonds through their rates will also be able to control system policy.

Another type of security for bonds is a lien on the property served by the system. Private landowners can of course pledge their property as security, and "assessment bonds" may be issued by many cities, counties and districts, so long as it can be shown that the property is specially benefitted. Practically speaking, assessment liens may be most useful for extensions of a municipal distribution system to particular areas. On the other hand, if they are to be liable for repayment, property owners in the area might prefer to set up a new special district and control the system themselves.

A city or county may also be in a position to offer backup guarantees for a private DH system. For example, in St. Paul, the city pledged its income from DH franchise fees if needed to cover shortfalls in the system's annual debt service payments. In addition, a city may apply for UDAG funds from HUD to be loaned for part of the construction financing of a privately-owned system, as was done in Trenton and St. Paul.

Legal Authority. Questions of legal authority may strongly influence the institutional structure of a DH project. First of all, a public entity such as a city, county or special district may not develop or operate a geothermal district heating system unless it has authority under state law or a city charter. Where authority is lacking or uncertain, a public project is on very shaky ground. In Colorado, ambiguous municipal utility statutes left the Pagosa Springs system without clear authority, and it was feared that the gas company serving the area, which stood to lose business to geothermal heating, might file a legal challenge. Local officials went to the legislature and won approval of statutory amendments which clearly and explicitly authorize cities to develop, finance and operate heating and cooling utilities.

In many cases a geothermal heating district corresponding to the area served by the system may appear to be the ideal structure, either for the entire project or for the distribution stage. However, in most states, clear authority to set up such a district is limited or nonexistent, which means that new legislation would be required before a district could be set up.

Another consequence of uncertain legal authority is that it may be impossible to finance a project. Conservative lenders always shy away from projects which may be subject to the delays and uncertainties of litigation, and in particular, bonds cannot be issued until a bond counsel certifies that the legal basis for the project is indisputable. Obtaining statutory authority is not always as easy as it was in Colorado. The City of Bellingham, Washington, is sponsoring legislation specifically authorizing municipal heat utilities because it is planning a DH system based on recovery of waste heat from an aluminum plant which it hopes to finance through municipal revenue bonds. This bill has twice been defeated in the legislature, and now the city is proposing a city charter amendment as another means of assuring its authority to act.

Financing may be affected in another way as well by the terms of legal authority. State and federal financing programs have specific standards of eligibility, and many are open only to public or only to private applicants. For example, the California Alternative Energy Financing Authority, which will issue the Litchfield bonds, can provide financing only for private energy projects. Despite the City of Susanville's strong desire to maintain maximum control over the project, this financing limitation means that ownership of the Litchfield system will have to stay in private hands until the bonds are paid off.

Reservoir management authority is also important. A DH system which has authority to manage the entire geothermal resource even if it is not wholly owned is in the best position to ensure maximum productivity over the long run. While such authority has not even been exercised at the state level in many states, it is much more likely to be granted to publicly-controlled local systems than to private ones. One state, Colorado, has already passed legislation providing for delegation of state geothermal management authority to geothermal heating districts and municipal geothermal utilities.

Public Utility Regulation. In most Western states, private distributors (and in some cases also producers) of geothermal heat may be subject to comprehensive state utility regulation, including limitations on the allowable return on investment through cost-of-service ratemaking. While the policies that will be applied by many state commissions are not known for certain because the issue has not yet come up, this uncertainty is in itself a constraint. On the other hand, municipal and other publicly-owned utilites are exempt from regulation in almost all states, and nonprofit corporations and other user associations are exempt in many. Some states also provide exemptions for those providing utility services to only a small number of customers. This current state of the law has the effect of discouraging privately-owned DH, at least where the system is designed to serve a wide area, and encouraging public or nonprofit ownership of at least the distribution aspects of the system.

However, it is also possible to change the law. In Nevada, which has extremely stringent utility regulation, geothermal developers succeeded in getting legislation adopted to ease the regulatory burden on geothermal DH. The state public utility law was amended to exempt geothermal producers from regulation, so long as they do not sell directly to the public, and to set up a new type of limited regulation for geothermal heat distributors. Now that the new regulatory scheme is in place, several private developers are going ahead with plans to become geothermal distributors.

Public Support. Another requirement of utmost importance for a geothermal DH system is public support. However structured, a system may face conflicts with existing geothermal users and may need voter approval for bonds or franchise. Any system would be in trouble if it were to face a hostile atmostphere at city hall, or even an indifferent one, given the need for numerous government approvals and the opportunities for local government facilitation of the project. Public support is also crucial for obtaining statutory amendments, new authorizing legislation and regulatory approvals from the state.

Public relations efforts are recognized as a necessity by sponsors of DH projects, considering that there are always a number of projects vying for public approval and attention. Where public relations are not strong enough to build solid support, opponents of the project for whatever reason can cause havoc, as recently occurred in Klamath Falls.

To get maximum support, the structure of the system should have maximum credibility. In some areas municipal ownership of public services has strong backing, or can develop support with a good program of education. In other areas, local government activity is looked on with some suspicion.

Some nongeothermal DH projects have been structured as independent nonprofit corporations because of public sentiment against extending the reach of government or in order to separate the system from the political influences and legal requirements of government ownership. In Klamath Falls, some type of residual anti-city sentiment was apparently aroused when a few existing geothermal users mounted an initiative campaign which won adoption of a measure which could completely block completion of the city's DH system.

Given all the considerations involved, it is clear that putting together a geothermal district heating system is no simple task. But the emerging experience shows that with diligence, persistence and creativity, it can be done.

IMPLICATIONS OF THE CALIFORNIA PUBLIC UTILITIES COMMISSION'S DECISION ON THE PROPOSED SOUTHERN CALIFORNIA EDISON/CHEVRON RESOURCES POWER PLANT AT HEBER, CALIFORNIA

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The California Public Utilities Commission (PUC) issued a decision on the Southern California Edison Heber proposal on May 19, 1981. The text of Decision No. 93035 is available from the Commission and is included in the workbook for this conference.

Edison had requested PUC authority to construct and operate a commercial baseload 41.1 megawatt dual-flash geothermal power powerplant at Heber in the Imperial Valley. The small size of the proposed plant, below 50 megawatts, meant that by law it did not require a PUC Certificate of Public Convenience and Necessity. In spite of the exemption, Edison filed for a certificate voluntarily in order to receive assurance that the proposed costs were prudent and reasonable from the Commission's point of view. The plant would use the same type Mitsubishi equipment as had been operating successfully for 3 years at the 55 megawatt Hatchobaru plant in Japan. The facility would thus use existing proven technology, and geological analysis showed that there is adequate geothermal energy in the reservoir to fuel the plant for the 30-35 year lifetime of the facility.

Presentation at the conference "Geothermal Energy: The Institutional Maze and Its Changing Structure", Geothermal Resources Council, Sheraton Newport Hotel, Newport Beach, California, December 2, 1981.

The problem the Commission had was with the geothermal fuel contract which Edison had negotiated with the fuel supplier, Chevron Oil Company. Chevron would produce the geothermal fluids and operate the reinjection facility to prevent land subsidence. The contract was executed in 1978, before the price of oil nearly doubled. The contract provides for escalating the price of the geothermal fuel at nearly the same rate as hikes in the price of oil. Edison admitted in testimony that the Heber facility would produce electricity at a higher cost than either oil or coal fired plants for at least the first 12 years of the project. Our staff calculated that Heber power would still be costing 7 percent more than oil fired power by 1992. Staff estimated that geothermal fuel cost could run $35 to 41 million a year by 1990. Staff also concluded that the risk provisions of the contract were unfavorably skewed to Chevron's advantage.

This decision has been controversial because the PUC has been on record as strongly commending Edison's commitment to develop 30 percent of its new capacity additions in the 1980s from alternative energy sources, of which geothermal is to play a key role. A Chevron representative has said that industry is "disappointed over the implications this decision has for other geothermal projects." However the Commission had to consider the impact on ratepayers and whether the proposed Heber arrangement was a prudent and reasonable investment. Since the project under these terms was projected to remain more expensive than oil fired power, we concluded it would not be in the interest of Edison's ratepayers. We remain convinced, however, of the substantial benefits of the Heber plant, namely the reduced dependence on uncertain supplies of foreign oil, and increased diversity and reliability of fuel supply for the utility. Our decision strongly urged Edison to resume negotiations of the sales contract. This was the first utility which has proposed to construct an advanced geothermal alternative which is not a demonstration project, and we undertook the optional consideration of the application because of its considerable significance. We stated in the decision that at more reasonable contract conditions this project would be "extremely valuable for Edison to pursue" and we certainly do <u>not</u> intend it to be a signal of disfavor toward geothermal development. The controversy, however, well illustrates the challenges we are going to have in the 1980s evaluating the economics of hot water geothermal facilities.

In the case of geothermal, as with other small power sources, a reexamination of traditional regulatory strategy is taking place. To the extent utilities are involved in geothermal electric generation, the regulatory agency must determine whether the risk associated with the exploration and development of a resource is excessive for the private sector without government support; whether a resource requires and merits further research development and demonstration support; when a resource should compete on its merits with other utility resource options; and what types of risks are appropriately assumed by the utility, its stockholders, and/or its ratepayers. For example, the concurring opinion in the Edison case by Commissioners Grimes and Gravelle stated that "full avoided cost" is a proper benchmark to determine the cost-effectiveness of a project, but it is not an absolute limit. While the economic value of a resource may exceed avoided cost, there must be a strong showing that there is an economic necessity to pay avoided cost. The opinion states that proponents of projects producing energy above avoided cost must be required to show both that the project has technological viability and that there is particular value to the ratepayers to pay avoided cost or more.

The avoided cost issue will also arise in the implementation of the Public Utility Regulatory Policies Act (PURPA). In California, up to now geothermal electricity has been produced largely by utilities which buy steam or brine from reservoir producers. Recent federal actions have created greater interest in geothermal generation by nonutilities. The Federal Energy Regulatory Commission (FERC) Order No. 135 (March 1981) extends the pricing benefits of PURPA to nonutility-owned geothermal facilities of less than 80 MW capacity. Utilities are required to pay avoided cost for electricity from geothermal facilities smaller than 80 MW.

In California, for most utilities, energy generation allows the utility to displace oil consumption. The average energy payment reflects the average incremental price of oil, usually lagged by one quarter. A geothermal producer wishing to sell power to the utility would be paid a price which includes a component for avoided energy as well as a payment for capacity, if the small power producer allows the utility to defer capacity or construction of new supply.

Pursuant to PUC order, all investor-owned electric utilities in California have published schedules of their avoided costs. These price offers are the basis for contractual offers between the utilities and small power producers.

Qualifying facilities (QFs) in California are now eligible to accept these rates for purchases. In addition, the Commission's Order Instituting Rulemaking No. 2 (OIR 2) will review and establish standards governing the prices, terms, and conditions of utility purchases of electricity from QFs consistent with FERC Order No. 69. OIR 2 serves to examine the appropriateness of utility standards used in their current offers, ensure compliance with FERC rules and establish new and/or different standards as appropriate. In order to encourage the development of QFs without delay, Commission Decisions D-93054 and D-93393 allow QFs to subsequently revise contracts signed now to reflect all more favorable prices, terms or conditions which may result from Commission orders in OIR 2.

DISTRICT HEATING: LEGAL, INSTITUTIONAL, AND PUBLIC RELATIONS ASPECTS

by

Diana King

First of all, "district heating" is any system which takes heat generated at a central source and distributes it to a number of dispersed locations. The distributed heat may be used for space heating, domestic water heating, space cooling or process heat needs. Some modern systems also distribute "cooling" in the form of cold water which has been chilled at a central plant.

District heating (DH) is not a new idea. Steam distribution systems have been in operation in the U.S. for a hundred years. Existing district heating systems range from those distributing heat to several buildings belonging to a single institution such as a hospital or university campus to public utilities which offer heat and/or cooling to the general public in the downtown business districts of a number of cities. Most are relatively small, but not all. Con Ed's New York City steam system, with about 90 miles of pipelines, is a very significant source of heat for that city's residential, commercial and light industrial needs. The old steam systems have been declining over the years, however, for a number of reasons, including the costs and inefficiency of their old steam pipelines, and the increasing costs of heat generation in conventional heat-only boilers fired by fossil fuels.

A new interest in DH has emerged of late, directly related to the increasing cost of oil and gas and to concern about conservation of fossil fuels and the danger of continued dependence on foreign energy sources. Much of the interest has focused on hot water distribution, in contrast to steam, and is based on the model of European systems which are providing district heating to substantial and growing proportions of the population, particularly in Scandanavia and the Soviet Union. New pipeline technology, cogeneration of heat and power, and planned development have made DH in these countries an economically and institutionally successful alternative to individual on-site heating systems.

In the U.S., this new interest has resulted in a number of DH studies and programs. Nongeothermal DH projects are well along in the planning stages in such places as St. Paul, Minnesota; Piqua, Ohio; Bellingham, Washington. The first of this group actually to begin construction is a DH project in Trenton, New Jersey, which is expected to be in partial operation by winter 1982.

Geothermal DH is not a new idea, either. A system which distributes hot water from underground sources has been in operation for almost a century in Boise. Other small systems supply a number of buildings in Ketchum, Idaho, and Pagosa Springs, Colorado. Iceland has the most extensive geothermal district heating, serving a large part of the population in many major cities.

For the same reasons that other American communities are thinking about utilizing the heat sources available to them for DH, many communities in the geothermal areas are taking a close look at DH based on their resources. District Heating appears to be a particularly appropriate means of utilizing these resources for a couple of reasons specific to geothermal.

First, many of the most attractive customers for geothermal heat — large industrial and commercial users with high energy needs — are unwilling to develop geothermal resources for their own use, regardless of the energy savings this could produce for them. But many would be interested in using geothermal energy if they could obtain it as they obtain other types of energy, by hooking up to a distribution system developed by someone else.

Second, uncoordinated separate development of a geothermal resource by a number of different users tends to lead to suspicion and conflict among competing users, legal problems and ultimately to wasteful exploitation of the resource. Development of the resource by a single entity for widespread utilization through a district heating system affords the best opportunity for the careful planning and reservoir management which will lead to maximum productivity over the long term.

The new interest in geothermal DH has already borne fruit. Two new small systems will be on-line this winter — in Susanville, California, and Pagosa Springs, Colorado. One in Philip, South Dakota, began operating last winter. Larger systems are under construction in Klamath Falls, Oregon, and Boise, Idaho. Several limited systems designed to serve specific residential customers are underway in the Reno area. In addition, planning studies and test drilling are being carried out in a number of other communities in Washington, Oregon, California, Idaho, Colorado, Montana, Wyoming and Nevada.

Some of these new systems have the potential for considerable expansion — to serve more of the existing energy needs and to serve new industrial and commercial customers who may be attracted by the availability of the low-cost geothermal energy. The City of Susanville is already expanding its geothermal activity into a new area by developing a second resource at Litchfield, a few miles outside the city. There it plans to serve a new agricultural/industrial development based on the cascading of hot water first supplied to the state prison.

Institutional issues discussed by other speakers at this meeting, such as permitting and leasing, may apply equally to DH projects, although in built-up areas, resources are more likely to be located on private or city property than on federal land, and environmental regulations will tend to be less of a constraint than for projects using higher-temperature resources. For the development of a DH system, the most complicated and difficult aspect of the "institutional maze" will often be the process of putting together an *institutional structure* with sufficient legal authority, public support, and financing capability to carry out the project.

A DH system can be structured entirely as a public project, through a municipal utility or special district. The Klamath Falls, Pagosa Springs, and Susanville city systems are set up this way. It can be entirely a private enterprise, developed and operated by a single private company. Two Nevada projects, one in Elko and one in the Moana section of Reno, are currently structured this way. Or, and this may become increasingly likely, a system may be implemented through a combination structure, with a number of different participants, including both public and private entities. Combination structures of various types have been worked out for the Philip, Boise and Litchfield systems, for example.

It will be easy to see why a combination structure may be most appropriate, if we look at a geothermal district heating project in terms of stages. The first stage is locating and proving a suitable resource. As for other geothermal projects, this resource confirmation stage is highly risky and requires a substantial capital investment.

The second stage is construction of production facilities and the distribution system. The risks at this stage are much lower, but the capital needs for pipeline installation are likely to be very high. Financing is probably the crucial factor in both the first and second stages, but the financing needs are very different — for venture capital in the first instance and for long-term capital at the lowest possible cost in the second.

The third stage is the ongoing operation and maintenance of a DH system. Credibility of management and the reach of public utility regulation may be the most important considerations at this stage.

The optimal structure for any particular DH system will depend in part on who initiates the project, and what interests it is mainly intended to serve. District heating can serve a number of different interests: (1) the interests of consumers in reduced heating costs; (2) community development interests; (3) the interests of land developers in increasing the value and marketability of their properties; and (4) the interests of geothermal energy companies in developing a market for geothermal heat. We have discovered that for the most part DH is not attractive simply as an independent business venture, or as an extension of gas or electric utility services — and this applies to DH based on other heat sources as well as to geothermal district heating.

One or more of these interests may be operating in any situation. And they operate differently at different stages. For example, heat users are unlikely to take exploration and resource risks, but may be willing to organize and finance construction and operation of their own distribution system, as they did in Philip. Developers of new residential subdivisions or condominium projects may be willing to confirm a local resource and install distribution pipelines, but do not want a permanent role as a heat utility. Some resource developers will want to limit their activities to well development and heat production, because they are not willing to accept the long payback period for investments in distribution pipelines or the burdens of public utility regulation. Others will not want even that great a continuing role and will want to turn over producing wells to a separate distribution organization so they can move on to developing new resources and putting together new projects.

Where a local government is interested primarily in the community development potential of a DH system, it often wants to control the entire project to the extent possible, so that it will be in a position to keep heat prices at a minimum and obtain the maximum in new economic development. On the other hand, a community interested mainly in assuring heat supplies for public and private buildings at reasonable cost may be more willing to see the system in private hands or structured as a user district or association.

ALJ/km/hh

Decision No. 93035 May 19, 1981

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the matter of the application of SOUTHERN CALIFORNIA EDISON COMPANY for a certificate that the present and future public convenience and necessity require or will require that Applicant construct and operate a geothermal electrical generation facility located in the State of California, County of Imperial near Heber, California.	Application No. 59512 (Filed March 10, 1980)

Hobart D. Belknap, Jr., Attorney at Law, for Southern California Edison Company, applicant.

Ellen LeVine, Attorney at Law, William Thompson, and Martin Bragen, for the Commission staff.

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O P I N I O N

Summary

Southern California Edison Company (Edison) requests Commission authority to construct and operate a 41.1 megawatt (MW) dual-flash geothermal facility near Heber, California. The Heber Geothermal Project (Heber) will be a commercial baseload resource using a demonstrated technology and will be operated and relied upon as a firm capacity resource from the beginning of operation.

The facility proposed by Edison is technologically feasible and commercially viable; however, the cost of the power that would be produced is not competitive with other forms of electrical generation. This is largely because the steam or brine contracts with the producer, Chevron, peg the brine prices to oil prices. The result is that while the facility is commercially viable, it is not commercially competitive. When terms are renegotiated so that the facility would be competitive with more reasonable brine contract terms, we think it would be extremely worthwhile for Edison to pursue. We must ensure new energy sources are cost-competitive as we exercise our duty to protect Edison's customers from bearing unreasonable costs through their rates. Our decision denying Edison the certificate to construct Heber at this time means Edison should either renegotiate its contract with Chevron or explore with other potential producers the possibility of obtaining a brine supply.

If Heber is in operation, it would reduce dependence on uncertain supplies of imported oil by up to 400,000 barrels yearly, improve air quality, and, finally, increase the diversity and reliability of the fuel supply available in the Edison system.

Heber relies on relatively simple and reliable technology. A similar plant operating in Japan has recently achieved a capacity factor of 90 percent. It has been shown that the anomaly from which the geothermal fluid will be produced is quite capable of supplying enough heat to fuel the 41.1 MW plant for 30 to 35 years. The Heber project rests on a very sound technical base.

Based upon preliminary engineering, the capital costs borne by Edison for the Heber project total $69 million. The other major cost component associated with Heber is the geothermal fuel expense. Under a Sales Contract, with its various provisions explained in the body of this opinion, Chevron Resources Company (Chevron) will supply and Edison will purchase heat contained in the fluid to operate Heber for a 30-year period. Edison feels that the Sales Contract, including the pricing mechanisms, is fair and equitable to both parties. Staff, on the other hand, concludes that the Sales Contract is unfavorably skewed to Chevron's advantage and requests that any Commission authorization be conditioned to more equitably protect the interests of Edison's ratepayers.

Given projected capital costs and fuel expenses, Edison presented cost comparisons of Heber with a coal-fired alternative and an alternative burning oil in an existing facility. Edison's projections indicate that through 1994 the revenue requirement for Heber is greater than that for a coal-fired or existing oil-fired alternative. On a levelized basis for the year 1982, the cost of delivered power from Heber is 17.9¢/kWh, as compared to 11.0¢/kWh for a coal-fired alternative and 16.6¢/kWh for existing oil-fired generation. Using assumptions most favorable to Edison, the average impact on rates in 1994 would be as follows: .052¢/kWh for Heber; .033¢/kWh for an alternative coal project; and .048¢/kWh for existing oil-fired generation.

Edison quite candidly acknowledged that Heber would not be cost-competitive with alternatives through the first 12 years of the project. Further, Edison presented no evidence from which the inference could be drawn that the Heber Project would become cost-competitive with alternatives at some point in the future. If anything, the record evidence supports the inference that geothermal energy, produced under contracts similar to the Sales Contract, will not be cost-competitive at any point in the future.

The staff considered the Sales Contract the major impediment to obtaining electricity from Heber at costs lower than from oil generation. Staff argued that Edison has significantly underestimated the cost of geothermal brine under the Sales Contract. Staff contends that Heber will cost as much as 30-40 percent more than coal or oil alternatives in 1982 and 7 percent more in 1994. Staff projects that on a levelized basis for the year 1982 the cost of delivered power from Heber will be 24.3¢/kWh, as compared to 11.0¢/kWh for a coal-fired alternative and 16.6¢/kWh for an existing oil-fired alternative.

Based upon Edison's showing alone, Heber's lack of cost competitiveness prompts numerous questions about the prudency of undertaking such a project. The staff showing only serves to further increase the doubts about Heber.

Are the economic risks imposed upon ratepayers by Heber outweighed by the significant benefits to be derived from the development of the Heber geothermal resource? We do not think that the record evidence can support such a conclusion.

Edison failed to provide the Commission any meaningful basis for determining that costs incurred pursuant to the Sales Contract are reasonable. Edison concluded that the price charged for brine is in an appropriate range on the basis of the negotiations and analysis of industry literature, reports, and confidential and proprietary contracts. Since fuel expenses are a major reason why Heber will not be cost-competitive, Edison's mere conclusory statements that the pricing mechanisms are equitable must fail as inadequate.

We are asked to approve Heber and ignore notions of cost-competitiveness and cost-effectiveness. Yet, cost is a fundamental tool in making decisions regarding the most efficient way to develop sufficient energy resources. Cost is a primary measure by which we judge the worth and reasonableness of a project. Heber, as currently structured, is not cost-competitive and therefore fails the test of reasonableness. Heber does not represent a prudent and reasonable investment to be ultimately borne by the ratepayer. Accordingly, Application No. 59512 is denied.

Introduction

By Application No. 59512, Edison requests Commission authorization to construct and operate a 41.1 MW dual-flash geothermal generation facility near Heber, California. Heber is five miles south of El Centro, California, in the southern portion of the Imperial Valley.

Heber, as proposed, will provide an additional source of electrical generation, using geothermal brine as a primary fuel. Geothermal fluid used in the plant will be produced by Chevron at facilities adjacent to Edison's site and delivered to Edison in accordance with the Geothermal Energy Contract (Energy Contract) and the Geothermal Sales Contract (Sales Contract) executed between Edison and Chevron in November 1978.

Notwithstanding the Commission's General Order No. 131 which exempts plants of Heber's generating capacity from any requirement to obtain a certificate of public convenience and necessity (certificate), Edison filed the subject application in order to secure "preliminary" assurances from the Commission that projected costs associated with Heber are prudent and reasonable.

Public hearings were held in Los Angeles on December 4 and 5, 1980, at which time Edison and the Commission staff presented testimony and exhibits. The matter was submitted on January 20, 1981, upon receipt of concurrent briefs.

I. Edison's Showing

In support of its application, Edison sponsored the testimony and exhibits of seven witnesses during the public hearings. These witnesses presented evidence regarding the following aspects of the Heber project: (1) its policy implications, (2) its technical feasibility, (3) its economic costs, and (4) its environmental impacts.

1. The Policy Implications of Heber

Edison testified that Heber will be a commercial baseload resource using a demonstrated technology and will be constructed to satisfy a system need. The plant will be operated and relied upon as a firm capacity resource from the beginning of operation.

Edison forecasts that it will require more than 6,000 MW of additional generating resources by 1990. Six thousand MW of additions will be required to meet anticipated increases in peak demand between 1980 and 1990, to provide a normal reserve margin, and to account for the termination of capacity purchase entitlements. To meet part of the anticipated increase in demand, Edison will require the use of the 41.1 MW capacity of Heber.

Edison views Heber as a crucial step in the implementation of its announced policy to accelerate development of alternative and renewable energy resources. To achieve such accelerated development, commercialization of each of the alternative and renewable energy resources is a necessity. For Edison this application represents an initial step toward commercialization of geothermal as an energy resource.

Edison underscores its commitment to development of alternative and renewable energy resources with its latest electric supply forecast in which approximately 30 percent of Edison's new generation capacity planned during the 1980s will derive from such resources. According to the resource plan, geothermal energy represents 420 of the 1,900 MW of alternative energy Edison will develop under its new policy. Edison feels that realization of its 420 MW goal requires approval of this application which will mark the first critical step toward commercialization of geothermal energy.

Although well aware of the applicability to the Heber project of General Order No. 131's exemption provision, Edison seeks preliminary Commission assurances that it will support Edison in the way project costs will be treated for ratemaking purposes. Edison does not propose unusual or extraordinary ratemaking treatment for Heber. Rather, Edison requests normal rate base treatment for a commercial plant although it cautions that some of the costs associated with Heber may be higher since certain technologies will be used for the first time on a commercial basis. However, Edison firmly believes the costs and risks involved in constructing and operating of a first-of-a-kind commercial geothermal plant are reasonable in view of long-range benefits gained by ratepayers through development of geothermal energy.

Numbering among the long-range benefits of commercializing the Heber geothermal resource are: (1) reduced dependence on increasingly uncertain supplies of imported oil by up to 400,000 barrels yearly, (2) improved air quality, (3) increased generation resources for the ratepayer, and (4) increased diversity and reliability of the fuel supply available in the Edison system.

Finally, Edison takes the position that without a certificate and its preliminary assurances or with a certificate unduly burdened by staff-proposed conditions it would find it difficult, if not impossible, to proceed with the Heber project.

2. The Technical Feasibility of Heber

Discussion of the technical feasibility of Heber focuses on two components: (1) the reliability of existing geothermal processing technology and equipment and (2) the reliability of the geothermal anomaly as an adequate heat source.

The first component, the equipment and process necessary to convert geothermal energy to electricity, can be described in the following manner:

> Geothermal fluid used in the proposed dual-flash power plant cycle will be produced by Chevron. The site for Chevron's production facilities will be contiguous to the power plant site making the production pipelines as short as possible. At full plant load, approximately 8,000,000 lbs/hr of geothermal fluid will enter the first stage flash (or separator) tank wherein steam is separated and flows to the throttle of a steam turbine generator. Cold brine from the bottom of the first stage tank flows to a second tank where additional steam is separated for use at a lower pressure region of the steam turbine. Spent brine from the second stage tank is returned to Chevron for reinjection into the Geothermal Reservoir.

> Exhaust steam from the turbine will go to a steam condenser and the condensed steam (condensate) will be used for cooling water makeup to the cooling tower. This cycle arrangement obviates the need for large quantities of cooling water from another source. However, in order to comply with the 100 percent reinjection objective of Imperial County's Geothermal Element, a water treatment plant will be designed, constructed, and operated by Chevron on the New River. A quantity of New River water equivalent to the condensate flow will be treated and injected into the Geothermal Reservoir. For miscellaneous power plant service water requirements, it is contemplated that water will be taken from the Dogwood Canal. Estimated average daily requirement is 80,000 gallons.
>
> The plant's heat rejection load is dissipated in a mechanical draft evaporative cooling tower consisting of ten cells each 42 feet long and each with one induced draft fan. The cooled water passing down through the tower is collected in a concrete basin below the tower. Circulating water pumps convey the water from the basin through the steam condenser and back to the top of the cooling tower.

Specific areas to be constructed in order to operate a geothermal facility at Heber are the production island, the power plant, the brine injection pumps and injection pipeline, the injection island, the water treatment plant, and its injection well. The production island is a group of wells that will be drilled into the Heber geothermal reservoir. Chevron is totally responsible for the cost of construction and operation of the production island and its facilities. Adjacent to the production island is the power plant which Edison will fund, engineer, construct, operate, and maintain. The brine injection pipeline system, which includes the desander, brine injection pumps, and approximately 7,000 feet of

30-inch pipeline will be engineered, constructed, operated, and maintained by Chevron. Edison, however, will pay for the construction and operation and maintenance of that line. This line, approximately one and a half miles in length, ends up at the injection island; which will be totally funded, constructed, operated, and maintained by Chevron. The injection island consists of a group of wells to reinject the spent brine back into the geothermal reservoir.

The remaining principal area of work is a water treatment facility which will be located approximately three miles southwest of the plant site on the bank of the New River. This facility will clarify New River water and reinject it into the geothermal reservoir to make up for water consumed by the power plant. This facility will provide 100 percent reinjection of fluid (brine) into the reservoir. It will be designed, constructed, operated, and maintained by Chevron with Edison funding the total facility costs. The water injection well, however, will be drilled, constructed, and funded by Chevron. It is necessary to reinject water into the reservoir because Edison will use the condensate from the plant condenser as makeup water to the cooling tower instead of using external sources of plant cooling water.

In concluding that it is reasonable to expect that the Heber plant should operate at a capacity factor of 75 percent, Edison's witness stated that the process and equipment associated with a dual-flash plant such as Heber is relatively simple in terms of its operation. He further testified that the equipment to be used at Heber is the same equipment used in a 55 MW dual-flash unit which has been in operation at Hatchobaru, Japan, for the past three years. The same vendor, Mitsubishi, who supplied the equipment for the Hatchobaru plant will provide equipment to Edison. Since Hatchobaru is essentially a carbon copy of the Heber plant and since the Hatchobaru plant has approached a 90 percent capacity factor in recent operations, Edison expresses a high degree of confidence in the process and equipment associated with Heber.

With respect to the second component of Heber's technical feasibility, Edison presented testimony regarding the nature of the geothermal anomaly at Heber. After his analysis and evaluation of the anomaly, Dr. Brigham of Stanford University concluded that enough hot water can be produced from the anomaly at high enough temperatures to support a 500 MW development for 30 years. He expressed with a high degree of confidence that enough heat can be recovered from the Heber geothermal anomaly to supply fuel to the initial 41 MW net power plant for 30 to 35 years. He further concluded that the failure of the wells to produce the geothermal brine or the pumps to operate is about as likely as occurrence of an earthquake of 8.5 magnitude.

3. <u>The Economic Costs of Heber</u>

a. <u>Capital Costs</u>

Based on preliminary engineering, cost estimates were developed for the power plant portion of the project. The estimated cost, including contingency and overheads, amounts to $51,400,000. Chevron, which will receive payment from Edison for construction, operation, and maintenance of the brine injection facilities and water treatment facilities, estimated costs for those facilities amounting to $17,600,000. Thus, the capital costs borne by Edison for the Heber project total $69 million.

HEBER GEOTHERMAL
CAPITAL COST BY ACCOUNT

(Dollars in Thousands)

FERC Account Code	Description	Direct Expenditures	Overheads	Total Cost
341	Structures and Improvements	$ 4,700	$ 1,200	$ 5,900
342	Fuel Holders, Producers, and Accessories (Chevron)	14,000	3,600	17,600
343	Prime Movers	12,600	3,200	15,800
344	Turbogenerator	16,000	4,100	20,100
345	Accessory Electric Equipment	6,140	1,520	7,660
346	Miscellaneous Power Plant Equipment	1,340	340	1,680
347	Transmission-Station Equipment (Switchyard)	120	30	150
397	Communication Equipment	100	10	110
	Project Total Cost	$55,000	$14,000	$69,000

b. Brine Supply Contracts and Costs

Under the Sales Contract, Chevron will supply and Edison will purchase heat contained in the fluid to operate Heber for a 30-year period. Under the Energy Contract, Edison has the first and prior right to purchase all geothermal energy for electric generation use from Chevron's share at Heber in excess of Chevron's existing commitments to San Diego Gas & Electric Company.

Edison testified that the Sales Contract executed between Chevron and Edison in November 1978, is the product of intense negotiations which spanned two and one-half years. It is Edison's sworn testimony that the contract cannot be renegotiated and reflects Chevron's final position on price. The contract price is significantly better than Chevron's original proposal and prompts Edison to conclude, upon consideration of other contracts for geothermal energy as well as industry publications, that the Sales Contract price is reasonable and competitive as now negotiated.

The terms and conditions of the Sales Contract address the sharing of costs and risks between the parties, such as pricing and escalation mechanisms, each party's obligations, and damages and penalties associated with failure of the reservoir or power plant to perform to the level expected. In aggregate, the intent of these terms and conditions is to provide substantial incentives for each party to perform to expectations, since a failure to do so will benefit neither of the contracting parties, no matter what the fault or cause.

The major terms and conditions, especially as they relate to costs and risks, are summarized below.

(1) <u>Pricing and Escalation Mechanism</u>

The fuel price formula, the primary mechanism for calculating a fair and equitable monthly fuel cost, consists of a demand component and a commodity component. The demand component, which is a fixed price subject to escalation, is intended to provide for recovery of fixed costs incurred by Chevron to meet its "supply obligation" to Edison. This supply obligation involves Chevron's capability to provide sufficient usable heat to continously operate the plant at its generating capacity. The commodity component provides Chevron recovery for a portion of the market value of the usable heat from the brine. The commodity charge is therefore proportional to the amount of usable heat supplied to Edison.

In conjunction, the two components are intended to represent the value of the usable heat from brine as an electrical generating fuel and to compensate Chevron for development, operation, and maintenance costs, as well as to provide Chevron a return on its investment. The total monthly charge is the sum of the demand charge and the commodity charge. Each of these charges is tied to a base price and individual escalator indices.

The base price for heat delivered is $.60 per million usable British thermal units (Btu). If Chevron is required to use pumps in more than 50 percent of the wells used for providing brine to the initial plant, the base price will become $.65/mm Btu.

Currently, the demand index, which governs escalation of the demand charge, corresponds to changes in the Consumer Price Index (CPI), a general economic index reflecting costs for consumer items. The commodity charge is tied to the commodity index which corresponds to changes in the Producer Price Index for Funds and Related Products (PPIO5). The PPIO5 is a composite fuel indicator reflecting the price changes in coal, coke, natural gas, electricity, crude oil, and petroleum products, with oil and petroleum products constituting approximately 50 percent of the fuel mix.

The Sales Contract provides for the intent of each index to be carried out for the life of the project. The specified contractual intent of each index is as follows:

> (a) The demand index shall be an independent indicator of changes in the costs of geothermal development and production.
>
> (b) The commodity index shall be an independent indicator of changes in the costs of energy supplied to base-loaded electric generating facilities on a national basis. (Sales Contract, § 14.5.)

The contractual terms provide for either or both of the escalation indices to be subject to review after five years from initial plant operation at the request of either party. If the parties cannot agree on the future escalation indices, then they shall be determined by arbitration. Any resulting new index may then be reviewed five years after the change. Edison thus concludes that the contract provides assurance that over the term of the contract the parties will adhere to the intent of each index.

With respect to the commodity index, Edison testified that there is no readily available government-produced index that tracks the price of fuel to base-loaded electric generation in this country. Selection of the PPIO5 as the commodity index resulted from negotiations and reflects the best efforts of Edison and Chevron to find a government-published indicator that meets the intended purpose of relating changes in the cost of fuel supplied to base-loaded generation. Edison stated that the commodity index will be changed in accordance with the contract if the PPIO5 does not accomplish its intended purpose.

Edison presented evidence demonstrating that the current fuel mix for base-loaded electric generation is weighted approximately 55 percent coal, 17 percent natural gas, 15 percent oil, and 13 percent nuclear, with the trend being away from oil. On this basis, Edison concludes that the intent of each index, including the commodity index, minimizes the impact of oil on the fuel brine price.

On the basis of the Sales Contract provisions, Edison projects net fuel expenses for each of the first 12 years of the project as follows:

Heber Annual Fuel Expenses

(Dollars in Thousands)

Year	Amount	Year	Amount
1982	$ 3,015	1989	$21,880
1983	$12,766	1990	$23,260
1984	$14,164	1991	$24,707
1985	$16,423	1992	$26,259
1986	$17,831	1993	$27,888
1987	$19,184	1994	$29,637
1988	$18,984		

(2) Risks and Damages Associated with Plant or Reservoir Failure

Chevron is obligated to provide Edison the quality and quantity of brine that is necessary to meet the Demand Fuel Requirement, i.e., sufficient usable heat to operate the initial power plant at full capacity. Failure of Chevron to produce to specification will result in a "Reduced Demand Charge" and "Liquidated Damages," or at Edison's option, under specific circumstances, to reversion to operations in which Chevron is reimbursed only for its direct cost of operating the field. If Chevron is unable to deliver any fluid meeting specifications, and Edison does not accept the out-of-specification fluid, Edison makes no payment to Chevron, and Chevron at its option incurs liquidated damages of $3.6 mm/yr. or operates the field for Edison with reimbursement only for its costs of operation.

In the event Edison is responsible for failure to operate at full capacity, Edison will continue to pay the full demand charge to Chevron even though the plant is operating at reduced capacity. In the event of total plant failure occasioned by action or inaction of Edison, Edison must continue to pay a full demand charge to Chevron for the entire 30-year life of the contract.

It is Edison's position that significant incentives exist for Chevron to produce to contract quality and quantity specifications. Furthermore, the contract is structured so that neither party benefits from a failure to perform.

(3) Termination

The Sales Contract is intended to bind the parties for the entire term of the contract, with two exceptions. One exception has to do with Edison's return of the remaining fluid to Chevron for reinjection. If this fluid does not meet specifications and damage cannot be prevented to Chevron's reserves and facilities, then Chevron has the option to terminate the Sales Contract, giving 60 days' notice. However, if Edison does meet reinjection fluid specifications, then Chevron assumes full risk of reinjection, i.e., potential problems associated with reinjecting fluid such as clogging of wells. The other exception involves fluid specification reduction. If fluid specifications cannot be restored by Chevron, Edison has the right to terminate the Sales Contract giving 60 days' notice.

The risks associated with the obligation to actually produce acceptable brine in adequate quantities fall directly upon Chevron under the Sales Contract. Furthermore, the Sales Contract is a requirements contract; Edison is not obligated to take all the brine Chevron produces but only amounts up to and including the supply obligation. Additionally, there are no price reopeners due to any financial hardship suffered by Chevron. If Chevron incurs unanticipated costs, such as drilling a large number of replacement wells, it is still locked into the pricing formula specified in the Sales Contract.

Finally, one of the most substantial benefits Edison has under the Sales Contract involves potential future plants. Edison has the first and prior right to purchase all geothermal energy from specified portions of Chevron's share of the Heber geothermal energy. Edison also has the right of first refusal for Chevron's heat at no worse terms than Chevron offers to anyone else. Edison believes that this benefit could pave the way for future plants using geothermal energy from the Heber reservoir. Edison contends that this right of first refusal for additional MW of geothermal energy is one of the most valuable aspects of the contract and will likely increase in value. Edison claims that any effort to reopen the contract might cause Edison either to lose or to pay a significantly increased price for its future right of access to the additional 150 MW of geothermal energy at the Heber field.

In sum based upon review of all terms and conditions, Edison concludes that the fuel supply contract does not impose uncertain or unlimited financial burdens on the ratepayer, does not force the ratepayers to pay for anything which does not directly benefit them, and assures that Edison can limit its financial exposure if the field or the plant does not perform as expected. Edison also notes that it thinks the Sales Contract does not set precedent for any subsequent contracts covering future development at Heber between Edison and Chevron.

c. Rate Impact

In support of its application, Edison presented an analysis comparing the anticipated effect on ratepayers given construction and operation of Heber with the effect on ratepayers given generation of comparable electricity by a coal-fueled and an existing oil-fueled alternative.

SUMMARY

ESTIMATED EFFECT ON RATEPAYERS

(¢/kWh Sales)

	Base Rates			ECAC			Total		
	Heber Geothermal	Alternative Coal	Alternative Oil	Heber Geothermal	Alternative Coal	Alternative Oil	Heber Geothermal	Alternative Coal	Alternative Oil
1982	(.54)	.03	.16	4.83	8.07	8.07	4.29	8.10	8.23
1983	7.99	.04	.17	5.11	9.07	9.07	13.10	9.11	9.24
1984	8.00	(.05)	.18	5.67	10.21	10.21	13.67	10.16	10.39
1985	8.03	.17	.21	6.59	11.23	11.23	14.62	11.40	11.44
1986	8.06	(.80)	.22	7.16	12.25	12.25	15.22	11.45	12.47
1987	8.08	(.74)	.24	7.73	13.22	13.22	15.81	12.48	13.46
1988	8.80	1.63	.26	8.46	10.60	14.15	17.26	12.23	14.41
1989	8.87	10.00	.28	9.83	3.65	15.14	18.70	13.65	15.42
1990	8.94	10.11	.31	10.54	3.78	16.20	19.48	13.89	16.51
1991	9.04	10.25	.33	11.31	3.87	17.34	20.35	14.12	17.67
1992	9.13	10.36	.36	12.16	3.96	18.54	21.29	14.32	18.90
1993	9.26	10.51	.38	13.06	4.03	19.85	22.32	14.54	20.23
1994	9.34	10.61	.41	14.04	4.10	21.24	23.38	14.71	21.65

Through 1982, the revenue requirement for Heber is less than that for the alternatives due to the flow through to the ratepayers of tax savings during the construction period. Thereafter, Heber has the highest revenue requirement. Edison's analysis shows that Heber would not be cost-competitive with coal-fired and existing oil-fired alternatives in the first 12 years. However, Edison's witness was willing to state that geothermal has a very good chance of being cost-competitive with alternative at some point in the future. There was no further elaboration of this contention.

Edison also presented an analysis comparing the economics of Heber on a levelized basis with existing oil and a coal-fueled alternative.

ECONOMIC COST COMPARISON OF ALTERNATIVES
1982 COMMON YEAR LEVELIZED DELIVERED POWER COST
(13 Percent Cost of Capital)

	Heber-Case I		Coal		Existing Oil	
	$/kW	¢/kWh	$/kW	¢/kWh	$/kW	¢/kWh
Generation Facilities	1,744	5.2	1,352	5.0	-	-
Initial Fuel Inventory	-	-	45	.3	-	-
Related Facilities	51	.2	90	.3	-	-
Operating & Maintenance	-	2.4	-	1.4	-	.3
Fuel	-	10.1	-	4.0	-	16.3
Total	1,795	17.9	1,487	11.0	-	16.6
Capacity Factor (%)	75		65		65	

Finally, the average effect on rates for the three alternatives was derived.

	Cents Per kWh		
	Heber	Alternative Coal	Alternative Oil
1982	.004	.008	.008
1983	.051	.035	.036
1984	.051	.038	.039
1985	.053	.041	.041
1986	.053	.040	.043
1987	.053	.042	.045
1988	.050	.036	.042
1989	.052	.038	.043
1990	.052	.037	.044
1991	.052	.036	.045
1992	.052	.035	.046
1993	.052	.034	.047
1994	.052	.033	.048

Rates in 1994 would be expected to be .019 cents less per kWh if the alternative coal project were built instead of Heber or .004 cents less per kWh if existing oil-fired generation were relied upon.

4. Environmental Impacts of Heber

The parties stipulated to admission of Edison's testimony regarding the environmental assessment performed in conjunction with the Heber project. A conditional use permit to construct the Heber facilities was obtained from Imperial County. The application for the conditional use permit was filed with the county of Imperial on or about January 16, 1979. In order to comply with the requirements of the California Environmental Quality Act the "Final Master Environmental Impact Report" (EIR) was prepared by the County prior to the issuance of the conditional use permit on January 22, 1980.

Based upon analysis and review of the EIR as well as Proponent's Environmental Assessment (PEA) prepared in compliance with the Commission's Rules of Practice and Procedure, Edison's witness concluded that the Heber project will not produce an unreasonable burden on natural resources, aesthetics of the area in which the project is to be located, public health and safety, air and water quality in the vicinity, or parks, recreational and scenic areas, or historical sites and buildings or archaeological sites.

II. Staff Showing

In presenting the testimony of two witnesses during the public hearings, the staff took the position that geothermal resources should only be developed when they are cost-competitive with other resource alternatives. The staff iterated its support for Edison's development of geothermal resources but opposed the unconditional grant of authority sought by Edison by this application.

Staff concluded that conditions on geothermal development must be imposed in cases, such as the proposed Heber project in which the costs of geothermal fuel unreasonably escalate the total cost of the project. Accordingly, the staff, in an apparent effort to assure that geothermal development is cost-competitive with other alternatives, proposes to base escalation of fuel costs on indices other than those tied to world oil prices. Staff urges conditional approval of the application and recommends that Edison either renegotiate its fuel supply contract with Chevron or agree that its shareholders will absorb a portion of fuel costs based on unreasonable cost escalators and contract provisions.

1. The Policy Implications of Application No. 59512

The Legal Division challenges the propriety of Edison's application for Commission authority to construct and operate a facility which does not require a certificate under current law and Commission orders. Legal Division feels that such efforts to seek an advisory opinion or preliminary assurances from the Commission regarding the reasonableness of the project constitute an unappropriate shift of the project's entire risk from the shareholders to the ratepayers.

Legal Division argues that ratepayers should not become guarantors of a project before the utility plant is built and operational. Conversely, shareholders should not be automatically and totally insulated from project risks even when the associated risks are ostensibly greater than those of more conventional projects. Legal Division contends that in light of Edison's optimistic characterization of the limited risks associated with Heber there is even less justification for shifting all risks to ratepayers by prior Commission approval of the project. Despite these contentions, the Legal Division simply recommends that Edison and other utilities be informed that future applications for prior approval of projects for which no certificate is required will not be entertained.

2. <u>The Economic Costs of Heber</u>

Staff accepts Edison's projections that the capital cost of Heber will total approximately $69 million. However, staff does feel that Edison's projected prices for geothermal fluid and replacement oil are too low. This analysis prompts staff to conclude that the estimated cost of Heber to the ratepayer would be significantly more than equivalent generation using oil in existing steam generation plants or coal in new large plants. Staff does acknowledge that implementation of Heber could provide operating data for development of larger and more efficient geothermal plants with associated economies of scale.

Staff considers the Sales Contract the major impediment to obtaining electricity from Heber at costs lower than from oil. Staff recognizes that the capital costs associated with geothermal plants typically exceed costs for other energy sources due to the need for construction of generation facilities, pumps, water treatment plants, etc. However, the Sales Contract, which will allegedly escalate the price of geothermal fluid at nearly the same rate as the price of oil increases, precludes Heber from being cost-competitive with other alternatives. Staff emphasizes that Edison itself has acknowledged that Heber would not be cost-competitive with coal and oil projects in the first 12 years. More specifically, staff contends that Heber will cost as much as 30-40 percent more than coal or oil alternatives in 1982 and 7 percent more in 1994.

The staff presented testimony in support of its cost contentions and its conclusion that Edison has significantly understated the expense of geothermal fuel under the Sales Contract.

As previously explained in Edison's showing, the Sales Contract divides the price of geothermal energy into a commodity and a demand component. Escalation of the commodity component is tied to the PPIO5 (see p. 13), while the demand component is escalated by the CPI. Staff argues that the PPIO5 is dominated by petroleum products and thus escalates with increases in world oil prices. Staff strongly challenges Edison's claim that only 50 percent of the PPIO5 is keyed to oil products.

For December 1978, staff demonstrated that the relative importance of commodities in the PPIO5 was as follows:

Commodity	Percent Weight
Coal	6.2
Coke	0.8
Gas Fuels	15.1
Electricity	21.1
Crude Petroleum	8.8
Refined Petroleum	48.0
	100.0

The weighted influence of refined and crude petroleum products by themselves is 56.8 percent of the index. Further, staff assumed that oil-generated electricity for baseload and peaking facilities influences the PPIO5 by 10.6 percent. Finally, an estimated 20 percent of gas fuels is petroleum gas which adds 3 percent to the weighted percent of the PPI05 attributable to oil production. Staff concludes that approximately 70 percent, rather than 50 percent, of the PPI05 is a function of the price of oil.

Staff also claims that it is equally important to note the relative weight given to each of the two pricing components in determining the ultimate cost of the geothermal fuel. With Heber operating at a 75 percent capacity factor, application of the pricing formula under the Sales Contract results in the commodity component having a 75 percent influence upon the price of geothermal fluid while the demand component has only a 25 percent influence. As a consequence of the different weighting factors ascribed to each component, staff calculations show that the PPI05 is given four times the weight of the CPI in calculating fuel costs. In the event Heber operates at 100 percent capacity factor, staff figures illustrate that the influence of the PPI05 on the price of geothermal fuel is 100 percent; the CPI would have no effect.

Based upon this analysis, staff concludes that the price of geothermal fluid will escalate at nearly the same rate as world oil prices. Staff maintains that Edison's failure to recognize the close correspondence of the price of geothermal brine to the price of world oil seriously undermines the validity of Edison's cost projections.

Using its own projections, staff estimated Edison's fuel expense obligations for 1985, 1990, and 1995, under three different scenarios. Staff's low scenario assumes high supply of oil, low demand, and low price. The medium scenario assumes medium supply, demand, and price. The high scenario assumes high demand, low supply, and high price.

FUEL COST AT 75 PERCENT CAPACITY FACTOR
LOW, MEDIUM, AND HIGH SCENARIOS

(Dollars in Thousands)

Scenario	1985	1990	1995
Low 1/	18,043	27,234	35,507
Medium	20,919	35,803	51,283
High	25,054	41,646	67,837

1/ Edison's projected cost increases for geothermal fluid approximate the same rate of increase as staff's low projection which is based on the Department of Energy's low price oil scenario (cf. Edison's fuel expense projections, p. 12).

Staff presented its own estimate of realistic fuel escalation rates for Heber. Using the assumption that the cost of Heber fuel would increase at the same rate as Edison's escalation rate for the use of oil, staff had Edison recalculate the levelized annual cost, and compared the result with Edison's calculations.

1982 COMMON YEAR LEVELIZED DELIVERED POWER COST
(¢/kWh)

	Staff	Edison		
	Heber	Coal	Oil	Heber
Generation Facilities	5.9	5.0	-	5.2
Initial Fuel Inventory	-	.3	-	-
Related Facilities	.2	.3	-	.2
Operation & Maintenance	2.5	1.4	.3	2.4
Fuel	15.7	4.0	16.3	10.1
Total	24.3	11.0	16.6	17.9
Capacity Factor	75%	65%	65%	75%

Staff draws the conclusion that Heber geothermal energy is clearly not cost-competitive with alternative projects available to Edison.

The staff paints an even grimmer picture of Heber's lack of cost-competitiveness in the event certain conditions are triggered under the Sales Contract.

1982 COMMON YEAR LEVELIZED DELIVERED POWER COST
(¢/kWh)

Cases	1	2	3	4	5
Generation Facilities	5.9	8.9	12.6	11.1	11.1
Related Facilities	.2	.3	.4	.4	.4
Operation & Maintenance	2.5	3.8	5.4	4.7	4.7
Fuel	15.7	18.9	23.1	14.1	12.5
Total	24.3	31.9	41.5	30.3	28.7
Capacity Factor	75%	50%	35%	40%	40%

Cases 2 and 3 indicate levelized project costs to Edison in the event that Edison is responsible for failure to operate at full capacity.1/ In these circumstances, Edison continues to pay the full demand charge even though it is operating at reduced capacity. Since the fixed demand charge for fuel will consequently be spread over fewer units of production, Edison's ratepayers will correspondingly realize higher energy costs until the production problem is corrected. If Edison cannot correct the problem, Edison is contractually bound to pay a full demand charge to Chevron for the entire 30-year life of the Sales Contract. The contract contains no termination clause for either party on grounds of economic hardship.

Cases 4 and 52/ illustrate project costs in the event of Chevron's failure to provide the specified quantity and quality of geothermal fluid. In this circumstance, Edison is entitled to pay a

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1/ It should be noted that staff concurs with Edison that the probability of achieving a 75 percent capacity factor at Heber is quite high.

2/ Case 5 costs are less than those in Case 4 since it assumes a reduction in fuel deliveries for more than 365 consecutive days and payment of liquidated damages by Chevron to Edison pursuant to the contract.

reduced demand charge to Chevron. If its failure continues for 365 days or more, Chevron, at its sole option, may either pay Edison liquidated damages or elect to continue field operations with Edison liable only for Chevron's operating costs. Total project costs for Cases 4 and 5, which assume failure of Chevron rather than Edison, nevertheless exceed costs under Case 1 which assumes Heber operating at the projected 75 percent capacity factor. In the admittedly unlikely event that Chevron fails to provide any geothermal fluid, Edison stands to lose most of its investment.

Staff argues that the foregoing analysis illustrates the unreasonably high cost of geothermal energy when it is substantially pegged to the world price of oil. Staff disputes the need to index geothermal fuel prices to the PPI05. Such indexing negates any economic advantage of turning to geothermal as an alternative energy source. While Heber may replace the actual use of 400,000 barrels of oil a year, it will not reduce Edison's dependency on world prices.

Staff recommends that geothermal prices should not be tied in any way to fuel prices for baseload generation which are pegged to world oil prices. In support, staff argues that geothermal is provided by one supplier at one fixed location. Accordingly, staff contends that a competitive market which controls fuel prices for other resources does not exist for geothermal. Further, staff proposes that only fuels which are direct substitutes for oil should be tied to the price of oil. Geothermal fluid is obviously not a direct substitute for oil and staff finds no justification to escalate geothermal fuel prices with world oil prices.

Therefore, the staff concludes that if geothermal energy is to compete economically with other energy alternatives, the Commission should condition approval of the application by requiring that the total fuel price for geothermal energy escalate no faster than the CPI.

Staff expressed reservations about the equity of certain other provisions of the Sales Contract and requests the Commission to impose additional conditions upon any authorization in order to protect the interests of Edison's ratepayers. Though Edison has characterized the Sales Contract as a "requirements" contract, i.e., a contract by which Edison is obligated to take only as much geothermal fluid as it needs to operate at a required capacity factor, staff is concerned that Edison will be obligated to reimburse Chevron for fluid produced beyond Edison's requirements. Staff fears that this situation could arise in circumstances where Chevron must produce fluid to prevent subsidence or protect its wells. Staff presented no evidence respecting the plausibility or likelihood of such a situation occurring in which Chevron would find it necessary to provide Edison more than its requirements in order to prevent subsidence. Nevertheless, staff seeks a blanket condition insulating Edison's ratepayers from the costs of handling any geothermal fluid beyond its requirements.

The Supply Contract outlines various conditions and options for Chevron given Chevron's failure to deliver contracted volumes. Staff feels that ratepayers should not realize increases in unit fuel costs if Chevron fails to meet its supply obligations. Once again, staff presented no evidence that such an event could occur under the proposed Sales Contract. However, staff requests that the Commission condition its authorization to require that unit fuel costs should not exceed fuel costs at full capacity in the event of reduced deliveries by Chevron.

Finally, staff maintains that since the consequences of project failure are so substantial, the risk of such failure should be equitably shared between Edison and its ratepayers. Therefore, staff recommends that if the project operates below 35 percent capacity at any given time, Edison's shareholders shall absorb depreciation expenses for that fiscal year.

3. Environmental Impacts of Heber

As indicated in Edison's showing, Imperial County prepared an EIR for the Heber project prior to its issuance of a conditional use permit on January 22, 1980. Rather than prepare its own environmental document, staff proposes that the Commission adopt the EIR prepared by Imperial County in accordance with Section 21166 of the Public Resources Code. Section 21166 reads as follows:

> When an environmental impact report has been prepared for a project pursuant to this division, no subsequent or supplemental environmental impact report shall be required by the lead agency or by any responsible agency, unless one or more of the following events occurs:
>
> (a) Substantial changes are proposed in the project which will require major revisions of the environmental impact report.
>
> (b) Substantial changes occur with respect to the circumstances under which the project is being undertaken which will require major revisions in the environmental impact report.
>
> (c) New information, which was not known and could not have been known at the time the environmental impact report was certified as complete, becomes available.

Staff testified that there are no substantial changes proposed in the project. Further, there are no substantial changes in respect to circumstances; and there is no new information concerning the project. Upon this basis, staff concludes that there is no need for preparation of an additional EIR.

The Draft EIR prepared by Imperial County for Heber was circulated on September 17, 1979. Comments were made by several public agencies including this Commission. Changes in the EIR were made in response to comments; and the Final EIR was adopted by Imperial County on February 11, 1980. On October 23, 1980, all adjacent and affected property owners and concerned public agencies were notified of the staff's proposal to use the above-referenced EIR as the completed environmental document for the subject application.

III. Discussion

1. Should Application No. 59512 Be Entertained?

While the language of the exemption provision in General Order No. 131 is manifestly clear, its intent and purpose is as equally apparent. The provision allows the construction and operation of generating facilities of 50 MW or less capacity without the delay inherent in the governmental permitting process. Its intent was not to preclude or prohibit the filing of an application for authority to construct and operate a similar facility. If an applicant does not wish to avail itself of the benefits of the exemption provision, that is the applicant's prerogative.

In determining whether or not to entertain an application which is not prescribed by law, the Commission can exercise wide discretion in weighing the importance of the subject matter, the availability of its resources, time constraints, etc. In Application No. 59512 Edison seeks preliminary assurances from the Commission that its initial project to produce geothermal energy on a commercial basis as an alternative energy source is structured in a manner which reasonably allocated the risks and benefits of geothermal development between Edison and its ratepayers.

There is no issue more important to California ratepayers than the accelerated development of alternative and renewable energy resources. Since the ratepayer will ultimately fund such development, it is incumbent upon this Commission to protect the ratepayers' interests as well as to provide some practical guidance to utilities, such as Edison, which have publicly announced commitments to these new energy sources. Heber apparently represents a fundamental step in the implementation of Edison's announced policy and may well set a pattern for future development. Therefore, since Application No. 59512 poses such critical questions respecting the development of alternative energy sources, we chose to entertain the filing.

2. Is Heber a Reasonable and Prudent Investment?

Edison contends that the record amply supports the conclusion that Heber constitutes a reasonable and commercially viable project which provides significant benefits and does not impose unreasonable technical or economic risks on either its shareholders or its ratepayers. Therefore, let us carefully examine the record to determine if it does indeed support the following constituent points of Edison's conclusion: (a) Heber provides significant benefits, (b) Heber does not pose unreasonable technical risks, (c) Heber does not involve unreasonable economic risks for Edison's shareholders, and (d) Heber does not impose unreasonable economic burdens upon Edison's ratepayers.

a. The evidence demonstrates certain definite long-range benefits resulting from commercialization of the Heber geothermal resource. Its availability will reduce dependence on uncertain foreign sources of oil in the amount of 400,000 barrels a year. Use of the Heber geothermal resource in lieu of oil will improve air quality to some unquantifiable degree. Its operation will demonstrate the commercial viability of a new generation source and will serve to increase the diversification and reliability of fuel sources available to Edison.

Finally, and perhaps most importantly, the Sales Contract contains an option which entitles Edison to purchase from Chevron enough brine from the Heber reservoir to support a total generating capacity of 200 MW. Since geothermal energy is limited, the value of this option, while unquantifiable, is significant. Further, the value of access to the geothermal resource should grow as demand increases for alternative resources.

Aside from the annual backout of 400,000 barrels of oil, the benefits associated with development of Heber have not been objectively determined or economically quantified on this record. Although not quantified, the benefits are real; and the record supports the conclusion that the Heber project provides significant benefits to Edison and its ratepayers.

b. The testimony indicates that the technology used in a dual-flash plant is relatively simple and has been commerically demonstrated by similar units in Japan and Mexico. A carbon copy plant in Japan, which has achieved a 90 percent capacity factor, uses equipment manufactured by the same company, Mitsubishi, which will provide the equipment at Heber; and the brine used for heat production is of comparably low salinity. Additionally, both the Japanese plant and Heber use reinjection.

The evidence further indicates that extensive analysis was made of the geothermal reservoir and confirms that the anomaly can amply sustain 41 MW of production at the plant. The record also shows that reinjection is technically feasible and poses no significant risk to the project. The testimony, supported by engineering studies, amply supports the conclusion that Heber does not impose unreasonable technical risks.

c. In its application Edison seeks unconditioned approval of Heber, as proposed, and requests conventional rate base treatment. Edison thinks that such treatment would equitably allocate risks and benefits between present and future ratepayers and shareholders. Their rationale is simple. Since ratepayers receive all the benefits of the project including both added capacity and experience gleaned from operation of the first commercial geothermal facility, all reasonable project costs should be included in rate base and all reasonably incurred expenses should be recovered as with any other commercial plant. Edison argues that disallowance of any costs would penalize shareholders without providing any corresponding benefits to them.

If Heber is approved, as requested, and given conventional rate base treatment, the only risk borne by Edison shareholders is the possibility that the Commission will disallow expenses on grounds that they were unreasonably incurred. Since Commission approval would allow rate base treatment and would inherently sanction the terms of the Sales Contract, only limited expenses associated with Heber, such as operation and maintenance costs, would be subject to ratemaking review. Thus, given approval of Edison's application, there is considerable support for the conclusion that Heber involves no economic risks for Edison's shareholders, much less unreasonable economic risks.

d. Does the record support the conclusion that Heber does not impose unreasonable economic burdens upon Edison's ratepayers? The economic impact on ratepayers is the crux of this matter and the ultimate determinant of whether Heber is a prudent and reasonable investment. Our conclusion respecting this most critical issue must be based upon the record we have before us.

By Edison's own showing, Heber will not be cost-competitive with coal-fueled or existing oil-fired alternatives through the first 12 years of the project. In fact, no evidence was presented that Heber would ever be cost-competitive with these alternatives over the 30-year life of the Sales Contract. The firmest evidence offered in support of Heber's economic viability was the statement of Edison's policy witness that "[O]ur analysis of geothermal is that it has a very good chance or it, quote, 'will be cost competitive with alternatives at some point in the future'."

Edison did acknowledge that the geothermal energy resource would have to become economically competitive with alternatives at some time in the future in order to warrant its continued development. Yet, the evidence presented fails to demonstrate in any way how and when such an eventuality can or will occur. In fact, the evidence of record, if anything, prompts the conclusion that geothermal energy produced under contracts similar to the Sales Contract will not necessarily be cost-competitive at any point in the future.

The capital cost of this geothermal project appears to exceed capital costs for coal projects. Edison also acknowledges that Heber represents a commercial rather than research and development project. Capital costs associated with geothermal facilities are relatively fixed, and there is no evidence to support a conclusion that future geothermal projects can take advantage of information gleaned from Heber to reduce their capital costs.

There are other questions relating to the capital cost of the project which Edison has not addressed. It is commonly known in financial markets that the nation's electric utilities are experiencing severe economic distress. While Edison is performing above the norm, it still is no exception. On the other hand, the major oil companies have substantial capital reserve, much of it internally generated. Under the circumstances, we are concerned that Edison has assumed responsibility for an estimated $17.6 million in capital expenditures for brine delivery, brine reinjection, and water treatment facilities. This increases Edison's capital costs for the project by over 30% at a time when it is capital short. The capital cost for brine delivery and reinjection may more properly be assignable to Chevron in that they are associated with the use and maintenance of the geothermal reservoir rather than operation of the power plant. We are not presently persuaded that this part of the project is a reasonable and prudent investment for Edison; further exposition is required. Proper responsibility for the cost of water treatment facilities is also unclear and requires further exploration on the record.

The second component which accounts for Heber's costs exceeding coal- and oil-fired alternatives relates to fuel expenses under the Sales Contract. Edison feels that the contractual pricing provisions with Chevron fairly and equitably protect the interests of the two parties. We must ask how such a determination is made.

Nothing in the Sales Contract indicates that Edison felt constrained in any way to limit its offer to a price which would allow it to produce electricity from geothermal brine at a cost-competitive with other sources of energy. Since Edison is requesting the ratepayer to underwrite and guarantee its contractual obligations, we are compelled to ask what limit Edison placed on its offer if it was not constrained by notions of relative cost. If cost-competitiveness was not a constraint, what factor or factors served to operate as a price ceiling on Edison's offers? What standard did it apply, other than a subjective feeling, to determine that the pricing mechanism is fair and reasonable?

Edison presented extremely limited testimony in support of its conclusion that the price for brine under the Sales Contract compares favorably with other projects of Heber's type. Edison noted that few comparisons are available due to lack of any publicly available contracts involving liquid-dominated systems. Edison testified that as a consequence of the limited availability of relevant information their conclusion that the price charged for the brine is in an appropriate range was formed on the basis of the negotiations and analysis of industry literature, reports, and confidential and proprietary contracts.

This type of vague and conclusory testimony hardly meets Edison's burden of proof. Edison has provided the Commission no basis for making a determination regarding the reasonableness of the Sales Contract. To this extent Edison has failed to sustain its burden of proof; and since fuel expenses so largely contribute to the total costs of a project which is admittedly not cost-competitive, the failure becomes critical. This failure to provide proof or sufficient explanation leads to endless questions about the actual provisions of the Sales Contract. For example, the demand component of the fuel price formula is intended to provide for recovery of fixed costs incurred by Chevron to meet its "supply obligation" to Edison. However, the capital costs incurred by Chevron in participating in Heber constitute proprietary information. How can Edison, much less the Commission, know if the demand component corresponds in reality to the costs actually absorbed by Chevron?

It is apparent that Chevron felt constrained in its negotiations by some notion of relative cost. Chevron negotiated a demand component which relates to capital costs ostensibly incurred by Chevron in constructing and operating its portion of Heber. Chevron further negotiated a commodity component which relates to the cost of fuels used for baseload electric generation. Why did Edison fail to consider relative costs, such as the incremental cost to Edison of producing a similar amount of electricity, as a limit upon its price offer?

Based upon Edison's showing alone, Heber's lack of cost-competitiveness prompts numerous questions about the prudency of undertaking such a project. The staff showing only creates more profound and disturbing doubts regarding Heber as currently structured. If Edison's cost projections are actually underestimated, as alleged by staff, Heber's lack of cost-competitiveness will only be exacerbated and the economic burden on the ratepayer increased.

An additional concern with the Sales Contract relates to provisions in clauses dealing with "Reduced Demand Charge" and Liquidated Damages". Edison will be obliged to pay the full demand charge to Chevron even if the power plant must operate at reduced demand or fails to operate at all. On the other hand, Chevron's failure to produce to specifications can, at Chevron's option, result in Edison having to pay Chevron its cost of operating the field.

This imbalance in remedies is untenable and cannot be accepted by this Commission. Even worse, no evidence has been presented regarding Chevron's cost of operating the field. Thus, there is no way to evaluate the exposure of Edison's ratepayers. If Chevron's operating expenses are high in relation to the contract price, this safety valve in the contract will become a bargain with no benefit. In essence, it appears that Chevron is asking Edison's ratepayers to assume all the risks while Chevron will assume all the profits.

Our final concern with the Sales Contract relates to the index to be used to escalate the cost of brine to Edison. Our staff has clearly shown that it relies excessively on the price of oil. While the price of oil may be one factor in determining the value of an alternative energy resource, excessive reliance on this factor is unacceptable to this Commission. A primary reason for our interest in alternative energy resources is to produce rates lower and more stable than are possible through reliance on oil. If prices for alternative energy resources are closely tied to world oil prices by contract, a primary value of the alternative is lost.

Is there any rational basis to approve the Heber project despite its economic unattractiveness caused by the Chevron contract? Edison argues in its brief that many of its assumptions were conservative and that Heber could prove prudent based on economics alone. For example, operation over the projected 75 percent capacity factor would not increase capital-related costs nor would it increase the demand portion of the brine cost. The unit costs of Heber generation would therefore be reduced when these costs are spread over a larger number of kWhs. However, such statements are not evidence; rather they are arguments. Edison is responsible for its own showing and is bound by the evidence of record.

In making these difficult decisions, economics has always played a critical role. We have previously implemented programs that have provided benefits as well as been cost-effective or cost-competitive. For example, the ZIP program - by which homeowners can receive zero interest loans to improve the energy efficiency of their homes - is cost-effective in that it is cheaper to save energy by subsidizing home insulation improvements than it is to build new power plants to generate a similar amount of energy. Cost-effectiveness prompted our decision to require Pacific Gas and Electric Company to pay "avoided cost" for any energy provided by cogenerators to the utility. In the implementation of each program, the concept of "cost-effectiveness" was used by the Commission as a ceiling on how much the utility should expend.

In Decision No. 91272 (Demonstration Solar Financing Program) and Decision No. 92653 (PGandE ZIP), we discussed at length the question of cost-effectiveness tests. We must again note the limitations of various cost-effectiveness tests that have been proposed. In the present case, a decision must eventually be based on cost-effectiveness criteria. The Concurring Opinion of Commissioners Grimes and Gravelle offers one possible approach on which to base such a decision. Today, however, we are not faced with this issue. Problems relating to the Sales Contract are so serious as to render the project unacceptable strictly on the basis of the contract alone.

In light of our disposition, there is no need to address the environmental issue.

Findings of Fact

1. Heber involves construction and operation of a 41.1 MW dual-flash geothermal generation facility near Heber, California.

2. Operation of Heber will reduce Edison's use of oil by 400,000 barrels a year, improve air quality, and increase the diversification and reliability of Edison's fuel supply sources.

3. Heber is a commercial facility using relatively simple and reliable processes and equipment which have previously been successfully operated in Japan and Mexico.

4. The geothermal anomaly at Heber can produce enough hot water at high enough temperatures to support a 500 MW geothermal development for 30 years.

5. The capital costs borne by Edison for Heber are estimated to be $69 million.

6. In addition to capital costs, the expenses incurred by Edison in purchasing geothermal fuel from Chevron under the Sales Contract constitute the two major components of Heber's ultimate cost.

7. Through 1994, the revenue requirement for Heber is greater than that for a coal-fired or existing oil-fired alternative.

8. On a levelized basis for the year 1982, the cost of delivered power from Heber ranges from 17.9¢/kWh to 24.3¢/kWh, as compared to 11.0¢/kWh for a coal-fired alternative and 16.6¢/kWh for an existing oil-fired alternative.

9. Using assumptions most favorable to Edison, the average impact on rates in 1994, is as follows: .052¢/kWh for Heber, .033¢/kWh for an alternative coal project, and .048¢/kWh for existing oil-fired generation.

10. Heber is not cost-competitive with the coal-fired or existing oil-fired alternative.

Conclusions of Law

1. The benefits associated with Heber of reduced reliance on oil imports, improved air quality, and diversification of fuel supply sources do not outweigh the negative economic impacts imposed on ratepayers by construction and operation of Heber.

2. Construction and operation of Heber, as currently structured, does not constitute a reasonable and prudent investment for Edison or its ratepayers and is not in the public interest.

O R D E R

IT IS ORDERED that Application No. 59512 is denied.

The effective date of this order shall be thirty days after the date hereof.

Dated May 19, 1981, at San Francisco, California.

We concur. See attached.
/s/ RICHARD D. GRAVELLE
/s/ LEONARD M. GRIMES, JR.
Commissioners

JOHN E. BRYSON
President
RICHARD D. GRAVELLE
LEONARD M. GRIMES, JR.
VICTOR CALVO
PRISCILLA C. GREW
Commissioners

LEONARD M. GRIMES JR., Commissioner
RICHARD D. GRAVELLE, Commissioner

We concur that the Sales Contract for geothermal fluid renders Edison's application unacceptable. Nevertheless, we commend Edison for approaching this Commission with its application. The Heber project could become an important step in the pioneering transition toward the greater use of alternative resources which Edison and other California utilities have begun.

In order to expedite the transition to alternatives, this Commission must soon establish clear criteria for determining the cost-effectiveness of proposed generation projects. In Decision No. 91272 (Demonstration Solar Financing Program) and Decision No. 92653 (PGandE ZIP), we addressed this question; but because of circumstances unique to each case, a firm decision on cost-effectiveness criteria was not required. Decision No. 91272 dealt with a demonstration program. Decision No. 92653 offered a program that is cost-effective by any criteria.

In OIR-2, now submitted for decision, clear guidelines will be established for the prices utilities will be authorized to pay for energy and capacity purchased from small power producers. In the present case, upon renegotiation of the Sales Contract, we will be faced with the first utility proposal to construct an advanced alternative which is not a demonstration. To assist the parties in developing a thorough record regarding the cost-effectiveness of utility proposed alternative energy projects, we offer our views on this issue today.

We believe that our regulated utilities have a strong obligation to seek and bring to fruition projects that produce energy at below their avoided cost. We also recognize that such projects are not always available. We believe that full avoided cost is a proper benchmark to determine the cost-effectiveness of a project. Regrettably, the determination of a true avoided cost has been elusive. While economists and policy makers continue their debate, the value of displacing oil fired generation has been used as a proxy for avoided cost. In Decision No. 91272 and Decision No. 92653, we pointed out that many elements of value are not taken into consideration by this proxy. We believe that until a more inclusive picture of avoided cost is developed, the avoided cost as represented by oil may be exceeded if a showing of particular value is made on the record.

Such a showing should not, standing alone, be persuasive in permitting purchases of energy above the avoided cost. We have a responsibility to the ratepayers to determine not only that there is economic value to exceeding the avoided cost of oil but also that there is an economic necessity to do so.

In the present case, we are faced with a record which contains nothing more than a negotiated price. A claim that the best possible price has been obtained through negotiation may suffice to justify the purchase of energy at below the avoided cost. However, when a proposed project would produce energy at or above the avoided cost, greater scrutiny is necessary to protect the interests of the ratepayers. This Commission should investigate such proposals to determine whether there is an economic necessity to equal or exceed the avoided cost. The burden of proof rests on the proponents of the project.

This burden entails demonstrating the particular value of the project to the ratepayers. Particular value may include, but should not be limited to:

1. A likelihood that energy from the project will cost less than the avoided cost for a significant part of the life of the project.

2. Promotion of a demonstrated and promising technology in which early investments entail a high risk to the utility.

3. Promotion of a demonstrated and promising technology which has not achieved economies of scale from mass production and appears likely to produce energy below avoided costs when such economies are achieved.

4. Reduced air or water pollution as measured by the value of trade-offs that would be necessary to generate comparable energy with oil.

5. Reliability or security of the fuel supply being greater than that for oil or, at a minimum, being domestically controlled.

6. Demonstrable benefit to the ratepayers caused by recycling of energy expenditures in the California economic.

7. More rapid return on investment of the utility due to shorter construction lead times.

8. Reduced or avoided capital requirements for the utility.

9. Greater diversity of energy resources.

10. Broader dispersion of generating stations.

Thus, the avoided cost should not serve as an absolute ceiling but remains a bench mark for evaluation. Proposals for projects producing energy substantially below the avoided cost may be presumed to be the product of an open market. Proponents of such projects should be able to limit their showing to matters of technological viability. Proposals for projects producing energy at or above the avoided cost, on the other hand, should be required to show both that there is particular value to the ratepayers to pay the avoided cost or more.

In the present case, such a showing has not been made. We recognize that this is a case of first impression. We invite the proponents to resume negotiations on the Sales Contract, and on submission of a new application, more thoroughly address the issue of cost-effectiveness.

/s/ Leonard M. Grimes Jr.
LEONARD M. GRIMES JR., Commissioner

/s/ Richard D. Gravelle
RICHARD D. GRAVELLE, Commissioner

San Francisco, California
May 19, 1981

ADDRESS ALL COMMUNICATIONS
TO THE COMMISSION
CALIFORNIA STATE BUILDING
SAN FRANCISCO, CALIFORNIA 94102
TELEPHONE: (415) 557-8681

Public Utilities Commission

STATE OF CALIFORNIA

January 19, 1982

FILE NO. 303

The Alternative Generation Section is preparing four reports on cogeneration pricing for the U.S. Department of Energy. The Task I report has been issued (April 1981) and the Task II and III reports will be available in February 1982. The Task IV report will be available in May 1982. While these reports can be obtained from DOE, we also plan to reproduce copies and make them available at approximately the cost of reproduction and mailing - the cost for each report as established by DOE. We are doing this in recognition of the need for timely information on cogeneration. Should you wish copies of any of these four reports, so indicate and return the lower part of this letter (approximated invoice charges are indicated).

Very truly yours,

Kenneth J. Kindblad

KENNETH J. KINDBLAD, Chief
Resource Planning and Projects Branch

Detach and Return

California Public Utilities Commission
Alternative Generation Section, Room 5151
State Building
San Francisco, CA 94102

Please send me the following CPUC staff reports prepared for DOE:

Task	Report Title	Invoice Charge
I	The Development of California Cogeneration and Small Power Production Pricing: A Case History of Prices and Contract Terms Under Decision No. 91109	$8.00
II	Handbook of Pricing Methodologies	$10.00 (Estimated)
III	California Cogeneration and Small Power Production Pricing Study (14 case studies)	$15.00 (Estimated)
IV	A Summary and Analysis of Standard Price Offerings in Response to the California PUC Decision in OIR-2, Cogeneration and Small Power Production Pricing Standards	$10.00 (Estimated)

ADDRESS ALL COMMUNICATIONS
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SAN FRANCISCO, CALIFORNIA 94102
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Public Utilities Commission

STATE OF CALIFORNIA

January 20, 1982

FILE NO. 303

TO OIR-2 DECISION RECIPIENTS:

Pursuant to notices appearing in Commission Calendars, the Commission is now required by law to charge 20¢ per page for copies of Commission decisions. If your request for a copy of the OIR-2 decision was made prior to September 30, 1981, you are not charged for the enclosed decision. However, any subsequent decisions involving OIR-2 or other proceedings on qualifying facility, pricing will include an invoice other than for parties and appearances.

Because our mailing list is so extensive, we cannot use it for further mailings. We therefore request that you return the lower part of this letter if you wish to receive all further decisions involving this subject at an invoice charge of 20¢ per page.

Very truly yours,

Howard A. Sarasohn

Howard A. Sarasohn
Assistant Executive Director

Enclosure

Please detach and return -

To: California Public Utilities Commission
Alternative Generation Section, Room 5151
State Building
San Francisco, CA 94102

☐ Please send me further decisions as they are issued on OIR-2 and proceedings related to qualifying facilities pricing. (Invoice charge will be 20¢ per page.)

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I N D E X

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ALJ/km/bw

Decision 82 01 103 January 21, 1982

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Rulemaking on the Commission's own motion to establish standards governing the prices, terms, and conditions of electric utility purchases of electric power from cogeneration and small power production facilities.	OIR 2 (Filed September 3, 1980)

(See Appendix A for appearances.)

O P I N I O N

Summary

This decision orders the major California electric utilities to file standard offers for power purchases based on avoided cost principles. These offers shall be available to all cogeneration and small power facilities that qualify under the Federal Public Utility Regulatory Policies Act of 1978. The decision finds that avoided cost pricing will promote the maximum efficient development of cogeneration and small power resources, diversifying the energy supply in California and reducing the state's oil dependence.

The standard offer gives qualifying facilities (QFs) a series of options to tailor contracts to meet their varied needs.

Within 45 days, the utilities are ordered to file the following standard offer options which will become effective upon a compliance review by the staff. These options are:

- Facilities providing as-available electricity (energy delivered without a long-term contract) will receive an as-available energy and an as-available capacity payment in ¢/kWh, varying by time of delivery. The as-available price will be based on a short-run avoided cost methodology, with capacity reflecting an estimate of the utilities' shortage cost (pp. 30-56).

- QFs which agree to certain performance standards may receive a firm capacity payment, rather than an as-available payment. The firm capacity payment is available in $/kW/year, and may be contracted for and levelized for up to 30 years. The firm capacity payment, like the as-available payment, is based on a shortage cost methodology. Firm capacity contracts will also include payments for energy (pp. 57-64).

The decision orders utilities to file within 90 days proposals for three other option which will become available after additional hearings. These options are:

- Energy payments may be fixed in advance for up to five years for QFs which agree to commit to provide energy over the term of the contract. This energy payment may be tied either to an as-available or firm capacity option. Payments will be based on projected variable operating costs of the utilities (p. 51).
- A long term contract, based on a utility's long-run resource plan for both energy and capacity shall be available for QFs. This offer will be based on a long-run avoided cost concept (pp. 64-68).

The decision also establishes guidelines for the standard offer relating to interconnection costs, refusal to purchases, line losses and other contract terms.

The decision allows utilities to file for review of non-standard contracts with this Commission for two years after the effective date of this decision.

This decision also sets standards for rates for sale of power to QFs. Standby rates currently in effect are found reasonable for all QFs on demand schedules, and will be updated in general rate cases in proportion to increases in per kW capacity costs. They are eliminated for QFs who achieve an 85% on-peak capacity factor. Alternate standby rates are adopted for QFs on time-of-use rates. A time frame for planning periods of scheduled maintenance is adopted and scheduled maintenance rates are set at regular tariff rates. Added demand charges are waived for maintenance fitting utility schedules. Interruptible service offerings are made available for all large QFs.

I. Introduction

California has a longstanding demonstrated interest in promoting cogeneration and small power production, as shown by various actions by this Commission and by the California Legislature (see, e.g., Public Utilities (PU) Code Sections 2801-2824). Cogeneration facilities simultaneously produce two forms of useful energy, such as electric power and steam. Cogeneration facilities use significantly less fuel to produce electricity and steam (or other forms of energy) than would be needed to produce the two separately. Small power production facilities use biomass, geothermal energy, waste or renewable resources, including wind, the sun, and water, to produce electric power. Reliance on these sources of energy can reduce the need to consume traditional fossil fuels to generate electric power.

In Decision (D.) 91109 in Order Instituting Investigation (OII) 26 we recited the following reasons for promoting the development of such alternate resources:

a. Cogeneration uses fuels more efficiently than when industrial processes and electric generation are performed separately.

b. Alternate generating sources diversify the utility's resource plan and minimize dependence on any single source of generation.

c. Generation from biomass, wood waste, and refuse offers independence from foreign fuel sources. The use of domestic fuels is important for reasons of international economics and politics.

d. The development of many small power plants contributes to system reliability. The probability of many small plants failing simultaneously is less than the probability of one large central station plant suffering a forced outage.

e. The lead time required for construction of a small facility is estimated to be several years less than for large central station power plants. Permitting and siting are considerably simplified due to the small size and location at an existing industrial facility.

f. The utility in many cases will not have to raise the capital to construct the facility, and the facility will not be included in the utility's rate base.

In D.91109, December 19, 1979, we adopted "avoided cost" as the reasonable basis for payment by a utility to purchase power from such facilities.

Meanwhile, cogeneration and small power production have also been the subject of federal actions intended to promote their development, particularly Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA). Each electric utility is required under Section 210 to offer to purchase available electric energy from cogeneration and small power production facilities which are defined as qualifying facilities under Section 201. For such purchases electric utilities are required to pay rates which are just and reasonable to the ratepayers of the utility, in the public interest, and which do not discriminate against cogenerators or small power producers. Section 210 also requires electric utilities to provide electric service to qualifying facilities at rates which are just and reasonable, in the public interest, and which do not discriminate against cogenerators and small power producers. Section 210 further requires the Federal Energy Regulatory Commission (FERC) to prescribe rules as FERC determines necessary to encourage cogeneration and small power production, including rules requiring electric utilities to purchase electric power from and sell electric power to cogeneration and small power production facilities.

On February 19, 1980, FERC issued its final rules implementing Section 210. (Docket No. RM79-55, Order No. 69 (45 Fed Reg 12214).) These regulations require that electric utilities purchase electric energy and capacity from qualifying cogenerators and small power producers at a rate equal to the utility's avoided cost of generating the power itself or purchasing it elsewhere. The criteria and procedure by which cogenerators and small power producers obtain qualifying status are set forth in the FERC rules issued under Section 201. (Docket No. RM79-54, Order No. 70, March 13, 1980 (45 Fed Reg 17959).)

The implementation of the Section 210 rules is reserved to state regulatory authorities. Within one year of the issuance of the rules, each state regulatory agency is required to commence implementation, by way of:

> "...the issuance of regulations, an undertaking to resolve disputes between qualifying facilities and electric utilities arising under...(the rules), or any other action designed to implement...(the rules)."

Within one year each state regulatory authority is required to file with FERC a report describing the manner in which it will implement the rules.

By Order Instituting Rulemaking (OIR) 2 dated September 3, 1980, this Commission initiated this proceeding for the purpose of establishing standards governing the prices, terms, and conditions of electric utility purchases of electric power from qualifying cogeneration and small power production facilities, under the FERC rules. The order and the "Preliminary Draft Staff Report on Cogeneration and Small Power Production Pricing Standards" were served simultaneously on respondents and interested parties. The original schedule contemplated written comments addressing the staff report to be filed by September 29, 1980, the final staff report, and a public hearing on November 3, 1980, for "oral comments on issues pertinent to this proceeding." By Administrative Law Judge's (ALJ) Ruling dated September 18, 1980, the time for filing written comments was extended to October 15, 1980, and the public hearing postponed until December 2, 1980. By a second ALJ's Ruling dated November 21, 1980, the public hearing was postponed until February 3, 1981, so that staff would have sufficient opportunity to assimilate the numerous and substantial comments in preparing its final report. The hearing dates set for December remained on calendar and parties appeared to offer further comments and to argue several pending motions. At the December hearing, staff moved for an interim order addressing the ultimate applicability of this decision to contracts signed during the pendency of this proceeding. Staff's motion was the subject of D.93054 dated May 18, 1981, and D.93393 dated August 4, 1981, which provide sellers an option to amend contracts to conform with the provisions of this decision.

The final staff report was issued on January 20, 1981. Public hearings to receive comments on the final staff report were held February 3, 4, and 5, 1981.

II. Procedural Matters

The designation of this proceeding indicates that this is one of the first matters conducted under our rulemaking procedures adopted June 17, 1980. The unfamiliarity of the procedure has apparently contributed to a concern that factual issues will be decided without the opportunity for evidentiary hearings. Southern California Edison Company (Edison), San Diego Gas & Electric Company (SDG&E), and Mass Production Systems (MPS) each filed a written motion asking for evidentiary hearings.

Edison argues that a prehearing conference is necessary to identify unresolved issues that in turn are necessarily resolved in an evidentiary hearing. It contends that an inadequate factual basis for this decision denies due process of law to affected parties.

In support of its position, Edison cites FERC rule Section 292.401(a) which provides for implementation of the rules "after notice and an opportunity for public hearing." It asserts that the hearing allowed in this matter is insufficient for FERC purposes. It also states that the staff report does not have an adequate factual basis upon which to establish the proposed standards. It argues that only an evidentiary hearing will allow this Commission to "establish standards which will equitably balance those varying interests which it is the responsibility of the Commission to protect."

SDG&E also requests a prehearing conference which it contends is required for the following reasons:

1. To expand the scope of the proceeding to permit an evidentiary hearing for the purpose of reviewing standard form contracts.
2. To determine the need for an evidentiary hearing on existing issues.
3. To place limitations on the proceeding.
4. To resolve certain procedural problems.

In its brief SDG&E observes some change in the staff position but argues that staff's proposal still unnecessarily limits subsequent evidentiary hearings.

MPS argues that the Commission should provide for evidentiary hearings (within the scope of OII 26) to investigate and adopt standards to ensure system safety and reliability of interconnected operations. It contends such standards are necessary to the development of safe, economical cogeneration and small power production hardware, leading in turn to qualifying facilities that rely on such hardware.

Staff replied initially that it would consider such motions in the nature of comments in preparing its final report. Various other parties support one or more of the motions.

Staff in its final report argues that this procedure satisfies the "public hearing" requirement imposed by FERC. It states that FERC rules specifically authorize state agencies to implement rules by issuing regulations or taking other action reasonably designed to implement the rules. The rulemaking procedure, staff further argues, is an appropriate means for the consideration and adoption of standards and guidelines governing the utilities' purchases from qualifying facilities. Although staff recommends evidentiary hearings to review the offers which the utilities will make in compliance with such standards and guidelines, staff believes that any evidentiary hearings which might have been instituted before the establishment of these standards and guidelines would have been premature, time-consuming, and ultimately inconclusive.

We agree with staff that the rulemaking procedure is an appropriate way to decide generic policy questions such as the issues we resolve in this decision. We also agree with the substance of the three motions that certain issues will require resolution in an evidentiary proceeding. In the following discussion, we provide for later evidentiary hearings that will address the primary concerns of the moving parties. Because the evidentiary proceeding we provide is not identical to any of the moving parties' proposals, however, we deny each of the motions for procedural purposes.

III. Applicability

This proceeding has been initiated to further implement our decision in D.91109, to respond to FERC rules, to discharge our responsibilities under Public Utilities Code §2821. To avoid confusion, we use the terminology and structure of the FERC rules throughout this decision. A number of parties to this proceeding have raised questions about the applicability of these rules either to certain California utilities, or to particular entities which are interested in contracting with utilities. We address these questions in this section.

The staff raised the issue of the applicability of these standards in cases where utilities have an equity interest in a facility. One criterion describing a qualifying facility is a limit of utility equity ownership to no more than 50%. In its final report staff analyzes applicable statutes and rules relating to utility ownership and offers the following summary:

> "The approach suggested by FERC is as follows: Given state regulatory authority over retail sales, the Commission may prohibit the parent utility from passing on to its ratepayers all

of the expenses paid to its subsidiary. In return the Commission would allow the utility subsidiary to earn a higher rate of return than the parent. Accordingly, the parent utility would only be entitled to recover through rates its purchases based on cost of service rather than avoided cost. This approach recognizes that ratepayers should derive some benefit from incurring the additional risk created by the utility subsidiary in potentially affecting capital ratios of the parent without limiting the amount of expenses recoverable by the parent. There appears to be little incentive for the utility to negotiate prices at other than the parent's avoided cost if its subsidiary could enjoy high profits, subsidized by the ratepayers of the parent."

"The FERC's approach thus equitably balances the risks and benefits faced by the parent and its subsidiary. In the event of project failure, the subsidiary could not recover its costs through amortization. Such costs would be borne by the subsidiary's stockholders. The parent, in turn, would make no avoided cost payment to the subsidiary, having received no power. In the case of project success, however, the unregulated subsidiary could retain all profits and earn a greater rate of return than its parent....

"Review of purchased power costs incurred by the parent utility from its subsidiary should be made in ECAC proceedings. Capital expenses incurred by the utility should be reviewed in general rate proceedings."

The resulting staff recommendation is that the Commission should consider limiting the amount of recovery of purchased power expenses paid to a QF owned in part by a utility.

Pacific Gas and Electric Company (PG&E) urges that this Commission reject staff's recommendation. It argues:

"When utilities invest in QFs the utilities' shareholders bear risks greater than those assumed in traditional utility investments.

> As a reward for taking the risk that expenses may not be recovered in the event of project failure, the utilities should have the opportunity to retain the full benefits of the venture, the same as any other investor in a QF. It has been determined by both the FERC and the Commission that to adequately encourage and reward investors in QF projects, the investor should be allowed to receive full avoided costs.
>
> "If the Commission wants to strongly encourage development of cogeneration and small power production facilities, it should allow utilities to participate in this energy market with incentives equal to those granted to others. The effect on the ratepayer is the same whether the power is purchased from a QF owned in part by a utility, purchased from a QF in which a utility has no equity interest, or generated from conventional resources. At the same time, a greater number of preferred resources will be developed."

PG&E concludes that such incentives will encourage utility investment in QFs, financially strengthen the utility, and improve its ability to build preferred resources, ultimately reducing the cost of serving its customers.

Edison also argues that staff's proposal is unreasonable. It contends that federal authority preempts state interference in utility - QF relations, and asserts that even without such preemption public policy considerations support the recovery of full avoided costs by the QF from the utility and by the utility from the ratepayer.

SDG&E also argues that "the supremacy clause would preclude reconsideration of whether the rates are just and reasonable for the purpose of rate recovery by the utility." It characterizes staff's position as apparently due to a misinterpretation of certain comments accompanying FERC proposed rules.

We find that staff's recommendation should not be adopted.

PURPA permits utilities to own up to 50% of a cogeneration or small power facility otherwise qualifying under the act with that facility still retaining its qualifying status. Such facilities should therefore be eligible for full avoided costs under the conditions adopted in this proceeding.

While facilities with less than 50% utility ownership are eligible for avoided cost (assuming all other requirements are met), we note that this Commission has continuing responsibility over the rest of utility operations, including financial health, which could be directly affected by a utility's equity involvment in qualifying facilities. The Commission has responsibility in three areas which are germane here.

First, the Commission must consider the potential anticompetitive aspects of utility behavior. In this regard, when a utility is approached by a large number of aspiring QFs, we must assure that its own affiliates do not receive special treatment, e.g., more rapid consideration, less difficulty in resolving interconnection issues, etc. It is important that utilities do not stifle competition in the QF market in this or any other way.

Second, there is a concern that utilities would have an incentive to keep avoided costs high (or choose methodologies that would produce such results) if their own affiliates could receive such prices. A related concern is that a utility would have an incentive to negotiate nonstandard offers that are above avoided costs if it has an ownership interest in the qualifying facility.

Our last, and perhaps most important concern relates to the fact that utility ownership of qualifying facilities would be a step toward utility diversification into unregulated activities. Any such diversification into unregulated ventures may have an impact on the regulated utility business for which this Commission is responsible. Our primary concern is the protection of the financial integrity of the regulated entity (i.e., new unregulated ventures should not impair the utility's ability to raise capital, its bond rating, etc.) and the avoidance of any subsidization by the regulated entity (and thus its ratepayers) of the unregulated business.

Utilities should be aware that while we are not denying their eligibility to participate as qualifying facilities under PURPA, such involvement will require greater scrutiny of utility operations on our part relating to the concerns addressed above. Any utility may come forward with a proposal for partial ownership of a QF and we will review these matters on a case-by-case basis, with the intent of protecting the interest of both ratepayers and any QFs who might be disadvantaged competitively.

Staff also suggests that avoided cost principles should not apply to facilities in which a utility owns an equity interest greater than 50%. Because such facilities are not "qualifying facilities" this issue is not ripe for resolution in this proceeding. Therefore, we make no judgment in this regard. Similarly, staff introduced the issue whether avoided cost principles should apply to facilities that are not "qualifying" for reasons other than ownership. The resolution of this issue is beyond the scope of this proceeding.

Advisory Services Corporation (ACS) raises the question of the extent of state regulatory jurisdiction over joint ownership arrangements where the utility owns the energy resource and the nonutility owns the facility. Staff argues that FERC does not intend that such an arrangement attain qualifying status. It states that "the underlying assumption is that the nonutility participant owns the resource which, without utility assistance in financing, would remain undeveloped." Staff contends that "the very basis for avoided cost payments does not apply to utilities developing their own resources," (emphasis in original) and concludes "the utility can clearly generate the energy and capacity itself, and does not require avoided cost payments."

While we are not persuaded to adopt staff's conclusion, ACS and the staff do raise an important question. Utility owned resources generally are purchased under the assumption that they will be employed on a regulated, cost-of-service basis. It is conceivable that a resource currently owned by a utility (and presumably acquired to be developed on a regulated, cost-of-service basis) could be more fully developed as a resource used in a qualifying facility. However, any profit involved in the transfer of such a resource from the utility as a regulated entity to a qualifying facility is certainly of interest, and will be considered in general rate proceedings.

The Bureau of Electricity of the City of Alameda (Alameda) cites a filing by this Commission before FERC in Docket No. RM-81-2 regarding geothermal development in which we asked that avoided cost principles not be applied to geothermal fields undergoing rapid commercial development. Alameda recommends that the Commission:

> "...extend to other forms of small power, biomass, or cogeneration facilities the same rationale that prompted it to seek from the FERC authority to exempt from avoided cost pricing standards geothermal facilities which are shown to be commercially feasible without such economic assistance. As the Commission noted in its FERC comments, avoided cost pricing does have the effect of excluding municipalities and other nonprofit entities from competing to develop geothermal sites because their avoided costs are lower than other entities, such as PG&E. Municipalities such as Alameda could be excluded from competing to develop other types of small power production or biomass generation facilities for the same reason. If in fact facilities can be developed at less than 'full avoided cost,' but are not due to the Commission's regulations, the developer reaps a windfall at the consumer's expense. This is not consistent with the public interest."

Consequently, Alameda proposes that we "retain, or if necessary seek to obtain" authority to exempt from avoided cost principles any QF where the seller is "ready, willing and able to develop on the basis of less than fully avoided costs."

We decline to adopt Alameda's recommendation, which we construe as an invitation to return to the "share the benefits" doctrine that we repudiated in D.91109. We believe that payment of avoided costs provides a basis for most fully exploiting all economical cogeneration and renewable energy resources. Although couched in the guise of promoting competition, Alameda's proposal is actually anticompetitive by limiting the selling price. However, nothing in this decision precludes a seller who is "ready, willing and able to develop on the basis of less than fully avoided costs" from agreeing to do so.

Another problem regarding the applicability of avoided cost principles is raised by Sierra Pacific Power Company (Sierra). It cites certain factors that it contends "make Sierra Pacific unique when compared to the large California utilities used in the evaluation and analysis of Co-Generation and Small Power Production Pricing Standards," including the following:

1. In view of its relative size, a single large QF would represent a disproportionate share of its total resources.
2. Because of its location and the configuration of transmission systems its flexibility to import or export power is limited.
3. The addition of a large QF could result in substantial excess capacity.
4. Its cheapest power is purchased from Utah Power & Light Company. During particular times of the year purchases of QF power would require curtailment of Utah power.

Based on these and other reasons, Sierra recommends that "the final regulations should contain some recognition of both the size of the utility and the size of the facility."

We find that Sierra's points are well made and that its unique status is appropriately recognized. However, rather than simply seeking to excuse Sierra from applying avoided cost principles, we conclude that these concerns are best reflected in the development of Sierra's avoided costs. This approach is discussed further in that portion of this decision regarding purchase terms and conditions.

San Bernardino Valley Municipal Water District (SBVMWD) has introduced the question whether avoided cost principles should apply to diversions of water from a utility-owned hydroelectric facility. The issue is illustrated by the current negotiations between SBVMWD and Edison.

Edison contends that water diversion plans are beyond the scope of this proceeding. Water diversion is alleged to be a matter of water law, not related to the issue of simultaneous purchase and sale between a utility and a QF. We note that this problem has also been raised in Edison's annual Energy Cost Adjustment Clause (ECAC) reasonableness review, Application (A.) 60321.

We agree that the proposed water diversion is beyond the scope of this proceeding as it does not involve a sale of electricity by a facility qualifying under FERC rules. In D.92496 we instructed Edison and SBVMWD to negotiate an agreement 60 days from the date of that decision. An extension of time was subsequently granted. We will be reviewing any agreement submitted and will take appropriate action in the next Edison ECAC filing.

IV. Purchase Terms and Conditions

A. Introduction

Under Section 210 of PURPA and the corresponding FERC regulations, each regulated utility is required to file projections of its incremental energy and capacity costs and its capacity construction schedules with its state regulatory authority for review and use in setting appropriate rates for purchase and sale of electricity between electric utilities and QFs. The first filings of these data were required by November 1, 1980. The rates determined by the Commission will be appropriate for the type of service involved and will reflect the costs avoided by the utility as a result of purchasing generation from the QF.

In determining avoided costs, the FERC regulations require that the following factors be taken into account to the extent practicable:

1. The data filed with the Commission concerning incremental generation costs;

2. The availability of capacity or energy from a QF during the system daily and peak periods, including:

   i. The ability of the utility to dispatch the QF;

   ii. The expected or demonstrated reliability of the QF;

   iii. The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement, and sanctions for noncompliance;

   iv. The extent to which scheduled outages of the QF can be usefully coordinated with scheduled outages of the utility's facilities;

   v. The usefulness of energy and capacity supplied from a QF during system emergencies, including its ability to separate its load from its generation;

   vi. The individual and aggregate value of energy and capacity from QFs on the electric utility's system; and

   vii. The smaller capacity increments and the shorter lead times available with additions of capacity from QFs;

3. The relationship of the availability of energy or capacity from the QF as derived in subparagraph 2, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

> 4. The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a QF, if the purchasing electric utility generated an equivalent amount of electricity itself or purchased an equivalent amount of electric energy or capacity.

Under FERC rules no electric utility is required to purchase electric energy or capacity during any period during which, due to operational circumstances, purchases from QFs will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of power itself.

In this part of this decision we consider whether to adopt more substantial data filing requirements as proposed by staff and the extent to which the particular factors identified by FERC should be taken into account in developing standard price offers for each utility.

B. Data Requirements

Section 292.302 of the FERC regulations requires that the following data be filed:

> "(1) The estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of not more than 100 megawatts for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than 10 percent of the system peak demand for systems of less than 1000 megawatts. The avoided costs shall be stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current year and each of the next 5 years;

"(2) The electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding 10 years; and

"(3) The estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases."

A special rule is provided for small utilities. State regulatory authorities are allowed to impose different data requirements after notice and opportunity for public comment.

Staff proposes that this Commission require that the following data be filed:

a. System avoided operating (running) cost in cents per kWh annually and by costing period in nominal and real cents per kWh by voltage level for 10 years. The marginal fuel(s) by each costing period and the nominal and real escalation rates used to estimate their cost will be reported. System incremental heat rates by time of use for 10 years (correlated with incremental fuel costs) will also be provided.

b. The electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, for capacity retirements and for terminations of contracts for purchased capacity for each year during the planning horizon, for a minimum of 10 years.

c. The estimated capacity costs at completion of the planned capacity additions and planned firm purchases, on the basis of dollars per kW, dollars per kW per year, dollars per kW per month, and cents per kWh (using the projected capacity factor) and the associated energy costs of each unit in cents per kWh. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases.

d. The estimated capacity costs of transmission and distribution plant in dollars per kW, dollars per kW per year, dollars per kW per month, and cents per kWh.

e. The estimated operation and maintenance, administrative and general, and all other fixed and variable operating expenses for avoided capacity and energy used in avoided cost calculations, expressed in dollars per kW, dollars per kW per year, dollars per kW per month, and cents per kWh.

f. The system marginal cost loss factors by time of delivery and voltage for energy and capacity from generation to each voltage level. Also, the net system aggregate loss factors by time of delivery and voltage for energy and capacity, to reflect avoided losses resulting from a reasonable mix of QFs.

g. The levelized annual cost rates for translating investment costs into annual charges, and present value rates used in any present value calculations.

h. The costs expressed in paragraphs a-e above will be on a test year (real) dollar basis or on an escalated basis, with the forecast escalation rates reported in either case. All assumptions of escalation rates, discount rates, incremental fuel increases, incremental heat rates and such, will be stated.

i. Results will be presented in summary table(s) for final total avoided costs (e.g., paragraphs a, c, d, e, f) after all effects are taken into account (e.g., losses).

The data filing is proposed to be made within 45 days of this decision and every two years, beginning June 30, 1982.

Specific reasons are offered by staff for the more thorough data filing requirements proposed. These are summarized as follows:

> Avoided Energy Costs - FERC requires a five-year forecast. Staff argues that QFs are reasonably provided an estimate of marginal energy costs over the life of a contract. Forecasts of marginal costs for at least 10 years are necessary to assist QFs in determining an estimate of potential cash flows. Forecasts should be reported in terms of constant and escalated dollars.
>
> Resource Plan - The Commission should use the same costing horizon for this purpose as for others. The proposal is alleged to be "sufficient and consistent" for this purpose.
>
> Transmission and Distribution - Whether transmission and distribution facilities are avoided by purchases from QFs is a factual question. Staff argues that avoided cost data should be filed and the matter examined, as there may be individual cases in which payment is justified.
>
> Operation and Maintenance, Administrative and General - Such costs are either fixed or variable. When a QF provides capacity, the avoided cost should include the avoided fixed costs. When a QF provides energy, the avoided cost should include the avoided variable costs.
>
> Loss Factors - Section 292.304(3) specifically provides that avoided costs may reflect costs or savings from variations in line losses to the extent practicable. Payments to a QF serving its own load should reflect the losses avoided by the utility from not having to generate the electricity itself.
>
> Levelized Annual Cost Rates - Each utility should be prepared to support its calculation of levelized annual cost rates used to translate dollars per kilowatt into dollars per kilowatt per year.

> Escalation Factors - Whether costs are expressed in real or nominal terms, the utility's assumptions regarding escalation should be filed to allow parties to use their own assumptions.

The utility response is varied.

PG&E proposes to include nearly all of the staff's provisions, omitting only the reference to loss factors. SDG&E similarly proposes to include nearly all of staff's provisions, omitting only the reference to transmission and distribution plant. Edison argues that to require further data in addition to that required by FERC would be excessive, burdensome, and would not be cost-effective.

The data required must be sufficient to develop a standard offer consistent with the adopted guidelines and for qualifying facilities to reasonably forecast the direction of avoided cost over time. The staff data requirements appear to be reasonable and will be adopted. However, many data items sought by staff are included in other documents of the utilities which are required to be filed with this Commission or with the CEC. To require all of this data to be filed every two years may result in both duplicative work and inconsistent data. Therefore we do not adopt staff's proposed filing schedule. Instead, we shall require staff to submit a revised plan for the filing of data for our consideration in further hearings. Staff shall consult with the utilities and the CEC regarding other filing requirements which currently exist. Staff's revised plan should seek to minimize duplicative filings and make available at all times the most current information available.

While we have asked staff to develop an ongoing plan for data filings, it is important that initial data filings be filed promptly. Therefore we shall require all of the above information to be filed within 45 days. These filings may incorporate data from other filings as appropriate to avoid duplication. We will consider modifying these data requirements after further proceedings on specific price offers or as needed.

The staff report addresses the questions of which utilities should be required to file data. "Sierra has not filed data under Section 292.302, but has filed marginal cost data under Section 133 of PURPA. CP National believes they should not be required to provide cost data." CP National buys its electrical requirements from PG&E and Nevada Power Company.

Staff recommends that Sierra file the specified data, but that CP National file only the rates it pays for purchases, together with the avoided cost data of its supplying utilities. CP National should be able to file by referring to the avoided cost data of its supplying utilities. We adopt the staff's recommendation.

C. <u>The Standard Offer</u>

1. <u>Introduction</u>

We have previously referred to the "standard offer". This is the expression widely used by the parties to describe the terms and conditions associated with the utility's obligation to purchase from a QF at the utility's avoided cost. The standard offer is available to all QFs, and represents a complete transaction, including prices, interconnection requirements, and other relevant factors. A central aspect of all such offers will be the standard rates for purchase.

Section 292.304, paragraph (c), provides, in part:

> "(1) There shall be put into effect (with respect to each electric utility) standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less.
>
> "(2) There may be put into effect standard rates for purchases from qualifying facilities with a design capacity of more than 100 kilowatts."

Standard rates for purchases may differentiate between QFs using various technologies on the basis of their differing supply characteristics and must be consistent with the factors listed in Part IV, A, above. As discussed below, in this decision we provide for standard rates for QFs of 100 kW or less and for more than 100 kW. The rate has relevance only in relation to the mutual obligations of the parties. In this decision we consider the nature and extent of such obligations. The result is the standard offer.

The standard offer has particular significance in terms of the existing and anticipated ratemaking treatment to be afforded utility purchases of energy and capacity provided by QFs. Purchases under the standard offer are *per se* reasonable and a utility's expenses for such purchases are recoverable in the same fashion as other purchased power expenses (in ECAC proceedings, for the larger utilities) without further review. Purchases at rates, terms, or conditions other than the standard offer are recoverable through ECAC or other appropriate procedures subject to a showing of reasonableness. Because of the different degrees of risk for the utility, there is widespread interest in whether the Commission will review nonstandard contracts prior to their becoming effective.

In adopting the parameters for rates that will be part of the standard offer, we are establishing a definition for a utility's avoided costs to be applied when purchasing energy from qualifying facilities under the terms and conditions of a specified standard contract. To facilitate discussion of the specific issues related to avoided costs as raised in this proceeding, we will first make some general observations.

The Commission has found in recent years that avoided cost (or marginal cost) pricing has significant benefits when applied to ratemaking. Avoided costs reflect the added costs to a utility of producing an additional unit of electricity. When marginal costs are used as the basis of rate design, consumers receive an efficient price signal. When adopted for purchasing electricity from third parties, the price encourages full economic development of those resources. Avoided cost pricing parallels the prices that would be established in a competitive market, providing many of the incentives for efficient resource allocation that a competitive market provides.

Some argue that ratepayers are disadvantaged when avoided costs are paid to qualifying facilities, because in some cases these facilities can produce electricity at less than the avoided cost price. While it may be true that some QFs could be brought on line at a purchase price below avoided cost, such a price would not be sufficient to bring in other QFs capable of producing power at prices up to the avoided cost price. The point of permitting avoided cost pricing is to encourage the fullest possible efficient development of QF resources that can effectively and economically compete with utility resources. By opening this market, the supply of electricity is increased, which should lower customers' rates over time. Heavy utility reliance on oil and gas fuels to generate electricity has caused rates in California to skyrocket. Avoided cost pricing is intended to stimulate development of substantial generating capacity that will reduce utility oil and gas consumption. In addition, system reliability is increased by the presence of larger numbers of smaller facilities.

If anything, this Commission believes that the avoided cost signal to QFs is a conservative one, as it does not include the tangible but hard to quantify "social costs" that are associated with new utility supplies and which are avoided through the purchase of QF power. These "social costs" include the risks associated with imported energy supplies and environmental degradation related to conventional generation. While several parties suggested that we explicitly include "social costs" in the avoided cost calculation, we are not including such factors at this time.

We prefer to recognize social costs in the general policy judgment that QF production is competitive at avoided costs. This conclusion is reflected in the terms adopted in this decision that are intended to promote QF development.

We concur with FERC rules which require full avoided cost pricing of power from qualifying facilities. The issue we face now is how to arrive at avoided cost, not whether it should be paid. This proceeding has demonstrated that defining and calculating avoided cost is far from a trivial exercise, involving conceptual, empirical, and technical issues. Some of the issues cannot be resolved without further hearings. However, we resolve most of the major conceptual questions in this decision, and this will simplify the hearings that follow.

Before discussing each of the standard offers in detail, we will discuss the relationship between the offers and the method for using avoided cost principles to derive each of the offers ordered herein.

The first type of offer described below is a standard offer for "as-available" QF power, the price which the FERC indicates should be based upon the "purchasing utilities' avoided costs calculated at the time of delivery." The value of a unit of QF power delivered at any given point in time is equivalent to the cost that the utility would have to incur to produce an equivalent amount of power at that time. This is the short run marginal cost of electricity production in the utility system. As this Commission discussed at length in a recent PG&E rate case, (D.93887, December 30, 1981), the short run marginal cost of utility electricity production is the highest variable operating cost per unit of electricity produced at a given time plus a shortage cost which reflects the effects of the added increment of production on reserve margins and reliability. As these costs are avoided through purchases of QF power, the purchase price paid to QFs under the first offer is tied to the short-run marginal cost. This will include an "energy payment" equivalent to the utility's margin operating cost and a "capacity payment" equivalent to the utility's marginal shortage cost. The purchase price, following the avoided short run marginal cost, varies by time of day and time of year.

The FERC rules also call for offers that are made "pursuant to a legally enforceable obligation...over a specified term...(with) the avoided costs calculated at the time the obligation is incurred." This type of offer thus takes the form of a long-term standard offer which must be based on projections of avoided costs. Such long term offers give greater certainty to both the QF and to the utility and its ratepayers. Following the same economic principles described above, we order long-term standard offers which are based on projections of the utility's short-run marginal costs. Such offers reflect the expected short-run marginal cost that the utility will avoid through purchases from QFs at each point in time over se[illegible]a time periods. The price includes an energy component which is tied to short run marginal operating costs in each period and a capacity component which is tied to short run marginal shortage costs in each time period. Energy payments are allowed for up to five years, firm capacity payments for up to thirty years. A levelized payment option is ordered for capacity payments.

A final long-term avoided cost offer described below is based on projected long-run marginal costs rather than short-run marginal costs. These offers should be roughly equivalent over time, since the utility's short run marginal cost can be expected over time to fluctuate around the utility's long-run marginal cost. The latter is defined as the capital and operating costs of marginal additions to the utility's generation capacity. The avoided cost price offer that is based on the long-run marginal cost will be a more stable pricing alternative and will place system capacity additions derived from QF investments on an equal footing with those derived from utility investments. This long-term resource plan-based price offer for firm energy and capacity will be for periods up to thirty years, with energy and capacity payments tied to the utility's long-run marginal energy and capacity costs.

We note in passing that while long-run standard offers can be based on either projected short-run marginal costs or projected long-run marginal costs, there is debate on the development of the long-run marginal cost. We will reserve for further review the proper relationship of energy and capacity in the long-run standard offer.

We are ordering utilities to file an array of offers based on different terms and conditions, and to provide reasonable notice of such offers. Just as most markets develop a combination of pricing arrangements ranging from a spot price to long-term contracts, we think it is appropriate that qualifying facilities receive a variety of standardized options to better serve their particular needs. In all cases, standard contracts should be based on avoided cost principles.

2. Standard Rates for More <u>Than 100 Kilowatts</u>

a. <u>In General</u>

The nature of the standard offer to QFs of more than 100 kW is the central issue in this proceeding. The adequacy of its terms will largely determine the extent of QF production. The flexibility of its terms will determine the extent to which parties resort to nonstandard contracts.

The term "standard offer" is itself an oversimplification. This decision directs that each utility offer a choice of contract terms at the seller's option. These choices are intended to be economically equal over the life of a contract. It is such equivalence that qualifies each as a standard offer.

The context for these choices is provided by FERC Regulation Section 292.304(d):

> "Each qualifying facility shall have the option either:

"(1) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or

"(2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:

"(i) The avoided costs calculated at the time of delivery; or

"(ii) The avoided costs calculated at the time the obligation is incurred."

Each of these choices is provided for in the "standard offer" as developed below.

b. <u>As-Available Contracts</u>

i. <u>Energy</u>

The utility's avoided energy cost at time of delivery in the as-available offer conceptually is based on short-run operating costs. It should reflect the variable cost of providing an additional unit of electricity. The methodology for actually calculating this number may be refined over time, as we become more sophisticated. Also, payments may be differentiated by time of use into more costing periods in the future as technology permits.

The utility's avoided energy cost at the time of delivery for most of the utilities is currently the product of the purchase price of oil used as the marginal fuel over the last three months and the forecasted incremental heat rates (IHRs) of the plants used by the utilities to follow load.

The intent of the energy prices is to capture as accurately and timely as possible the current marginal energy cost incurred by the utility. To accomplish this the IHRs will henceforth be calculated using the current resources of the utility without speculation on the operational date or operational characteristic of major new units. The impact of major new units will be included in the calculation of energy prices only when they have actually become operational, and actual operational experience will be used to assess the impact on marginal energy costs. This is consistent with the calculation of short-run energy cost which we recently adopted in the PG&E and SDG&E general rate decisions.

Staff believes the as-available energy payment by any utility should be uniform to all QFs, treating any adjustments in the aggregate. PG&E disagrees. It argues that differences between QFs should, where possible, be reflected in prices. It states:

> "Although a QF may pay for generation, transmission, distribution, and losses in its customer rate, it does not mean that its full avoided cost price should include all these items. . . .
>
> "Although certain costs are calculated on a systemwide basis for rate-making, it does not logically follow that they should be calculated on a systemwide basis for QF pricing.
>
> "It appears that FERC meant to discriminate among QFs based, to the extent practicable, on the factors outlined in Section 292.304(e). It is up to the Commission to decide the limits of practicability in reflecting these factors in purchase prices for QF power."

PG&E recommends that transmission and distribution costs not be incorporated in the standard price offers based on full avoided cost. It also proposes to evaluate line loss impacts on a case-by-case basis.

We adopt the notion of a uniform energy price. Transmission and distribution costs should be analyzed in the aggregate and appropriate adjustments made. We conclude that it is not practicable to treat such factors on an individual basis. Costs or savings resulting from variations in line losses should also be aggregated for standard offer purposes except for remote sites. It is unreasonable to reduce the payments to centrally located QFs because of higher line losses that are experienced by a utility in receiving power from a large remote QF. Losses will be examined individually for projects one MW or larger developed at sites remote from load centers where the incremental loss increase resulting from substitution of QF generation at the remote site exceeds 150% of average transmission system losses. Losses will be examined individually for such remote facilities.

ii. Capacity

The most controversial issue in this proceeding is the nature of the obligation to be undertaken by a QF in order to qualify for capacity payments. The general utility position is that energy provided by a QF on an as-available basis does not allow a utility to avoid any capacity costs. PG&E does recommend that utilities pay for as-delivered capacity at 35% of the current single-year capacity price, but states that this Commission must recognize that such a payment is intended to "encourage" the development of QFs. "The utilities will not be able to justify these payments as true avoided costs unless and until data not now available are collected and studied."

The intended beneficiaries of PG&E's proposal are not impressed. There is no recognition on their part that a 35% payment would "encourage" their participation. Two alternates have emerged: payments based on 50% or 100% of the capacity value.

Staff offers an analysis that suggests that the threshold question is philosophical - whether to treat QFs as an increase in supply, or as a reduction in demand. While various parties complain of the oversimplification that results from such labels, the concepts have proven analytically useful.

If QF production is treated as an increase in supply, objective performance standards are appropriate. "As an increase in supply, the value to the utility depends on whether the utility has control of the power (dispatchability), whether the electricity is reliable, is available for more rather than fewer years, is available during emergencies and so on." This is the approach favored by the utilities.

According to the staff, much more lenient requirements are appropriate if QF production is treated as a reduction in demand:

> "...the QF need not be dispatchable by the utility in order to qualify for the full avoided cost rate. The QF need not produce a certain predetermined reliability. The QF need not sign a long-term contract and be subjected to termination penalties and sanctions for noncompliance. The QF need not schedule outages with the utility, or supply power (decrease demand) during emergencies."

This approach is generally supported by prospective QFs and is characterized as consistent with marginal cost-based rates.

Staff does not propose to limit the reduction in demand approach to QF production serving only the QF's own load. It states that treating positive net input to the system as a decrease in demand is appropriate:

> "...(1) if one is willing to depend on the QF market and QF equipment to insure supply just as one depends on the customer market and customer equipment to insure demand; (2) if one views QF electricity as a reduction of the number of megawatts the utilities of California must supply (since demand is reduced) rather than as a fixed resource in the resource

> plans for California utilities; (3) if one believes the effect on the electric system is the same from a QF reducing demand on the utility (freeing utility plant for other use) as from a QF providing a positive net input; (4) if one believes the underlying economic forces will control the relationship without the need for objective performance standards; (5) if one is willing for ratepayers to assume some risk for the development and operation of the QF market comparable to the risk ratepayers now assume for utility-owned plants; (6) if it is administratively infeasible to enforce objective standards in some cases (especially very small QFs); (7) if one desires to give QFs the most freedom reasonable to build and operate their facilities according to the economic forces which permeate the relationship; (8) if full avoided cost rates do not allow the utility to control an investment owned by others; and (9) if the lessons of conservation have taught us that a reduction in demand is the same as an increase in supply."

Although the staff report discusses each approach at length, staff takes no position regarding this issue.

SDG&E supports the "increase in supply" approach and contends that this Commission is without discretion to do otherwise. It argues that the FERC regulations require the consideration of the particular factors enumerated in Part IV, A above, and states:

> "...it is practicable to apply many of the factors pertaining to capacity to the individual capacity rate. Staff would not apply some of the factors even though it is practicable to do so because of its philosophic debate as to whether QFs should be treated as an increase in supply or a decrease in demand. Since the PUC does not have discretion to refuse to apply a factor once it is determined to be practicable to do so, the debate should be pragmatically resolved in favor of treatment of QFs as an increase in supply."

SDG&E further contends that aggregate capacity is not practicably reflected.

Edison states that energy provided by a QF on an as-available basis does not allow a utility to avoid any capacity costs:

> "It would be imprudent indeed for a utility to defer or refrain from installing capacity resources on the mere hope or even expectation that enough as-available energy will be available when needed to meet the peak load imposed with a prudent reserve margin.
>
> "Prudent utility planning requires that sufficient committed capacity be available when needed to meet the peak load imposed with a prudent reserve margin."

. . .

> "Even if a QF is contractually bound to provide capacity resources, the length of that contractual obligation will determine how long a utility is able to defer a capacity installation, and therefore, the actual capacity-related cost which will be avoided."

Edison does support a "pay for performance" concept which Edison states "neither assumes a capacity value nor does it assume no capacity value." It is alleged to pay a QF for its true capacity value regardless of technology.

As stated earlier, PG&E does propose a payment for as-delivered capacity, though it contends that its proposal cannot be justified in terms of true avoided costs. PG&E expressly supports the "increase in supply" approach. It argues:

> "A QF willing to give PG&E more control over its generation by accepting performance standards and contractual obligations has a higher value to the utility. The performance of a QF selling contracted capacity will be measured to evaluate its equivalence to utility generation. In cases of Firm Capacity, it is PG&E's position that objective standards, termination provisions, and sanctions are absolutely necessary. Price alone does not provide sufficient incentive to deliver the capacity when it is needed."

PG&E proposes that QFs selling contracted capacity will be paid up to the full cost of a PG&E resource, and that such payment can be made on a levelized basis.

Nonutility parties generally support the "reduction in demand" approach. CEC states that the "demand reduction" model is clearly superior:

> "Treatment of (QFs), at least below 50 megawatts in size, as miniature power plants does not reflect the aggregate benefits to the system which result from their small size. We note that the aggregate experience of a group of (QFs) will be better than the experience of any individual (QF). This is a case where the whole is greater than the sum of the parts. This is particularly important for wind generation, where the dispersion of windmills over a large geographic area may result in more benefits to the system than the sum of individual windmill capacity values or individual windfarm capacity units. The key to correct pricing for performance of small units is recognition of the diversity of outages in small units. Utilities have recognized this diversity for years in developing rates and demand forecasts for customer classes; yet they by and large propose not to use this conventional analysis for small dispersed generators.
>
> "... The application of reliability and dispatchability criteria applicable to the supply model by utilities would result in underpayments to (QFs) relative to aggregate performance and even relative

> to performance of conventional power plants. Our detailed examination of the wind contract for PG&E, for example, indicates that if Rancho Seco were a windmill (or any type of (QF) for that matter), it would not receive capacity payments."

CEC supports a time-differentiated capacity payment in cents per kWh, paid for performance.

The Natural Resources Defense Council, Inc. (NRDC) also supports the "demand reduction" approach. It criticizes the "supply increase" method as overlooking:

> "...the difference in <u>size</u> of supply provided by a QF and a regular power plant. Where QFs are small their lack of availability will have far less impact on the utility system than would a failure by a major power plant."

It states that performance standards fail to provide recognition of reliability obtained by aggregate performance. "QF reliability will be increased by the use of time-differentiated rates, which will encourage QF generation during periods when it is needed most." Due diligence is cited as the only necessary condition.

MPS supports the "reduction in demand" approach as conceptually accurate:

> "Where the utility has no direct control of the customer's resource (generating equipment), the utility only experiences customer generation as a reduction of load. The utility serves a different demand curve than it otherwise would. Since the demand curve is the direct determinant of the utility's incurred costs, the alteration

> of this curve is the utility's avoided costs. It should be noted that the only effect experienced by the utility generating stations is the total reduction in system load caused by the instantaneous sum of all customer generation. This is an accidental result, exactly like the accidental result of all customer load, the traditional demand curve."

It argues that since both consumption and generation have exactly the same effect on the utility's load curve, the established method of regulation of sales serves as an excellent model for regulation of utility purchases.

Henwood Associates, Inc. (Henwood) agrees that "as available power will exhibit predictable patterns in a fashion analogous to customer demands."

> "... It should be recognized that this is a result which depends upon the number of QFs being present in the market-place and that a transition period will occur between now when few producing QFs are in existence and later when the requisite number of QFs have succeeded with their plans.
>
> "This transition period gives rise to an argument which (may be called) the chicken and egg argument. . . .
>
> "In essence this argument goes that without many QFs, the aggregate capacity value of as-available energy does not exist; hence no capacity payment is required.

> "This, of course, reduces the price paid to as-available QFs, thereby reducing the number of viable projects in strict conformance with well-accepted economic theory.
>
> "The ultimate result, of course, could be insufficient QFs ever to justify as-available capacity payments.
>
> "Now the converse to this argument is that if as-available capacity payments are made now, this may induce more QFs to come into being, thereby justifying these payments.
>
> "It appears that the choice of authorized payments revolves around the expectation of success or failure of the small power production program.
>
> "If success is expected, then as-available capacity payments are justified from the outset.
>
> "If failure is expected, these payments are not justified at the outset and could only be justified with later success of the program."

In view of the purpose of PURPA, Henwood argues that "success" should be a basic assumption underlying this decision.

Additional comments in this regard are offered by various nonutility parties.

We have quoted these parties at this length to indicate what we find to be compelling reasons supporting the "reduction in demand" model. Consequently, we will provide for capacity payments for as-available energy as part of the standard offer.

The "as available" capacity price we will adopt in this proceeding is based on the shortage concept as expressed earlier, which is based on the utilities' short-run marginal cost. The capacity then is consistent with "as available" energy payments, which are also based on short-run marginal cost. We agree with the parties who recommended that capacity payments be time differentiated, to reflect a higher price during peak periods when the possibility of shortages is greatest.

We are not dissuaded by SDG&E's legal argument that we lack discretion in this regard. As stated above, the standard rate must be "consistent" with the provision that certain specified factors shall be taken into account "to the extent practicable." One of the factors is:

> "(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system."

FERC plainly intends that aggregate capacity value be recognized.

We do not find that aggregate capacity has an equivalent value to firm capacity. To the extent that an individual QF is willing and able to contract to provide firm capacity additional costs can be avoided which should be reflected in the payment to the QF. These are provided for in the firm capacity offers presented below in which QFs receive full annual capacity payments based on specific performance commitments.

Having established the acceptability of a capacity payment for as-available energy, we now address the question of whether a QF producing electricity on an as-available basis is entitled to 100% of capacity value. If there is a capacity value recognized for as-available energy, staff recommends:

> "...initially a capacity payment be made in cents per kilowatt-hour assuming a 50% capacity value derived from full 25-30 year avoided capacity cost at 100% capacity factor. . . . That is, offers will be based on the assumption that every 2 kilowatts of installed capacity from intermittent sources provides for a flow of electricity which will allow the utility to avoid 1 kilowatt of capacity. The payment should be by time of delivery for large QFs and be at the option of the QF (depending on the meter the QF installs) for small QFs by either time of delivery or on an average basis."

As stated earlier, PG&E proposes that a 35% value be assigned. There is a wide difference of opinion among the parties regarding the resolution of this issue.

NRDC asserts that staff's recommendation undervalues QF contributions:

> "On the one hand, it could mean that a QF would receive a payment in cents per kilowatt-hour for the value of one-half of its installed

> capacity, operating at a 100% load factor. . . . However, the ambiguity of the wording could allow the interpretation that a QF would receive credit for only 50% of the capacity value actually provided."

It argues that QFs whose capacity factors typically exceed 50% should get corresponding capacity credit.

Several parties argue that the staff proposal is inadequate. Pan Aero Corporation (Pan Aero) argues that:

> "As to aggregate capacity value, the aggregate capacity value for as available capacity should be 100%, not the arbitrary 50% as recommended in the report.
>
> "Aggregate capacity should be prorated to cents per kilowatt-hour so that the full value is earned if the QF capacity factor is equal to the typical capacity factor of utility oil plants."

MPS agrees that 100% is the indicated capacity value and contends that even at that level QFs will be underpaid, "because of the inherent tendency toward daytime production possessed by all qualifying resources combined."

Metropolitan Water District of Southern California (MWD) argues that staff's proposal does not conform to FERC's intention that the fully avoided capacity cost be reasonably allocated, based on the QFs individual supply characteristics.

> "However, a reasonable allocation of the full-avoided capacity cost can be properly obtained through the staff's suggested option of time-differentiated capacity payments. Basically, this amounts to distributing the

> utility's full-avoided
> capacity cost by time period
> based upon a 100-percent
> capacity factor plant during
> each respective time period."

In this way the payments for capacity would be based totally on the performance by time period.

Edison supports the "pay for performance" concept which it contends renders unnecessary an assumed capacity value. Its proposed method is described as follows:

> "To be eligible for full
> capacity payment, a QF must
> attain a monthly capacity
> factor of 51% or greater by
> time period. The payment
> is based on the QF's monthly
> capacity factor by time
> period times the full capacity
> payment. Below 51% capacity
> factor, the capacity payment is
> reduced by 50%. The payment
> is then based on the QF's
> monthly capacity factor by
> time period times 25% of the
> full capacity payment, as
> the capacity factor of the
> QF increases or decreases,
> capacity payment increases
> or decreases proportionally."

This method is alleged to work regardless of technology.

SDG&E argues that the 50% aggregate capacity value is arbitrary and that it will be denied due process of law if such a value is adopted. It maintains its position that no capacity payment should be made.

The issue of the extent to which as-available energy will receive a payment for capacity value is inextricably related to the method used to estimate capacity value. Staff proposes that the capacity payments for as-available be in cents per kWh, by time of delivery and voltage, based on 25-30-year avoided capacity costs. SDG&E complains that there is no foundation for the assumption that QFs who supply aggregate capacity will do so for 25 to 30 years. It contends that:

> "To require current ratepayers to pay today's QF the value of a 25-30 year contract on the 'crystal ball' assumption that a new QF will replace him in the future to complete a 25-30 year term is again a blatant subsidy to the QF at ratepayer expense."

It argues that the length of the contract should determine the calculation of the appropriate capacity value.

PG&E proposes using the single-year capacity price, rather than the 25-30-year levelized price recommended by staff. It argues:

> "Our proposal results in a much simpler standard offer. If a single year value is used, there is no need for contract length, notice, termination or sanction provisions. If a levelized value is used, such provisions are necessary to recapture excess capacity payments if a QF fails to operate for the extended term. Under our proposal all QFs would be paid the correct amount regardless of the life of their project. A QF who

> operates for 30 years will receive the same life cycle payment as if he had been paid a 30 year levelized value. A QF who operates for 10 years will receive the same life cycle payment as if he had received a 10 year levelized payment."

Since the single-year capacity price changes each year, all QFs selling as-available energy will receive the same capacity price.

The consensus that does emerge from all of this is that the aggregate capacity payments should be based on performance, adjusted by time period. We agree that staff's proposed 50% value is ambiguous, arbitrary, and should not be adopted.

Instead we adopt a capacity payment for power from as-available sources equivalent to 100% of the shortage value of such power, as described in the following paragraph. This payment will be made in cents per kWh, will vary by time of delivery, and will be paid for each kWh produced and delivered by the QF. Thus actual performance will determine the amount of the capacity payment.

As we have already discussed, the capacity payment we adopt on an as-available basis is based on a short-run avoided cost methodology. We will therefore not adopt the staff's recommendation of a forecast of future year capacity costs, but instead require utilities to use estimates of current shortage costs. For PG&E, in its most recent rate case, 100% of the annual capacity cost of a gas turbine was estimated to be the correct proxy for current shortage costs. PG&E allocated this capacity cost by time of day and time of year in a way that reflects the shortage cost incurred by marginal additions to load in each time period over the year. This approach would appear to be appropriate for our present purposes. Accordingly, PG&E, Edison, and SDG&E shall determine the as-available capacity price based on the 1982 estimated cost of peaking capacity (utilizing a combustion turbine facility as a proxy). Sierra shall determine the as-availabl capacity price based on the avoided (marginal) capacity costs as determined in the most recent case.

Costs should include generation and generation-related transmission. Contract length, notice, termination, and sanction provisions are not related to as-available offers, and should therefore not be included.

Aggregate capacity value will be available as a cents per kWh addition to the energy price only for energy delivered through a meter to the utility. The QF choosing the interconnection option of simultaneous purchase and sale will receive explicitly an aggregate capacity value for all energy generated, as the entire generator output is metered at the generator before any energy goes to the QF's load and to the utility. Under the sale of surplus power option, however, the meter at the point of interconnection with the utility will only measure that surplus portion of the generator's output which is delivered to the utility after the QF serves its own load. Thus the QF will receive, in payments by the utility, only a portion of the capacity value for the total output of its generator. The remainder of the capacity value of the generator's output will, however, be recognized in the form of utility charges (including charges for capacity), which the QF will avoid by serving its own load.

There does appear in the record an issue regarding the appropriate capacity payment for small hydro facilities. Different treatment may be reasonable for hydro because of the probability that a large portion of the resource will fail simultaneously for an extended duration, limiting its aggregate value. The problem is compounded by a concern that hydro would be overvalued during wet years when capacity is relatively better than dry years.

The different points of view are summarized by Henwood:

> "...PG&E has proposed to use the absolutely worst year of record, 1977, to establish capacity values.

> "This naturally results in the minimum capacity value assignable to the hydro plant.
>
> "Staff, on the other hand, proposes to use the average of dry years.
>
> "Now, to my knowledge, there have been no conclusive studies ever performed which establish the best way to value hydro capacity in utility systems.
>
> "In fact, the Idaho Power Company plans capacity using the average hydro conditions, despite the fact that more capacity and more energy in their system comes from hydro than does in PG&E's system.
>
> "Since the industry itself values hydro capacity conditions nonuniformly, our recommendation is that much more thought, perhaps even in the form of a PUC or Energy Commission sponsored study into this area, should be given to the question before this very important and fairly permanent pricing treatment of hydro capacity contributions is set by the proceedings.
>
> "The other problem we see is when steam-flow gauging records are insufficient or unavailable, as is the case in many of the smaller projects being developed in California.
>
> "Of the seven projects our firm is currently involved in, only three have gauging records, and none of the projects have gauging records of a sufficient duration for PG&E's proposed 50-year water study."

We believe that capacity payments for as-available hydro should not differ from other technologies. Instead, as the methodology is perfected for calculating as-available capacity costs, the as-available payment should be low during wet years relative to dry years because the chance of shortages is lower in wet years.

Staff recommends the deletion of PG&E's Factor F-1, which makes adjustments to energy prices to small hydro QFs for the effect of hydro conditions on incremental heat rates and fuel inventory. PG&E argues that, if Factor F-1 is eliminated, its avoided cost prices would have to be increased. Its energy prices are based on forecasted avoided costs which do not consider cost impacts due to variations in hydro conditions. QFs generally oppose the imposition of Factor F-1.

We conclude that Factor F-1 should not be allowed. We are not convinced by PG&E's arguments that its computation of avoided costs should be modified by the elimination of Factor F-1. These arguments should be considered together with a complete examination of the computation of marginal energy costs in the compliance review to follow. Because most small hydro projects are in the planning stage, this delay will not have a significant cost impact to PG&E.

c. Long-Term Contracts

i. Energy

The FERC provides the seller of energy with the option of payments based on either (1) avoided costs calculated at the time of delivery, or (2) avoided costs calculated at the time the obligation is incurred. Payments under the first option should be the same as payments for as-available energy, as provided above. Payments under the second option require long-term energy price offers.

A major issue in this proceeding is the terms utilities should provide to QFs for commitments to deliver energy in future years. In this section we will discuss the issue of establishing a price for the energy portion of avoided cost based on a forecast of energy rates in the future. Many argued that utilities should commit in advance to future energy rates, and further recommended that the Commission order a levelized payment option as well.

A long-term energy price offer allows both a QF and the utility the certainty of a known price which can be valuable for planning. We therefore will order utilities to file a proposed price offer which commits both the utility and the QF to energy payment prices for up to five years, based on a forecast of the utilities' variable costs. Under such an offer, the QF must commit to provide all the energy it produces to the utility over the contract period. We will order the offer to be a proposal for review in hearings by other parties before it becomes effective. This price offer will be available to all QFs.

Staff proposes that the QF be allowed the further option of levelizing the price so that a greater portion of the total payment is received in the early stages of the contract. FERC comments addressing this provision expressly provide for the levelizati option:

> "A facility which enters into a long term contract to provide energy or capacity may wish to receive a greater percentage of the total purchase price during the beginning of the obligation. For example, a level payment schedule from the utility to the qualifying facility may be used to match more closely the schedule of debt service of the facility. So long as the total payment over the duration of the contract term does not exceed the estimated avoided costs, nothing in these rules would prohibit a State regulatory authority or nonregulated electric utility from approving such an arrangement."

Thus we have the discretion to provide for levelized payments as part of the standard offer.

Edison opposes levelized energy payments. It characterizes the necessary estimates as "purely speculative", and not reliable. It argues:

> "Paying levelized costs for an increasing cost stream is unfair to present ratepayers because it results in paying for a benefit before that benefit accrues. Even five-year levelizing has this effect, and the proposed ten-year levelizing, coupled with the total inability to accurately predict future fuel costs, represents an impermissible burden on ratepayers and is not necessary to encourage QF development."

Edison proposes that if levelized payments are required, the payments should not be allowed to exceed 85% of avoided energy costs levelized over a period of not more than three years.

PG&E also opposes levelized energy payments because it "presents too many risks" for the ratepayers. It agrees that if the Commission requires such payments, a reduction from the avoided cost should be authorized. It further recommends:

> "Energy contracts under such circumstances should be limited to an appropriate term. This will reduce exposure to forecast uncertainty and early termination due to a QF's failure to perform. The potential overpayments using levelized energy prices are enormous, and in the event of early termination, large sums will have to be recaptured from the QF."

The problem increases as the length of term increases.

PG&E also recommends that levelized payments not be available to cogenerators using oil or gas.

> "Because of the high operating costs of these facilities, the QF's revenues must escalate to track the increasing project fuel costs. If a levelized energy payment is available to QFs using oil or gas, it is likely that those QFs will begin incurring operating losses before the end of the contract life."

It warns that QFs will not continue to operate merely because they made excess profits in the early years of their projects.

PG&E does not necessarily oppose all forms of levelized energy payments. It proposes that in the case of nonstandard contracts, it can assess the ability of the QF to perform over the duration of the levelization period and provide for such payments if appropriate.

SDG&E also opposes levelized payments. It warns that "levelized energy payments will result in up front financing as overpayments will occur in the early years."

Several nonutility parties support levelized payments. California Energy Commission (CEC) analogizes levelized payments to insurance contracts, and argues that ratepayers and QFs both benefit, assuming forecasts are reasonable. Ratepayers

> "...cannot gain if costs are less than forecast, but they are also protected from higher avoided costs than with fore-casted and protected from consequent economic losses.

> "This isn't putting a risk on the ratepayers. It is giving them certainty. At the same time it also protects the QFs.
>
> "The QF doesn't gain if the utility underforecasts and oil prices are actually higher, but the QF is protected from losses if the utility overestimates future costs."

CEC does agree with PG&E that levelized payments should not be made to QFs using oil or gas as a fuel.

Levelized payments are also supported by the jointly filed comments of Great Western Malting Co. and Windfarms, Ltd. (Great Western). They consider such payments "critical" to some QFs for financing purposes. They oppose the discounted payments proposed by the utilities:

> "The utilities' argument that levelized energy payments should be discounted incorrectly assumes that the risk that levelized payments will inaccurately forecast actual energy costs falls solely on utilities or their ratepayers."

They contend that the QF also takes a substantial risk that actual costs will exceed estimated costs.

They further object to the argument that a discount is appropriate because large numbers of QFs will not fulfill their contracts. They characterize this premise as based on unsupported assumptions.

We conclude that levelized payments should not be included as an option under the standard offer. We recognize that levelized payments can encourage QF development by improving QF access to financing, and therefore consider this type of payment schedule to be desirable in some cases. However, because levelized payments can create added risks for ratepayers and because the magnitude of this risk depends completely on the specific QF project in question, we find that levelized payments are more appropriately considered by the utility and, if necessary, the Commission on a case-by-case non-standard contract basis.

Levelized payment schedules create potential risks to ratepayers that are not present in other types of long term QF contracts such as that adopted above. In the process of paying the QF prices in excess of avoided costs in the early years of the levelized contract, the utility and its ratepayers bear the risk of contract non-completion due to project failure. If a contract is terminated early because of project failure, the ratepayers will have paid costs in excess of the value of the power received and will not receive that countervailing benefits that would normally accrue during in the later years of the levelized contract. The degree of such project risk that is actually present can be expected to vary significantly from one QF to another, and will depend on the technical and economic characteristics of the specific QF project. Therefore, it is not appropriate to offer this payment option on a uniform basis to all QF's under a standard offer that is deemed per se reasonable for ratemaking purposes. Rather, such risks should be considered by the utility on a non-standard contract basis after review of the specific QF project in question. If necessary, such contracts can receive Commission scrutiny under our non-standard review process.

The non-levelized energy payments under the long term energy price offer described in this section may be tied to either as available capacity payments provided for in the last section, or to a firm capacity payment using a short run avoided cost methodology, which we will describe next.

ii. Firm Capacity

As stated above, FERC regulations provide for payments for firm capacity, based on avoided costs calculated either at the time of delivery, or at the time the obligation is incurred. There is no hesitation on the utilities' part to pay for firm capacity, within the limitations of their own resource plans. For standard offer purposes firm capacity is properly recognized as an "increase in supply" with corresponding standards, termination providions, and sanctions.

The firm capacity payment properly reflects the factors recited in Part IV, A, above related to the availability during the system peak periods, including:

a. Dispatchability,

b. Reliability,

c. Contract duration, termination, and sanctions,

d. Scheduling of outages, and

e. Availability during emergencies.

The value of each of these factors shall be calculated, based on standards comparable to performance standards the utility would impose on its own plants. These standards must, however, be fair to QFs and not impose unnecessary burdens that will discourage that development of these preferred resources. The sum of each of these factors and the resultant capacity value will be offered on both a dolla per kW per year and a cents per kWh basis as currently done. A QF that exceeds operating standards normally expected of utility plants should be able to earn a higher capacity payment.

The firm capacity contract may be tied to energy payments as-delivered (similar to the energy payment in the as-available section) or to a contract for energy payment in future years as provided in the previous sections. The firm capacity payment discussed in this section is based on a short-run marginal cost methodology, in which the capacity payment reflects the costs of a shortage.

Both the firm and the as-available capacity payments ordered by this decision are based on the shortage cost concept. However, QFs with firm capacity contracts may receive a higher payment than QFs with as-available contracts. For example, a QF with a firm capacity contract that operates with a capacity factor similar to utility plant could receive the full annual capacity payment. As-available QFs would receive only a percentage of the annual capacity value for similar performance because the annual capacity payment is allocated in cents/kWh for as-available capacity.

The value of firm capacity will be based on the avoided (marginal) capacity cost used in the utility's last general rate case.

As discussed above, FERC allows for the option of levelized payments if the QF chooses payment based on avoided costs calculated at the time the obligation is incurred. The option for levelized capacity payments for periods up to 25 to 30 years as currently offered, should remain.

Dispatchability will be achieved in price offers by time basing capacity and energy prices and by requiring the QF to maintain availability during peak load periods with a reasonable allowance for forced outages. QFs will be expected to operate at maximum capacity on notice to meet utility needs for capacity during peak load periods and emergencies, consistent with limitations which may exist at the time in the QF's equipment or fuel, water, wind or other source of energy supply. Cogenerators also will, at times, have limitations on their ability to utilize the process heat produced at maximum capacity.

For receipt of a firm capacity payment, reasonable contractual requirements for reliable operation and availability during utility system peak load periods are necessary where QFs are to receive the full avoided cost capacity value. Contractual requirements must, however, be simple and not restrictive to the point of seriously discouraging QF development. QFs should not be expected to operate with a reliability greater than the utility plants they displace. Likewise, the QF can be required to maintain an availability during system peak and mid-peak load periods comparable to, but not greater than, utility plants displaced. Where resource limitations exist to reliable operations, such as with wind parks, plant capacity factor may be a better measure to use in contractual requirements for reliable operation.

In discussing rates for supplementary and maintenance power, we determine that demand charges incurred during periods of scheduled maintenance should be waived during such periods under tariff schedules for standby service. It is waiver applies to QFs selling surplus power to the utility. It is reasonable for a utility purchasing firm capacity from a QF to require that the QF schedule maintenance of that generation during periods established by the utility. The utility will provide reasonable periods for QF scheduled maintenance and only request deferments in the customer's requested maintenance schedule on 60 days' notice. Capacity payments will not be reduced during scheduled maintenance periods. QFs on simultaneous purchase and sale contracts will continue to pay for any energy (kWh) and demand (kW) used during scheduled maintenance periods at regularly filed tariff rates.

Special provisions are necessary for small hydro QFs offering firm capacity to reflect adjustments for dry year unavailability. Two options shall be offered hydro QFs larger than 100 kW for determining their base stream flow and monthly firm capacity rating. Option 1: the QF may use flow data directly applicable to the QF's facility, when available. Alternately under Option 2 the QF may use the flow data for the closest adjacent and similar area to the QF's facility. Capacity values for Option 2 shall be developed by areas sufficiently limited in size so that the true value of local areas is not lost or obscured. Capacity values for Options 1 and 2 shall be paid in dollars per kW per month and shall be subject to the provisions required for firm capacity.

For Options 1 and 2, the minimum June through August flow, from which the monthly firm capacity rating is derived, will be based on the five lowest flow years, as proposed by CEC, taken from a 50-year minimum continuous record. Where 50 years of data cannot be developed, utilities and QFs should agree upon a shorter time period with fewer minimum flow years averaged into the monthly capacity rating.

The price offering for small hydro QFs should include an illustrative example of the development of monthly firm capacity ratings based on dry years stream flow data. The price offer will also specify the data on stream flow required by the utility.

In its preliminary report staff recommended that utilities be required to provide QFs the option of a full capacity payment "up front", because the utilities would make such investments in the absence of QF development. The reaction of the parties was mixed. In its final report staff recommended that up-front capacity payments not be required as part of the standard offer.

Several parties continue to support up-front payment. The California Manufacturers Association (CMA) suggests that:

> "...in some cases it may also be appropriate to provide the QF the option of an up-front payment. An equitable method would be to place these payments in rate base amortize them over the life of the contract, and remove them from rate base using the same standards and procedure for removal of utility plant."

The risk for the utilities would be largely eliminated.

CEC originally supported up front payments but, like the staff, changed its position. The utilities unanimously object to up front payments, arguing generally that the resulting financial outlays would strain their financing abilities while imposing an additional risk relative to the capability of a QF to perform.

Staff considers this issue deserving of further study.

> "The complexities of the issue of up front capacity payments deserve additional research before such payments are required as options in standard price offers. This research will accomplish such objectives as identifying and analyzing: (1) the conditions under which such payments would financially strain utilities; (2) the implications of putting such payments in rate base; (3) the juxtaposition or fairness of the utility being somewhat like an owner (having paid the utility's avoided capacity cost which may pay most or all of the QF's capital investment costs) but not having control of the facility's management or operations; (4) the actual usefulness of up front capacity payments since such payments as now proposed would be at the first operation of the QF (after

> construction and financing are complete); and (5) the proper assessment of risk (such as QF risk from proper avoided cost calculation, recognition of only the risk to ratepayers of QFs, or a net assessment including the risk to ratepayers of utility operations)."

In the meantime staff expects utilities to develop prudent alternatives to the standard offer and suggests that innovative proposals be considere by this Commission in its evaluation of utility efforts to develop alternate energy sources.

We are satisfied that up front capacity payments are not reasonably included as part of the standard offer. We agree that such payments could introduce an element of substantial risk into the standard offer. Since the QF has sole choice among the standard offer provisions, the utility would be precluded from exercising discretion regarding the suitability of a particular QF in regard to its ability to perform. Such discretion is critical to orderly undertaking of such risks.

Such payments are reasonably considered outside the context of the standard offer. Utilities are free to agree to such provisions on a negotiated basis and to seek whatever ratemaking treatment may be shown to be reasonable. There is no need for additional study of this issue.

iii. Energy and Capacity: Long Run Marginal Cost

Several parties addressed the problem of matching together the appropriate energy and capacity payments to ensure the QF is paid the full avoided cost. This issue is of particular concern to QFs that wish to enter into long-term contracts without ending up in a situation where their payments are based on a combination of today's low capacity cost (based on a gas turbine) with low energy costs in the future (due to new baseload generation). The problem is discussed by staff, but in the opinion of Dr. Harry Davitian, representing the San Diego Energy Recovery Project (SANDER):

> "To phrase the problem with the staff's approach in its simplest form, there is no connection made between the computation of avoided energy costs and the computation of avoided capacity costs, even though in actuality there is a direct relationship."

Davitian contends that since utilities are emphasizing the construction of capital intensive, low variable cost capacity, the bulk of the costs avoided in the future will be related to capital investments in the purchase of capacity, not to variable costs. A computational approach that does not adequately reflect such savings in capacity costs will not provide the proper pricing signal to cogeneration and small power-producing facilities.

Davitian asserts that the staff's approach is impossibly vague. He proposes a method called a "differential revenue requirement approach", which he describes as follows:

> "...the utility's total annual costs, including all fuel, operating and maintenance costs, capital amortization, taxes, etc., are estimated, both with and without a projected contribution of power from the qualifying facility or type of qualifying facilities.
>
> "The difference in the two costs is directly attributable to the contribution of power from the qualifying facilities.
>
> "To properly account for the changes that might occur in the utility's capacity purchases, purchase power agreements, sales of power agreements and the associated changes in energy costs, a capacity exchange model is used in this type of calculation.
>
> "In each year of the study period, a differential cost can be established and can be expressed in terms of cents per kilowatt-hour of power provided by the qualifying facilities."

The energy and capacity components of the avoided costs can then be derived.

Great Western also complains that staff's proposed methodology is not adequately explained. It offers its own proposal for matching energy and capacity:

> "Capacity payments, on either an as-delivered basis or by contract, should reflect the avoided costs of a utility building a plant solely for capacity, i.e., the avoided cost of a combustion turbine or combined cycle facility. This sort of a plant would remain the yardstick for the capacity payment throughout.
>
> "The energy payment should be made up of two components. First is the utility's avoided running costs for its marginal plant - the costs of fuel, operations and maintenance, etc. Second, if the marginal plant in the utility's resource plan is something other than a low capital cost combustion turbine, the additional capital costs of that plant, over and above the capital costs of a combustion turbine, should be allocated to the energy payment. This accurately reflects the fact that, when a utility expends the additional capital necessary to construct a coal-fired thermal plant, for example, it is doing so not simply to build capacity but to reduce future energy costs. If the utility simply

> wanted to build capacity, it would build a low capital cost combustion turbine. The additional capital spent should therefore be considered an energy cost. Thus, if this additional capital expense is avoided, due to the fact that QFs are generating electricity, that fact is properly reflected in the energy payments to QFs."

In addition to linking energy and capacity payment, this method is alleged to reflect a utility's actual resource plan and therefore its actual avoided cost.

As we discussed in the introduction to this section, we stated that avoided costs can be developed based on a short-run concept or a long-run concept. Either concept is appropriate for developing standard offers assuming suitable terms and conditions are associated with the offer. The offers discussed thus far in this decision are based on short-run avoided costs. Because of the concern of the parties that short-term avoided cost may be too volatile, and may not adequately reflect the QF's value in the utilities' long-range resource plans, we acknowledge the desirability of an offer based on long-run avoided cost principles. Therefore, we will order utilities to file a proposed offer using long-run avoided costs within 90 days of this decision date.

In order to assure full examination of alternative approaches in the evidentiary proceeding, PG&E, Edison, SDG&E, and PP&L are directed to develop avoided costs and a price offering based on their resource plans. The cost data and price offering should allow up to a 25-year contract with a firm pricing structure for capacity and energy. Long-run marginal cost estimates will be based upon the fixed costs associated with the utility's resource plan and its system projected marginal operating costs. The recommendations of Davitian and Great Western are also to be analyzed by the utilities and discussed in their presentation.

iv. Bond Guarantees

CEC argues that the standard offer should also provide for cost-based bond or loan guarantees.

> "A cost-based loan or bond guarantee is a contingent liability underaken by a utility at its cost which guarantees the repayment of a bond or loan for a (QF). Given the utilities' size and position in the typical power sales agreement, they can 'package' projects that need these guarantees for 'reinsurance' with other investors, or self 'insure' with sinking fund type accounts levelized over the project.

> "Bond or loan guarantees may be the only way in which many municipalities and smaller developers will be able to get their projects financed and constructed. This is due, in part, because of the impossibility of marketing bonds, particularly municipal bonds, even for economically justified projects, without guarantees for the debt from some organization recognized as financially acceptable by the financial community."

It warns that without such "standardized" terms the utilities will "negotiate" discounts from their actual costs.

The CEC's proposal is one of many conceivable financial arrangements which could assist development of qualifying facilities. The problem with adopting such a loan as part of the standard offer is that the risks associated with the loan guarantee will vary by project, making it impossible to fairly standardize terms. For this reason, we will not adopt the CEC's proposal as part of the standard offer, but rather allow such proposals to be negotiated as nonstandard offers. With existing avoided costs offered as a foundation for negotiation between utilities and QFs, we believe these negotiations can be undertaken fairly.

will be limited to 600 hours per year of paying a price lower than the published avoided cost price or refusing deliveries under conditions of maintenance or minimum load. Utilities that choose to pay lower prices would be required to pay prices higher than the published avoided cost price when actual avoided costs are higher than the published price for up to, but no more than, 600 hours per year.

Staff further recommends that utilities propose a notification procedure that will provide adequate notice to QFs of times of nonpurchase and prevailing prices. A list of periods of anticipated nonpurchase is suggested so that QFs would be able to schedule maintenance to coincide with such periods. A minimum of 48 hours notice is proposed for QFs with baseload or intermediate-type plants. A minimum of two hours notice is suggested for QFs with peaking-type plants.

Nonpurchases are proposed to occur in the following order of priority: first, small power producers who can inventory fuel; second, topping cycle cogenerators who can bypass the electric generation and save some fuel; third, bottoming cycle cogenerators and small power producers where fuel cannot be stored.

Staff further proposes that each utility be required to present a report in every ECAC proceeding explaining and supporting periods when prices are lower than published or when nonpurchase occurs.

PG&E proposes:

> "Utilities shall not be required to accept power from QFs during (1) emergencies; (2) times of pre-announced maintenance on the utility system which are limited to the

> shortest possible duration; and (3) operating conditions of minimum load on utility plants, the continued operation of which is necessary to serve anticipated daily load swings. Such minimum operating conditions include operation of geothermal facilities, utility dispatched hydro-electric facilities and firm purchases to obtain optimum use of these resources.
>
> "To account for the availability of economy energy, which is energy purchased by the utility at a price below the Standard Offer published prices, utilities may either:
>
> "a. Calculate their avoided energy cost to include an annually expected number of hours of economy energy. During periods when economy energy is available, the utility shall not refuse to accept QF energy deliveries based upon price; or
>
> "b. Offer the lower avoided cost price to QFs when economy energy is available and only curtail, and not pay for, energy and As-Delivered Capacity (if the QF has chosen that option for capacity payment) made available by a QF which refuses to accept the lower price."

It would limit the number of hours of nonpurchase or lower prices to 600 per year.

PG&E also agrees that a report should be filed in ECAC proceedings (though not as detailed as proposed by staff) and with staff's recommendations regarding notice to QFs and priority of refusal to purchase.

Edison states that it is concerned with the possible impact of paying published avoided costs to QFs when lower cost energy is available. It indicates that during such periods, the lower cost energy may be substantially below the cost of energy produced from the low sulfur fuel oil. It warns that a utility would be severely criticized if it were unable to meet its public utility obligation to its customers to provide lowest cost power, and an unjustified burden would be placed on the utility shareholder if the avoided cost payments were not recoverable in an ECAC proceeding. It concludes that payment at prices below published avoided cost, when its true avoided cost is less than the published price, is consistent with PURPA and FERC regulations.

SDG&E contends that "if the energy payment tables are properly calculated, the actual avoided costs to the QFs will be properly reflected and paid." It suggests that the problem of nonpurchase for economic reasons can be resolved through proper costing periods. By adopting a "super off-peak" reflecting anticipated periods of low cost energy, the times when avoided cost energy rates would be so far out of line with actual avoided costs to justify refusal of deliveries would be minimized.

SDG&E does support the ability to pay at less than published costs for certain maximum hours during the year, and accepts 600 hours as reasonable.

SDG&E states that staff's recommended notice requirement is "excessive". It offers two-hour notice for baseload and 30-minute notice for peaking units as "more realistic." It also objects to staff's nonpurchase priority. It argues that "curtailments must be based only on size, from largest to smallest. In an operational emergency, it is impossible to spend time deciding who has fuel capabilities and who does not."

In general, we find that the utilities have interpreted this provision more liberally than apparently intended by FERC. The language of the regulation expressly limits its application to periods when the choice is between a QF and self-generation. There is no recognition of economy energy purchases.

This interpretation is supported by FERC comments:

> "This section was intended to deal with a certain condition which can occur during light loading periods. If a utility operating only base load units during these periods were forced to cut back output from the units in order to accommodate purchases from qualifying facilities, these base load units might not be able to increase their output level rapidly when system demand later increased. As a result, the utility would be required to utilize less efficient, higher costs units with faster start-up to meet the demand that would have been supplied by the less expensive base load unit had it been permitted to operate at a constant output."

This concern does not appear to contemplate economy energy purchases.

This issue must be addressed in the context of the standard offer options described above. The QF may contract to be paid on the basis of "the avoided cost calculated at the time of delivery." The right to not purchase arises only when that cost is less than zero, a negative avoided cost.

The QF may instead contract to be paid based on "the avoided costs calculated at the time the obligation is incurred." This method yields the sort of "published prices" apparently referred to in the various comments. There is no basis for refusing to purchase from such QFs merely because actual avoided costs occasionally go below published prices. There is just as much of a chance that actual avoided costs will be occasionally higher than published prices. Allowing for nonpurchase in the first instance without providing for a higher payment when appropriate is unfair. Providing for both higher and lower payments is inconsistent with the purpose of the option to be paid based on avoided costs calculated at the time the obligation is incurred. Therefore this QF should be refused electric purchases only when the avoided cost is negative.

QFs have expressed concern that there may be no maximum number of hours during which refusal to purchase energy may occur. They feel this may result in financing problems (among other problems) since the utilities then are viewed as having an open ended opportunity to refuse purchases. A refusal to purchase would, of course, be subject to Commission review as provided by FERC. A more pragmatic method is required to allay these concerns. First, this decision will order that refusal to purchase, except in cases of emergency and scheduled maintenance, shall be limited to QFs of 1 MW or larger. Second, a refusal to purchase should only occur when a negative avoided cost occurs. Refusal to purchase should only apply in certain narrowly defined circumstances, unlikely to occur more than 100 hours per year.

Staff earlier recommended limiting the periods when a utility could pay a lower price or refuse to purchase to a time period "up to 600 hours" per year. Since the avoided cost price will reflect estimates of periods when avoided costs are higher or lower due to low load and high availability of hydro, periods need not be allowed during which a lower price is paid. In fact, FERC rules do not appear to allow utilities to pay a lower price during selected periods.

The earlier 600-hour limit stemmed from a PG&E estimate of the maximum number of hours in a high rainfall year that their hydro plants would otherwise need to be curtailed and spill water. FERC rules require that the utility experience a negative avoided cost situation to permit nonpurchase. However, a negative cost would not occur when a utility curtails its own hydro. There remain few instances where negative costs would occur. For example, if a baseload or a large oil-fired intermediate load plant were shut down at night, due to an excess of QF electricity, but then could not be restarted and brought up to its rated output for the next day's peak load, and necessitated instead startup of a plant with very high generating costs (e.g., a gas turbine peaker or an expensive emergency purchase of capacity), the cost to meet the day's peak load might substantially exceed the avoided cost of the previous night's shutdown, thus giving a "negative avoided cost". A proper generating mix, including intermediate load plants of various sizes and possessing the ability to be throttled and even cycled should, in most cases, prevent occurrence of a negative avoided cost situation. It is recognized, however, that QFs need assurance at the outset of a reasonably small time period for nonpurchase. While no limit is specifie herein, we do not think refusal periods, as defined, will be more than 100 hours per year and we will monitor utility actions.

FERC provides for effective notice to the QF so that the QF has ample time to cease delivery. In this respect we consider SDG&E's proposed two-hour notice to a baseload facility inadequate. The notice proposed by staff and PG&E is reasonably fair to the QF while remaining within the utility's planning horizon. No recovery will be allowed for payments resulting from insufficient notice unless the utility proves it was unable to provide greater notice, and that it attempted to make economy energy sales of the QF's power. We agree that QFs should be assigned priorities, in anticipation of the possibility that only partial restriction would occur. Staff and PG&E propose establishing priorities by technology. SDG&E proposes that size determine priority.

We are not persuaded by SDG&E's contention that it cannot consider fuel capabilities at the time of nonpurchase. We suggest that the time to consider such matters is during normal operating conditions when a priority scheme can be developed for later use. Refusal to purchase by size would be no more workable. The ability of the QF to function independently during times of nonpurchase is entirely the responsibility of the QF.

Thus we adopt staff's proposed priorities with modifications to reflect the more limited conditions we have established under which purchases may be refused. Specifically, while we recognize that an advanced notice of 48 hours for QFs with baseload or intermediate plants and two hours to QFs with peaking plants is a reasonable criterion there may be situations where 48 hours' advanced notice is not possible.

The notification procedure serves a second purpose. It also alerts the utility of a pending condition that should direct it to consider the opportunity to make economy energy sales. Before refusing to purchase from a QF, the utility should undertake to make such sales on behalf of the QF. We expect that the utility will undertake prudent planning to prevent negative avoided costs from occurring. The negative impact associated with the below minimum load condition suggests that prudent planning would entail arranging for economy energy sales as a margin of safety.

One distinction does arise between QFs for nonpurchase purposes, related to the particular form of standard offer. There is no capacity obligation during times of nonpurchase for as-available contracts. The obligation to pay for capacity during these times applies only to firm capacity contracts.

The orderly review of the application of these procedures requires that a report be filed by each utility in conjunction with its annual ECAC review. Utilities without ECAC proceedings will file an annual report no later than each January 31 to cover the preceding calendar year. In this regard staff proposes that the report include at least the following:

a. The hours and duration of nonpurchase;

b. The amount of energy not purchased;

c. The utilities to which the electricity was offered for sale;

d. The prices at which the electricity was offered for sale;

e. The prices at which the neighboring utilities were willing to buy the electricity;

f. The QFs whose power the utility refused to purchase;

g. The lower prices offered to the QFs which the QFs refused;

h. A statement from each QF certifying the QF was notified within 48 hours for a baseload or intermediate QF and within two hours for a peaking QF, and that the QF actually refused the lower price;

i. The operating conditions under which the utility invoked the refusal to purchase and which required the refusal; and

j. A statement from each neighboring utility explaining their operating conditions at the time of the refusal to purchase which prevented them from taking the electricity at some mutually acceptable price.

PG&E and SDG&E object to various provisions as excessive and burdensome.

Paragraphs (h.) and (j.) do provide for information not in the control of the reporting utility. To that extent we agree with PG&E and SDG&E that such information should not be required. In addition, ascertaining the exact amount of energy not purchased, as called for in Paragraph (b.), may prove difficult; therefore, estimates of these amounts will be sufficient. We also decline to adopt the staff's position which led to the recommendation contained in Paragraph (g.). However, the remaining items relate to data that is in the control of the utility and that should be gathered in the ordinary course of its business. There is no apparent hardship related to providing such information, at least during the early stages of QF development. We will require inclusion of these items in the annual reports. The report should also state the hours of advanced notification given each QF for each nonpurchase and, in cases where the prescribed minimum notice was not given, an explanation of why more extended notice could not be given.

f. Simultaneous Purchase and Sale

Simultaneous purchase and sale is a regulatory convention that allows a QF simultaneously to sell its own generation to the utility while purchasing its requirements from the utility. It is intended to respond to the situation where the retail rate is less than the avoided cost, by providing that the QF receives the full benefit of avoided cost pricing principles. The QF is not required to separate its load from its resources to qualify. The electricity flow is the same regardless. The difference is cash flow. Staff recommends that the QF have the opportunity to convert to and from simultaneous purchase and sale as it deems necessary, to protect itself from future regulatory and utility changes and future rate and tariff changes.

PG&E warns that indiscriminate switching between options by a QF will place unreasonable burdens on the utility. It agrees that the right to convert is reasonable if the following procedures are applied:

"1. The QF will be subject to the terms and conditions of all applicable filed tariffs and contracts in effect covering the existing and proposed facilities used to serve and/or interconnect the QF's project.

"2. The QF will be required to reimburse the utility its out-of-pocket costs, with appropriate credits, resulting from any change in the utility's facilities required to accommodate the QF's change in sales option. Increased or decreased interconnection and service facilities will usually require new agreements and result in an adjustment of charges to the QF to meet such new requirements. Where the QF's switching of sales options will render the utility's facilities idle in whole or in part, the QF may elect to do one of the following: (1) pay the utility to rearrange its facilities to meet the new and reduced requirements, or (2) with the utility's approval, pay the utility to reserve any excess capacity in its facilities. Such charges will be in addition to any other utility charges applicable to the QF's new service requirements.

"3. The QF will provide the utility with reasonable and appropriate notice of its new requirements brought about by any switching in sales options in order to allow the utility adequate time to accommodate the QF's request."

It provides an example that illustrates its proposal.

SDG&E agrees that simultaneous purchase and sale is a required option, but takes a much less flexible view regarding switching.. It proposes that the QF make the election at the time the contract is made and that no switching be allowed. It argues:

"If no election were required at the one time of execution the utility would be unable to forecast sales and revenues in a general rate application. It seems unlikely that a filing which contains substantial sales variances depending on how the final revenue is allocated, would be acceptable to the Commission.

"A failure to make such a firm election would also allow any QF to at least partially thwart Commission policy being implemented in these

> rates. For example, had this policy been in effect when the Commission ordered implementation of Time-of-Use rates, the QF could have avoided such rates by ceasing to sell and using its own generation. SDG&E supports the position that any customer can avoid Commission policy by generating for his own use. However, a QF who wants to take advantage of Commission purchase policy through simultaneous purchase and sale should be subject to Commission policy on the sale side as well."

It contends that allowing the QF to switch results in an unreasonable burden on other ratepayers and the utility.

We agree with the staff in principle that the QF should be able to convert to and from simultaneous purchase and sale unless the QF has selected forecasted or levelized energy payments under a long-term contract. In such cases, the QF must commit its entire output to the utility. Conversions should be limited to once per year as is currently the practice under Rule 12 for changing rate schedules.

We agree with PG&E that in practice the conversion must be conditioned on reasonable notice and full compensation. Notice requirements should not be excessive. However, if the interconnection and metering installed for selling surplus power are not compatible with simultaneous purchase and sale, a longer delay may be necessary for conversion. The QF may also encounter additional interconnection costs if conversion of the original wiring and metering is required. The QF that pays for a more costly interconnection and metering arrangement under simultaneous purchase and sale and then converts to selling surplus power would not be able to recover the additional costs except in terms of a salvage cost. The QF that receives capacity payments under simultaneous purchase and sale through a long-term contract and converts to sell surplus will face termination provisions.

g. Exceptions

The foregoing discussion addresses the matter of the terms of the standard offer to be applied to facilities of more than 100 kW. There remains the matter of how these principles will apply to Sierra and Pacific Power & Light Company (PP&L).

We discussed earlier Sierra's concern that QF production causes certain potential problems because of its size, location, and configuration. We consider the import of its position to be that its actual avoided costs are susceptible to substantial fluctuations depending on the number and size of prospective QFs. This problem is best resolved by excusing Sierra from the obligation to provide a standard offer to QFs of more than 100 kW. Instead, Sierra will be allowed to contract with each on a nonstandard basis that reflects the actual costs avoided by each QF consistent with the avoided cost principles in this decision.

PP&L asks for some form of exclusion or waiver from some portions of the final staff report and this decision. It contends that PP&L is "entirely unlike the model utility that is assumed to exist in the staff's final report." It argues that "the utility assumed to exist is an oil-fired geographically centralized utility, one that uses oil as a primary source of energy, one that serves a relatively centralized and contiguous territory." It cites a number of factors that distinguish it from the others.

We agree that PP&L is different in material respects. We therefore order the utility to propose a standard offer for review by parties based on its avoided costs. We will determine what additional action to take after reviewing its filing. We will not order the utility to adopt the specific standard offers filed in this decision at this time.

3. Standard Rates For 100 Kilowatts or Less

FERC Regulation Section 292.304(c)(1) provides:

> "There shall be put into effect (with respect to each electric utility) standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less."

Such standard rates must be consistent with the specified factors affecting rates for purchases and may differentiate among QFs on the basis of technologies.

Staff recommends that standard rates for QFs of 100 kW or less should be simple, paying for both energy and capacity in cents per kWh. Staff proposes that the rates be either time or non-time differentiated, at the QF's option. As with the larger QFs, staff suggests that the capacity payment be based on an aggregate capacity contribution of 50% of the full 25-30 year avoided capacity cost at a 100% capacity factor, regardless of technology. Transmission and distribution avoided costs and losses would be paid to QFs choosing simultaneous purchase and sale.

The utilities respond in much the same terms as with regard to the standard offer issues related to larger QFs. PG&E proposes that the capacity component of the prices should be based on an aggregate capacity contribution of 35% (as opposed to 50%) of the full one-year avoided capacity cost. SDG&E does not agree that the capacity portion of the rate should be paid on a cents per kWh basis for both time and non-time differentiated deliveries. It objects to any capacity payment method that makes substantial payments on a non-time differentiated basis. It characterizes staff's proposed 50% value as an arbitrary gratuity at the expense of the ratepayers. Edison complains that staff's recommendations reflect staff's improper attitude toward the avoided cost concept. Edison repeats its contention that costs cannot be deemed to be avoided.

We agree that the standard rate for small QFs should be simple. We adopt staff's recommendation that the payment for energy and capacity be expressed in terms of cents per kWh and be offered on either a time- or nontime-differentiated basis. In the context of this proceeding, this result is best achieved by a payment equal to the standard rate calculated for large QFs providing as-available energy as provided for above.

Our "as-available" offer for large facilities is on a time-differentiated basis, to reflect the fact that capacity is more valuable during peak periods than during other periods. In the event a qualifying facility less than 100 kW chooses not to buy a time-differentiated meter, the price incentive to be available during periods when capacity is most needed will be reduced. Consequently, utilities may propose capacity payments for qualifying facilities without time-of-use meters that aggregate over a year to 50% of the capacity for those with time-of-use meters.

Larger QFs will receive regular service from a utility under the applicable filed tariff schedule, standby service under a standby tariff, and parallel generation interconnection under either a parallel generation tariff or a standby tariff. Power will be purchased by the utility under a contract based on either the standard price offer or a negotiated pricing arrangement. For small QFs under 100 kW (and even for larger QFs if the utilities deem it feasible to do so), simplified service arrangements are necessary. This should be accomplished by tariffs which cover services supplied by the utility, including parallel generation interconnection, and provide for simplified agreement forms.

These simplified tariffs will be based on the standard price offer and will not preclude small QFs from choosing options available under the standard price offer which may not be contained in the simplified tariffs. An example could be the option of simultaneous purchase and sale which would require additional metering and contract terms not provided for under the tariff offerings for small QFs.

The tariffs governing sales by QFs to utilities are in some respects conceptually different from usual tariffs which cover the terms and prices of services provided by the utility. Because of this difference, certain aspects of our General Order 96-A should not apply to the tariffs covering the QFs' sales to utilities (as opposed to tariffs setting forth the services provided by the utility to the QF and technical arrangements, such as interconnection requirements). First, any contracts authorized by these tariffs need not contain the contract provisions required in Section IX of General Order 96-A. Second, the provisions of Section X, concerning contracts and services at other than filed tariff schedules, should not apply to contracts differing from the terms of the simplified tariffs. The discussion of nonstandard contracts in the following pages also applies to deviations from the tariffs governing the QFs' sales to utilities.

D. Nonstandard Contracts

1. In General

We have provided for a "standard offer" that is intended to be widely applicable to QFs of diverse characteristics and to effectively promote cogeneration and small power production. The more generally suitable the standard offer, the less need for parties to negotiate nonstandard contracts.

Nevertheless, there remains the likelihood that nonstandard contracts will be necessary. The range of possible conditions that might lead to such contracts is too broad to support more than idle speculation. The object of negotiations is to produce a contract that is the economic equivalent of the standard offer.

We indicated above that payments under the standard offer are deemed reasonable and are recovered through ECAC. Payments pursuant to nonstandard contracts are recoverable through ECAC upon a showing of the reasonableness of such payments. This differing ratemaking treatment leads to one of the major issues in this proceeding - whether this Commission should devise a procedure for reviewing the reasonableness of nonstandard contracts in advance of their effectiveness. This issue is discussed below.

Another issue that concerns many parties is the prospect of protracted negotiations over contract terms. Several parties have proposed specific schedules for offers and replies, intended to alleviate this problem. This issue is also discussed below.

2. Advance Approval

Staff observes that uncertainties associated with nonstandard contracts might delay the development of cogeneration and small power production.

> "For example, utilities might hesitate to sign contracts containing price terms other than those approved in advance by the Commission, for fear that such price terms would be considered not 'sufficient to encourage cogeneration and small power production' (Section 292.304(b)(3)), or that payments made for power purchased under nonstandard contracts would not be fully recovered."

Although advance review by the Commission of nonstandard contracts might help to reduce uncertainty, staff recommends that the Commission not give advance review and approval. It recommends that review be limited to ECAC proceedings.

Staff warns that advance review might actually delay development, contrary to its intended purpose. The procedure might take months, with the prospect of a longer process if any party petitions for rehearing or petitions the Supreme Court for review. Any decision other than unconditional approval might require further negotiations, delaying the contract. The possibility of Commission review might cause the parties to rely less on their own bargaining skills and more on the judgment of the Commission.

Staff is uncertain regarding the exact nature of review anticipated.

> "If the Commission is reviewing executed contracts, such review would appear to be superfluous, because in that case the utility and the QF would have already freely agreed to a mutually satisfactory arrangement. Review for fairness to ratepayers would occur, as with other utility contracts for the purchase of energy or fuel, in the utility's general rate case or ECAC proceeding. If, on the other hand, the Commission is asked to review proposed contractual terms, the Commission runs the risk of inserting

> itself in the midst of contract negotiations or of becoming an arbitrator of the parties' differences. It would be inappropriate for the Commission to become an active participant in negotiations involving a utility which is subject to the Commission's regulation and a QF which is not directly under the Commission's jurisdiction and which has been specifically exempted from state regulation (§292.602(c))."

Staff is concerned that the QF would not want to disclose the information that would be necessary for effective arbitration.

Further, staff states that even the most cursory forms of advance review would require considerable time of the staff and Commission. Reviewing all nonstandard contracts, including those which vary only slightly from the standard offer, would be unnecessary and inefficient, but staff doubts whether effective guidelines could be devis that could distinguish between minor and major variations.

Staff observes that the purchasing utility does assume a risk by proceeding without prior Commission approval. It suggests that the Commission should clearly state that utilities are expected to assume some risk in contracting with QFs and urges that the Commission look favorably on a utility that willingly assumes such risk.

Staff recognizes the interest of many parties in having a procedure for advance review. It proposes such a procedure for comment though its recommendation is that no such procedure be adopted. The essence of its proposal is that either a utility or a QF may submit a "Request for Review" of a specific contract provision. The Commission may accept the matter for review, in which case, an application shall be filed. The Commission decision may be deemed precedential as regards similar provisions in similar contracts.

The utilities and many interested parties urge the Commission to undertake advance review. Both legal and policy arguments are offered in support of this position.

PG&E argues that Public Utilities (PU) Code Section 2821 requires the Commission to approve the payment terms of nonstandard contracts prospectively, referring to the following portion of the statute:

> "The Commission shall approve and establish equitable charges to be paid by an electrical corporation which purchases electricity from any private energy producer employing other than a conventional power source for the generation of electricity. . . ."

PG&E contends that the use of the words "to establish" and "to be paid" in the statute require that the Commission act prospectively. PG&E expects that as precedents are declared, only those contracts that deviate substantially from the standard offer or from those contracts previously reviewed will be submitted for review. PG&E predicts that review will be infrequent.

As a policy matter, PG&E argues that even if advance review is not required by statute, staff's proposal to deny advance review would deter QF development. Under such circumstances utilities will include a provision in all nonstandard contracts allowing the utility to adjust the contract to the terms and conditions subsequently approved by the Commission, and recover all payments in excess of those subsequently authorized. In such circumstances the QFs would have no certainty and the purpose of nonstandard contracts would be defeated.

PG&E is not persuaded by staff's warning that the review procedure might take months. PG&E argues that the time required of the Commission and the staff will not be conserved by postponing review until ECAC proceedings, since the same review is required before or after the effective date of the contract.

Edison contends that the Commission should review and approve or disapprove all nonstandard contracts between utilities and QFs prior to such contracts becoming effective, whenever the price paid exceeds the utility's avoided cost.

> "In those rare instances where the overall benefits of a transaction, such as demonstrating a new technology, appear to justify the payment by a utility of a price in excess of its avoided cost, the Commission should review and either approve or disapprove the contract prior to its becoming effective. The Commission's review burden would be small under this approach because the utility will seldom wish to pay more than it can be compelled to pay. If the transaction appears to be truly beneficial, overall, the utility should not be subjected to second guessing by the Commission in a subsequent proceeding."

Edison suggests that there is no need for the Commission to review nonstandard contracts where the utility pays less than avoided costs.

Edison proposes that General Order 96-A, Section X should be amended. That section requires that no utility shall make any contract that deviates from its filed tariffs without Commission authorization. Edison suggests that amendment is required to remove uncertainty and ambiguity regarding whether that provision applies to purchases by a QF.

SDG&E believes that nonstandard contracts can perform an important function in promoting cogeneration and small power production. SDG&E warns that such contracts may at times exceed avoided costs and at times fall below avoided costs.

> "For this reason, the proposal made by Southern California Edison that only nonstandard contracts which exceed avoided costs should be subject to PUC approval is incomplete. SDG&E would suggest rather that the Commission only approve contracts upon which the QF and the utility have agreed but which they have not yet executed. The PUC's approval should be limited to the rate itself and the recoverability of that rate by the utility."

SDG&E foresees that eventually there will develop "a uniform nonstandard contract rate which many parties could utilize."

SDG&E contends that policy and legal considerations require advance approval. Regarding policy, it states that staff misunderstands the character of purchased power contracts that are not subject to Commission approval:

> "Since the majority of such purchased power contracts has (sic) already been determined by the FERC to be reasonable, the utilities are not nearly as vulnerable to an adverse PUC determination as Staff would suggest. Most purchased power contracts are not like ordinary commercial agreements in that regard."

SDG&E points to its Heber Binary Project and the Magma Niland Geothermal purchased power contract as examples of prior approval entertained by this Commission.

SDG&E argues that the Commission should provide for advance review as a matter of simple fairness, referring to the prospect of a rate of return penalty if the terms of its contract are not sufficiently fair to the QF, or having expenses disallowed in an ECAC proceeding if the payments are too high.

SDG&E makes the same legal argument advanced by PG&E - that PU Code Section 2821 requires advance approval. SDG&E contends that while this proceeding may constitute sufficient review of utility standard offers, it is clearly not sufficient for nonstandard contracts "since these contracts are not the subject matter of this proceeding." SDG&E suggests that staff's concern that the Commission might end up in the role of an arbitrator is resolved "by simply requiring that the parties agree in the first place as to the terms of the contract before it is submitted to the PUC for approval."

SDG&E concludes that "if the PUC will not grant prior approval to the nonstandard contracts, the utility must protect itself in some form." SDG&E anticipates that it would react similarly to the manner described by PG&E - inserting into the contract a provision that payments are subject to modification upon an adverse determination by this Commission and that overpayments would be recovered from the QF. The resulting uncertainty would discourage QF development. SDG&E urges this Commission to reaffirm its commitment to cogeneration by approving a procedure for prior approval of nonstandard contracts.

CEC supports the utility position. It contends that prior review will be essential to QF financing efforts.

> "This conclusion is based upon a clause which each of the utilities have placed in their contracts, which states in effect, that the contracts shall not be effective until the Commission has approved each and every term and condition of the contract. The net effect of this kind of clause is to mandate renegotiation of the contract should the Public Utilities Commission say no to any term or condition."

CEC warns that few investors will be willing to commit their resources under such conditions.

CEC suggests that this Commission should also provide negotiation and arbitration assistance. It states that such a service might expedite QF development and prevent some project proponents from abandoning their projects due to high transaction costs. QF reluctance to provide necessary information might be overcome by appropriate protective orders relative to trade secrets and confidential business information.

NRDC agrees that "greater assurance must be given that non-standard contract costs will be reimbursed." It suggests that the Commission provide a review of nonstandard contracts, or at least for review of certain forms of nonstandard contracts. If the Commission is not willing to make the necessary staff resources available, NRDC urges that we issue a stronger statement to the effect that utilities will be reimbursed for reasonable expenditures incurred under nonstandard contracts.

Great Western also agrees that:

> "...it is essential that the Commission establish a procedure for advance review of non-standard contracts between utilities and QFs in order for cogeneration and small power production to be fully developed and encouraged."

Great Western argues that in order for projects to be developed, both contracting parties must have some measure of certainty. The utility must have confidence that it can recover the cost of QF power. The QF must be able to predict its income stream in order to persuade investors and lenders to contribute the necessary capital. This confidence on both sides depends on assurance from the Commission.

Great Western anticipates that without such assurance utilities will insist on a contract provision allowing for an adjustment if the Commission disallows any recovery under the contract. Such a provision creates the kind of uncertainty that makes financing difficult.

Great Western suggests that the burden on staff and the Commission can be reduced if the Commission accepts for review only executed contracts that have been fully accepted by both parties and that will become effective upon Commission approval. As a further measure, it suggests reasonable size and time limits on contract review, such as a limit of 5 MW or greater and a rule that contracts would be deemed approved unless disapproved within 60 days.

As a last resort, Great Western urges that the Commission should clearly express that it expects utilities to accept some risk in entering into contracts that encourage QFs. It suggests that the standard of review should be whether the contract was reasonable at the time it was made, not at the time it is renewed.

MPS argues that staff's recommendation is based on a simplistic distinction between purchase and sale. It contends that the obligation to purchase is a public utility obligation identical to the obligation to sell at reasonable, nondiscriminatory rates. Consequently, MPS asserts that General Order 96-A applies to utility purchases from QFs and that the Commission is required to provide for advance review of nonstandard contracts.

Union Oil Company of California (Union) disagrees with the utilities. It states that one of the several recognized barriers to QF development is industry's fear of being regulated as a utility.

Union asserts that PURPA and the FERC regulations were intended to eliminate this regulatory barrier and to allow industry to negotiate freely with utilities. Union contends:

> "Prior review would not only carry the onus of regulation where none is warranted, it would also be time-consuming and costly. It would tend to discourage rather than encourage industry seeking contracts to sell power. In addition, it would require direct intervention of the Commission in what would ordinarily be private negotiations between two (or more) business interests. This would have the appearance as well as the indirect effect of, further regulation, even apart from the ECAC and general rate proceedings."

Union goes so far as to suggest that review and approval of contracts by the Commission and the indirect terms and conditions of these contracts through the device of after-the-fact refusal to allow recovery of costs in ECAC or general rate cases is an unwarranted inhibition to the further development of cogeneration.

Pan Aero and Transition Energy Projects Institute (TEPI) also oppose advance review. TEPI suggests that if advance review is adopted, that only concluded contracts be submitted unless there are irreconcilable differences requiring Commission review.

<u>Discussion</u>

The threshold question is the legal question. After consideration of the authorities cited, we conclude that we are not legally compelled to provide for advance review of nonstandard contracts.

As indicated, several parties argue that advance review is required by PU Code Section 2821. We find this argument without legal merit.

PU Code Section 2821 does provide that this Commission "shall approve and establish equitable charges...on its own motion or on application of an electrical corporation or a private energy producer." We consider this mandate to be no more than a direction that we provide for a "standard offer". We conclude that by this decision we are acting on our own motion to "approve and establish equitable charges." We find no additional burden to entertain applications on behalf of parties that are not satisfied with the "equitable charges" established by this Commission.

We also seriously doubt whether PU Code Section 2821 would provide the procedural vehicle intended by the parties. In general, these parties seem to have in mind a procedure whereby an executed contract is proffered for approval or disapproval. But if we assert jurisdiction under PU Code Section 2821, our authority would be to "approve and establish" charges to be paid under a nonstandard contract. Thus, we would have jurisdiction to substitute our own judgment and to modify the contract accordingly. This is certainly not the process intended by the parties.

We are also not persuaded that General Order 96-A has any relevance to this issue, except as an argument by analogy. On its face it applies to utility sales to customers, not to utility purchases that may be from customers.

While we do not find ourselves legally obligated to provide advance review of nonstandard contracts, we have decided to provide such review for applications filed during the next two years. Both utilities and QFs argue that advance review of non-standard contracts may in some cases be necessary. We are persuaded that without advance approvals, creative nonstandard offers could be stymied and that QF development would thereby suffer.

The nonstandard contracts we anticipate generally involve some sort of debt guarantee, levelized payment or payment floor which reduces risks for QFs and places those risks upon ratepayers. In return for taking such risks, ratepayers are afforded some reduction on avoided cost payments. Given current ratemaking treatment for costs associated with QF purchases, utilities are intermediaries in the transaction as costs are flowed through ECAC. In the case of standard offers, utilities are secure that payments to QFs will be recovered. With nonstandard offers the utility has no such assurance unless advance review is permitted. Without advance review, a utility risks being found imprudent for non-standard contract payments; a potential cost for which the utility has no compensatory benefit. Under the circumstances, a utility is likely to choose not to write nonstandard contracts at all, or to include in such contracts a provision to void the agreement if an associated expense is disallowed by this Commission, or to demand such concessions from QFs beyond the standard avoided cost offer that QFs are discouraged from departing from standard offers at all.

The issue, then, is whether we wish such nonstandard contracts to be written. It is not necessarily clear that we do. In adopting standard offers, we are presenting our conclusion on what is an appropriate payment for electricity provided by a QF. We believe our standard offer is a fair price for ratepayers, and provides an excellent opportunity for QFs to prosper. We would expect most parties to find such an offer satisfactory, and that special financing or other measures to reduce risk be sought from financial or other institutions.

While we believe that the standard offer should be satisfactory generally, we can envision some cases in which nonstandard treatment would benefit both the QF and ratepayers. Especially as the QF market is developing, and before financial and other institutions understand its nature, some QFs may wish to seek alternatives to reduce risk. For example, the agreement SDG&E recently reached with Kelco to provide a floor on avoided cost in return for a reduction in payment appears to be desirable to all parties, including ratepayers. We can imagine other such contracts which benefit ratepayers. We will entertain such applications within the guidelines established.

The guiding principle for nonstandard contracts upon which applications should be based is that the contract terms, taking into account the associated risks, should not be more than expected avoided costs under the standard offer. Ratepayers are expected in most non-standard offers to accept some technological or market risk, in which ratepayers should be returned compensating benefit. Applications for nonstandard contracts should clearly state all the differences between the contract and the standard offer, and identify all gains and costs for ratepayers. The application should further demonstrate why rate-payers should either be indifferent to or prefer the nonstandard contrac over the standard contract. In the rare event that the nonstandard offe is above avoided costs, an explanation of how ratepayers otherwise benefi should be presented. In all cases, the burden is on the applicant t demonstrate why the nonstandard offer is in the ratepayers' interest. We must caution all parties that the Commission will review these contracts as a banker reviews a loan application, with scrutiny and skepticism. While we want to encourage QF development, we do not wish to burden ratepayers in the process.

In terms of procedure, we will allow utilities to file nonstandard offers for review. We ask that utilities submit only those offers for which the utility has significant questions about whether we would find the offer prudent. Once the Commission has reviewed and expressed its opinion as to the consistency of a contract price and terms with avoided cost principles, utilities should be expected to use these principles to sign similar contracts without review. We will attempt to handle applications for projects less than 10 MW through ex parte procedures. Applications over 10 MW will generally require hearings. Exceptions may be made depending upon the novelty of a particular application, or the degree of ratepayers' exposure.

The staff shall review applications for approval of nonstandard contracts expeditiously and where hearings are necessary, they shall be set promptly. If the staff finds that staff review cannot be completed and hearings begun within 45 days because of the workload of other matters pending before the Commission, the Executive Director shall report this to the Commission, which may then reorder work priorities to resolve related issues promptly.

Our staff makes strong arguments in this proceeding against advance approval. It argues advance approval could lead to delay of projects, and to direct involvement of this Commission in the negotiations with QFs. On the first point, we acknowledge that review of contracts may be time-consuming. It is for this reason that we ask that QFs generally seek financial support through other institutions, not through nonstandard offers. At least while the market is developing, however, we see merit in permitting some nonstandard contracts even though such review will be time-consuming. We would prefer to have good projects somewhat delayed than not constructed at all.

Finally, on the issue of PUC involvement in negotiating nonstandard offers, we do not believe it will be necessary or appropriate to become involved. Utilities and QFs are to negotiate with each other, and we will review the product for approval or disapproval. We have no intention of intervening or rewriting contracts.

To assure review of this procedure after we have had experience with it, we will establish a sunset provision. Unless we make an affirmative decision to reinstate our procedure, we will not consider applications for prior approval of nonstandard contracts filed two years after the effective date of this decision.

3. Negotiations

Staff states the obvious: "Utilities are expected to negotiate in good faith with QFs." Staff proposes certain guidelines that are intended to provide a standard:

> "A utility must respond specifically to proposals of a QF within 60 days of the receipt of the QF's initial contract proposal and within 30 days of the receipt of subsequent proposals related to the initial proposal. Rejection of a QF's proposal shall be accompanied by a specific counter-offer concerning the subject matter of the QF's proposal. If the utility is unable to respond to the QF's proposal within 30 days, it shall inform the QF of (1) the specific information needed to evaluate the proposal, (2) the precise difficulty encountered in evaluating the proposal, and (3) the estimated date when it will respond to the proposal."

Other parties respond with schedules of their own.

We are not sure that the give and take of contract negotiations can be reduced to a formal schedule. We are not inclined to require such a procedure without a more convincing argument that it is necessary, or likely to be successful. Enforcement would require the parties to conduct their affairs in an overly rigid fashion. For example, the QF's "initial contract proposal" might evolve, rather than simply appear. We would rather not have to decide which was the day the proposal was complete, or whether the utility's estimated time for response is reasonable.

Nevertheless, we recognize that staff has addressed an important problem. Protracted negotiations that lead nowhere are exactly what this regulatory scheme is intended to avoid. The utilities are expected and shall be required to bargain conscientiously toward a conclusion. The best evidence of good faith is a collection of written documentation compiled along the way. When the utility is unwilling or unable to accept a QF's proposal, the utility must respond with a timely counteroffer, or an explanation (as proposed by the staff) of:

1. The specific information needed to evaluate the proposal;
2. The precise difficulty encountered in evaluating the proposal; and
3. The estimated date when it will respond to the proposal.

The Commission will entertain formal complaints raised by QFs who can demonstrate that the utility has failed to bargain in good faith. Such complaints from QF's shall be treated expeditiously by the staff, and where hearings are necessary, hearings shall be set promptly. If the staff believes that QF complaints cannot be resolved quickly because of the workload of other matters pending before the Commission, the Executive Director shall report this to the Commission so that the Commission can assign priorities to these matters and resolve the QF complaints as quickly as possible. A utility found not to have bargained in good faith will stand in violation of this order and will be open to potential punitive action by this Commission.

We are also concerned that QFs considering a negotiated contract are not fully aware of their rights to request a contract under the terms of the standard price offer. Should the QF propose prices or terms outside the standard price offer, we will expect the utility to advise the QF that the contract discussions are proceeding on a negotiated basis, distinct from the standard contract, before responding with a nonstandard contract. The notice shall include a summary of terms available under the standard offer, and an offer to enter into a standard offer contract. Likewise, if the utility initiates a nonstandard contract with its attendant price offering, the utility will be expected at the same time to present to the QF the standard offer.

4. Contract Renegotiation Provision

We are concerned about the utility-proposed renegotiation contract term which would allow the utility to modify a signed contract retroactively (and prospectively) in the event any provision is found unreasonable in the future. Such a term would apparently destroy the certainty that financial institutions require for their participation. We find that such a term should not appear in standard offers. A contract term which would allow the utility to modify a signed contract retroactively and prospectively in the event any provision of the contract term is later found unreasonable is not a reasonable term in a standard offer contract.

V. Wheeling

FERC regulation Section 292.306(d) provides for limited wheeling:

> "If a qualifying facility agrees, and electric utility which would otherwise be obligated to purchase energy or capacity from such qualifying facility may transmit the energy or capacity to any other electric utility. Any electric utility to which such energy or capacity is transmitted shall purchase such energy or capacity under this subpart as if the qualifying facility were supplying energy or capacity directly to such electric utility. The rate for purchase by the electric utility to which such energy is transmitted shall be adjusted up or down to reflect line losses pursuant to § 292.304(e) (4) and shall not include any charges for transmission."

In its comments FERC indicates that there are several circumstances in which a QF might prefer that an electric utility with which the purchasing utility is interconnected would make such a purchase - for example, if the avoided costs of the second utility are higher. However, if the first utility does not agree to transmit the purchased energy or capacity, it is not forced to wheel and retains the purchase obligation.

Staff states that the extent of state authority to order wheeling is limited by federal law by virtue of the preemption doctrine. It points to PU Code Sections 2801-2816 as providing this Commission with limited jurisdiction to order interconnection for the purpose of transmitting energy on behalf of a "private energy producer," assuming that certain specified findings are made. Staff argues that these sections avoid federal preemption because jurisdiction is limited to transmission for the private energy producer's own use and because the transmission is limited to the service area of a single utility. Staff concludes that, although the Commission has no authority to require wheeling when federal jurisdiction attaches, utilities should be urged to consider wheeling requests on a case-by-case basis.

The utility response is varied. PG&E states that staff's position agrees with its view. Edison argues that even transmission on behalf of a private energy producer is subject to exclusive federal jurisdiction through application of the commingling doctrine. SDG&E focuses on conditions that it proposes to require in the event that QF generation is made available by a wheeling utility.

CEC contends that this Commission should state clearly that utilities are encouraged to wheel. It states that this Commission can and should use our authority to ensure that utilities do not use their monopoly control over transmission lines to hinder QF production. It offers the following statement for our endorsement:

> "The Commission will not tolerate the utilities' use of their control over the transmission system to limit access by small power producers who seek to use the transmission lines to transmit power to a purchaser of the small power producers' energy. Such actions will be considered by the Commission in setting rates for utilities in future ratemaking proceedings, and in evaluating the utilities' imagination and vigor in implementing and pursuing conservation and the development of small power production and renewables."

CEC suggests each utility report regarding requests for transmission service as part of its rate case showing.

Union states that wheeling can be a major factor in promoting cogeneration and small power production. It urges this Commission to strongly encourage utilities to consider all requests to transmit power and to accommodate such requests on a fair and nondiscriminatory basis. It warns that otherwise even such large companies as Union may be discouraged from pursuing opportunities.

NRDC argues that staff's conclusion regarding the extent of our jurisdiction is based on an unnecessarily narrow view of wheeling issues. It recommends that we consider fashioning "narrowly tailored wheeling requirements to further the objectives of PURPA."

CMA addresses specifically the issue of wheeling between two facilities of the same industrial entity. It argues that the principle of simultaneous purchase and sale fundamentally changes the concept of wheeling. It contends that the principle applies whether the resources and load are on the same site or separate sites. CMA observes that the utilities readily accept the same site principle, but reject its extension to separate sites.

We agree that wheeling is an important concept that can make a material contribution to cogeneration and small power production in California. For that reason we state plainly that each utility's willingness to wheel will be examined in the context of its overall conservation activities in conjunction with general rate case proceedings.

Regardless of a utility's willingness to wheel power for its neighbor, each utility, for some reason, appears to limit its cogeneration and small power activities to the confines of its own service territory. This occurs even though locally available generation may not match requirements. Further, some generating sites, while located in other service territories, may still be closer to the buying utility's load center than would alternatives such as out-of-state power purchases. We find that it is not prudent for a utility to fail to pursue an otherwise beneficial facility simply because it is located in another service territory. In addition, this Commission will view with disfavor any actions or inactions by a utility which will interfere with the signing of a contract between a neighboring utility and a cogenerator or small power producer located in its service territory.

In the discussion above we considered whether to limit utility recovery in cases of utility participation in successful cogeneration and small power production ventures. We indicated that such participation should be favored. In relation to wheeling this principle applies to the prospect that a major facility may require utility financing or guarantees in order to be built (a classic "nonstandard" contract) that the "host" utility is unwilling or unable to provide (for example, the utility may already have excess capacity). In this case another utility may be able to participate under terms and conditions that benefit all parties.

The attractive feature of wheeling is that it introduces actual competition into the market. To the extent that competition occurs, the burden of regulation is proportionately reduced.

Respondent utilities are required to buy energy and capacity from a QF located in the service area of another utility whenever the conditions of Subsection 292.303(d) of the FERC rules are met.

Subsection 292.303(d) is clear that the price paid to the QF by the purchasing utility shall not include any charge for transmission but may be either raised or lowered to reflect the savings or costs resulting from line losses. The discussion accompanying the final FERC rules indicates that the serving utility would collect any applicable transmission charges for wheeling power from the QF and that, in the case of respondent utilities, the rates for these charges would be set under Part II of the Federal Power Act. Transmission charges by the serving utility should take into consideration the extent to which the QF's power displaces power that would otherwise be transmitted from the utility which receives the QF's power to the serving utility. For example, if all of the QF's power displaces power that would otherwise be delivered by the purchasing utility to the serving utility, the transaction becomes a bookkeeping rather than a physical exchange, and therefore no transmission charges would appear to be justified.

At this stage of this proceeding we are optimistic that the respondent utilities subject to this Commission's jurisdiction will respond to wheeling requests in a fair and nondiscriminatory manner. If our optimism is well-founded, we will need not decide the extent of action needed to encourage wheeling. If our optimism is unfounded, we will take what ever action is appropriate.

In this posture we must necessarily require information to be provided periodically regarding utility actions in this regard. Therefore, we will require each utility to report at the end of January of each year on wheeling performed during the previous year, the parties for whom the wheeling was performed, the terms and conditions applied to the transaction, the technical wheeling arrangements, the status of any pending requests to wheel, and the circumstances relating to any request that was refused.

VI. Rates for Sales to QFs

A. Introduction

FERC Regulation Section 292.305 provides that rates for sales to QFs shall be just and reasonable, in the public interest, and shall not discriminate against any QF in comparison to rates for sales to other customers served by the electric utility. Rates based on accurate data and consistent systemwide costing principles are deemed not to discriminate, to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics. Upon request of a QF, each utility must provide:

1. Supplementary power,
2. Backup power,
3. Maintenance power, and
4. Interruptible power.

The appropriate state regulatory agency may waive the requirements upon a finding that compliance would impair the utility's ability to render adequate service to its customers, or place an undue burden on the utility. The regulation expressly provides that the rate for sales of backup or maintenance power should not be based upon an assumption that forced outages or other reductions in output will occur simultaneously, or during system peaks, or both, and shall take into account the extent to which scheduled outages of the QF can be usefully coordinated with the utility's own scheduled outages.

B. Supplementary Power

Supplementary power is electric energy or capacity used by a facility in addition to that which it ordinarily generates on its own. The concept is not applicable when simultaneous purchase and sale is elected, as the QF is supplied all of its requirements by the serving utility.

Staff states that QFs are now furnished supplementary power under regularly filed tariffs applicable to all customers of the same class as the particular QF. Staff contends that such service does not involve costs that differ from costs to serve other customers. It finds that present practice reasonable and recommends that it continue. No party objects to this recommendation.

C. Backup Power

Backup power is electric energy or capacity available to replace energy generated by a facility's own generation equipment during an unscheduled outage. Again, the concept does not apply when simultaneous purchase and sale is elected.

Staff argues that there is a significant cost to a utility to provide backup power to a QF that is not recovered through energy rates charged for supplementary power and not reflected in avoided cost payments. Staff contends that reasonable standby rates, based on the utility's cost of providing backup power, should be charged to QFs.

Staff states that:

> "Standby rates as now filed by PG&E, SCE and SDG&E are designed to recover the utility's cost of providing only a fraction of a MW of backup generation costs together with transmission and distribution costs. . . . Standby rates, by themselves, do not recover the utility's cost of providing backup power. The rates were set so that the standby charges combined with the recovery of demand charges through regularly filed tariffs in those months in which the QF requires backup power would recover the utility's costs."

Staff asserts these rates are consistent with the FERC requirement that such rates not be based on the assumption that all QFs will fail simultaneously. Staff recommends that this Commission not adopt a formula for developing standby rates. Existing rates are allegedly below rates that would result from such a formula. Staff suggests that the Commission accept existing basic standby rate levels in dollars per kW per month as reasonable and allow rates to increase in general rate cases in proportion to increases in per kW capacity costs.

Staff recommends no standby rates for QFs not now served by rate schedules with demand schedules. Standby rates for new technologies such as photovoltaics should not be finalized at this time. Appropriate rates could be developed as data on the technology becomes more refined.

Staff recommends that all utilities develop and file alternative standby rates for QFs on time-of-use rates. These rates should be similar to Schedule SCG-2 of Edison. A three-month ratchet, including the month of occurrence, is recommended. The ratchet would not exceed 90% of the demand in the month of occurrence and would be extended by three more months for each additional occurrence, but not to exceed 12 months. Staff recommends that PG&E, with no ratchet provision in its present time-of-use tariffs, should develop and propose an appropriate alternative standby rate.

Staff further recommends that standby charges should be waived for any QF that attains an 85% capacity factor without down-time during on-peak periods, excluding scheduled maintenance, in any month. This waiver is in recognition of the lower cost to serve QFs that operate with high reliability.

Staff also proposes that standby rates be made available to self-generators used to reduce peak demand. Staff states that such rates are appropriately higher than rates to QFs, "in recognition of the lesser value of self-generation to the utility." Self-generators reduce the utility's peak demand but do not conserve energy through enhanced efficiency or fossil fuels as compared to a cogeneration or small power production facility.

PG&E does not have a ratchet provision in its present time-of-use tariffs. PG&E opposes staff's proposal that it develop such provisions as part of "an appropriate alternative standby rate." It states that its present schedule offers low standby rates to both large and small cogenerators.

> "This schedule does not burden a QF with disproportionately higher standby charges if the size of the cogeneration facility is larger than 40 percent of the load."

PG&E asks to be excused from filing the proposed rate.

PG&E disagrees with staff's proposed waiver of standby costs where the QF attains an 85% capacity factor in any particular month. PG&E claims that attempts to comply would be difficult because a utility does not ordinarily meter cogeneration production and would have no basis for accurately computing the capacity factor. Installation of the additional meters would increase the cost of interconnection.

PG&E also disagrees with staff's alternative recommendation. PG&E agrees that no generation costs, except for spinning reserve, are incurred in providing standby service outside of peak hours.

However, it contends that portions of the transmission and distribution system are dedicated to serve certain customers and that such costs are reasonably reflected in rates.

Edison objects to staff's proposed three-month ratchet provision. Edison claims that the 12-month ratchet is appropriate because the monthly standby charges are designed to recover 1/12th of the annual costs that Edison incurs in providing standby service. If the ratchet is reduced to three months, a higher charge would have to be imposed to recover the "full cost" of providing standby service.

Edison also opposes staff's proposed waiver of standby charges where the QF attains an 85% capacity factor in any particular month. Edison warns that such a provision would tend to eliminate standby charges altogether, since standby charges are already waived if the customer generation suffers an outage (and Edison supplies the demand) on-peak.

SDG&E agrees that existing ratchet provisions are reasonably modified to encourage reliable customer generation. It suggests that this might be done by extending the time effect of the ratchet and increasing the ratchet level for repeated outages.

SDG&E does have reservations about staff's proposed waiver of standby charges based upon performance. If staff's proposed waiver of demand charges during scheduled maintenance (discussed below) is also adopted, SDG&E contends that "the combination of the two waivers would mean that the QF pays neither a standby charge for demand nor a demand charge when it actually imposes demand during scheduled maintenance." This is alleged to discriminate against retail customers who do pay for demand.

CMA states that demand ratchets and demand charges for generation, transmission, and distribution are not appropriate. Electricity used by the QF should be charged at the utility's marginal running cost. However, CMA agrees that standby schedules such as developed by Edison are an acceptable alternative for balancing FERC's intent with the purpose of standby schedules by reflecting significant differences in cost between periods.

The University of California (UC) prefers staff's alternative approach to standby rates. UC contends that, considering all QFs as a class and the diversification of probable QF outages, the inclusion of capacity or demand charges/payments in rates should operate to provide for any standby capacity requirements.

Solar Turbines International (Solar) supports the staff recommendation with regard to self-generators. Solar argues that SDG&E's existing ratchet-type standby charge operates inequitably in favor of generators who are generating a small percentage of their total requirements.

> "The cogenerators who are generating a large percentage of their capacity would opt for the flat charge rate, and the cogenerators and self-generators who are generating a small percentage of their power would opt for the ratchet clause, which means that the only generators which would be penalized by this ratchet clause would be the self-generators who are generating a large percentage of their power."

Solar recognizes that self-generators do not effectuate all of the objectives of PURPA. However, it contends that they do accomplish some of these as well as do cogenerators, and asks for appropriate treatment.

CEC recommends that rates be established without standby rates and that service be provided under conditions in tariff schedules. CEC states that under standby rates, the QF pays for its own reserve margin, but receives no benefit from its contribution to reduced reserve requirements. CEC suggests that certain distribution costs required to provide standby service can instead be recovered through facilities charges.

We find that the utility position is consistent with the increase in supply approach discussed in relation with capacity payments above. The CEC position is more consistent with the reduction in demand approach, as it recognizes the central proposition that the proliferation of cogeneration and small power production enhances reliability in the aggregate. However, we do not yet reach the conclusion drawn by CEC - that no standby rates should be charged.

Instead, we consider that standby rates are properly derived residually, based on the calculation of avoided costs and the determination of retail rates.

We earlier stated the proposition that standby rates do not apply when simultaneous purchase and sale is elected. In that case, the economics of the transaction are a function of two variables - the avoided costs and the retail rates. Simultaneous purchase and sale is a fiction - from the point of view of the utility, the operation of the system is exactly the same whether or not simultaneous purchase and sale is elected. We can think of no reason why the standby rate should be a major factor in a QF's decision whether to elect simultaneous purchase and sale. Therefore, the standby rate should be designed so that the total economic package is the same for a QF facing the election.

The present utility standby rates, which have been developed after much discussion and analysis, provide a good basis to achieve this balance. Standby rates apply to the QF that is serving its own load and requires backup power for periods when its generation is down. If the QF is suffering an unscheduled outage, it pays the regular tariff rates for power purchased from the utility, which include a demand charge for that month. These rates when taken together provide for a reasonable recovery of backup utility generating costs when requisite consideration is taken of the noncoincidence of QF failure.

We will extend standby rates to all QFs, not just cogenerators, with demand schedules. We agree that these rates should be updated in general rate cases in proportion to increases in per kW capacity costs. We will also adopt the staff recommendations which provide for some options that should cover the diverse needs of different types of QFs. Currently, under certain utility price offers QFs must maintain 80% availability on-peak to receive firm capacity payments. The elimination of standby charges for QFs who attain an 85% on-peak capacity factor will provide a desirable incentive for reliable availability at the most critical times. Alternative standby rates should be promulgated for QFs on time-of-use rates to distinguish between the impact on the utility system of QF failure on-peak as opposed to off-peak. Failure on-peak imposes an incremental demand on the utility that is properly reflected in a demand payment, as in Edison's Schedule SCG-2. Failure off-peak imposes no such system demand problem. We adopt the staff's three-month ratchet proposal, as part of this rate scheme. This option should be appropriate for a QF with small generation output compared to its total demand. PG&E will be ordered to adopt a standby rate proposal consisten with these provisions.

D. Maintenance Power

Maintenance power is electric energy or capacity supplied during scheduled outages of the QF. By prearrangement, a utility can agree to provide such energy during periods when the utility's other load is low, thereby avoiding the imposition of large demands on the utility during peak periods. Again, the concept does not apply when simultaneous purchase and sale is elected.

Staff states that PG&E now provides maintenance power to QFs under a special condition whereby customers are charged for energy furnished during scheduled maintenance under the regular rate schedule applicable to that customer. Added demand imposed on the utility by the scheduled outage is ignored for the purpose of computing demand charges under the regular rate schedule.

Staff recommends that QFs pay for energy delivered by the serving utility at regular rates during periods when their own generating unit is shut down. Staff proposes that PG&E's special condition (Special Condition 2 of Schedule S-1) be adopted by other utilities to provide for the waiver of added demand charges during scheduled maintenance periods. In adopting this provision, other utilities may take into consideration differences as to months that are appropriate to that utility for scheduling maintenance consistent with system peak loads. In establishing scheduled maintenance periods, the utility will state that reasonable periods will be allowed and that deferrals of the QF's requested schedule will be made on not less than 60 days' notice.

As an alternative, staff suggests that maintenance power rates be set at the utility's marginal cost:

> "The argument for charging the utility's marginal (avoided) cost is to keep the utility whole. Tariffs are now set considering, but not equal to, the marginal cost. When a QF uses maintenance power, the utility by definition suffers its marginal cost (change in total cost for a charge in output). The utility will lose money on maintenance power to the extent filed tariff rates are used and they are below the marginal (avoided) cost. Conversely, the utility will earn revenues above their expenses on maintenance power when filed tariffs are used and they are above the marginal (avoided) cost."

In this case the rate charged is the same as the price the QF would otherwise receive as payment if it were delivering power (assuming it is paid based on current avoided costs).

Staff in its alternate further suggests that demand charge ratchets should not apply for maintenance power if the QF cannot schedule maintenance in the few months offered by the utility. Demand charges should apply for the month in which power is used, but should not be carried forward for the next 11 months.

SDG&E opposes the waiver of demand charges incurred for additional demand during scheduled maintenance periods. SDG&E states that while current schedules do waive any ratchet penalty for demands imposed during scheduled maintenance periods, all portions of retail rate schedules are appropriate to charge for power used. To eliminate any portion of the retail charge could be viewed as discriminating in favor of QFs.

SDG&E disagrees with the concept of dropping the ratchet penalty for unscheduled outages or outages scheduled without the concurrence of the utility. SDG&E views QFs as alternatives to utility generation and considers the ratchet provision a reasonable means of ensuring that the QF will build reliable units and schedule maintenance to avoid periods of high demand.

CMA states that if maintenance is performed during the scheduled period, no demand is imposed and a demand charge is inappropriate. Limited (three months) ratchets may be appropriate for QF on-peak demand resulting from unscheduled breakdown. The shorter ratchet is proper recognition of the fact that requirements for maintenance power will not be simultaneous.

We find that this issue is properly addressed relative to the standard offer choices discussed above. The QF that chooses to provide as-available energy and associated capacity is under no obligation to schedule maintenance consistently with utility load requirements. Since payments to the QF are based on the utility's avoided costs, such a QF that is "out" during peak periods forgoes payments at the most lucrative time. As retail rates evolve toward marginal costs, such a QF also pays higher rates at such times by application of the retail rate schedule. We rely on such price signals to promote efficient operation of such facilities. We note that the higher the capacity payment at peak, the greater the incentive to schedule maintenance for off-peak periods. This relationship supports our conclusion that QFs providing as-available energy should be paid for capacity.

Those QFs that contract to provide firm energy are properly subject to the utility's scheduling requirements. We find the timing provisions set forth in PG&E's Special Condition 2 to Schedule S-1 to provide a reasonable standard for scheduling. The value of this commitment is correctly reflected in a higher capacity payment, as greater costs are avoided. Power during scheduled maintenance periods should be provided to the QF at the regular tariff rate. Added demand charges are appropriately waived for those QFs who are able to meet utility schedules. However, some QFs will have no opportunity to schedule maintenance to conform to utility peaks because of the seasonal nature of such QFs' operations. In such special cases, the demand ratchet triggered by this added demand should be limited to three months, with the exception that a three-month ratchet (three months including the month of occurrence) should apply for the first outage and three more months added for each additional outage (up to the present 12 months). PP&L, Sierra, and CPN shall be ordered to file rates consistent with this section.

E. Interruptible Power

Interruptible power is electric energy or capacity supplied to a QF subject to interruption by the electric utility under specified conditions. Many utilities have used interruptible service to avoid expensive investment in new capacity that would otherwise be necessary to assure adequate reserves at time of peak demand. Under this approach utilities assure the adequacy of reserves by arranging to reduce peak demand, rather than by adding capacity. Interruptible service is therefore normally provided at a lower rate than noninterruptible service.

Staff observes that Edison and SDG&E presently offer standby rates based on interruptible service. Such rates are available to large customers with loads greater than 1,000 kW who are on time-of-use rate schedules. Staff states that PG&E does not have an interruptible rate compatible with cogeneration by QFs. Staff suggests that PG&E be directed to file such rates.

Staff states that implementation of interruptible rates requires a phasing in, starting with large customers. Staff warns that interruptible service to smaller customers may cost more than the benefits are worth. Staff claims that more experience is needed with experimental offerings before such rates can be offered to smaller customers. However, utilities are required under PURPA to offer interruptible rates to all QFs unless a waiver is granted by this Commission.

PG&E agrees with staff. SDG&E states that:

> "The problem with expanding Interruptible Standby is the practical one of how does one interrupt the standby service without interrupting any remaining firm service. If the QF is willing to accept total service interruption or some positive measure can be taken to interrupt only the standby portion of the service, SDG&E has no objection to expanding Interruptible Standby."

SDG&E agrees with staff that interruptible rates may not be cost-effective for small customers.

The interruptible rate concept is applicable to QFs to the extent that QF's generation is used to serve its own load. We consider the FERC reference to "lower rate than noninterruptible service" as limited to customers of the same class, not that the interruptible rate must be lower than any noninterruptible rate. We recognize that interruption can provide both capacity and energy savings, and conclude that the actual rates should be based on the benefits that result from the avoided cost calculation and prevailing retail rates so that the appropriate price signal is available to the QFs.

As recommended by the staff, Edison and SDG&E should expand their current interruptible service offerings to cover all QFs above the current 500 kW minimum and PG&E should offer similar interruptible service to QFs to the extent that interruptible rates are filed for all large customers. PP&L, Sierra, and CP National should state their willingness to provide interruptible service to large QFs on a contractual basis. Interruptible rates for smaller QFs will be explored when more information is obtained on the costs and benefits of such offerings. Offerings to smaller QFs should occur at the same time that similar interruptible rate offerings are made to classes of customers below 500 kW.

VII. Standards for Safety

A. Introduction

FERC Regulation Section 292.308 provides that the appropriate state regulatory agency may establish reasonable standards to ensure system safety and reliability of interconnected operations. Standards may be recommended by any electric utility, QF, or other party. If standards are established, the state regulatory agency shall specify the need for such standards on the basis of system safety and reliability.

FERC's comments in regard to this section indicate that FERC:

> "...believes that the reliability of qualifying facilities can be accounted for through price: namely, the less reliable a qualifying facility might be, the less it should be entitled to receive for purchases from it by the utility.
>
> "As a result, the Commission has not included specific standards relating to the reliability in the sense of the ability of qualifying facilities to provide energy or capacity."

Instead, the focus is on safety equipment that can ensure that QFs do not energize utility lines during utility outages.

Our staff states as a basic objective that "reasonable uniform standards should be established and be part of each utility's new parallel generation tariffs." This matter is related to the problem of interconnection, discussed in the following section of this decision. The solution of these technical problems is crucial to the success of this entire program because the effectiveness of the standard offer will be defeated if protracted negotiations occur over conditions of actual delivery of the energy and capacity.

B. Staff Recommendation

Staff observes that various abnormal conditions can occur on a utility system. Some of these conditions will require detection devices and proper operation of protective equipment to prevent a hazard to the public or utility linesmen. For example, downed utility lines could pose a hazard to the public if a QF's generator continued to energize the line. Protective equipment must be provided to detect this condition and disconnect the QF's generator from the downed circuit.

Staff states that the QF should assist the utility in maintaining system integrity. For example, the QF's relays should not frequently trip so that the QF cannot be relied upon to carry its share of the load. System disturbances also could result from inadvertent tripping of large QF generators. Staff proposes that utilities present adequate examples of how their guidelines deal with maintaining service standards and system integrity so that the QF is told clearly and simply not only what type of equipment is needed, but also the reasons the equipment is needed and what the equipment is expected to do.

Staff has identified three functional standards that it considers essential for safe and reliable operation, with a list of corollary conditions. The standards are as follows:

1. Sense and properly react to utility failures/malfunctions;
2. Assist the utility in maintaining system integrity and reliability; and
3. Protect the safety of the public and utility personnel.

The corollary conditions are that the QF provide protection against the following adverse conditions, which can cause electric service degradation, equipment damange, and harm to others:

1. Prevention of inadvertent and unwanted reenergization of a utility dead line or bus;
2. Interconnection while out of synchronization;
3. Overcurrent;
4. Utility system load imbalance;
5. Ground faults;
6. Generated ac frequency outside permitted safe limits;
7. Voltage generated outside permitted limits; and
8. Poor power factor.

Staff suggests that QFs of 100 kW and larger may also be required to have overcurrent protection, utility system load imbalance protection, and a suitable power factor or power factor compensation up to nameplate generation capacity.

Regarding the respective responsibilities of QFs and serving utilities regarding design, installation, operation, and ownership of interconnection equipment, staff believes that the QF should be required to protect its own equipment in such a manner that faults or other disturbances on the utility system do not cause damage to the QF's equipment. Further, staff proposes that the QF take certain responsibility for protecting the public and utility operating personnel. Staff provides that the QF "may employ industrial quality interconnection equipment" for this purpose, with design review by the utility.

Except for the utility manual disconnect and feeder reclose blocking equipment, staff proposes that the QF have the option of owning, operating, and maintaining the interconnection protective equipment, or paying the utility. The utility must complete design review within a specified period and respond in writing, either accepting the QF's plans or providing detailed information regarding deficiencies.

Staff states that progress is being made in arriving at fairly uniform interconnection requirements. It asks that each of the utilities provide illustrations of how its requirements would apply to certain specified situations. Staff proposes that each utility complete its guidelines based on staff's recommendations in this matter.

Staff classifies three sizes of generating facilities: small - below 100 kW; medium - 100 kW to 1 MW; and large. Staff recommends that utilities review their requirements for small size facilities with the objective of simpler requirements and standardization. Dedicated transformer requirements should be limited to not greater than 1.15 times the QF's generator nameplate capacity. Daily logs of generator trips and separations for small QFs shall not be required. Staff suggests that utilities establish requirements for the medium-sized facilities that are simpler than for the larger size. For all sizes staff suggests that utilities include diagrammatic examples of interconnection arrangements in their guidelines.

Staff states that utilities now require a voltage and frequency window-type of control for induction generators and other utility line-commutated generating devices, to assure such devices will trip off the line and stay off in an emergency. Staff contends that this practice is the lowest cost control method capable of performing well, and staff recommends its continued use. However, staff suggests that utilities examine other means of safeguarding the public and operating personnel, while assuring system reliability.

Staff proposes that these principles be incorporated in parallel generation tariffs to be filed by each utility under General Order 96-A, with modifications to be reviewed before becoming effective to protect QFs from arbitrary changes.

Staff states that an alternative and more time-consuming procedure would be for this Commission to issue detailed interconnection regulations in the form of a general order. Staff recommends that such action not be taken at this time, as it considers its listed functional requirements and conditions as an adequate basis for the utility tariffs. Staff warns that protection equipment is still evolving and detailed regulations might impede such evolution. Staff states that it would be under a considerable burden if it has to develop such standards. Staff describes the tariff approach as less cumbersome and possibly leading to more rapid adoption of equitable and standardized rules. Staff suggests that the utilities should be given the opportunity to work cooperatively with QFs in developing such rules and that we consider a general order only if this approach fails.

As the final point in this regard, staff addresses the question of what requirements should be imposed on QFs regarding liability and indemnification. Staff recommends that utilities be permitted to include provisions that restate common law principles of liability and indemnity in QF contracts. Under staff's approach, utilities may require a QF to provide proof of liability insurance coverage in a commercially reasonable amount not to exceed a reasonable estimate of the utility's relevant actual risk of loss. This requirement would be waived where the QF is 20 kW or less, providing its generator delivers power to the utility grid through a dedicated transformer. Staff proposes that utilities may require a QF to name the utility as an additional insured under the QF's liability insurance, except when such naming makes it impossible for the QF to obtain liability insurance or in cases where the QF is 100 kW or less in size.

C. Utility Responses

PG&E agrees generally with staff's identified functions of protective equipment. PG&E suggests that "harmful wave forms" be added as an additional adverse condition that the QF is required to provide protection against.

PG&E agrees generally with staff's discussion of QF and utility responsibilities. However, PG&E does propose to allow utilities to require QFs of 1 MW or larger to use utility grade interconnection equipment, while QFs of less than 1 MW may employ industrial quality interconnection equipment that meets state and local codes.

PG&E proposes to expand the scope of staff's treatment of small QFs to allow utilities to require QFs to maintain records of when the unit was not available for operating maintenance outages, trip operations due to faults, and other unusual events, and to allow the utilities to reserve the right to review such records.

Edison objects to staff's suggestion that "industrial quality relays" are adequate for all interconnection protection, regardless of size. Edison states that there are good reasons to employ utility quality devices in specific instances where close coordination of the utility and QF protective devices is required to maintain reliable service from the QF and the utility. Edison claims that large QF generators are significant sources of short circuit current when connected to a distribution system and must be closely coordinated with existing utility relays to ensure reliable operation and avoid false operations. In many cases industrial grade relays do not have the necessary flexibility, stability, or calibration accuracy to allow coordination with utility system relays.

Regarding the respective responsibilities of the QF and utility with respect to equipment design, installation, operation, and ownership, Edison recommends that operators who elect to provide the interconnection protective equipment themselves shall be responsible for any damage or injury to the public, utility personnel or equipment, or to other utility customers and their equipment, caused by the generating facility. If the operator elects to have the utility provide the equipment, the utility shall be responsible for such damage or injury.

Edison characterizes staff's recommendation regarding liability and indemnity provisions as "acceptable as far as it goes." However, Edison claims that the common law has been supplemented to some extent by statutory law and suggests that a restatement of that statutory law appear in contracts. In particular, Edison refers to an alleged obligation to reimburse the indemnitee for all costs incurred or all out-of-pocket costs or all judgments paid or all damages suffered, including appropriate attorney's fees and other costs of litigation.

SDG&E agrees with staff's recommended functional standards. However, it does not agree that staff's proposed condition (e) is required for QFs under 100 kW, because most customers at that level are expected to connect to its system with a delta wye transformer.

SDG&E agrees that the QF has responsibility for protecting its own system, equipment, the public, and utility operating personnel. It further agrees that QF designs for interconnection should be subject to utility review for functional adequacy. SDG&E offers its own schedule for review, suggesting a minimum of six and a maximum of eight weeks. SDG&E does not agree that the QF should have the option of paying the utility to install interconnection protection equipment. SDG&E objects that the QF should not be allowed "to transfer the funding of this responsibility to the utility."

With regard to liability and indemnification issues, SDG&E states that staff's reference to common law is neither helpful nor appropriate. SDG&E suggests that utilities and cogenerators should be permitted to continue as they have in the past to write indemnification provisions as they feel necessary.

SDG&E objects to staff's treatment of QFs of very small QFs that provide power to the grid through a dedicated transformer. SDG&E states that size has little to do with the extent of liability which may be incurred by a QF due to an accident. SDG&E asserts that, as the size the the QF diminishes, the need for insurance increases because the QF's own resources tend to be smaller. Based on the same reasoning, SDG&E opposes staff's recommendation that small QFs be excused from naming the utility as an insured under specified circumstances.

D. Third Party Comments

CEC agrees that this Commission should take definitive action regarding interconnection and parallel operation to establish as much standardization as feasible. CEC states that staff did properly require the QF to protect against electric service degradation, equipment damage, and harm to others by providing a series of events for which protection must be provided. However, CEC complains that staff left the establishment of the actual criteria to the utilities. CEC suggests that interconnection requirements may be appropriately considered in a separate proceeding because of the complexity of the issue, but should not be left unresolved.

Union is concerned that utilities may impose costly and unnecessary burdens on QFs in the absence of clear interconnection guidelines. Union states that interconnection costs should be net costs and the Commission should incorporate an appropriate discount factor in order to recognize that some interconnect costs would have been incurred if the utility had constructed its own facility. Further Union proposes that the utility's ability to oversee and approve the technology and equipment selection of a QF should be narrowly confined.

As stated above, MPS requests that we provide for evidentiary proceedings to investigate and adopt standards to ensure system safety and reliability of interconnected operations. MPS states:

> "This Commission should recognize that the control methods available to QFs inherently limit the technological opportunities which can be safely and economically developed and offered in the marketplace."

MPS objects to the unilateral imposition of burdensome or incompatible control methods by utility personnel who are neither qualified nor familiar with the technologies to which these methods will be applied.

Mr. Holbrook of Power Towers, Incorporated (Holbrook), observes that, of the several utility intertie proposals, staff seems to endorse the most stringent. In particular Holbrook objects to the isolated transformer requirement as technically unnecessarily and economically devastating to many potential applications for wind power. Holbrook also describes the difficulties of a wind generator vendor and buyer where a third party (the utility) is in a position to subsequently determine the feasibility of a facility.

Henwood states that there will be honest differences of opinion between QFs and utilities regarding appropriate types and quality of interconnection facilities. Since these differences can have rather significant cost impacts, Henwood states that Commission review of utility interconnection requirements is necessary to reach an equitable solution.

Henwood argues that the only way the QF can maintain control over interconnection costs is to have the option to design, construct, and maintain its own interconnection facilities.

Henwood objects to the utilities being named as insured, as suggested by staff, because of the cost to the QF.

Pan Aero states that the QF should have several options regarding interconnection costs, including: (1) to pay for its interconnection equipment and to own and maintain such equipment; (2) to pay the utility monthly charges for utility ownership and maintenance of interconnection equipment; and (3) to own the interconnection equipment and pay the utility only for maintenance of such equipment.

Pan Aero points out that under the staff recommendation, the QF must protect its own equipment from faults on the utility system, as well as protect the utility and its ratepayers from faults in the QF's system. Pan Aero contends that the QF should have no greater burden than the utility, and asks: "If the QF must protect the utility, why shouldn't the utility also protect the QF from faults in the utility system?"

Great Western suggests that the Commission should keep in mind the cost of interconnection equipment and the burden such costs can impose on QFs. Great Western agrees that the QF should have the option of owning and installing the interconnection equipment and that the utility should pay for any equipment the utility installs above the standard. Great Western asks that the Commission be prepared to resolve any disputes between QFs and utilities concerning the adequacy of proposed interconnection plans.

Great Western argues that there is no need for indemnity provisions. It claims that so long as each party acts with due diligence and in accordance with good engineering practice, each should have no liability to the other. Neither the utility nor the QF should be required to assume greater responsibility for losses resulting from its acts or the failure of its equipment. With respect to liability insurance, Great Western asks that such requirements be limited to preclude utilities from imposing onerous requirements on QFs.

E. <u>Discussion</u>

As stated above, the effectiveness of the standard offer will be substantially impaired if the parties nevertheless must negotiate terms and conditions of the physical connection to the utility network. We therefore believe that general uniform interconnection safety standards should be specified. A rulemaking proceeding such as this is a proper vehicle for adoption of policy guidelines for interconnection which assure integrity of both the utility and QF systems consistent with public safety.

As indicated above, staff has identified several standards which are essential for maintaining safety and reliability. No party has effectively disputed these standards, and we shall adopt them. Each utility should file parallel generation tariffs which incorporate the staff-recommended reliability standards plus a prohibition on harmful wave forms. The tariffs should incorporate compatible interconnection guidelines currently in effect, and should specify separate guidelines for QFs below 100 kW, between 100 kW and 1 MW, and above 1 MW. We agree with staff that for small QFs under 100 kW, simpler requirements should apply. We therefore find reasonable the dedicated transformer requirements and reporting standards recommended by staff for QFs under 100 kW. Similarly, we expect simplified interconnection requirements for QFs between 100 kW and 1 MW. For all QFs, diagrams of illustrative interconnection configurations should be included.

We expect that the QF will attach interconnection equipment which is compatible with the protective standards incorporated within the utility's parallel generation tariffs. We agree with staff that the QF has responsibility for conforming to these standards to assure system integrity and safety. By placing this responsibility upon the QF we do not believe it necessary to endorse any specific type of interconnection equipment so long as the QF's equipment meets the protective standards outlined. We expect, however, that QF equipment will meet applicable and local safety codes. Except for the utility manual disconnect and feeder reclose blocking equipment, the QF shall have the option of owning, operating, and maintaining the interconnection equipment, or paying the utility to do so. With this option the QF can maintain a degree of control over interconnection costs. Costs of equipment in excess of the minimum standards we have prescribed should be borne by the party requesting the equipment.

Liability and indemnification provisions contained in the standard offer should restate principles of common law and current statutes. We believe it appropriate for a QF to provide coverage at a commercially reasonable amount, consistent with the utility's actual risk of loss. In addition it is reasonable to require QFs over 100 kW in size to name the utility as an additional insured under the QF's policy, except when such naming precludes the QF from obtaining liability insurance. This requirement is consistent with generally recognized practices in commercial contracts.

The tariffs which the utilities shall file will be subject to preliminary review by our staff, and accepted for filing on an interim basis. Unique situations should be handled by a deviation procedure under General Order 96-A. We make these tariffs interim in recognition that interconnection requirements are still evolving. We make no final judgment at this time regarding specific technical requirements necessary to assure operating reliability. We recognize that wide differences of opinion exist as to particular requirements which may need to be the subject of a general order. Accordingly, after six months we shall review these tariffs to assess their effectiveness, and, at that time, shall determine whether more detailed requirements are appropriate.

VIII. Interconnection Costs

A. Introduction

FERC Regulation Section 292.306 provides that each QF shall be obligated to pay any interconnection costs which the State regulatory agency may assess against the QF on a nondiscriminatory basis with respect to other customers with similar load characteristics. The State regulatory agency shall determine the manner for payment of interconnection costs, which may include reimbursement over a reasonable period of time.

FERC Regulation Section 292.101(b)(7) defines "interconnection costs":

> "'Interconnection costs' means the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs."

There is an obvious relationship between certain of these costs and the standards of operating reliability discussed above.

B. Positions of the Parties

Staff states that in order to determine what are reasonable interconnection costs it is first necessary to determine what are the minimum acceptable interconnection standards.

Staff recommends that a procedure similar to the special facilities provisions of existing tariff schedules should be established for interconnection costs. Staff proposes that the QF have the option to either: (1) advance to the utility the estimated net installed cost of the interconnection facilities and also pay the monthly cost of interconnection ownership charges as authorized in the utility's interconnection tariff, or (2) not elect to advance the estimated installed cost of the interconnection facilities and instead pay a monthly combined charge for added facilities as authorized in the interconnection tariff. Such a charge would cover both facilities and ownership costs. With the second option, the customer agrees to pay the net unpaid balance, including interest, of the installed cost of the interconnection facilities, plus removal charges, less estimated salvage value. Staff proposes that CP National Corporation be excused from this approach on account of its status as a buyer of its entire requirements in California. Instead, CP National Corporation could include the method of payment either in its contracts with individual QFs or in separate facilities contracts.

PG&E agrees with staff's recommendation, with certain modifications. PG&E suggests that when an agreement is terminated, the QF may be entitled to a refund of part of its advance payment to the utility. PG&E proposes that the QF may be required to make an additional payment to cover the cost of the equipment removal and outstanding installation expenses.

Edison states that although staff's list of protective functions is relatively complete, specific instances will require additional equipment, most likely in the cases of large generators. In such cases Edison contends that the need for the equipment will be apparent and the utility and QF will mutually agree that it is necessary. Edison suggests that the QF should pay for the equipment in such cases.

SDG&E states that the costs of interconnection as specified by the utility should be borne by the QF. If the Commission finds that SDG&E's interconnection guidelines are not reasonable, SDG&E is "willing to discuss revisions" to its interconnection guidelines.

SDG&E objects to staff's proposal that the QF have the option to obligate the utility to make a capital investment for interconnection costs. SDG&E states that to require the utility to add this funding burden to its other capital requirements negates one of the largest benefits of cogeneration. SDG&E suggests that utility funding be at the option of the utility.

C. Discussion

The basic proposition is straightforward. Each QF is responsible for the cost of interconnection which exceeds the cost the utility otherwise would incur to connect the QF as a customer. The costs of interconnection borne by the QF shall be only those costs necessary to meet the minimum reliability standards discussed above. The cost of additional requirements imposed by the utility shall be borne by the utility.

We are satisfied that staff has provided a sound payment basis, as modified by PG&E. SDG&E's concern regarding the possible financial burden of utility financing can be taken into account in calculating avoided costs, if an evidentiary basis can be shown.

Some QFs, particularly smaller ones, may require distribution-type line extensions. Wherever such line extensions are comparable to those serving residential or commercial customers, the charges to the QF should also be comparable to those charged other utility customers, including refunds to customers. Distribution-type line extensions costs presently are covered in utility Tariff Rules Nos. 15, 15.1, and 15.2. Unless the QF's load characteristics on any line extensions required for the QF are different than for regular utility customers, the line extension costs should be the same for each to avoid discriminatory pricing practices.

IX. System Emergencies

FERC Regulation Section 292.307 provides that a QF shall be required to provide energy or capacity to an electric utility during a system emergency only to the extent: (1) provided by agreement between such QF and electric utility; or (2) ordered under Section 202(c) of the Federal Power Act. During any system emergency an electric utility may discontinue (1) purchases from a QF if such purchases would contribute to such emergency; and (2) sales to a QF provided that such discontinuance is on a nondiscriminatory basis. A "system emergency" is a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property.

There is little discussion of this point among the parties. The standard offer adopted by this decision for as-available electricity does not obligate the QF to be available during an emergency. Staff states that there are adequate incentives built into pricing offers to encourage QFs to be on-line when system emergencies are likely to occur.

Capacity payments for firm capacity under standard offers neither obligate the QF to separate its load and resources nor obligate QFs to curtail their own load during emergencies. The added costs of such separation of the load and resource would be excessive and of questionable value. QFs that continue to buy power from the utility in excess of their generation, through standby rates or under a simultaneous purchase and sale arrangement will, of course, be subject to curtailment in accordance with systemwide curtailment policies as established by the Commission. To qualify for a firm capacity payment, however, the QF will be expected to operate at maximum capacity on notice to meet utility needs for capacity during peak-load periods and emergencies, consistent with limitations which may exist at the time in the QF's equipment, fuel, or other source of energy. Capacity in excess of the QF load, should be available to the utility during emergencies to the extent the utility can use the electricity and it is practical for the QF to make delivery.

Utility Incentives

We believe that one idea not addressed in this proceeding deserves consideration. In most markets, brokers receive a fee for their role as intermediaries between buyers and sellers. Similarly, it could be argued that utilities in their roles as intermediaries between QFs and ratepayers should receive a small fraction of the avoided cost payment as a brokerage fee. For example, utilities might receive one-half of one percent of the avoided cost payment, leaving QFs with the remaining 99.5 percent. We specifically are not suggesting here that consumers pay an additional payment to utilities beyond the avoided cost. We invite interested parties to comment within 45 days on whether utilities should receive such a fee as an incentive for good performance in their role as a broker. We would also be interested in any specific proposals for establishing such fees.

X. Implementation

In this decision, we have decided that a qualifying facility should be presented with options in the standard offer, each of which is consistent with avoided cost principles but which also has different terms and conditions to meet different needs of the qualifying facilities. The options we order in this decision today do not exhaust the different arrangements that we can envision that are consistent with avoided cost pricing. We may conceivably order others in the future, or refine those adopted prospectively as appropriate.

As we stated earlier, additional hearings are required to complete this process. However, some offers are similar to those that have been filed already by the utilities in response to Resolution E-1872 (March 4, 1980), and we expect that these offers can become available without prolonged review. Others will require further hearings. Specifically, the "as-available" offer and the offer for firm capacity (based on the short-run marginal cost methodology) should be implemented quickly, while the levelized, escalating, and resource plan-based offers will require more extensive hearings.

Accordingly, we adopt the following schedule for submission.

Each respondent shall file the offers for (1) as-available energy and capacity and (2) firm capacity (based on the short-run marginal cost methodology) with this Commission as an application within 45 calendar days from the date of this order. The offers should include contract terms and conditions complying with the guidelines developed in this decision. Utilities filing these applications shall serve them on all parties to this proceeding.

Because the forms of the as-available and firm capacity offers are similar to the interim price schedules currently being offered by the respondents under Resolution E-1872, and because the information to support the prices contained in these offers is developed in general rate cases, these offers may take effect expeditiously. The staff will review these offers upon filing, and the offers will take effect two weeks after the date of filing unless the Commission acts to suspend any of the offers, pending review at hearing. QFs may accept these offers as soon as they become effective, and costs incurred by utilities pursuant to the resulting contracts are reasonable and may be recovered in the same fashion as other purchased power costs.

Each of these offers will be reviewed in subsequent evidentiary hearings which may result in prospective modifications to the offers but which in no way will affect either the validity of contracts resulting from the initial standard offers or the utilities' recovery of their costs under such contracts. These evidentiary hearings, furthermore, will be narrowly restricted to the issues of each utility's compliance with the requirements of this decision and of the factual basis for the prices contained in each standard offer. The evidentiary proceeding will <u>not</u> be a forum for reexamining the issues resolved in this decision. QFs who believe that beneficial modifications to the standard offers may result from the evidentiary hearings may accept the utilities' initial standard offer for a short term and later accept any modified offer upon the expiration of the initial contract. A QF who is satisfied with a utility's initial standard offer may contract for a longer term with the assurance that any later modifications will be prospective only and will not alter its agreement with the utility.

In D.93054 dated May 19, 1981 (as modified in D.93393 dated August 4, 1981), we required a provision in respondents' interim price schedules which gave QFs who entered into contracts with utilities after May 19, 1981 and before the conclusion of this proceeding the option of amending their agreements to conform with "the final decision and order" in OIR 2. Because such QFs were apparently somewhat satisfied with their agreements with the utilities, and to avoid excessive amending of these agreements, we determine that the proper time for consideration of conforming amendments is the completion of our evidentiary review of the appropriate standard offer. Thus, after we have reviewed, for example, a utility's standard offer for as-available energy and capacity and have ordered any necessary modifications, a QF who had earlier contracted on an as-available basis with that utility may convert its contract to the new standard contract. Such a QF need not, of course, wait until the completion of our review of all forms of the standard offer before exercising its option.

The other standard offer contracts (e.g. levelized, escalating, and resource plan-based contracts) adopted in this decision will require more extensive hearings. These offers shall be submitted as applications to the Commission under the guidelines set out above within 90 calendar days from the date of this order and shall be served on all parties to this proceeding. We will hold pre-hearing conferences in those proceedings after they are filed, and determine the scope of the subsequent hearings.

Findings of Fact

1. The California Legislature and the Public Utilities Commission have a longstanding demonstrated interest in promoting cogeneration and small power production.

2. Cogeneration and small power production have also been the subject of federal actions intended to promote their development, particularly Sections 201 and 210 of PURPA.

3. Each electric utility is required under Section 210 to offer to purchase available electric energy from cogeneration and small power production facilities which obtain qualifying status under Section 201. PU Code Section 2821 enables the CPUC to establish equitable charges for purchases of power from private energy producers.

4. For such purposes electric utilities are required to pay rates which are just and reasonable to the ratepayers of the utility, in the public interest, and which do not discriminate against cogenerators or small power producers.

5. Section 210 also requires electric utilities to provide electric service to QFs at rates which are just and reasonable, in the public interest, and which do not discriminate against cogenerators and small power producers.

6. Section 210 further requires the FERC to prescribe rules as FERC determines necessary to encourage cogeneration and small power production.

7. On February 19, 1980, FERC issued its final rules implementing Section 210. These regulations require that electric utilities purchase electric energy and capacity from qualifying cogenerators and small power producers at a rate equal to the utility's avoided cost of generating the power itself or purchasing it elsewhere.

8. The implementation of the Section 210 rules is reserved to the appropriate state regulatory authorities.

9. By OIR 2 dated September 3, 1980, this Commission initiated this proceeding for the purpose of establishing standards under the FERC rules, to further implement our decision in D.91109, and to discharge our responsibilities under PU Code Section 2821.

10. Among the criteria describing a QF under Section 201 is a limit of 50% utility equity ownership interest.

11. Utility ownership of a QF will require scrutiny of the relationship between the utility and its affiliate.

12. Utility ownership of an energy resource developed by a nonutility QF does not defeat the application of avoided cost principles.

13. The profitability of sales of a utility-owned resource to a QF should be considered in a general rate case.

14. Sierra and PP&L are unique, in view of their relative size, location, and system configuration.

15. A water diversion does not involve the direct sale of electricity by a QF and therefore is beyond the scope of this proceeding.

16. Under the FERC rules, each regulated utility is required to file projections of its incremental energy and capacity costs and its construction schedules with its state regulatory authority for review and use in setting appropriate rates for purchase and sale of electricity between electric utilities and QFs.

17. FERC rules require certain specified factors to be taken into account to the extent practicable in determining avoided costs.

18. FERC rules require certain specified data to be filed by electric utilities for the purpose of avoided cost calculations.

19. Additional data, as proposed by staff, would be valuable in developing standard offers and in aiding QFs in forecasting the direction of avoided costs over time.

20. CP National buys its electrical requirements from PG&E and Nevada Power Company.

21. Social costs are tangible but hard to quantify factors that are difficult to include in avoided cost calculations.

22. FERC rules provide for a standard offer for purchases by a utility from a QF.

23. FERC rules provide that utility purchases from a QF shall be at the utility's avoided cost.

24. Avoided costs reflect the added costs to a utility of producing an additional unit of electricity.

25. Purchases by an electric utility from a QF under a standard offer are recoverable through ECAC or other appropriate procedures without further review.

26. The standard offer is a choice of contract terms at the QF's sole option.

27. The QF may choose to provide firm energy or capacity, based on either the utility's avoided costs at the time of delivery or the time the obligation is incurred.

28. The QF may choose to provide energy as-available, based on the utility's avoided cost at the time of delivery.

29. Calculation of the utility's avoided energy cost at the time of delivery is based on the variable cost of providing an additional unit of electricity.

30. As-available energy payments are properly differentiated by time-of-use.

31. Transmission and distribution costs are not practically treated on an individual basis and should be treated in the aggregate.

32. Costs or savings resulting from variations in line losses should be aggregated for standard offer purposes.

33. The "reduction in demand" model is a useful tool for analyzing whether QFs should receive a capacity payment for the delivery of as-available energy.

34. Aggregate capacity value is recognized by the "reduction in demand" approach consistent with FERC regulations.

35. The higher the payment for capacity associated with as-available energy, the more likely such capacity will be provided during system peaks.

36. QF production will grow in increments that will provide an opportunity to prove reliability through experience.

37. The impact on the system of the failure of individual QFs is not comparable to the impact of the failure of a large central station facility.

38. Calculation of the utility's avoided capacity cost at the time of delivery is based on the utility's estimate of current shortage costs.

39. As-available capacity payments should be based on performance, adjusted by time period, and paid in cents per kWh.

40. The as-available capacity payment is based on 100% of the annual capacity value of the utility's current shortage costs.

41. As-available capacity costs include generation and generation-related transmission costs.

42. Contract length, notice, termination, and sanction provisions are not related to as-available capacity value.

43. Capacity payments for as-available hydro should not differ from other technologies.

44. The option for the QF to be paid based on costs calculated at the time the obligation is incurred allows a QF the certainty of a known price.

45. The energy component in a long-term contract is based on forecasted short-run marginal operating costs.

46. FERC rules allow for levelized energy payments.

47. Estimates of future fuel costs are an integral part of utility resource planning.

48. Forecasted energy payments for up to five years are reasonable.

49. Levelized energy payments are not an appropriate payment option under the standard offer.

50. To the extent that an individual QF provides firm capacity that allows additional costs to be avoided, these additional costs should be reflected in a higher payment to the QF.

51. The firm capacity payment associated with a short-run energy cost is based on a short-run marginal cost methodology in which the capacity payment reflects the costs of a shortage to the utility.

52. Firm capacity payments properly reflect the QF's availability during peak periods, including: dispatchability; reliability; contract duration, termination, and sanctions; scheduling of outages; and availability during emergencies. The value of these factors should be computed on a cents per kWh basis as well as a dollars per kW per year basis, so that a QF that exceeds reliability standards will be paid accordingly.

53. The payment for firm capacity should be uniform to all QFs, except hydro.

54. Special provisions are necessary for small hydro QFs offering firm capacity to reflect adjustments for dry year unavailability.

55. The firm capacity value of a hydro QF is reasonably based on an average of the five lowest flow years.

56. Payment for firm capacity should differentiate between small hydro producers based on actual stream flows.

57. A levelized firm capacity payment for up to thirty years is reasonable.

58. Up-front capacity payments would introduce an element of substantial risk into the standard offer.

59. Loans and guarantees greatly increase the expense to the ratepayer and should be provided only after a thorough evaluation of the proposed project.

60. Insofar as an improved reserve margin always improves reliability at least to some degree, the capacity payment always has some positive value.

61. FERC rules provide that utility purchases are not required during any period during which, due to operational circumstances, purchases from QFs will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself.

62. Economy energy purchases are not a condition that permits a utility to refuse to purchase from a QF.

63. The right to refuse purchases from QFs arises only when the avoided cost at the time of delivery would be less than zero.

64. The QF is entitled to reasonable notice prior to a utility's refusal to purchase.

65. Notice to baseload or intermediate QFs of a utility's refusal to purchase at least 48 hours is a reasonable minimum. Two hours notice is reasonable for QFs with peaking-type plants.

66. Utilities should set priorities, as proposed by staff, for refusals to purchase from QFs.

67. Before refusing to purchase the utility should undertake to make economy sales on behalf of the QF. In such cases. the QF is paid based on the economy energy price and no wheeling charge may be imposed by the utility.

68. A report should be filed annually by each utility regarding refusals to purchase from QFs.

69. Simultaneous purchase and sale is a regulatory convention that allows a QF simultaneously to sell its own generation to the utility while purchasing its requirements from the utility.

70. Generally, the QF should be able to convert to and from simultaneous purchase and sale subject to reasonable notice and compensation provisions. QFs which select the option of forecasted or levelized energy payments under a long-term capacity contract must commit their entire output to the utility.

71. FERC rules require standard rates for purchases from QFs with a design capacity of 100 kW or less.

72. The standard offer for small QFs should be expressed in terms of cents-per-kWh and be offered on either a time or nontime differentiated basis.

73. The small QF should have the choice whether to have time differentiated payments, subject to paying for the necessary meter.

74. Time differentiated metering will be required for small QFs electing the simultaneous purchase and sale option and QFs selling a majority of their power to the utility under the sale of surplus power option.

75. Advance review will reduce the utility's risk in signing nonstandard contracts.

76. Payments under nonstandard contracts are recoverable through ECAC or other appropriate proceedings upon a showing of reasonableness.

77. A contract negotiation schedule would be difficult to enforce.

78. Wheeling can make a material contribution to cogeneration and small power production

79. FERC rules require that each utility provide: (1) supplementar power; (2) backup power; (3) maintenance power; and (4) interruptible power.

80. FERC regulations provide that the rate for sales of backup or maintenace power should not be based on an assumption that QFs will fail to provide power simultaneously or during system peaks, or both.

81. QFs are now furnished supplementary power under regularly filed tariffs applicable to all customers of the same class as the particular QF.

82. Standby rates should not be a mjaor factor in a QF's decision whether to elect simultaneous purchase and sale.

83. Current basic standby rate levels in dollars per kW per month are reasonable as modified in this decision and may reasonably be increased in general rate cases in proportion to increases in per kW capacity costs.

84. The elimination of standby charges for months in which a QF attains an 85% on-peak capacity factor will provide a desirable incentive for reliable availability at the most critical times.

85. Standby rates should be derived residually, based on the calculation of avoided costs and the determination of retail rates.

86. Since payments to QFs are based on the utility's avoided costs, a QF that is undergoing maintenance during peak periods foregoes payments at the most lucrative time.

87. It is premature to develop standby rates for QFs not currently served by rate schedules with demand schedules.

88. Standby rates should generally be extended to all QFs with demand schedules. They should not be finalized for new technologies like photovoltaics until more analysis is possible.

89. It is reasonable to establish time-of-use-based standby rates to distinguish the impact of QF failure upon a utility. On-peak failure is appropriately accounted for with a demand payment with a three-month ratchet.

90. QFs that contract to provide firm capacity are properly subject to the utility's scheduling requirements.

91. The provisions set forth in PG&E's Special Condition 2 to Schedule S-1 provide a reasonable standard for scheduling maintenance and exemptions from added demand changes.

92. Some QFs will have no opportunity to schedule maintenance to conform to utility peaks because of the nature of the QF's operations.

93. It is reasonable that QFs with seasonal operations shall pay added demand charges with a three-month ratchet if they cannot coordinate maintenance with a utility's schedule.

94. Interruptible rates should be available to larger QFs on time-of-use rates.

95. Interruptible service can provide both capacity and energy savings.

96. FERC rules provide for reasonable standards to ensure system safety and reliability of interconnected operations.

97. Such standards are crucial to the success of this entire program because the effectiveness of the standard offer will be defeated if protracted negotiations occur over conditions of actual delivery of energy and capacity.

98. Staff has identified various functional standards which are essential for safe and reliable operations.

99. FERC rules require that each QF shall be obligated to pay any interconnection costs which the state regulatory agency may assess against the QF on a nondiscriminatory basis.

100. Interconnection costs are related to reliability standards.

101. Interconnection facilities are analogous to special facilities provisions of existing tariffs.

102. FERC rules require a QF to provide energy or capacity to an electric utility during a system emergency only to the extent: (1) provided by agreement between such QF and electric utility; or (2) ordered under Section 202(c) of the Federal Power Act.

103. Adequate incentives are built into standard offers to encourage QFs to be on-line when system emergencies are likely to occur.

Conclusions of Law

1. The rulemaking procedure is an appropriate vehicle for establishing standards governing prices, terms, and conditions of electric utility purchases of electric power from qualifying cogeneration and small power production facilities under FERC rules.

2. Motions by Edison, SDG&E, and MPS are denied.

3. A QF owned in part by an electric utility is eligible for full avoided costs under the conditions adopted in this proceeding.

4. Utilities and QFs remain free to negotiate contracts containing terms which differ from those of the standard offer.

5. Additional data as proposed by staff is useful in validating the avoided cost methodology.

6. The standard offer should provide for a capacity payment for as-available energy.

7. The standard offer should provide for a forecasted energy payment.

8. A QF willing to commit to provide firm capacity should receive a higher capacity payment than a QF on an as-available basis.

9. The standard offer should provide for a levelized firm capacity payment for up to thirty years.

10. The standard offer should provide for prices based on long-run marginal cost.

11. Loans and guarantees should not be included in the standard offer.

12. Refusals to purchase should be arranged by technology and reasonable notice should be provided.

13. Simultaneous purchase and sale should be at the QF's option, subject to reasonable conditions.

14. The standard offer should provide for simplified rates for QFs of 100 kW or less.

15. Section 2821 of the Public Utilities Code does not require advance review of nonstandard contracts.

16. A utility's willingness to wheel should be considered as part of its overall conservation activities.

17. Utilities should offer supplementary power, standby power, maintenance power and interruptible power consistent with this decision.

18. The Commission should entertain formal complaints raised by QFs who can demonstrate that the utility has failed to bargain in good faith. A utility found not to have bargained in good faith would stand in violation of this order and will be open to potential punitive action by this Commission.

ORDER

IT IS ORDERED that:

1. Within 45 days of the effective date of this order, each utility shall file the following data:

   a. System avoided operating (running) cost in cents per kWh annually and by costing period in nominal and real cents per kWh by voltage level for 10 years. The marginal fuel (s) by each costing period and the nominal and real escalation rates used to estimate their cost will be reported. System incremental heat rates by time of use for 10 years (correlated with incremental fuel costs) will also be provided.

   b. The electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, for capacity retirements and for terminations of contracts for purchased capacity for each year during the planning horizon, for a minimum of 10 years.

   c. The estimated capacity costs at completion of the planned capacity additions and planned firm purchases, on the basis of dollars per kW, dollars per kW per year, dollars per kW per month, and cents per kWh (using the projected capacity factor) and the associated energy costs of each unit in cents per kWh. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases.

   d. The estimated capacity costs of transmission and distribution plant in dollars per kW, dollars per kW per year, dollars per kW per month, and cents per kWh.

   e. The estimated operation and maintenance, administrative and general, and all other fixed and variable operating expenses for avoided capacity and energy used in avoided cost calculations, expressed in dollars per kW, dollars per kW per year, dollars per kW per month, and cents per kWh.

f. The system marginal cost loss factors by time of delivery and voltage for energy and capacity from generation to each voltage level. Also, the net system aggregate loss factors by time of delivery and voltage for energy and capacity, to reflect avoided losses resulting from a reasonable mix of QFs.

g. The levelized annual cost rates for translating investment costs into annual charges, and present value rates used in any present value calculations.

h. The costs expressed in paragraphs a-e above will be on a test year (real) dollar basis or on an escalated basis, with the forecast escalation rates reported in either case. All assumptions of escalation rates, discount rates, incremental fuel increases, incremental heat rates and such, will be stated.

2. Within 45 days of the effective date of this order, each utility shall file by application and serve upon all parties to this proceeding, a standard offer for as-available energy and capacity, and for firm capacity based on short run marginal cost methodology.

3. The above offers shall become effective two weeks after the date of filing, unless otherwise suspended by the Commission. Prior to compliance hearings, these offers shall be considered initial offers. Upon becoming effective, utilities shall send copies to all QFs negotiating contracts and all persons having requested copies of their price offers.

4. A QF or utility which signs an initial offer may not modify such offer until the term of the resulting contract expires. Any later modifications made by the Commission to the utility offers will be prospective only and will not alter the terms of the initial offer.

5. A QF which has contracted with the utility after May 19, 1981, and before the filing of the initial offers may modify its contract to conform to the standard contract adopted by the Commission after evidentiary hearing.

6. Utility offers for as-available energy and capacity shall, among other things:

a. differentiate payments to QFs by time of use
b. pay for capacity in cents per kWh produced
c. include transmission and distribution costs in the aggregate
d. include costs or savings from line losses in the aggregate
e. recognize the aggregate capacity value of QFs
f. base capacity payments on 100% of the annual capacity value of each utility's estimate of current shortage costs

7. Each utility shall file annual capacity payments differentiated by time of use based on the 1982 estimated cost of peaking capacity.

8. Utility offers for firm energy and capacity shall, among other things:

a. allow QFs the option of receiving avoided cost energy payments at the time of delivery or at the time the contractual obligation is incurred.
b. include the value of (1) availability during system peak periods, (2) dispatchability, (3) contract duration, termination, and sanctions, (4) scheduling of outages, and (5) availability during emergencies, and shall be comparable to performance standards the utility would impose on its own plants.
c. base capacity on the avoided (marginal) capacity cost used in each utility's last general rate case.
d. include transmission and distribution costs in the aggregate
e. include costs or savings from line losses in the aggregate
f. base the aggregate capacity value for hydro on the average of five dry years, or on other alternatives discussed in the decision.

9. Within 90 days of the effective date of this order each utility shall file by application served upon all parties, a standard offer based on a forecast of energy payments for up to five years. This option shall be available to all QFs.

10. Within 90 days of the effective date of this order, each utility shall file, by separate application served upon all parties, a standard offer for long-term firm capacity based on each utility's resource plan. Long-run marginal cost estimates shall include all fixed costs associated with each utility's resource plan, and system marginal operating costs.

11. Each utility shall file, within 45 days of the effective date of this order, by application served upon all parties, simplified standard offers for QFs below 100 kW in size. Payment for energy and capacity shall be expressed in terms of cents per kWh and shall be offered on either a time-or nontime-differentiated basis. Capacity payments on a nontime-differentiated basis shall be 50% of the annual capacity value of each utility's estimate of current shortage costs.

12. Standard offers shall allow QFs to convert to and from simultaneous purchase and sale. However, such conversions shall be limited to once per year. The option to convert from simultaneous purchase and sale to sale of surplus shall not be available to a QF which chooses the forecasted energy payment option under either an as-available or long-term contract.

13. All payments made by utilities to QFs under the standard offer and approved nonstandard contracts shall be subject to recovery in ECAC or other appropriate proceedings.

14. Utility purchases are not required from QFs during

periods when the utility's avoided cost is negative, as defined in the decision.

15. Utilities shall, whenever possible, notify QFs of the possibility that purchases may be refused, with a minimum of 48 hours notice to QFs with baseload or intermediate plants, and a minimum of two hours notice to QFs with peaking plants.

16. Curtailment for reason of nonpurchase shall be for QFs of 1 MW or larger only, and shall occur in the following order:

a. Small power producers who can inventory fuel;

b. Topping cycle cogenerators who can bypass the electric generation and save some fuel; and

c. Bottoming cycle cogenerators and small power producers.

17. Each utility shall file annually a report regarding periods during which purchases were refused for the previous year. Utilities subject to ECAC shall file in conjunction with their annual reasonableness review. PP&L shall file yearly, beginning January 31, 1983.

18. Existing standby rates shall be extended to all QFs with demand schedules. Standby charges shall be waived where the QF attains an 85% capacity factor in a given month.

Each utility shall file within 45 days alternate standby rates with a three-month ratchet for QFs on time of use rates.

19. PP&L, Sierra, and CPN shall file standby rates which recognize the seasonal operations of certain QFs in their service areas. Such rates shall provide for a three-month demand ratchet.

20. Edison and SDG&E shall expand their current interruptible service offerings to cover all QFs above the current 500 kW minimum. PG&E shall offer similar interruptible service to QFs to the extent that interruptible rates are filed for all large customers.

PP&L, Sierra, and CPN shall provide interruptible service to large QFs on a contractual basis.

21. Each utility shall file with its standard offer interim parallel generation tariffs which specify interconnection reliability

and safety requirements. These tariffs shall incorporate the functional standards adopted in this decision. The tariffs shall specify separate guidelines for QFs below 100 kW, between 100 kW and 1 MW, and above 1 MW.

A QF shall have the option of owning, operating, and maintaining the interconnection equipment, or paying the utility to do so.

22. Utilities shall require QFs to pay for interconnection costs. The QF shall be granted the option either to: (1) advance to the utility the estimated cost of the interconnection facilities and also pay a monthly charge as authorized by the Commission, or; (2) not advance such additional costs and pay a monthly charge as authorized by the Commission. The QF shall pay a facility termination charge defined as the estimated installed cost, plus the estimated removal cost, less the estimated salvage value for interconnection facilities to be removed. The utility shall deduct from the termination charge the advance previously paid, if any. If the advance paid is greater than the termination charge, the utility shall refund the difference without interest to the QF.

23. Each utility shall file a report beginning January 31, 1983, indicating the extent of wheeling performed during the previous year. Such report shall name the parties for whom wheeling was performed, include the terms and conditions, and technical arrangements of the transaction, and describe the status of any pending requests to wheel. The report shall also describe the circumstances relating to any wheeling request which was refused.

24. Nonstandard contracts shall be reviewed in the manner set forth in this decision. Advance review of such contracts shall cease two years from the date of this order, unless the Commission extends it further.

25. The standard offer shall be available to all QFs for acceptance and shall be consistent with the terms and conditions provided for in this decision. It shall remain in effect until further order of this Commission.

26. PP&L shall be exempt from filing the standard price offers ordered in this decision. Instead, PP&L shall file a standard price offer based on avoided cost principles, which is consistent with its operations. Such filing shall be made by application within 45 days from the effective date of this order and shall be served upon all parties to this proceeding.

27. Sierra shall be exempt from filing standard price offers for QFs over 100 kW

28. Each utility shall bargain in good faith with QFs.

29. Each utility shall undertake outreach efforts to assure all potential QFs are aware of opportunities available pursuant to this order. Particular emphasis should be placed on notice to small business and minority organization.

This order is effective today.

Dated January 21, 1982, at San Francisco, California.

JOHN E. BRYSON
President
RICHARD D. GRAVELLE
LEONARD M. GRIMES, JR.
VICTOR CALVO
Commissioners

Commissioner Priscilla C. Grew
present but not participating.

APPENDIX A

LIST OF APPEARANCES

Respondents: Robert Ohlbach and David L. Ludvigson, Attorneys at Law, for Pacific Gas and Electric Company; Eugene Wagner, Attorney at Law, for Southern California Edison Company; Stoel, Rives, Boley, Fraser & Wyse, by Thomas Nelson, Attorney at Law, for Pacific Power & Light Company; Margaret Sullivan, Attorney at Law (Colorado, Iowa), for San Diego Gas & Electric Company; and John Vetromile, for CP National.

Interested Parties: Laura B. King, for the Natural Resources Defense Council (NRDC); Morrison & Foerster, by Alan Cope Johnston, Attorney at Law, for Great Western Malting Company/Windfarms, Ltd.; Robert W. Schempp, for The Metropolitan Water District of Southern California; Hanna & Morton, by R. Lee Roberts, Attorney at Law, for Occidental Geothermal, Inc.; John Curtis Lakeland, for Mass-Production Systems; Matthew V. Brady, Attorney at Law, for the California Energy Commission; Harry K. Winters, for the University of California; Harvey M. Eder, for Public Solar Power Coalition; Miller, Balis & O'Neil, by Robert A. O'Neil, Attorney at Law (Massachusetts, District of Columbia), for the City of Alameda (Bureau of Electricity); Bryan Gross, for South San Joaquin and Merced Irrigation Districts; C. Hayden Ames, Attorney at Law, and Carthrae M. Laffoon, for Geothermal Generation, Inc.; P. R. Mann & Associates, by Philip R. Mann, Attorney at Law, and Robert E. Burt, for the California Manufacturers Association; James W. Gruebele and Gary Olsen, for the Dairyman's Cooperative Creamery Association; Bert Brook, for the Hudson Lumber Company; C. Edward Taylor, for Louisiana-Pacific Corporation; Donald Hardy, for Pan Aero Corporation; Randall Tinkerman, for Transition Energy Projects Institute; Burton J. Gindler, Attorney at Law, for Kelco; McDonough, Holland & Allen, by Bruce McDonough, Attorney at Law, for San Bernardino Valley Municipal Water District; Harry Davitian, for San Diego Energy Recovery (SANDER) Project; David K. Takashima, for Agricultural Council of California; Mark Henwood, for Henwood Associates, Inc.; Neil K. Holbrook, for Power Towers, Inc.; Frank Hodgson, for Hans W. Wynholds Company; J. C. Solt, for Solar Turbines, Inc.; Latham & Watkins, by David L. Mulliken, Attorney at Law, for Solar Turbines International; Michael McQueen, Attorney at Law, for Union Oil Company of California; and Otto J. M. Smith and Kenneth R. Meyer, for themselves.

Commission Staff: Sara Steck Myers, Ellen LeVine, and Brian T. Cragg, Attorneys at Law, and John Quinley.

(Notice: This glossary is intended to aid the reader in understanding this decision. Legally binding definitions must be derived from the context of the decision and applicable FERC rules.)

GLOSSARY
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AGGREGATE VALUE - The value of electricity production to the entire utility system as opposed to more local conditions, e.g. avoided transmission and distribution costs may be aggregated over the utility's entire system and paid to a QF on a prorated basis without regard to its distance from the load center.

AS-AVAILABLE ENERGY/CAPACITY - Electricity provided by a QF to a utility as it becomes available, rather than at prearranged times and in prearranged quantities.

AUXILIARY POWER SOURCES (APS) - Electric generating facilities designed to be used in the event of an outage on the local utility grid.

AVERAGE COST PRICING - The pricing of electric service designed to recover the total costs on a system in order to make total revenues (including rate of return) equal to total costs. Total costs are based on costs as recorded in books of account and forecasted to be recorded in such accounts.

AVOIDED COSTS - The incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.

BACK-UP POWER - Electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.

BASELOAD - The minimum continuous load on a power system over a given period of time.

BIOMASS - Any organic material not derived from fossil fuels.

BIOMASS CONVERSION - The process of conversion of any organic material not derived from fossil fuels (such as wood waste, rice hulls, walnut shells, etc.) into electricity or energy.

BOTTOMING-CYCLE COGENERATION FACILITY - A cogeneration facility in which the energy input to the system is first applied to a useful thermal energy process, and the reject heat emerging from the process is then used for power production.

GLOSSARY

CAPABILITY - The maximum load which a generator, turbine, transmission or circuit, apparatus, station, or system can supply under specified conditions for a given time interval without exceeding approved limits of temperature and stress.

CAPACITY - The load for which a generator, turbine, transformer, transmission circuit, apparatus, station, or system is rated. Capacity is also used synonymously with capability.

CAPACITY COSTS - Those costs associated with capital investments in electricity production and delivery.

CAPACITY FACTOR - The ratio of average load on a generating resource to its capacity rating during a specified period of time expressed in percent.

CAPACITY PAYMENTS - Those payments which reflect the value capacity received.

COGENERATION - The sequential production of electricity and heat, steam, or useful work from the same fuel source.

COGENERATION FACILITY - Equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam), used for industrial, commercial heating, or cooling purposes, through the sequential use of energy.

COMBINED CYCLE - Waste heat from a gas turbine topping cycle is utilized for the generation of electricity in a steam turbine/ generator system, thereby increasing the efficiency of heat utilization.

CURTAILMENT - A period during which a utility declines to purchase available electricity from a QF, generally due to low demand or system maintenance requirements.

DEBT SERVICE - Periodic payments due on loans made to a QF.

DISPATCHABILITY - That condition of the qualifying facility whereby, through engineering design, installed equipment, operating conditions, and procedures, the electric utility has the ability to dispatch the facility for operation at any time, in a manner agreed upon by the parites.

ECAC (ENERGY COST ADJUSTMENT CLAUSE) - Periodic adjustments of utility rates to reflect fuel and related costs.

ENERGY COSTS - Those costs associated with fuel use in electricity production.

ESCALATED PAYMENTS - A payment commitment for future years determined from forecasted rates of avoided costs.

FIRM CAPACITY PAYMENTS - Payments for electricity provided in predetermined quantities and at predetermined times, which may be based on avoided costs at time of delivery or at the time the obligation is incurred.

FIRM POWER - Power available at all times during the period covered by the commitment, except for forced outages and scheduled maintenance. Firm power is provided with sufficient legally enforceable guarantees of deliverability to permit the purchasing electirc utility to avoid the need to construct a generating unit, to build a smaller and less expensive plant, or to purchase less firm power from another facility.

FORECAST - Future values determined by a mathematical model.

HEAT RATE - A measure of generating station thermal efficiency generally expressed as Btu per net kilowatt-hour. The average heat rate is computed by dividing the total Btu content of the fuel burned by the resulting net kilowatt-hours generated. The marginal heat rate is calculated as the additional (saved) Btu's to produce (not produce) the next kilowatt-hour.

INCREASE IN SUPPLY - An economic model of electrical production by QFs whereby such production is viewed as increasing aggregate supply of energy, implying that QFs should be subject to operating and performance standards comparable to a utility's own generating plants for purposes of determining pricing.

INTERCONNECTION - The physical system of electrical transmission between the QF and the utility.

INTERCONNECTION COSTS - The reasonable costs of connection, switching, metering, transmission, distribution safety provisions, and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs.

INTERRUPTIBLE POWER - Electric energy or capacity supplied by an electric utility subject to interruption by the electric utility under specified conditions.

KILOWATT (kW) - An electrical unit of power which equals 1,000 watts.

KILOWATT-HOUR (kWh) - A basic unit of electrical energy equal to the use of 1 kilowatt for a period of one hour.

LEVELIZATION - A financial arrangement whereby payments are constant over a specified period and are based on forecasted values and the value of money over time.

LINE LOSSES - Losses in electricity which occur during its transmission and distribution.

LOAD - The amount of electric power delivered to a given point on a system, or total amount of demand on the system.

LOAD FACTOR - The ratio of average to peak use during a specified period of time, expressed in percent.

LOAN OR BOND GUARANTEES - A utility liability which guarantees the repayment of a bond or loan on behalf of a QF in the event that the QF is unable to make timely payments.

MAINTENANCE POWER - Electric energy or capacity supplied by an electric utility during scheduled outages of the qualifying facility.

MARGINAL COST PRICING - The pricing of electric service designed to equate the rates for electric service with the marginal costs of that electric service.

MARGINAL COST - The change in total cost caused by a change in output. Marginal cost can also be understood as the additional cost to produce an additional unit of output, or the savings from producing one unit less of output (i.e. avoided cost).

GLOSSARY

MONOPOLY - A market structure in which there are many buyers but only one seller.

MONOPSONY - A market structure in which there are many sellers and only one buyer.

NATURAL GAS - Either natural gas unmixed, or any mixture of natural gas and artificial gas.

NONFIRM POWER - Electric power available as surplus only, which is supplied by the power producer at the producer's option and can be interrupted by the power producer at will.

NONSTANDARD CONTRACTS - Negotiated contracts between utility and a QF which do not conform to standard offer guidelines previously approved by the CPUC.

OIL - Crude oil, residual fuel oil, natural gas liquids, or any refined petroleum products.

PEAK LOAD - The maximum electric load consumed or produced in a stated period of time. It may also be characterized as the minimum instantaneous load within a designated interval of a stated period of time.

PURCHASE - The purchase of electric energy or capacity or both from a qualifying facility by an electric utility.

QUALIFYING FACILITY - A cogeneration facility or a small power production facility which is a qualifying facility under 18 CFR, Chapter I, Part 292, Subpart B of the FERC regulations.

RATE - Any price, rate, charge, or classification made, demanded, observed, or received with respect to the sale or purchase of electric energy or capacity, or any rule, regulation, or practice respecting any such rate, charge, or classification, and any contract pertaining to the sale or purchase of electric energy or capacity.[a]

RATE BASE - The utility investment on which the utility is allowed to earn a rate of return.

REDUCTION OF DEMAND - An economic model of electrical production by QFs whereby such production is viewed as reducing aggregate demand for energy, implying that QFs need not be subject to utility operating and performance standards for purposes of pricing determinations.

REFUSAL TO PURCHASE - See curtailment.

REFUSE-DERIVED FUELS - Fuels derived from municipal waste used as fuel for electric energy production or low Btu gases from sewage treatment plants for use in turbines.

RELIABILITY - In the context of the decision, the reliability of a QF to the electrical utility and to the system, which may be determined by a specified set of standards.

RESERVE MARGINS - Extra capacity available to: (1) meet anticipated demands for power; (2) serve load in the event of a loss of generation resulting from an unscheduled outage. Reserve margin is the ratio of excess capacity to anticipated peak load expressed as a percent.

SALE - The sale of electric energy or capacity or both by an electric utility to a qualifying facility.

SIMULTANEOUS PURCHASE AND SALE - A regulatory convention that allows a QF to simultaneously sell its own generation to the utility while purchasing its requirements from the utility; an exchange of electrical flow does not necessarily occur - the difference is cash flow.

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a/ Rates are defined in the California Public Utilities Code to include rates, fares, and charges (§ 210). § 451 of the Code identifies rates as all charges demanded or received by any public utility for a product or commodity furnished. We recognize the FERC definition of rate to include any price for purchase and use the term rate herein to refer also to prices. However, the term price is also used in this report to allow for a separate identification, in some cases, of payments for purchases from the more traditional use of the term rates as referring to charges demanded or received under filed tariffs.

GLOSSARY
Page 7

SMALL POWER PRODUCTION - Any unregulated electricity production facility as defined primarily in the FERC rules, including hydroelectric facilities, geothermal, biomass refuse-derived fuel, and wind facilities.

SOCIAL COSTS - Tangible but hard-to-quantify costs to society of an economic or technological activity.

SPINNING RESERVES - Reserves that are operated at less than the rated capacity to relieve imbalance on the system.

STANDARD OFFER - A utility offer to purchase electricity from a QF that is formed within guidelines previously adopted by the CPUC.

SUPPLEMENTARY FIRING - An energy input to the cogeneration facility used only in the thermal process of a topping-cycle cogeneration facility, or only in the electric generating process of a bottoming-cycle cogeneration facility.

SUPPLEMENTARY POWER - Electric energy or capacity supplied by an electric utility, regularly used by a qualifying facility in addition to that which the facility generates itself.

SYSTEM EMERGENCY - A condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property.

SYSTEM POWER VALUES (SPV) - PG&E's model of the marginal costs of additional capacity and energy, based in Application 58545, OII 26, and PG&E price offers on a combined cycle plant as the marginal plant.

TIME DIFFERENTIATED PAYMENTS - Payments made according to time-of-day or time-of-year delivery periods.

TOPPING-CYCLE COGENERATION FACILITY - A cogeneration facility in which the energy input to the facility is first used to produce useful power output, and the reject heat from power production is then used to provide useful thermal energy.

TOTAL ENERGY INPUT - The total energy of all forms supplied from external sources other than supplementary firing to the facility.

TOTAL ENERGY OUTPUT OF A TOPPING-CYCLE COGENERATION FACILITY - The sum of the useful power output and useful thermal energy output.

UP-FRONT PAYMENTS - Initial large outlays provided to QFs by utilities to assist in financing large capital expenses incurred for construction.

USEFUL POWER OUTPUT OF A COGENERATION FACILITY - The electric or mechanical energy made available for use, exclusive of any such energy used in the power production process.

USEFUL THERMAL ENERGY OUTPUT OF A TOPPING-CYCLE COGENERATION FACILITY - The thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application.

VALUES TO PERPETUITY - The costs (values) of owning and operating a generating plant for an infinite number of years, assuming plant replacement at the end of its useful life. Values are then levelized to the initial year.

WASTE - By-product materials other than biomass.

WHEELING - The use of transmission facilities of one utility system to transmit power to another utility system or between customer facilities within a single utility system or between utility systems.

(END OF GLOSSARY)

d. <u>Zero Capacity Payments</u>

Staff raises the following issues in regard to zero capacity payments:

> "Do utility price offers which make no payment for capacity in the first few years of the 1980's reflect the ability of the utility to avoid costs? Are they reflective of the shorter lead times available with additions of capacity from QFs? Are they just and reasonable?"

Staff concludes that costs are actually avoided each year. Reasonable calculations of actual avoided cost would include the following: identified plant, reserves, power pool prices, shortage costs, opportunity costs, and replacement costs. Therefore, "capacity rates for purchase matrices will contain no zero values (rare instances excepted), or blank entries."

Edison agrees that rates for purchase of capacity should be based on "actual avoided costs", which:

> "...may result in zero capacity value during the initial implementation period of this OIR No. 2 due to prior planning commitments, as well as during some future situations when capacity purchases would be to the disadvantage of ratepayers."

It argues that short-term QF contracts are not conducive to the development of reliable and efficient generation resources and result in unnecessary risks. It suggests that staff ignores facts and asks: "How can the Staff seek to require a capacity payment to a QF when the added capacity is of no value to the customer?" Zero capacity payments are alleged to be sometimes necessary to be fair to the ratepayer.

SDG&E agrees that "capacity benefits are never exactly zero." However, it relies on a quote from United States Supreme Court Chief Justice Warren Burger to support the proposition that such a determination is "of an adjudicative character" and can only be made in an evidentiary hearing.

PG&E supports the staff recommendation.

The issue of whether zero capacity payments are ever possible is better understood consistent with the distinction between short- and long-run marginal cost presented earlier. For short-run marginal cost, the capacity represents the costs associated with the possibility of a shortage. Insofar as an improved reserve margin always improves reliability at least to some degree, the capacity payment always has some positive value. Assuming that the firm contracts offered by the utilities are tied with a utility's short-run energy cost (implying a short-run avoided cost concept) those contracts should always include a positive capacity payment though it may vary depending on the probability of a shortage. We conclude that a capacity value should exist for a one-year contract executed at the beginning of the year of delivery. This value should be the avoided (marginal) annual capacity cost based on the 1982 estimated cost of peaking capacity. This value should be available to QFs executing firm contracts on a $/kW and ¢/kWh basis similar to longer term contracts.

e. Refusal to Purchase

FERC regulation Section 292.304(f) provides, in part:

> "Periods during which purchases are not required.
>
> "(1) Any electric utility which gives notice

> pursuant to paragraph(f)(2) of this section will not be required to purchase electric energy or capacity during any period during which, due to operational circumstances, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself.
>
> "(2) Any electric utility seeking to invoke paragraph(f)(1) of this section must notify, in accordance with applicable State law or regulation, each affected qualifying facility in time for the qualifying facility to cease the delivery of energy or capacity to the electric utility."

FERC states that this provision does not override "contractual or other legally enforceable obligations" of the utility to purchase from a QF and that such nonpurchase periods may be taken into account in setting rates for purchases. There is widespread interest in the way this provision will be reflected in the standard offer.

Staff offers a series of recommendations. It proposes that utilities not be allowed to refuse to purchase energy or capacity which is fixed by contract over a duration of obligation, except for conditions of emergency, maintenance, or minimum load. As an alternative, staff suggests utilities may offer the actual lower avoided costs to QFs if actual avoided costs are lower than those sufficient for as-available deliveries. Under the alternative the utility must accept all deliveries tendered by the QF and offer the actual lower avoided cost. Utilities

SCE Resources in the 1980's

S. J. Nola Speech

to

Geothermal Resources Council

on

December 1, 1981

S. J. Nola

SCE Resources in the 1980's

Geothermal Resources Council

Today the electric utility industry, and the Edison Company in particular, are at the cutting edge of revolutionary changes in an energy system which fuels our economy and supports a way of life we have come to cherish.

Change is the constant factor in our efforts to plan for the future resources needed to provide reliable electric service to our customers. Our ability to maintain quality service in this dynamic environment will depend on the imagination and flexibility with which we approach the future.

SOUTHERN CALIFORNIA HAS A STRONG ECONOMY, ITS RESOURCE NEEDS ARE INCREASING.

Edison has the responsibility for serving eight and one-half million people, one-third of the state's population. Our service territory covers 50,000 square miles. To reliably provide electricity for our customers, Edison currently has over 15,000 MW of installed capacity and, in 1980, used the equivalent of 60 million barrels of oil and natural gas.

In the next ten years, California's population is projected to increase by 340,000 people per year--an increase of approximately one and one-half percent a year. Real Gross State Product, a measure of the total output of California's economy after inflation, is projected to increase by over 3% annually. As a result, Edison's energy requirements are forecast to increase by about 2% per year, substantially lower than historical growth rates.

In order to meet the projected 1990 demand for electricity, Edison anticipates a need for over 5,000 MW of additional capacity during the next decade. This need will be met through a mix of conventional resources, purchases from other utilities, and alternative and renewable generation sources. This increase in capacity is required for growth in customer loads, the retirement of older generation units and termination of purchase power contracts.

EDISON'S BUSINESS ENVIRONMENT

In the decade of the 60's and 70's, California out-paced the nation in population increase, new jobs, and economic activity, and this leadership is likely to continue. For example, on August 27, of this year; backed by a strong defense, high technology, and energy extraction industries; and warmer than normal weather; Edison's peak demand requirements grew by 7% over last year. Significantly, this increase in electrical load has occurred during a period when most of the country is enduring decidedly lack-luster economic performance. Maintaining California's strong economy requires reliable sources of electricity. However, in the current financial and regulatory environment, meeting energy requirements exclusively through conventional generation resources is no longer feasible.

Oil which was plentiful and inexpensive through the 60's has become scarce and expensive. Back in 1968 we projected that the price of a barrel of oil in 1985 would be $2.34. We now expect that price to be close to $60 per barrel. As recently as 1975 we anticipated the long-term price of oil would level at approximately $20 per barrel. In comparison, Edison's current costs are approximately $40 for a barrel of oil.

Back in 1968 we forecast that the cost of electrical energy produced from oil in the eighties would be .6¢/kWh. Today it costs the average Edison customer more than 7¢ for every kilowatthour we have to generate with oil. And, similiarly, the costs of energy generated from other conventional resources, such as coal and nuclear, have also increased substantially. Against the back-drop of staggering increases in the cost of conventional fuels--particularly oil, uncertainty about future loads, environmental and regulatory constraints on conventional technologies, and high interest rates, Edison is striving to manage its future.

EDISON'S RESOURCE STRATEGY

Our future resource strategy embraces a broad range of objectives. Specifically, we have committed our corporate resources to: developing renewable and alternative energy resources; reducing dependence on imported oil; stabilizing electricity prices; balancing risk; protecting the environment; and providing a reliable supply of energy on which industries--and jobs--depend.

The cornerstone of our future resource strategy lies with the continued commitment to conservation and load management activities. To the extent that our customers can use fewer units of energy to maintain the same or improved standard of living, we are reducing our oil dependence and moving a step closer to re-establishing a productive and healthy economy.

While the the more efficient use of our existing electrical system has reduced the need for new generating capacity, an expanding California economy will require the addition of 5000 MW of new resources during the next decade.

To meet these needs, Edison will be entering a period of transition from traditional resource orientation to an orientation which emphasizes balance and flexibility. Renewable and alternative resources will comprise approximately one-third of capacity additions planned for the decade. By 1990, Edison's resource mix will be evenly divided--with one-third coming from renewables, hydro, and non-oil purchases; one-third from coal and nuclear; and one-third from oil and gas.

CONVENTIONAL RESOURCES CONTINUE TO BE NEEDED IN THE 1980S.

Edison will be relying on conventional resources for the early 1980s, primarily nuclear resources. The San Onofre nuclear generating units 2 and 3 near San Clemente, California, which are about 95% complete, and the Palo Verde nuclear project in Arizona, which is about 70% complete, will add 2340 MW to the Edison system. These capacity additions will offset oil consumption by 23 million barrels annually on the Edison system and will provide electricity for 1,300,000 people.

Twelve hundred megawatts of non-oil purchases will augment Edison's conventional resource base and allow for a more orderly transition to renewable and alternative sources of capacity. These include 330 MW of capacity supplied by Mexico geothermal sources, 510 MW of Edison's resale cities share of coal capacity from the Intermountain Power Project, and 120 MW of hydroelectric capacity from the California Department of Water Resource's Devil Canyon plant. We are also pursuing development of additional transmission interconnections with neighboring utilities to purchase energy and capacity as opportunities arise.

Conventional resources will provide the mechanism by which a transition to renewable and alternative resources can be achieved. The bulk of Edison's renewable and alternative generation capacity will be added in the latter part of this decade. Until these resources are demonstrated and commercially proven, conventional resources--particularly nuclear--must be utilized.

RENEWABLE AND ALTERNATIVE RESOURCES WILL MAKE A SIGNIFICANT CONTRIBUTION IN THE 1980S.

Edison has established a goal of 2100 MW of renewable and alternative resource additions by 1990. I would like to indicate the goals for the major types of additions, and discuss the progress being made in developing geothermal resources. These goals include 740 MW from large and small hydro facilities, 120 MW from wind resources, 420 MW from geothermal, 310 MW from solar, 130 MW from fuel cells, and 380 MW from cogeneration.

Edison's Geothermal Program

In addition to purchasing 330 MW of geothermal resources from Mexico's Cerra-Prieto field, Edison's goal is to add 420 MW of geothermal resources by 1990. These resources are planned for the Imperial Valley. They are liquid dominated geothermal resources varying from high temperature, high salinity to low temperature, low salinity. Edison currently has three major projects: the first at Brawley, the second at Salton Sea, and the third at Heber. The Brawley and Salton Sea units are 10 MW single-flash demonstration projects, while the Heber unit is a double-flash commercial development.

The Brawley Unit was dedicated on October 15, 1980. During its first year of operation Brawley has reached its full rated capacity of 10 MW. The power plant performance has been good with an 80% availability. Brine handling difficulties, however, have limited the plant's average capacity to approximately 7 MW and reduced its annual capacity factor to 50%.

Brine handling difficulties at Brawley are the result of highly saline fluids which average 15% dissolved solids. Equipment scaling, injection well plugging, and steam pipe corrosion are the cheif causes of the reduced plant output. Union Oil, operator of the well field, is currently experimenting with alternative brine handling processes and is replacing high-pressure carbon-steel steam piping with corrosion resistant chrome-molybdenum alloy piping.

Edison's 10 MW Salton Sea geothermal unit is now under construction on the south end of the Salton Sea. It is approximately 50% complete with start-up planned for April 1982. The power plant configuration will be similar to Edison's Brawley unit. The brine handling system, however, will employ second generation technology, building on our experience with the Brawley anomaly. The Salton Sea project will also deomonstrate the feasibility of utilizing brines with 25% dissolved solids content.

The Brawley and Salton Sea projects are the key steps in demonstrating the technical viability of using highly saline geothermal resources. Our current experience indicates that while the future is promising, technical solutions to brine handling problems will have to be found before these resources can be considered economically viable. In addition, full development of the geothermal resources in the Imperial Valley requires that firm transmission paths can be secured and that an adequate cooling water supply can be found.

Edison anticipates commercial development of geothermal resources at the Heber anomaly will begin in the mid-1980's. Brine conditions at Heber are expected to be good and Edison anticipates that as much as 200 MW of geothermal resources exist at the anomaly. Edison has entered into negotiations with Chevron to develop the first increment of the anomally's potential. The brine will be flashed to steam and used to drive a turbine-generator. To maximize the units thermal efficiency a double-flash system has been proposed. The Heber project is expected to produce 47 MW and run at a 75% capacity factor. Heber will be the first commercial scale liquid dominated geothermal resource in the United States. It is intended that this project will establish the commercial feasibility of geothermal resources at Heber.

In addition to the Brawley, Salton Sea and Heber projects, Edison has solicited entrepreneurial participation in development of geothermal resources. As a result of Edison's February 2, 1981 Geothermal Solicitation Announcement, Edison has entered into negotiations for purchase of geothermal steam and for the purchase of electricity generated from geothermal energy.

Cost of Geothermal Resources

While Edison has established cost goals which will make geothermal resources a viable alternative to oil-based generation, additional technical refinements are required to make the current technology economic. This is particularly true of the highly saline geothermal resources. To date Edison has spent 16.3 million on the 10 MW Brawley unit for a cost of $1630/kW. The Salton Sea unit costs are estimated at $3000/kW in 1982 dollars. It now appears that energy generated from the Brawley and Salton Sea demonstration projects could cost as much as 17 or 18¢/kWh in the initial years of the project. Costs may be even higher depending on the technical improvements which are required to solve brine handling problems. By comparison, Edison's current cost of generating energy from its oil and gas units is approximately 7.1¢/kWh, or less than half the cost of energy produced at Brawley and the Salton Sea.

The high cost of generating power from these highly saline geothermal resources underscores the need for further demonstration efforts and continuing research and development support. The lessons learned at our Brawley plant, and the second-generation technical enhancements planned for Salton Sea should significantly improve Edison's ability to achieve its cost goals.

The cost of power from commercial geothermal developments is forecast to be $1500/kW in 1980 dollars exclusive of the steam drilling and injection system. Edison's estimate for the life-cycle power cost of "mature" geothermal technology is 15¢/kWh. This makes geothermal competitive with oil generation and among the more cost-effective renewable resources planned by Edison. These costs are compared to other resource options on the attached Life-Cycle Power Cost chart. Geothermal resources offer the potential of stablizing electricity prices by reducing our dependence on expensive oil. They will help to minimize our vulnerability to disruptions in the supply of oil and gas. And, they comprise a major portion of our committment to the development of renewable and alternative resources.

<u>WHY THE SWITCH TO RENEWABLES?</u>

Renewable and alternative resources tend to be small in size with shorter lead times characterized by expedited application procedures, limited regulatory jurisdiction, and relatively brief construction periods. The generally short construction periods and small size of renewable and alternative resources, results in less capital being tied up for shorter periods of time. These technologies hold promise for easing the severe capital constraints now facing the utility industry. Renewable and alternative resources also have broad political support, and public acceptance is expected to be generally high. This compares favorably with conventional resources such as coal and nuclear which have encountered environmental, regulatory, and public opposition.

The uncertainties surrounding growth of electric load, licensing and approvals of large projects, and availability and cost of capital can be managed more effectively with a balanced resource mix which includes renewables.

Other advantages of renewable and alternative resources include reduced oil dependence and reduced environmental impacts, especially air emissions. Edison's goals for renewables include demonstration of technologies in the early 80's with commercial deployment and achievement of cost-goals in the late 80's and early 90's.

To the extent that new capacity offsets existing oil and gas fired generation, each additional megawatt of capacity based on alternative and renewable energy sources reduces Edison's dependence on foreign oil. With this reduction in liquid fuel dependence, comes the potential for stabilizing the cost of service.

I emphasize the word "potential" because under an existing Federal law called the Public Utilities Regulatory Policies Act (PURPA), non-utility energy producers may demand, and receive from the host utility, up to full avoided cost for the energy the non-utility producer generates. Under the California Public Utility Commission's interpretation, this is considered to be Edison's highest priced resource, that is, oil. With this interpretation, Edison's published avoided cost of energy is 7.1 cents per kilowatthour. Based on a thirty-year purchase power contract beginning in 1981, Edison is required to pay non-utility energy producers up to an additional 1.3 cents per kilowatthour for capacity. This PURPA type payment would total 8.4 cents per kilowatthour. Purchase of energy from non-utility entities at the cost of oil does nothing to stablize the ratepayer's cost of service and, in fact, locks him into oil prices. While PURPA was intended to accelerate the development of renewable and alternative resources, it has in effect institutionalized the economic burden of oil on the ratepayer.

I suggest that stabilizing the cost of service can best be achieved through free market competition between energy producers. Under this system, efficiency is rewarded and the ratepayer receives the benefit of reduced energy costs. The principle I am suggesting is simple: In those situations where there is an economic need for monopoly, regulation may be substituted for competition; where there is no requirement of monopoly, free market competiton should prevail.

While the long-term outlook for renewable and alternative technologies is encouraging, and the potential contribution is substantial, the development of these resources is not without risk. Near-term costs will be dominated by research and development expenditures and may not compare favorably with the cost of conventional technologies. Operating characteristics and technical performance of developing technologies are not well defined and require further study and refinement. Moreover, under existing regulation, the potential for stabilizing rates through the non-utility development of renewable and alternative technologies is uncertain.

CONCLUSION

The 1960s and early 70s were a period of growth with plentiful natural resources and attractive capital availability.

"Growth" was a concept warmly embraced by most people. With the advent of energy shortages and unprecedented inflation in the mid-to-late 70s, Edison entered a period of marked adjustment characterized by higher electricity prices, increased conservation efforts, a greater emphasis on environmental quality, restricted energy supplies, and significantly more difficult capital formation.

These changes in the business environment have dictated that new alternatives be explored in the 1980s. Among the most significant is Edison's ability to manage its load growth without adversely restricting personal freedoms or economic development. A continuing emphasis on conservation and load management programs will minimize the need for additional generating sources and the accompanying capital demands. Moreover, the benefits of oil displacement and a more favorable regulatory environment make management of load growth a cornerstone of Edison's alternatives for the 1980s and the transition to a renewable resource future. Geothermal is expected to make an important contribution to Edison's renewable resource strategy.

From a broader perspective, Edison intends to enter the 1980s by anticipating, rather than reacting to, its business environment. By adopting a balanced and flexible resource strategy we will be able to maintain control over the company's future, meeting the needs of our ratepayers in a timely, reliable, and economic manner. Edison's resource strategy for the 80s incorporates an acceleration of renewable and alternative resources, licensing of additional nuclear capacity, increased purchases, and a continued emphasis on management of load growth. This resource strategy recognizes financial constraints as well as the need for increased control over the components influencing our cost of service. It responds to the issues of oil consumption and environmental quality. It is cognizant of the unique public sentiment and regulatory climate which prevails in California, and it is designed to effectively manage risks which accompany this company's change in corporate policy.

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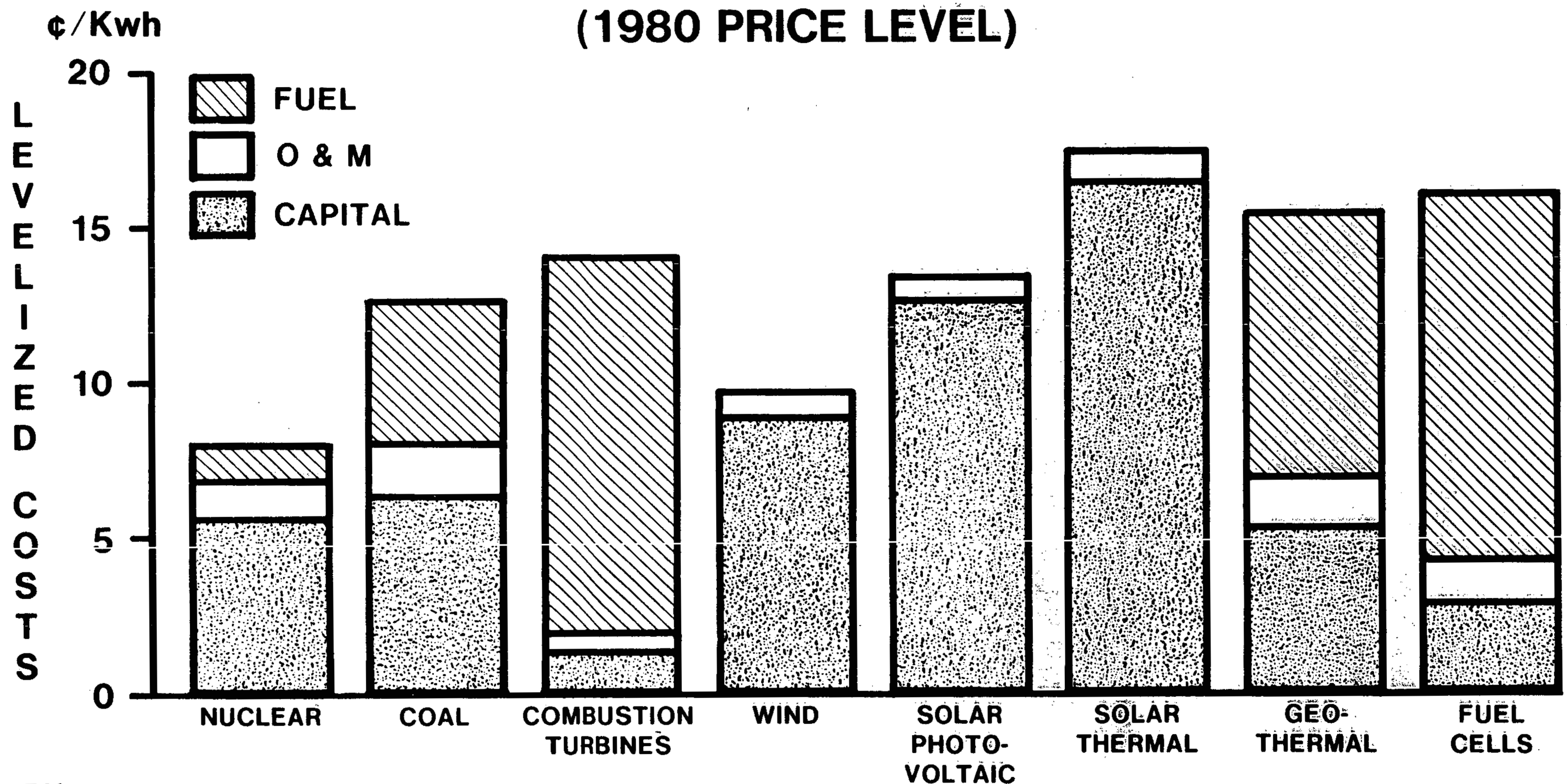
LIFECYCLE POWER COSTS

(1980 PRICE LEVEL)



	NUCLEAR	COAL	COMBUSTION TURBINES	WIND	SOLAR PHOTO-VOLTAIC	SOLAR THERMAL	GEO-THERMAL	FUEL CELLS
TOTAL CAPITAL COSTS ($/KW)	1500	1400	350	900 (2)	1200 (2)	2500 (2)	1500 (2)	500 (2)
CAPACITY FACTOR (%)	70	60	5 (1)	25	25	40	75	40

(1) MAKE UP ENERGY FROM SYSTEM OIL GENERATION TO YIELD A 65% CAPACITY FACTOR INCLUDED. PRIMARY FUEL ASSUMED TO BE NATURAL GAS.

(2) GOAL FOR MATURE TECHNOLOGY COSTS.

Electric System Planning
May 1981

OPPORTUNITIES FOR INDUSTRY in the DEVELOPMENT OF GEOTHERMAL ENERGY at U.S. MILITARY INSTALLATIONS

The presentation will review the exploration philosophy and game plan being conducted by the Geothermal Utilization Division of the Naval Weapons Center, China Lake, California.

The attached publication and site listing will indicate typical potential areas for geothermal exploratory work. An updated listing of Navy sites will be presented, and the reasons for changing estimates and changing degrees of interest will be noted.

Subjects for industry to consider include:

1. exploration and development adjacent to military activities--your activities.

2. exploration and development on military activities--leases through the Department of the Interior or contracts through the Department of Defense.

3. joint projects and data sharing projects to avoid base boundary and access problems during exploration.

TABLE 3. Naval Installations With Favorable or Possible Geothermal Potential.

Electric power		Space heating/cooling		Geopressurized	
Favorable	Possible	Favorable	Possible	Favorable	Possible
	NAS Fallon	NAS Fallon			Air Sta. Beeville, TX
Bravo 19 Fallon			Nuclear Power Training Facility Idaho Falls		
	Bravo 16 Fallon				Air Sta. Corpus Christi, TX
	Bravo 20 Fallon				
Facili-ties Adak	Subic Bay Complex		Norfolk Complex		Air Sta. Kings-ville, TX
			Charleston Beaufort Parris Is. Facilites		
	Air Sta. Barbers Point				
NAF/NATO Command Lajes AFB Azores	Fleet Ops, Control Cen. Kunia, HI	Keflavik, Iceland (online Buying Space Heat from Ice-land)	Jackson-ville, NC & Lejuene Area	New Orleans Facilities	CB Cen. Gulfport
Magazine Lualualei, HI					
MCAS Kaneohe					
NAF NAVCOMSTA Naples, Italy	MCB 29 Palms	MCB 29 Palms	MCLSB Barstow		

TABLE 3. Naval Installations With Favorable or Possible Geothermal Potential (Cont.).

Electric power		Space heating/cooling		Geopressurized	
Favorable	Possible	Favorable	Possible	Favorable	Possible
NAF Signolia Catania, Sicily	Observatory Flagstaff Sta. Flagstaff, AZ				
	OMTF, White Sands, NM				
	NAF, El Centro				
	Chocolate Mtn. Aerial Gun. Range		Diego Garcia		
Salton Sea Test Fac.	McMurdo Sound		McMurdo Sound		
			El Centro Aerial Gun Range		

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GEOTHERMAL POTENTIAL AT U S AIR FORCE BASES

CARL F. AUSTIN
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NOVEMBER 1978

FINAL REPORT FOR PERIOD JAN 77-SEPT 78

Approved for public release; distribution unlimited

CEEDO

CIVIL AND ENVIRONMENTAL ENGINEERING DEVELOPMENT OFFIC
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Hot Springs

20. ABSTRACT (Continue on reverse side if necessary and identify by block number)

The Air Force has completed a study of the geothermal potential of USAF bases. This report lists the power generation potential, space or industrial heating potential, and geopressure potential at each USAF base. This report also discusses in detail the data available for those USAF base which exhibit the greatest potential for use of geothermal energy. Bases with significant potential that are discussed in detail include: Mountain Home (space heating), Saylor Creek Range at Mountain Home (power), Ellsworth Air Force Bases (space heating); Keesler Air Force Base (geopressurized geothermal resource*), Hill Air Force Base

20. Abstract (continued)

(space heating), and William Air Force Base (power) in the Continental United States and Bellows Air Force Base, Hawaii (power), Lajes Air Force Base, Azores (power), and Ankora Air Station, Turkey (space heating) outside of the Continental United States. Open literature and unpublished field studies provided the basis for evaluation.

PREFACE

This report documents work performed during the period January 1977 through September 1978 by the Geothermal Technology Division, Naval Weapons Center (NWC), China Lake, California, and was funded under the Investigational Engineering Program.

The authors of this report are Carl F. Austin and J. A. Whelan, Naval Weapons Center, who are responsible for the technical accuracy of the data reported. The opinions expressed are also those of the authors and do not reflect the view of the Department of the Air Force or the Department of Defense unless so designated by other authorizing documents.

This report contains preliminary findings based on currently available data. Final evaluations of geothermal potential should be based on more detailed site specific data and field analysis. Information contained in this report dealing with legal and institutional factors should be evaluated in light of changes to public law (Title VII, Public Law 95-356, 8 September 1978) which occurred during publication of this report.

Captain William A. Tolbert, Air Force Civil and Environmental Engineering Development Office (CEEDO), is the project officer for this report. The study on which this report is based was initiated by Captain Jon M. Davis, Air Force Civil Engineering Center, prior to CEEDO's activation in April 1977.

This report has been reviewed by the Information Office (OI) and is releasable to the National Technical Information Service (NTIS). At NTIS it will be available to the general public, including foreign nations.

This report has been reviewed and is approved for publication.

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INTRODUCTION

A. DEFINITION

Geothermal resources may be defined as hot water, hot dry rock, hot carbon dioxide, hot dry steam, or simply any hot geologic material within the crust of the earth, often generated by shallow magmatic materials which were forced into the crust of the earth from below, with the ultimate heat source almost always the decay of dispersed radioactive elements within the earth. These hot zones occasionally manifest themselves on the surface of the earth in the form of hot springs and natural steam vents. The presence of hot springs does not assure that there is sufficient energy to provide space heat or to generate power; however, this presence may be used as an indicator to locate geothermal sources that may potentially be economically feasible.

B. OPPORTUNITIES

This report describes and discusses the geothermal potential that is recognized to date at various sites located on or near continental United States Air Force bases and at selected Air Force facilities overseas. The potential is evaluated in three basic categories:

- o Power generation potential which is limited to geothermal sources that produce temperatures greater than 350°F (177°C).

- o Space heating potential which is limited to geothermal sources that produce temperatures greater than 130°F (54°C).

- o Geopressure utilization which is generally expected to be limited to sources that produce pressures greater than 10,000 pounds per square inch (PSI).

C. MISSION NEEDS

The rationale for Air Force development of its fee owned lands can be divided into two broad categories:

- o Mission encroachment - Mission protection

- o Secured energy supply

The following statements are not all inclusive. As in most cases, when a single subject is the focus of analysis, the statements in each category often overlap.

1. <u>Statements of Need</u>

a. Mission encroachment - mission protection. Development of geothermal energy on impact or test ranges may be incompatible with the base mission unless a major effort is undertaken to reconcile the potential conflicts between the two uses. Loss of this land to uncontrolled industrial use could result in the loss of mission capability.

It is necessary for the Air Force to control development of its fee owned land in order to experiment with different management alternatives for resolving use conflicts. By directly involving itself in the development and management of the geothermal resource, the Air Force can understand exactly what problems arise and can develop solutions which encompass the requirements of both uses. The potential exists for both uses to co-exist with a minimum of conflict if Air Force pressure is sufficiently strong to force the issue. Air Force presence as an active participant in the field development is imperative if the base's future mission is to be accomplished on an equal priority with geothermal energy development. Only as an active participant in field development can the Air Force assure effective consideration of the particular base's mission. It cannot be assured by working indirectly through a second agency which is not directly affected by the results of its decisions.

b. Since the Air Force will not be constrained to follow established leasing and royalty requirements, it has the flexibility to trade off the equivalent value of geothermal resource royalties in order to develop and implement solutions to conflicts as they are identified during field development. This management latitude is unique to the Air Force's development of its fee owned land.

c. An added benefit is obtained if the Air Force program preceeds leasing and development of the rest of a Known Geothermal Resource Area (KGRA) on Air Force lands. Where industry might balk at implementing measures to prevent use conflicts, the Air Force will be in a position to provide them with hard facts, including facts on solutions to these problems. Solutions to many problems could be well defined and ready to implement if the Air Force rapidly develops its own land. For example, the types of facilities and systems required to protect the mission environment could be explicitly defined, their operational success and mitigation effectiveness for both limited, and full scale field development evaluated, and capital and operational costs defined.

This ability to actively pursue and develop solutions to protect the Air Force's mission, rather than work through an outside agency whose interest is primarily in the resource, will be critical to future compatibility between the mission and inexorable development of this national energy resource.

d. In a broader and longer term context, a demonstrated ability to manage the Air Force's geothermal resources and to resolve potential use conflicts will affect the future pattern of geothermal development at other military facilities containing such resources. Not only will solutions to problems developed on an Air Force base be applicable to other military activities, but the Air Force will develop manpower resources and demonstrate an expertise in developing and managing a secured energy resource. This should provide support for permitting DoD agencies to manage such resources at other locations.

The precedents established at the first Air base developed can be used to protect other activity missions, while allowing valuable energy resources to be exploited without conflict. Precedents established will primarily determine the future ability of military activities to prevent mission encroachment in a nation faced with burgeoning energy shortages.

e. As described above, the precedents established during development of Air Force fee owned land will influence future programs at all other military activities. If the Air Force loses control of its fee owned land to another agency under pressure for geothermal development, a dangerous land management precedent could be established, specifically regarding Air Force or other military fee owned land. The loss of control over such land, especially where a strong, legitimate mission based need can be demonstrated would, in effect, implicitly classify DoD fee owned lands as available for resource exploitation during times of shortages when the need for effective military capability would probably be very high.

f. If fee owned lands are successfully developed by a contractor, the contractor may have enough incentive to lease the withdrawn land adjacent to fee owned lands. The area could then be developed as a single unit. In such a situation, the Air Force's contractor would already be familiar with a compatible development program which would reduce the overall effort required to maintain compatibility within base boundaries. Since a strong working relationship with the contractor would already exist, the Air Force would have a better opportunity to directly influence management of adjacent withdrawn land where the lessee would be responsible only to the Bureau of Land Management (BLM), and the United States Geological Survey (USGS). Regardless of which industrial agent obtains the lease on adjacent land, proven concepts in the Air Forces contract could be applied to unit operations.

2. Secured Energy Supply

A strong rationale supports development of a secured energy supply for military activities. A secured energy supply would allow an activity to weather shortages or forced allocations of fossil fuel resources without affecting mission capability. Additional benefits include freedom from disruption during civil unrest or war, i.e., it becomes an easily protectable energy source. A nonfossil fuel based (alternative) energy source releases substantial amounts of fossil fuel to the economy which, in turn, reduces dependence on foreign oil sources and possible energy blackmail. Finally, a secured energy source releases energy capacity previously devoted to military activity supply back to the civilian sector. This, indirectly, increases energy supplies without the capital costs of building new power plants.

At this time, the Naval Weapons Center, China Lake, has the greatest known potential of any military activity for developing an alternative, self-sufficient source of energy. Based on estimated energy potentials on Air Force acquired lands and at other locations, it may be possible to wheel power to other military activities not within wheeling distance of China Lake, permitting these bases energy self sufficiency as well.

a. Perhaps the most significant need for a secured energy source at an Air base is the freedom to continue and/or expand operational capability during a severe energy crisis or during a war where energy supplies are cut off. Not only could these bases continue to function during such a period of stress, but, thus could absorb other Air Force programs without energy constraint, if necessary. The significance of this unique capability cannot be over emphasized. In a crisis environment, the military will be only one of many interests attempting to maintain its energy supplies. With some degree of flexibility, based on a secured energy source, important research and test programs would not have to be cut back or foregone.

b. A secured energy source at any Air base would allow sophisticated and advanced high energy consuming programs to be relocated to that base, where they could continue to function without interruption by short-term energy shortages or politically determined shifts of energy supply from the industrial sector to the residential sector. High energy projects not technically feasible today due to their large transient effects on power grids would be particularly suited to a secured energy supply situation.

c. The cost of energy is rising and will continue to rise in the foreseeable future. As energy costs rise, a steady attrition occurs in effectiveness of the Research and Development budget. If, as is anticipated, a secured energy source at an Air Force RDT&E base will establish a flat or slowly rising cost for energy over the long term, the effectiveness of the R&D budget can be substantially increased. The net effect will be more R&D capability for a given amount of funding. This will, of course, be an inducement for locating additional research at such air bases, which further increases budget effectiveness.

d. Utilization of geothermal resources on Air Force fee owned land to provide energy will offset the need for substantial amounts of oil and gas. The primary direct benefactor will be the civilian economy because energy will be released for their consumption. This effectively increases the energy available and reduces the need for constructing new plant capacity. A reduction in the need for new power plants also reduces overall energy costs to the public sector.

e. One important aspect of controlling geothermal energy resource development has some unique value to the Air Force. As the search for alternative fuels to power aircraft support activity proceeds, one possibility is the collection or production of hydrogen, which can be reclaimed with geothermal CO_2 to produce hydrocarbon fuels for vehicular fuel. The non-condensible gases within a geothermal reservoir always contain CO_2 and can contain hydrogen (H_2) which could be separated and condensed for use in vehicles. Alternatively, H_2 could be produced artificially from geothermal waste fluids for the same purpose. In both cases, the energy from the field then becomes exportable in forms which can be used for powering rocket vehicles.

f. With an energy supply belonging to the Air Force located within air base boundaries, it would be possible to effectively protect the supply during civil unrest without being requested to do so by elected government officials. In essence, Air Force ownership of the energy source makes it a "protectable" source, while maintaining a low profile. Under extreme conditions, a guaranteed, protectable source of energy increases overall military capability, while assuring supplies under extreme conditions.

D. PROBLEMS

Geothermal fluids are often contaminated with a wide variety of suspended and dissolved solids and can also contain gaseous matter. As these fluids cool and the pressures are reduced, the precipitation of dissolved solids occurs. This often results in the formation of complex scale. In addition to the solids and precipitates, the fluids can range from highly acidic to highly alkaline. Utilizing these fluids can result in interrelated corrosion, erosion, and scaling problems within a given system.

A geothermal fluid may alter appreciably over a long period of time due to gradual changes in reservoir conditions. Changes in the reinjection and recharge rates, both natural and induced, could alter the water table which can further affect the source temperature. Reinjection of waste water into the reservoir may eventually alter the fluid chemistry.

E. LEGAL AND INSTITUTIONAL FACTORS*

Geothermal steam presents a very real opportunity for a number of Air Force installations to become energy self-sufficient. This may include both the production of electric power and direct heat applications; or, the character of the resource may limit its potential to direct heat applications. Conversely, in some cases the location may permit electric power development but preclude direct heat application. Where the geothermal resource is of high quality and attractive for commercial development, there will be heavy industrial pressure to make the resource available for leasing under the Geothermal Steam Act of 1970. This coupled with the fact that Congress has historically favored development by the private sector, suggests that there would be considerable opposition to exclusive Air Force development of a major commercial geothermal resource.

In many cases a geothermal resource on an Air Force installation would not be attractive to commercial developers due to:

- o Remoteness from available market
- o The quality or quantity of the resource available
- o Physical hazards, or national defense and security considerations

The following paragraphs summarize the numerous institutional and legal considerations surrounding such development of geothermal resources located on lands administered by the Air Force.

1. <u>Institutional Factors</u>

The complexity of the institutional interfaces encountered in geothermal development cannot be overemphasized. A private developer must do extensive research to assure that all requirements of cognizant agencies are satisfied before he can proceed with a geothermal development. For a federal agency (e.g., the Air Force) the legal/institutional constraints are somewhat different. The federal executive agencies, generally, must comply with federal guidelines, and in some cases, with state and local substantive requirements where these are more stringent than the federal (i.e., the Clean Air Act, the Noise Control Act, the Federal Water Pollution Control Act). However, federal agencies generally are not, at the present time, required to comply with procedural matters, including the obtaining of permits at the state and local levels.

*Naval Weapons Center - Geothermal Legal/Institutional Studies, by LCDR J. M. Commander and Peggy Davis. China Lake, California, NWC, September 1977. (NWC TM 3165, publication Unclassified).

One exception to this is the recently enacted Resource Conservation and Recovery Act of 1976 which requires compliance with all federal, state, interstate, and local requirements, substantive and procedural, expressly including the obtaining of permits, for solid waste management facilities or disposal sites, or for engaging in activity which results in disposal of solid or hazardous waste.

It has been found that development of good relations with state and local agencies is essential if federal programs are to avoid controversy. Moreover, if the Resource Conservation and Recovery Act of 1976 indicates a trend in Congress' policy, extension of the requirement to other areas, particularly environmental, is a very real possibility. State and local agencies, therefore, should be kept abreast of plans and progress even where there is no legal requirement to obtain a permit. It also should be emphasized that all such contracts should be made through, or with the concurrence of, the appropriate division of the Air Force Engineering and Services Center.

2. Legal Factors

a. Resource definition. Geothermal resources have been used for centuries for direct heat applications (hot baths, space heating). During the last century, geothermal resources were used for the production of boric acid. They also present a potential source for many other minerals. Early in the twentieth century the technology for production of electricity from dry steam was developed in Italy. Recent improvements in technology have made it possible to use hot water flashed to steam. Active research and development projects are investigating production of electricity from hot water, hot dry rock, and geopressured zones.

The importance of geothermal resources as a source for electric power was recognized in this country only after the Geysers area in California became a successful undertaking. Failure to recognize the potential of the resource at an earlier date led to a legal vacuum. Increasing interest in geothermal development has led to a rush to fill this vacuum. To date, fifteen states and the federal government have enacted statutes specifically relating to geothermal development. These statutes are neither uniform nor consistent relative to the characterization of the resource. Moreover, to a greater or lesser extent, they emphasize the production of electric power to the exclusion of comprehensive development of the entire resource.

It is clear that the laws affecting geothermal resources are in an early state of development, as is the technology. An important area for legal scholarship is the development of a definition of the resource that will serve adequately in the settlement of ownership disputes, and in the regulation of exploration, development, and production.

The Geothermal Steam Act of 1970, the federal statute, is of paramount importance to this study. Its provisions apply to all lands owned by the United States, but it authorizes disposition of resources only from certain described lands. The Act fails to state exactly what a geothermal energy system is. The description includes heat and other energy in specific formations (i.e., steam, hot water, and hot brine systems). The words "geothermal steam and associated resources" as used in the statute might, on their face, even include coal, oil, and natural gas, as well as other minerals resulting from the geothermal process. This reading of the statute would clearly be too broad in that it would lead to internal contradicitons because "by-products" is defined elsewhere in the Act to exclude oil and natural gas. The legislative history of the Act indicates that it was the intent of Congress to include the types of geothermal systems known in 1970 to be useful for production of electric power (i.e., steam, hot water, and hot brine systems). This raises serious questions as to whether hot dry rock and geopressured reservoirs are included. The Act fails to characterize the resource, but implies that geothermal resources are minerals.

The question of resource definition will probably have to be clarified by Congress or by the courts. The question of the characterization of the resource will ultimately be settled in the courts. Several recent court decisions indicate a trend toward characterizing geothermal resources as a mineral resource.

b. <u>Resource ownership</u>. In most cases, Air Force installations are located on lands owned by the Unites States. These lands, generally, fall into one of two broad categories:

(1) Public Domain Lands - lands acquired by the United States by treaty or purchase from another country and which have remained in federal ownership from the time they were acquired; and

(2) Acquired Lands - lands acquired from private owners by purchase, condemnation, donation or other means.

In either case, where both the surface and mineral estates are owned by the United States, it is probably safe to say that the United States is also owner of the geothermal resource. On public domain lands, except for minerals located or leased under mineral leasing or mineral location laws, ownership of the minerals generally is in the United States. On acquired lands, it is necessary to research the title to determine whether mineral rights were also obtained when the lands were acquired.

... point in time, the ownership of the resource where mineral rights have been severed from the surface estate is in question. In the latest court decision (United States versus Union Oil Company), the United States Circuit Court of Appeals (9th Circuit) has held that, when the United States granted surface ownership to a patentee under the Stock Raising Homestead Act but retained ownership of the mineral rights, this reservation included geothermal resources. Some continue to argue that geothermal resources are a water right and thus are the property of the owner of the water rights. This position has been weakened considerably by the Union Oil case, as well as the two other cases which have been decided to date. Until the question is finally decided, the only completely safe basis for developing a resource will be ownership of the full fee title, including both the surface and the mineral estates. In some cases, it may be necessary to have ownership of water rights, which is usually determined under state laws.

It must be noted that ownership is not the only water rights question involved in geothermal development. Under current technology, development of the geothermal resource necessarily includes use of water as the transfer medium. If this development uses potable water (i.e., suitable for irrigation or domestic use), the right to use the water for production of geothermal resources must be determined. If such rights are not owned by the United States, they must be obtained. Moreover, any disposal of geothermal fluids must be handled in a manner that would not damage the quality of the groundwater in the area.

c. <u>Disposition of geothermal resources on Air Force lands.</u>

Although the Air Force does have authority to lease lands not currently needed for the Air Force mission, this authority has been interpreted not to include water power or mineral resources. Even if this were not so, the express prohibition in the Geothermal Steam Act of 1970 against acquisition of rights to geothermal steam or associated resources, except under the provisions of the Act, would preclude use of this authority. Clearly, due to this prohibition in the Geothermal Steam Act, the Air Force cannot transfer to others, rights to geothermal resources located on Air Force lands. Parenthetically, it should be noted that, if Air Force lands should be leased by the Department of the Interior under the Steam Act, the general Air Force leasing authority may constitute the most satisfactory means for providing sites for power plants and associated facilities on Air Force installations.

d. <u>Authority of the Secretary of the Interior</u>

The Geothermal Steam Act of 1970 is at best ambiguous on the question of whether geothermal leases may be issued on lands administered by federal agencies other than the Department of Interior and Agriculture, those specifically mentioned in the leasing authority.

The Secretary of the Interior in his regulations appears to have assumed that he does have such authority. Interpretations of law in regulations issued by the head of an executive agency responsible for administration of the law are given considerable weight in court. It is, therefore, entirely possible that, unless at some time in the future a court should find the regulation of the Secretary of Interior in conflict with the law, his interpretation will be accepted as correct. In the case of land administered by agencies of the Department of Defense, the Engle Act provides a possible basis for arguing that, at least so far as minerals are concerned, public domain lands withdrawn and reserved for military use are, in fact, lands administered by the Secretary of the Interior. This is because the Engle Act places all "minerals" underlying such lands under the jurisdiction of the Secretary of the Interior. The argument, of course, would be strengthened by final classification of geothermal steam as a mineral-type resource. It must be remembered that this argument exists only for public domain land withdrawn for military use. The Engle Act is not applicable to acquired lands.

e. Air Force Development of Geothermal Resources on Air Force Lands.

The Air Force has no express authority to develop geothermal resources underlying its lands. The Air Force may imply authority where such development is necessary to the fulfillment of the Air Force mission. An inherent problem with implied authority is any attempt to define its limits. The first rule we must observe is that an implied authority will not overrule a specific authority or a specific prohibition. In the case of geothermal steam, Congress has provided that such resources will be developed by lease when they are located on land owned by the United States. It would be possible to argue that this is the only means of development intended by Congress and that no implied authority might be used to permit the Air Force to develop such resources for its own use. The Steam Act, however, is not clearly applicable to Air Force lands and, read as a whole, does not require a conclusion that Congress meant to deny use of such resources to agencies occupying the land where such use is important to their mission. These facts lead to the conclusion that the Air Force may develop geothermal resources on its own lands for its own use. Of course, the prohibition against transfer of the rights to geothermal steam or associated geothermal resources under any other law remains a barrier to any lease or other type transfer. This prohibition also may present a problem in the disposal of by-products. Finally, with reference to public domain lands, the Engle Act may have placed geothermal resources underlying such Air Force lands under the jurisdiction of the Secetary of the Interior. Therefore, on public domain lands it is recommended that no development be planned without concurrence by the Secretary of the interior. An implied authority, while it may present a proper basis for a small program to meet specific needs, always presents greater hazards when an attempt is made to use such authority to institute a major program.

3. Conclusions and Recommendations

Under suitable institutional/legal conditions, Air Force development of geothermal resources is legally feasible. The implied authority of the Air Force to utilize the lands on which its installations are located to fulfill the Air Force mission may provide sufficient authority for the Air Force to use the resource. Each case, however, must be evaluated individually. Factors which must be considered include:

- Ownership of the lands and mineral resources located thereon
- Terms and conditions under which the Air Force controls the lands in question
- Authority of other departments and agencies over mineral resources located on the lands
- All other laws and regulations effecting development on the lands concerned

F. LOCATION

Distance to the geothermal source (site) can create problems of hot fluid transport, power line right-of-way, and other legal and ownership problems. For the purposes of this report, only sources within the immediate area or within the boundaries of the individual Air Force bases will be considered.

U. S. AIR FORCE INSTALLATIONS WITHIN THE CONTINENTAL UNITED STATES

Geothermal resources available to the U. A. Air Force installations with the continental United States are somewhat limited. The following activities have been identified as having potential geothermal resources:

Mountain Home AFB and Saylor Creek AF Range, Idaho
Ellsworth AFB, South Dakota
Keesler AFB, Biloxi, Mississippi
Williams AFB, Chandler, Arizona
Hill AFB, Ogden, Utah

See Appendix A for a summary of Geothermal Potentials of other Air Force Installations.

1. MOUNTAIN HOME AIR FORCE BASE AND SAYLOR CREEK RANGE

Mountain Home AFB, Idaho has probable potential for Geothermal heating, while the Saylor Creek Air Force Range has definite heating potential. Power generating potential is possible in the Saylor Creek Range.

a. Geology

Generalized rock types found in Elmore County (Mountain Home AFB) are Pliocene and Pleistocene sediments, pleistocene basalts, and Tertiary silicic volcanics overlying Cretaceous granite. In Owyhee County (Saylor Creek Range), the rocks are primarily Pliocene sediments and basalts overlying Tertiary silicic volcanics (Young and Mitchell, 1973)1 (see Figure 1).

The silicic volcanics are Miocene rhyolites. Data present at this time are insufficient to determine whether the rhyolites or granites have the capacity to act as a reservoir. The Idavada volcanics, present in both the Mountain Home AFB and Saylor Creek AFR areas, underlie the Idaho Group. This unit is considered to be the most important aquifer and source of hot water (Young and others, 1975)2. The Idavada volcanics are lower Pliocene silicic volcanics; generally the water produced from the complex has significantly higher temperatures than those at nearby wells from overlying units.

The thickness of this complex in the Bruneau-Grand View area is believed to be 915m (3,000 feet) or greater. The underlying granite could be fractured enough from faulting to act as a significant acquifier.

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[1]Young, H. W., and Mitchell, J. C., 1973, Geochemical and Geologic Setting of Selected Thermal Waters, in Geothermal Investigations in Idaho, Idaho Department of Water Administration, Water Information Bull.No.30, Part 1, Boise, Idaho,pp 12-16, 19-22, 25-33

[2]Young, H. W., Whitehead, R. L., 1975, An Evaluation of Thermal Water in the Bruneau-Grand View Area, Southwestern Idaho, in Geothermal Investigations in Idaho, Idaho Department of Water Resources and U.S.G.S., Water Information Bull.No.30,Part 2, Boise, Idaho,pp 14-39, 43-46

SERIES			GROUPS AND FORMATIONS	
QUATERNARY	RECENT		SNAKE RIVER GROUP	Recent lava flows
	PLEISTOCENE	UPPER		Melon Gravel*
				Bancroft Springs Basalt
				Sand Springs Basalt
				Crowsnest Gravel*
				Thousand Springs Basalt
				Sugar Bowl Gravel*
				Madson Basalt
		MIDDLE	IDAHO GROUP	Black Mesa Gravel
				Bruneau Formation*
		LOWER		Tauna Gravel
				Glenns Ferry Formation*
TERTIARY	PLIOCENE	UPPER		
		MIDDLE		Chalk Hills Formation
				Banbury Basalt*
		LOWER		Poison Creek Formation
			Idavada Volcanics	

* Formations present in Mountain Home study area

FIGURE 1. SEQUENCE OF CENOZOIC ROCKS IN THE WESTERN SNAKE RIVER PLAIN (RALSTON AND CHAPMAN, 1968)

Structurally, the area has high angle faults on the north side of the Snake River Plain graben. These faults are located northeast of the Mountain Home area. The Bruneau-Grand View area is laced with faults trending northwest. Most of these are down-thrown on the north, toward the Snake River. Vertical displacement can be up to several hundred feet (Young and others, 1975).

b. Source of Heat

The probable source of heat in this area is deep circulation (Young and others, 1975). The area has above normal geothermal gradients. Heating of the ground water to a temperature of 83°C using a geothermal gradient of 6.5°C/100m would require circulation of water to a depth of 1140m. The high geothermal gradient may be due to the thinning of the upper crust in the Snake River Plain (see Figure 2).

c. Geothermal Gradients

(1) Mountain Home: Geothermal gradients in the base area are on the 4.0-6.0°C/100m contours, with higher gradients of 8.9-9.0°C/100m just north of the base.

The base gets its water from six wells, tapping the general groundwater system. The average discharge is 2,231,000 gal/day. A driller's report indicates the Bruneau Formation basalts were encountered at 360-400 feet (91-122m) below land surface (Ralston and Chapman, 1968)[3].

The water temperatures are 67-70°F (19.4-21.1°C) throughout the base hydrologic sub-area. Chemical analysis indicates uniformity of composition (Ralston and Chapman, 1968) : however, published geochemical data is not available.

(2) Saylor Creek Air Force Range: No data are available for the immediate area, but a geothermal gradient map (see Figure 3) indicates gradients of 8.2-20.9°C/100m on the western margin of the area in the vicinity of Hot Springs. One gradient of 34 and another of 32.8 in the area may be isolated geothermal highs for the area.

d. Summary

Both Mountain Home AFB and Saylor Creek AFR have definite potential. Mountain Home for heating, and Saylor Creek for heating and power. A definite heat source has not yet been defined in the region and data is lacking for the range.

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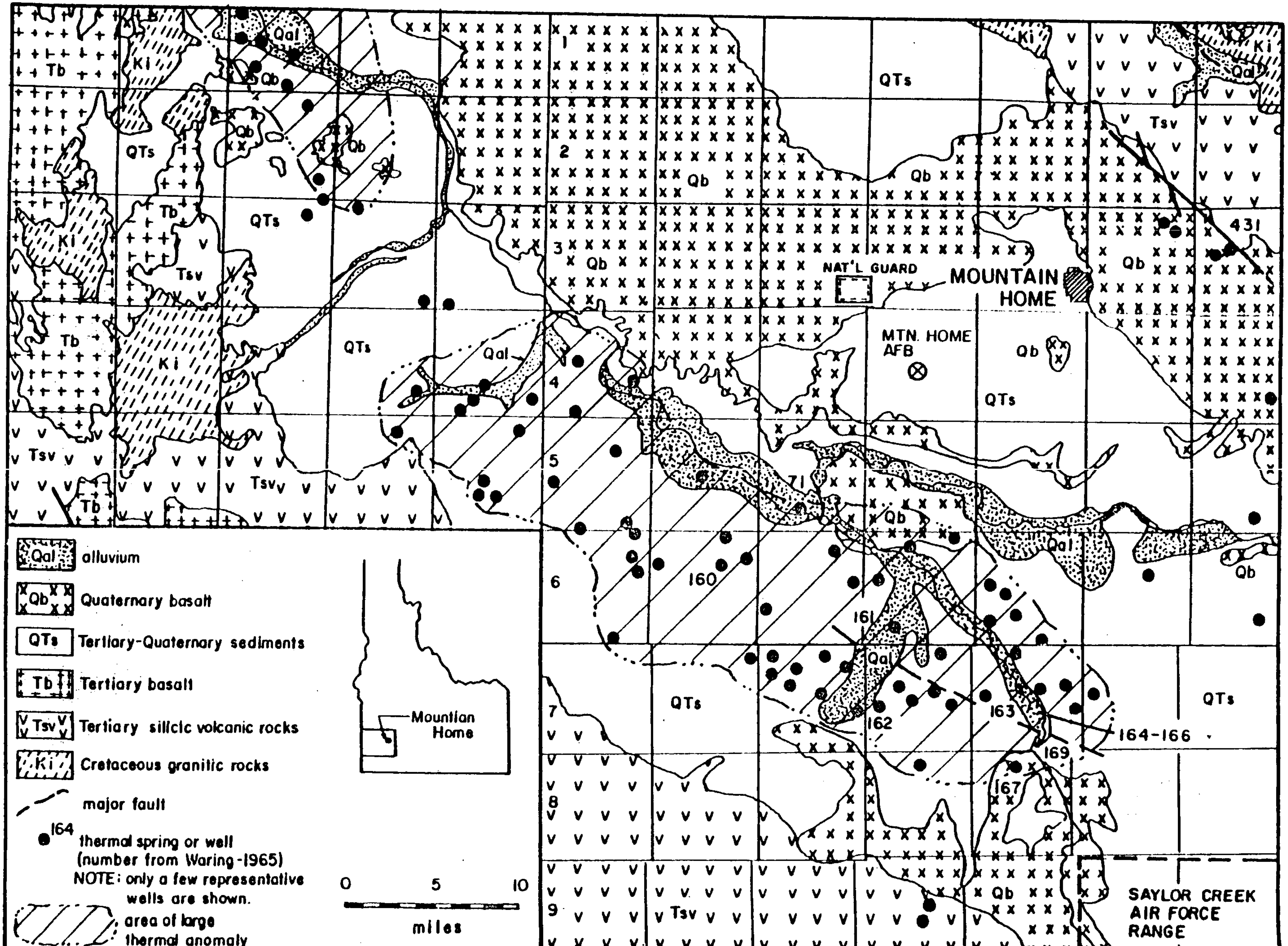
[3] Ralston, D.R., and Chapman, S.L., 1968, Ground Water Resource of the Mountain Home Area, Elmore County, Idaho, Idaho Department of Reclamation Water Information Bull. No. 4, Boise, Idaho, 63 pp


MOUNTAIN HOME
NAT'L GUARD
MTN. HOME AFB
SAYLOR CREEK AIR FORCE RANGE
QTs
Qb
Qal
Tb
Tsv
Ki
160
161
162
163
164-166
167
169
171
431
Qal alluvium
Qb Quaternary basalt
QTs Tertiary-Quaternary sediments
Tb Tertiary basalt
Tsv Tertiary silicic volcanic rocks
Ki Cretaceous granitic rocks
major fault
164 thermal spring or well (number from Waring-1965)
NOTE: only a few representative wells are shown.
area of large thermal anomaly
Mountain Home
0 5 10
miles

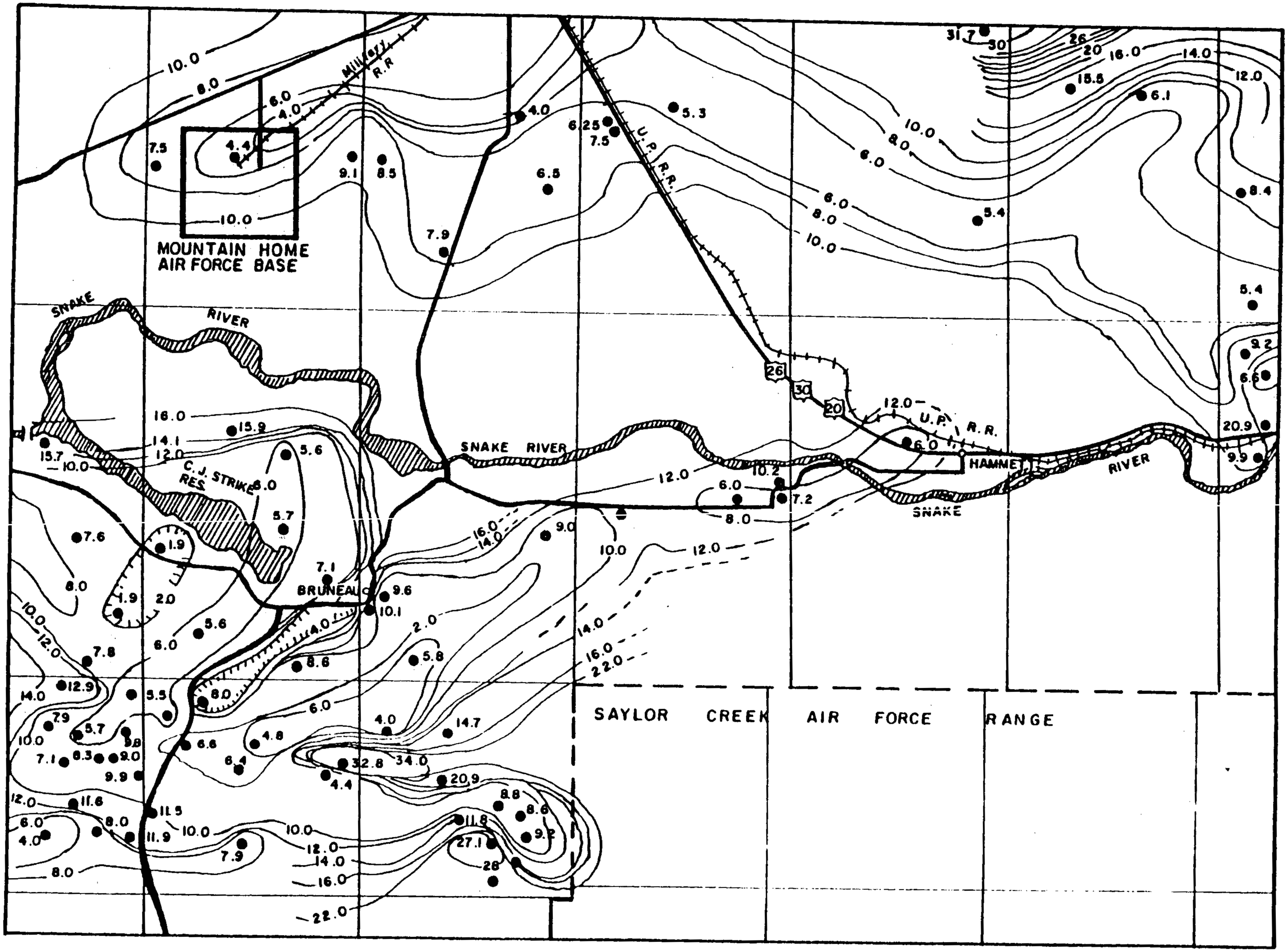


FIGURE 3. GEOTHERMAL GRADIENTS IN THE MOUNTAIN HOME/SAYLOR CREEK AREA (WHELAN, 1977)

Most data available indicate the source of high geothermal gradients is probably due to deep circulation of water which is recharged by spring run-off entering exposed volcanic outcrops in the nearby highland. The acquifers are both in sedimentary and volcanic rocks (vesicular basalts and tuffs), with the hottest water being driven from volcanic aquifers.

e. Recommendations

Wells in existence should be logged to get temperatures, water chemistry, heat flow, thermal gradients, and total depths, both on Mountain Home AFB and Saylor Creek AFR.

It is felt that the above data, in combination with published geophysical and geological data, should provide adequate information for selection of a drilling target. It should be noted that if data obtained from the Saylor Creek Range does not indicate power potential, it should be elimininated from consideration for heating alone because of the impracticality of distributing hot water of heating temperatures over a distance of this magnitude to Mountain Home, where it would be used (40km). However, if gradients and heat flow temperatures prove to be anamalously high, a drilling target should be selected for power exploratory purposes on the Range. The Naval Weapons Center geothermal staff, in conjunction with the energy staff at Mountain Home AFB have recommended a drilling site in the central base area.

2. ELLSWORTH AIR FORCE BASE

Ellsworth AFB has a potential for geothermal heating. The potential for water-dominated systems suitable for power generation is unknown.

a. Source of Heat

The source of the geothermal gradient anomalies is not known at this time. It has been postulated that the probable causes are friction, or deep circulation at the boundary of relative movement of two precambrian shield provinces in South Dakota, a boundary concordant with geothermal anomalies, causing the heating, resulting in high gradients.

A well located in Section 13, T2N, R8E near (or on) Ellsworth AFB has a recorded down-hole temperature of 49.4°C (121°F), adequate for heating purposes. The geothermal gradient for this hole is 3.1°C/100m (1.7°F/100 feet) with total depth of 1349m (4425 feet). This well was drilled in 1947 for water by the U. S. War Department.

Other geothermal gradients available in the immediate vicinity of the base are plotted on Figure 4. In the built-up portion of the base, geothermal gradients between 4.0°C/100m and 4.5°C/100m would be expected. At depths of 950m (3200 feet) and 1100m (3500 feet), water suitable for space heating should be encountered.

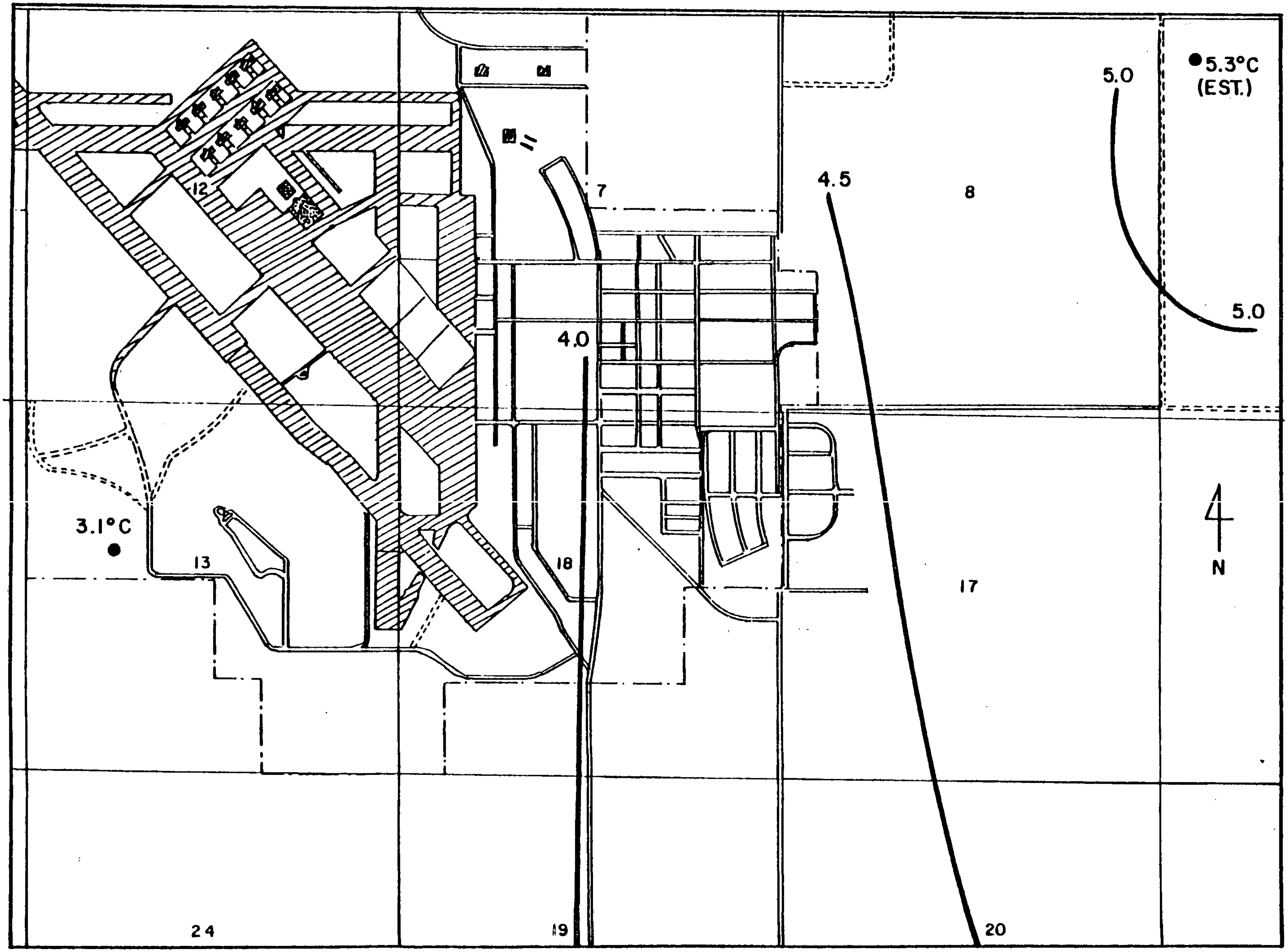


FIGURE 4 GEOTHERMAL GRADIENTS DETERMINED FROM WELL DATA ON

b. Summary

The location of Ellsworth AFB, and its relation to hot springs in the area, lead to the conclusion that there is definite potential for geothermal resource utilization at the base. This conclusion is further augmented by the fact that in Midland, South Dakota, some 100 miles to the east, a small school is currently being heated by geothermal water.

c. Recommendations

A thorough study should be performed of wells in the area to get temperatures, water chemistry, heat flow, thermal gradients, and total depths. It is felt that this data, in combination with published geophysical and geological data would provide adequate information for selection of a drilling target. A relatively deep test hole should be drilled to approximately 1850m (6000 feet) to study gradients at this depth as well as analyze aquifiers and provide material for geochemical water analysis.

3. WILLIAMS AIR FORCE BASE

Williams AFB Chandler, Arizona, has definite potential for geothermal heating. The potential for water-dominated systems suitable for power generation is unknown, but looks interesting.

a. Source of Heat

The geologic source of the geothermal gradient anomalies is not known at this time. However, an area known as the NOMAD geothermal field is located adjacent to and probably under Williams AFB.

Geothermal Kinetics, Incorporated (GKI), a private corporation, has leased and drilled 2 wells in Section 1 of Township 2 South, Range 6 East. Well number 1 has a total depth of 9,207 with the depth to water of 421 feet. The temperature of the water is 301°F. Well number 2 has a total depth of 10,450 feet with similar findings. Well number 1 has a flow rate of 6000 gallons per minute and is considered "producible." Figure 5 illustrates the portion of the NOMAD geothermal field originally leased by GKI in relation to base property. It is on the GKI lease that two test wells have been drilled by industry.

b. Summary

The area of Williams AFB adjacent to the NOMAD geothermal field has a definite potential for supplying geothermal water for the base needs.

c. Recommendations

Wells in existence should be logged to obtain temperatures, water chemistry, heat flow, thermal gradients, and total depths. This data, in conjunction with published geophysical and geologic data will provide the necessary information to select an optimum drilling site for base utilization of the underlying geothermal water.

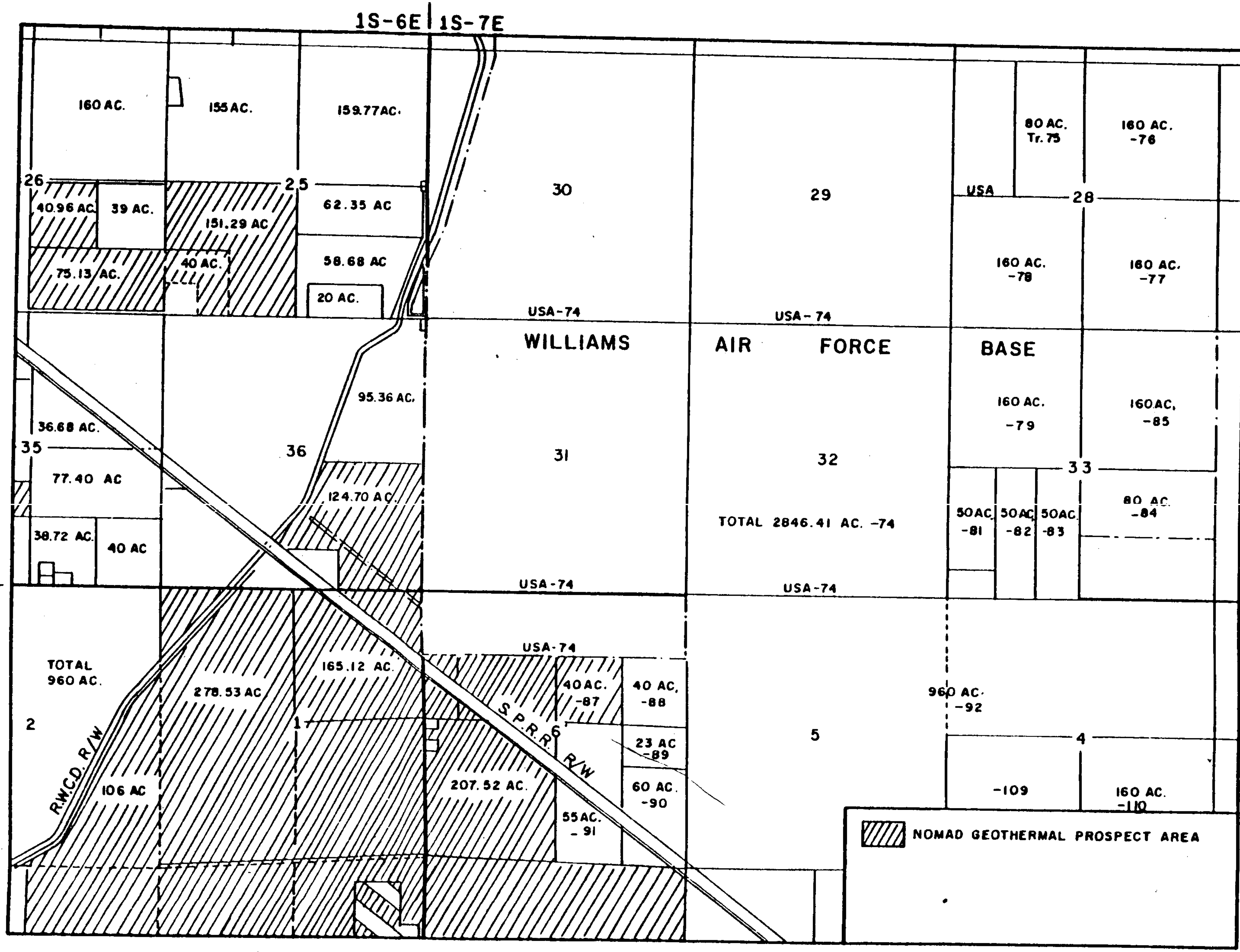


FIGURE 5. NOMAD GEOTHERMAL FIELD PROXIMITY TO WILLIAMS AIR FORCE BASE

Keesler AFB, Biloxi, Mississippi, is located in an area known as the Gulf Coast Geopressurized Zone. The geopressure potential for Keesler AFB is very good due to its proximity to known high pressure wells located in extreme southwestern Alabama.

a. Geology

The Gulf Coast geosyncline was formed during the Cenozoic by clastic sediments eroded from the central United States, particularly the Rocky Mountains. These sediments consist of interfingering marine sands and clays. In general, subsidence of the syncline into the oceanic crust has kept pace with the on going deposition, with the focus of deposition shifting gulfward with time. Major faults parallel to the basin margin accompany this subsidence vertically offsetting the bedding as deposition moved seaward, thereby forming discrete reservoirs in the sedimentary section.

b. Source of Heat

High sedimentation rates of up to 1.2 meters per thousand years in the Gulf Coast geosyncline basin coupled with intrusions of semi-molten salt diapirs have created subsurface hot (90°-300°C), pressurized, aquatic reservoirs containing dissolved methane gas. These "geopressured" reservoirs lie under a zone of impermeable shales and clays that are within 1.5 to 3.0 km of the surface and extend to depths of 7 to 15 km. Three energy producing phases may in the future be extracted from these geopressured reservoirs: kinetic (hydraulic fluid pressure), geothermal (heat), and combustion (methane).

The potential geothermal energy is within reach of current technology and drilling techniques, but to date not even pilot plant studies have been made. It is estimated that off-the-shelf hardware for its exploitation will not be available for about ten years. Problems remain too, in detailing exact reservoir characteristics in a localized area. Serious problems exist as to: what aquifier,water can be reinjected into; power requirements for reinjection; and the possibility of land subsidence caused by extraction of the waters. Legal problems may arise as to whether the resource comes under petroleum, ground water, or geothermal law.

c. Geopressure Gradients

Detailed data on the reservoir under Keesler is not known, however, Stone and Paddison (1977)[4] note that:

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[4] Stone, A.M., and Paddison, F.C. (1977) Status of Geothermal Energy in the State of Alabama, Operational Research, Geothermal Energy Development and Utilization, 33, Geothermal Program. Region 5 ZJOCQO, Support: ERDA DGE, 2p

"Several test wells (oil) drilled in Baldwin, Escombia, and Clark Counties (extreme S.S. Alabama) have run into geopressurized reservoirs that caused serious problems. The Watson well, drilled by Phillips Petroleum and Getty Oil encountered high pressure and after much trouble was closed off. Another well ran into calcium chloride at 16,000 feet and required a drilling mud of 21 lb/gal in order to kill the well.

A well in the Piney Wood field hit an area where pressures of 20,000 psi blew it out. Stainless steel casing had to be used; costs for completing the well were $15 to $18 million rather than the expected $1 to $2 million."

d. <u>Pressure Requirements</u>

Minimum geopressure required to generate power is on the order of 10,000 PSI. As noted previously, there is evidence that adequate geopressure is available in the area.

e. <u>Summary</u>

The Keesler AFB area has definite potential as a source for geopressure. The availability of geothermal water systems appears however to be minimal.

f. <u>Recommendations</u>

In the immediate vicinity of any anticipated future production a deep test well is required to establish the following:

(1) Sustained flow rate from a particular level in a particular reservoir.

(2) Flowing well-head pressures and temperatures.

(3) The exact depth to the isothermal surface required for production.

(4) Water samples from the reservoir to be used showing:

   (a) Amount and type of dissolved solids.

   (b) Amount and composition of dissolved gases.

   (c) Change in salinity during constant flow.

Effort should also be directed toward understanding the chemistry and controls of the geochemistry of formation waters from the geopressurized zone and from the normally pressurized zone where the spent geothermal fluids would be reinjected. Developments in exploitation of geopressured zones should be continuously monitored.

5. HILL AIR FORCE BASE

Hill AFB, Ogden, Utah has probable potential for geothermal resource utilization. The extent of these resources is unknown at the present time since the necessary data is currently unavailable. Evaluations are however in progress, and will be provided when completed.

The geologic setting at Hill Air Base suggests that deep drilling might produce fluids suitable for space heating. Commercial test drilling in a comparable geologic setting to the north at Brigham City encountered 295°F water at 12000 feet in a marble horizon, but flows were only of the order of 50 gpm. The data in hand regarding Hill Air Base was transmitted to EG&G and is incorporated in their detailed study (Ref Donovon and others (1978)). One note of caution was demonstrated at the Brigham City test hole as the hot fluids ran 65,000 to 70,000 ppm dissolved solids, suggesting corrosion and scaling as well as disposal concerns.

Geothermal resource information available for U. S. Air Force installations outside the Continental United States is basically limited to information from published sources and professional papers. Utilizing this information, the following installations have geothermal resources either on the base or in the immediate surrounding area.

Bellows AFB, Oahu, Hawaii
Lajes AFB, the Azores
Cigli Air Base, Turkey
Ankara Air Station, Turkey

1. BELLOWS AIR FORCE BASE

Bellows AFB, Oahu, Hawaii has probable potential for the production of geothermal power and space heating.

a. Geology

The Island of Oahu represents the remnants of two major volcanic centers in which the principle volcanism took place between two and three million years ago. Erosional remnants of these two volcanoes are represented today by the Waianae Mountains along the west coast of Oahu and the Koolau Range along the southeastern coast (see Figure 6).

It is reasonable to expect that if any subsurface heat remains in these two dormant volcanoes, the major part of it would be concentrated in these volcanic stocks. The amount of heat persisting until the present time will depend on how effective the cooling has been. That the central stock of Koolau Volcano may still be warm is indicated by resurgent activity which occurred as recently as 31,000 to 33,000 years ago.

Magnetic surveys performed across the island indicate the presence of dense rock in a stock-like mass under each of these mountain ranges. (Strange, Mockensky, and Woolard, 1965)[5].

b. Seismicity Surveys

Changes in the velocity of seismic "P" waves through the surface of the earth are widely used to locate zones with unusually high temperatures. This discrete change in travel time has been used to delineate the general outline of the stock or magma chamber beneath the remnant Koolau Volcano (see Figure 7).

[5] Strange, W.E., Machevsky, L.F., and Wollard, G.P., A Gravity Survey of the Island of Oahu, Hawaii: Pacific Science, v. 19, pp 350-353

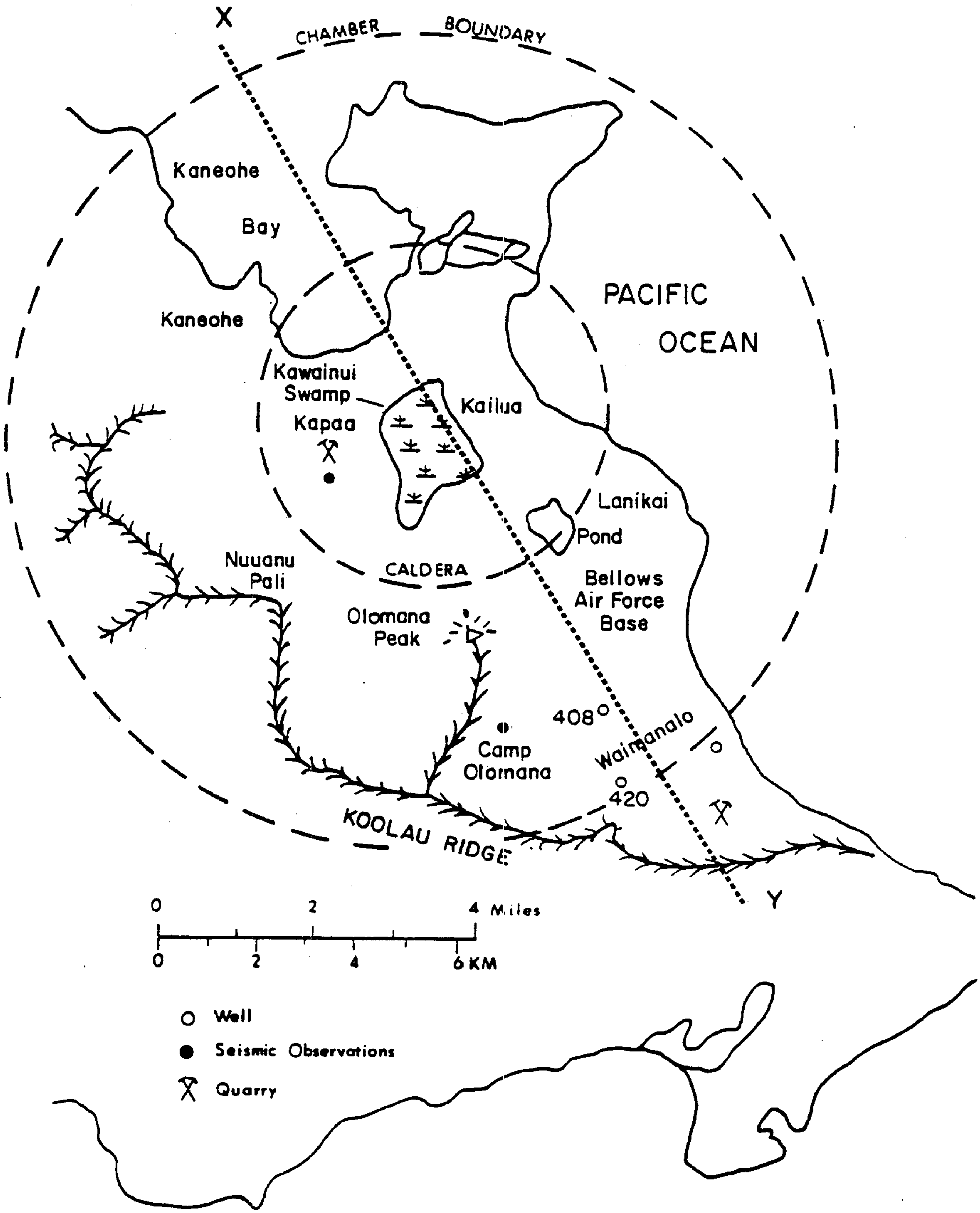

FIGURE 6. AREA SURROUNDING THE ANCIENT MAGMA CHAMBER OF KOOLAU VOLCANO (GEOTHERMAL ENERGY MAGAZINE)

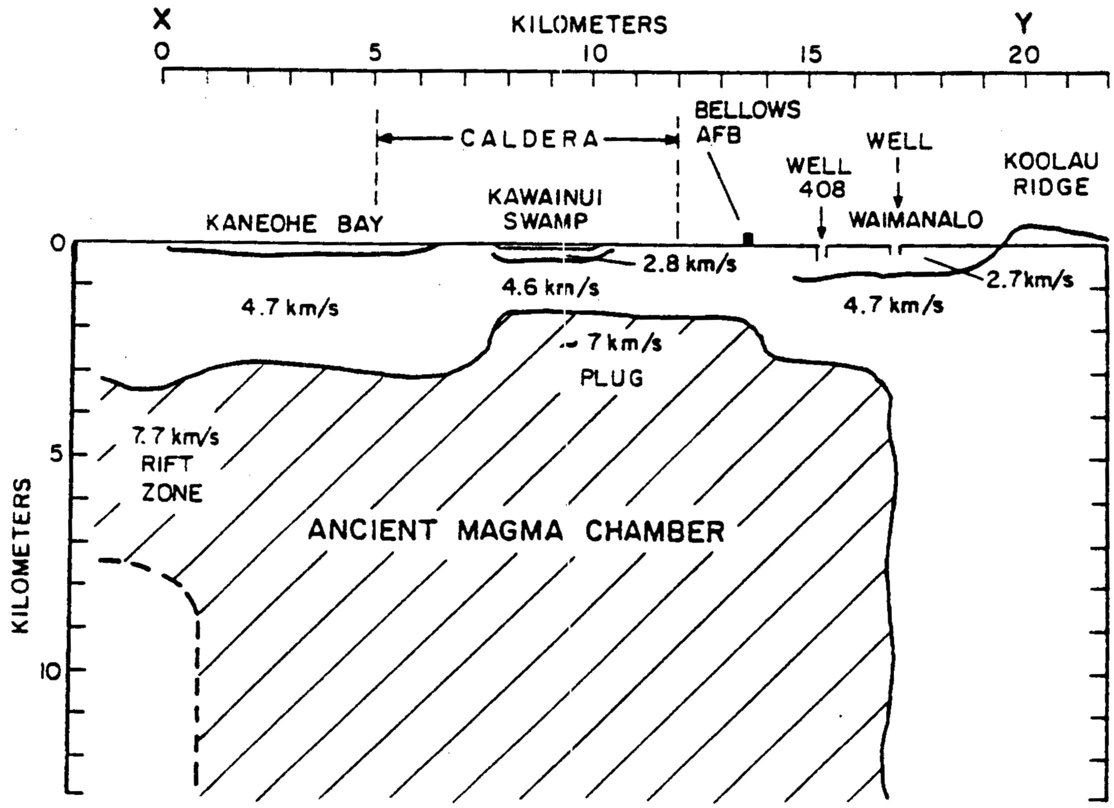

FIGURE 7. VERTICAL PROFILE OF CROSS-SECTION ALONG LINE XY SHOWING RELATIVE POSITION OF BELLOWS AFB, (GEO-THERMAL ENERGY MAGAZINE)

c. Summary

Geothermal gradients from wells in the vicinity of Bellows AFB are presently unavailable, so an accurate determination of the temperature change with depth is impossible at this time. Using the plot of the relative location of Bellows AFB to the ancient Magma Chamber (see Figure 7) it can be extrapolated that the potential for geothermal resource utilization at Bellows AFB is very good. A comprehensive program to determine thermal gradients should be pursued.

2. LAJES AIR FORCE BASE

Lajes AFB, Terceira Island, Azores, appears to have good geothermal potential. The base is also a NATO base, and is located in the northeastern portion of the Island of Terceira, three miles (4.8 km) east of the city of Praia do Victoria. Terceira is in the District of Angra do Heroismo.

Several islands in the Azores Archipelago have geothermal potential for power and/or heating. Estimates of potential power have been made as many hundreds of megawatts being available in these islands.

a. Geology

Terceira and San Miguel Islands are considered to have the greatest potential for geothermal resources. Both islands are of volcanic nature with San Miguel having three major volcanos and Terceira having two.

The basic stratigraphic sequence is a series of basaltic flows, trachytic flows, basaltic breccia, ash falls, and ignimbrites. This sequence appears to be typical of both Terceira and San Miguel.

On San Miguel Island, drilling done in 1973 by geoscientists from Dalhousie University and Lamont-Doherty Geological Observatory on the flanks of Agua de Pau, a major volcano (950m elevation above sea level) garnered down-hole temperatures of 200°C (392°F). This temperature was encountered at 550m initially and, at the time of last measurements, at 290m depth (Muecke, et al, 1974)[6].

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[6] Muecke, G.K., Ade-Hall, J.M., Aumento, R., MacDonald, A., Reynolds, P.H., Hyndman, R.A., Quintino, J.;, 1974, Deep Drilling in an Active Geohermal Area in the Azores, in Nature, Vol. 252. 11/22/74, pp 281-285

The boiling point was exceeded during drilling and steam erupted from the hole when the drill rod was removed. No flow measurements were made and permeability of the core has not been measured. The eruption of steam and hot water was stopped after 20 minutes before any depletion was noted. Power potential of this hole, therefore, is not known.

The 200^{o} water boiled when it reached the temperature-pressure boiling curve near 215m depth.

Temperatures were nearly constant to 100m ($20^{o}C$ - $25^{o}C$), then a sudden jump in temperature to over $100^{o}C$ ($212^{o}F$) occurred between 100 and 175m depths. A uniform gradient was then established of $250^{o}C$/km ($25^{o}C$/100m) to 550m depth. After that, a low gradient of less than $10^{o}C$/km ($1^{o}C$/100m) was established to the bottom of the hole, approximately 900m.

Terceira Island has two large calderas in the eastern and central parts of the island (see Figure 8). The volcanos are aligned on a west-northwest trend. A graben strikes northwest in the northeastern portion. The oldest rocks are ankaramites, succeeded by relatively young basalts, trachytes and olivine basalts (Ridley, et al, 1973)[7].

Although there are no hot springs known on Terceira, the central volcano, Caldeira de Guilherme, has water vapor present and temperatures of $90^{o}C$ ($194^{o}F$) (Waring, 1965). There is much CO_2 and H_2S, and sulfur deposits are present. The rocks are considerably decomposed, probably indicating severe hydrothermal alteration.

Faulting is generally right lateral transform with tension normal to the axis of the Ridge (Mid-Atlantic Ridge). Normal faulting results along with crustal extension. The faulting in the Azores is directly related to Ridge activity (Arroyo and Udias, 1972)[8].

b. Source of Heat

The source of heat has not been defined, however hot water flows, parallel to the bedding, down dip from the volcanic source. The low-bottom hole temperatures indicate that the source is not under the drill site. Impermiable beds at 102m restrict vertical circulation of the hot water. Figure 8 illustrates the base location in relation to the volcanics.

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[7] Ridley, W.I., Watkins, N.D., MacFarlane, D.J., 1973, Oceanic Islands, Azores, in Oceans, Basins and Margins, Vol. 2, North Atlantic, pp 450-457

[8] Arroyo, A. Lopez, and Udias, A., 1972, Aftershock Data of Azores-Gibralter Earthquake of February, 1969, in Bull. Seis. Soc. Amer., Vol. 62, June, 1972 pp 717

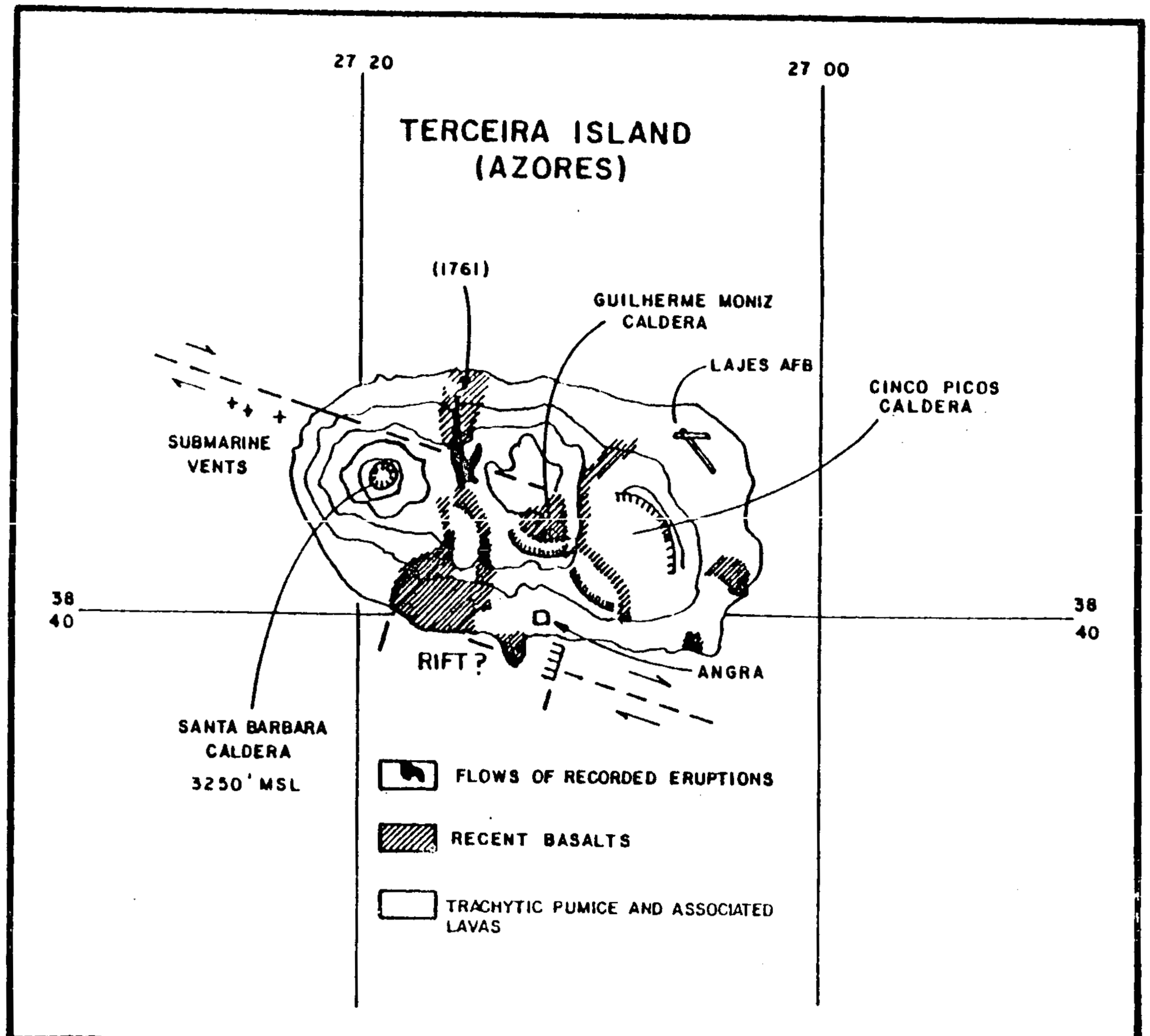

FIGURE 8. LOCATION OF LAJES AIR FORCE BASE ON TERCEIRA ISLAND
(MACHADO AND QUINTEHO)

c. Summary

The results of drilling tests on San Miguel Island, and the similarity of structure between the two islands suggests a strong probability of similar geothermal resources which should provide as a minimum adequate geothermal water.

d. Recommendations

The Air Force should attempt to obtain whatever information is available from the Institute de Gesciences dos Azores, San Miguel. Assuming that proprietary information becomes available, this information should substantiate the preceeding suppositions and a target site should be selected for an exploratory drilling program.

U. S. AIR FORCE INSTALLATIONS IN TURKEY

U. S. Air Force installations with geothermal potential located within Turkey are limited to Cigli Air Base, Izmir, and Ankara Air Station Ankara. Figure 9 illustrates the proximity of these areas to known geologic structures.

3. CIGLI AIR BASE (Closed)

Cigli Air Base, Izmir, Turkey is located in or near the Izmir-Seferihisar geothermal area (see Figure 10). The potential for water dominated power generation is uncertian. There is definite potential however for the production of geothermal hot water.

a. Geology

Five groups of springs with a total approximate flow of 110 l/sec and a maximum temperature of 82°C as geothermal indices; with widespread occurrences of silicification, limonitization, and travertine are remarkable in this area of the Aegean Coast in western Anatolia. General geological, volcanological, tectonic, hydrogeochemical, and geophysical studies and drilling activities have been completed.

The most important belt in the area is a northeast-southwest-trending graben formed at the beginning of the Tertiary. Paleozoic metamorphic schists and Upper Cretaceous clayey schists, claystone, limestone, serpentine, and diabase occupy the southeast end of the graben, while at the northwest end, Upper Cretaceous flysch with dominant limestone facies occurs. Figure 11 shows two characteristic sections of the Seferihisar area.

The graben has been filled with beds of sandstone, claystone, millstone, clayey limestone, limestone, and coal, which are Neogene in age. Young faults cutting these 1200m thick levels with cap rock characteristics have possibly provided the formation of perlite, tuff, aglomerate, tuffite, and ignimbrite at the top. In the later phase (probably Upper Pliocene or at the beginning of the Quaternary), young rhyolite and rhyodacite domes appeared, passing through these tuffs and agglomerates.

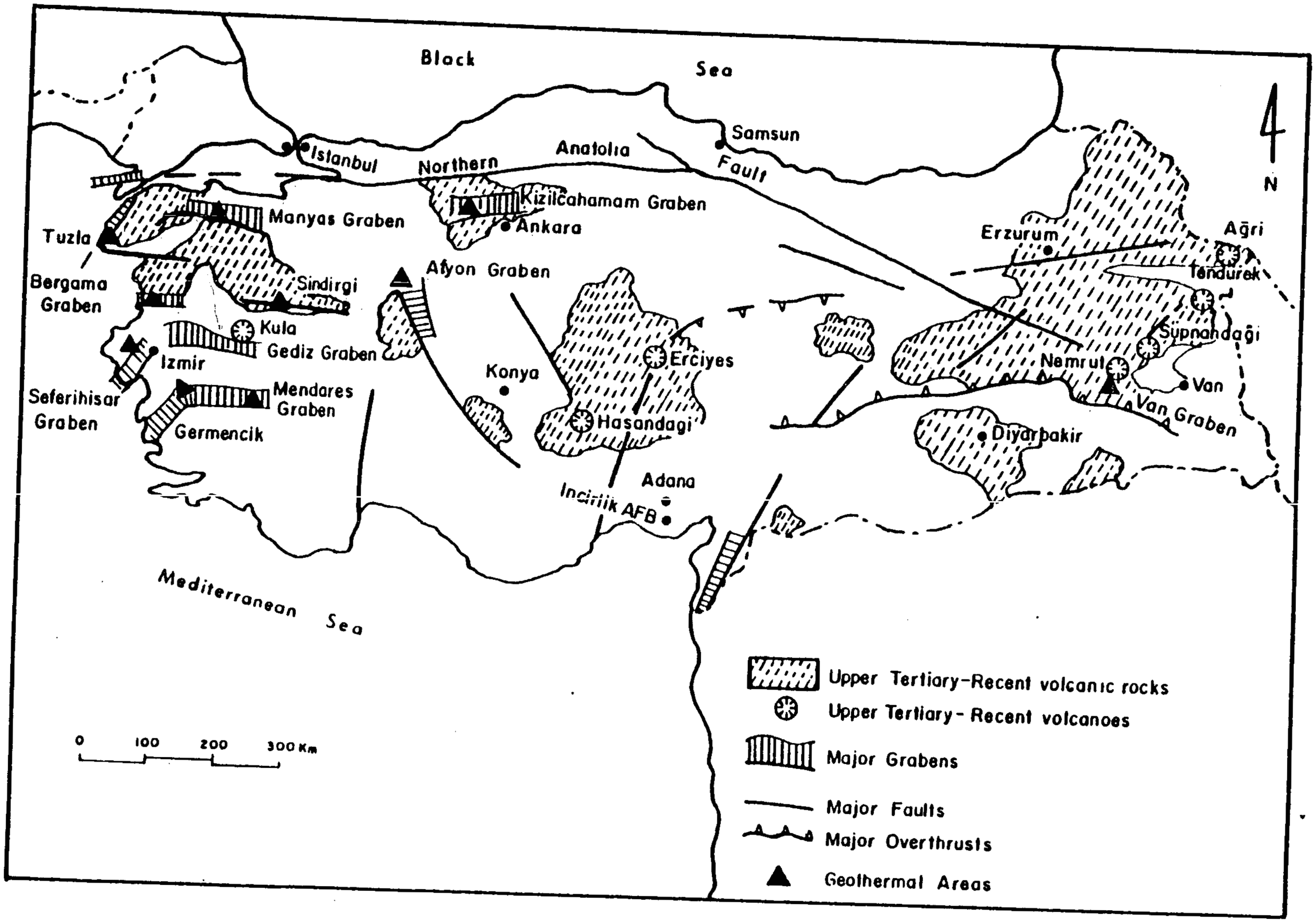

FIGURE 9. GENERAL TECTONIC AND VOLCANIC FEATURES OF TURKEY (KURTMAND AND SAMILGIL)

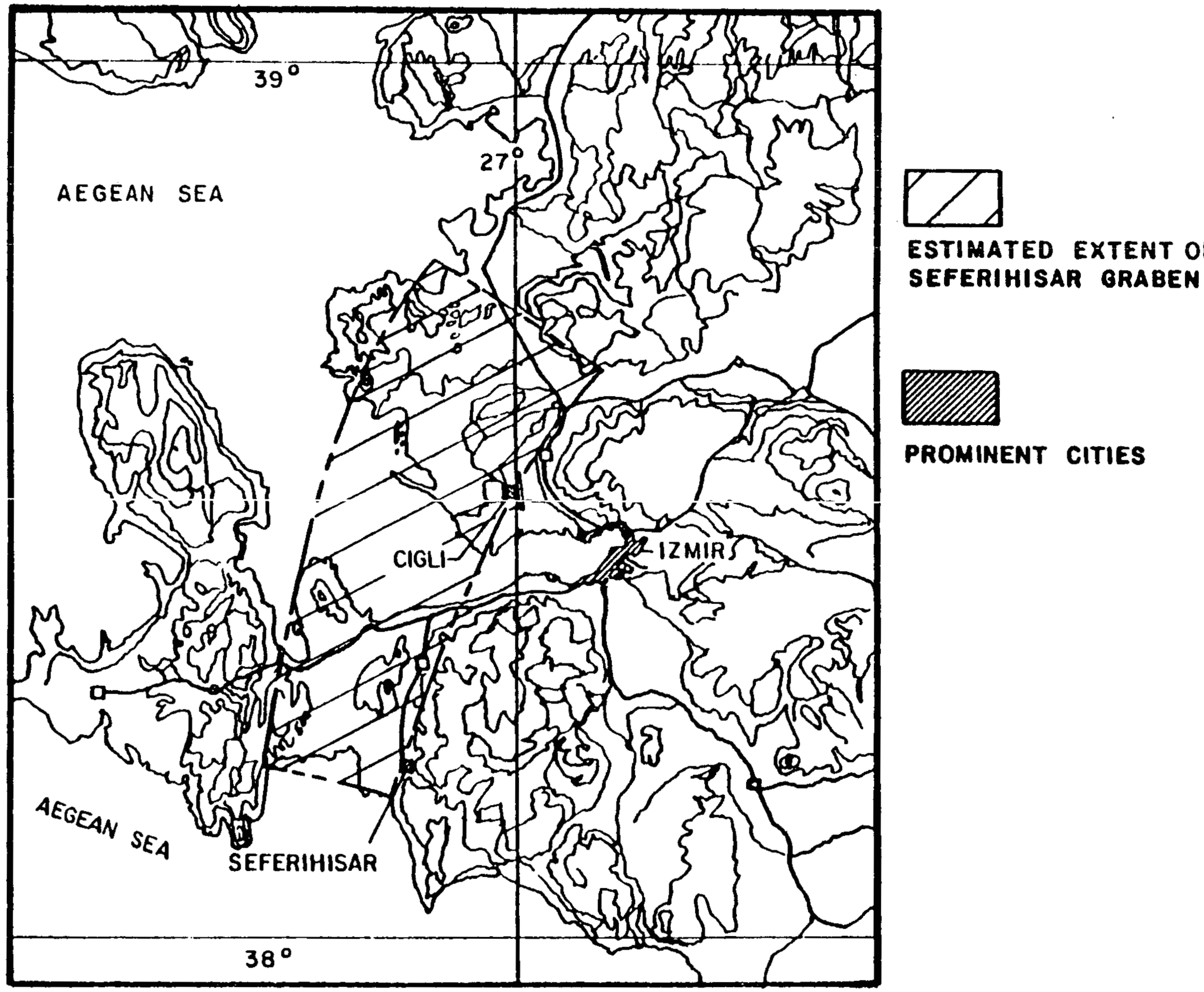

FIGURE 10. PROXIMITY OF CIGLI AIR BASE TO THE SEFERIHISAR GRABEN

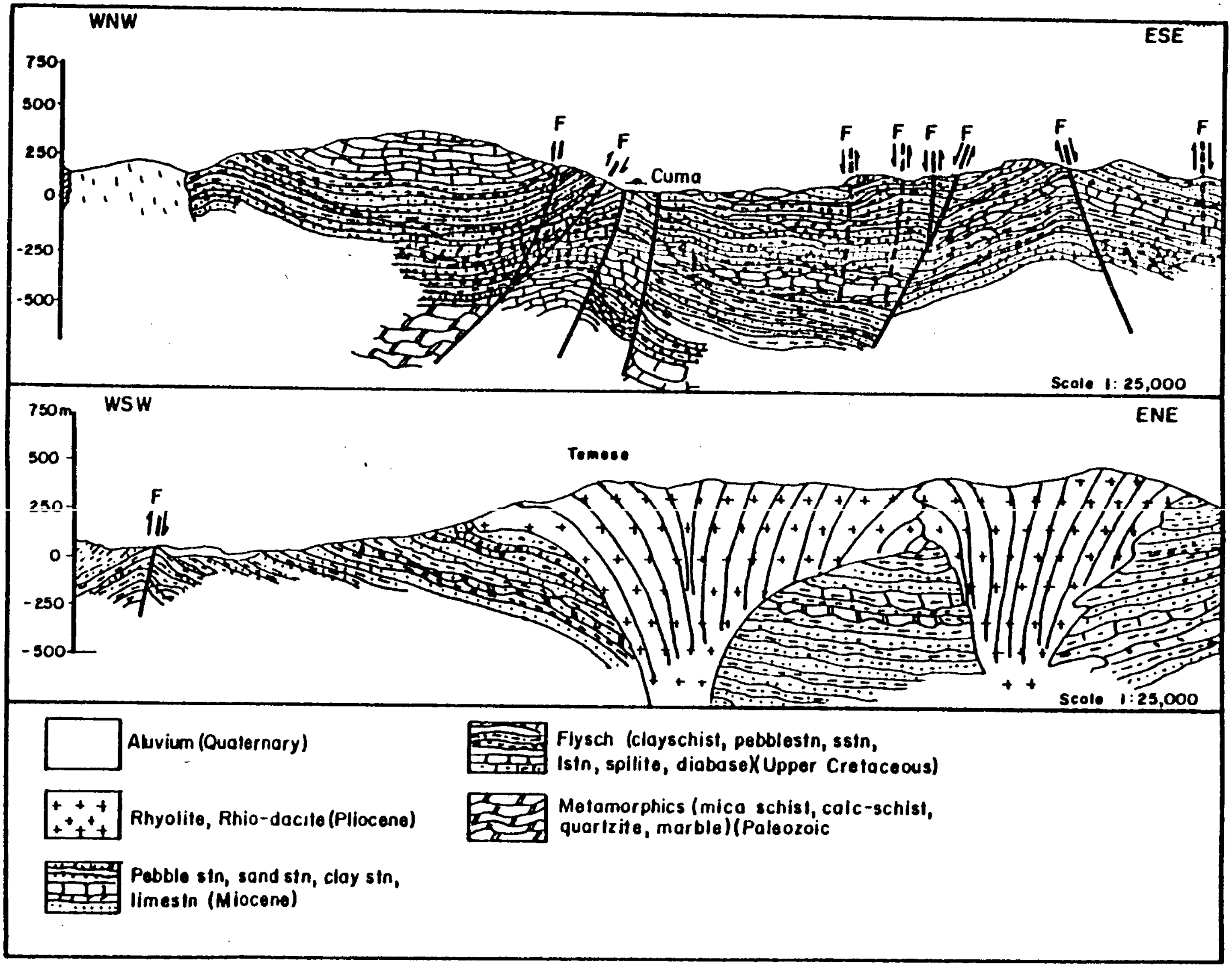

FIGURE 11. CHARACTERISTIC GEOLOGIC SECTION IN THE SEFERIHISAR AREA (KURTMAN AND SAMILGIL)

b. Source of Heat

A probable magma pocket of the young acidic volcanics, still in its cooling period, is thought to be the source. The existence of such a factor is also indicated either by present hot water springs and alteration zones or by high values of isogradient curves at 90 to 110m intervals and isotherms at 100m based on test drillings in the Neogene cover. Probable reservoir levels of the whole sequence are constituted of Paleozoic marbles, limestones within the Upper Cretaceous flysch, and the limestones of the Neogene bottom. The heat of the Cuma springs, in which sea water contamination has its lowest value, is established by hydrogeochemical analysis, and comes from an appreciably hot water reservoir.

c. Summary

Cigli Air Base has definite potential for hot water production. The area has been evaluated by the MINERAL RESEARCH AND EXPLORATION INSTITUTE (MTAE) in Ankara Turkey. Fikret Kurtman and Erman Samilgil[9] of MTAE have authored a recent paper discussing and evaluating the general geological, volcanological, tectonic, hydrogeochemical, geophysical, and drilling studies in the area.

d. Recommendations

Considering the fact that extensive studies have been performed on the area, it is recommended that the recently published information be obtained from MTAE. Deep drillings with descent to the second reservoir are being programmed and should be encouraged. Further studies in this vicinity are certainly warranted.

4. ANKARA AIR STATION

Ankara Air Station, Ankara, Turkey is located in or near the Ankora - Kizilcahamam geothermal area and has probable potential for geothermal heating.

a. Geology

Numerous springs with temperatures between 22°C and 55°C are present in the northern, western, and southern parts of the region surrounding Ankara. The ones on the northern side especially, are remarkable for appreciably young (Pliocene) volcanism and related hydrothermal alterations. By means of geologic and gravimetric studies, the following grabens were determined; Murget graben which is situated 40 km northwest of Ankara; Cubuk graben, situated 30 km northeast of Ankara; and Kizilcahamam graben, situated 80 km north-northwest of Ankara. Figure 12 shows a geologic section near Kizilcahamam.

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[9] Kurtman, Fikret and Samilgil, Erman; Geothermal Energy Possibilities, Their Exploration and Evaluation in Turkey; Proceedings of the Second United Nations Symposium on the Development and Use of Geothermal Resources, San Francisco, California, 20-29 May 1975, pp 447

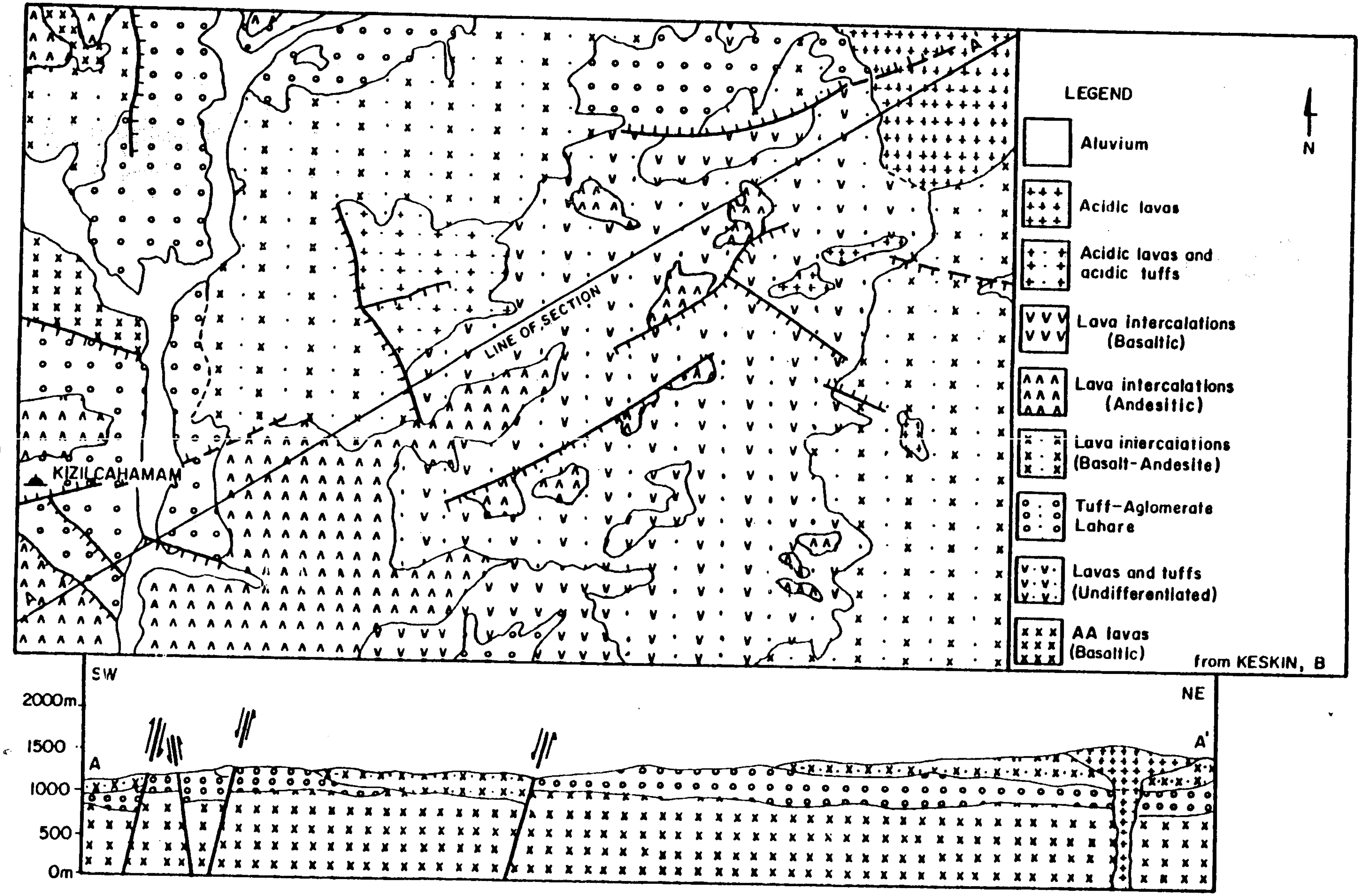

FIGURE 12. GEOLOGIC SECTION NEAR KIZILCAHAMAM
(KURTMAN AND SAMILGIL)

Hydrogeochemical studies indicate that a reservoir temperature of 195°C is expected in Kizilcahamam and 90°C in Murtet and Cubuk.

The purpose of studies carried out in Kizilcahamam graben is for the production of electrical energy. The tentative log of the planned deep drilling program is as follows:

(1) 0 to 500m: lava, tuff, tuffite (cap rock).

(2) 500 to 1000m: Fissure eruption of aa-type plateau basalt (first reservoir rock).

(3) 1000 to 1100m: Upper Cretaceous limestone (second reservoir rock).

(4) 1100 to 1400m: Upper Cretaceous, marl shale, and conglomerate (cap rock).

(5) 1400 to 1500m: Upper Jurassic-Lower Cretaceous limestone (third reservoir rock).

The first well drilled in the Cubuk Plain near the city of Ankara encountered water between depths of 113 to 116m with a temperature of 32°C and a flow rate of 150 l/sec. Due to the unexpected enormous amount of water, this drilling was stopped before reaching the hot water horizon, and a second bore-hole was started near the first. In the second well, water was found between 218 and 549m. The temperature was 40°C and flow rate 300 l/sec. Presence of these water horizons with high flow rates, but at shallower levels, temporarily interfered with the continuation of drilling operations to reach the deep-seated reservoirs, and the second drilling was also stopped.

b. Summary

Since Ankara Air Station's location in proximity to several geothermal areas is known, it appears that further investigation and evaluation by the MTAE will delineate the area's potential for geothermal resources. Land use and topographic maps of the area are unavailable.

c. Recommendations

The evaluations and studies by MTAE should be encouraged so as to provide adequate data on Ankara Air Station's geothermal potential. If the potential justifies the effort, a drilling program should be initiated to capitalize on available geothermal water from the most promising reservoir.

APPENDIX A

Summary of Geothermal Potential of Air Force Installations

The Geothermal Utilization Division, Public Works Department, Naval Weapons Center, is continuously reviewing the geothermal potential of military installations around the world. The initial phase of review is to determine the geologic setting of the installation. Such factors as known hot springs, warm or hot wells, seismic activity, mercury, arsenic, or uranium mineralization are considered. Data were taken from geologic literature and from unpublished studies available to the authors. This preliminary review is useful to determine the priority for more detailed studies and to plan such studies. Informal reports were prepared on some installations where considerable library data were utilized.

Evaluation of geothermal potential of areas is not a static process. Additional geologic studies, the drilling of good or poor wells in an area, preliminary geologic or geophysical field studies may cause the assessed potential of an area of installation to be changed.

Legal and institutional problems are discussed in the main report.

The bases with the greatest geothermal potential are:

Mountain Home Air Force Base (space heating), Saylor Creek Range at Mountain Home (power), Ellsworth Air Force Base (space heating), Keesler Air Force Base (geopressurized geothermal resource), Hill Air Force Base (space heating), and Williams Air Force Base (power) in the Continental United States; and Bellows AFB Hawaii (power), Lajes AFB Azores (power), Ankara Air Station Turkey (space heating), and Cigili Air Base Turkey (space heating) outside the Continental United States. These facilities are discussed in the basic report.

Evaluations of other Air Force facilities are given in the following Table:

FACILITY	LOW	SPACE HEATING FAIR	SPACE HEATING GOOD	SPACE HEATING HIGH	ELECTRIC POWER PRODUCTION FAIR	ELECTRIC POWER PRODUCTION GOOD	ELECTRIC POWER PRODUCTION HIGH	GEOPRESS-URIZED RESOURCE*	REMARKS & REFERENCES **
Altus AFB Altus, OK.	X								
Andrews AFB, Camp Springs, MD.	X								
Barksdale AFB Bossier City, LA.								X	NWC Informal Report #1
Beale AFB, Marysville, CA.		X							NWC Informal Report #9
Bergstrom AFB, Austin, TX.	X								May have geopressurized potential
Blytheville AFB, Blytheville, AR.	X								
Bolling AFB, (N) Washington, D. C.	X								
Brooks AFB (N) San Antonio, TX.								X	NWC Informal Report #1
Cannon AFB, Clovis, NM.	X								
Carswell AFB, Fort Worth, TX.	X								May have geopressurized potential
Castle AFB, Atwater, CA.	X								

GEOTHERMAL POTENTIAL

FACILITY	LOW	SPACE HEATING FAIR	SPACE HEATING GOOD	SPACE HEATING HIGH	ELECTRIC POWER PRODUCTION FAIR	ELECTRIC POWER PRODUCTION GOOD	ELECTRIC POWER PRODUCTION HIGH	GEOPRESSURIZED RESOURCE*	REMARKS & REFERENCES**
Chanute AFB, Rantoul, IL.	X								
Charleston, AFB North Charleston, SC.	X								
Craig AFB, Selma, AL.	X								
Columbus AFB, Columbus, MS.								X	May have geopressurized potential
Davis-Monthan AFB, Tucson, AZ.			X						Possible geothermal potential NWC Informal Report #5
Dobbins AFB, Marietta, GA.	X								NWC Informal Report #2
Dover AFB, Dover, DE.	X								NWC Informal Report #16
Duluth International Airport, Duluth, MN.	X								
Dyess AFB Abilene, TX.	X								
Edwards AFB, AFFTC Rosamond, CA.	X								Possible space heating potential
Eglin AF Aux. Field No.9, Mary Ester, FL.	X								NWC Informal Report #12

		GEOTHERMAL POTENTIAL							REMARKS & REFERENCES**
		SPACE HEATING			ELECTRIC POWER PRODUCTION			GEOPRESS-URIZED	
FACILITY	LOW	FAIR	GOOD	HIGH	FAIR	GOOD	HIGH	RESOURCE*	
Eglin AFB, Valparaiso, FL								X	NWC Informal Report #12
Eielson AFB, Fairbanks, AK	X								NWC Informal Report #1
Ellington AFB Ellington, TX.								X	NWC Informal Report #1
Ellsworth AFB, Rapid City, SD.				X					Gries 1977 & NWC Informal Report #6
Elmendorf AFB, Anchorage, AK.	X								Miller 1973
England AFB, Alexandria, LA.								X	NWC Informal Report #1
Ent AFB, Peterson, CO	X								NWC Informal Report #4
Fairchild AFB, Spokane, WA.	X								NWC Informal Report #3
Francis E. Warren AFB Cheyenne, WY.	X								
George AFB, Victorville, CA.		X							Needs more study
Goodfellow AFB San Angelo, TX.								X	Possibly in geopressurized zone

FACILITY	GEOTHERMAL POTENTIAL LOW	SPACE HEATING FAIR	SPACE HEATING GOOD	SPACE HEATING HIGH	ELECTRIC POWER PRODUCTION FAIR	ELECTRIC POWER PRODUCTION GOOD	ELECTRIC POWER PRODUCTION HIGH	GEOPRESSURIZED RESOURCE*	REMARKS & REFERENCES**
Grand Forks AFB, Grand Forks, N.D.	X								
Griffiss AFB, Rome, NY	X								
Grissom AFB, Peru, IN	X								
Hancock Field Syracuse, NY	X								
Hickam AFB Oahu, Hawaii	X								
Hill AFB, Ogden, UT.		X							Donovon and others, 1978. Little Mountain Facility has good space heating potential, Wen~~dover Bombing Range has power potential.~~ & NWC Informal Reports #14 & 15.
Holloman AFB, Almogordo, NM.		X							Needs More study
Homestead AFB, Homestead, FL.	X								NWC Informal Report #12
HQ AFAFC, Denver, CO.	X								NWC Informal Report #4
Keesler AFB, Biloxi, MS.								X	NWC Informal Report #1
Kelly AFB, San Antonio, TX.								X	NWC Informal Report #1

FACILITY	LOW	SPACE HEATING FAIR	SPACE HEATING GOOD	SPACE HEATING HIGH	ELECTRIC POWER PRODUCTION FAIR	ELECTRIC POWER PRODUCTION GOOD	ELECTRIC POWER PRODUCTION HIGH	GEOPRESS-URIZED RESOURCE*	REMARKS & REFERENCES**
Kincheloe AFB, Kinross, MI.	X								
Kingsley Field Kingsley, OR.				X					NWC Informal Report #3
Kirtland AFB Albuquerque, NM.		X							Needs more study
K. I. Sawyer AFB, Gwinn, MI.	X								
Lackland AFB (N) San Antonio, TX.								X	NWC Informal Report #1
Langley AFB Hampton, VA.	X								
Laughlin AFB, Del Rio, TX.	X								
Laurence G. Hanscom AFB, Belford, MA.	X								
Little Rock AFB Jacksonville, AR.	X								
Loring AFB Limestone, ME.	X								
Lowry AFB, Denver, CO.	X								NWC Informal Report #4

FACILITY	LOW	SPACE HEATING FAIR	SPACE HEATING GOOD	SPACE HEATING HIGH	ELECTRIC POWER PRODUCTION FAIR	ELECTRIC POWER PRODUCTION GOOD	ELECTRIC POWER PRODUCTION HIGH	GEOPRESS-URIZED RESOURCE*	REMARKS & REFERENCES**
Luke AFB, Glendale, AZ.		X	X		Poor				NWC Informal Report #5
MacDill AFB Tampa, FL.	X								NWC Informal Report #12
Malstrom AFB Great Falls, MT.	X								
March AFB Riverside, CA.		X							
Mather AFB Sacramento, CA.	X								
Maxwell AFB Montgomery, AL.	X								
McChord AFB Tacoma, WA.	X								NWC Informal Report #3
McClellan AFB Sacramento, CA.	X								
McConnell AFB Witchita, KS.	X								
McGuire AFB Wrightstown, NJ.	X								
Minot AFB Minot, ND	X								
Moody AFB Valdosta, GA.	X								

GEOTHERMAL POTENTIAL

FACILITY	LOW	SPACE HEATING FAIR	SPACE HEATING GOOD	SPACE HEATING HIGH	ELECTRIC POWER PRODUCTION FAIR	ELECTRIC POWER PRODUCTION GOOD	ELECTRIC POWER PRODUCTION HIGH	GEOPRESSURIZED RESOURCE*	REMARKS & REFERENCES**
Mountain Home AFB Mountain Home, ID.				X	X				NWC Informal Reports #7 & 8
Myrtle Beach AFB, Myrtle Beach, SC,	X								
Nellis AFB Las Vegas, NV.		X							Needs more study
Newark AFS Newark, OH.	X								
Norton AFB San Bernadino, CA.			X		X				
Offutt AFB Omaha, NE.	X								
Patrick AFB Cocoa Beach, FL.	X								NWC Informal Report #12
Pease AFB Portsmouth, NH.	X								
Plattsburgh AFB Plattsburgh, NY.	X								
Pope AFB Fayetteville, NC.	X								
Randolph AFB San Antonio, TX.								X	NWC Informal Report #1

FACILITY	LOW	GEOTHERMAL POTENTIAL: SPACE HEATING FAIR	GOOD	HIGH	ELECTRIC POWER PRODUCTION FAIR	GOOD	HIGH	GEOPRESS-URIZED RESOURCE*	REMARKS & REFERENCES**
Reese AFB Lubbock, TX.	X								
Richards-Gebaur AFB Belton, MO.	X								
Rickenbacker AFB Columbus, OH.	X								
Robins AFB Warner Robins, GA.	X								
SAMSO AFS Los Angeles, CA.	X								
Scott AFB Shiloh, IL.	X								
Seymour Johnson AFB Goldsboro, NC.	X								
Shaw AFB Sumter, SC.	X								
Sheppard AFB Wichita Falls, TX.	X								
Tinker AFB Oklahoma City, OK.	X								
Travis AFB Fairfield, CA.	X								

		GEOTHERMAL POTENTIAL							REMARKS & REFERENCES **
		SPACE HEATING			ELECTRIC POWER PRODUCTION			GEOPRESS-URIZED	
FACILITY	LOW	FAIR	GOOD	HIGH	FAIR	GOOD	HIGH	RESOURCE*	
Tyndall AFB Panama City, FL.								X	NWC Informal Report #12
USAF Academy Monument, CO.	X								NWC Informal Report #4
Vance AFB Enid, OK	X								
Vandenburg AFB Lompoc, CA.		X							
Webb AFB Big Spring, TX.	X								
Westover AFB Chicopee, MA.	X								
Whitemen AFB Sedalia, MO.	X								
Williams AFB Chandler, AZ.			X	X		X	X		NWC Informal Report #5
Wright-Patterson AFB, DAyton, OH.	X								
Wurtsmigh AFB, Oscoda, MI.	X								

FACILITY	LOW	SPACE HEATING FAIR	SPACE HEATING GOOD	SPACE HEATING HIGH	ELECTRIC POWER PRODUCTION FAIR	ELECTRIC POWER PRODUCTION GOOD	ELECTRIC POWER PRODUCTION HIGH	GEOPRESS-URIZED RESOURCE*	REMARKS & REFERENCES**
Japan:									
Misawa AB	X								
Yokota AB	X								
Tachikawa AB	X								NWC Informal Report #19
Guam:									
Anderson AFB	X								NWC Informal Report #23
Alaska:									
King Salmon	X								
Murphy Dome	X								Miller 1973
Ladd AFB	X								Miller 1973
Shemya	X								NWC Informal Report #10
Canal Zone:									
Howard AFB	X								
Albrook AFB	X								
Labrador:									
Goose Bay	X								
Greenland:									
Sondrestrom AB	X								
Thule AB	X								
Hawaii:									
Bellows AFB				X			X		

FACILITY	LOW	SPACE HEATING FAIR	SPACE HEATING GOOD	SPACE HEATING HIGH	ELECTRIC POWER PRODUCTION FAIR	ELECTRIC POWER PRODUCTION GOOD	ELECTRIC POWER PRODUCTION HIGH	GEOPRESSURIZED RESOURCE*	REMARKS & REFERENCES **
Iceland:									
Keflavik Airport				X					On Geothermal Space Heating through USN Contract
Azores:									
Lajes Field			X			X			NWC Geothermal Report #20
Spain:									
Moron AB	X								
Torrejon AB	X								
Zaragoza AB									Needs more study
Netherlands:									
Camp New Amsterdam	X								
Italy:									
Aviano AB	X								
San Vito Dei Normanni AS	X								
Germany:									
Augsburg SCTYG		X							Delisle and others (1975)
Spangdahlem AB		X							"
Bitburg AB		X							"
Hahn AB		X							"

GEOTHERMAL POTENTIAL

FACILITY	LOW	SPACE HEATING FAIR	SPACE HEATING GOOD	SPACE HEATING HIGH	ELECTRIC POWER PRODUCTION FAIR	ELECTRIC POWER PRODUCTION GOOD	ELECTRIC POWER PRODUCTION HIGH	GEOPRESS-URIZED RESOURCE*	REMARKS & REFERENCES **
Germany: (Con't.)									
Ramstein AB	X								Delisle and others (1975)
Sembach AB	X								"
Lindsey AS	X								"
Rhen-Main AB									"
Vaihingen USAFSAS		X							"
Wiesbaden AB			X						"
Zweibrucken		X							"
Tempelhof, Cen Aprt.	X								
Greece:									
Hellenikon AB	X								
Crete:									
Iraklion AS		X							
Turkey:									
Cligi AB			X						NWC Informal Report #18
Ankara AS			X						NWC Informal Report #25
Incirlik AB		X	X						NWC Informal Report #24
Diyarbakir						X			
Karamursel AS							X		
Sinop	X								
Ismir							X		In an area being prospected.

GEOTHERMAL POTENTIAL

FACILITY	LOW	SPACE HEATING FAIR	SPACE HEATING GOOD	SPACE HEATING HIGH	ELECTRIC POWER PRODUCTION FAIR	ELECTRIC POWER PRODUCTION GOOD	ELECTRIC POWER PRODUCTION HIGH	GEOPRESS-URIZED RESOURCE*	REMARKS & REFERENCES**
<u>Overseas</u>									
Phillippines:									
Clark A.B.			X		X				
Taiwan:									(All Areas) See NWC Informal Report #17
Tianan AS	X								
Ching Chuan Kang AS	X								
Koahsuing AS	X								
Shu Lin Kou AS			X						In an area being prospected.
Okinawa:									
Kadena AB		X							
Naha AB		X							
Korea:									Geothermal potential of S. Korea considered low
Kunsan AB	X								
Taegu AB	X								
Kwangju AB	X								
Osan AB	X								

		GEOTHERMAL POTENTIAL							REMARKS & REFERENCES**
		SPACE HEATING			ELECTRIC POWER PRODUCTION			GEOPRESS-URIZED	
FACILITY	LOW	FAIR	GOOD	HIGH	FAIR	GOOD	HIGH	RESOURCE*	
United Kingdom:									
Alconbury RAF		X							Needs more study
Bentwaters RAF		X							Needs more study
Chicksands RAF	X								
Lakenheath RAF		X							Needs more study
Mildenhall RAF		X							Needs more study
Upper Heyford RAF	X								
Denmark:									
Copenhagen MAAG	X								
Norway:									
Oslo	X								
Iran:									
Teheran	X								Needs more study
Australia:									
Woomera Aprt	X								

*Geopressurized resources would utilize water at temperatures of 90°C to 300°C at pressure of 8000 to 16000 psi produced from depths of 12,000 to 20,000 feet. There waters contain 7 to 11 st m^3/m^3 methane. It is proposed to utilize the mechanical energy of the water as well as the heat energy. Natural gas would also be extracted. Geopressurized zones have been discovered and outlined by oil well drilling. To date the technology of utilizing geopressurized zones is <u>beyond the state of the art</u>. Economical disposal of tremendous volumes of water and subsidence are two serious problems. It is doubtful <u>commercial application will</u> occur before 15 years.

**NWC Informal Reports are listed in Appendix B.

REFERENCES CITED

Delisle, 6., Kappelmeyer, O., and Haenel, R. (1975). Prospects for Space Heating in Law-Enthalpy Areas. In Proceedings second United Nations Symposium on the Development and Use of Geothermal Resources. U.S. GPO pp 2283-2290.

Donovon L.E., Gertsch, W.D., Stoker, R.C. and Davis, L.P. (1978). A preliminary Accessment of the Feasibility of Developing Geothermal Energy for Space Heat and Process applications at Hill Air Force Base, Utah. Unpub. Dept. EG&G, Idaho, Inc. 47p.

Gries, J.P. (1977). Geothermal applications on the Madison (Pahasapa) Aquifer System in South Dakota. DOB rept. 1DO/1625-2.

Miller, T.P. (1973). Distribution and Chemical Analyses of thermal springs in Alaska. USGS Open File Map.

APPENDIX B

LISTING OF

Informal Reviews of Geothermal Potentials by Geothermal Utilization Division, Public Works Department, Naval Weapons Center, China Lake, California:

Continental United States:

1. Geothermal Potential of the Military Facilities in the Gulf Coast Area W. D. Brumbaugh and J. Whelan, 9p. 30 April 1977

2. Geothermal Potential of Military Installations in Georgia. W. F. Daniel 4p.

3. Geothermal Potential of Military Installations in Washington and Oregon, W. F. Daniel, 1p.

4. Preliminary Report on the Geothermal Potential of Military Bases in Colorado, Casey Danielson, 9/77, 12p. (USAF Academy, Fort Carson, Rocky Mountain Arsenal, Lowery Air Force Base, Lowery Bombing Range, Buckley Field (USN).

5. Geothermal Potential of Federal Military Reservations in Arizona. C. Danielson, 34p.

6. Geothermal Potential of Ellsworth Air Force Base, South Dakota, J. Hyde and J. A. Whelan, 18 April 1977, 6p.

7. Preliminary Report - Geothermal Potential of Mountain Home Air Force Base, Mountain Home, Idaho. Joy Hyde and J. A. Whelan, 11p. 29 April 1977.

8. Final Report. Geothermal Potential of Mountain Home Air Force Base and Saylor Creek Air Force Range, Idaho. Joy Hyde and J. A. Whelan, 9p.

9. Preliminary report on the Geothermal Possibilities of Beal Air Force Base. R. D. Paulsen and J. A. Whelan, 6p., 19 Dec. 1977.

10. Geothermal Potential of Shemya Island, Alaska, J. Whelan, 8pp. 9/77.

11. Geothermal Potential of the Naval Ammunition Depot, Hawthorne, Nevada. J. Whelan, 10p.

12. Geothermal Potential of Military Bases in Florida, J. A. Whelan, 3p.

13. Geothermal Potential of Military Bases in Nebraska, J. Whelan, 1p. (Lincoln AFB, Offutt AFB, Cornhusker Ammunition Depot, Grand Island and NAD Hastings).

14. Geothermal Potential of Hill Air Force Base, Little Mountain Facility. J. A. Whelan, 25p.

15. Geothermal Potential of the Wendover Range, The Desert Test Center, and the Hill Air Force Range, J. A. Whelan, 15p.

16. Geothermal Potential of Dover Air Force Base, Delaware, J. A. Whelan, 6p.

Foreign

17. Geothermal Potential of Military Installations on Taiwan, Republic of China, by William F. Daniel, 2p. (shu Lin Kau Air Station, Ching-Chuan Kang Air Station, Koosuing Air Station and various Air Force and Navy Installations in Taipei and Taiwan.

18. Report of Geothermal Resources at Cligi Air Base, Izmir, Turkey. W. Daniel, 3p.

19. Geothermal Potential of Major Military Installations in Japan. W. Daniel, 3p.

20. Preliminary Report, Geothermal Potential of Lajes Air Force Base, Terceira Island, Azores, J. Hyde and J. Whelan, 9p, 24 April 1977.

21. Geothermal Potential of NAF Sigonnella, Sicily. J. A. Whelan 29 Aug 1977, 9p.

22. Geothermal Potential of Saipan, Marianas Islands, J. Whelan, 2p.

23. Geothermal Potential of Guam, Marianas Islands, J. A. Whelan, 4p.

24. Geothermal Potential of Incirlik Air Base, Turkey, J. Whelan, 1p. 31 March 1977.

25. Report of the Geothermal Energy Possibilities of the Ankara Air Station, Ankara, Turkey, By W. Daniel, 3pp.

26. Geothermal Potential of Yap Islands, Caroline Islands, J. A. Whelan, 2p.

27. Geothermal Potential of Truk Islands, Caroline Islands, J. Whelan, 2p.

28. Geothermal Potential of Tinian, Marianas Islands, J. Whelan, 1p.

29. Geothermal Potential of Naval Facility at Naples, Italy, J. Whelan 2p. 31 March 1977.

30. Geothermal Potential of Military Bases in Puerto Rico. J. Whelan, 3p. (Army: Fort Buchanan, Santo Domingo, San Juan; Navy Roosevelt Roads)

INITIAL DISTRIBUTION

HQ USAF/LEY	2	AUL/LSE	1
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AFCS/DE	1	Det 1 ADTC/PR	1
ATC/DE	1	Det 1 ADTC/EC	1
AAC/DE	1	Det 1 ADTC/ECW	12
AFLC/DE	1	ADTC/CS	1
USAFSS/DE	1	ADTC/DL	1
CINCUSAFE/DE	1	AFAPL/POE	1
CINPACAF/DE	1	DOE/Geothermal Div	2
AFOSR	1		

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SPECIAL REQUIREMENTS AND PROCEDURES for GEOTHERMAL DEVELOPMENT ON NAVY LANDS

The inception of geothermal development projects, both as Navy contracts and as Department of the Interior leases on Navy lands is an experiment in multiple land use.

In this case, the primary use is that of the Navy, a use which varies with each locality being considered. The geothermal operator must comply with Navy rules and regulations WHETHER the operator has a lease from the Department of the Interior (DOI) or is there by virtue of a contract with the Navy. This is because the Navy, not DOI, is the surface manager. In Navy parlance these special requirements are called lease constraints. Those for the Coso leases are attached as Appendix A. The contractor at Coso operates under very similar constraints, presented as Appendix B.

Each of these constraints is to be briefly discussed as to why it was included and what it was intended to accomplish.

Other types of constraints intended to cover special conditions can be expected at other Naval Installations. Examples of some of these are presented in Appendix C, and the types of conditions where they might be required will be discussed.

Appendix D is the instruction used for industrial access to the Coso area prior to the lease sale so that industry would have a chance to look the area over if they wished to. Similar instructions would be used for access to other areas prior to lease sales on contract bidding.

None of these constraints are arbitrary--they are our best effort to protect the Navy/taxpayer investment in facilities, aircraft and lives while still enabling industry to do what it does best--explore for and produce energy. We are always willing to listen to serious suggestions regarding our co-existence on the same piece of land.

When we put together a constraints package for a given test range or facility, and when you in industry critique it (for how you respond to an RFP, or a lease sale is truly a critique of our reasonableness) we must both consider such things as the following:

- How will our operations affect yours?
- How will your operations affect ours?
- Are there minor adjustments either of us can make that give a handsome payoff in compatibility?
- Can we schedule things to take advantage of weather and of down times on facilities?
- Can we utilize terrain to avoid limitations on structure height?

If we make every effort to communicate with each other and to understand each others needs and operational and economic realities, then it is our firm belief that we can see successful multiple use in the form of geothermal development on many areas within and beneath Navy lands.

MEMORANDUM OF UNDERSTANDING
Between
Naval Weapons Center, Department of Navy
Bureau of Land Management, Department of Interior

GEOTHERMAL LEASES IN COSO GEOTHERMAL AREA

It appearing that the Secretary of the Interior, acting through the California State Director, Bureau of Land Management (BLM) and the Department of the Navy, acting through the Commander, Naval Weapons Center (NWC), China Lake, California, have a mutual interest in certain real estate involving both acquired and/or withdrawn lands lying within and without the boundaries of NWC, and being generally within the sub-surface to a circular surface area of a diameter of approximately forty-two (42) kilometers and centered at approximately 36° 05' latitude and 117° 50' W. longitude for the production of geothermal steam and associated geothermal resources. This area is depicted on the attached plat;

And it further appearing that although approximately the eastern sixty percent of this area lies within the boundaries of the NWC and, therefore, the surface of the area is under control and administration of the Department of the Navy, through the Commander, Naval Weapons Center; and that approximately the western forty percent of this area lies outside the boundaries of the NWC and, therefore, under the administration of the Department of the Interior, through BLM;

And it appearing that expeditious development and exploitation of geothermal steam and associated geothermal resources is of great importance to the United States, its agencies and its people;

And it also appearing that such development can be accomplished only with the highest degree of cooperation between the two governmental agencies which are parties hereto;

And it appearing that the NWC is an irreplaceable facility essential to the Navy in fulfilling its National Defense responsibilities;

And it appearing that it is in the National interest that there be orderly, optimum and expeditious development and exploitation of geothermal resources in the Coso area in such a manner that the NWC may continue to perform, fully, its National defense functions;

Therefore, it is deemed appropriate that this Memorandum of Understanding be entered into between the parties and their designated officials;

This Memorandum records the understanding of the parties as follows:

Enclosure (1)

1. Public lands withdrawn for the purpose of the NWC defense mission shall be available for geothermal leasing upon NWC's written consent thereto with those stipulations determined necessary to make geothermal operations compatible with the mission of NWC. BLM will, to the extent authorized by applicable law, commit withdrawn lands within NWC to leases in accordance with mutually agreeable schedules.

2. NWC will proceed with its geothermal exploration and development program on acquired lands in the above-described area to provide a secure power supply for the Navy and to gain Navy expertise and experience in employment of this new energy source for support of military missions.

3. NWC and BLM shall cooperate in obtaining modifications to the applicable Public Land Orders to permit the leasing and development of geothermal resources on those lands described above. Jurisdiction over the subsurface and surface of NWC lands covered by this Memorandum necessary to permit development and exploration of the geothermal resources will be vested in the Secretary of the Interior, subject to such surface use controls and/or constraints as may be stipulated by NWC.

4. BLM agrees to coordinate lease stipulations for the public lands in proximity to the NWC lands with the Navy in consideration of the Navy's mission at NWC.

5. The parties agree to immediately take steps to determine methods under which NWC lands can legally be leased and to set forth schedules and programs for completing environmental analyses, leasing schedules, and methods of lease supervision and management of NWC lands, together with mutually acceptable lease conditions on adjacent public lands. Control of access, supervision of operations and handling of data shall be developed as part of lease terms and future agreements between the involved agencies. Lands within the NWC withdrawn area will be withheld from leasing until appropriate terms for development, utilization, or management are approved by the Navy.

6. In general, BLM and NWC agree to fully support each other in this mutual effort, and specifically, to support each other as necessary to accomplish the fullest development of the resource. BLM and NWC agree to cooperate in the development of terms and conditions which will enable lessee operations and NWC operations for exploration and production of geothermal resources in a compatible manner, including but not limited to, utilization, procedures and/or joint development.

7. It is mutually understood by BLM and NWC that the Commander, Naval Weapons Center does not have authority to fully implement this agreement and that NWC will expeditiously request that authority.

8. It is mutually understood by BLM and NWC that the surface use controls and/or constraints will be identified per paragraph 3, within approximately 60 days of the execution of this agreement. Those stipulations will then be made a part of this MOU by amendment. It is further understood that after the initial 60 day period, any emerging control/constraint necessary to prevent an adverse impact on the NWC mission will be incorporated into the BLM leases.

DATED: Dec. 6, 1977

W. L. Harris
Commander, Naval Weapons Center
China Lake, California
DEPARTMENT OF THE NAVY

DATED: Nov. 30, 1977

Ed Hastey
State Director, Bureau of Land Managemen
California
DEPARTMENT OF THE INTERIOR

AMENDMENT TO
MEMORANDUM OF UNDERSTANDING
Between
Naval Weapons Center, Department of Navy
and
Bureau of Land Management, Department of Interior

GEOTHERMAL LEASES IN COSO GEOTHERMAL AREA

Pursuant to paragraphs three and eight of the Memorandum of Understanding between the Naval Weapons Center, Department of Navy, and the Bureau of Land Management, Department of Interior, executed on 6 December 1977, it is jointly agreed by the undersigned that the following Navy constraints of geothermal operations on Naval Weapons Center lands will be incorporated into the Memorandum of Understanding.

1. General.

Constraints will be placed on geothermal operations within the boundaries of the Naval Weapons Center to ensure the safe and economical development and production of those geothermal resources within the NWC boundary and to ensure that any leasing, development or production does not conflict with the mission of NWC. In addition to the lease terms and requirements contained in the lease form, the lessee shall comply with the following special stipulations unless they are jointly modified by the Commander, NWC and the State Director, Bureau of Land Management, with concurrence of the USGS Area Geothermal Supervisor.

2. Administrative Responsibility.

The Commander, NWC, is the responsible agent of the Federal Government for the utilization of the land surface and airspace of NWC. As such, the Commander, NWC, is responsible for the protection of the health and safety of all personnel, military and civilian, within the confines of NWC, and is responsible for the continuing preservation of the ability of NWC to perform its mission of air delivered weapons research, development, test, and evaluation.

3. Access.

Access to the NWC is a privilege granted by the Commander, NWC. Exercise of this privilege requires adherence to NWC traffic regulations, check in/check out procedures, radiation control measures, environmental controls, area access limitations, and electronic emission controls and such other published administrative regulations as appropriate. Access shall be on a not-to-interfere basis with NWC test schedules, and shall be limited to that specific lease block or area being explored, developed or produced. Access schedules shall be established on a weekly basis with NWC. NWC shall provide uninterrupted short term access for reasons of geothermal safety or other drilling incidents requiring access to a specific site for geothermal operations. Experience to date shows that in any given month, scheduled and unscheduled daylight downtime will not regularly exceed 10% and nightime downtime will not regularly exceed 2%. Access shall require that for each lease holder, one responsible contact point shall at all times know who is present on NWC lands, and this contact point shall be reachable at all times in event evacuation is ordered.

4. Security.

The mission of the NWC is such that visitors cannot be granted access to NWC lands without going through NWC security procedures. All non-citizen visits must be arranged through NWC with a minimum notice of 96 hours for non-communist-bloc visitors. The latter will be considered on a case-by-case basis. Accessible areas visitors use will be delineated by NWC.

5. Environmental.

NWC retains the right to suspend any operation judged by the Center to present an imminent threat to the environment. During all operations, all federal, state and local environmental standards shall be rigorously observed. No components of the environment shall be unnecessarily disturbed. NWC shall have the right to impose those emission standards required to protect the Center's mission.

6. Sites and Routes.

All vehicular traffic shall be limited to routes approved by NWC. Power plant sites, drill pad sites, and pipe line routes will be selected subject to NWC approval to ensure that such sites will have a minimum impact on NWC range operations. All site plans shall be submitted to NWC for review and approval. Routes to and from work areas within lease blocks shall be approved by NWC.

7. Shelters.

Lease operators shall have the option of either moving employees outside NWC boundaries upon request of the designated representatives of the Commander, NWC, or retiring to NWC approved personnel shelters provided by the lessee during those times when the NWC operations require personnel protection at the work site.

8. Radioactive Sources.

No radioactive sources shall be brought into NWC until appropriate Navy permits have been obtained. These permits will be issued after NWC has verified the license of the operator to be valid for the proposed effort and has approved written standard procedures for use and for handling lost or damaged sources.

9. Injuries and Accidents.

All disabling injuries occurring within NWC boundaries will be reported within 24 hours to NWC. NWC will have the right to suspend any operation judged by NWC to present an imminent danger to any personnel on NWC property or to government property.

10. Electronic Radiation.

Electronic emissions will not be permitted without prior review and authorization by the NWC. Periods of emission will be coordinated with the Center and, at times, the Center may require electronic emission silence for periods of up to four hours.

11. Plant Protection.

All well-heads shall be revetted to a degree acceptable to NWC; all wells so designated by NWC shall be fitted with an approved below ground or revetted flow limiter; all pipe lines shall be fitted with automatic flow limiters as approved by NWC and all power plants shall be equipped with a hardened control room approved for continuous occupancy during NWC tests.

12. Information.

All information on incidents involving both NWC equipment and/or personnel and the geothermal operators will be released to the public jointly by NWC and the Department of Interior. Particular attention will be given to information concerning incidents that have the potential for high public interest. Any serious injury or fatality and any geothermal blowout will be reported at once to NWC.

13. Military/Government Property.

All military and government property found on the land surface or embedded in the land shall be left in place. NWC shall be informed of the presence of all suspected or potentially hazardous material immediately and NWC personnel will inspect and remove such material in a timely manner. In case of doubt, NWC is to be called for an inspection.

14. Data Exchange.

Data on flow, chemistry of fluids and reservoir conditions and structure shall be provided to NWC with such data to remain proprietary in accordance with current practices and procedures as developed by the Area Geothermal Supervisor and set forth in 30 CFR 270.

15. Legal Jurisdiction.

Law enforcement on NWC lands will remain the responsibility of NWC. The use of geothermal operator employees in a guard function or the contracting by the geothermal operator for security guards on NWC lands will be subject to review and approval by NWC.

16. Right of Inspection.

NWC shall have the right of inspection at all times to ensure and verify compliance with these constraints.

Dated: 8 July 1980

W. B. Haff

Commander, Naval Weapons Center
China Lake, California
DEPARTMENT OF THE NAVY

Dated: 8 July 1980

James W. Ruch

State Director, Bureau of Land Management
Sacramento, California
DEPARTMENT OF INTERIOR

II CONSTRAINTS

It shall be the responsibility of the Contractor to conform to and abide by all applicable laws; ordinances; rules; regulations; and permit, approval, and easement requirements relating to the development of the geothermal resource at the Coso KGRA area, access to and from the general sites, and construction on and use of property under the control of NAVWPNCEN China Lake. In addition to the laws and regulations identified in Environmental Protection Plan, Section V, and the General Provisions to the Contract, Appendix "A", the Proposer is referred to Naval Weapons Center Instructions (see Appendix "H"); the Geothermal Resources Operational Orders as published by the Geological Survey; the Geothermal Steam Act; the Geothermal Energy Research, Development and Demonstration Act; the Federal Land Planning and Management Act; the Defense Withdrawal Act of 1958 (P.L. 85-337); Title 30, the Code of Federal Regulations; and the Occupational Safety and Health Act, or any successor statutes thereto, all as from time to time amended. Unless specifically advised by the Contracting Officer to the contrary, the Contractor shall meet the applicable requirements of all State and Local Laws and Regulations, including the Notice of Intention (NOI) and Application for Certification (AFC) regulations promulgated by the California Energy Commission. This list is not all inclusive and it is the sole responsibility of the Contractor to acquaint himself with all applicable laws, regulations, and other legal constraints or requirements. Because of the nature of the NAVWPNCEN mission, the Navy has placed certain constraints on geothermal operations within the boundaries of NAVWPNCEN. These constraints ensure the safe and economical development and production of those geothermal resources within the NAVWPNCEN boundary and ensure that any exploration, development, or production does not conflict with the mission of NAVWPNCEN. All on-site and other inspection performed by the Navy will be at Navy's cost.

A. Administrative Responsibility

The Commander, NAVWPNCEN is the responsible agent of the Federal Government for the utilization of the land and airspace of NAVWPNCEN. As such, the Commander, NAVWPNCEN is responsible for the protection of the health and safety of all personnel, military and civilian, within the confines of NAVWPNCEN, and is responsible for the continuing preservation of the ability of NAVWPNCEN to perform its mission of air weapon research, development, test and evaluation.

B. Access

Access to NAVWPNCEN is a privilege granted by Commander, NAVWPNCEN. Exercise of this privilege requires adherence to Navy traffic regulations, check-in/check-out procedures, radiation control measures, environmental controls, area access limitations, and electronic emission controls. Access to range lands shall be on a not-to-interfere basis with Navy test schedules and shall be limited to that specific area being explored, developed or produced. Access schedules shall be established on a weekly basis with the Navy. The Public Works Officer, NAVWPNCEN will have the authority to provide emergency access for reasons of geothermal safety or other drilling incidents requiring uninterrupted short term access to a specific site or geothermal operation. Access shall require that there be identified one responsible contact point for the Contractor who shall at all times know who is present on NAVWPNCEN lands, and this contact point shall be reachable at all times in event evacuation is ordered. Experience to date shows, in any given month, scheduled and unscheduled daylight downtime will not regularly exceed ten percent and scheduled and unscheduled nighttime downtime will not regularly exceed two percent.

C. Security

Contractor personnel do not have to be U.S. Nationals, but the mission of the NAVWPNCEN is such that personnel cannot be granted access to NAVWPNCEN lands without being cleared for entry by the Navy. All non-citizen visits must be arranged through the Navy with a minimum notice of 96 hours for non-iron-curtain-bloc visitors. The latter will be considered on a case by case basis. The accessible areas and routes from these areas will be stipulated by the Navy.

D. Environmental

All vehicular traffic shall be limited to routes approved by the Navy. The Navy will retain the right to suspend any operation judged by the Navy to present an imminent threat to the environment. During all operations, all federal, state, and local environmental requirements shall be rigorously observed. The Navy shall have the right to impose emission standards required to protect the mission of NAVWPNCEN.

E. Sites and Routes

Power plant sites, drill pad sites and pipeline routes will be selected subject to Navy approval to ensure such sites will have a minimum impact on NAVWPNCEN range operations. All site plans shall be submitted to the Navy for approval. Routes to and from work areas will be approved by the Navy.

F. Shelters

Operators and other Contractor personnel shall have the option of either evacuating NAVWPNCEN upon request or retiring to Navy approved personnel shelters during those times when NAVWPNCEN operations require personnel protection at the project site. Construction criteria for personnel shelters are included in the Technical Specifications, and installation will be totally at Contractor's expense.

G. Radioactive Sources

No radioactive sources shall be brought into NAVWPNCEN until appropriate Navy permits have been obtained. These permits will be issued upon the Navy verifying the license of the operator to be valid for the proposed effort, and the Navy approving a standard operating procedure for dealing with lost sources and handling damaged sources.

H. Injuries and Accidents

All disabling injuries occuring on NAVWPNCEN land will be reported within 24 hours to the Navy. The Navy will retain the right to suspend any operation judged by the Navy to present an imminent danger to people or to government property.

I. Electronic Radiation

No electronic radiation will be permitted within NAVWPNCEN until a permit is obtained which certifies this emission will not interfere with the NAVWPNCEN mission. The Navy may, at times, require electronic emission silence for up to four hours.

J. Plant Protection

To prevent damage, all wellheads shall be revetted as specified in the Technical Specifications, all wells shall be fitted with an approved below-ground flow limiter, all pipe lines fitted with automatic flow limiters, and all power plants equipped with a hardened control room.

K. Public Release of Information

There shall be no public release of information or photographs concerning the aspects of this contract or other documents resulting therefrom without prior written approval of the Navy.

L. Military/Government Property

As a result of past and ongoing NAVWPNCEN operations, the existence of unexploded ordnance and other hazardous material in the Coso KGRA is very likely. The danger that such material represents cannot be overemphasized. Therefore, all military or government property found on the land surface or embedded in the land shall be left in place. The Navy shall be informed of the presence of all hazardous or potentially hazardous ordnance or other material at once and Navy personnel will inspect and remove such material in a timely manner.

M. Data Exchange

Data on flow, chemistry of fluids and reservoir conditions and structure shall be provided to the Navy within 90 days of the date the data is obtained by the Contractor with such data to remain proprietary to the contractor for five years or contract termination, whichever occurs first. The Navy may use such data for independently evaluating the resource.

N. Legal Jurisdiction

Law enforcement on NAVWPNCEN lands will remain the responsibilit of the Navy except that the Navy may permit Inyo County deputized corporate security guards on NAVWPNCEN lands following Navy acceptance of specific Contractor security plans.

O. Blowout Contingency Plan

Prior to the commencement of any drilling into the geothermal reservoir, the Contractor shall prepare a contingency plan acceptable to the Navy for use in the event of a blowout of a geothermal well.

P. Geothermal Resources Operational (GRO) Orders

The GRO Orders, as published by the United States Department of Interior, Geological Survey, Conservation Division, Office of the Area Geothermal Supervisor, and Title 30, chapter II of the Code of Federal Regulations shall be adhered to subject to certain interpretations that are discussed in more detail under Technical Specifications, Section VI.

Q. Right of Inspection

Navy shall have the right of inspection to ensure and verify compliance with these constraints.

R. These constraints shall be included in all subcontracts.

Specific to [redacted]

No Specific Hazard or Restrictions

No Surface Access - To any controlled area marked "Restricted Area" or where exploration is inconsistent with present utilization of surface (i.e. runways, roads, thoroughfares, permanent installations, etc.)

Height - Height of any structure must not infringe glide path minimum obstacle clearance height. Further information is contained in FAA Handbook 8260.3B CHG 1 (Terminal Instrument Procedures; TERPS and FAA Handbook 7400.2B.) Basically, there are general wedge-shaped areas (as shown in attached illustrations) extending several miles from the end of the runways in which the contracting geothermal operator will be required to demonstrate that any structures do not exceed applicable height limitations and do not encroach navigable airspace.

Specific to [redacted]

Ocular Hazard - When the Commanding Officer, [redacted] designates, the contractor's options are: evacuate or else place personnel in approved shelter during laser emission periods. Expected evacuation or shelter requirement for the period January 1982 to January 1985 are 5 hours per week initially, increasing to 30 hours per week toward the end of this time period.

No Surface Access - The no surface access area is shown on the map. In the event production appears probable from this area as the result of adjacent geothermal production, the Commanding Officer, [redacted] shall seek authorization from higher Navy authority to schedule range closures for periods of up to 120 days to enable production drilling. Special controls of surface standing water ad other specular materials will be required.

Height - All structures temporary or permanent exceeding 50 feet above the ground require specific approval from the Commanding Officer, [redacted]. No structures will exceed 150 feet in height.

Specific to Range [redacted]

No Ocular Hazard

No Surface Access - On each side of flight line as shown on map.

Height Restriction

(1) No structures over 150 feet without specific permission of Commanding Officer, [redacted]

(2) Immediately South of County road within all of Section [redacted] except SW 1/4, no structures over 20 feet in height.

INSTRUCTIONS TO POTENTIAL LESSEES

WHO WISH TO MAKE ADVANCE RECONNAISSANCE VISITS

TO THE COSO KNOWN GEOTHERMAL RESOURCE AREA (COSO KGRA)

I. Introduction

A significant portion of the land comprising the Coso KGRA lease sale to be conducted by the Bureau of Land Management is within the boundaries of the Naval Weapons Center, China Lake, California (NAVWPNCEN). The mission of the NAVWPNCEN is "to be the principal Navy research, development, test and evaluation center for air warfare systems (except anti-submarine warfare systems) and missile weapons systems; and the national range/facility for parachute test and evaluation." Potential lessees should be aware that the NAVWPNCEN national defense role is paramount, and that other activities (including geothermal operations) conducted on the NAVWPNCEN lands will be subordinate to the primary mission of the Center.

General guidance concerning the restrictions imposed on all geothermal operations that are to be conducted within the NAVWPNCEN boundaries by BLM lessees are contained in an MOU between BLM and the NAVWPNCEN. This MOU (including amendment 1) is presented in the Final EIS dated September 1980, prepared by the BLM for the leasing of Coso and is an enclosure to this notice as well.

The purpose of this notice is to amplify the general guidance provided in the MOU for the leasing activities by presenting the specific steps needed in the event a firm desires to do advance reconnaissance within the NAVWPNCEN boundaries.

II. General Policy

The Navy program of modifying the withdrawal of part of a Navy test range to permit geothermal energy development is an experiment in multiple use. The NAVWPNCEN will take all reasonable steps that do not compromise the Center's primary mission to ensure that prospective lessees and ultimately lease or unit operators are impacted to a minimum by the Navy presence. The success or failure of the Coso lease sale and subsequent operations will to a large extent determine future policy with respect to other Navy lands with geothermal potential. To this end, the NAVWPNCEN command will be receptive throughout both pre-leasing and post-leasing activities to suggestions on how to make the geothermal activities on the NAVWPNCEN test ranges more successful and more compatible with the NAVWPNCEN mission. Thus, we have decided to offer a 90-day period for advanced reconnaissance prior to the actual lease sale.

III. Access to the NAVWPNCEN

Access to the NAVWPNCEN is a privilege granted by the Commander, Naval Weapons Center. Exercise of this privilege requires an adherence to NAVWPNCEN requirements for scheduling, safety, security, environmental protection, area access limitations, electronic emission control, and reimbursement of costs. Each person who enters the Center (except for the housing area) must have in his possession a valid NAVWPNCEN pass, he must be logged into the test ranges, logged out on leaving, and in some instances he must be escorted. The following paragraphs will guide you through the procedures:

a. You decide you wish to come aboard the NAVWPNCEN to conduct geothermal studies of some sort.

b. You write a letter addressed to:

Commander (Code 266)
Naval Weapons Center
China Lake, CA 93555

In this letter you tell us what you want to do, when you want to do it, where you want to do it, how you want to do it, who will do it, and who is your point of contact. This does not need to be in minute detail, but should be in enough detail so we can understand how to fit your activities in with other people's plans as well as the Center's mission needs. Surface access to lands outside of the lease sale area for the purpose of providing geophysical or geologic context will be considered on a case-by-case basis.

c. We will respond to you indicating tentative schedules, asking for any needed clarification of your plans (we may do this by phone to speed things up) and telling you which activities may have environmental or other difficulties attached, what permits we require (you may need others we do not require), what bonding we require, if any, and we tell you how to open an account with us to cover the cost of our providing escorts, copies of reports you request, and our processing of your environmental documentation or other permits you need from us.

d. At least four days prior to your visit, to save time, you advise Code 266 of the names and other data on any non-citizens you plan to bring aboard by filling out and sending us a copy you make of the attached form for each non-citizen. When you get settled in town (Ridgecrest, Inyokern, Pearsonville, Little Lake, Olancha, etc.) you call us and tell us who is locally in charge and reachable 24 hours a day so your crew can be evacuated if need be on short notice, and so we can find out, without searching all the bars in town, if you left the Center without remembering to check out. (Remember, if we hold up a test on your account, the average active range time cost you could be billed for is $150,000/hour. Having a NAVWPNCEN escort will avoid this risk.)

e. You come in and see Code 266. We verify on maps what and where and when. We tell you when escorting is needed and when you can be left on your own to do your own check in/check out. We give you passes good only for the areas you will work in. We give you and your crew a briefing on the rules and regulations you need to be aware of, including the fact that entry into areas you are not cleared for will terminate your access privilege. You will be warned in writing as well as in a briefing on the problems of ordnance contamination and the hazards of laser operations.

f. You do what you planned to do.

g. You complete your cleanup, if needed.

h. We inspect the cleaned up areas, give you a letter we are happy (or unhappy) with the cleanup, and when we are happy you get a letter of release. We collect your passes and wish you every success as you leave the NAVWPNCEN.

IV. Data

The data you collect at your expense is your property as far as the NAVWPNCEN is concerned. We will make every reasonable effort to protect the proprietary nature of what you do while aboard. You should also note that the operations of the Navy geothermal contractor are proprietary and we will protect his activities from scouting, as appropriate.

The NAVWPNCEN has an extensive library of data on Coso. You are welcome to come and use it, and can pay the NAVWPNCEN for copies made. We do not check materials out. A Bibliography is attached so you will know what we have.

V. Scheduling

The NAVWPNCEN mission has priority. We will do our best to be flexible, however. Beyond the NAVWPNCEN mission, it is first come, first served in the. event of a conflict of area or methodology, with the NAVWPNCEN the final arbiter of who was first (i.e. no one can manipulate the schedules just to keep others out.)

VI. Escorts

When you have foreign nationals in your crew, you will have to be escorted. (Approximate cost, $300/8-hour shift, with a half-day minimum.) If you are having tight schedule conflicts, a radio-equipped Navy escort may prove cost effective for you as you will be out of the working area or under cover less often. If several of you are in the same area at the same time, you may want to share an escort to cut costs. In some areas, and when we run some types of tests, you will have to be escorted no matter what you are doing.

VII. Permits and Reviews

We expect those operations of negligible impact that we can approve locally to take about 3 man days to review and approve. If you propose something complex or with possible serious impacts, it will take longer. If you can obviously not finish your study in the 90 days that we will make the range available, we will require you to modify your plans. Remember, there are no off-road vehicle operations except for some types of All Terrain Vehicles or All Terrain Cycles in some areas. In general, a heat flow hole drilled in an already disturbed area has a negligible impact, in the event you want to do some shallow drilling.

The Navy maintains strict control of radioactive sources, and use of these on the NAVWPNCEN lands takes a special Navy permit. Use of radios, radio-telephones, and other electronic emitters also takes special Navy permits. We can issue these at the NAVWPNCEN with adequate notice and equipment data.

The Navy does require that you adhere to the provisions of the BLM (Title 43 CFR, Subpart 30) and that copies of all applications, Notices of Intent, reports, etc. that you file with BLM also be filed by you with the Navy at the

NAVWPNCEN for our information. The NAVWPNCEN will review and approve all environmental documents submitted for activities aboard the NAVWPNCEN during the 90 day period.

VIII. Funding

The reimbursement of the Navy for its costs of scheduling, escorting, duplication of reports, and processing of permits will be borne by the industry, firm, or individual for whom the work is done. Payment will be in advance, into an account at the NAVWPNCEN. Our accounting system stipulates you will pay our regular project overhead rates plus unfunded costs and surcharge for any work we do on your behalf. When you send us your plan of operations we will give you an estimate of the costs, so you can make a reasonable deposit. On completion, unused funds will be returned, and we will give you a strict accounting of where the funds went that were spent. No one, including DOE and its contractors, can obtain credit. It is all cash in advance with us, but you will find the Navy to be practical, pragmatic and reasonable.

IX. Airspace

The NAVWPNCEN airspace is tightly controlled at all times, but is frequently made available to the public on weekends and at night. Working in the NAVWPNCEN airspace is simply another scheduling problem for us to solve together. The closest major field (with commercial passenger service) is Inyokern. You should not try to operate out of the Navy field at China Lake.

X. We look forward to working with you. If you have questions, feel free to contact Mr. Carl Halsey of my staff at (714) 939-3259.

Carl F Austin

CARL F. AUSTIN
Head, Geothermal Utilization Division

3. The customer's requirements

4. The company's selling approach

D. Development of Final Proposal Plan

1. Within one day after the Proposal Coordination Meeting, each person assigned responsibility for a specific task should prepare and furnish to the Proposal Manager a detailed outline of the area for which he is responsible

VIII. Time Phasing the Proposal

A. The research to gain the required background information

B. The point at which the configuration or program plan must be frozen

C. Time for adequate writing and editing of the various inputs in order that the technical, management and cost approach can be coordinated and presented to effectively implement each other. The time for this portion should be based on the number of sources from which written information will be furnished and should increase in direct proportion to that number

D. Time should be set aside for a final review of the proposal volume as a total package and, in the case of major and important proposals, for the review by the company Proposal Evaluation Board

E. Time must be alloted for the actual production of the proposal, including, when necessary, layout, art work, drafting, typography, and printing. Much of this work, of course, can be done simultaneously with other areas

F. Provisions must be made for required reviews and sign-offs

G. Adequate time for either mailing or hand delivery to the customer by the time specified

LAWS AND REGULATIONS GOVERNING PROCUREMENT

INTRODUCTION

A knowledge of the statutes and regulations governing procurement is essential for all personnel performing functions in the Government contracting field. To understand these regulations it is necessary to have some understanding of how and why they came to be developed. Billions of dollars are spent each year by the Department of Defense and other Government Agencies. Experience going back to the very foundations of the country has shown a need for establishing procedures for the proper control of these expenditures. Many laws and regulations have been developed to insure that these vast sums are expended in a legal manner for the purposes for which they were appropriated. Many persons new to the Government contract business see little rhyme or reason in the multitude of regulations and the immense amount of paper work in connection with Government contracts and subcontracts. The more inexperienced of them get the impression that these regulations are designed with no purpose in mind but to harass Government contractors and prevent efficient performance under Government contracts. This Chapter will provide a brief outline of how these laws and regulations came to be developed, with the hope that an understanding of how and why they came to be developed will make compliance with them easier.

THE CONSTITUTION OF THE UNITED STATES

The President of the United States, because of his dual capacity as the nation's Chief Executive Officer and Commander-in-Chief, is responsible for the direction of National Defense with its associated Government purchasing functions. Article 1, Section 8 of the Constitution authorizes Congress to enact laws affecting military procurement. This authorization is given in one of the six specific war power grants in Section 8. This particular war power grant also states that Congress shall have the right to raise and support armies but that no appropriation for this purpose shall be for a period longer than 2 years. The two year provision has been interpreted to apply to such items as clothing, subsistence and pay but not to means for attack or defense such as guns and ammunition. Each year the Congress decides just how much money will be appropriated. Congress, therefore, controls procurement by controlling the appropriations to support it, a power specifically granted by the Constitution.

EARLY PROCUREMENT STATUTES

In 1792 the Department of the Treasury which had been established in 1789 along with the Department of War was given the responsibility for purchases and contracts for the Army. In 1795, a Purveyor of Public Supplies was established in the Treasury to act as the Government's purchasing agent. In 1798, a separate Department of the Navy was established. During the same year, Congress declared that "All purchases and contracts for supplies or services for the military and naval service of the United States shall be made by or under the direction of the chief officers of the Department of War and Navy respectively." The Purveyor of Public Supplies still remained responsible, however, for executing the orders received from the military departments for providing stores and supplies. Considering the historic interest of Congress in the profits of Contractors, it is interesting to note that the first procurement problems and abuses arose out of the activities of Congressmen in securing Government contracts for friends and firms with which they were associated. In 1808 a law was passed requiring the insertion of a clause in every Government contract that no member of Congress might benefit therefrom. This prohibition is still present and is included in all Government contracts as the "Officials Not to Benefit" Clause, ASPR 7-103. 19.

THE EARLY DEVELOPMENT OF COMPETITIVE BIDDING

The ethics of both public officials and business firms in the early days of the Republic left much to be desired. Accusations of graft and favoritism in the award of Government contracts were common. Incoming administrations investigated the activities of the former administration. The political party out of power kept a watchful eye on the activities of the "ins". Congress soon realized that the only effective way to prevent abuses was to require that Government purchases be made by open bid. Over a period of years, Congress, by a series of statutes extended the requirements for competitive bidding to all Government purchases with very limited exceptions. The rigid requirements of our present system of advertising developed slowly as experience was gained.

The Act of March 3, 1809, established a general requirement that formal advertising be used in the procurement of supplies and services. This was the first of a long series of Acts which was to lead to the establishment of formal advertising as the method for practically all Government purchasing. This statute provided that all purchases and contracts by the Secretaries of the Treasury, War and Navy would be made "either by open purchase or by previously advertising for proposals respecting the same." Other Acts passed in 1842 and 1843 extended the requirement for formal advertising. They required the use of sealed proposals, public bid openings and satisfactory security for performance requiring forfeiture not exceeding twice the contract amount. The Act of March 3, 1845, and August 31, 1842, re-emphasized the use of advertising and extended its use to public buildings. As an index of Congress' continuous interest in the field of Government procurement, it is interesting to note that immediately prior to the commencement of the Civil War, at a time when the Nation was being torn apart by factional and political differences, Senator Jefferson Davis, who shortly thereafter was to become the first President of the Confederacy, offered an amendment which was to become the Act of June 28, 1860.

> That all purchases and contracts for supplies and services in any of the departments of the Government except for personal services when the public exigencies do not require the immediate delivery of the article or articles or performance of the service shall be made by advertising a sufficient time previously for proposals respecting the same. When immediate delivery or performance is required by the public exigency, the articles or services required may be procured by open purchase or contract at the places and in the manner in which such articles are usually bought and sold or such services engaged in between individuals. No contract or purchase shall hereafter be made unless the same is authorized by law or under an appropriation adequate to its fulfillment except in the War and Navy Department for clothing, subsistence, flour, fuel, quarters or transportation, which, however, shall not exceed the necessities for the current year. No arms or military supplies whatever which are of a patented invention unless the same shall be authorized by law and the appropriation therefor explicitly set forth that it is for such patented invention.

The Civil Sundry Appropriations Act of March 2, 1861, was the fundamental procurement regulation under which the Civil War was fought. Many historians are of the opinion that the decisive factor in the war was the industrial might of the North. There was a tremendous expansion of plant capacity in the North and the importation and training of immigrants was increased so that at the close of the war, the North was far stronger industrial-wise than at the beginning of the war. For the South, the opposite was true. Its economy was based on a one crop agricultural system. The usual problems arose early in the war over the use of formal advertised procurement procedures and the exceptions to its use led to recriminations with regard to war profiteering and excessive profits both during and after the war. Both the North and the South were plagued with profiteering by war contractors and several scandals early in the war caused shake-ups in the administration in the North.

Upon revision and amendment in 1874 and 1878, the Civil Sundry Appropriations Act became known as Revised Statute 3709. In 1910, this Act was again revised re-emphasizing formal advertising as the required method of procurement. The following exceptions which allowed negotiation were provided, however:

(1) Emergency purchases in the event of a public emergency.

(2) Purchases less than $500. If negotiation was used, however, the approval of the Secretary of War was required in all cases over $100.

(3) Procurement from the Federal Prison Industry.

(4) Procurement of horses and mules.

(5) Purchase of proprietary items.

(6) Procurement of medical supplies.

(7) Procurement of classified items.

(8) Purchase of bunting.

(9) Purchase of dies and gauges.

R. S. 3709 was to be, with its amendments, which for all practical purposes required the use of formal advertising in almost every procurement situation, the Standard regulation governing defense contracting until it was replaced by the Armed Services Procurement Act in 1947.

While the use of formal advertising has certain advantages in preventing abuse and favoritism in the award of Government contracts, in times of war and emergency with resultant rapid increase in defense requirements, the use of formal advertising procedures is extremely slow and inefficient. The United States was forced to fight two major wars, hamstrung by a procurement system which had been developed to provide for the peacetime support of a federal defense establishment which, in some cases, numbered fewer than 100,000 soldiers and sailors.

THE ARMED SERVICES PROCUREMENT ACT OF 1947

Since the majority of the laws and orders passed or issued during World War II were temporary in nature, the end of the war necessitated the return to the provisions of Revised Statute 3709 with its emphasis on competitive bidding. The war, however, had demonstrated the inefficiency of competitive bidding in times of national emergency. The services and industry had demonstrated that negotiation could be used in awarding contracts. It was realized that return to the inflexible procedures of formal advertising would mean that supplying the needs of the military would soon revert to a relatively small group of professional Government suppliers with the consequent loss of invaluable defense know-how acquired by industry during the war years. The importance of the industrial production capacity of the United States in the successful outcome of the war was also recognized along with the importance of effective purchasing practices and • procedures that would enable the military services to mobilize this industrial might as soon as possible. The uncertain conditions after World War II also argued against the reversion to business as usual which had taken place after World War I. The Procurement Policy Board of the War Production Board recommended in November, 1945 that the Government agencies propose procurement legislation to take effect when the emergency procurement legislation expired. They recommended that the proposed legislation recognize that formal advertising is the preferred method of procurement by the Government but should make provision for broad authority to negotiate price and other contract terms when circumstances required it, and to dispense with formal advertising completely during any future national emergency. In accordance with these recommendations a bill was prepared and introduced in the 80th Congress on January 7, 1947 as H. R. 1366, the Armed Services Procurement Bill. This bill pulled together in one statute all Department of Defense procurement authority and replaced all of the former laws in the process. It was based primarily on the experience gained during the war. This Bill was approved by the President on February 19, 1948 as Public Law 413 of the 80th Congress. It became effective 90 days later on May 19, 1948 on which date the First War Powers Act as a procurement authority ceased. The effect of the Bill was to unify Army and Navy and Air Force procurement authority under one statute. In 1956 Public Law 1028 was passed by the 84th Congress in its second session. This Act revised and codified existing law affecting procurement under Title 10 of the United States Code which is entitled "Armed Forces".

The Armed Services Procurement Act states that formal advertising is the preferred method of procurement. However, it authorizes negotiated purchases where circumstances require or justify a departure from formal advertising. The act provides for the use of the type of contract best adapted to the circumstances. It permits the making of advance payments, authorizes the Comptroller General to remit liquidated damages which may be accrued from a Contractor's delay and provides statutory authorization for joint procurement between the services.

The Act specifically sets forth 17 exceptions to the requirement for procurement by formal advertising. These exceptions include many of those formerly allowed under the various exceptions to Revised Statute 3709 and others which were found from experience in war time procurement to be necessary.

The exceptions are as follows:

1. When determined to be necessary in the public interest during the period of a national emergency delcared by the President or by Congress.

2. When the public exigency will not permit delay incident to advertising.

3. When the aggregate amount involved does not exceed $1,000.

4. For personal or professional services.

5. For any services to be rendered by a university, college or other educational institutions.

6. When supplies and services are to be procured for use outside the United States and its possessions.

7. For medicines and medical supplies.

8. For supplies purchased for authorized resale.

9. For perishable supplies.

10. For supplies or services for which it is impractical to secure competition.

11. When the agency head determines that the purchase or contract is for experimental, developmental or research work or for the manufacture or furnishing of supplies for experimentation, development, research or testing.

12. For supplies or services purchase of which should not be disclosed for security reasons.

13. For technical equipment necessary in order to insure standardization and interchangeability of parts necessary in the public interest.

14. For technical or specialized supplies requiring substantial initial investment or an extended period of preparation for manufacture when competitive bidding might require duplication of investment or preparation already made or would unduly delay procurement.

15. When the bid prices received as a result of advertising are unreasonable or have not been independently arrived at in open competition.

16. To make or keep available a supplier in the interest of national defense to meet a national emergency or in the interest of industrial mobilization.

17. As otherwise authorized by law.

SIMILARITIES AND DIFFERENCES BETWEEN GOVERNMENT AND COMMERCIAL CONTRACTING

INTRODUCTION

The Government has inherent power to enter into contracts. This principle was given early recognition by the United States Supreme Court. This inherent power to enter into contracts is not based upon any specific constitutional or statutory grant, but exists as an incident of sovereignty.

SIMILARITIES TO PRIVATE CONTRACTING

Legal principles governing contracts with the Government are substantially the same as those governing contracts between private persons. There must be valid acceptance, consideration, certainty of terms, and competent parties. When the United States becomes a party to a commercial contract, it incurs all the responsibilities of private persons under like circumstances. In the construction of contracts, the United States is governed by the same rules that apply to private individuals. An implied contract arises on the part of the United States to return money illegally obtained. When the United States goes into the insurance business, it must be assumed to have accepted the ordinary incidents of suits in such business. In one case, interest was awarded against the Government in accordance with the terms of the insurance policy that it had issued.

The Government is bound to examine materials and reject the same, if defective, within a reasonable time after their receipt or be held liable therefor. In an equity suit, the Government is subjected to the same presumptions of law and fact as an individual. If the United States comes down from its position of sovereignty and enters the domain of commerce, it submits itself to the same laws that govern individuals there.

DIFFERENCES FROM PRIVATE CONTRACTING

The principal distinguishing features of Government contracting stem from statutory requirements, the dual personality of the Government as contractor and as sovereign, the limited character of procedures for enforcement of contractual liability of the Government, and the nature of the law applicable to Government contracts.

Statutory Requirements

Generally, Government Departments derive their authority to acquire supplies by virtue of specific legislation. This legislation takes the form of enabling statutes, procedural statutes, and appropriation acts. Generally, the acquisition of real estate must be authorized by a specific enabling act of Congress. Usually, this legislation is coupled with an appropriation. The purchase of supplies and services by the Department of Defense and NASA (the term "supplies" means all forms of property except real estate) is normally made under the Armed Services Procurement Act of 1947 (act of February 19, 1948, P. L. 413, 80th Congress), which is procedural in nature, and the particular appropriation act under which the purchase is made. Other Government agencies are governed by the Federal Property and Administrative Services Act. Every contract that is to be paid out of appropriated funds is subject to the limitations imposed by the appropriation act against which the contract is charged. In addition to the statutory requirements heretofore mentioned, there also exist certain laws which impose general limitations on the authority to contract. These laws relate to the obligation and expenditure of appropriated moneys and the mandatory inclusion in Government contracts of certain clauses covering a wide range of subjects such as minimum wages, purchase of American products, renegotiation, prohibition against contingent fees, etc.

Government Agencies are generally subject to the decisions of the Comptroller General of the United States interpreting the various statutes and appropriation acts under which contracts are made. The Comptroller General is the head of the General Accounting Office, which by law is independent of the executive departments. All accounts in which the United States is concerned either as a debtor or creditor shall be settled or adjusted in the General Accounting Office unless otherwise specifically provided.

Dual Personality

The United States assumes two roles, one as a sovereign and the other as a contractor. Although the Government submits itself to the same laws that govern individuals when it enters the domain of commerce, it cannot be held liable for an obstruction to the performance of its contracts resulting from its public and general acts as a sovereign, whether executive or legislative.

Sovereign Immunity From Suit

The Government is immune from suit, except to the extent that it has voluntarily consented to be sued. This immunity extends to proceedings in rem against property owned by the Government.

Consent To Be Sued

The Government has consented to be sued generally in actions founded, amont other things, upon express or implied contract with the United States, or for liquidated or unliquidated damages in cases not sounding in tort. (The Tucker Act). This consent, however, has been construed by the courts to extend only to suits on contracts implied in fact but not to actions based on contracts implied in law. Such actions may be brought in the United States Court of Claims without regard to the amount involved, and in the District Courts of the United States where the amount involved does not exceed $10,000.

Law Applicable

In determining questions arising under Government contracts, courts are not bound by the law of any particular state as in private contract cases. Insofar as a Federal common law can be said to have developed in the field of contracts, it will be applied in cases involving Government contracts where the question to be determined is not governed by the Federal Constitution or a Federal statute.

AGENCY IN GOVERNMENT CONTRACTING

Authority of an officer or agent to contract in behalf of the Government must stem from the Constitution or from a Federal statute. The contracting representative of the Government is known ordinarily as a contracting officer. He is a special agent possessing only such authority as is given him either expressly or by necessary implication. It therefore becomes important to ascertain from the Constitution or applicable statute the extent of the agent's authority. The risk of lack of authority falls on the contractor.

Further, one who lacks authority to make an express contract on behalf of the Government may not be his acts bind the Government on an implied contract. It is immaterial that the claimant conferred a benefit if the Government representative had no authority to receive the benefit on behalf of the Government.

A proper understanding, therefore, of the extent of the Contracting Officer's authority is absolutely essential for persons dealing with the Government.

A Contracting Officer means any person who, in accordance with departmental procedures, is currently designated a Contracting Officer with the authority to enter into and administer contracts and make determinations and findings with respect thereto, or with any part of such authority. The term also includes the authorized representative of the Contracting Officer acting within the limits of his authority.

A contract is a binding and complex relationship between the Government and the contractor. The Government is very sensitive to the use of public funds and the relationship between efficient contracting and national defense. The contractor, on the other hand, runs his normal business risk, plus the risk of dealing with a sovereign and complex agency, operating within unfamiliar lines of organization and bound by inflexible statutes. The Contracting Officer is established by the Government as a single and responsible focal point, and is the clearing house for the management of each contract. A Contracting Officer functions, not as an individual, but as the medium through which the requirements of his office are fulfilled. He is limited by the scope of his appointment.

The responsibilities of a Contracting Officer are many and diverse. The Supreme Court of the United States has stated that he must act as an impartial and unbiased judge. The decision and findings by the Contracting Officer is a condition precedent to an appeal by the Contractor under the disputes clause. Contracting Officers must personally sign all contracts and modifications entered into by them and they are responsible under law and regulations for their acts as Contracting Officers. They cannot plead superior orders as a justification for an unlawful action since when operating within the bounds of his authority and his delegated responsibility, no superior may influence a Contracting Officer or bypass him with a decision of his own. The appeal board and the courts have determined many times that the Contractor is entitled to a decision by the Contracting Officer. This decision can be rendered by no one else. In the exercise of his responsibility, the Contracting Officer is bound to use reasonable care, skill and judgment. He is not, however, supposed to use morbid caution.

AUTHORITY OF THE CONTRACTING OFFICER

It is important to note here the difference between a Government agent and a private agent. Ordinarily, a principal is responsible for the actions of his agents. However, a Government agent cannot bind the Government if he operates beyond the bounds of his authority. If he does, the Government is not bound by his action.

The Comptroller General made the following statement in 16 CG 329:

> There is a well known distinction between the liability of individuals and the Government with respect to their agents in that the former are liable to the extent of the power they have apparently given their agents, while the Government is liable only to the extent of the power it has actually given its agents by law, and the unauthorized acts of such agents cannot stop the Government from asserting their invalidity.

For example, in procurement by formal advertising if it is determined after the contract is awarded that the Contracting Officer did not conform to the substantive requirements for procurement by formal advertising the Comptroller General may determine that the contract is not valid. In such cases, the Contractor's recourse is a claim to the Comptroller General.

The doctrines of estoppel or apparent or ostensible agency are not applicable against the United States. It is important, therefore, for a person contracting with the United States to ascertain the extent of the Contracting Officer's actual authority. Lack of such authority in the Contracting Officer relieves the United States of responsibility for his actions. This is a risk that must be borne by anyone contracting with the United States.

GOVERNMENT AGENT A FIDUCIARY

A fiduciary or trust relationship exists between the Contracting Officer and the Government. A contractor, however, deals with the Government at arm's length. The Contracting Officer must conduct himself with absolute fidelity towards the Government. If he shares in profits through secret arrangements with a contractor in any contract affecting his duties, the contract is tainted with fraud and may be rescinded by the Government. It is a crime for an officer or agent of a corporation or firm, or any person directly or indirectly interested in the profits or contracts of a corporation or firm, to act as an officer or agent of the Government for the transaction of business with such corporation or firm.

APPOINTMENT OF CONTRACTING OFFICERS

The selection, appointment, and termination of appointment of contracting officers in the Department of Defense may be made only by the Secretary of the Department, the Head of a procuring activity, or their designees, and by persons of comparable position in other Government departments and agencies.

A Contracting Officer may not redelegate his authority unless he has been authorized to do so. The Comptroller General has held that purchases in behalf of the United States may be made only by contracting officers. Further, the Comptroller General has noted that certain statutes contemplate personal responsibility of the agent making purchases on behalf of the United States. Accordingly, he has held that Government contracts should not be proxy signed but should be signed by the officer or employee who is actually authorized to make the contract.

APPARENT AUTHORITY

Application of the rule that apparent authority does not bind the Government may lead to undesirable results in emergencies because of the necessity for speed in procurement. Accordingly, special provision in World War II was made for payment of fair compensation where a person relied in good faith upon the apparent authority of an agent. Substantially the same right has been made available with respect to services or facilities arranged to be furnished to the Department of Defense under an informal commitment by the procedures of the formalization of informal commitments in ASPR XVII.

RATIFICATION

A contract which is not binding solely because the Government representative who made it lacked authority becomes binding upon ratification of an authorized officer. Such ratification or affirmance relates back to the act or transaction ratified. Ratification may be express, as by affirmative consent, or implied, as by acquiescence.

CONTRACTS SUBJECT TO APPROVAL

Where a contract is entered into subject to approval by higher authority, the giving of such approval is a condition precedent to the existence of a valid contract. In the event the contractor proceeds to perform before action by higher authority has been taken, and approval is later denied, the contractor may not recover even on the basis of implied contract.

Where a contract requires approval of higher authority as a condition to its validity, the act of the Contracting Officer in executing the contract subject to such approval is within the scope of his authority. Approval, therefore, differs from ratification, since in ratification the original act itself is assumed to have been unauthorized. However, the legal consequences of approval and ratification are, in general, substantially the same. Indeed, reference is often made to approval and ratification interchangeably.

MINIMIZING RISK

The risk involved in dealing with the Government can be minimized, however. Problems in connection with contracts awarded by formal advertising arising from either the lack of authority of the Contracting Officer or his deliberate or inadvertent failure to use proper procedures are so complex that there is no room for discussion of them here. Luckily, these problems arise but rarely. Neither is this problem especially important in connection with the initial negotiation of contracts, since the involved procedures for the letting of such contracts developed by the various services will usually preclude the possibility of a Contracting Officer signing a contract which he is not legally entitled to sign.

Limited Authority Of Government Technical And Administrative Personnel

It is important in the administration of contracts. A contractor has relations with many kinds and types of Government employees during the performance of the contract, technical advisors, inspectors, property and audit personnel. It is important to remember that Government personnel of this type can only operate within the limit of their assigned authority. The Government is not bound by their actions or instructions to the contractor unless they have been granted specific authority. Before taking any action that is not called for by the contract, the contractor would be wise to require proof that the person issuing the instructions has the requisite authority to do so. A principal cause of friction in this area is unauthorized actions by Government technical personnel. Except for the purchase of standard items each contract will have a technical person assigned to monitor the contract. In some cases, R & D contracts will include in the contract scope of work a statement that the contractor will conduct his operations in accordance with the instructions of a technical officer. Personnel of this type are limited to issuing instructions within the scope and terms and conditions of the contract. The contractor is not required to accept and the Government is not obliged to pay for any work not performed in accordance with the contract and the Contracting Officer is the only person who has the authority to modify a contract. The burden is on the contractor to insure that he takes instructions only from those authorized to give them.

Human Relation Problem

This presents an interesting problem in public relations and contract administration to the average contractor. Government personnel sometimes get disturbed if their authority is questioned. Internally, the contractor is faced with the problem of insuring that his engineering staff, who are usually the worst offenders in this regard, understand the scope of work and the extent of the authority of the Government personnel with whom they deal. The engineer must be made aware that he is expected to make an item in conformance with contract requirements, not what he, the Government technical person, or both would like to make. Many contractors have lost considerable sums of money because they did not find out until too late that what they thought were orders from responsible military or civilian personnel of the Government were really only suggestions. Not only is the Government not obligated to pay for costs incurred as a result of accepting such unauthorized contract modifications, but the contractor can be held responsible for furnishing an item strictly in accordance with the requirements of the contract. The contractor is not reimbursed for the unauthorized work and may be forced to incur the expense of restoring the item to its original condition.

EFFECT OF CONSOLIDATION OF CONTRACT ADMINISTRATION ON CONTRACTING OFFICER CONCEPT

After several years of planning, DOD consolidated all contract administration and support functions of the Army, Navy, Air Force and Defense Supply Agency. The National Aeronautics and Space Administration also participates. The Defense Supply Agency was assigned responsibility for the management of the consolidation and the operation of the Defense Contract Administration Services Regions. The following support and contract administration functions are included in the jurisdiction of the DCASRs: (1) Contract Administration, including the review and approval of contractor's accounting, estimating and purchasing systems; allowability and allocability of costs, negotiation of overhead rates and many other administration procedures as provided for and in accordance with the terms of the contract; (2) Negotiation and execution of contract termination settlements; (3) Plant clearance; (4) Property administration; (5) Quality Assurance, including the inspection and acceptance of materials and monitoring the contractor's quality control program; (6) Production and industrial pre-award surveys, industrial mobilization planning; (7) Industrial security; (8) Transportation.

The assignment of Contract Administration responsibilities to the Defense Contract Administration Services Regions has necessitated the separation of duties related to procurement with some duties normally performed at a purchasing office and some normally performed at a contract administration office. For convenience of expression, therefore, the regulation provides that when requiring performance of specific duties by a Contracting Officer, the Contracting Officer at the Purchasing Office will be referred to as the Procuring Contracting Officer (PCO) and the Contracting Officer at the Contract Administration Office will be referred to as the Administrative Contracting Officer (ACO). In addition, the Contracting Officer responsible for the settlement of terminated contracts may be referred to as the Termination Contracting Officer (TCO). Under certain circumstances, these three areas of responsibility may be handled by separate individuals or by the one Contracting Officer, depending upon the scope of his appointment and authority. The reference in the ASPR to PCO, ACO and TCO does not, of itself, require that duty be performed at a particular office or activity or restrict in any way a Contracting Officer in the performance of any duty properly assigned. For example, a duty specified by the regulation to be performed by the ACO will be performed by a Contracting Officer at the Purchasing Office when Contract Administration or responsibility for that duty has been retained in the Purchasing Office. The contractor should be informed of the names and responsibilities of the Contracting Officers assigned to his contract by formal notice, and he should also be informed of any changes in these responsibilities.

SUMMARY

Certain requirements are common to both Government and private contracts such as valid acceptance, consideration, certainty of terms, and competent parties.

While the general rule is that the legal principles governing contracts with the Government are substantially the same as those governing contracts between private persons, there are some areas of difference. The more important differences lie in the following areas: interference by the Government with the performance of its own contract; statutory requirements; limited character of procedures for enforcement of contractual liability of the Government; and the nature of the law applicable to Government contracts.

In determining questions arising under Government contracts, courts are not bound by the law of any particular state as in private contract cases. Insofar as a Federal common law can be said to have developed in the field of contracts, it will be applied in cases involving Government contracts where the question to be determined is not governed by the Federal Constitution or a Federal statute.

The term "contracting officer" means any officer or civilian employee of any Department who, in accordance with procedures prescribed by each respective Department, has been or shall be designated a contracting officer (and whose designation has not been terminated or revoked) with the authority to enter into and administer contracts and make determinations and findings with respect thereto, or any part of such authority. The term also includes the authorized representative of the contracting officer acting within his authority.

A contractor cannot rely on a Government Agent's apparent authority. The general rule is that the Government is not bound by the acts of its agents which are beyond the scope of their actual authority, and hence will not pay contractors who rely on the apparent authority of the Government agent. This rule has been relaxed somewhat by the procedures in ASPR XVII for the formalization of informal commitments.

Contractors must remember that they are not dealing with the Government directly, but with an individual Contracting Officer who, within the scope of his appointment and authority, operates with wide latitude and is expected to exercise his individual judgment and initiative.

In a large procuring activity in which the actual negotiation is performed by assistants to the Contracting Officer, generally known as negotiators or buyers, this same wide latitude of judgment is exercised by the negotiator, subject, of course, to review and approval by the Contracting Officer and senior members of his staff, who generally, for lack of time and lack of intimate knowledge of the details of the negotiation, will accept the recommendations of the negotiation staff unless patently contrary to regulations or the dictates of good common business judgment. This wide latitude given to Contracting Officers requires the contractor to exercise considerable skill and judgment in dealing with them. The contractor must know the authority of those Government representatives with whom he deals.

He must take steps to insure that he and each of his employees who come in contact with Government personnel take instructions only from those authorized to give them. Failure to exercise this elementary precaution may result in substantial losses, both of money and reputation.

DOD APPROACH

INTRODUCTION

The Geothermal Steam Act of 1970 authorizes the Department of Interior to lease for development geothermal resources owned by specific agencies. Defense lands are not included in that Act. However, a significant geothermal resource does exist within Defense boundaries with no provision for leasing by any agency. The Military Construction Authorization Act of 1979 took a step towards correcting this deficiency.

1979 MILCON ACT

Section 803 of the 1979 Military Construction Authorization Act provides for the development of geothermal resources by the Heads of the Military Departments for the use or benefit of the Department of Defense. This authority, however, is limited to those lands owned in fee by Defense and does not extend to withdraw public domain lands.

Section 803 also provides authority for contracts of up to 30 years for the purchase of energy from energy production facilities using other than fossil or nuclear fuels. This is a unique provision, and is the only such long term contractual authority in the Federal sector.

DEVELOPMENT OF SOURCES OF ENERGY ON MILITARY LANDS

Section 803.

(a) The Secretary of each military department may develop for the use or benefit of the Department of Defense any geothermal energy resource within lands under his jurisdiction other than public lands administered by the Secretary of the Interior.

(b) (1) If the Secretary of a military department determines that it is in the interest of the Government to do so, he may contract, for a period not to exceed thirty years, for the provision and operation of energy production facilities on real property under his jurisdiction and for the purchase of energy produced from such facilities, except that no such contract may be made for the development of energy resources derived from nuclear or fossil fuel sources

(2) Any contract under paragraph (1) may be made only--

(A) after the approval of the Secretary of Defense of the proposed contract: and

(B) after the Committees on Armed Services of the Senate and House of Representatives have been notified of the terms of the proposed contract, including the dollar value of such contract and the amount of energy to be delivered to the Government under such contract.

(c) This Section shall take effect on October 1, 1978.

TECHNIQUE

Defense, having recognized the futility of attempting to close out industry from the development of geothermal resources within DOD lands sought out an methodolgy to allow for development while protecting the mission of the activity involved.

The basic approach is through the cooperation of both Defense and industry, using a set of constraints over actions taken by either party in the joint use of the land. DOD using this approach has taken the authority provided by the MILCON Act and competitively offered lands for development at no cost for the resource. This is intended to be as similar to a lease sale as is possible.

The developer is then required to explore for and produce the resource for ultimate sale to DOD. This effort is at no cost to Defense with the developer's investment being recouped through the long term sale of the energy produced.

If these lands had been offered for leasing by DOI, the constraints over the developers actions would be contained in the lease as they are contained in the contract with DOD. The developers would have the same level of freedom to produce the resource, however, he would be paying for the resource and would have no guaranteed buyer of the energy produced.

CONSTRAINTS

The constraints are typically quite simple and govern such items as access to the site, security, environmental concerns, roads, shelters, accidents, legal jurisdiction, blowout protection, etc. The purpose of these constraints is to protect the developer from any harm due to the ongoing military operations at the base while at the same time assuring the base Commander he can continue with his mission responsibilities.

HOW TO DEAL WITH DOD

The first and most important step in dealing with DOD is to make your capabilities known to the appropriate contracting office. This will ensure that when a request for proposals leading to development of geothermal resource is made, your firm is on the list of those receiving the request.

Two documents have been included which will assist you in contacting the proper office. Selling to the Military lists all those offices which handle construction work. These are the appropriate offices to contact for consideration on a request for geothermal development. The second, How to be Considered for NAVFAC Contracts deals with the Navy in greater detail. I have included a third document on the details of Selling to Navy Prime Contractors.

As a final measure, the Commerce Business Daily, published by the Department of Commerce should be reviewed, as all soliciations by the Government must be published in it.

SUMMARY

Dealing with DOD for geothermal development within Defense lands is very similar to leasing the same resource through DOI. Identical constraints will be included, the contractor is free to develop the resource as he would if it were leased, and the leases and geothermal resource orders are identically applicable to both. The main difference is that there are no bids and royalties involved in obtaining the resource and there is a guaranteed buyer of the energy produced.

TWO-STEP FORMAL ADVERTISING

INTRODUCTION

As its name implies, two-step formal advertising is a method of procurement conducted in two phases. The first step consists of the request, submission, evaluation, and, if necessary, discussion of a technical proposal without pricing to determine the acceptability of the supplies or services offered. The second step consists of a formally advertised procurement confined to those offerors who submitted an acceptable proposal in step one. The objective of the two-step procedure is to permit the development of a sufficiently descriptive statement of the Government's requirements so that subsequent procurement may be made by straight formal advertising. It is a means by which the Government can have the flexibility of negotiation in step one and the competitive pricing of formal advertising in step two.

The following discussion and cases are designed to illustrate some of the problems in connection with the use of two-step formal advertising from the standpoint of both the Government and the contractor.

Two-step formal advertising is used by all the Services for the purchase of a wide variety of items at a wide range of dollar values. Basically, it is used when more than one qualified bidder can be expected to bid and where the technical data is incomplete for formal advertising but technical evaluation criteria are available. It can be used for an initial or follow-on procurement and may be used where Invitation For Bids for "one-step" formal advertising have been issued but were cancelled. It may be used for a wide variety of procurements ranging from study programs to the production of complex items. For the latter items, it is used in combination with multi-year and life cycle costing procedures.

If additional technical information is needed to prepare specifications adequate for use by one step formal advertising on a subsequent procurement, this information will be obtained under the contract resulting from the two-step procurement.

From the standpoint of the Government, the policy is to use two-step formal advertising when it is not possible to use straight formal advertising in preference to the use of negotiation.

Conditions For Use

(1) Available specifications or purchase descriptions are not sufficiently defining or complete to permit full and free competition without engineering evaluation and any necessary discussion of the technical aspects of the requirement to insure mutual understanding between the Contractor and the Government.

(2) Definite criteria exist for evaluating technical proposals such as applicable design or performance requirements; special requirements for operational suitability and ease of maintenance; necessary background experience in development and production engineering in the general engineering areas involved; and need for special skills or facilities.

(3) More than one technically qualified source is expected to be available both initially and after technical evaluation.

(4) A firm fixed price contract or a fixed price with escalation will be used.

ASPR, Section II, Part 5, provides that the letter request for technical proposals will include:

(1) The best practicable description of the supplies or services required.

(2) Notification of the intent to conduct the procurement in two steps and the actions involved.

(3) The requirements for the technical proposal such as the drawings, data and any other presentations to be submitted. No prices are to be submitted in the first step. If they are, they will be disregarded.

(4) The criteria for evaluating the technical proposals.

(5) A statement that the technical proposals shall not consider prices or pricing information.

(6) The date or date and hour by which the proposal must be received and the Late Technical Proposal provision in 7-2002.3 (this replaces paragraph 7 and 8 of Standard Form 33A. This provision provides that any late proposal will not be considered unless it is received before the invitation for bids in Step Two is issued and it was sent by registered or certified mail not later than the fifth calendar day prior to the date specified for the receipt of offers, it was sent by mail (or telegram if authorized) and the late receipt was due solely to mishandling by the Government after receipt at the Government installation, or it is the only proposal received. The only acceptable evidence of the mailing date is the U. S. Postal Service postmark on the wrapper or on the original receipt from the U. S. Postal Service.

The same provisions apply to late "bids" in Step Two.

(7) A statement that in the second step of the procurement, only bids based upon technical proposals determined to be acceptable, either initially or as a result of discussions, will be considered for award; and that each bid in the second step must be based on the bidder's own technical proposals.

(8) A statement that offerors are advised to submit proposals which are fully and clearly acceptable without additional explanation or information, since the Government may make a final determination as to whether a proposal is acceptable or unacceptable solely on the basis of the proposal as submitted and proceed with the second step without requesting further information from any offeror; however, if the Government deems it necessary to obtain sufficient acceptable proposals to assure adequate price competition in the second step or deems it otherwise desirable in its best interest the Government may, in its sole discretion, request additional information from offerors of proposals which the Government considers reasonably susceptible of being made acceptable by additional information clarifying or supplementing but not basically changing any proposal as submitted and, for this purpose, the Government may discuss any such proposal with the offeror.

(9) A statement that each source submitting an unacceptable technical proposal will be so notified upon completion of a technical evaluation of his proposal and final determination of such unacceptability.

(10) A statement either that only one technical proposal may be submitted by each offeror, or that multiple technical proposals may be submitted. When compliance with specifications permit the utilization of essentially different technical approaches, it is generally in the interest of the Government to authorize the sub-

mission of multiple proposals. If multiple proposals are authorized, the Request shall include a statement that multiple technical proposals are authorized and that each technical proposal submitted will be separately evaluated and the offeror will be notified as to its acceptability.

Although the Government's delivery or performance requirements are not evaluation factors under Step One, information about those requirements may be of assistance to potential bidders in determining whether or not to submit a technical proposal. Accordingly, a request for technical proposals may contain a statement indicating what the Government's probable contract delivery or performance requirements will be. The statement should also advise that such information is not binding on the Government and that the Government's actual delivery or performance requirements will be contained in invitations for bids issued under Step Two.

EVALUATION OF STEP ONE PROPOSALS

Technical evaluation of the proposals will be based upon the criteria contained in the Request for Technical Proposals. The evaluation will not include consideration of capacity or credit. The regulation formerly provided that first step technical proposals would "not be categorized as unacceptable when a reasonable effort on the part of the Government to obtain clarification or additional information could bring the proposals to an acceptable status and thus increase competition." Now the regulation provides that offerors should "submit proposals which are fully and clearly acceptable without additional explanation or information since the Government may make a final determination as to whether a proposals is acceptable or unacceptable solely on the basis of the proposal as submitted and proceed with the second step without requesting further information from any offeror..."

However, the policy provides that "the Government may, in its sole discretion, request additional information from offerors of proposals which the Government considers reasonably susceptible of being made acceptable..." Where formerly upon completion of the technical evaluation each proposal was categorized as acceptable or unacceptable, the new policy calls for three categories as follows:

1. Acceptable

2. Reasonably susceptible of being made acceptable by additional information in clarifying or supplementing, but not basically changing the proposal as submitted.

3. In all other cases, unacceptable.

If the Contracting Officer determines that there are sufficient proposals in the first category to assure adequate price competition under step two, and "that further time, effort and delay to make additional proposals acceptable and thereby increase competition would not be in the best interest of the Government, he may proceed directly with step two." In addition, any proposal which modifies, or fails to conform to the essential requirements or specifications of the request for technical proposals shall be considered non-responsive and categorized as unacceptable.

Contractors should re-evaluate their procedures for submission of technical proposals in step one. Under the previous procedure, the Contracting Officer was more or less obligated to discuss first step technical proposals unless they were clearly unacceptable. Under the current procedures, he is not obliged to do so if he has sufficient completely acceptable proposals. Prospective contractors, therefore, must take greater pains to insure that their technical proposals conform as closely as possible to the requiremenets of the specifications.

Extent Of Government Authority To Clarify Technical Proposals In Step One

The Comptroller General will not question the extent of the effort by the Government to secure clarification of a step one proposal unless there is evidence of fraud, prejudice, abuse of authority, arbitrariness, or capricious action.

The Comptroller General's decision was concerned with the extent of the Government's efforts to secure clarification of a technical proposal in the first step. In his decision, the Comptroller General states that whether or not the proposal needs clarification and the extent of the clarification sought by the Government is a matter for the procurement agency to decide and the Comptroller General will not interfere unless there is evidence of fraud, prejudice, abuse of authority, arbitrariness or capricious action.

The decision notes that the ASPR provisions are designed to obtain a number of different proposals to achieve the desired end required by the Government. It then compares two-step and brand name procurement and states that the purpose of two-step procurement is to provide a "broader base of competition."

> "The basic object is to provide a broader base for competition than is provided in a brand name or equal procurement. In the latter case, the items sought is circumscribed by the brand name item, whereas in a two-step procurement, the first step provides a broader field for proposers to work in preparing their proposals. In view of this broad scope and purpose, we cannot subscribe to a view that would restrict the clarification or evaluation of proposals. We would defeat the concept of two-step procurement if we attempted to place undue restrictions on the procedure or judgements involved in the first step. Except as indicated below, (evidence of fraud, prejudice, abuse of authority, arbitrariness, or capricious action) we are not disposed to limit the judgment of the procuring agency in attempting to clarify a proposal in order to accomplish its acceptability where the proposal has not been finally rejected as non-acceptable." (Comp. Gen. B-157827, Feb. 7, 1966)

NOTIFICATION OF UNSUCCESSFUL PROPOSERS

Upon final determination that a technical proposal is unacceptable, the Contracting Officer shall promptly notify the source submitting the proposal of that fact. The notice shall state revisions of the proposal would not be considered and shall indicate in general terms the basis for the determination. For example, that rejection was based on failure to furnish sufficient information or on an unacceptable engineering approach. If, as a result of the evaluation of technical proposals, it appears necessary to discontinue two-step formal advertising, each prospective contractor will be notified in writing of the discontinuance and the reason therefor. When step one results in no acceptable technical proposal or only one acceptable technical proposal, the procurement may be continued by negotiation.

STEP-TWO PROCEDURES

Upon completion of the technical evaluation, a formally advertised procurement strictly in accordance with procedures will be conducted. The IFB will be issued only to those sources whose technical proposals have been evaluated and determined to have been acceptable. The supplies or services to be procured will be in accordance with the bidder's technical proposal as finally accepted. Each bidder is bidding on his own proposal. Since all those bidding are bidding on technical proposals which meet the Government requirements, the contract will be awarded to the lowest, responsible, responsive bidder. The evaluation and award procedures will be essentially the same as those discussed for formal advertising.

Technical Proposal Cannot Be Revised After Bid Opening Under Step Two

The Comptroller General has stated that a technical proposal cannot be revised after bids are opened in step two if it affects the price, quality or quantity of the items bid upon.

In the examination of a technical proposal, after the bid opening in the second step of a two-step procurement, it was discovered that the low bidder had included an oscilloscope that would not meet the specifications required. The deficiency was undetected by either the contractor or the Contracting Officer prior to the opening of the bids in step two. If it had been noted, it could have been corrected prior to the bid opening. Second, if the Contracting Officer had not noticed the error, the low bidder would have been obligated to furnish an oscilloscope in accordance with the requirements of the contract.

In his decision, the Comptroller General stated that since the Contracting Officer was placed on notice that the bidder's technical proposal and bid price was based on the incorrect assumption that the oscilloscope offered could be changed to meet the specification, the Government could not, by an award based on such bid price, obligate the bidder to furnish an oscilloscope that did meet the specification. In order to do so, it would require a revision of the low bidder's technical proposal. Whether this could be done, the Comptroller General notes, requires a consideration as to whether the revision would be prejudicial to the rights of other bidders. In this regard, the decision notes that it well settled that a bid must be rejected if the deviation from the requirements of the specification affect price, quality or quantity of the items bid.

Since the difference in price between a satisfactory oscilloscope and the one offered was large enough to justify the conclusion that it would have required the low bidder to raise his bid price above that of his competitor, the Comptroller General concluded that to permit a revision of the technical proposal either with or without a revision in the bid price, would be prejudicial to the other competitor. (Comp. Gen. B-157084, 45 Comp. Gen. Feb. 10, 1966)

OR EQUAL PROCUREMENT BY TWO-STEP ADVERTISING

Two-step formal advertising is often used in place of "brand name or equal" procurement where the description in the IFB's specifications of the essential characteristics of the brand named item is not adequate for purposes of straight formal advertising. In this situation, step one will consist of bidder's presentations of technical proposals on items other than the specified brand item. The step one proposals are designed to show that although the proposed items may have characteristics different from the brand item, they still meet the Government's needs.

In cases where difficulties may be experienced in describing what is desired in Invitation For Bids, the use of the name of the maker of an item in an Invitation To Bid followed by the words "or equal" is used. However, the Comptroller General has ruled that the desire on the part of a particular agency for a particular make of item "is not, of itself, sufficient justification for the purchase thereof to the exclusion of other makes if equally adaptable to the needs of the service" (16 Comp. Gen. 171 173), and that the naming of a particular make of article, even with qualifying words such as "or equal", should be avoided when it is reasonably possible to describe the needs of the Government in the specifications with sufficient clarity to apprise prospective bidders of what is required. (10 Comp. Gen. 555)

The Comptroller General has construed the term "or equal" when used in this sense to mean that an alternate item must be equal to the product specified insofar as the needs of the agency are concerned but not necessarily an exact duplicate thereof in detail or performance. (Comp. Gen. Dec. B-124587, Dec. 5, 1955).

The Comptroller General has consistently held that the Government advertising statutes require that every effort should be made by the procurement agencies of the Government to state advertised specifications in terms that will permit the broadest field of competition within the needs reasonably required, not the maximum desired. (32 Comp. Gen. 384 387)

In general, the Comptroller General requires that, rather than use a specification for a designated proprietary article or equal, which he considers unnecessarily restrictive of competition, the agency, where possible or practical, should describe its actual needs in specifications which set forth the particular features that the agency deems necessary. This enables prospective bidders to determine whether they can meet the needs of the agency and what, if any, modifications might be called for in their standard or customary production models, with the result that competition will be broadened.

PROPOSAL PREPARATION

PART 1
INTRODUCTION

I. Definition of a Proposal

A. A proposal is an offer to supply a product, perform a service, or a combination of both. In some cases, where standard off the shelf items are the subject of the proposal, the proposal may be an offer of the item itself based on standard advertising material showing the specifications, performance, and price of the item.

II. The Function of a Proposal

A. The function of a proposal is to sell the managerial and technical capabilities of the firm to carry out the work required at a reasonable cost.

III. The Importance of Proposals

A. Most important company activity

1. Secures contracts

2. Establishes reputation

a. One carelessly written proposal can destroy the company's reputation with a major customer

B. Advertising

1. To secure a chance to prepare a proposal

2. Proposal is the point of sale

C. Corporate image is based on

1. Quality of the product you produce

2. Your personal representation to the customer

3. Your written material

D. Proposal effort is more important than public relations, the company newspaper, or the advertising department

E. Problems in proposal preparation

1. Management's failure to appreciate their importance or, if they do, to do anything constructive to improve their quality

2. Lack of organization

3. Lack of time - results from lack of organization

4. Lack of communication - results from scattered personnel. Last minute design changes may not reach all concerned. Results in design discrepancies or last minute adjustments

5. Most important communication failure occurs in a technical proposal

IV. Mechanics of Proposal Preparation

A. A great deal of time, trouble and money can be saved if detailed procedures and instructions concerning the mechanics of proposal preparation are provided to each segment of the company which will be responsible for providing input to proposals

B. Proposal Library

V. Procedures for Proposal Preparation

A. A preliminary analysis of the RFP by technical, manufacturing, and finance to determine whether a proposal should be made and the extent of the effort to be made

B. The development of the initial proposal plan and outline. This should be a joint effort of the proposal manager, technical manager and cost manager

C. A proposal team should be organized and briefed on the overall proposal plan and provided with copies of the proposed outline and approach

D. The format, style, and quality level of the reproduction and binding should be determined

E. A proposal schedule should be developed to which all personnel should be forced to rigidly adhere

F. A list of illustrations needed should be developed

G. The schedule and the procedures should provide time for careful editing and proper production of the proposal

H. Proposal review checklists should be established

I. A Proposal Review Board should be established to review proposals to insure that they are completely responsive to the requirements of the Request for Proposal in all areas, including technical, management, and cost

VI. Bid/No Bid Decision

A. After the Request for Proposal is received and logged in, it should be screened immediately and a decision made to bid or not to bid

B. Wins Based on the Quality, Not Number, of Proposals Generated

C. Importance of Advance Information

VII. Development of the Proposal Plan

A. A proposal plan should be developed. This is a joint effort of the Proposal Manager, Technical Manager, and Cost Manager. Without a plan, relevant material will be omitted and the proposal will be disorganized and repetitious

B. Proposal Preparation Package

1. General information on the origin and nature of the proposal

2. Program objective and scope

3. Special requirements of RFP

4. Technical approach - minimum design and performance requirements - possible optional items unless contract is fixed price

5. Statement of Work

6. Delivery schedule

7. Task responsibility assignment matrix

8. Detailed proposal outline

9. Costing instructions

C. Proposal Coordination Meeting

1. Company philosophy and approach to the proposal

2. Importance of the proposal to the company's future welfare

Part 2
Writing The Proposal

I. Necessity For Preparation

   A. The expertise of many professions and skills is required to effectively communicate to the customer

II. Production Control

   A. Establishing the size and scope of the proposal writing task

   B. Dividing the workload into manageable proportions

   C. Scheduling intermediate milestones to meet prescribed target dates

   D. Allocating qualified people to the proper task

   E. Quality Control

III. Proposal Preparation Is A Team Effort

   A. The development of an effective proposal requires a team effort by all elements of the company

   B. Experts of many specialties and skills within the company organization will contribute to the preparation of the proposal

      1. The Systems Engineer

      2. The Design Engineer

      3. The Configuration Management Specialist

      4. The Program Planning and Control Specialist

      5. Product Assurance, Reliability and Maintainability Specialist

      6. The Logistician, or Support Specialist

      7. The Data Manager

      8. The Estimator

      9. The Contract Manager

      10. The Lawyer

C. Requirement for a team effort

D. Need for coordination and review

E. Shortage of time

1. Lack of organization results in lack of communication

2. The most important communication failure occurs in the Technical Proposal

IV. Planning the Work

A. Preliminary planning should start early

B. Determining the size and scope of the proposal effort should be the first step on the agenda of the proposal manager

1. Review the principal source documents to the extent they are available, particularly the customer's planning documents. This information should be furnished by marketing

2. Review the Request for Proposal, if it has been issued, to determine the approximate amount of effort required

3. Develop the management concepts, priority requirements, target dates and other relevant background information for the proposal preparation

4. Discuss with the key functional managers the roles of their departments in preparing the various parts of the proposal. Often it will be found that the many elements of the proposal can be prepared by using the normal processes and resources of the functional organizations

5. Review prior proposals and develop a tentative list of tasks and data that should be considered for inclusion in the proposal

6. Prepare an initial outline of the proposal with the assistance of the technical, management and cost proposal managers, for distribution in the initial briefing of the proposal team

V. Kick-Off Briefing

A. At this meeting, the extent of the job is outlined, the work divided and assigned, and essential target dates established

B. A summation by the project manager of:

1. The general characteristics, purpose, and employment concept of the system or equipment or component

2. The work breakdown structure, identifying and defining the tasks to be performed both during the proposal preparation period and the pending contract

3. The budget assigned to the proposal

4. Any special funding features, incremental funding, etc., relevant to the pending proposal effort

5. Requirements, if any, for logistically supporting the item, including the identification of principal secondary items, particularly the most critical components if such information is available

C. The technical manager should discuss the following:

1. The technical performance requirements of the system or equipment and the technological or state of the art problems that will require solutions in meeting these objectives

2. The test and methodology that will be used to prove to the customer that the company has met the performance objectives

3. An analysis of the Request for Proposal to identify those areas which specify performance requirements versus design requirements

D. A statement by the marketing representative of:

1. The long term marketing objectives of the company with emphasis on how the current proposal fits into the long range marketing objectives

2. The relationship between the proposed work and other companion or related work that will be performed at the same time or in the future as part of the present marketing plans

E. A statement by the contract manager concerning:

1. The type of contract that is contemplated and its influence on the proposal, for example, an incentive type contract based on technical performance will require particular specificity in defining the performance requirements in relation to the customer's statement of work, and how their accomplishment is to be demonstrated.

2. A review of the terms and conditions of the Request for Proposal

F. An explanation by the Configuration Management Specialist of how the work breakdown structure will be organized to conform with the customer's requirements

G. The assignment by the proposal manager of responsibility for individual parts of the proposal

H. Scheduling the proposal effort by establishing due dates for preliminary and final drafts, and for intermediate and final review

I. The distribution of source material such as a copy

VI. Getting Ready To Write

A. As much relevant knowledge about the Request for Proposal as is practical

B. All the background information connected with the development of the customer's requirement

C. The individual writer should review all company past proposals in the areas of his interest

D. All the customer's regulatory and guidance literature applicable to the work to be done or to the approach to be taken should be reviewed

E. A literature search should be made

F. Technical papers and texts available in data banks maintained by the Defense Documentation Center should be reviewed

VII. Organizing The Work

A. Divide the subject matter to be covered into its logical component parts

B. Develop an outline of how the subject will be covered

C. Identify those component tasks that are already defined or available in existing proposals

D. Isolate those tasks that represent technological or design problems that will necessitate additional research

E. Single out those functions or aspects of the work that will require special care in their presentation within the proposal

F. Determine those areas where additional help will be required if scheduled dates established by the Proposal Manager are to be met and attempt to get the needed assistance without delay

VIII. Writing the Proposal

A. Wide range of interests and abilities among evaluators and interested readers

B. Use clear simple language

C. Basic outline for each principal proposal area

1. Precis

2. Body

3. Summary

D. Mathematical analysis or statistical information should be included in appendices

E. Distinction between a technical report and a proposal

1. Reports are informative and a reader will look for information

2. A proposal is a selling document. The responsibility to reach the reader is upon the writer

F. Three types of argumentative proof need

1. Authoritative - sincerity, completeness

2. Logical - validity of approach is proven by supporting technical information, explanations, examples, analogies, illustrations, charts, drawings, etc.

3. Emotional - base proposal on Government frame of reference, benefits to national defense, stress economy, performance, and cost. Place strong emphasis on current interests of DOD or the agency concerned.

G. Writing style

1. Organize the presentation

a. Tell them what you are going to tell them

b. Tell them

c. Tell them what you told them

2. Be specific - avoid unqualified general terms; e.g. high, low, great, small, longer, etc. Use specific terms; e.g. 15.8 feet, or qualified general terms; e.g. large (30, 000 square feet)

3. Use the right word

a. Use the lowest meaningful word. This increases the number of readers who will understand the presentation

H. Writing method

1. Write voluminously and then cut and edit to desired length

I. Edit carefully

1. Proper organization into Parts, Sections and Sub-Sections

2. Proper paragraphing

3. Punctuation

4. Spelling

J. Common style faults

1. Too scientific. Proposal is written to impress the reader with the "erudition" of the writer, not to see the reader

2. Madison Avenue approach - indicated by glittering generalities rather than specific proofs, fancy rather than fact, heat rather than light, wishful thinking rather than realism, and talk rather than ability. Some proposal phrasing could serve as a guide for snake oil merchants and used car dealers but has no place in proposals

3. Lack of logic - indicated by the strange powers attributed to service programs which invariably guarantee the success of entire projects or by the all too frequent mismatch of dependent and independent clauses; e.g., cause and effect relationships

4. Begging - indicated by the imploring aspect of some proposals. Never beg for contracts, earn them

5. Padding - indicated by overstatement: e.g., "Every possible effort will definitely be made . . . , "has no more effect on the reader than "Efforts will be made . . ."

IX. Use of Illustrations

A. Related directly to proposal

B. Explained in text

C. Uncluttered

X. Charts

A. Related to proposal

B. Meaningful to reader

C. One idea - one chart

XI. Use Appendices To:

A. Expand significant areas of the proposal where inclusion in the body might confuse or interfere with the continuity of the presentation

B. To add additional information after the original proposal is forwarded

XII. Edit Carefully

A. Arithmetic

B. Clarity

C. Logic of presentation

D. Consistency

E. Completeness

F. Accuracy

G. Emphasis

H. Grammar - spelling - punctuation - style

1. Develop style with a high level of impact

XIII. Prepare Final Summary

A. Capsule proposal

1. Precise

2. Spotlight the unique or outstanding features - use separate section to focus attention on key selling points

3. The major reasons why your organization should receive the contract

XIV. Most Frequent Proposal Shortcomings

A. Oversimplification of the technical problem or requirement

B. Misinterpretation of the specifications or failure to comply with them

C. Lack of understanding of the technical requirements

D. Proposed engineering program is not technically feasible in the available time table

E. Over-optimism in performance estimates of the proposed equipment

F. Insufficient detail in cost and pricing information

G. Lack of realism with respect to how proposed equipment can be integrated or made to work with other planned or existing equipment or operational philosophies

H. Proposal contains vague generalities and/or sweeping statements which reflect the philosophy: "We understand your problem. Just give us a contract and leave it to us"

XV. Additions To Proposals

XVI. Unsolicited Proposals

A. Need to know contract

B. Investigate complete field before spending money

C. Personal investigation

1. Similar proposals

2. Current R&D contracts

D. Make an informal presentation

1. Use top technical people

2. Make it complete

a. One page proposals

E. Iron out objections

F. Develop formal presentation

1. Keep all interested parties informed

G. Follow through to insure that proposal reaches the right personnel

XVII. Common Defects in Unsolicited Proposals

A. Funds not available for the program at the time received

B. System for which new development is proposed is in obsolescent stage

C. Proposed program timetable is too far out of phase with research and development timetable of weapon with which it would be used

D. Need for proposed equipment is not established, or it offers too little improvement to justify the cost and effort

Part 3

PROPOSAL FORMAT

I. Introduction

A. The scope and tone of various proposals will differ

B. However, the basic informational content and the format should be essentially the same whether it deals with a complete system, a subsystem, or a component and whether it is in response to a Request for Proposal or is an unsolicited proposal

C. It is important that a proposal say something, that it says it well, and that it is presented in a manner that will assist the telling

II. Standard Proposal Format

A. The principal elements of a proposal are:

1. The Technical Proposal

2. The Management Proposal

3. The Cost Proposal

B. Each part is important and each is evaluated separately by the customer. Since each must stand on its own feet, some duplication may be necessary. The relation between them can usually be established by means of a common introduction

C. In writing each individual section of the proposal, Technical, Management, and Cost, the same general format should be used. Each proposal or principal area within it should be composed of (1) a precis or initial summary; (2) the body of the proposal; (3) a summary of the principal points developed in the body; and (4) where necessary, appendices

D. The Executive Summary should summarize the pertinent points of all three proposals

III. The Executive Summary

A. The Executive Summary is an important part of the Proposal. It is read by everyone. Its function is to:

1. Summarize general information as to the origin and scope of the Proposal;

2. Provide general information on the requirements of the Request for Proposal and the interests of the contractor

3. Provide a brief summary of the program, its purpose, objectives, and basic problems; and

4. Furnish a statement and analysis of the problem with a recommended solution

B. The Executive Summary should be written so that it can be used either as the introduction to a single volume proposal, or repeated as the introduction to the individual volumes in a multi-volume proposal

C. The following items should be considered for inclusion:

1. Basis for proposal submittal (response to formal Request for Proposal, letter, purchase request, or unsolicited proposal)

2. RFP number and date

3. Sources of additional information, bidder's conference, date and location, other information and how obtained (letter, telephone, etc.)

4. Program objective, scope and duration

5. Statement of the problem

6. Alternate solutions considered. Relationship of proposed program to other inhouse programs, company sponsored independent technical effort, and company long range business objectives

7. Description of end product

8. A clear, concise statement of the technical requirements which the proposal fulfills, or, in the case of an unsolicited proposal, the particular areas involved

9. Description of the expected end result of the program

10. Relationship of proposed work to the state of the art, including the presently available components, equipment, techniques, or systems

11. The value of the program for the immediate future application and a prediction of performance in relation to proposal requirements

12. Expression of interest in conducting the work

13. Proposer's qualifications, including specialized facilities and related management and technical experience

14. Relationship of proposed program to successful previous programs

15. Factors that will insure the operational effectiveness and cost effectiveness of the end item and that will provide for minimum costs in the conduct of the program and in the performance of the contract work

16. Reasons why the company should receive the contract. This should include a review of the principal competitive advantages which caused the firm to decide to make the proposal in the first place. These include unique facility or personnel capability, a unique technical approach, or directly related experience

17. A brief summary of the information developed in the preceding items

18. A brief summary of the contents of the Proposal

IV. The Technical Proposal

A. The Technical Proposal is the most important part of the proposal since it illustrates the contractor's understanding of the problem and presents his proposed method of solution

B. The Technical Proposal should be organized and written so as to be compatible with the Request for Proposal, the statement of work, company organization and accounting structure, and proposed cost estimates

C. The Technical Proposal should provide an analysis of the problem, a discussion of the operational environment, and an accurate and clear description of the proposed system and/or hardware, including drawings or sketches of the proposed configuration

D. The analysis of the problem is particularly important. This analysis should be complete enough to convince the customer that the company fully understands the problem

E. The customer is primarily interested in what the item will do for him

F. The relationships between the item in the proposal and the major system within which it will function, or other parts of the system, should be carefully outlined

G. The proposal should explain how the item will accomplish the results required

H. Any areas which involve a particularly unique approach by the company, a breakthrough or an advance in the state of the art, should be carefully described in detail

I. All the physical characteristics of the item, mechanical, chemical, and otherwise, should be carefully spelled out

J. Data on performance and the parameters in which the item will operate may be presented with tables, charts and graphs. These should be prepared to insure that they provide proper impact and are thorough and accurate

K. Exceptions should not be taken; rather, performance trade-offs should be offered. A "trade-off" is an approach which shortens development lead time and reduces development costs without affecting the minimum performance requirements of the system

L. Major considerations in writing the technical proposal:

1. A description of novel ideas or technical approaches developed by the company in its analysis of the problem

2. A statement of the major technical problems which must be solved with an indication as to the amount of effort budgeted to each. This is a major check point for the customer in both technical and cost areas since it shows him whether or not the company truly understands the problems inherent in the procurement

3. A discussion of the technical approaches that have been explored or will be explored and why the company's approach may be expected to yield the desired results

4. A brief discussion of the alternate solutions ranging from the routine to the imaginative which were explored and rejected and the reason for their rejections. This point assures the customer that the company's engineers have not come to a snap decision with regard to the problem, and will show the customer the extent of the research engaged in prior to the development of the company's solution. It is also a subtle way of knocking down approaches that may be used by competitors

5. Unrealistic and unreasonable performance requirements and their associated costs should be identified. The customer may not always realize the effect of some of the performance requirements imposed by the Request for Proposal or he may not be aware of the delay and cost associated with their accomplishment. These areas should be pointed out in the proposal and possible alternate solutions providing for shorter time or lower cost should be presented. The more difficult areas or problems to be solved should be identified and detail provided showing how performance requirements which require a breakthrough in the state of the art will be achieved

6. The proposal should state where the company intends to deviate from the specifications. Be careful - the customer may resent any deviations as a reflection on his understanding of the problem. Such deviations should be kept to a minimum and adequate justification provided

7. The proposal should contain an estimate of the cost of the maintenance procedures and schedule and to what extent special test or support equipment will be required

8. The proposal should show that the company did its utmost to use existing items or components, and if new components must be developed, the proposal should explain why existing ones cannot be used

9. Any unique or unusual component reliability requirements exceeding those obtainable from conventional components should be described and justified

10. The proposal should show that the company will place emphasis on producing an item suitable for production without further development or engineering effort

11. The proposal should, within limits of security, show the relationship of the present proposed contract effort to any existing or previous contracts which the company has performed for either the same service or for the other customer, indicating the customer, the type of project, the funds available or already spent, and the results achieved to date. This is an especially important point, since if the company is already engaged in a field of effort required by the contract, the customer will receive the benefits of the work done previously

12. If the company intends to use privately developed data or techniques, it should be explained in advance

13. If the proposal is for development, an honest estimate as to the likelihood of the program resulting in hardware should be given

14. Company facilities available for research and development, production and testing, plus an estimate of the cost of any new industrial facilities, special tooling, or test equipment which the company intends to procure for the contract should be listed and a statement made as to whether the customer will be requested to pay for these, or whether the company will pay for them, or whether the costs will be shared. If these costs will be amortized over future contracts, details should be furnished

15. All test equipment and the calibration program should be summarized and explained

16. A description should be given of the technical services to be provided, including site operation and maintenance, field support, spare parts provisioning, systems analysis and off-site operations

17. Program planning charts should be furnished which indicate milestones of expected specific technical accomplishments. Provision should be made for periodic review and evaluation. PERT charts, bar charts, and Line of Balance techniques should be used where applicable

18. Resumes of technical personnel should be furnished

M. The following is a list of Sections that may be included in the Technical Proposal. Not all Sections will be applicable to all proposals and the scope of each Section will vary depending on the type of proposal. For small proposals, a paragraph may suffice. For larger ones, extensive treatment may be necessary

1. Description of Technical Approach

2. Work Breakdown Structure

3. System Engineering Concepts

4. Subsystems Analysis

5. Systems Test and Evaluation Plan

6. Operational Diagram
7. Block Diagram
8. Task Descriptions
9. Degree of Risk
10. Safety
11. Compatibility
12. Human Factors
13. Personnel and Equipment
14. Training
15. Reliability
16. Maintainability
17. Quality Assurance
18. Cost, Time and Performance Trade-Offs
19. Related Experience
20. Program Schedule
21. Program Plan
22. Engineering Plan
23. Fabrication and Manufacturing Plan
24. Configuration Management
25. Data Management
26. Facilities
27. Logistics
28. Transportability
29. Preservation, Packaging, Materials Handling and Marking
30. Make-Or-Buy
31. Subcontracts

32. Technical Personnel

33. Audiovisual Documentation

34. Technical Manuals

35. Biomedical/Bio-environmental

36. Computer Resources Management

37. Environmental Protection

38. Nondestructive Inspection

39. Parts Control and Standardization

40. Preoperational Logistics Support

41. Final Technical Summary

V. The Management Proposal

A. The purpose of the Management Proposal is to explain precisely how the company intends to manage the proposed contract

B. It should elaborate on the history, organization, management experience, and management philosophy of the company

C. It must demonstrate that the company has an understanding of the external organizational relations with the Government and contractors necessary to accomplish the project

D. It must outline the overall management concepts employed by the company and the specific type of management that will be provided for the proposed project

E. Project Management

1. The most important part of the Management Proposal is the description of the type of management which the company intends to provide for the project

2. The type and extent of project management should be carefully spelled out

3. The following items may be considered in the preparation of the Project Management Section:

a. Outline of overall management plan

b. Description of corporate organization

(1) Organization structure

(2) Relationship of project organization to overall company organization

c. Outline of plant organization

(1) Organization structure

(2) Relationship of program organization to plant organization

d. Outline of project organization

(1) Organization structure

(2) Project Manager's responsibilities and authority

(3) Availability of additional personnel

e. Management controls

f. Company - Government interface and liaison

g. Subcontractor interface and controls

h. Key management personnel

(1) Basis for selection

(2) Resumes

4. Importance of Project Management

F. Sections in Management Proposal

1. History of the Company

2. Project Management

3. Management Control Techniques

4. Master Plan and Scheduling

5. Production Capability

6. Subcontracting Program

7. Facilities

8. Manpower

9. Financial Capability

10. Past Performance

11. Cost Reliability

12. Logistics Support

13. Interference with Other Contractor Programs

14. Quality Record

15. Accounting Policies

16. Value Engineering Program

17. Cost Reduction Program

18. Small Business Program

19. Socio-Economic Programs

20. Plant Security

21. Plant Safety

VI. The Cost Proposal

A. The Cost Proposal is as important as the Technical and Management Proposal. The reasonableness and adequacy of the cost estimate will have a significant impact on the company's chances of winning

B. The purpose of the Cost Proposal is to present cost in such detail that the prospective customer will be thoroughly convinced that the proposed costs represent a reasonable estimate for the scope of work

C. Outline of the Cost Proposal

1. Statement of Work

2. Delivery Schedule

3. Cost/Schedule/Performance

4. Control Systems

5. Funding Summary and Schedules

6. Terms and Conditions

7. Government Property

8. Certifications & Representations

9. Work Breakdown Structure

10. Elements of Cost

11. Cost Format

12. Cost Estimating Techniques

13. Cost Breakdowns

14. Supporting Data

15. Cost Accounting Standards

16. Design-To-Cost

17. Life Cycle Costs

D. Problems with Cost Estimates

E. The importance of the Cost Proposal

1. The customer uses the Cost Proposal to cross check the Technical Proposal to determine whether or not the company has a real understanding of the problems inherent in the proposal

2. The Cost Proposal should be considered as an important and integral part of the proposal effort and care should be taken to insure that the Cost Proposal and the Technical Proposal complement each other

3. The manner of presentation and the adequacy and accuracy of the cost data presented influences the customer strongly in his evaluation of competitive proposals.

F. Below Cost Proposals

G. Effect of Cost and Pricing Data Requirements

H. Profit Proposals

1. Weighted guidelines

2. Other Government agencies use essentially the same criteria, even through they do not use the "weighted guidelines"

VII. The Final Summary

A. The Final Summary should summarize all the points developed in detail in the entire Proposal and should be used to give a precise statement of what is being proposed. The unique or outstanding features and major selling points should be carefully highlighted by being placed in an appropriate section with, if possible, an explanatory illustration

VIII. The Appendices

IX. References

X. Editing and Format

I. TECHNICAL PROPOSAL

Title Page

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PRODUCING AND SELLING ENERGY

INTRODUCTION

Under the contractual terms used by DOD in developing geothermal resources the contractor can only sell the energy produced to the procuring contract office. In the case of electricity, for example, the electrical energy can only be purchased by the office that solicated for the development. However, there is existing authority which not only allows for the transfer of this electricity to other DOD activities, but to all federal agencies.

THE ECONOMY ACT

31 USCA 686, The Economy Act, is the authority allowing for contracting for supplies or services by cross-servicing with other federal agencies. The flexibility provided by this Act is best illustrated by examining the contract for development of the COSO KGRA at China Lake, California.

The contracting office, Naval Facilities Engineering Command, Western Division, San Bruno, CA, is the contracting office for all Navy electrical energy requirements on the West Coast. Under the authority of the Economy Act, power produced at COSO under contract to the Navy can also be provided to all DOD and federal agencies on the West Coast.

The sale of this electricity would be to the Navy, with fund transfers being an interagency contract or agreement problem not involving the geothermal developer. The sole limitation on Navy's transfer of electricity to others will be the utility companies ability to wheel the power to the desired location. Banking, wheeling and other arrangements necessary to transfer of the power are currently the purview of the resource developer with the contract allowing for payment to the utilities for these services by the sale or bartering of the energy produced.

This entire arrangement, including the Economy Act, recognizes the efficiencies inherent in large purchases of services such as electricity and the economies which can be shared by all federal agencies through such contractural arrangement.

FEDERAL PROPERTY ADMINISTRATION ACT

The Federal Property Administration Act of 1949 is the statute of primary importance in federal contracting for utility services. It resulted in the establishment of the General Services Administration and fixed both the authority and duty of GSA to issue regulations dealing with contracting and property management activities of executive agencies, including but not limited to the purchase of utilities.

A statement of areas of understanding between DOD and GSA on the matter of procurement of utility services was entered into in 1950 as a result of the Federal Property Actministration Act. This statement along with providing for DOD purchasing its utility requirements separate from GSA also provides that DOD will assist GSA in procuring utility services for other agencies of the government which are located in the contract area.

This statement of understanding provides further authority for transfer of geothermal energy produced under contract for DOD to other federal agencies. The only limitation is again the ability of the utilitiy companies to transfer the energy to the desired locations.

SUMMARY

DOD possesses the necessary authority to provide power to all DOD activities and other federal agencies. This capability allows for the purchase of all electrical energy produced from a geothermal resource under contract to a DOD agency. This authority although limited by the utilities capability to transfer power to other locations should provide a load base sufficient to use all power produced.