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Innovation versus Monopoly: Geothermal Energy in the West

Final Report

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ABSTRACT

Geothermal steam and hot water are potential raw energy sources for electric generation in the West, provided that certain problems in the structure and behavior of the energy and utility industries can be overcome.

Geothermal resources can be used only for fairly small generating units (under 150 megawatts in size) but are none-the-less cost-competitive with fuels now in general use. The small size of its units makes geothermal generation attractive mainly to small utilities, e.g., largely municipal or rural cooperative systems, and a few industrial users.

Currently, large petroleum companies are the biggest holders of prime geothermal sites; site acquisition has far outpaced drilling activity on their part. Small firms engaged in geothermal field work tend to be "service companies" for larger partners, or else lease brokers. There is a potential for cooperation between small geothermal developers and small utilities -- if differences in pricing philosophy can be resolved.

"Energy" companies developing and selling geothermal resources may be expected to try to tie their price to that of their other fuel products; utilities will not be interested in geothermal generation unless it offers a cost advantage over other fuels. Cross-fuels ownership by large oil-based enterprises leads to a lack of interfuel price competition -- with geothermal prices being fitted into the lockstep as well, if these firms gain substantial control of that resource.

In much of the West, the transmission and coordination services necessary to small utilities if they are to build geothermal power plants are not easily obtained. Transmission grids and power pooling arrangements are dominated by large privately-owned utilities, which maintain a climate hostile to small utilities. Federal power projects are often dependent on private utilities for transmission, and commonly cooperate with these systems to the detriment of smaller utilities. (The Pacific Northwest is in large measure an exception to this state of

affairs.

Large utilities thus have the incentive and the means to bar smaller systems from developing independent geothermal generation. They themselves have little incentive to develop such small-scale generation, especially as regulatory practice virtually assures them recovery of the cost of other fuels. Utility fuel purchasing practices, as a result, are often inefficient.

The prospect for significant development of geothermal resources is not overly encouraging, unless government policies with respect to regulation, antitruct enforcement, leasing of geothermal lands (which now favors large buyers and the "warehousing" of tracts), and research are redirected toward such development and vigorously pursued.

PREFACE

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While one of the authors is a member of the staff of the Postal Rate Commission, it should be emphasized that the views expressed in this volume are his own and do not purport to reflect the opinions, or carry the

endorsement, of the Postal Rate Commission, any of its Members, or any other member of its staff.

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While acknowledging the valuable assistance received from many quarters, the authors of course accept responsibility for any errors that may remain.

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EXECUTIVE SUMMARY

THE PURPOSE OF THIS STUDY

This study seeks (a) to identify the potential roles of geothermal energy in electric utility system planning: (b) to determine the institutional factors (e.g., industrial organization, ownership, regulatory requirements and public resource management programs) affecting decisions as to the introduction of geothermal energy units operating as part of, or in conjunction with utility systems; (c) to determine the authority for, and history of relevant regulatory and antitrust activity on geothermal energy, and, (d) to determine whether these regulatory and antitrust actions adequately and effectively permit and foster innovation. Then we assess relevant regulatory, antitrust, and resources policy and practice to determine the efficacy of government authorities' actions in dealing with institutional and structural features so as to forward development of new energy sources and permit the introduction of new entrant firms.

Prior studies about geothermal energy have generally been concerned with overall considerations of technical and economic feasibility. This study aims at placing these subjects into the framework of industrial structure and government policy.

Much of the thrust of our national energy program has been directed toward development of new and better processes for the physical production, distribution and use of energy. This is the case for geothermal energy.

This study inquires into the role played by the ownership, structure and business practices of electric utilities and petroleum firms in determining the rate at which geothermal technology is developed and employed to produce energy.

HIGHLIGHTS OF CONCLUSIONS

Geothermal energy presents a significant potentially lower cost energy source alternative for power generation in the Western states. It might provide, at costs competitive to other fuels, some five thousand to ten thousand megawatts of capacity, or the equivalent of 6.7-13.5 percent of the new electric generating capacity planned for the Western states in the 1975-78 period. The energy that could be generated from such capacity would be the equivalent of 14.1 percent of 1975 residual fuel oil usage in the West.

We operate from the assumption that geothermal energy should be developed in a way exploiting its competitive potentials vis-a-vis other fuels, and that a diverse, competitive structure within the sector, to an extent consistent with technical efficiencies, would conduce to this end.

The present organization of the bulk power industry in parts of the West is not conducive to entry or expansion by the size of firm likely to find geothermal units most appealing.

The prominent - even dominant - position of major petroleum companies in the geothermal industry seems likely to limit or foreclose the role open to specialized geothermal concerns, and appears to be conducive to "warehousing" of geothermal prospects. Their position also seems likely to diminish inter-fuel competition.

The activities of government agencies have often tended to reinforce existing industrial organization, and not to foster diversity. There is apparently no clear, comprehensive, or consistent policy for developing competitive potentials within and between fuels sectors, and in fuel-using sectors.

Government could seek rapid development of geothermal resources by strategies which include encouraging an influx of participants likely to give impetus to the area, and a diverse and competitive structure within it.

The Geothermal Resource

The geothermal resource occurs widely in nature. However, the economically extractable portion of this resource appears to be limited (currently and over the next decade) to its dry steam and very hot water occurrences. The number of dry steam and very hot water resource occurrences. The number of dry steam and very hot water resource occurrences rapidly declines as the temperature of the occurrence rises.

Geothermal energy is converted to electric power by use of low pressure turbines drawing their geothermal fluid from a group of wells proximate to the generating unit. This in turn limits the size of geothermally driven generating units to 50 to 150 megawatts.

The domestic development of geothermal energy has to date been limited to The Geysers dry steam resource in California.

Geothermal technology is in an infant state. Important technological problems remain to be solved, or to be demonstrated as being solved, especially for briny fluids.

Environmental problems may plague some development efforts.

The location and development of a geothermal field, and the installation of a generating unit may be expected to entail a five to seven year lead-time.

Potential Use for Power Generation

In spite of environmental and technological problems, it appears that significant quantities of geothermal energy could be developed for power generation at costs below those for alternative power generation. Up to 10,000 megawatts of generating capacity using geothermal energy might be developable, in the Western states, at costs below those for comparable power sources.

We assert that substantial amounts of geothermal energy can be developed at a lower cost than for alternative power sources on the basis of comparisons of the cost of geothermal energy sold at a price defined by the costs of production and conversion to electricity, rather than by the price of alternative fuels.

Development of a substantial portion of the 10,000 megawatts of useful geothermal resources could substantially affect utility fuel use patterns as indicated by the following table showing how the resulting energy production compares with the fuel oil energy employed in the Western states in 1974.

10,000 megawatts constitutes the equivalent of 11.4 percent of the installed capacity in the Western states at the beginning of 1975 and 13.5 percent of the total new capacity planned to be installed in that

TABLE

RELATIONSHIP BETWEEN GEOTHERMAL BASELOAD CAPACITY AND EQUIVALENT CONSUMPTION OF RESIDUAL FUEL OIL

	Case 1 1000 mw of Geothermal Capacity 1/	Case 2 5000 mw of Geothermal Capacity 1/	Case 3 10,000 mw of Geothermal Capacity 1/
Annual geothermal generation at 70% capacity factor	6,132 million kwh	30,660 million kwh	61,320 million kwh
Equivalent barrels of fuel oil at 6,000,000 Btu/barrel and 10,000 Btu/kwh heat rate	10,220,000 barrels	51,100,000 barrels	102,200,000 barrels
Geothermal generation expressed as percentage of equivalent California-Mountain States fuel oil consumption (1974)	13.58%	67.89%	135.77%

1/ Case 1 is regarded as a highly conservative assumption by comparison with the supply curve; Case 2 is regarded as moderately conservative. The supply curve herein presented shows potential development of up to 10,000 mw (Case 3).

region in the period 1975-84.

This capacity could produce the equivalent of about 17.4 percent of the total electric energy output (kwh) in the Western states in 1975.

The size of geothermal units is far less than those for comparable types of generation using coal, oil or uranium.

The 5-7 year lead-times for geothermal development roughly correspond to lead-times for coal or oil fired electricity generation plants and may be a year or two shorter than lead-times for nuclear generating units.

The size of geothermally driven generating units and the managerial problems associated with their innovative development are such as to make such units attractive to some small power systems, and apparently less appealing to larger power systems.

The Field Development Sector

The would-be developer of geothermal energy must obtain a series of approvals from environmental, conservation, and local land use agencies, including, for work on the federal domain, consecutive approval of exploration and development plans. Numerous approvals must be obtained for attendant electric generation plant from environmental and regulatory agencies.

Geothermal development does not produce revenues until such time as a group of wells and facilities is installed and operated. Thus negative cash flows persist for some years longer than is often the case for on-shore oil and gas field development.

In spite of government administrative delay and technological and cash-flow problems, active interest exists among utility systems and field exploration and development companies in geothermal development.

The activities of the geothermal industry consist, primarily, of the geophysical evaluation of tracts, leasing, the further evaluation and drilling of geothermal occurrences, and production of geothermal energy.

Preliminary geophysical evaluations are undertaken by about 10-20 specialized geothermal enterprises, and by petroleum companies.

Leasing is undertaken by petroleum companies, small enterprises appearing to act as land brokers, a few specialized firms, and a few industrial firms and utilities.

Much of the geothermal leasing activity to date has occured on federal and state lands.

The United States has leased for geothermal energy development over one million acres; states about 672,000 acres. Though the amount of leasing on private lands is not known with precision, the number of acres

leased is thought to exceed federal leased acreage.

Federal and state lands, not yet leased, may contain substantial geothermal resources.

Major petroleum companies have dominated the leasing of lands containing geothermal prospects. Such companies held 47.9 percent of the federally leased acreage as of April, 1976. Other large independent petroleum companies held 12.6 percent of the federal acreage. (The pattern in state leases is similar). In a 1974-early 1975 period for which records are available, "major" and large independent petroleum companies paid 88.4 percent[1] of the "cash bonuses" for particularly valuable sales offered by the federal government. This pattern appears to have continued in subsequent federal geothermal lease sales.

In the leasing of more speculative prospects, generally without cash bonus bidding, there has been more diversity of lease ownership.

Leasing patterns are such as to sometimes encourage holders of adjoining acreage to jointly act in developing their tracts.

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[1]The major petroleum companies paid 62.9 percent of the federal geothermal bonuses.

Drilling activity has been undertaken at a quite modest rate - particularly outside of The Geysers dry steam area. In recent years, less than 50 wells per year have been drilled.

Drilling has generally either been accomplished by (a) large petroleum companies acting alone, or, occasionally, in joint enterprises with other large petroleum companies, or occasionally with small firms holding adjacent leases; or (b) joint enterprises involving a specialized geothermal firm and a utility or industrial firm.

Companies usually employ drilling contractors, although a few specialized geothermal firms have their own drilling rigs.

Distinct patterns have appeared in the geothermal field development process.

Small firms holding leases, and/or providing geophysical investigations have tended to become primarily service companies - for the larger enterprises. The larger firms provide funds for activity such as drilling and development.

Utility firms lack field development expertise, and, if they are public power systems, they lack access to income tax write-offs associated with field work. Accordingly, utility participation in field development work is likely to be carried out in joint enterprises.

Large petroleum companies have generally preferred to conduct their development activity without joint ventures.

Such companies have occasionally taken in small service companies in joint ventures.

Large companies occasionally enter into joint ventures among themselves where they have overlapping lease ownerships.

Large petroleum companies seem to avoid joint ventures with utilities.

Large petroleum company development of geothermal resources does not appear to be fully commensurate with their advantageous capital and lease holding positions.

Though large petroleum companies appear to have the most valuable tracts, their proportion of total drilling does not fully reflect this situation.

Some large companies with large leaseholdings have not initiated drilling activity.

The overall rate of drilling activity seems relatively low.

A pattern of extensive joint venturing exists in geothermal field development.

The practice of joint enterprise in the geothermal industry has

petroleum antecedents.

These enterprises result in coordination of joint drilling schedules by the party providing financing - often a large oil company.

Joint agreements can result in the large utilities and oil companies preempting the services (and tracts) of fairly unique specialized firms, for large geographic areas.

Joint enterprises tend to create mutual linkages and dependencies among joint entrepreneurs.

Income tax provisions relating to petroleum exploration, if extended to geothermal, may encourage joint ventures.

Utility incentives to engage in joint ventures include their lack of development expertise and their expectation that, otherwise, independent suppliers will seek, and tend to get, prices pegged to alternative fuel prices rather than geothermal source costs.

Sales of Electricity

The marketing of geothermal energy as electricity will occur through high voltage transmission grids.

Sales of firm power and energy require (a) access to transmission grids; (b) access to planning and operating coordinating services provided among utilities to economically obtain reserves; and (b) supplemental power

and energy.

To obtain fully compensatory rates for geothermal electric power generation, the output must be saleable as "firm" power and energy.

Access to bulk power markets and coordination is an essential precondition to economic power generation.

Access to markets and coordination can be difficult for an entrant.

Control of high voltage transmission and the inter-utility pools for planning and operating coordinating services is largely concentrated into the hands of the California Power Pool companies in California, and similarly is controlled in Utah by Utah Power and Light Company.

In the Los Angeles area, several municipal power systems, having self-generation, pool their operations.

In the Pacific Northwest, transmission and coordination is carried out by the Intercompany Pool of private utilities, the regional public power systems (e.g., Washington Public Power System) and the Bonneville Power Administration.

In the Southwest, New Mexico utility systems pool <u>inter se</u> while they and Arizona utilities are increasingly coordinating with others such as the Nevada Power Company.

In California and in Utah, states with prime geothermal occurrences, the dominant power systems have employed their market power so as to exclude or impair the ability of small utility systems and industrial firms to enter upon a course of self-generation, according to the U.S. Department of Justice and a number of state and local governmental authorities. Activities have included restrictive tariff provisions, refusals to coordinate, and restrictive coordination provisions and preemption of power sources.

The Bureau of Reclamation has power generation resources and some transmission lines which, if employed together with authorities of the Interior Department in issuing transmission line rights-of-way, could provide alternate avenues for small systems seeking coordinating services and high voltage transmission.

The restrictive activities of the major private utilities in California and other Western states have limited the utilization and extension of public facilities which could otherwise provide power marketing alternatives.

Limits on access to bulk power arrangements in several major Western markets constitute a substantial barrier to development of geothermal electric generation by diverse firms, and would seem to inhibit the

overall development of the resource.

Utility Fuel Market

Utilities in the West constitute a growing market for fuels.

Western utilities consume large quantities of residual fuel oil, natural gas, and coal, while nuclear capacity is increasing.

The utility fuel market on the West Coast has become increasingly dependent upon residual fuel oil as utility fuel demands have risen, natural gas has become less available and nuclear development has been slower than was once anticipated.

Substantial increases in the use of coal, principally at mine-mouth plants in the Rocky Mountain and Southwestern states, are forecast.

The Western utilities generally acquire their coal, oil and uranium under large volume long-term contracts.

Residual fuel oil is purchased from a small number of oil companies - principally majors.

Coal is acquired from a few large firms or from utility affiliated fuel companies.

The use of large new mines to supply long-term large quantity utility coal contracts creates capital and resource limitations upon entry into the utility coal fuel supply business.

Utility affiliated firms are increasingly coming to participate in the coal and uranium industries.

Utility fuel affiliates have disincentives, stemming from utility rate-making and regulatory practices, to provide price competition.

Terms of fuel purchase agreements appear to greatly favor vendors.

Prices of fuel to Western utilities have risen sharply in recent years.

Production of western coal has been environmentally constrained.

Cross Ownership of Fuels

Cross ownership of fuel resources could result in slower paced fuel source development, including geothermal, and higher prices than might occur under more competitive conditions of industrial organization.

Concern about cross-ownership of fuels focuses on larger petroleum company holdings.

The large petroleum companies are, by far, the largest and wealthiest firms in the fuels sectors.

The petroleum industry is characterized by patterns of resource ownership and operation which tend to limit competition.

There is a pattern of concentrated ownership of refinery capacity,

crude oil pipelines, and key sources of additional crude oil -- such as the Alaskan North Slope, large Outer Continental Shelf resources, offshore moving facilities, and foreign crude oil and refinery sources.

The larger petroleum companies are extensively linked among themselves. These linkages involve, inter alia, joint ventures in exploration and production, unitization agreements, joint pipeline arrangements, and exchange agreements.

This pattern of concentrated ownership and extensive inter-oil-company linkages is evident in West Coast petroleum supply.

As of 1975, four major firms owned 54.1% of West Coast refinery capacity, and eight firms owned 76.5% of such capacity.

Alternative refinery capacity, elsewhere, for producing residual fuel oil is largely owned by the same firms.

The major petroleum companies control large potential oil sources: key offshore tracts, the Alaskan North Slope, and through "equity" rights and preferential access agreements, the major foreign oil sources. These firms also control a substantial portion of the on-shore California production; they individually and jointly own the California intra-state private carrier pipeline grid, the pipelines in Alaska, and the offshore moving facilities whose use is essential for economically moving crude oil.

The major petroleum companies on the West Coast, as the other majors, are extensively linked financially by indirect board-of-directors interlocks through financial institutions, and by common security holders and bankers.

Six major petroleum companies dominate the supply of fuel oil to West Coast electric utilities.

The large petroleum companies supplying residual fuel oil to West Coast utilities are not likely to be seriously challenged in that market.

Residual fuel oil purchases by West Coast utilities are principally accomplished by use of large quantity long-term supply contracts, containing price terms that are very favorable to the large petroleum companies selling the oil.

The large petroleum companies have extensive resource holdings in the alternative raw fuels for future utility-power generation: coal, gas, uranium, and geothermal.

Large petroleum companies have a major position in coal production.

Large petroleum companies hold 18% of the federal coal leases. They constitute nine of the twenty largest coal lessors. In production,

larger oil companies constitute seven of the fifteen largest producers (with 22% of production in 1973). Twenty-four oil companies control 44% of leased coal reserves; only eight of these companies produce coal.

Major oil companies own some of the very best coal leases -- e.g., in the Eastern Powder River Basin. These leases and others they hold have not been produced.

Increasing capaital requirements for increasingly large electric generation - dedicated fuel supply complexes are raising entry barriers in coal mining.

Eighteen large petroleum companies produced over 72% of U.S. natural gas production. Seven large petroleum companies hold 56% of the production capacity in the Gulf of Mexico, our major source of new gas; and Arctic gas is produced by majors.

Large petroleum companies, considered as a group, are the single largest factor in the highly concentrated nuclear fuel business.

Large petroleum companies control 62% of uranium mill production, constitute six of the seven firms holding 70% of uranium reserves (1971), and own six of 16 uranium production plants (in 1976).

In the uranium industry, as in coal, sales generally are made under long-term, large quantity contracts. Supplying these contracts

necessitates amassing large aggregates of capital and resources.

Segments of the nuclear industry such as mining (4 firms doing 55.3%, and eight firms 80.8%, of production); and milling capacity (4 firms 58% and 8 firms 87.7%), are concentrated.

As noted before, large petroleum companies have a dominant position in the emerging geothermal energy sector.

The pattern of petroleum company acquisitions of alternative fuel supplies has not ended -- there have been recent major acquisitions such as ARCO's acquisition of Anaconda (which is in uranium mining and milling), and Standard Oil of California's acquisition of AMAX (which is a significant factor in coal mining).

Large petroleum company domination of geothermal energy could retard the rate of geothermal development.

The large petroleum companies which are common owners of various types of fuel can be expected to develop energy resources in a manner maximizing their overall returns on investment, rather than exploiting the competitive potential of each fuel as opposed to other fuels.

The large petroleum companies participating in the geothermal sector may import the pattern of petroleum company trading relationships into this sector.

Large petroleum companies appear to be preempting many of the prime geothermal sites, and services of specialized firms.

The trend of geothermal development thus far suggests a tendency toward a relatively concentrated structure, heavily influenced by firms with primary interests in another fuel sector, rather than a diversity of relatively strong firms highly competitive as between themselves and as to other types of energy sources.

Large petroleum companies appear to be preempting many of the prime preferential sites, and services of specialized firms.

Government

Though government agencies have authority to substantially affect energy sectors, their initiatives regarding industry structure and operation in the energy sectors, have been limited so as to affect industry structure or basic modes of operation. If a diversified, competitive industry structure is desired in geothermal energy, informed and vigorous pro-competitive government intervention appears to be required.

Government agencies are involved in the leasing of geothermal resources, field conservation control, pollution control, economic regulation under the antitrust laws, utility regulation, regulation under the securities laws, and power marketing and research support.

Federal antitrust laws are principally enforced by the Department of Justice and the Federal Trade Commission. Additionally, the Nuclear Regulatory Agency has antitrust jurisdiction, and the FPC is obligated to consider antitrust aspects of matters coming before it in electric utility cases.

Federal antitrust law and policy includes doctrines and precedents related to vertical and horizontal integration in industrial organization, as well as to anticompetitive conduct.

The mergers and extensive linkages among petroleum companies referred to previously raise major antitrust questions.

The power pooling arrangements among larger Western utilities, excluding other power systems raise major antitrust questions.

Application of antitrust principles to the petroleum and electric utility industries presents difficult questions regarding choice of law when the jurisdictions of various countries overlap, and when domestic antitrust and regulatory jurisdictions overlap.

The level of effort of antitrust agencies in petroleum matters is subject to criticism -- as regards failures to act on major features of industry organization and practice, and as regards acquiring and maintaining a capability to perceive and deal adequately with such major aspects of

the energy industries. It must be recognized that government policy has often favored noncompetitive arrangements in petroleum, and inhibited antitrust agency initiative.

In bulk power supply matters, the Justice Department was largely inactive until the 1960's, but has since played a leading role in court and agency proceedings.

The applicability of antitrust law and policy to regulatory industries has come increasingly to be recognized.

Proceedings before the Nuclear Regulatory Commission have played a major role in antitrust efforts regarding bulk power supply in recent years. It is too soon to definitely determine the efficacy of these proceedings.

Utility regulation in the West is undertaken by the Federal Power Commission and by state agencies.

The FPC has resisted giving consideration to antitrust problems, and has not sought to act in ways furthering access by others to critical inter-utility coordination arrangements. Such arrangements are a central factor in bulk power supply markets.

The FPC has not sought actively to inquire into the anticompetitive dimensions of arrangements among utilities, and has allowed proceedings involving antitrust questions to languish for years.

The FPC does not generally have jurisdiction to require wheeling or load growth planning coordination.

State utility commissions regulate the retail rates for electricity. Also, some states have authority to certificate or license utility power generating and transmission facilities.

Many State Commissions are sparsely manned.

Retail rates (among other factors) may be such as to discourage partial self-generation by utility customers.

In the past, State regulation has at times sought to restrict entry into bulk power supply.

State conservation commissions have jurisdiction regarding the unitization of petroleum (and sometimes geothermal) production, and they regulate well drilling.

State conservation regulation appears to be fairly prompt regarding well drilling.

State control over production is susceptible to being used to pro-ration supply so as to maintain energy prices -- as has occurred in the petroleum industry.

The Securities and Exchange Commission, and State "Blue Sky" Commissions have jurisdiction regarding the public sale of securities.

SEC jurisdiction in this area is limited to mandating disclosure. State agency jurisdiction sometimes encompasses issues regarding the "suitability" of securities for public offering.

Disclosure requirements, while providing information to investors, tend to weigh more heavily on small firms than upon larger firms. This is especially the case if larger firms have multiple lines of business which are not separately reported in their financial statements.

Recent legislation seeks to require development of better accounting practices in the production sector of the petroleum industry.

The financial reporting practices for utilities generally are based on the FPC's uniform system of accounts.

This system consists of financial, not cost accounting, categories. No system of accounts has been promulgated for fuel company affiliates of utilities.

The Interior Department is engaged in the leasing of federal resources, and relatedly, supervision of federal leases.

The program for federal geothermal leasing was slow to start, and has apparently concentrated on the issuance of leases upon competitive cash bonus bids.

Applications for non-competitive leases have not been acted on rapidly.

Applications for leases involving lands within Forest Service (U.S. Department of Agriculture) jurisdiction have languished.

Lead-times for approvals needed from government for exploratory work have lengthened.

The requirements of geothermal leases do not effectively require diligent development by lessees.

The Department of the Interior's leasing program does not appear to seek diversification of ownership of geothermal leases by firms seeking to develop leases.

Reliance on bonus bids to choose lessees favors large companies with substantial liquid capital.

Failure to mandate diligent development, and lack of action in the face of widespread undeveloped lease holdings of geothermal and other fuel resources encourages "speculative" warehousing of leases.

The Interior Department has jurisdiction over federal power marketing in the Pacific Northwest and has had a major influence on bulk power markets there. In other Western areas, federal power generation and marketing has been limited by Bureau arrangements with large private utilities.

Originally, dependence of the federal power marketing agencies upon private utilities for transmission, coordination and supplemental power was imposed by efforts of those utilities.

Subsequently, the federal power marketing agencies of the Bureau of Reclamation have sought to accommodate and even preferentially favor large private systems as opposed to smaller systems.

Electric transmission lines crossing federal lands in the West require right-of-way permits from the Interior Department (or from the Forest Service). However, this licensing authority has been little used to open up bulk power markets to new entrants or other forms of competition.

Smaller and entrant systems have not been able to look to federal power marketing activity of the Bureau of Reclamation (Interior Department) to provide them access to coordination for areas outside the Pacific Northwest.

The federal power marketing activities of the Bureau of Reclamation have not been carried out in a manner consistent with fostering diversity in bulk power supply, or providing opportunities for entry by new generating entities.

Government energy research and development subsidization is carried out, principally, by the Energy Research and Development Administration.

Government sponsored research constitutes a very significant portion of energy research work.

The allocation of its benefits may affect the emerging structure of the geothermal industry.

Government research could help foster a broad base of geothermal development firms by devices not now extensively or systematically used: purchasing field data and analyses from firms engaged in exploration and evaluation, creating a public data base on geothermal prospects; orienting research toward areas not yet leased; building federal generation and other devices. This sort of approach could lessen dependence of smaller firms on large private sources of capital and information.

The geothermal loan guarantee program, administered by ERDA, appears to be necessarily structured toward the development and not the exploratory phase of geothermal work.

The geothermal loan guarantee program, as presently constituted, effectively prevents public power systems from obtaining guarantees for their sales of debt.

Government research and other subsidization programs employ informal non-public decisional procedures for formulating major programs and for allocating their benefits.

There is concern over the accessibility of the benefits of research and subsidization programs to entrant firms and to public power systems.

Recognition of the importance of such government programs is leading to a tendency for legally mandating more formal deliberations in government subsidization programs.

SYNOPSIS OF RECOMMENDATIONS

Our recommendations suggest improvements in, respectively, the purchase markets and supply markets confronting a geothermal developer. Their aim is to improve prospects for diversified, competitive development of (a) geothermal supply markets, and (b) the bulk electric power markets into which geothermal energy might flow.

As regards bulk electric power markets we recommend that:

(1) The Department of Justice's antitrust efforts should be encouraged. The Department's efforts should be directed against barriers to access to power pool coordination and against provisions in coordination arrangements tending to curtail competition among power systems.

(2) Application of the doctrine of primary jurisdiction

(referring issues raised in court cases to administrative agencies for initial decision) should be limited.

(3) Actions should be taken to create a regulatory climate at the Federal Power Commission that will proffer even-handed treatment to large and small electric power systems, and which will undertake to give serious, technically competent consideration to anticompetitive aspects in power pool coordination, including wheeling services and tariff provisions.

While we lack an overall institutional remedy to suggest for the FPC, we would suggest ameliorative measures in the way of (a) increased use of discovery processes; (b) elimination of the practice of separating antitrust issues from rate cases which now result in such issues being consigned to interminable collateral proceedings; (c) upgrading the technical competence of FPC staff personnel; and (d) fuller use of the FPC's authority to suspend the collection of rate increases for five months pending rate proceedings.

The FPC's lack of jurisdiction to mandate that planning coordination or wheeling services be proffered among power systems limits its ability to afford complete antitrust remedies. However, if such authority were to be legislated without changes being made in the doctrines of primary and exclusive jurisdiction, the net result might be to oust the courts, and possibly to restrict the Nuclear Regulatory Commission from exercising their antitrust jurisdiction over bulk power supply. In light of the FPC's history of not affording pro-competitive relief in matters within its jurisdiction, extension of FPC jurisdiction cannot now be recommended.

Legislation should be enacted authorizing the FPC to issue interim rate orders restricting the collection of rates pending their full review of treatment to large and small electric systems.

(4) Rate-making agencies should seek to encourage cost-conscious utility fuel purchasing and seek to orient utility fuel development toward providing cost competitive energy. To

this end, use of fuel adjustment clauses should be restricted, and a system of accounts for utility fuel affiliates should be promulgated.

(5) Federal power marketing practices should be overhauled to encourage entry into bulk power supply. To that end, Federal power marketing should be placed in independent Federal corporations authorized to construct transmission facilities.

Stipulations on Federal permits for power line rights-of-way should be strengthened to require that permittees coordinate with others.

Planning and right-of-way permitting procedures should be made more public and responsive to the need to permit access to transmission to diverse power systems.

Federal power marketing contracts and right-of-way permits should be reviewed with regard to their consistency with antitrust law and the representations given when they were entered into.

As regards the fuel sectors, we recommend that:

(1) The United States (and State governments) vigorously pursue leasing policies intended to (a) diversify resource ownership, and (b) require diligent exploitation of leased resources.

This action would include the use of new forms of lease bidding, such as net royalty, or other non-cash bonus bid approaches, separate leasing for exploratory and development, and increased federal testing of public lands with disclosure of test results.

The United States should pursue a program to purchase geothermal field data and should construct its own yardstick, geothermal generating stations.

The United States should intensify antitrust measures to encourage and maintain diverse ownership in field sectors in addition to other measures hereinafter referred to.

Increased sophistication is needed in government antitrust measures in the fuels industries.

(2) Federal loan guarantees should be available to public power systems.

(3) Research procurement should be sought to be carried out in ways accessible to both large and small firms.

(4) Divestiture of cross-fuel ownership, or alternatively, restriction of cross-fuel ownership -- if such restriction be on a basis that can reasonably be expected to limit cross-fuel holdings so as to avoid substantial foreclosure of others, or diminution of inter-fuel competition. Furthermore, the restrictive approach should only be chosen if it can be expected to be effectively implemented in light of the prior lack of government action in petroleum matters.

CHAPTER 1

INTRODUCTION

This is a book about the energy industry in the American West, but it is not a simple survey of that industry. Instead, it has a special focus: the relationship between the Western energy industry and an emerging (or potentially emerging) energy source. Geothermal energy, it appears, could have a significant place in the Western energy industry. To understand the nature and scope of its potential role, we have studied the structure of the electrical raw fuels sectors of that industry as they are today. This book details what we have found about the way the Western energy industry functions today, in the infancy of geothermal development, as well as about the way further exploitation of geothermal resources is governed by the roles and relationships of raw fuel companies, electric utilities and the government in the West.

Geothermal energy provides a particularly striking example of how industry structure affects the development of a new energy source. Because geothermal development draws upon, and potentially affects, both the petroleum and the electric power industries, it is heavily influenced by the structure of both those industries and the relationships between them.

Geothermal energy is derived from steam and hot water found within the earth.[1] The product of a series of wells in a geothermal field is brought together to provide energy to drive electric generators. While some is used for heating, the bulk of geothermal energy must be utilized in generating electricity. Geothermal resources occur in only a limited number of sites, and the steam or hot water produced from them cannot be transported for long distances--except in the form of electricity. Thus the primary geothermal energy must be converted to electric power and carried to consuming markets over high voltage transmission lines. Access to these transmission grids is thus a necessity for any entity hoping to develop geothermal resources.

The development of geothermal resources entails the expenditure of considerable time and effort. A reserve of adequate size and quality must be found and sufficient wells drilled to support an electric generating unit before product revenues can be realized. Environmental protection requirements must be met. Frequently land tracts must be leased from the federal government. These matters add time and expense. The resulting cash flow lag is a significant barrier to entry.

The overall capability of geothermal resources to support cost-competitive generation is quite limited, as compared to coal or uranium. Still, geothermal generation could be developed in sufficient quantity to displace substantial absolute volumes of other fuels in specific areas. (Over 15 years, with vigorous development, about as much capacity might be developed as is used by the largest single electric utility in California today).

Since efficient geothermal energy units will be smaller than those required for coal or nuclear projects, availability of these small units promises special benefit to the smaller utility systems. Smaller systems - frequently owned by governmental units or cooperatives - frequently require additional capacity, and seek to control it independently. Unless they use a newer technology such as geothermal energy to build their own units, they must obtain new base-load power from coal or nuclear units. New nuclear or coal capacity for small systems will require joint enterprises or arrangements with large privately owned utilities, who compete - sometimes acrimoniously - with these small systems.

Actual plans for geothermal generation appear to run far behind the potential for development of such generation on a basis cost competitive with other types of generation in such applications. Instead, the infant geothermal industry's activity is primarily directed at locating and leasing tracts of land which appear to have promising resources. Exploratory drilling has occurred in a limited number of cases. Electricity production occurs, in the United States, only in the Geysers area of California.

Firms involved in this industry range from small enterprises acquiring tracts and selling technological services such as geophysical testing, to medium-sized and large industrial firms which often have extensive holdings in other fuels. Certain utilities also participate in various aspects of the industry. Smaller firms wishing to participate in exploratory activity typically enter into joint enterprises with these utilities and industrial firms to obtain financing. Otherwise, these small firms are generally limited to speculation in land.

This situation leaves the development pace to the utilities and petroleum firms. The petroleum firms seek a price for their geothermal product tied to the price of crude oil. The utilities do not wish to embark upon a course of innovative power generation absent some fuel cost benefits -- and so they seek a lower purchase price not tied to oil prices. Furthermore, larger utilities, confronted with the problems of allocating their limited financial and professional resources to meet rising demand on huge systems, seem to be inclined to focus on units of 500 to 1,000 megawatts rather than on development of a geothermal resource with 50 to 150 mw units.

Our study of the geothermal industry has been carried out along the lines of an orthodox antitrust inquiry.

We first obtained an understanding of the steps involved in developing geothermal resources and the magnitude of the resource involved. Then we identified the participant firms and government agencies and their roles. With this background, we identified relevant sales and supply markets. We examined these markets to see if conditions in them were competitive and development was progressing and what the factors were that make for more or for less competition and development. Where we found factors retarding competition and development we sought to identify their causes and inquired about the availability of remedies.

CHAPTER 1

Notes:

1 In the future, molten rock may take its place as a geothermal energy source.

CHAPTER TWO

GEOTHERMAL ENERGY AND ITS USE

Geothermal energy is derived from the internal heat of the earth. This energy is usable at those points where it occurs in concentration in an extractable form (such as hot water or steam) within sufficient proximity to the surface.[1] Unfortunately, it cannot be transported in the form of heat over distances to market; rather it must be converted to electricity and shipped by wire if it is to be distributed for use.[2]

Geothermal resources vary in their temperature and other physical characteristics such as steam purity. The hotter a stream of geothermal fluid is, the lower its content of brines and substances other than water, the easier it is to use for power generation.

As Figure 1 shows, useful geothermal fluids (hydrothermal convection systems) become sources as their quality improves.

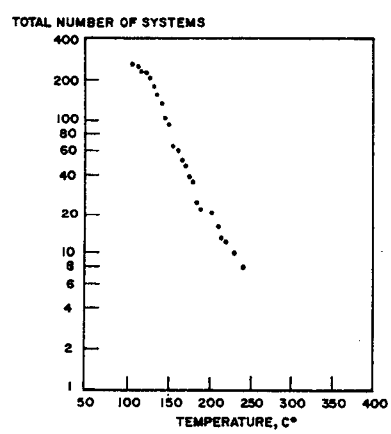


FIG I. TEMPERATURE DISTRIBUTION OF GEOTHERMAL SPRING SYSTEMS

Only a few geothermal systems have sufficient quality to permit ready development with current technology. Access to these resources is essential for utility generation. This is particularly the case for enterprises requiring low risks, such as small firms with strained capital budgets. The developers of these resources will likely have financial and technical advantages over later entrants.

At present only those geothermal resources that have fluid temperatures hot enough to make them vapor dominated can be economically exploited. Use of liquid-dominated systems is expected to become economic as technology develops, while some students believe that domes containing pressurized fluids which in turn contain gas (geopressured systems) could some day be usefully exploited.

The general magnitude of the vapor dominated resource is equivalent in heat energy to about 17 billion barrels of oil.

Geothermal resources are located in the western states, particularly in Idaho, Nevada, Oregon and California. California is the predominant location for very hot water systems (temperature over 150°C.). Large lower temperature resources occur in Idaho and Oregon. The large resource found in Wyoming at Yellowstone National Park is not available for commercial extraction.

Building on data from the U.S. Geological Survey, Dr. LaMori developed the following table estimating the total number of hydrothermal convection systems in the United States if the distribution of such resources follows that reported to date:

TABLE 1

HYDROTHERMAL CONVECTION SYSTEMS

	USGS	IF 2/3 DISCOVERED	IF 1/2 DISCOVERED	IF 20% DISCOVERED
ELECTRIC UTILIZATION				
T 210°C	14	18	36	90
T 150°C-210°C	52	82	164	410
NON-ELECTRIC UTILIZATION				
T100°C-150°C	196	325	650	1625
T50°C-100°C	-	1400	2800	7000
Number at 15°C	-	5000	10,000	25,000

As regards the size of the geothermal resource, LaMori states as his conclusions:

1) There is not likely to exist thousands of systems capable of electric production using presently available technology, i.e., greater than 150°C.

2) It looks like only a few hundred systems exist.

3) A conservative estimate of about 100 systems cannot be ruled out.

The Potential Contribution of Geothermal Energy

To determine whether the large accumulations of geothermal energy in the Western States are an economically extractable energy reserve requires looking at the cost of harnessing this energy relative to the costs of other types of electric power generation. We can confidently estimate costs for employing geothermally-driven power generation only with respect to vapor dominated and very hot water systems. Figure 2 presents such an estimate for the costs of generation erected at one point in time. The supply curve reflects the variation in quality among geothermal sites by showing increasing costs as increasingly poorer sites are employed; the total volume of good quality sites is reflected in the total amount of generation, shown as megawatts of installed capacity, on the curve's horizontal axis.

The supply curve is derived from work done for the Energy Research and Development Administration (ERDA) at the Battelle Memorial Laboratory in Richland, Washington. This work, while disputed in part by some observers is projecting geothermal costs which are too low, is quite detailed. We have sought to make a very conservative correction for underestimates of cost--an endemic problem with new technologies--by adding additional cost curves showing costs fifty percent higher than those estimated.

This curve, assumes higher costs not offset by increased tax deductions or tax benefits. When we compare this curve's costs for geothermal energy with the costs of nuclear generation or coal-fired generation, or fuel oil generation, it appears that a substantial amount of geothermal generation could be developed at less cost than competing energy sources.

The costs shown in Figure 2 are as of December 1974 and should be increased by 20 percent to account for inflation through December 1976.

Costs shown reflect the following items:

1) Use of the sum-of-the years digits depreciation over thirty years for power plants and use of depreciation periods for classes of wells. These vary with well type and typically are ten years. Firms have adopted a practice of using ten to thirty years for their cost estimates.

2) Provision for well replacement.[3]

3) Well capacity at 20% above the design capacity required to run the turbines.

4) Fixed charge rates of 17% for plant costs; and rates of return of approximately 20% for field investment, based on a 15% return on equity and

an 8% average cost of debt applied to a capital structure that is 42% debt (as per 20 large oil companies).[4]

5) Well spacing estimated at 20 acres.

Investment tax credits are not reflected.[4] These are estimated at 2 to 3% of costs for a 10% credit. No contingency fund is included. The curves treat all units of capacity as being simultaneously installed.

In actual fact, tax costs may be reduced by changes in the Internal Revenue Code and by employing forms of business enterprise discussed hereinafter. The returns on investment required to bring forth capital will vary with the types of enterprises engaged in geothermal development and their alternative investment opportunities.

The time required for development of a series of wells in a geothermal field and a generating facility appears to be on the order of five to seven years. This span is comparable to those for competing fuels: It is about equal to the lead-time for coal-fluid generation, and is several years less than the lead time for a nuclear unit. The risks of inflation may be expected to weigh more heavily on more capital intensive nuclear and coal projects, while the earlier stage of geothermal technology may cause greater risks (and opportunities for cost cutting) to be attributed to that form of energy.

As indicated, a considerable amount of geothermal capacity (over 12,000 mw) would be developed at bus bar cost below that for fuel alone (not counting any special charges for oil-burning equipment). This generation could be developed at dry steam and hot water sources of high temperature and lower salinity.

The uppermost curve reflects costs of geothermal development increased by 50 percent to account for inflation and cost overruns. At current prices for residual fuel oil in the West Coast ($15+/barrel), the total cost of geothermal generation from many "dry steam" prospects could be recovered at less than the energy cost for oil.

The costs shown are those estimated as the actual costs of producing power from geothermal resources. They should not be confused with the price that would have to be charged at the generating plant outlet if geothermal energy were sold to utilities at prices based on the cost of alternative fuels -- that is, based on something other than actual cost. Under that pricing mechanism, higher bus bar costs would result and few geothermal units, in all likelihood, would be built.

This comparison indicates that 5000 to 15,000 megawatts might be obtained from geothermal sources at a cost below that expected for nuclear or fossil -fueled base-load generating units.[5]

For the future, costs for nuclear units are expected to rise to around $1200 per kw (33+mills per kwh). Nuclear-unit bus bar costs will exceed

40 mills. Nuclear fuel availability is a matter of concern, as are fuel costs which are rising rapidly.[6]

The delivered costs of electric energy include transmission expenses, in addition to the plant bus bar cost. At high load factors, transmission costs may be expected to be between $5 and $10 per kilowatt per year (or 0.5 to 1 mill per kwh) for distances of a few hundred miles, using publicly owned transmission systems, and about 20 percent more on private transmission grids.

The addition of one or two mills to the plant outlet cost to cover transmission and line losses would permit base-load geothermal energy to be transmitted 400-800+ miles at Bonneville Power Administration transmission rates, and 320-600+ miles at rates 20% higher.

It can be seen that with the use of such wheeling rates over intrastate distances in California, the cost of geothermal power from dry steam or hot low salinity sources is very competitive with coal or nuclear power, for those interested in units of 50-100 mw.

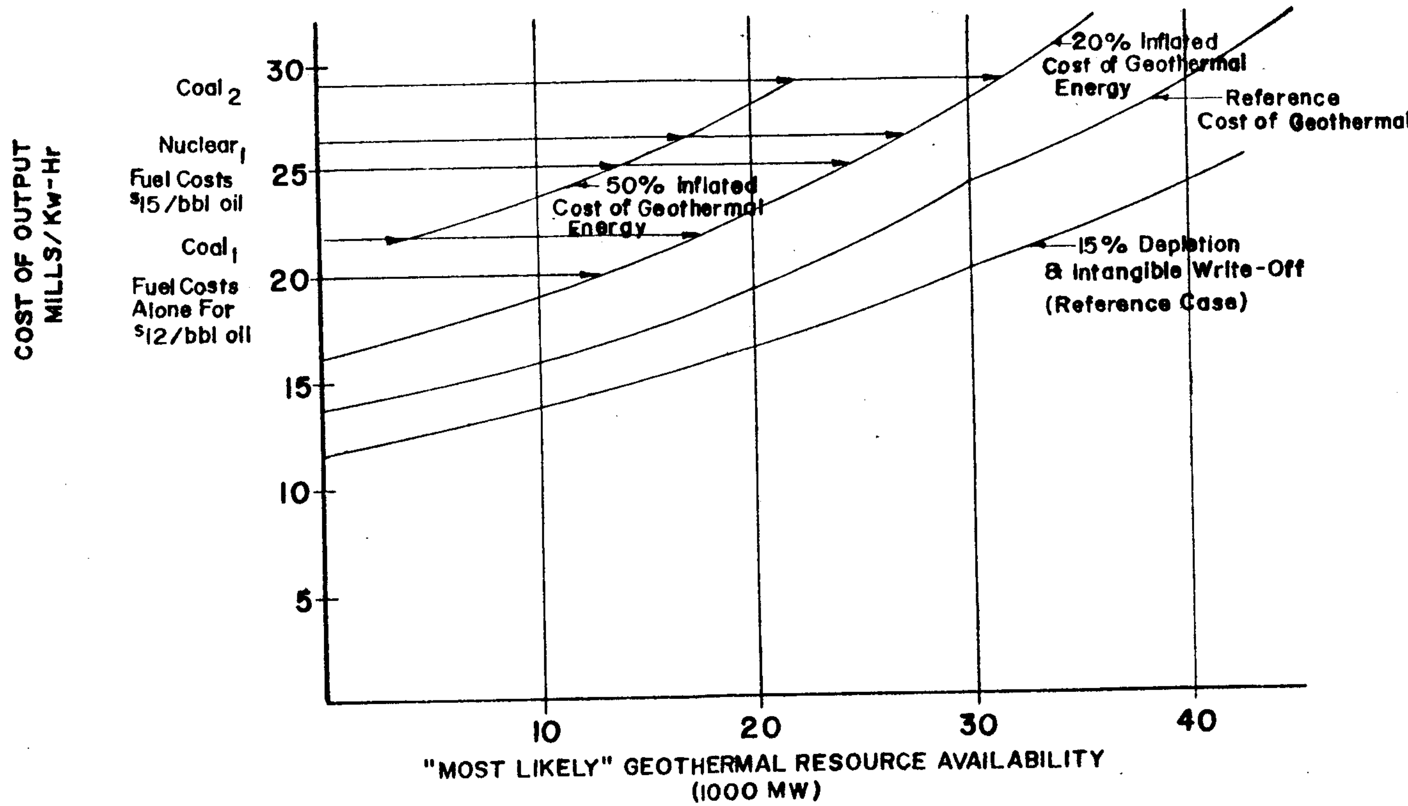
Accordingly, the market for geothermal energy in California appears to be California utilities. In the other regions of the West, such as Utah, local systems would be principal users of locally-generated geothermal energy.

Geothermal generating units must be located proximately either to load centers or to high voltage lines. Because even large geothermal fields may be expected to be developed and produced gradually, it is unlikely that very high voltage lines will be built for substantial distances to serve such development. The line capacity cost is too great. This factor constitutes a limitation of geothermal energy development.

Geothermal generation, provided at cost (including a reasonable return), would encounter cost competition from oil, coal and nuclear-fueled generation at the points indicated in Figure 2 as intercepts of the geothermal cost-curves and the costs shown respectively for generation of electricity from other energy sources. Thus, if geothermal generation has a cost of 20 to 50 percent over the December 1974 reference cost, between approximately 14,000 and 17,000 Mw of a geothermal capacity could be developed at a cost less than that for nuclear units. This is the equivalent of about twelve to fourteen nuclear generating units.

It should of course be noted that the geothermal costs shown are estimates for one point in time. They do not reflect "learning curves" or temporary cost shifts. The costs of coal and nuclear generation are not represented as supply curves, but rather are single point estimates of bus bar costs. It is unclear what the supply curve for nuclear power is, in light of cost of money and fueling uncertainties.[7] The supply curve for coal in the range dealt with here could be expected to be rather flat in the West

FIG. 2 GEOTHERMAL SUPPLY



Further Explanatory Notes Regarding Figure 2

1. $Coal_1$

The busbar price (22.5 mills) of coal-fired generation with capital costs of coal-fired generation of 15.2 mills/kwh ($600 per kw), operating and maintenance costs of 3.3 mills and fuel costs of 4 mills. No provision is made for transmission. Thus, this cost is comparable to busbar costs of geothermal generation at sites distant from load centers.

2. $Coal_2$

The busbar price of coal-fired generation having capital costs of 15.2 mills, operation and maintenance costs of 3.3 mills, fuel costs of 4 mills, and transmission related costs of 7.5 mills - 29.5 mills total. This roughly represents the competitive price of coal from east of California.

3. $Nuclear_1$

The 27.3 mill busbar price represents a current unit cost of $650 per kilowatt (68% load factor), operating and maintenance costs of 3.3 mills, and fuel costs of 5.8 mills.

4. Residual Fuel Oil

Fuel oil costs for $15 and $12 per barrel residual fuel oil are included (at 10,000 Btu per kwh heat rates) to show the cost at which geothermal could be supplied as energy sans capacity. Actual oil use costs should be raised several mills to reflect operating charges. This would show $12 per barrel oil at about the cost of coal.

with its high strip-mineable resources. Several factors indicate that coal and nuclear costs picked for comparison are likely to be higher relative to the estimated geothermal costs. Coal costs at 25 to 31 mills and nuclear plant costs of 35 mills per kwh permit the costs of high temperature low salinity geothermal resources to escalate by 50% and still be attractive on a per megawatt basis for locations near load centers. While coal is clearly the price competitive fuel at present, a break in cartel pricing could make residual fuel oil very attractive. Oil-fired capacity only costs 13-14 mills.[8]

One thousand megawatts of installed geothermal capacity operating at a 70 percent capacity factor could produce as much energy as 10.22 million barrels of residual fuel oil per year (6132 million kwh). In 1974, West Coast utilities received 68,032,000 barrels of residual fuel oil, while Mountain state utilities received 7,239,800 barrels.[9] Thus, California and Mountain State oil consumption is 7-8 times the expectable equivalent "fuel" output from 1000 mw of geothermal services.

Table 3 shows relationships between installed geothermal baseload capacity and equivalent residual fuel oil consumption for three cases (1000,5000, and 10,000 mw of baseload capacity); all three cases are possible under our supply curve.

Geothermal Power Project Costs

Two different cycles may be used for geothermal power generation, depending on the heat energy per unit of volume in the geothermal fluid. Figure 3 illustrates schematically the cycle in which the fluid (or a portion segregated from the rest of the fluid) is a steam having sufficient heat energy and volume to drive a turbine directly. Where the geothermal fluid has less heat energy per unit of fluid, it must be used to vaporize a second ("binary") fluid, having a lower boiling point. The vaporized binary fluid then drives the turbine. Figure 4 describes this binary process. Geothermal units are necessarily planned to run on a continuous basis because any cycling of operations requires a substantial amount of start-up time due to problems associated with cooling of wells. They are what are known as base-load units; their output is not varied to follow short term demand changes.

To the extent that alternate base-load power sources are not available when load growth projections indicate they are needed, geothermal units could have a special attractiveness--if sufficient geothermal capacity could be licensed and developed quickly enough and if prerequisite interconnection and coordination agreements can be entered into.

Timing is a crucial element in the costs of geothermal development as it is to other capital intensive energy projects. The possibility of

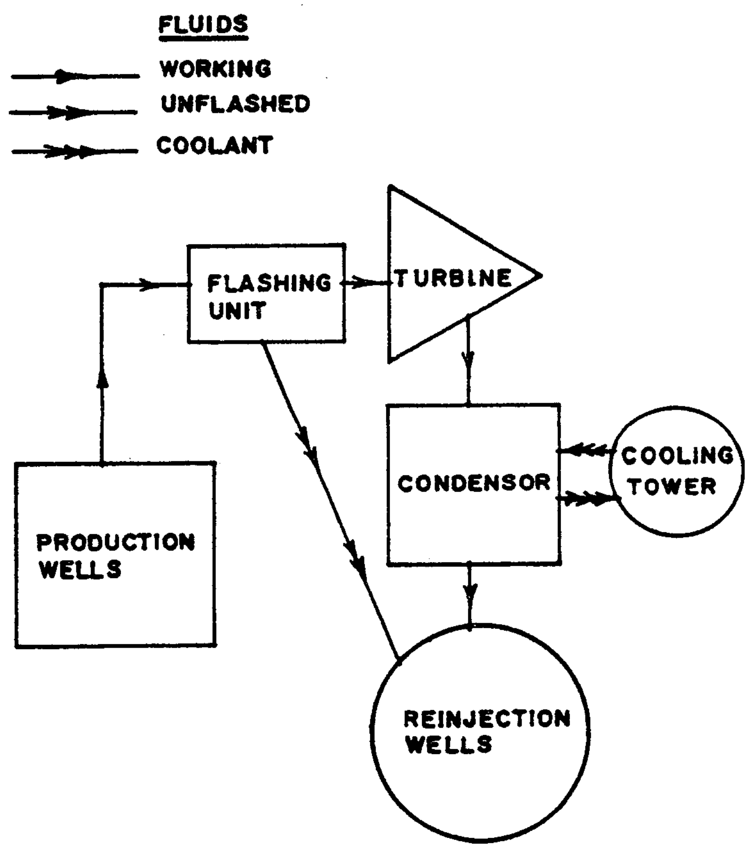


FIG 3. FLASHED STEAM UNIT SCHEME

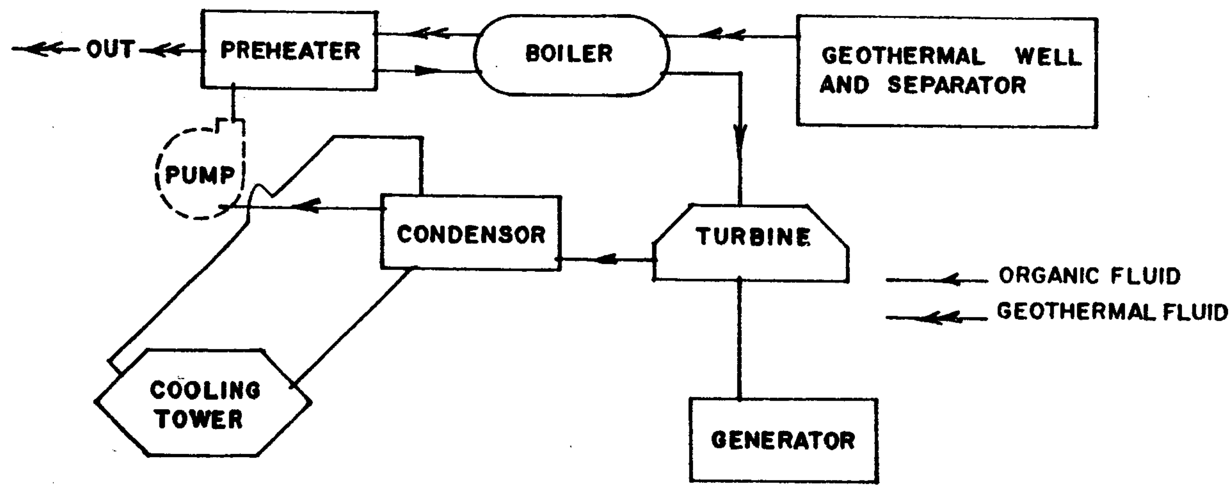


FIG 4. BINARY CYCLE FOR GEOTHERMAL EXPLOITATION

delay of geothermal development lowers the attraction of geothermal energy for smaller utility systems who cannot readily absorb slippage of scheduled new units. In addition, the devastating results of poor timing in a development program are only worsened when losses and interest charges cannot be shared with the tax collector—as is the case for public power systems.[10]

If a geothermal field developed for a 55 mw unit and containing 12 wells (costing $500,000 each) is delayed from production for one year, the cost to an energy enterprise that can earn 20% on its money would be $1,200,000, subject of course to partial recoupment through rising fuel prices.

The location of a geothermal resource involves the use of geophysical art and science to evaluate a range of prospects. This evaluation process for narrowing a list of prospects employs a series of tests to pick the prospects that appear to warrant drilling for geothermal development. Tracts warranting drilling, a matter as to which professional opinions may differ, must then be assembled. When drilling rights are secured around a potential site exploratory holes are sunk. If their results appear promising, further evaluative drilling takes place. If the results are favorable a series of development wells with attendant fluid transmission piping are installed and tested. This complex of wells is coupled to a generating unit to convert the geothermal heat into transportable electrical energy.

The state of geophysical learning is such that some wells drilled may be expected not to produce. The risk of encountering such "cold" holes appears to be less than that incurred in "wild-cat" exploration for petroleum.[11] A further risk is the "marginal" well; here the determination whether a well is or is not economically exploitable may well depend on uncertainties—or differing judgments--as to technology.

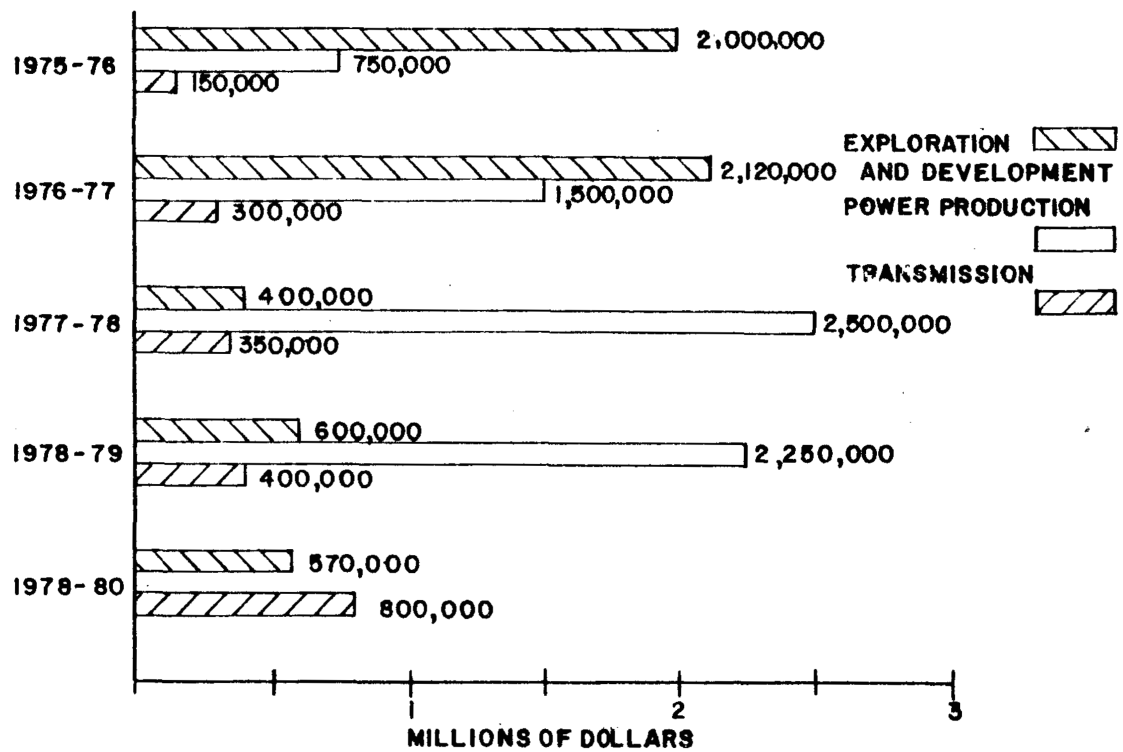
Drillers seek to manage their risks either by exploring a number of prospects in the case of larger firms or by attempting to employ capital invested by others, a method favored by some smaller firms, or by use of both methods.

The capital costs of an exploration program rise sharply when the drilling phase is entered into, and again substantially rise when post-exploratory development of a field begins.[12] During the successive stages of development, lags between cash outlays and receipts become more expensive to bear.

Another illustration of the costs of a complete exploration and development program is set forth in Figure 5 which shows planned expenditures for the City of Burbank's $16 million program to develop a 50 mw geothermally driven generating unit.

While actual drilling has been infrequent to date, enough data exist to indicate that the two or three successful wells needed to indicate the

FIG. 5 PLANNED EXPENDITURES FOR CITY OF BURBANK
50 MW GEOTHERMAL GENERATING UNITS



presence of a geothermal field are generally estimated to cost several million dollars. For a wildcat area, where the drilling success ratio is far below that of the Geysers, the Imperial Valley and some other areas,[13] employees of a major company have stated that a $16 million drilling program would be required,[14] while estimates by an independent firm were in the $10 to $15 million range.

Other geothermal enterprises have stated that lesser sums are required, asserting for instance that the drilling costs of smaller firms are substantially below those of larger enterprises. Several small enterprises seek to develop $2 to $3 million programs to drill up to six wells. They are looking for two or three successes which could confirm a field and serve as the basis for raising development funds.

Costs of drilling geothermal wells exceed those normal for shallow onshore oil and gas exploration.[15] These higher drilling costs may retard the rate of drilling, consequently limiting the rate of which geophysical theories are tested.

Moreover, data obtained during drilling are kept confidential.

Limited drilling and the failure to disclose drilling logs are likely to result in slower development of field exploration techniques. Slower development of these techniques increases and maintains levels of exploratory risk.[16] Drilling information may be shared by parties to a joint venture or to a plan for "unitized" development.

Developers can, however, shift part of the cost of geothermal development to taxpayers. The tax devices used to accomplish this, as we show below, encourage the use of joint enterprises and appear to be more favorable to established enterprises than to would-be entrants.

With the possible exception of outlays for dry steam wells, investment is capitalized and subsequently amortized for income tax purposes. (Expenses incurred for research and for leases subsequently abandoned are sometimes expenses rather than amortized.) Geothermal investment can receive benefits of investment tax credits and accelerated depreciation, and rental and interest expenses of "third party" financing are deductible. Costs shown heretofore reflect financing by private firms. Municipal enterprises could, subject to problems discussed in our barriers section, reduce their costs through use of tax-exempt financings, or by joint venturing. Geothermal developers generally cannot take tax deductions for depletion (for petroleum companies 22½% of gross revenues up to 50% of net revenue) or for intangible drilling expenses (expenses incurred for labor, fuel, repairs, hauling and supplies used in drilling and completing a well - a substantial portion of total drilling costs).[17]

For dry steam geothermal systems, intangible drilling cost ("IDC") deductions are allowed and have been estimated to reduce total production cost figures by 1.2 mills (from 14.5 mills to 13.3 mills per kwh), providing tax reductions are not offset by higher royalty or financing charges. Dry steam developments may also use a 22½% depletion allowance. For hot water sources, requiring a greater fluid flow and number of wells to support a unit, cost estimates could be reduced by as much as 2 mills if IDC deductions were available and by up to 3 mills if a 15% depletion allowance were granted (28.9 mills without tax deduction, and 23.9 mills with both deductions (Dec. 1974 costs).[18]

Investors in oil and gas drilling funds have, in the past, obtained a tax shelter through the practice of using "nonrecourse" loans. Such loans have been made to a drilling program, and the funds have been used for "intangible" drilling costs. These costs are then deductible on the tax returns of program's partners.

Use of such loans has been resisted by the Internal Revenue Service and,under recent tax legislation,[19] its use by individuals may be ended in regard to future leases.

If the incentives are offered to limited partners in joint ventures, geothermal development will still be faced with a time-lag problem which may make oil and gas drilling more inviting.

Smaller firms' net income would change if costs are reduced and tax benefits are not just passed along. This change in net income could occur only if, and to the extent that, product prices do not follow marginal costs of production.[20] In a competitive market, reduced costs would be expected to be mirrored in lowered prices. Absent competitive conditions in the geothermal market, other factors, such as opportunity costs reducing investment, or increases in rents for scarce items negate effects of a depletion allowance.

Tax exempt entities, if depletion and intangible drilling costs deductions are permitted, will find it necessary to carry out geothermal work through joint ventures. Unless they can share costs with the taxpayers in this manner, they cannot be competitive.[21]

While there is evidence that the availability of intangible drilling costs deductions would reduce the exploratory risk of geothermal venture investors, it is far from clear that absent such incentives energy could not be produced and sold at the better sites which will be first developed at a return on investment adequate to attract development capital without a subsidy from the taxpayers.

As depletion would be available only upon successful production, it would only increase capital available if (a) additional money were invested in anticipation of receiving this deduction or (b) if depreciation deductions were not passed along to investors as dividends or to buyers in lower prices but rather were retained by the firm and plowed back into geothermal work, or (c) if properties which are explored by firm A would command a better price when sold to firm B for development in consequence of the availability of a depletion allowance.

The cash-flow lag and the overall levels of outlay for geothermal energy development constitute barriers to entry to smaller enterprises. The tax treatment given geothermal projects favors those developing the more promising vapor dominated systems, and those with other income to shelter from taxes. It is not as favorable to entrant firms seeking limited partnership financing as is tax treatment for petroleum.

Geothermally driven generating units are limited in their economic size by the large size of the low pressure turbine they would employ.

Figure 6 shows the costs of generating capacity--as affected by size and type of power unit-- for exploitation of a low salinity source.

Figure 6 illustrates two important points regarding costs. First, the unit economies of scale cease to increase at about 55 megawatts. Second, binary cycle units are cheapest per unit of output. However, binary power cycle costs are particularly sensitive to the rate and efficiency at which heat is transferred from well-derived fluid to the material driving the turbine. Poor heat transfer coefficients[22] result in higher costs as larger heat transfer areas (heat exchangers) must be constructed.[23]

As Figure 6 shows, costs of units above 55 Mw size are uniform.

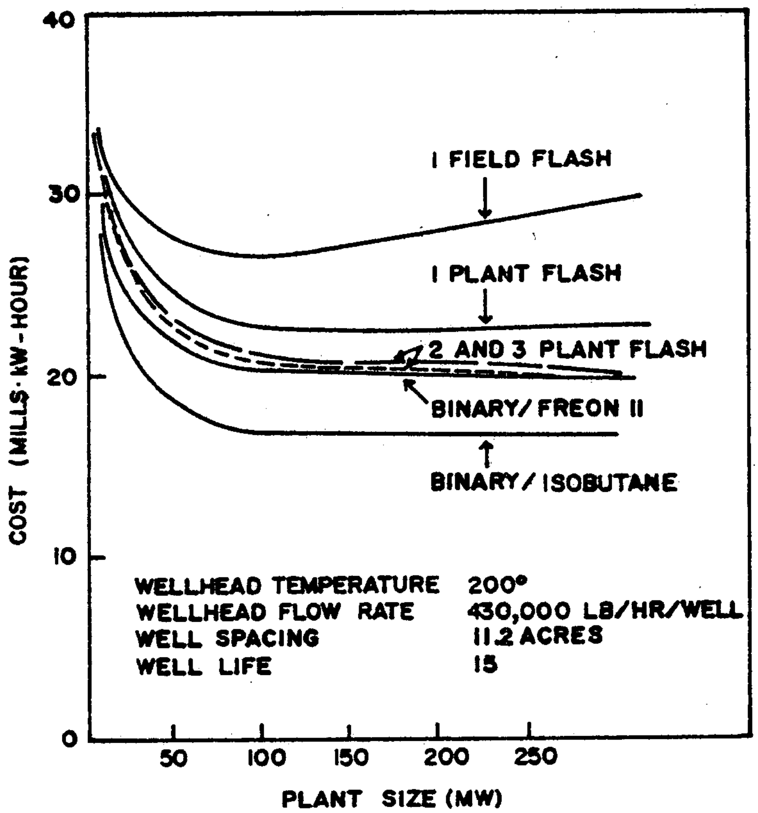


FIG 6. THE EFFECT OF PLANT SIZE AND POWER CYCLE ON GENERATING COSTS FOR ELECTRICITY

SOURCE : BLOOMSTER (NOV. 1975)

The dominant factors determining costs of power are the wellhead temperature, wellflow rate, and the cost of wells - i.e., the heat delivered per hour related to the cost of installing the field plant to produce this heat.[24] Once economies associated with larger units are exhausted, it makes more sense to replicate units. This replication improves system reliability confirming the effects of the unavailability of a unit.

Geothermal units thus are small when compared with 800 megawatt coal-fuel units or 1200 megawatt nuclear units-- the economic system for such energy sources.

Forecasts of Geothermal Contribution

Definite plans for utility employment of geothermal energy are quite limited.

The Western States Coordinating Council, reporting generating resource projects for all states from Montana and Colorado west, forecast 1980 and 1989 capacity as follows:

	Megawatts	
	1980	1989
Hydro	51194	55332
Thermal	70608	99414
Miscellaneous	477	1247
	122279	155993

The projected 1980-84 increase in thermal capacity is 28,806 mw; that for geothermal is 770 megawatts.[25]

When the projected growth of 28,806 megawatts is compared with the megawatts of geothermal capacity that would be economic if priced at cost, it is seen that geothermal power could play a meaningful role in the market for new Western electric generating capacity, i.e., the market for generation to go on line in the early and mid-1980's. For this to occur, there must be a combination of intent to accomplish this task with a reduction in barriers discussed below.

Longer range projections for supply (1985-1994) forecast total additions of 91,000 megawatts:

Hydro	9.2%
Nuclear	62.1%
Fossil	26.1%
Other	2.6%.[26]

These data show that utility plans for future generation envision reliance on nuclear energy and fossil fuel.

The utility planning choice among geothermal, and nuclear or coal, may make use of--but does not necessarily depend upon--estimates of supply cost. An engineering analysis may show, for instance, that under certain factual conditions the supply cost of geothermal energy would be lower than that of either coal or nuclear fuel. However, utility planners may feel constrained to add an element of cost--perhaps not quantified, or quantified only roughly--to the geothermal estimate, in order to recognize their perception of the risk in exploiting a novel energy source.

Moreover, an engineering analysis will reflect supply cost--and not necessarily price. It is price with which utility planners must be concerned, at least so long as they are purchasing primary energy rather than developing it for themselves. Therefore, their perception of the differences between ideal competitive conditions and actual market conditions may lead them to hypothesize a corresponding difference between the supply cost estimate (based on engineering analysis) and the estimated price (based on inter alia, supply cost, energy market concentration, and the apparent pricing policies of those who control geothermal and other primary energy sources).

It is interesting to note the substantial decline in government projections for geothermal utilization. In October 1975, Energy Research and Development Administration (ERDA) estimated that 6,000 Mw of geothermal electric capacity would be available by 1985 given a successful federal program implementation.[27] This was considerably more ambitious, or optimistic, than the electric utility group's expectations.

Considering development of hydrothermal and geopressured resources in the absence of a federal program, ERDA estimated that by 1985 1,500 mw will be on line, and perhaps by the year 2000 the geopressured resource may be added to the line of resource options. ERDA explains that the bulk of the 1,500 mw is planned expansion in the Geysers, with limited additional development of liquid-dominated hydrothermal resources in southern California and scattered small-scale non-electric applications.[28]

By January 1977, ERDA's forecast of geothermal capacity available by 1985 had fallen to 3,000-4,000 mw. Table 5 presents this revised forecast.

TABLE 5

INTENDED COMMERCIAL GEOTHERMAL UTILIZATION

POTENTIAL GIVEN SUCCESSFUL

FEDERAL PROGRAM IMPLEMENTATION

	1985	2000	2020
Electric Capacity (Mw)	3,000-4,000	20,000-40,000	70,000-140,000
Electric Applications --			
Equivalent Fossil Fuel Energy (quads/yr)	0.2-0.3	1-5-3-0	5-10
Non-electric Applications (quads/yr)	0.1	1	8
Total Energy (quads/yr)	0-3-0-4	2.5-4.0	13-18

Source: ERDA, Program Approval Document, Fiscal Year 1977, Geothermal Energy Development, January 17, 1977.

These ERDA forecasts suggest no geothermal capacity is expected to be developed in the Raft River area in the near future, while they do anticipate development in the Imperial Valley of California. However, our discussions with electric utilities and our review of scheduled load additions indicate that no commercial units have been scheduled for the Imperial Valley. Plans announced by California municipal systems may result in additional capacity, especially in the Geysers.[29] Some flashed steam capacity (50-100 mw) may be installed in Utah. The scheduling of binary cycle units, necessary for development in such hot water areas, will probably await the results of ERDA research.[30]

Municipal utility enterprises active in geothermal development, such as the City of Burbank, California; Bountiful, Utah; and NCPA, need to acquire a supplementary source of power. Their load growth continues without an offsetting increase in the available federal power. Similarly, the Sacramento Municipal Utility District is seeking base load power to fill the supply void left by indefinite postponement of a nuclear unit. All these systems are engaged in geothermal programs. Bountiful, Burbank, NCPA, and the City of Santa Clara are actively leasing and have entered into joint enterprises to explore for geothermal energy. Because of concern about a capacity shortage on the West Coast around 1980, capacity that might be available in the interim is specially appealing. Unfortunately geothermal lead times are such as to make little relief likely by 1980.[31]

The smaller economic size of geothermal units, relative to nuclear or fossil-fueled base load generating units, makes geothermal generation appealing to small power systems seeking to control their own generation and wishing to reduce wholesale purchases from larger utilities. This small size detracts from their attractiveness to large utilities.

Smaller utilities are reluctant to venture into what are for them the unknown waters of geothermal energy unless they can anticipate obtaining energy at a price below that of petroleum. These smaller systems appear to believe that they must develop their own geothermal resources, alone or in a joint enterprise with another enterprise (probably another small system) to obtain energy at prices other than those tied to prices for alternate fuels.

Among larger utilities, Pacific Gas and Electric Company's plans for The Geysers are the only definite project for geothermal development.[32] Other utilities are or have been engaged in exploratory work. Work on one demonstration plant has begun. All of these larger systems' geothermal plans are an outgrowth of uncertainties regarding their ability to construct nuclear units in California, and their ability to construct coal-fired stations in the mountain states and build transmission lines.

Industrial concerns interested in self-generation of power are a potential alternative market for geothermal energy. Not a few such firms have engaged in geothermal programs. Several, such as Dow Chemical and Amax, are so engaged in a major way.

The number of firms generating their own electricity has decreased over time.[33] The economies of scale and resulting lower rates achieved in the larger generating units built by utilities, coupled with managerial preferences and anticompetitive utility practices in regard to providing backup and other coordination services, usually make power purchases cheaper than self-generation.[34] However, the rapid rise in power costs may change this situation.

GEOTHERMAL LANDS

An examination of the ownership of rights to find and produce geothermal steam reveals some important things about the structure, functioning, and future prospects of the geothermal industry. Among the land-related factors relevant to this inquiry are:

> The pattern of ownership of rights to explore and develop;
>
> The way in which owners of these rights make use of them; and
>
> The effect of land-acquisition mechanisms now in use (chiefly government and private leasing) on ownership

and development patterns and industry structure.

Among the relevant questions are: Do geothermal rights tend to fall into the hands of firms owning other types of primary energy resources? Are geothermal prospects being stockpiled, acquired for speculation, or obtained for prompt development? How do geothermal leasing practices influence the type of firm which can successfully assemble a tract? Do lease terms encourage or discourage rapid development.

In reading the description of governmental and private leasing which follows, it should be borne in mind that there is a significant disproportion between lease acquisitions and actual drilling.[35] While acquisition of prospects is sometimes accompanied by geological and geophysical evaluation (done by the acquiring firms, or for them by independent contractors), drilling and development need not accompany acquisition, and often do not. This fact suggests that the acquisition of rights is the principal business of many firms in the geothermal industry.

The right to enter and test the possibilities of a trace of land is usually obtained through a lease. Prospective acreage is leased from federal and state governments and from private parties.[36] Leases on privately held lands are acquired through negotiation, while leases on government lands are acquired under competitive bidding procedures or by filing. Geothermal rights are held by a variety of enterprises: large and small petroleum companies, specialized geothermal firms, private utilities and their subsidiaries, municipal and REA cooperative utilities, and industrial concerns.

Federal Leases

Leasing of geothermal tracts on the federal domain is of interest both because a substantial portion of geothermal resources are believed to be located there (or on adjacent acreage) and because of the availability of information on these extensive and widespread lands.

The federal lands appearing to have some promise or interest as geothermal resource tracts are classified as Known Geothermal Resources Areas (KGRA) and are leased by competitive bidding; other federal lands may be leased upon application.

Lease sales did not commence until January 1974, some three years after the enactment of the Geothermal Steam Act of 1970.[37] Since then, only half the units offered or reoffered have been bid on, and in many sales bidding has been limited. Sales by competitive bidding consist of auctions in which would-be lessees submit sealed bids for "bonus" amounts of cash they offer to pay the government for a lease. The bids are accompanied by deposits.

Tables 6 and 7 show that the federal leases issued by competitive bidding have gone primarily to petroleum companies, with the balance to geothermal enterprises. Petroleum companies lessees range from an "independent," Anschultz, to large firms such as Shell Oil, Standard Oil of California and Phillips Petroleum.

TABLE 6

FEDERAL COMPETITIVE LEASES ISSUED

as of June 30, 1975

State	Party	No. of Leases	Acreage
Arizona	None		
California	Geothermal Resources Intl.	2*	3,710
	Magma	3	5,065
	Occidental	2	382
	Republic GI	4	8,478
	Shell	2	3,874
	Signal+	2**	876
	Thermogenics	1	175
	Union	5***	3,448
	Total	21	26,008
Colorado	Anschutz	1	916
	Phillips	2	4,120
	Total	3	5,036
Idaho	None		
Montana	None		
Nevada	Calvert	2	5,123
	Chevron	5	11,591
	Geothermal Resources	1	1,772
	Getty	2	4,940
	Natomas	2	3,980
	Southern Union	1	2,402
	Sun Oil	1	2,161
	Total	14	31,969

TABLE 6 (Continued)

New Mexico	Anadarko	Total	9	18,477
Oregon	Republic GI	Total	1	1,347
Utah	American Geothermal	Total	3	7,579
	Getty		1	1,920
	Phillips		10****	18,912*****
	Union		7	14,390
		Total	21	42,801
Washington	None			
Wyoming	None			

* Leases granted under grandfather rights for:

Chevron	1 lease	1,815 acres
Getty	1 lease	1,895 acres

** One lease granted under grandfather rights for:

Natomas	1 lease	626 acres

*** One lease granted under grandfather rights for:

Signal	1 lease	737 acres

**** One grandfather lease granted for 40 acres. from A.L. McDonald and William L. McDonald

***** Another document provided us by BLM, Utah State Office, indicates this figure should be 17,721 acres.

\+ Aminoil acquired former Signal Oil and Gas properties from Burmah Oil and Gas

TABLE 7

DISTRIBUTION OF FEDERAL GEOTHERMAL LEASES BY COMPANY

KGRA	Owner	Bonus	Acreage
Geysers	Shell Oil	$4,500,000	3,874
	Signal Oil (Aminoil)	2,130,600	876
	Occidental Petroleum	447,004	382
	Union Oil	220,933	3,448
	Thermogenics	22,050	175
Mono-Long Valley	Republic Geothermal	515,767	1,773
	Getty Oil	98,592	1,895
	Chevron Oil	18,459	1,815
East Mesa	Republic Geothermal	650,106	6,705
	Magma Power	11,398	5,065
Vale	Republic Geothermal	13,831	1,347
Roosevelt Hot Springs	Phillips Petroleum	798,856	18,872
	Union Oil	51,993	2,560
	Getty Oil	24,000	1,920
	A.L. McDonald, *et al.*	2,335	40
Brady-Hazen	Natomas Oil Company	88,912	5,074
	Southern Union Production	15,108	2,402
	Geothermal Resources, Int'l	14,000	1,772
Beowawe	Chevron Oil	595,652	6,890
	Getty Oil	75,602	4,940
Hot Springs Points	Chevron Oil	240,893	4,701

TABLE 7 (Continued)

KGRA	Owner	Bonus	Acreage
All KGRA's			
(Cont'd)	Occidental Petroleum	$447,004	382
	Union Oil Company	272,926	6,008
	Getty Oil	198,194	8,775
	Natomas Oil	88,912	5,074
	Thermogenics	22,050	175
	Southern Union Production	15,108	2,402
	Geothermal Resources, Int'l	14,000	1,772
	Magma Power	11,398	5,065
	A.L. McDonald, et al	2,385	40

Source: BLM Upland Minerals Division, Branch of Mineral Leasing

The average price per acre in federal lease sales has been $53.71[38] per acre with specific prices ranging widely. At the sales where prices exceeded $50 an acre, with one exception the high bidders have all been petroleum companies who are significant producers and suppliers of fuel to West Coast utilities from source areas such as Indonesia.[39] Table 8 shows the price bid per acre. The prospect of bidding against major petroleum companies has dismayed a number of smaller public and private enterprises who have concluded that they had better seek non-competitive leases. The prospect of adding a heavy bonus to the high start-up costs of a geothermal project is a significant deterrent.

TABLE 8

FEDERAL GEOTHERMAL LEASES - COMPETITIVE

Company	Aggregate Bonus ($)	Acres	a/b ($)
Phillips Petroleum	798856	18872	42.33
Chevron	855004	13406	63.78
Republic Geothermal	1179704	9825	120.07
Getty Oil	188194	8775	22.59
Union Oil Co.	272926	6008	45.43
Natomas Co.	88912	5074	17.52
Magma Power	11398	5065	2.25
Shell Oil	4500000	3874	1161.59
So. Union Production	15108	2402	6.29
Geo. Resources Int'l.	14000	1772	7.90
Burmah Oil (Aminoil)	2130600	876	2432.19
Occidental Petroleum	447004	382	1170.16
Thermogenics	22050	175	126.00
A.L. Mcdonald et al	2385	40	59.63

Source: Bureau of Competition and Economics, Report to the Federal Trade Commission on Federal Energy Land Policy: Efficiency, Revenue, and Competition, (October, 1975), reprinted by Senate Interior Committee, 94 Cong., 2nd Sess. as Serial No. 94-28 (92-118), (1976).

Small enterprises have greater representation in the ownership of non-competitive leases, as Table 9 shows.

TABLE 9

FEDERAL NONCOMPETITIVE LEASES ISSUED

as of June 30, 1975

State	Party	No. of Leases	Acreage
Arizona	Phillips	4	6,507.77
California	None Issued		
Colorado	None Issued		
Idaho	Nancy Anschutz	2	3,763.63
	ARCO	6	13,545.02
	Bill Maddox	4	7,749.01
	Sue Rodgers	5	8,521.72
	Steam Corp.	2	3,685.16
	Sun Oil	5	6,306.22
	Union	1	640.00
	Total	25	44,210.76
Maryland	None Issued		
Montana	None Issued		
Nevada	Al-Aquitaine	8	19,068.76
	Amer. Thermal	5	8,346.015
	Anadarko	8	20,416.05
	Anschutz Corp.	6	13,882.15
	Burmah	2	4,471.00
	Calvert Geothermal*	1	635.00
	Chevron	2	3,510.245
	Lowell Harrison	2/3	1,067.46
	Geothermal Resources	4	8,097.14

TABLE 9 (Continued)

		No. of Leases	Acreage
	Francis Grinnin et al.	1	1,595.60
	Richard Hoefle	2	1,920.00
	Peter Hummel	1	1,440.00
	Douglas Hunt	5	8,418.22
	Lamar Hunt	2	2,580.15
	Nelson Hunt	1	480.00
	Magma	4	9,229.52
	Mobil	5	11,591.43
	Pacific Geothermal	1	640.00
	James Palmer	2/3	1,067.46
	Phillips	2	2,840.00
	Marcellene Sands	1	640.00
	Caroline Schoellkopf	6	11,133.56
	Southern Union	5	11,055.00
	Sun Oil	10	11,043.11
	Thermex	6	14,228.44
	Edward Towne	2-2/3	5,561.56
	Union Oil of California	5	10,705.07
	Total	87	185,662.94**
New Mexico	Jack Grimm	5	9,568.61
	Lamar Hunt	6	15,353.40
	Nelson Hunt	8	18,618.90
	Caroline Hunt	3	6,365.56
	Norma Hunt	7	15,419.20
	W.H. Hunt	8	20,058.20

TABLE 9 (Continued)

State	Party		Leases	Acreage
	Thomas Hunt		6	15,169.40
	Nancy Hunt		4	7,040.00
		Total	47	107,593.27***
Oregon	Franklin W. Baumgartner		4	4,505.00
	Getty Oil		1	640.00
	Pacific Energy Corp.		1	640.00
		Total	6	5,785.00****
Utah	James Becker			5,961.27
	Chevron			6,175.70
	Earth Sciences			1,040.40
	Milton Fisher			5,401.26
	Geothermal Expl.			5,754.52
	Lamar Hunt			12,195.95
	Nancy Hunt			7,801.98
	Nelson Hunt			6,339.76
	Norma Hunt			640.00
	Thomas Hunt			1,900.01
	Malcolm Justice			2,182.24
	Gary Seltzer			1,284.07
	Steam Corp.			3,416.50
	Thermex			3,737.65
	Union Oil			3,806.06
	Trevar Windsor			3,868.72
		Total		71,506.09*****

TABLE 9 (Continued)

State	Party	No. of Leases	Acreage
Washington	None Issued		
Wyoming	None Issued		

** 4 noncompetitive leases have been assigned by Chevron to Geothermal Resources International totalling 6,244.92 acres. Another BLM source counts 103 leases with 194, 163 acres.

*** Another BLM source gives 104,210 acres

****Another BLM source gives 2 leases of 1,268 acres

*****Another BLM source counts 40 leases totalling 62,331 acres

While 939 noncompetitive applications have been filed in California (560 on lands administered by the Bureau of Land Management and 379 on Forest Service land), 387 await action and only five leases had been issued as of July 31, 1976, one to Eason Oil Co., two to Mobil Oil Co., and two to Southern Union Products Co. The Bureau of Land Management (BLM) has been slow in granting leases upon noncompetitive applications, and a large backlog of such applications has developed.

State Leases

The land holdings of many western states encompass substantial geothermal prospects. However, while many of these states have made provision for geothermal leases, no state lands have been leased for geothermal activity in Arizona, Montana, Nevada, Washington, or Wyoming. In some states, lack of information as to the possible extent and value of geothermal resources has deterred leasing.

In California, only a portion of the more than one-half million acres of state-owned lands within potential geothermal areas has been explored for development. Under the current framework for leasing California state lands, (established by the Geothermal Resources Act of 1967 California Public Resources Code (Division Six),the State Lands Commission may issue short-term geothermal prospecting permits on a first-come, first-served basis, or it may issue long-term leases, either preferentially, under certain conditions, or by competitive bid. Applications may not be for less than 640 acres nor for more than 2,560 acres for onshore lands. In the case of submerged lands, the maximum size application allowed is 5,760 acres. No permittee may have an interest in more than 25,600 acres.

California prospecting permits give permittees an exclusive right to explore the land for three years with a possible two-year extension. Upon discovery of a geothermal resource under a prospecting permit, the permittee has a preferential right to a geothermal lease for a period of 20 years and for so long thereafter as geothermal resources are produced up to a lease term of 99 years.

The State Lands Division of California is currently experimenting with a program of leasing geothermal lands through bidding on a net royalty basis. In such bidding, the state is offered a share of the net profits from a leased tract. Such leasing methods, it is hoped, will permit bidding by entities such as public bodies wishing to develop geothermal energy but unable or reluctant to increase front-end risk investment, or by smaller independent firms now effectively barred by the capital requirements of bonus bids. One such lease sale has occurred. At that sale, the City of Santa Clara was high bidder on 135 acres in The Geysers area.

Table 10 summarizes grants of prospecting permits and leases.

TABLE 10

CALIFORNIA STATE GEOTHERMAL PROSPECTING PERMITS AND LEASES

as of November 24, 1975

I. CURRENT PROSPECTING PERMITS (As of November 24, 1975)

Permittee	No. of Permits	Acreage
American Thermal	4	8,898
Getty	2	9,857
Getty-Mono	3	14,738
Gulf	4	14,918
Total	13	48,411

II. CURRENT LEASES (as of June 27, 1975)

Lessee	No of Leases	Acreage
Imperial	4*	535
Union	2	3,988
Total	6	4,523

*Inactive; produced only hot brine.

In Colorado, geothermal leases are let only upon application. The 1974 Colorado Geothermal Steam Act is part of the state's water laws; permission is required from the State Engineer before wells may be dug. Regulation is by the Oil and Gas Conservation Commission, subject to the State Engineer's appraisal of the seniority of water uses under Colorado prior appropriation doctrines. Table 11 summarizes Colorado leases.

TABLE 11

COLORADO STATE GEOTHERMAL LEASES

as of June 1975

Lessee	No. of Leases	Acreage
Antares Oil	1	5,760
Austral Oil	1	640
M.L. Gillespie	3	6,640
Gulf Oil	2	1,920
Mapco*	2	68,351
Petro-Lewis**	1	11,764
C.A. Underwood	16	47,437
Total	26	142,512

Source: Geothermal Energy, June, 1975.

Notes: *Mapco is the only lessee reported to have drilled, and its well has been plugged.

**Petro-Lewis is leasing and exploring in the Mount Princeton area under a letter of intent from Public Service Company of Colorado to acquire steam.

In Utah, state lands are leased upon application, with competitive bidding required only for tracts on which leases have terminated or lapsed. Table 12 summarizes grants of leases in Utah.

Under Utah law geothermal production would occur under the state water laws, and accordingly applications for water rights appropriations must be made to the Division of Water Rights. Interference with prior appropriations will become a problem only if communication occurs between surface and geothermal waters. This matter is under investigation by the State Engineer, and all applications are "pending".[40]

Utah Power & Light Company has blanketed the State with applications for approximately 100,000 wells on 10 acre spacing by filing on all likely prospects. UP&L would have a priority of appropriation and protection against offset drilling. Table 13 summarizes these applications.

TABLE 12

GEOTHERMAL LEASES FOR UTAH STATE LANDS

all let since January 1973

Company	No. of Leases	Acreage
Thermal Power Co. of Utah	15	16027
American Oil Shale Corp	4	5567
Resource Leasing Corp.	2	1279
Chevron Oil Co.	2	2584
Phillips Petr. Co.	18	23562
Sonja V. McCormick	14	11242
Steam Corp. of America	4	2528
Wm. A. Stevenson	4	2166
J.W. Covello	6	5454
R.E. Puckett	36	53009
Chas. L. Golding	7	6240
Gerald C. Harrison	2	2824
Davon Inc.	3	3050
Malcolm F. Justice Jr.	4	2784
Milan S. Papulak	1	240
Donald F.X. Finn	4	4453

TABLE 12 (Continued)

Company	No. of Leases	Acreage
James A. Murphy, Jr.	1	2167
Roy Barnes	3	791
L. Doral Christensen	1	80
W.O. Darley	1	600
Worley Valley Oil Operation	1	160
Chris A. Marks	1	361
Intercontinental Energy	1	364
Eliz. A. Justice	2	960
Malcolm V. Justice Jr.	1	120
Calvin F. Beckstrom	5	4887
	157	158594

Source: Conversation with Mr. Val Finlayson, Utah Power and Light, and Mr. Morgan, Office of the State Engineer.

TABLE 13

UTAH WATER RIGHTS APPLICATIONS - ALL PENDING

Company	No.	Quantity (Sec.Ft.)	% Total
Utah Power & Light (UP&L) and Thermal Power Co.	15	41632	19%
UP&L and Geo-Drilling Co.	11	87552	40%
UP&L and Geothermal Kinetics Systems Corp.	10	64400	29
UP&L Subtotal			88%
Chevron Oil Co.	6	18484	8%
Union Oil Co.	1	2000	1%
Phillips Petroleum	1	1680	1%
Frank J. Allan	3	2176	1%
J.K. Letts	2	1536	1%
A.L.McDonald	3	75	
Wm. L. McDonald	3	75	
Utah State Land Board	1	25	
Total		219635	

The State of New Mexico owns eleven percent of the state's land area. Leasing tracts are selected by following trend maps and applications to state and federal governments, and are leased by competitive bidding with a royalty of 10% of gross revenue or 8% of net revenue.[41] State leases on June 27, 1974 embraced about 90,881 acres. Leases have primary terms of five-years with the right to renew for succeeding five-year terms if geothermal resources are, or are capable of being, produced or utilized in commercial quantities from the leased land or from lands utilized with the lease. Annual rentals are $1.00 per acre, and delay rents after the discovery of commercial quantities of geothermal resources are $2.00 per acre. The lessor reserves the right to prescribe a development program and to approve or disapprove development programs submitted by lessee. A $5000 bonding is required prior to operations on a lease tract.[42] Table 14 summarizes New Mexico lease information.

TABLE 14

NEW MEXICO STATE GEOTHERMAL LEASES

as of June 27, 1975

Lessee	No. of Leases	Acreage
Antwell, Alan J.	4	1.948
Amax*	29	11,771
Burmah (Aminoil)	65	25,853
Calvert Geothermal**	8	5,423
The Cherokee	7	4,433
Chevron*	14	6,695
Deuterium	17	7,210
Fogelson, E.E.	9	4,080
Folmar, Cecil J.	5	3,109
Grimm, Jack	1	640
Gulf Oil	16	6,471
Hodges, Leland	11	3,865
Kelly, John***	5	2,624
Southern Union	18	3,869
Thermal Expl.	3	2,890
Total	212	90,881

*AMAX is controlled (20% equity ownership) by Standard Oil of California (SOCAL). Chevron is a subsidiary of SOCAL.

**Sun Oil Company

***Former Assistant Secretary (Mineral Resources) U.S. Dept. of Interior

Idaho

Idaho's geothermal resources are believed to be the hot water type;[43] and drilling for them is regulated by the State Department of Water Resources.[44]

Table 15 is a summary of the very considerable leasing of state lands by the Idaho Department of Public Lands. Leases on private lands are reported to be held by Gulf Oil, Anschutz and Phillips Petroleum. Union Oil, Sun Oil and Magma have also indicated varying degrees of interest.

Drilling has been undertaken by the Anschutz Corporation (in the Grandview-Bruno area), by Gulf Oil and by Geothermal Kinetics Inc. (in a venture with Utah Power and Light).[45]

TABLE 15

IDAHO STATE GEOTHERMAL LEASES

as of March 1, 1975

Lessee	No. of Leases	Acreage
Anschutz Corp.	164	55,213
Nancy P. Anschutz	165	75,787
Malcolm Mossmann	72	25,561
Chevron Oil	19	3,113
Gen Oil	23	14,271
Don Gould	4	1,980
Gulf Oil	174	68,853
F. Joe Kanta	4	1,491
Phillips Petroleum	10	5,089
Raft River R.E.C.	12	8,235
Warren Sorrells	12	7,692
Sun Oil	2	880
Total	661	268,111

The Raft River Electric Cooperative has leased 100,000 acres that include some state lands. With financial support from ERDA, and to a lesser extent from the Northwest Public Power Council, it has drilled two wells, currently being tested. Raft River is seeking further ERDA support to drill two more wells; and to build a 10 mw pilot plant which it hopes to have operational by 1978. This binary-flashing unit, if successful, would be followed by a larger commercial unit.[46]

Oregon

Oregon has a number of geothermal resource areas. Among the oil and geothermal firms exploring in this state is a joint venture of Weyerhaeuser, Pacific Power and Light and Portland General Electric, which all hold leases of private lands in Klamath County.[47]

Table 16 lists firms holding leases on Oregon State lands.

By the end of 1975, only three wells had been drilled in Oregon, one by Gulf, one by Magma, and one by San Juan Oil (MAPCO, Inc.), none successful.

TABLE 16

OREGON STATE GEOTHERMAL LEASES

As of December 1, 1975

Lessee	No. of Leases	Acreage
Amax*	1	1,280
Chevron*	1	2,800
Intercontinental Energy	2	1,920
Max Millis**	1	2,240
Total	5	8,240

PENDING APPLICATIONS

Weyerhaeuser)
in Klamath County
Hydro Search)

COUNTIES:

Lake

Harvey

Malheur

*Only one drilling - did some exploratory drilling in Harvey County but stopped several months ago.

**Controlled by Standard Oil of California

Note: Of 458 geothermal lease applications in Oregon, Sun Oil Co. has

TABLE 16 (Continued)

73 and Chevron Oil Co. has 48. <u>Geothermal Energy</u>, 18 Nov. 1974

GEOTHERMAL EXPLORATION AND DRILLING

While extensive acreage has been subjected to geothermal leases, drilling has gone forward on a more limited basis.

In 1975 and 1976 drilling was limited to respectively 45 and 51 wells in the continental Western states - six by the federal government.[48] Very little drilling occurred in new areas: all California drilling except for one well was in the Imperial Valley and at The Geysers.[49] Table 17 lists wells drilled by region and Table 18 lists wells by operators.

TABLE 17

SUMMARY OF GEOTHERMAL DRILLING
In the Western United States in 1975-76

State	Operator	Wells	Observation Wells
California			
Geysers Region	Union	24	
	Amindil	14	
	Shell	6	
	Pacific Energy	4	
	McCullock	1	
	Chevron	1	
	Amax		3
	Magma	1	
Imperial Valley	Republic	10	
	Union		3
	Chevron		4
	Magma	2	
Long Valley	Republic	1	
Idaho	Idaho National Engineering Lab	4	2
Nevada	Magma	4	

TABLE 17 (Continued)

State	Operator	Wells	Observation Wells
Nevada (Cont)	Magma	4	
	Chevron	1	
	Union		3
	Phillips	2	
New Mexico	Union	2	
Oregon	San Juan (MAPCO)	1	
	Thermal Power	1	
Utah	Phillips	7	
	Union	3	
	McCullock	2	
	Thermal	2	

TABLE 18

1975-76 GEOTHERMAL DRILLING IN THE

WESTERN UNITED STATES

Operator	Wells Drilled 1975	Observation Holes* 1976
Union	15	19(6)
Aminoil	8	6
Republic Geothermal	4	7
McCullock		3
Shell	3	3
Chevron	(5)	2(1)
Magma	4	3
Phillips	5	3
Thermal Power		3
Idaho Nat'l Engr. Lab.		2(2)
Pacific Energy	3	1
Amax		(3)
San Juan (Mapco)	1	52(12)

* Separately counted in Paren

In 1975, 24 wells were drilled in The Geysers area and in 1976, 18 wells were drilled there. Outside of California, in 1976 no wells were drilled in Colorado, Arizona or New Mexico and 15 elsewhere. Six in Nevada, one in Oregon, six in Utah and two in Idaho, including one by the Idaho National Laboratory (INEL). In 1975, more wells were drilled in California, two wells were drilled in New Mexico, six in Utah, two in Idaho (by INEL), four in Nevada and one in Oregon.

It is interesting to note that the Union Oil Company, which drilled over one-third of the wells in the 1975-76 period is a crude-short company that has traditionally had an interest in non-traditional energy sources such as oil shale. The role of small specialized firms and independents is particularly pronounced outside of The Geysers. The dominance of major and very large oil firms in acquiring prime prospects is in drilling at the very promising site in south central Utah (Beaver and Millard county). There seven of the ten wells drilled in 1975-76 were by Phillips, with one by Union.

In total, as of August 1975, nine geothermal wells had been drilled on federal lands, two were in progress, and applications were pending for six more. In 1976, five wells were drilled. Table 19 lists those who had drilled or received permits to drill geothermal wells on federal lands on August 28, 1975.

TABLE 19

EXPLORATION & DRILLING ON FEDERAL LANDS

as of August 1975

State	Party	Notice of Intent	Application To Drill	Wells Drilled
California	Burmah (Aminoil)	1	4	2
	Republic	1	2	
	Republic GI	2*		
	Shell	1	3	2**
	Union	1		
Nevada	Chevron	1		
	Southern Union	1		
Utah	Phillips	2	8	5**

* Not issued yet. Waiting on EA and letter of approval

** Plus one drilling.

The paucity of geothermal well drilling can not be attributed to government regulatory delay. Federal regulation is confined to federal lease tracts and would not sharply restrict the number of applications for drilling permits. State and local regulatory time spans for drilling are brief, especially outside of California. Power plant regulation problems occurred in The Geysers and in consequence of development practices.

The costs of regulation involved in obtaining federal permits appear to be greater than those for permits from some western states. While these permit costs may be burdensome to smaller firms, the larger entities with leases should be able to overcome this barrier.

Lessees seeking to drill on federal lands are required to post compliance bonds. The Bureau of Land Management (BLM) requires a $10,000 bond to be filed prior to bidding, for each lease. Alternatively, a lessee may post a $50,000 statewide bond, or a $150,000 nationwide bond. Explorationists seeking to proceed under a notice of intent to explore federal lands need not have a lease.[50] However, they must file a protection bond. Holders of national or statewide oil and gas bonds can meet this requirement just by amending their bonds to include geothermal exploration. The obligation may otherwise be met by a $5,000 bond for each exploratory activity or by holding a pre-entry $25,000 statewide or a $50,000 national bond.[51] Small enterprises, and particularly those lacking prior gas or oil exploration experience, bear a heavy burden in meeting lease bonding requirements. They may seek bonds on security proffered by substantial participants in their own enterprises.

Between leasing and exploration, there is a planning lag of up to one year. The USGS requires federal lessees, prior to beginning work, to submit a plan of operations, which takes three to four months to be reviewed.[52] A Notice of Intent to explore on the public lands,[53] which takes up to 30 days to process, must be filed with the BLM. In addition, there may be state and local permits and authorizations to be obtained before drilling can begin.

After exploration, the lessee spends about a year collecting data for an environmental analysis.[54] Then a plan for production must be filed with USGS[55] where, reportedly, the time required for review of such plans has increased to several months.[56] Because of the dovetailing of filing lead time and engineering planning time needs, "regulatory" delay does not appear to be severe.

The United States does not appear to employ lease rental provisions to require rapid prosecution of lease exploration by its lessees.

In order to have acreage produced so that royalties will be paid, the United States imposes due diligence requirements on its lessees. A major incentive to diligent exploration of lease holdings is the structure of lease rental fees.

The General Accounting Office (GAO) states that leasing regulations can be strengthened to promote early exploration and development of leased lands:

> The /Interior/ Department's leasing regulations do not require lessees to drill exploratory wells to evaluate an area's potential for heat, power, minerals, or fresh water. Under the geothermal leasing regulations, however, each geothermal lease is to provide for the diligent exploration of the leased resources until there is production in commercial quantities. Failure to perform such exploration may subject the lease to termination. [57]

The structure of lease rental fees affects the incentive of lessees to explore leases, rather than just hold them speculatively. Section five of the Geothermal Steam Act specifies minimum annual rental payments of $1.00 per acre, and the Bureau of Land Management has set annual rentals at $2.00 per acre for competitively let tracts. With production, a lessee may substitute a minimum royalty of $2.00 per acre in lieu of rent.[58] Rental fees on the leased acreage can be increased after the fifth year if there is no production, or be eliminated once production begins.

After the fifth year, certain expenditures for diligent exploration may be credited against rental fees.

A USGS official responsible for supervising geothermal leases told the GAO that USGS had not established a firm guideline on the required level of diligent exploration in the first five years of a lease and would probably not terminate leases if, during that period, no exploration activity were undertaken. GAO found no record of any lease being terminated for lack of due diligence. Our subsequent inquiries at BLM and USGS reflect the same state of affairs.

For the sixth and succeeding years of a geothermal lease term, Interior Department regulations provide a formula for computing minimum expenditures necessary for diligent exploration. The minimum rents and expenditures necessary to maintain a lease for 2,560 acres if no commercial production takes place during the 10-year lease are (a) total rents of $12,800 for the first five years and $64,000 over the first ten years and (b) no minimum expenditures in the first five years, and a total of $102,400 in ten years.[59]

The GAO recommended that due diligence requirements[60] now totalling but $166,400 in ten years be tightened to require expenditures during the primary term to more closely approximate the $800,000-plus costs of a deep well, and it urged that more specific requirements be imposed for minimum development during the initial five years of a lease.

As noted in a FTC Staff Report, competition within the geothermal industry would help insure that the federal government receives fair value for its lands and, if geothermal energy is to reach its full potential, leases must be available to competitive enterprises who would foster development of alternate energy sources:

> "The fact that the leading geothermal developers are also leading West Coast petroleum suppliers suggests that interfuel competition may not be greatly enhanced."

The paucity of geothermal drilling is particularly clear in regard to leased state lands. Wildcatting has been conducted by a number of enterprises, most notably such specialized firms as the Magma Companies, Republic Geothermal and Geothermal Kinetics, Inc. On the other hand, several large firms that had acquired extensive acreage and were actively exploring are now, after some "cold" holes, apparently just holding on to their land. In this group are Sun Oil, Gulf Oil and Getty Oil.

The development stage has been actually reached in only one area, The Geysers in California, where a great deal of drilling has been done by Burmah Oil and Pacific Energy Corporation to extend the defined resource area. Even there, uncertainty and what the industry perceives as long delay in getting generating units licensed and on-line have greatly curtailed drilling. PEC and Burmah wells there have been shut in for several years.

Some industrial energy users, e.g., Dow Chemical, Anaconda, Weyerhaeuser and to some extent Amax, have become involved in geothermal resource development activities. Dow, which now owns part of Magma, also purchases and transports natural gas for its own use in Northern

California. Amax, 20% of whose equity ownership was recently acquired by Standard Oil of California, owns large reserves of coal, and uses a substantial amount of purchased electric power at its works near the Mt. Princeton geothermal area of Colorado. Amax is exploring with Petro-Lewis for geothermal resources in this area. The industry participation is parallel with and in the alternative to other joint enterprises between utilities and small geothermal companies.

The limited amount of drilling in most western states is consistent with either a lack of financing, high risk perception, speculative lease-holding, a limited number of prospects, anti-competitive restraints on development, or some combination of the above.

If good sites are limited in number, the possibilities for speculative withholding and anti-competitive practices are enhanced. Withholding in turn delays technological innovation, increasing risk and creating financing problems.

The large number of leased tracts that have not been drilled clearly evidences some speculation - as parties know their financial situation when they take leases, and have developed their risk perceptions.

Because development is largely financed through joint ventures with utility or petroleum firms, speculators may have assurance that development will not occur in ways that upset energy prices.

DEVELOPMENT ARRANGEMENTS

Smaller geothermal firms either associate with large enterprises that finance their activity, or they seek to finance exploration drilling by joint venturing with another energy company or energy consumer. The larger firms demonstrate more of a go-it-alone attitude by joint venturing only where their acreage overlaps. They avoid action that would commit them to a subsequent sale of energy, such as joint venturing with consumers, asserting that they intend to prove up their acreage before offering its output. While delaying entering into sales may assure a vendor that he knows more about what he is selling, it also may be a means of reaping locational values or rents.

The dependence of some geothermal enterprises on joint venturing to secure capital can result in a community of interest with energy users who wish to secure their future supplies at lower prices. These users obtain needed capital.

Table 20 lists some recent joint ventures of consumers and energy firms. Ventures have previously occurred between GRI and SCE; GRI and the Los Angeles Department of Water and Power; Sierra Pacific Power Company and Magma; Petro-Lewis and Public Service Company of Colorado; and Dow Chemical with its affiliate Magma and with Chevron.

TABLE 20

JOINT ENTERPRISE

Financial Contributions, Securities Holdings, Similar Arrangements

Union Oil owns 300,000 shares of common stock of Magma Power Co. Hughes Aircraft provides capital for use of Pacific Energy Corporation. Dow owns a portion of Magma Power Company.

Joint Ventures (Separate business enterprises established by two or more entities, for defined purposes)

Pacific Energy Company: Burmah--well drilling operation.

Petro-Lewis: AMAX--exploration (in Colorado)

Geothermal Power Corp.: Natomas--exploration, in Modoc County, Cal.

Republic Geothermal: City of Burbank--exploration, drilling in Cal.

Anschutz: Gulf Oil

American Thermal Resources: separate joint enterprises with Mapco, Dow, Gulf, and Standard Oil of California (Chevron).

Chevron: separate joint endeavors with Geothermal Resources, Inc., American Thermal Resources, Utah International, Mountain States Resources, and Phillips Petroleum.

Earth Power Co: AMAX

Geothermal Resources: separate ventures with Occidental Petroleum and Natomas

McCulloch: negotiating joint venture with Utah Power & Light Company

Magma: Union Oil--well drilling, Nevada

Land Deals--Farm-outs or pooled acreages

Sunoco: Land farm-outs to Al-Acquitaine and Signal (now Aminoil).

Southern Pacific Land Company: Phillips evaluating 1.5 million acres.

Dowdle Oil: Farm-out to Natomas.

Mapco: Farm-out to Republic Geothermal

Magma, Chevron, and the New Albion subsidiary of San Diego Gas & Electric have pooled acreage at Heber, California.[61] *

Drilling Contributions

Magma has received drilling contributions from Union Oil and from Southern California Edison. It has an agreement to earn a contribution from Amax in Oregon.

> The Los Angeles Department of Water and Power has made a $25,000 bottom hole contribution toward a well drilled by Republic Geothermal in a joint enterprise with the City of Burbank, California.**

* In its 1975 annual report, Standard Oil Company of California reports owning 75% of its Imperial Valley Project.

** On hydro project lands the Water & Electric Board of the Northwest Public Power Council also owns some geothermal prospects. In Idaho, the Raft River Rural Electric Cooperative and the Northwest Public Power Council, with ERDA funding, have drilled two wells and are planning a 10Mw binary-flashed steam pilot plant.

Utilities have participated directly and through fuel company subsidiaries in geothermal exploration in Utah, Idaho, Arizona, Oregon and Southern California. See Table 21.

TABLE 21

UTILITIES WHICH RECENTLY PARTICIPATED

IN GEOTHERMAL ENDEAVORS

STATE	UTILITY	ASSOCIATE
Arizona	Arizona Public Service	Geothermal Kinetics, Inc. (GKI)
	Tucson Gas & Electric	Geothermal Kinetics, Inc. (GKI)
	Salt River Project	Geothermal Kinetics, Inc. (GKI)
California	City of Burbank	Republic Geothermal
	Southern California Edison (Mono Power)	Getty
	San Diego Gas & Electric (New Albion)	Magma
	Imperial Irrig. District	Chevron
	Northern Calif. Power Agency	RFL Ltd.
Oregon	Pacific Power & Light	Weyerhaeuser Lumber Co.
	Portland General Electric	"
Idaho	Raft River Cooperative*	
	Fall River Rural Elec. Coop.	
Utah	Utah Power & Light	GKI

TABLE 21 (Continued)

STATE	UTILITY	ASSOCIATE
Utah (Cont)	Utah Power & Light	McCulloch

* In Idaho, the Raft River Rural Electric Cooperative and the Northwest Public Power Council, with ERDA funding, have drilled two wells and are planning a 10 Mw binary-flashed steam pilot plant.

The Imperial Irrigation District is reported to have leased geothermal prospects, although District personnel did not confirm this report.

There has been a small but significant number of joint ventures between industrial companies and geothermal firms. Table 22 sets out industrial company participation in geothermal exploration, identifying three such joint ventures.

TABLE 22

INDUSTRIAL FIRMS WHICH HAVE RECENTLY PARTICIPATED

STATE	COMPANY	ASSOCIATE
Montana	Anaconda	GRI
Colorado	Amax	Petro-Lewis
California	Dow	Magma
Oregon	Weyerhauser	(no Partner)

The tendency of utilities and industrial firms to join with specialized geothermal firms may reflect the matching up of capital and managerial talent with firms having specialized skill and knowledge.

Geothermal joint ventures are reportedly not favored by larger firms who do not need financial assistance, and who believe that joint venturing merely adds to time needed for a project.

Because joint venturing is a significant means of financing geothermal development, it is important to understand the roles of carried or carrying partners in development, as well as the relationships among various firms.

Joint enterprises, either joint ventures or utilizations, are sought for exploration and development:

(a) when acreage holdings of several companies intersect;

(b) when smaller firms want to market their geothermal prospects by associating themselves with enterprises seeking opportunities to drill and acquire a working interest in development programs;

(c) when the expertise of one firm is sought by others;

(d) to spread drilling risks; or

(e) to secure control of the output of a particular resource.

Joint venture agreements provide a means for inter alia, financing the costly drilling of geothermal wells. In some cases an enterprise primarily engaged in obtaining geothermal leasing will enter into a joint venture with a large company, which may hold adjoining acreage. In such a venture the oil company may earn an interest in the lessee's acreage and production, therefore,by completing a specified drilling obligation. The lack of a "new issues" market, absence of the tax benefits available to oil and gas joint ventures, and the fact that investment needs are larger and time to payout longer than for comparable oil ventures all appear to have impaired, but perhaps not destroyed, the ability of geothermal enterprises to raise venture capital by methods other than by association with another firm or by joint venturing.

The joint venture agreements we have studied involve smaller enterprises as one party, and frequently involve utilities. We have not reviewed joint venture agreements among major enterprises; however, we understand that such agreements are few in number and may generally involve sites where acreage holdings overlap.

The agreements reviewed are patterned after those in the oil and gas industry. They use similar terminology, and similar concepts for ownership of shares, areas of interest and arrangements for cash participations and operating decisional choices.[63] The smaller enterprise is usually contributing know how and/or land, and the larger enterprise is providing the financing and thereby earning an interest in the tract.

Geothermal joint venture agreements designate an operator and an area of interest in which the parties will operate as joint venture. They frequently include provisions under which a party may elect whether it wishes to participate in a well, and provisions permitting the separate sale of product by each venturer. If an energy consumer is a party to the venture, there will be an option to purchase output according to a pricing formula.

Because the cost responsibilities of a joint venturer may otherwise exceed their cash flow capabilities, smaller lessees may seek to retain only a royalty interest, while farming out their acreage. Smaller entities may be required to assign their interest to others, when the point comes where they can no longer carry their "half" of joint venture expenses or outlays.

When a joint venture is entered into, the smaller partner may be required to proffer a share of any interest he may have or acquire in any tract of land in the "area of interest" designated by the agreement. Such areas can involve wide geographical expanses. Joint venture drilling schedules are, as a practical matter, tied to decisions of the carrying party as to when and at what rate it will expend funds. As in oil and gas ventures, provision may be made for one party to drill if another "nonconsents" to participate in a well. The non-consenting party may be allowed to "back in" to a share of any production after the drilling party has recouped its investment several times over.

Drilling is usually done by an independent contractor retained by the "operator" of the venture, although a few specialized geothermal firms have their own rigs.

TECHNOLOGICAL AND ENVIRONMENTAL PROBLEMS

Technological problems, delay, and uncertainty currently plague the geothermal industry.[64] Locating the resource requires the use of geological, geophysical and hydrological prediction methods yet to be tested by extensive drilling. Moreover, the proper mix of survey methods appropriate for different areas is still under development.

Industry personnel have resisted efforts to perform federal research on geophysical prospecting techniques on federal acreage. They have sought to have such work limited to further delineating areas and explored by others.

One explanation for this position has been that federal exploratory work reveals the worth of the acreage and may drive up the lease costs on the federal land and on adjoining tracts. This point needs no response. Another explanation has been that experimental techniques are best evaluated where actual holes have already been drilled. This overlooks the fact that lessees have not allowed researchers to work on drilled tracts, as an alternative to testing unleased government acreage. Further, government testing to "prove up" private lands may lead to unfortunate political consequences.

Location and commercial use of hot water sources present problems of safety and environmental protection as well as of efficiently harnessing the energy.

The hot water type of geothermal resource is most commonly found as a fluid of varying and sometimes high temperature and salinity. Technology must be developed that will make available such resources of varying temperatures and salinities, in an environmentally acceptable manner.

Areas of technical uncertainty in geothermy are mirrored in ERDA's "Definition Report" for the Geothermal Energy Research Development and Demonstration Program (October 1975). This report states that the required hydrothermal technology development effort includes the following activities:

(a) Reservoir engineering and field development to improve the economics and reduce the risk, for example, of premature reservoir failure. Tasks include improving technology for drilling,[65] well-digging, reservoir modeling, well simulation, and down-hole pumps.

(b) Development of technology to utilize geothermal energy including heat exchangers, condensers, total flow systems, and absorption refrigerator systems.

(c) Work in brine chemistry, scale control and corrosion- and erosion-resistant materials.

(d) Construction of field test facilities to test components.

(e) Development of advanced systems and applications.

(f) Study of environmental effects of field production and development of technology to control emissions, efficiency, noise and land subsidence.

(g) Demonstration of pilot plants and commercial-scale units, with two such commercial-scale facilities tentatively planned.

This program encompasses the area of technical uncertainty affecting the geothermal industry. To develop and disseminate better techniques for locating, evaluating and producing geothermal energy, field data are essential; many of the problems require empirical solutions. In light of the expense and the limited number of on-going geothermal exploration programs, federal acquisition (e.g., purchase or direct exploration) and disclosure of field data might be very worthwhile.

Geothermal development can be expected to go forward only if environmental problems can be solved. Solution of these problems would eliminate uncertainty and delay in the granting of permits. A partial inventory of environmental problems includes:

(a) Topographical alterations due to the number and spacing of drilling pads. While closer spacing gives faster rates of withdrawal, impact on the land surface could be reduced by wider spacing and use of more expensive directional drilling for several wells from one pad.

(b) Erosion and siltation, especially around drilling pads.

(c) Water pollution, for example, from spills of drilling mud or steam condensate, or by impairment of aquifer water quality.

(d) Subsidence, requiring reinjection of fluids.

(e) Dust and particulate matter.

(f) Emissions from cooling towers, which may include hydrogen sulfide, ammonia, boron, chlorine and other chemicals.

(g) Noise, such as occurs when wells are vented to the atmosphere.

(h) Some seismic uncertainty.

Noise and hydrogen sulfide emissions are the most significant problems to local people in The Geysers. The effects of carelessness of prior operators are evident in current proceedings.[66]

In California, first-line environmental control decisions are divided among different jurisdictions and a variety of agencies. Well siting regulation is a county function, as well as a function of the State Division of Oil and Gas and, for State domain, the State Lands Commission Power Plant Regulation is currently being transferred from one state agency to another; air pollution control is under another state agency;[67] water pollution control is under a district agency.[68]

Pollution control requirements and development delays increase when geothermal resource areas are rural and not industrialized. The local population may require that it be shown why proposed developments should be allowed. Leaving "temporary" pipe lines in place for protracted periods and failing to develop and adopt emission controls does not promote local approval for geothermal growth.

Public acceptance of geothermal development is also affected by the degree of public confidence in governmental regulatory bodies. While other areas may have fewer or different environmental problems, activity in The Geysers will affect public attitudes elsewhere. The Geysers Plan currently is being operated under a variance from air pollution control regulations.

Installation of equipment for the control of hydrogen sulfide emissions from generating unit cooling towers is not scheduled to be completed until 1981.[69] At that time, emissions from venting wells will still be uncontrolled.[70]

Applications to construct Units 14 and 15 were filed with the Public Utility Commission on July 24, 1973, and March 1, 1974, respectively. Certification required an environmental impact statement entailing a long procedure. Decisions were not made until the fall of 1976.

Delays encountered in developing an environmental impact statement for Geysers Unit 12 were attributed by Tom Cordell, Sonoma County Environmental Officer, in part to a decision by Union Oil personnel to ask the limited county staff to devote most of their efforts to assessments of additional development wells and not to Unit 12.

Assertions of supervening development needs for reasons related to the energy crisis have not to date been persuasive. Courts have forbidden pollution control agencies to deviate from their statutory mandates, and legislative loosening of pollution control laws has, generally, been quite limited.[71]

In the future, geothermal development may encounter severe new environmental restraints. If California state proposals to limit emissions to 150 pounds of a compound per day are adopted, geothermal practices in regard to drilling, and field testing of wells, and field piping could be severely affected.

Utilities, petroleum companies, and geothermal enterprises must consider the effects of technological uncertainties in their investment planning. Holders of geothermal acreage must weigh the carrying charges on leases against the benefits of waiting for extraction technology to improve and fuel prices to rise. They must predict future lease acquisition charges to determine whether to lease more or to drill on currently-owned leases. Smaller firms with pressing cash flow requirements must consider whether they should develop properties, assign acreage and retain only royalties, or seek joint venture development.

Technical uncertainty and delay in turn breeds further delay. Large petroleum companies with high rate-of-return criteria for investments do not wish to sink investment dollars into projects for which payout is five years away and will only occur if high prices are realized. Although such companies are in a position to warehouse projects by leasing acreage for future development or subleasing, they lack the incentive to supplant government research efforts or to try to solve geothermal utilization problems.

Innovation involves investment in risk-bearing activity. Utilities facing large investment requirements for power supply may be reluctant to embark upon unfamiliar, risk-bearing courses--they may seek to shift risks to others, and they will tend to be protective of their markets.

Firms which are experiencing good financial results are more likely to extend their holdings into new but related product lines, e.g., from petroleum to geothermal. However, the service firms on which petroleum companies rely for much of the innovative work in petroleum field exploration are not heavily capitalized, and oscillate between very good times when they are fully occupied, and slack conditions. These service companies are not geared for long delays in realizing the value of work done.

Current practices for leasing and developing prospects reflect concerns for avoiding drainage by others and for reliably securing an adequate resource supply.

Our discussions with geothermal industry participants indicate that it is considered necessary to obtain leases for an entire prospect before development either alone or in a joint enterprise. Their reasons include: not providing free information to adjacent leasees, avoiding drainage of a property by rival wells, and relatedly, avoiding problems of coordination and allocation among lessees. Small developers are concerned that a field purchaser might ignore them in favor of a sole source vendor. Firms conducting exploration activity are concerned that their work might lead to adjacent areas being classified as KGRA's.

These concerns have led to joint enterprises, and have created capital and time barriers to development as firms feel it necessary to lease to effectively utilize a prospect before development.

Geothermal development is in a regulatory quagmire: multiplicity of problems has spawned a multiplicity of agencies and inter-agency groups. One way of lessening the problem might be to reduce the number of problems which necessitate extensive inquiry. If field developers and utilities on a project coordinate how questions are presented for regulatory action overtaxed agencies might make "bottleneck" decisions in a more timely manner while decisions less critical to a project are put off.

Each stage of regulation reflects legitimate public concerns about protecting the environment, the public domain, and the property of others. The number of agencies involved reflects to some extent the variations in land ownership and the different interests and apprehensions of persons at varying degrees of remoteness from proposed operations. The totality of regulatory procedures reveals multiple points at which environmental impacts are assessed. This indicates that there is redundant work in an area where the limited number of component personnel should concentrate on substantive issues. Consequently, developmental decisions are often delayed or made so expensive as to raise economic barriers to smaller enterprises.

Exclusion of enterprises which could develop geothermal resources while complying with pollution control requirements, could result in adverse consequences to the "human environment," which statutes such as the National Environmental Policy Act are concerned to protect. This results not only from the direct non-productive use of dollars, but also from the effect that increased concentration of industrial ownership may have on the governability of business enterprises.[73]

The investigations for and writing of environmental impact statements have required considerable time periods. At times this process has been lengthened by applicants' slow responses. In addition, waste and delay have resulted from a lack of focus on the material issues to be decided.[74]

A failure to focus on and resolve material issues leads to a failure to protect the environment. Such a failure makes the environmental impact statement an unguided missile: an end in itself, of little use in drawing reasoned conclusions from an adequate record. An example of this problem is found in the licensing of The Geysers units.

While considerable time and effort were apparently expended on air pollution questions in recent Geysers licensing proceedings, the decision rendered fails to contain explanatory findings of fact, and basically concludes that resolution of air pollution problems is a matter for other agencies. The impact reports fill up hundreds of pages. But they do not lead to decisions which cope with major problems. In failing to make findings and resolve disputes, the decisions reflect a process of trial by attrition, not by reasoned judgment.

The purposes of the National Environmental Policy Act ("NEPA") 42 USC § 4321 et. al and its State law progeny[75] might better be served by the presentation of prohibitive evidence at a hearing where it would be subject to cross-examination and rebuttal. Most importantly, at a hearing such evidence would, of necessity, be focused on the major issues, without speculation on matters with little relationship to the physical processes at hand.[76]

Delay problems plague geothermal leasing at the federal as well as the State level. In particular, the Department of Agriculture's Forest Service has been a serious bottleneck to geothermal exploration in some areas.

Applications for geothermal leases within lands administered by the Forest Service are not affirmatively acted upon by the Interior Department until the Forest Service concurs.[77] There appear to be instances where the Forest Service first determined that an environmental assessment is required prior to its concurrence, and then failed to proceed to develop such an assessment.[78]

As before noted, the detrimental effect of delay weighs especially hard on smaller enterprises who must plan their power supply in advance and who want to proceed with geothermal development, but are not likely to be able to bid against parties with speculative "front-end" money.

Delay increases the likelihood of an overlapping filing and consequent designation of an area as a Known Geothermal Resource Area, and competitive bidding.

While the Forest Service is delaying issuance of an environmental assessment of proposed schedules under a lease of federal lands, pre-lease exploratory work by a prospective developer is apt to stop. If the developer generates information indicating the presence of a geothermal resource, it is obligated to supply this information to the Interior Department. If the Interior Department determines a geothermal resource exists, it is obligated to seek competitive bids. The party generating the information then may lose the competitive bid, and has no means of recovering the costs of work done from the value discovered as a result of the work.

As Mr. Barnett, consultant to the rural electric cooperatives, testified:

> If we were to proceed without those leases being issued to collect additional geological information, that very information could be used against our purposes and have the area described as a known geothermal area and open the area to competitive bidding to whoever might find an interest after our initial exploration...[79]

Caution as regards exploration impacts on the environment is readily understandable. Difficulty in setting priorities for limited agency budgets is understandable. But a continuation of present budget priorities seems likely to stymie potential geothermal development work. Delay in evaluating proposals to develop a resource usable by small public utilities, while pressing ahead with coal or gas leasing used by major companies which often have dominant market positions, seems likely to add a bias toward greater economic concentration in the electric utility sector.

POTENTIALS FOR PRECLUSION OF GEOTHERMAL PROSPECTS AND SERVICES

Entry into geothermal development can be substantially restricted when services of firms most familiar with an area are exclusively contracted for by a limited set of potential buyers.

Geothermal firms are in large part service enterprises - grouping prospect tracts and performing exploration services. Such firms are limited in number. Some are, of course, more familiar than others with prospects and problems of particular areas.

In at least one major instance, purchase and sale agreements and joint venture agreements contain, respectively, red-line or area-of-interest provisions giving the purchasing party, or the financing party other than a purchaser, the option to purchase output, or participate in all prospects of the second party located within the designated area.

The areas covered by such agreements can be quite large, encompassing entire states in the case of joint ventures.[80] Purchase and sale agreements typically cover smaller areas.

It can be argued that designation of large areas is required to protect a prospect from drainage, or to prevent a service company from prematurely going off to other jobs, or to reduce the possibility that information obtained in one project will be improperly applied to benefit another.

Such provisions can, however, restrain trade--particularly if the number of prospects is limited, or a contracting party is a leader in an area, or the most likely acreage is preempted in an infant industry fraught with uncertainty.

Such competitive issues have been raised in a formal court proceeding.[81] While the court found reason to be concerned with such issues, it left their determination to a public utility commission, which discovered no anti-competitive impact in the facts before it.

The Northern California Power Agency raised antitrust issues in a California Public Utility Commission proceeding on a PG&E application to build generation units in The Geysers area.[82] The Commission refused to afford a forum for the contentions. On appeal, the California State Supreme Court remanded the order of the California Public Utilities Commission certificating the generating units, so that the Commission might adequately consider and make findings on the antitrust issues raised regarding steam purchase contracts. The Court noted, in holding that the issues required examination, that the "red-lined" area was of substantial size and economic consequence.

Upon remand, the Commission rejected the allegation of anti-competitive effects--as it has done on subsequent licensing proceedings. However, the Commission has never made more than bare conclusory findings on this subject.

Although alternative prospects are available in The Geysers area, it is not clear what the effect of contractual practices has been upon other would-be entrants. In the context of other power coordination practices, it appears, as will be discussed infra, that such practices, and practices such as Utah Power & Light Company's extensive filing of water appropriation claims, have a chilling effect on entry.

Joint venture agreements tying up a development company for all acreage in a State do not seem justified on the basis of a need to appropriate value of services in a particular field or pool. If service companies and sites are plentiful there is little need to be concerned about a particular service firm's severing relationships. If knowledgeable service companies or prospects are rarer - as appears to be the case with current technology - tying up service firms may create a real problem for later entrants. The services of service firms can be assured, perhaps more reliably, by other types of contract provisions.

Petroleum companies, and land companies hoping to sell leases to them, have acquired substantial acreage on geothermal prospects.

Firms such as Gulf Oil, Socal, Union Oil, Getty and Phillips Petroleum have amassed substantial holdings. As the information in our section on exploratory activity shows, these firms, and other firms leasing geothermal acreage, appear to have undertaken little drilling. For instance, Amax

(Socal) has not drilled on its extensive Geysers area holdings.

A would-be entrant will find substantial acreage withdrawn from the market, and must compete for future acquisitions with firms having deep pockets and, apparently, warehousing practices.

STATE PRODUCTION CONTROL

Western states have legislative provisions regarding well spacing and encouragement of production up to maximum economic rates.[83] These provisions reflect concern about equitable treatment of owners of adjacent tracts. The statutory provisions related to conservation, creating authority to affect output levels, bring into being a device used by some State Conservation Commissions in the petroleum industry to restrict production so as to maintain prices.

An example of such provisions in geothermal legislation is found in New Mexico's Geothermal Resources Conservation Act which, at Section 65-11-4 (9, Part 2, New Mexico Stats.) prohibits "waste" which is defined, at Section 65-11-5 (C) to include production in excess of the reasonable market therefor.

The Oil Conservation Commission is authorized, at Section 65-11-9, to limit, allocate and distribute the total amount of geothermal resources which may be provided from a reservoir. The Commission, at Sections 65-11-10 and 11 is authorized, after notice and hearing, to allocate production among geothermal wells, including in the allocation any well it finds is being unreasonably discriminated against through denial of access to a geothermal resources transportation or utilization facility which is reasonably capable of handling the geothermal product of the well.

Similarly, the Commission is authorized to allocate production well spacing among owners of a geothermal reservoir, (Section 65-11-11), and can mandate utilization.

Owners of land within a well spacing unit are to be compensated for production - either under a voluntary pooling agreement, or in like manner. (Section 65-11-13).

In the event that some owners of a "working interest" in a reservoir do not pay in advance a pro-rata share of drilling costs, there is to be a deduction from revenues attributable to such part owner of drilling and completion costs, plus an allowance for risk set by the Commission.[84]

As regards discrimination by a purchaser toward producers, Section 65-11-14 provides that one taking or purchasing geothermal resources in a geothermal reservoir is to be a "common purchaser" of all tenders at a reasonable point without discrimination among producers - even if a purchaser is also a producer; subject to a number of qualifications which leave substantial discretion to purchasers and the Commission.[85]

Geothermal developers appear to rely primarily upon contracts to allocate responsibilities, rather than the provisions of state regulatory law, or their enforcement.

Fear of being left out, or of not achieving an all-embracing voluntary pool, may have led to such statutory provisions; and in particular situations may lead to hurried and inequitable arrangements, or delay exploration.[86]

Long lead-times, the close relationship between field and generating plant development, and inability to store produced geothermal energy, require advance joint planning between producers and generating entities. Parties not involved in that planning will likely be excluded from sales as a practical matter. As in electric power supply coordination, access to planning is vital.

The provisions of state law allowing state pro-rationing of production, noted at the outset of this section, could conceivably prove a problem to efficient willing producers.

Pro-rationing has tended to favor inefficient producers.[87] It offers each state an opportunity to attempt to function as a little OPEC,[88] maximizing its economic rent. Oil pro-rationing has never been fully effective as a price controller. But it has significantly affected oil structure and performance.[89]

There is no federal enactment regarding geothermal energy equivalent to that which sanctions state pro-rationing in the oil industry.[90] State regulation of "economic" as opposed to "physical" waste may be constitutionally suspect as well as unworkable if there are a number of prospects in various states.[91]

Smaller enterprises principally located in only one state may be disadvantaged by the state's production controls - as compared to other larger enterprises who can trade in several states, and, for generating firms, who have access to interstate power lines.

MARKETING GEOTHERMAL POWER

There are two major marketing patterns for geothermal energy: sales from field developers, as in The Geysers, and developer-user joint ventures.

The field developer (including a joint venture) is ordinarily responsible for delivering the working fluid to the generating plant intake. The price he receives will probably be related to either generating unit output or the quantity of energy made available to the generating unit.

Prices may be set either on the basis of costs (including return on investment) or by the "commodity value" of energy. Some utility systems have sought to tie price to the costs of development while developers seek price provisions that are tied to alternate fuel costs and contain escalation clauses. Developers sometimes seek take-or-pay or other minimum charges.

Geothermal prices for resources developed without utility participation are likely to reflect costs of alternative fuels, while prices of energy produced with utility participation in development will more often be based on costs incurred.

A firm generating electric power for sale to others usually must be a utility that files tariffs with either a state utility commission or the Federal Power Commission. Thus except for industrial entities engaged in generation of their own power needs, generation will be by utilities, not by oil/geothermal entities who seek higher rates of return on investment.

A combination of factors may incline utilities to prefer to own sources of geothermal energy-supply generation rather than to purchase energy produced by others. Rate base advantages may accrue from ownership. Bulk power market positions are not threatened by ownership. Risks to operating security may be minimized by ownership.

As against this, utility financing and risk avoidance problems might be alleviated if geothermal units were to be installed by others[92] and their output purchased.

An arrangement intermediate between utility construction and separate ownership of a geothermally powered generating station is to have a separate entity construct such a station and the utility purchase it after the unit proves itself. Institutional problems may interfere with such post-operative sales. The return earned on the unit would be subject to regulatory review under the Federal Power Act as the seller would be a public utility having to file tariffs for its sales in interstate commerce. If the selling firm is owned by another enterprise or person, an exemption will have to be sought under Section 3 of the Public Utility Holding Company Act. 15 USC 79 (c).

Pacific Gas and Electric Company presently generates more electricity from geothermal energy than any other entity in the world. However, as was shown above, large utilities cannot be expected significantly to increase their involvement in geothermal projects.

A primary reason is that the scale of a project is too small to warrant the managerial resources required. Other reasons may include public relations concern over boosting what might be construed by the voting public to be a viable alternative to nuclear power, and the reduction in concern over escalation in fuel prices with the advent of fuel adjustment procedures. Also, utilities having large alternative sources of power may have less need to expose themselves to the risks involved in a new technology.

It will be shown in Chapter 3 that a hostile environment for small utilities exists in the western United States and that this environment has the double effect of creating an urgent desire to develop an independent generating capability and frustrating present attempts to fulfill that desire. Many smaller public power systems in the West are seeking to enter into self-generation. Heretofore many of these systems have relied on federal hydro generation or purchases from large private systems. Federal hydro power can no longer meet their expanding needs and reliance on wholesale purchases can be very detrimental to system growth and survival because of anticompetitive problems, described hereinafter.

The small scale of geothermal generation is well within the reach of small utilities. (Larger fossil or nuclear units entail joint ownership arrangements.) The load growth possibilities of geothermal capacity loom far larger for a small than for a large utility, and make better use of managerial time for a smaller utility. The smaller system often does not have simultaneous competing opportunities for large nuclear or fossil units under its management control.

To utilize geothermal units successfully, however, small utilities need access to reserve capacity, transmission, and bulk power supply coordination services. These can be sought from large investor-owned utilities and the Federal power agencies. Transmission is needed to connect geothermal fields with load centers,[93] and uncertainty as to coordination and wheeling or exchange services could rob small systems of their already constricted ability to plan and finance geothermal development within the time span that a field developer is willing and able to wait for a market.[94]

Small systems are generally not interested in geothermal energy if its price is tied to that of oil; they want a cheaper energy source. Their development plans will likely reflect this desire. There is a belief in some public power quarters that pricing problems in the geothermal area are created by petroleum company control of geothermal resources.

It has been shown in a previous section that petroleum companies have obtained most of the leases to federal geothermal lands and that there is little evidence of development. The large petroleum companies' failure to engage in rapid development efforts apparently is due to the existence of more advantageous investment opportunities elsewhere.

Geothermal activities take seven to ten years to result in production and revenue. Investments in gas and oil operations generate revenue earlier, involve more reliable technology, receive more favorable tax treatment, and have higher anticipated rates of return than investments in geothermal generation.

In addition, petroleum companies have much more flexibility in dealing with oil and gas than in dealing with a geothermal field. A geothermal field can only yield heat that would be valuable to facilities installed in close proximity to the field.

The market most likely would be confined to one of the few electric utiltiies in the area.

Moreover, geothermal energy so developed would compete with other energy products of the same petroleum companies such as residual oil, natural gas, coal, and nuclear fuel. Sullivan, McDougal, and Van Huntley noted that an inverse relationship between petroleum company activity in offshore drilling and geothermal development on the west coast could be observed before and after the Santa Barbara oil spill incident.[95]

Warehousing of geothermal prospects by major and large "independent" petroleum companies is accomplished by often being the high bidder at sales in which there is competition to secure leases and by being the only bidders for those tracts whose commercial worth is so speculative and remote that bidding is not practical for smaller enterprises bent on development.

The low prices and few bids received indicate that leasing of poorer prospects is going on at a rate in excess of markets for development, yet ERDA and petroleum companies continue to lobby for leasing by BLM and the Forest Service.

As of April 30, 1977, the federal government had 1,612,463 acres under geothermal leased to others--mostly undrilled.[96]

Independent geothermal developers have been active. However, they are limited in the degree to which their activity could be expanded by financing problems and "speculation"--withholding development in anticipation of price increases.

Unlike major oil companies, the independent developer has to obtain external financing. Given the technological uncertainties, absence of tax advantages, and limited market for geothermal heat, such financing has been forthcoming primarily from the electric utilities which would be the purchasers of the geothermal heat, and from joint enterprises headed by large oil companies.

Large investor-owned utilities do not have the incentive to significantly expand their present contractual commitments to finance independent geothermal developers. Small utilities such as municipals and cooperatives, have the loads[97] and an intense motive to participate with independent geothermal developers in rapid development of geothermal energy resources, but are held back by the hostile environment in which they exist.

Joint enterprise between independent geothermal developers and small utilities for the development of geothermal generation might be a promising strategy for small utilities. To such joint enterprises - such as joint venture arrangements for finding and developing geothermal resources - a small utility would bring much of the financing and a capability to convert geothermal energy into marketable electricity. The independent geothermal developer brings to the partnership some financing, technical expertise and manpower for development and operation of geothermal wells, and the ability to use investment tax credits, and other available tax write-offs.

Again, before this strategy could become widely used certain changes will have to occur in the environment for small utilities, and the small utility and the developer would have to see eye-to-eye on energy pricing.

Industrial firms are constrained as developers and users of geothermal energy because they are unaccustomed to, and unenthusiastic about, being subject to the utility regulation. As geothermal developers, they might be forced into unfavorable sale and repurchase agreements by uncooperative utilities; and bulk power coordination may be available, if at all, only on harsh terms.[98]

Industrial energy consumption is heavily concentrated in a relatively small number of industries - primary metals, chemicals, petroleum refining, food processing, paper, and ceramics. These industries are most likely to be attracted by the economies of a system of self-generation which also affords process heat or cooling water. Geothermal process heating requires low salinity fluids occurring near plant sites.[99]

Joint production of process heat and power requires coordination of generation and process heat use. Self-generation can be operated in parallel with a utility system with which sales and exchanges are effected if regulatory and competitive problems[100] are overcome.

Self-generation requires capital outlays while purchase, on the other hand, gives current expenses reducing taxable income.[101] The return on plant is unlikely to equal that earned in production.

Industrial self-generation could, like municipal self-generation, attract enterprises for whom a 100 megawatt resource is significant. This is particularly so if the industrial load is interruptible, so that stand-by arrangements are not critical.

Rapidly rising industrial power rates may make use of "waste" heat at industrial sites more attractive.[102] As energy costs become a larger proportion of total costs, more management time and other corporate resources may be used to limit increases in energy costs. Also, we have been told that the possibility of reducing power costs while obtaining a secure power supply has been a factor inducing industrial investment in geothermal power.

In California, air pollution control regulation may prevent the use of coal-fired boilers, oil is very expensive, and natural gas supply is being curtailed. These conditions make geothermal self-generation more interesting.

Industrial public power generation will not be feasible without receipt of credit for geothermally driven generation as "firm" capacity not requiring unusually large reserves. Before utilities will treat the capacity of a generating unit as "firm", they will insist on its assured availability, and may insist on controlling the operation of the unit. In the absence of a capacity credit, (a) an industry or utility may save no demand charges on its bill, and (b) the price for its power will be at a "dump energy" rate, only a little above incremental operating costs.

If capacity sales are made only after a substantial discount for reserve requirements, the kilowatts credited as sold are reduced, and recovery of capital may be jeopardized.

To the extent geothermal capacity is not marketed as firm capacity, energy sales may occur only at economy or "dump" rates. Prices for "economy" transactions are usually midway between the seller's incremental energy costs and the buyer's incremental energy costs.[103] (For example, if a seller has energy costs of 7 mills (not including recovery of capital charges) and a buyer has energy charges of 23 mills, the sales price is 15 mills.) Dump sales are for but a few mills. If capacity is not treated as firmed up, "dump" sales seem much more likely than "economy" sales.

Sales to other power systems - made at split savings or on a cost plus basis - would be profitable. Also, if use of geothermal energy lowered average costs, utility would profit due to regulatory lag.

Purchase and Sale Agreements

The use of geothermal energy to produce electric power necessitates a close, long-term relationship between steam producers and utilities.[105]

Terms of agreement for the purchase and sales of geothermal steam determine the distribution of risks, the ability to sell or purchase from alternate parties, and the cash flows a developer will experience. These factors both reflect and determine the market power of parties, and they define capital requirements of field development.

If the market for geothermal energy were such that sellers competed against each other to make sales, then prices would be set at the cost of producing energy at the increment being sold. However for a market perceived as encompassing all types of energy for base-loaded units, vendors will seek a price reflecting the buyers' other choices and will compete only if one vendor believes another's transaction would cost him a sale.[106] Because of the novelty and risk of geothermal energy, vendors perceive that the value of the geothermal commodity is somewhat less than that for alternate, more conventional energy types. Consequently, their offering prices will start at a discount from the prices of energy alternatives.[107]

Geothermal developers of all types are seeking such a discounted price. We have found in our interviews that the cash flow requirements and specialized nature of some smaller firms make them more vulnerable, and hence mroe willing to give larger discounts than some of the larger enterprises. Similarly, some smaller firms are particularly receptive to the idea of joint venturing with customers who would own part of the working interest.

As noted, geothermal energy vendors want prices based on the amount of heat delivered by them, rather than on kilowatt-hours generated. They believe a cents-per-million-Btu price would encourage efficient use of the steam and enhance its value. Their concern about the consequences of being tied to a particular generator has led at least some producers to seek take-or-pay provisions that require the purchaser to pay for a minimum amount of energy, if tendered, even if the generating unit is not operating. Take-or-pay provisions limit the buyer's flexibility in choosing between energy sources.

Buyers who are seeking to reduce prices to costs (with a return of less than the 20-25% sought by a number of developers) must, first, assess their ability and willingness to enter into a geothermal venture on the scale necessary to ensure evaluation and testing of a sufficient number of geothermal prospects.[108] Secondly, they must assess the impact of a price on future geothermal investment both by their suppliers and by their shareholders or governing boards. Finally, they must try to find a way out of the present seller's market for energy.[109]

Some preliminary appreciation of the problem may be obtained by comparing company heat costs (inclusive of return on investment) with prices. If a drilling and development program costs \$10 to \$16 million, as estimated by an FTC staff report, yielding a capital cost per kilowatt of \$262.00,[110] the amortized cost per mill rate at an 80% capacity factor would be:

$$\frac{262}{7000} \text{ X } \text{(Fixed Cost Rate)}$$

"Fixed costs" (or an amortization rate) of 20% yield a cost of 7.5 mills; and fixed costs of 25% would yield 9.35 mills. (We are ignoring well operation and maintenance costs, which are expected to not exceed a mill per Kwh).

Using field development costs of $31.5 million as presented in a recent paper by Greider of SOCAL, we find that for an 80% capacity factor operation, and a rate of return on investment of 20-25%, costs not including operation and maintenance range from 4.5 to 5.6 mills per Kwh. By comparison, discounts of 20% from the price of $12 a barrel for oil yield fuel costs of 16 mills per kilowatt hour.

This kind of cost calculation gives a utility considerable incentive to push for cost-based pricing, or to consider developing its own geothermal resource.

Agreements such as those entered into by NCPA, Burbank and Utah Power and Light Company are likely harbingers of the future pattern of development for smaller geothermal enterprises. Such enterprises will probably look to utilities for financing, while providing prospect tract aggregation services and/or expert geothermal exploration services.

The small firm in a utility joint venture can seek to make sizable profits on its share of production and still leave a large share of production for the utility; also, the small firm could make a large portion of these profits from project tax deductions: e.g., abandonments, accelerated depreciation, investment tax credits, and perhaps depletion and intangible drilling costs - which utilities are unlikely to be able to use because they are tax exempt or have very low effective tax rates.[111]

Non-joint venture marketing will be attempted by larger petroleum companies. These firms seek prices based on "the value of the energy" as determined by costs of alternative utility fuels. They have the wherewithal to submit higher bonus bids in anticipation of later selling geothermal energy at such prices. These firms also do not make money solely by providing services and have the cash flow to permit warehousing of geothermal prospects.

In offering sales of steam without requiring prior buyer participation in field development and production, larger firms may be offering utilities a less risky avenue into geothermal development.

On the utility side of the market, utilities looking for a low cost alternate fuel seem unlikely to be able to participate in highly competitive bidding for lease tracts. High lease bonus bids would tend to drive up project costs, and raise the prices of energy produced. Also, smaller firms are not likely to have the resources to pay large bonuses. Thus sales from competitively let properties may be expected to generally be from producers to utilities; on other tracts, producer-utility joint ventures are to be expected.

While utilities are not high risk-taking entities, and prefer to participate in projects on prime sites, possibilities for leasing private land, and low bid prices may permit them to find some suitable prospects.

Smaller power systems are accustomed to lower federally generated power costs and are very cost conscious. They cannot simultaneously participate in many projects to avoid risks in delay of one or two. Accordingly, they seek participation in development programs in a way giving them an active role in decisions governing timing of development and providing lower cost energy.

Larger utilities having a number of generating resources may feel less restrained in dealing with large petroleum companies in a mutually dependent arrangement such as geothermal development than they would with smaller firms. In purchasing steam, utilities may prefer to deal with substantial firms who have the assured financial capability to develop a field over a period of years. Their participation in fuel resource projects will necessarily be directed first toward securing coal and uranium resources for their future large base load units. Combination utilities, such as the Pacific Gas and Electric Company also are engaged in gas supply ventures.

Overall, the current situation in which large utilities deal primarily with large petroleum firms (or large firms grouped in joint ventures with small ones), and smaller utilities deal with smaller firms, is likely to persist. Vendors of geothermal energy thus may generally tend to be either large companies and independently engaged primarily in sales of petroleum, or vertically integrating utilities.

Frederick Scherer has stated that "the more prone input markets are to a breakdown of price competition, the stronger is a firm's incentive to integrate upstream."[112] Vertical integration by utilities will only result in cost competitive entry if the utility has reason to be cost conscious. Otherwise, it may merely provide an opportunity to pass along to consumers the price charged by a utility's unregulated fuel affiliate, and preclude markets. If pressure from regulators, or better yet, competition in bulk power markets induces a utility to be cost conscious, utility fuel affiliates could provide competition to oil companies.

Vertical integration, by both large and small utilities, is unlikely to be of such scale as to present severe diminutions of competitive potentials. Smaller systems which vertically integrate are unlikely to present market preclusion problems, by virtue of their limited size. Because of other cost disadvantages--in part a result of anticompetitive coordination and rate-setting by larger utility systems--the smaller systems are more likely to pass fuel savings along in order to keep their rates competitive.

At the same time, these small systems do provide an alternative mode of geothermal development seeking cost based pricing--not prices based on alternative fuels or what the traffic will bear. Were geothermal developers to come forward with cost-based prices, there is no reason to believe that they would find the market closed to them.

Geothermal firms are concerned about the range of markets available to their production. A variety of customers could provide joint venture opportunities, while avoiding the influence that a single customer may bring to bear. Furthermore, buyer competition may bid up field prices.

Geothermal developers that we contacted were sanguine about having at least one market for their energy from proven fields, but not about having multiple outlets. They were aware of possible wheeling problems, generally expecting to offer the product only to the local utility. Such limited marketing expectations may be attributed in part to the reluctance of one private utility to erect plants in the service area of another.[113] This reluctance has been reported to us by utility personnel, energy companies, and by a California Public Utility Commission staffer who has been "informed" it is Commission policy.[114]

Geothermal energy sales are, to date, all made to the Pacific Gas and Electric Company in The Geysers. Vendors there are: (1) a joint enterprise made up of Union Oil Company of California plus a joint enterprise of Magma Power Company and Thermal Power Company (now a subsidiary of The

Natomas Company); (2) Aminoil (successor to Burmah Oil and Gas Company); and (3) Pacific Energy Corporation.[115]

The contracts under which steam is purchased and sold in The Geysers are noteworthy in several respects. In each case, the seller developed steam to support a unit, prior to the contract, and is obligated to develop steam well in advance of receipt of any revenue. In each case, all present and future reserves of the seller in a larger "red-lined" area are dedicated to PG&E, who has access to producer field data.

Producers have a duty to continue to explore and develop their acreage. The obligation of PG&E to install units to employ developed steam is loose.

PG&E has a substantial amount of time within which it may elect to construct a generating unit. In the Union-Magma-Thermal agreement, PG&E may defer a unit for up to eleven years.[116]

Producers can only sell steam to third parties if such steam is free of PG&E's purchase rights, and only if it can first be established in a arbitration proceeding that such sales will not detract from the steam supply of PG&E units within their expected remaining life. In such arbitration current lack of a generally accepted reservoir theory might prove an insuperable barrier to outside sales.

In each case, the price of steam is tied either to average costs for fossil and nuclear generated kilowatt-hours, or (for Pacific Energy

Corporation) the average annual cost for gas and oil. For all these contracts average fuel costs are weighed by the lowest PG&E unit heat rates.

For a geothermal unit to be economical it must be able to employ the high voltage transmission lines of others, to sell its output as a part of the bundle of power services required by most users, and to find alternative markets in which to sell output in excess of demands of regular customers.

Thus a certain level of cooperation among power systems is requisite. We will now describe how power systems compete with one another and how larger systems decline to cooperate with smaller ones seeking self-generation. This refusal to coordinate constitutes a major barrier to development of geothermal energy.

CHAPTER 2

Notes:

1 Concentration of extractable heat at depths less than three kilometers (about 9900 feet) may be considered economic resources. With the present technology and economic limits imposed by the opportunity cost of substitute fuels, drilling can only be done profitably to a depth of between 9,000 and 10,000 feet. At greater well depths, drilling costs increase at an exponential rate, and problems of cooling of rising fluid in wells commencing to flow increase.

2 Localized use of geothermal energy for space and water heating occurs in the West. However, the geographic coincidence of such demand and supply is limited.

3 Use of accelerated depreciation by a utility on its tax return may not be paralleled in its rate cases where straight line depreciation may be used. The tax saving resulting from accelerated depreciation is not required to be passed through to consumers in some states. This "normalization" in which tax expenses are charged rate payers as if straight line depreciation had been used on utility tax returns provides interest free capital.

4 Financial and Tax Assumptions are:

	Reservoir (%)	Powerplant (%)
Capitalization		
Debt	42	59
Equity	58	41
Bond Interest Rate	8	8
Return on Equity	15	12
Federal Income Tax Rate	48	48
Property Tax Rate	2.5	2.5
Royalty Payment	10	--
Revenue Tax Rate	--	4

In this study it was assumed that the plant would be down for maintenance and repair 20 percent of the year. Thus, the plant availability is 80 percent . supra. p. 11

5 Additionally, development of geothermal energy would result in avoidance of other "external" costs associated with pollution and with the use of foreign-derived fuel that might be incurred with other fuels.

6 See e.g., Wall Street Journal June 7, 1976, and Edison Electric Institute, Nuclear Fuel Supply (1976).

7 Nuclear power plants are very capital intensive, and their costs directly track construction lead times. Furthermore they have been subject to siting problems on the West Coast, as well as severe cost inflation.

8 Oil fuel costs are now 20 to 25 mills per kwh, assuming a heat rate of 10,000 btu per kwh. Busbar costs of fuel can be computed by dividing fuel prices by the heat content (Btu's) in a barrel of oil and then multiplying by the heat rate.

9 FPC Staff Report Annual Summary of Cost and Quality of Steam Electric Plant Fuels, 1973 and 1974.

10 The most recent geothermal units in The Geysers have gone into operation far behind their original schedule. Delays in scheduled operation of new units are endemic in the power industry. See infra.

11 This lower risk apparently reflects the present early stage of geothermal exploration in which sites with surface explorations remain unexplored. As this easy layer of sites is tested, the successive layers of sites may be more risky to explore. If technology does not develop or perform as projected risks may shift.

12 The distribution of costs among various elements of 55 mw isobutane binary-cycle plant have been estimated by C.H. Bloomster of Batelle Pacific Northwest Laboratories in Economic Analysis of Geothermal Energy Costs (November 1975).

13 For instance, two of three wells drilled by Magma and Union Oil at Brady Hot Springs, Nevada appear to be commercial.

14 The drilling program cost forecast, which ranges from a maximum negative cashflow of $16 million down to $11,000,000, assumes a 25% rate of return; $10 million would be required at a 15% rate of return. Rates of return of 20 to 25% were stated by Mr. Greider and several other petroleum company personnel to be "realistic" for geothermal. With 350° F. water, a price of 30 mills would be required for a 15 to 20% return on investment. 20 mills required for a 15 to 20% return with water of 400° F.

Lease bonus amounts are determined by predicting program producing risk and then adding increments of bonus sums until the anticipated rate of return is reduced to the lowest level deemed "acceptable." Projected costs are lower for smaller programs and those less oriented toward wildcatting or perhaps otherwise anticipating a higher success rate. Government personnel estimate costs ranging from $4.5 to $8 million to find and develop a field for electric generation.

15 Wells in The Geysers run from $600,000 to $800,000 although one costs about $1,300,000. Use of directional drilling from drilling islands might add $200,000 to well costs. Conversation with Mr. Mel Schrecongost, California Division of Oil and Gas, Sacramento, California.

16 The risks of drilling a "cold" hole are primarily exploratory, and not development risks. Burmah Oil's Annual Report for 1974, page 20, indicates that four of the five steam wells drilled by Burmah Oil and Gas in California in 1974 were successful and brought the number of completed wells to thirteen. ERDA research plans regarding drilling of "slim" holes could greatly assist in reducing the costs of exploration and resource delineation.

17 In The Geysers area, taxpayers prevailed in United States v. Reich, 454 F.2d 1157 (CA 9, 1970) (and see, Geo. D. Rowan, 28 ICM 797 (1969)) which held that intangible drilling expenses and depletion deductions are available. However, the Internal Revenue Service has not acquiesced to this holding.

The Senate Finance Committee recently (May 1975) voted to proffer intangible drilling deductions and a 22% depletion allowance to geothermal development. These provisions passed the Senate but were dropped in conference.

18 Complete passing along of tax savings to reduce costs at the busbar would result in no additional capital formation via retained earnings by field discoverers or producers. If, as may be expected, the "wildcat" explorers are different than are the field developers, percentage depletion will confer little benefit on explorers in tax savings which would result

prior to production.

19 P.L. 84-455, 26 USC § 465 (1976). Knutson employs these six hypothetical references cases:

REFERENCE CASE DATA

Category Represented	Wellhead Temperature °C	Flow Rate 10^3 lb/hr/well	Well Cost $ Thousands	Cost of Generation Mills/kW-hr
Dry Steam	182	100	300	14.5
HTLS 1	250	500	300	15.6
HTLS 2	225	500	300	18.9
HTLS 3	175	700	300	24.0
HTLS 4	175	600	300	25.9
HTLS 5	175	500	300	28.9

Id page 14.

Treating tax reductions as net reductions in costs, he presents the following table: showing "cost reductions due to lower taxes":

THE GENERATION COSTS FOR DIFFERENT TAX SUBSIDIES

Cost of Generation (mills/kW-hr)

Resource Category	Reference Case	15% Depletion Allowance	Intangible Write-off	Both Allowed
Dry Steam	14.5	13.2	13.3	12.2
HTLS 1	15.7	14.5	14.8	13.7
HTLS 2	18.9	17.2	17.6	16.1
HTLS 3	24.0	21.7	22.4	20.3
HTLS 4	25.9	23.3	24.0	21.7
HTLS 5	28.9	25.9	26.6	23.9

Id. p. 17.

A 15% depletion allowance is shown and not the 22% allowed for oil and gas. This is explained by Knutson as follows:

There is a limitation that the depletion allowance cannot exceed 50 percent of the net income from the property. This limitation reduces the effective percentage depletion available. With this limitation in mind, a 15 percent depletion was used in determining cost of generation in this study.

20 Taxes are just another cost.

21 Municipal entities may appear to have competitive advantages--chiefly their low-cost financing ability. But this advantage cannot be brought

into play until drilling costs have been successfully borne. At that earlier stage, entities for advantageous deductions available for drilling expenses are in a more favorable position.

22 Rate of heat transfer per hour per unit area of heat exchanger per unit temperature difference between fluids (Btu/hr/ft^2/$^\circ$F.).

23 Heat exchanger costs vary directly with well fluid temperature, unit costs of exchangers and heat transfer coefficients.

24 For a given temperature, there is a strong relationship between flow rates and energy costs.

25 April 1975 Report of West Systems Coordinating Council to FPC.

26 2.6% of 91,000 megawatts is 2,366 megawatts. (This 2,366 mw includes geothermal, fuel cells, etc.)

27 ERDA, Definition Report: Geothermal Energy Research, Development & Demonstration Program (ERDA-86) (October 1975) p-I-12.

28 Id-, p. I-13.

29 The Northern California Power Agency (NCPA) seeks to develop 165 mw ultimately, with 66 mw by 1979-80. The City of Burbank seeks to develop several hundred megawatts and develop geothermal power, preferably in The Geysers.

30 ERDA-sponsored work with San Diego Gas and Electric (SDG&E) in the Imperial Valley on development of heat exchangers is going to take several

years, and will then require testing in a 10 to 50 mw unit. The rate at which other systems can be expected to amend their ten-year planning cycle to add a novel type of generation is limited. This is especially so in light of the dissuasive effect that federal power marketing programs and loan guarantee proposals may be expected to have on investment by public bodies.

31 Thus it is unlikely that a geothermal program could be started in time to take over a substantial portion of the California State Department of Water Resources' present power supply arrangements (800 mw) which lapse in 1983.

32 The plans of the larger systems must be firmly developed years in advance of fruition. These plans as reported to the Federal Power Commission (FPC) (1975) do not envision geothermal development elsewhere. Plans submitted to ERDA for research work by SDG&E do foresee limited pilot development of 10 to 50 mw over a decade. Utah Power & Light also may install some generation. For other utilities, plans for geothermal generation are not firm.

33 However, as late as 1968, self-generation provided 17% of industry electric power.

34 The following reasons were listed in a recent report by the Dow Chemical Company:

1. Corporate income tax rates that favor expense over capital investment and foster shorter-term thinking.

2. Risk differences requiring industrial firms to seek higher returns than do utilities.

3. Decreasing central station power rates -- leading to substitution of power for steam and decreasing the industrial steam base.

4. Unavailability of labor skilled in handling coal-fired boilers. (Gas and oil-fired package boilers--requiring little supervision--are generally not suitable for power generation.)

5. Shortened work weeks in many industries, leading to operating problems and decreased usage of capital equipment.

6. Widening of the gap in size--and hence economy of operation--between central station and industrial generating equipment.

7. A management attitude that "We're not in the power business"--or one that attempts to impose on power operations the policies regarding operation, maintenance, spares, etc., which govern the principal business of the firm. (Power plant maintenance generally comes infrequently, but is expensive when it is needed. Managers without a power background may attempt to keep production up by arbitrary economies, which succeed temporarily because power plants normally have substantial built-in reserves. This policy may result in sudden and serious breakdowns--and a number of

firms have abruptly switched to purchased power after such a shutdown. The process is seldom reversed.)

8. Utility practices that have long discouraged the generation of power by any other type of entity--e.g., rate schedules favoring the large industrial user (whether or not cost-justified), and heavy demand charges (levied even if no power is used) making it uneconomic to use the utility to back up industrially-owned generation.

Dow reports that industry continues to generate steam for lack of a good alternative, but that the above factors have led to a change from self- generation to reliance on utilities for power--and a resultant neglect of the economic potential of by-product power generation. See Dow Chemical Company, Draft Report "Energy Industrial Center Study", NSF Grant OEP 74-20242.

35 In 1976, about 1,400,000 acres were federally leased for geothermal exploration and potential development. In the same year, five new wells were drilled.

36 Additionally some prospective tracts held by firms involved in the geothermal industry were acquired primarily for other purposes-e.g., by a land company or a utility. Federal lands may be entered for "casual work" by non-lessees upon filing of a notice with the Interior Department.

37 30 USC § 1001, *et seq*. If either the federal or the California

state government prevails in pending proceedings to settle the question of title to geothermal resources when mineral rights are reserved, the significance of government leasing will be increased even more.

38 For the 282,787 acres leased by competitive sale as of June 30, 1976.

39 The one such sale in which the highest bidder was not a petroleum company drew few bids.

40 Lessees may not hold the entire beneficial interest in a tract.

41 Telephone conversation with Mr. Jack Kennedy, Minerals Division, New Mexico Land Office.

42 Rules and Regulations Relating to Geothermal Resources Leases, New Mexico State Land Office.

43 Telephone conversation with Mr. John Mitchell, Idaho Department of Water Resources.

44 Under the Idaho Geothermal Resources Act, Idaho Code Sec. 42-4001.

45 UP&L is reported to have a geothermal lease on Fort Hall Indian Reservation in Idaho.

46 Telephone conversation with Mr. Ed Schlender, Manager of Raft River Electric Cooperative. Raft River's lands are checkerboarded by federal lands so that the Cooperative may be confronted with the choice of either facing offset wells or trying to bid against oil companies. Schlender favored preference leasing for public bodies, and noted that in leasing state

lands, an adjacent developer has priority. He praised the USGS and their open-file reports.

47 Telephone conversation with Vern Newton, State of Oregon.

48 The Idaho National Engineering Laboratory working in the Raft River area, Idaho. ERDA funded this work as well as a well in Hawaii.

49 The Geysers drilling included field extension efforts. Of the fourteen privately drilled wells outside of California, Magma drilled four in Nevada, and Phillips Petroleum six at Roosevelt Hot Springs.

50 As of November 1974, there were 51 exploration permits outstanding having terms ranging from six weeks to two years.

51 Conversation with Mr. Bob Pablovich of Uplands Mineral Division, BLM, and see 42 CFR, part 3206.

52 30 CFR §270.34; a second exploratory hold would take a much shorter time to process.

53 43 CFR §3209.

54 CFR §240.34 (k). A federal lessee is required to submit exploration plans to the USGS. Then an environmental analysis is prepared. If and when a reservoir is defined, a permit is required for surface use by a power plant and transmission lines.

55 30 CFR §240.35.

56 Telephone conversation with Mr. T. Reid Stone, USGS, and conversation with Mr. Barry A. Boudreau, USGS, Menlo Park, California.

57 GAO, "Problems in Identifying, Developing, and Using Geothermal Resources", March 6, 1975.

58 30 USC 1004(d)

59 The law provides that a geothermal lease shall embrace a reasonably compact area of not more than 2,560 acres.

60 43 CFR 3202. 5.

61 Bureaus of Competition and Economics, Report to the Federal Trade Commission on Federal Energy Land Policy: Efficiency, Revenue and Competition, (October 1975), Reported by Senate Interior Committee 94 Congress, 2nd Session as Serial No. 94-28, (92-118), 1976.

62 Burmah, which acquired its Geysers interests in the 1974 acquisition of Signal Oil & Gas (the parent company), is a British petroleum firm which has held shares of BP and Shell Transport Co. and owned a number of tankers. It is currently being "bailed out" by the British government. Aminoil, owned by the Reynolds Company, recently acquired Burmah's domestic holdings.

63 See Rocky Mountain Mineral Law Institute. Proceedings of Offshore Exploration. Drilling and Development Institute (1975) for a good discussion of oil joint ventures.

64 The Geothermal Energy Research, Development, and Demonstration Act of 1974, §104, 30 USC §1124 defines the goals of the research program established "for the purpose of resolving all major technical problems inhibiting the fullest possible commercial utilization of geothermal resources in the United States" as including:

> "(9) the identification of social, legal, and economic problems associated with geothermal development (both locally and regionally) for the purpose of developing policy and providing a framework of policy alternatives for the commercial utilization of geothermal resources;...
>
> (11) the establishement of a program to encourage States to establish and maintain geothermal resources clearing houses, which shall serve to (A) provide geothermal resources developers with information with respect to applicable local, State, and Federal laws, rules and regulations, (B) coordinate the processing of permit applications, impact statements, and other information which geothermal resources developers are required to provide, (C) encourage uniformity with respect to geothermal resources development, and (D) encourage establishment of land use plans, which would include zoning for geothermal resources development and which would assure that geothermal resources developers will be able to

carry out development programs to the production stage."

65 Apparently the programs of Southern California Edison Company and San Diego Gas & Electric Company.

66 Telephone conversation with Tom Cordell, County Environmental Officer, Sonoma County.

67 The California Code provisions regarding air pollution control were overhauled in 1975 (Stats. 1975 ch. 957, §12).

68 Pollution control agency personnel and environmentalists feel that cooperation between industry and environmental agencies has not been all that it might be.

Under the provisions of the California Environmental Quality Act, issuance of a geothermal prospecting permit or a lease constitutes a project having significant environmental effect. Accordingly a draft and a full Environmental Impact Report (EIR) are prepared either by State Lands Division or a consulting firm, at the applicant's expense and are respectively circulated. After a minimum of 30 days the final EIR is presented to the State Lands Commission. At this time the Commission in a public meeting will:

1. Hear comments on the proposed project;

2. Determine if a final EIR has been prepared by the Division following evaluation of comments and consultation with public agencies which

issue approvals for the project;

3. Certify that a final EIR has been completed in compliance with California Environmental Quality Act (CEQA) and that the Commission has reviewed and considered the information contained therein;

4. Determine if the project will or will not have a significant effect on the environment;

5. Consider authorization of the proposed project.

<u>69</u> Pacific Gas & Electric Company, Amended Environmental Data Statement, Geysers Units 14 and 15 (1974).

<u>70</u> The California Public Utilities Commission in Decision 85720, (April 20, 1976), granting certificates for PG&E for Geysers Units 14 and 15, states:

> "PG&E claims that it is now capable of meeting the air quality standards prescribed by the Northern Sonoma County Air Pollution Control District as such standards apply to Units 14 and 15. Based on his evaluation of the record the examiner, as stated in the Final EIR, noted that:
>
> > "7. The Stretford process is an effective hydrogen sulfide abatement system now practicable for installation on Units 14 and 15. If installed, as proposed,

on Units 14 and 15 emissions of H_2S from the units will meet the requirements set forth in the California ambient air-quality standard."

In its exceptions the State Air Resources Board states that even with abatement Units 14 and 15 will:

"...emit substantial additional amounts of H_2S into the air in the region where concentrations of this pollutant already exceed the California ambient air quality standard."

The ARB proposed the following substitute findings:

" The Stretford process, while of measurable benefit, is not a totally effective H_2S abatement system. When H_2S emissions from the other Geysers units are added to those of Units 14 and 15, even with controls operating, the California ambient air quality standard will not be met. Additional emissions from Units 14 and 15 will exacerbate this problem."

The decision reports that the Air Pollution Control Officer of the Sonoma County Air Pollution Control District testified that he would not grant authority to construct further units unless abatement action were undertaken on existing units.

While the Public Utilities Commission found that granting the applications will have no significant impact on the environment due to H_2S emissions, it went on to note that its approval could be negated by the Northern Sonoma County Air Pollution Control District.

71 In Clean Air Constituency v. California Air Resources Board, 423, P.2d (Calif., 1974) the State Supreme Court held that the Air Resources Board lacked authority to delay a vehicular emission control program "for reasons related to the energy crisis" as such reasons did not relate to the purposes of the Board's enabling legislation. 523 P.2d at 624-26. Also See Natural Resources Defense Council v. EPA, 489 F.2d 390 (CA 5, 1974). The court in rejecting a state implementation plan, held that considerations of economic costs were to be subordinate to public health considerations.

72 The interests forwarded by environmental agencies can only be encouraged by regulatory of fiscal methods. Unless regulation or taxation imposes costs of pollution control on developers, these costs are shifted to others, and the stimulus to innovative pollution control is lost along with the market for pollution control equipment.

Regulatory methods are needed in a new industry because the cost data needed for a fiscal control system are lacking.

73 The adverse effects of this concentration on the human environment may be best understood by taking a deep breath in many "one-mill" towns.

74 Irrelevance of portions of federal environmental impact statements has also been criticized, Myers, 4 Ecology Law Quarterly 914 (1974-75).

75 E.G., The California Environmental Quality Act, Cal. Public Resources Code §21000 et. seq.

76 NEPA was intended to be not only an environmental full-disclosure law but also was intended to effect substantive changes in decision making. Environmental Defense Fund, Inc. v. Corps of Engineers, 470 F. 2d 289 (CA 5, 1972); cf. Scenic Hudson Preservation Conference v. Federal Power Commission, 453 F.2d 463 (CA 2); cert denied, 407 US 926 (1971). The obligation NEPA imposes on agencies is to consider environmental consequences while requiring (1) rigorous inquiry, Calvert Cliffs Coordinating Committee, Inc. v. Atomic Energy Commission, 146 US App. D.C. 32, 449 F.2d 109 (1971); Greene County Planning Bd. v. Federal Power Commission, 455 F.2d 412 (CA 2), cert denied 409 US (1972); (2) a reasoned decision, Monroe County Conservation Council, Inc. v. Volpe, 472 F.2d 693 (Cal., 1972); NRDC v. Morton, 148 US App. DC 5, 548 F.2d 827 (1972); and cf., Hanley v. Kleindeinst, 460 F.2d 640 (CA 2) cert. denied 407 US 990, and (3) a statement which is not a brochure, (cf., Brooks v. Volpe, 350 F. Supp. 269 (D.C. Wash., 1972) supplemental 350 F. Supp. 287); See, EDF v. Armstrong, 382 F. Supp. 50, (D.C. Ca., 1972); EDF v. Froehlke, 473 F.2d 346 (CA 5, 1972); Sierra Club v. Froehlke, 345 F. Supp. 440 (D.C. Wash., 1972), Greene County, supra.

(This case and Morton supra, called for a single coherent statement and rejected substitution of written testimony, but this testimony had not been circulated to afford other agencies a real opportunity to come forward.)

While questions of broad significance may be required to be addressed Swain v. Brinegar, 517 F.2d 766 (CA 7, 1975); Sci. Inst. for Public Info. v. AEC, 581 F.2d 1078 (CADC, 1973), procedures should assist judgments, Sierra Club v. Morton, 510 F.2d 813 (CA 5, 1975): Lathan v. Brinegar, 506 F.2d 677 (CA 9, 1975); Sierra Club v. Morton, 395 F. Supp. 1187 (DCDC, 1975) and Union of Concerned Scientists v. AEC 499 F.2d 1069 (CADC, 1974); Sci. Inst. for Public Info., supra; cf. NRDC v. TVA, 347 F. Supp. 128 (DC Tenn), 502 F.2d 852.

77 This situation is reflected in testimony presented in the fall of 1975 to the Subcommittee on Energy Research and Water Resources of the Senate Interior Committee.

An administrative tribunal in the Interior Department, the Interior Board of Land Appeals, has determined that the Department has the authority and duty to develop environmental impact statements on forest lands for proposed oil leasing, in a case where the Forest Service has not developed such a statement. Chevron Oil Company, IBLA 76-424, decided March 15, 1976. This decision may provide, by parity of reasoning, authority for the Bureau of Land Management to prepare environmental impact statements so that it might make determinations upon applications for geothermal leases, and not be bound to await Forest Service action.

78 Hearing on Geothermal Energy Development, Sen. Interior Comm., 94th Cong., 1st Sess. (1975).

79 Id, p. 75-76.

80 Areas of interest are often designated in petroleum joint venture agreements.

81 Note California Power Agency v. PUC, 5 C.3d 370, 96 Cal. Rep. 18, 486 P. 2d 218 (1971), and cf., allegations in Letter of Advice of Attorney General in regard to PG&E's application for the Mendocino Plant, 37 F. R. 1642 (1972).

82 Units 7 and 8 which were the first served under the 1970 Contract between PG&E and Magma, Thermal Power, and Union Oil Companies. The first well was drilled by Magma in 1955 and in 1958. Magma and Thermal had entered into a contract with PG&E. In 1960, the first unit - 12.4 mw - went into operation, and additional units went into operation in 1963 and 1968.

83 See, e.g., Utah Code Anno. §73-1-20, 14 Colo. Rev's Stat., 1973, §34-70-101, 35. et. seq.

84 The charge for risk may be set on an amount up to 200% of the "non-consenting" owner's share of these costs.

85 Any common purchaser taking geothermal resources produced from wells within a geothermal reservoir shall take ratably under such rules, regulations and orders, concerning quantity, as may be promulgated. Such rules, regulations and orders may consider the quality and the quantity of the geothermal resources available, the pressure and temperature of the point of delivery, acreage attributable to the well, market requirements and other pertinent factors.

Nothing in the Geothermal Resources Conservation Act shall be construed or applied to require, directly or indirectly, any person to purchase geothermal resources of a quality or under a pressure or under any other condition by reason of which such geothermal resource cannot be economically and satisfactorily used by such purchaser by means of his geothermal utilization facilities then in service.

86 These problems emphasize the need to carefully lay out government tracts, and to carefully watch drilling proposals - so as to treat all lessees equitably without unduly delaying exploration.

87 McDonald, Petroleum Conservation in the United States: An Economic Analysis (1970); Vafai, Market Demand Prorationing and Waste-A Statutory Confusion, 2 Ecology Law Quarterly 118 (1972).

88 New Mexico has created a body under its Energy Resources Act, 9 Part 2 New Mexico Stats. § 65-13-1, to consider how the state might capture

economic rents from resources located in the state; Montana has sought to capture such rents by imposing a large severance tax on coal-rising to 30% of gross sales for strip mined coal over 900 Btu per pound heating value. Revised Codes of Montana, Part 3, 1975 Interim Supplement for Title 84 to 95, Section 84-1312-1318.

89 As noted in the Attorney General's 1967 Report, "In sum, the conservation regulatory system, accomplishes only an indirect and partial balancing of overall crude supply, which permits higher prices to be established than would normally prevail if no controls existed. At its utmost, the effectiveness of control is limited to insuring only that no supplies enter crude oil markets outside the regular market channels maintained by the industry..."

90 Under Federal law, the Connally Hot Oil Act, 15 U.S.C. 715, it is illegal for a private party to ship in interstate commerce petroleum or petroleum products produced, transported or withdrawn from storage in excess of amounts permitted under State Law.

This restriction on shipment can be suspended by the President if he finds that the amount of petroleum or products moving in interstate commerce is so limited as to be a cause of lack of parity between supply and consumptive demand resulting in an undue burden or a restriction of interstate commerce.

91 As regards oil prorationing, "the key to the effectiveness of State regulation, then, was a federal consent to these market controls, and federal enforcement of prohibitions on interstate shipment of oil produced in violation of them. Memorandum for the Attorney General, accompanying Report of the Attorney General pursuant to Section 2 of the Joint Resolution of September 6, 1963, consenting to an Interstate Compact to Conserve Oil and Gas (July 1967). This report was one of an annual series of Justice Department Reports regarding the Interstate Oil Compact Commission. The June, 1964 report describes State market demand control, while the 1969 Report contains an extensive history as to the Connally Hot Oil Act.

92 Costs to a utility purchasing unit output would be an operating expense not providing a rate of return. However, purchasing power under a long-term contract, in lieu of building units, provides off-the-balance sheet financing needed by utilities having poor capitalization and interest coverage ratios.

93 For instance, development of 500 mw, which would be the goal of a SMUD geothermal project, would entail new transmission lines.

94 It is noteworthy that the larger public power systems, having generation and a capability to build geothermal or other units, are the same systems that can best anticipate obtaining participation in alternate

joint coal or nuclear units, with related coordination and transportation.

95 Michael Sullivan, Steven McDougal, and F. Van Huntley, Patterns of Geothermal Lease Acquisition in the Imperial Valley: 1958-1974. University of California, Riverside, August 1974, pp. 102-105.

96 At the 19 Federal geothermal lease sales held between mid-1975 and mid-1977, the ratio of bids received to units bid on has exceeded two at only two sales, and has been one at 9 sales, and zero at three. Prices per acre has been under $10 per acre at all but 5 sales, and have been under $3.00 per acre in several recent sales. The Bureau of Land Management continues to offer more than double the number of leases than even speculators will bid on.

97 NCPA cities alone have loads of 580 mw and receive 230 mw from the federal Central Valley Project (CVP), and 350 mw from Pacific Gas and Electric Company (PG&E). They have 52 percent load factor and will require 500 mw over their federal allotment by 1980.

98 Most industrial processes require firm power--which cannot be obtained from an isolated generating unit. Hence the need for reserve arrangements.

99 Sites for listed energy intensive industries are limited by transportation and, relatedly, raw materials requirements.

100 Problems encountered in recent efforts to obtain total energy systems are described infra.

101 Furthermore, with self-generation, if intra-corporate transactions are made on a "cost" basis, there are fewer gross revenues for depletion.

102 In regard to self-generation, utility personnel have argued that because they have a general charter to supply the public, utilities should have a monopoly. However, failure to develop cheaper energy sources, and requiring industries to pay more than needed, have harmful effects on the economy. A monopoly would eliminate diversity of approaches and rates of development, and would preclude coordination by utilities with generators paid for by a new source of financing. It would also eliminate a source of pressure on utility rates and cost-consciousness.

103 At times such sales are made at incremental energy costs plus 15 percent.

104 The profit potential of regulatory lag in bulk power sales is dependent upon the price and terms at which geothermal energy and capacity is proffered to utilities.

105 Because a number of wells will be required to provide energy for a generating unit, coordination of producer field activity will also be required.

106 Vendors would of course compete for control of resources, e.g., drilling prospects.

107 The value of energy never exceeds that of alternate energy sources and prices are governed accordingly. When development began at The Geysers, PG&E insisted on paying no more than its alternate average costs of generation. It should be noted that sales agreements at The Geysers were not set at incremental costs of energy but at average rates, and that the prices based on alternate average busbar costs have no take-or-pay provisions, and are not set at a price for Btu's delivered.

108 Because of the risks of exploration, planning a drilling program should encompass risk analysis. By improving analyses and analyzing more structures, the probability of locating a commercial resource improves. See Megill, An Introduction to Exploration Economics (1971).

109 Receptiveness to cost sharing (and product sharing) arrangements and promotional zeal vary not only between but within enterprises.

110 $262.00 is taken from Table 11.6 of the FTC Staff Report on Federal Energy Land Policy (October 1975).

111 Utilities use their low effective tax rates to assist their financing. In lease financing, the utility pays for financing, in part by allowing lessor to have title to the leased property and to deduct investment tax credits and accelerated depreciation.

112 Testimony of F.M. Scherer, Senate Subcommittee on Antitrust and Monopoly Hearings; The Petroleum Industry: Vertical Integration, Part

III, 94th Congress, 2d Sess. (1976) at page 1834.

113 An employee of Southern California Edison told us that SCE considers The Geysers to be "PG&E's resource."

114 Publicly owned utilities involved in the Raft River Project are confident about their being able to obtain wheeling over Bonneville Power Administration power lines.

115 Also, the Northern California Power Agency has entered into a joint enterprise to explore for and develop geothermal resources on acreage in The Geysers. In this agreement, NCPA agrees to carry its leaseholder partner.

116 The contracts provide that 20 pounds of steam is to be delivered per kilowatt hour in contemplation of, and perhaps freezing, the use only of condensing turbine generating units.

CHAPTER THREE

ELECTRIC UTILITIES AND THE CLIMATE FOR GEOTHERMAL DEVELOPMENT

The electric power industry's basic functions are the generation, transmission and distribution of energy to ultimate customers. These functions are coupled through interconnection and coordination of power systems. Some utilities engage in all of the industry functions while others only perform one or a few functions, e.g., distribution. Figure 7 provides a description of the industry.

Technical advances in generation and transmission have made possible enormous economies of scale in the electric power industry. Few, if any, existing investor-owned utilities are alone large enough to exhaust these economies.

Private utilities have often sought to expand through acquisitions and mergers. They have frequently used the holding company device. To a significant degree, consolidations have been aimed at achieving scale economies. Particular goals have included the use of a united organization to coordinate planning, to share reserves and to achieve operating economies. Utilities have also sought to cooperate in varying degrees with one another to achieve these objectives.

The working of power systems is referred to as integration where it proceeds by means of uniting ownership, and coordination where the expansion involves cooperation between firms.

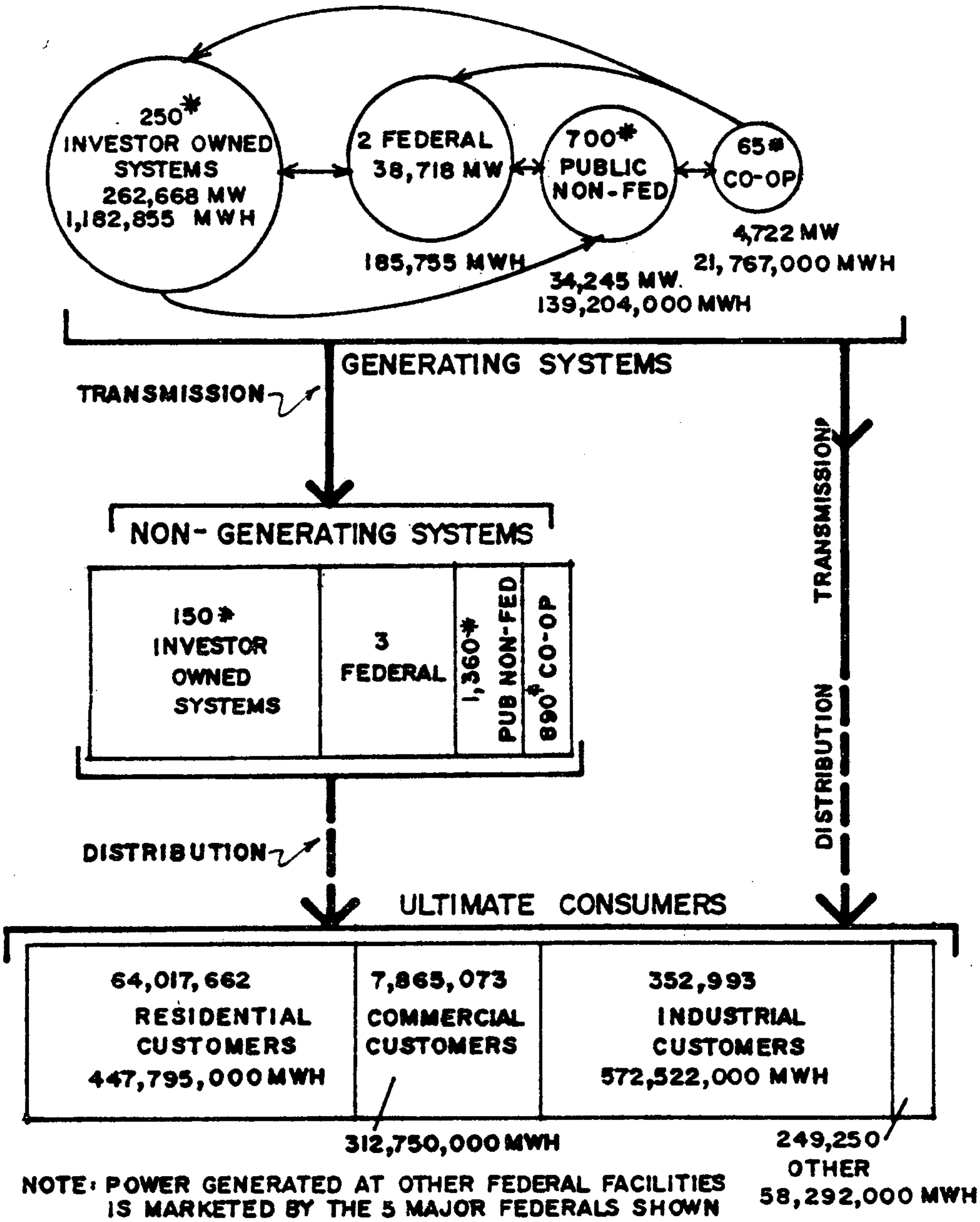


FIG 7. THE ELECTRIC POWER INDUSTRY 1970

* ESTIMATED

SOURCE: FEDERAL POWER COMMISSION

The Role of Power Pooling

Interconnection and joint operation and planning of electric power systems (pooling) is necessary to find outlets for the output of generating units. Reaching these outlets is necessary to realize the economies of scale which large, high capital cost equipment can provide if fully utilized. It also permits systems to employ cheaper-source units ahead of more expensive ones, thus minimizing operating costs, and to share reserves.

Isolated systems must maintain generating capability sufficient to serve forecast loads and to provide adequate reserves in the event of forced or scheduled outages of generating units. They also cannot share reserves or economies of scale obtainable from units too large for one system to install alone. Similarly, an isolated system can not engage in trading with other systems to take advantage of inter-system variations in operating costs.

The structure of the industry today is the product of an evolutionary process which occurred over the past century.[1] Small isolated utilities combined into groups of interdependent systems through transmission tie-lines that permitted the flow of energy between the systems during periods of equipment outages. Utility managers found that they could reduce operating costs through capacity sharing transactions and economy energy exchanges. As the size of the most economic units increased, utilities were prompted to move to more extensive and longer-term coordinated planning. Figure 8 describes the functional stages of this evolution. Each stage represents an increase in the degree of sophistication, but the stages are not mutually exclusive.

Figure 8

FUNCTION STAGES OF COORDINATION WITHIN THE ELECTRIC UTILITY INDUSTRY

Stages	Purpose of Interconnection	General Description	Types of Transactions/Service
I	Reliability	Decrease probability of loss of load due to forced outage or other equipment failure (for a given mix of generation and transmission).	Reserve sharing and/or emergency support.
II	Reliability and Operating Efficiency	Minimize cost of serving a given load at a specified level of reliability with existing mix of generation and transmission.	Economy exchange; daily diversity exchange; maintenance scheduling and energy exchange; short-term power exchange.
III	Reliability, Operating Efficiency, and Joint Planning	Determine the mix of generation and transmission voltages and configurations that minimizes the cost of serving electric loads over time at a given level of reliability.	Seasonal capacity exchange; staggered construction, including unit power and long-term power exchange.

The actual degree of planning and operating coordination among utilities varies. Some pools have a far higher degree of coordination than others; e.g., under some coordination arrangements economic dispatch is limited to periodic transactions, and not done on a moment-to-moment basis. Similarly, planning coordination may be limited to sales of capacity excess to needs of a unit-owner's system, and may not encompass coordinated construction of generating units of sizes designed to serve needs of several coordinating utilities.

An explanation of some of the more important features of coordination in pools follows.

Key Features of Electric Power Pools

Reserve Sharing

Utilities plan to have sufficient generating capacity to meet their peak loads when provision is made for reserve capacity to cover equipment outages, frequency regulation, load swings, errors in forecasting loads, and slippage in planning and construction schedules.[2]

The sharing of reserves is the corner-stone of power pooling and accordingly will be discussed in some detail. Absent reserve sharing, an entrant generating firm using geothermal power may be unable to sell firm power.[3]

Reserves may be classified in terms of the immediacy of their availability (e.g., spinning reserves, ready and "standby" units[4]) and in terms of their roles (e.g., reserves for scheduled maintenance as opposed to reserves to be used in the event of an unscheduled operating event).

Spinning reserve is that portion of operating reserve capacity which can pick up in 5 to 10 minutes.

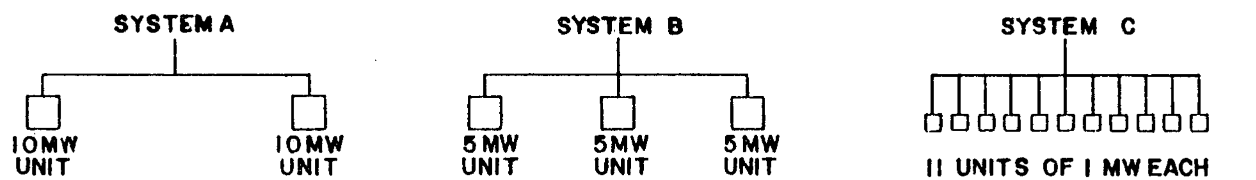
Ready reserve is that portion of reserve capacity which can take load within 10 to 20 minutes. Generally, hydraulic turbine-generators, quick-starting diesel engine-generators and gas turbine-generators can be used for ready reserve. Standby reserve is the remainder of a utility's reserve capacity. It generally consists of older units with relatively high operating costs.

Reserve sharing arrangements may also vary according to the duration of the service to be provided. Separate provisions will be made for short-term operating contigencies, and for reserves to be provided for month-long periods to meet problems of planning or long-term unit outages.

The amount and type of reserves a utility must maintain depends on the number, size, and type of its generating units and the configuration of its transmission lines.

To understand the purposes of reserve sharing, first let us consider the situation of a simple system operating in isolation. If the system is to have 10 mw of firm load-carrying capability, Figure 9 shows three ways in which firm power might be provided. Spinning reserves must always equal the capacity employed on the largest unit generating. Accordingly a choice must be made between use of larger units having lower costs per unit of capacity and the rising reserves required by such units use. This trade-off is illustrated in the lower portion of Figure 9.

FIG. 9. THREE WAYS TO PROVIDE FIRM POWER



DEPENDABLE CAPACITY 20 MW	DEPENDABLE CAPACITY 15 MW	DEPENDABLE CAPACITY 11
FIRM LOAD CARRYING CAPACITY 10 MW	FIRM LOAD CARRYING CAPACITY 10 MW	FIRM LOAD CARRYING CAPACITY 10 MW
RESERVES 10 MW	RESERVES 5 MW	RESERVES 1 MW
UNIT SIZE 10 MW	UNIT SIZE 5 MW	UNIT SIZE 1 MW
RESERVES MUST BE 100% OF FIRM LOAD	RESERVES MUST BE 100 % OF FIRM LOAD	RESERVES MUST BE 100 % OF FIRM LOAD

NOTE THAT LARGER UNITS GIVE LOWER COSTS PER UNIT OF OUTPUT WHILE REQUIRING LARGER RESERVES.

Interconnected systems can share reserve capacity. Reserve sharing requires both adequate interconnected power transmission capacity and contractual arrangements to provide emergency power and to maintain sufficient reserve capacity so that agreed upon reliability criteria are maintained.[5]

The system reserve is the difference between the system capability inclusive of receipts under power purchase contracts and the supply requirement of a system. Installed reserve requirements of electric systems generally range from 15 to 20 percent. 1970 FPC Power Survey II-1-58.

There is active trading of operating reserves among interconnected systems where the cost of capacity is customarily quoted in dollars per megawatt-day and the price varies with sources. Interconnection agreements frequently provide for a fixed service charge to be paid irrespective of any actual deliveries of power; emergency power and energy may also be provided on the basis of subsequent return in kind.

As a system grows larger, the benefits conferred on the system by entering into such coordination with smaller systems declines progressively. Smaller systems, however, benefit greatly by this coordination. A smaller system contributes progressively less reserves as a percentage of load to a larger system than it receives while the smaller system's load-carrying ability (with existing plant) rises.[6]

Coordinated Development

Utilities also coordinate the installation of capacity. To understand the purpose of this type of coordination, let us again consider the case of an isolated system. While system loads will rise fairly smoothly over time, new units must be installed in discrete lumps. This results in excess reserves until load again catches up with capacity. See Figure 10.

When several systems coordinate load growth, the number of units installed in the coordinated network increases. Each unit is a smaller proportion of the total network load. The step-like installed capacity curve comes closer to the line which corresponds to the curve for required capacity for the network, so that excess capacity is reduced.[7]

Coordination of development can be achieved by joint unit ownership, by each system building units in turn and making short-term or long-term sales of power, or by a jointly-owned separate generating company. With such coordination, the size of planned units can be based on the aggregate annual load growth of the coordinating systems. Achievement of scale economies and more intensive use of plant sites can result.

Again the larger of unequal-sized systems generally gains less from load growth coordination than the smaller.[8]

Coordination to Match Resources and Loads

Different types of capacity have different load carrying characteristics.[9] Systems attempt to match capacity load carrying characteristics with load

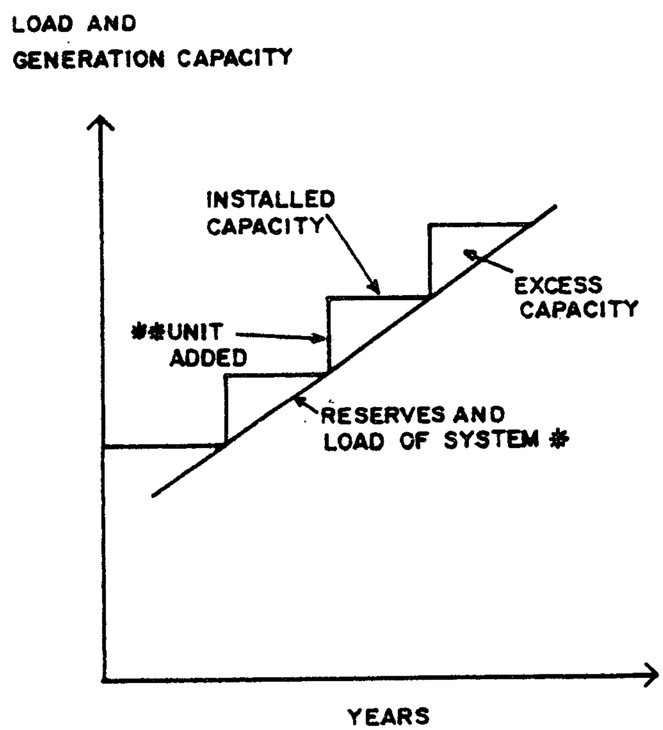


FIG 10. CAPACITY AND LOADS

* THE SLOPE OF THIS LINE IS SET BY ANNUAL LOAD GROWTH

** PLANNING COORDINATION CAN BE EMPLOYED TO INCREASE THE SIZE OF UNITS ADDED AS WELL AS TO REDUCE EXCESS CAPACITY durations. Linking hydro and thermal units permits some economical possibilities not otherwise available. Coordination between electric utility systems allows additional scope for such link-ups to occur.

For example, the "dependable" capacity of a system using hydro units can be maximized by allocating the hydro use to expectable peak demand periods; and by providing thermal unit capacity back-up for dry years.

The situation is illustrated by Figure 11, representing a system load duration curve.

A unit capable of generating 50 megawatts at any given time, but with a limited source of energy (e.g., water supply), could be assigned only thirty megawatts of dependable capacity were it required to serve at Area B on the load duration curve of Figure 11. It could be credited with 50 megawatts of dependable capacity if it were planned to serve at Area A, representing a shorter time period.

Transmission Coordination

Coordination of power systems requires interconnected transmission. The feasibility of interconnecting transmission facilities depends upon distance and load, as illustrated in the set of examples set out on Figure 12.

Installation of larger transmission lines can result in lower transmission losses and reduced carrying costs per kilowatt. Transmission coordination reduces the effect of loss of a line or transformer.

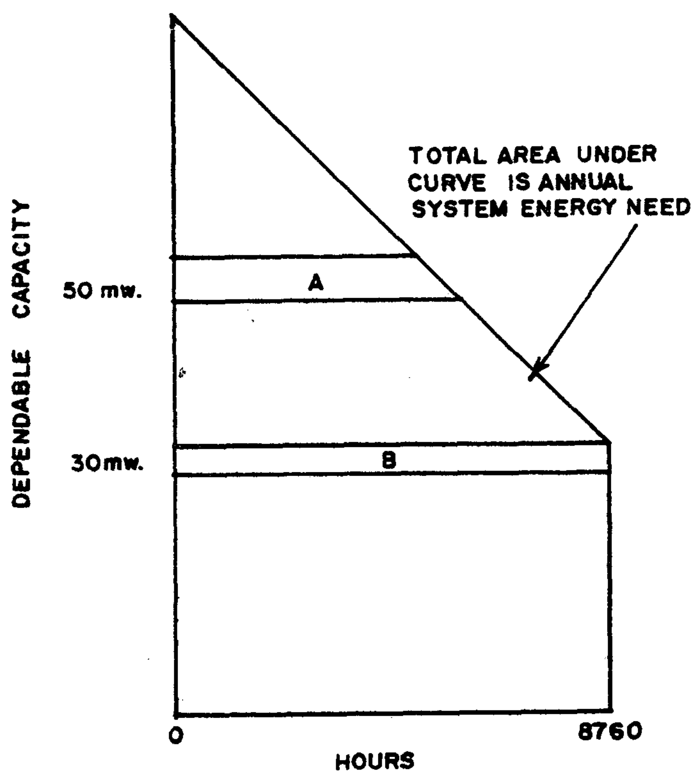


FIG 11. LOAD DURATION CURVE

WITH ENERGY IN AREA A = THAT OF AREA B, UNIT LOADED AT A WILL HAVE 50 mw. DEPENDABLE CAPACITY, WHILE AT B, ONLY 30 mw.

FIG. 12a ECONOMICS OF TRANSMISSION COORDINATION

CASE I

CASE I ECONOMICS FAVOR CONSTRUCTION OF TRANSMISSION LINE WHERE COST OF DEVELOPING ISOLATED GENERATION MORE THAN OFFSETS THE COST OF TRANSMISSION INTERCONNECTION.

Space can be conserved by coordinated planning to permit more complete use of the limited number of transmission corridors. This may be essential for construction in an environmentally concerned era.

A system dominating transmission may be able to choose whether smaller systems in its region have opportunities to use the various forms of coordination, or are prevented from realizing such possibilities.

Economic Dispatch

A utility generally attempts to bring existing generation units into operation as load increases in the order of the units' marginal delivered costs--from least cost toward higher cost units. System operators often seek to adjust output from each generation source so that the marginal cost of output from each source is equal.

By interconnecting, it is possible for two or more contiguous utilities jointly to practice this "economic dispatch." As the combined load of the several utilities increases, that unit with the lowest marginal cost is brought into service first, regardless of which of the utilities owns it. In this manner, production costs of the several utilities are jointly minimized.

Diversity in incremental costs for different generating sources may arise because of differences in the loads of various units at any given time, different effects of climate, other seasonal differences, differences in fuel supply, and costs or benefits associated with alternative disposition of the units.

Potential benefits of joint dispatch increase in proportion to the diversity of the load patterns of the utilities. Absent transactions of this sort, a utility would not make available a large unit with low marginal costs to another utility approaching its peak load and having only its least efficient units to put into service. With economic dispatch, the utility with cheaper idle generating resources can sell energy to the other utility at a small fraction of the other utility's internal generation cost.

Although less effective, periodic longer term transactions for exchanges of energy can capture some of the economies of joint dispatch.

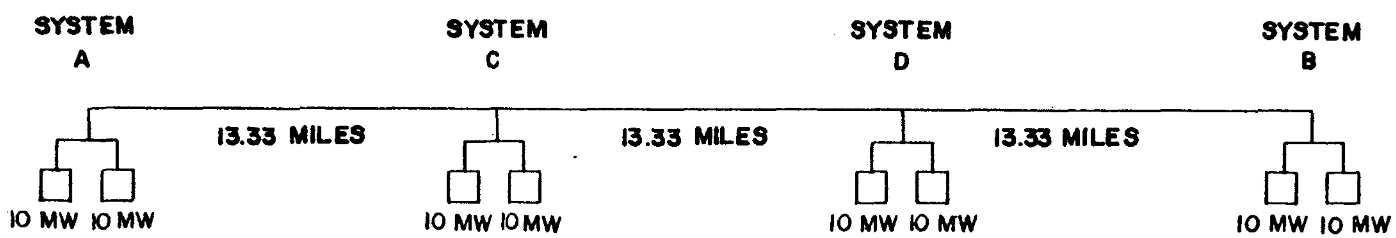
Potential Coordination Obstacles in Pools: The Pooling of Trust

The benefits of power pooling are only obtainable to the extent that a variety of problems are overcome by participating utilities.

Each member of a pool is interested, understandably, in getting the most benefits it can. A member may be inclined to take advantage of other members. This might be termed "opportunistic behavior." The problem of trust in pools is that a wide variety of situations which frequently occur in pools could lead to opportunistic behavior on the part of one or more members. Consequently pool members may be inclined to limit the degree of their coordination. Instead of attempting to achieve the full economies of coordination, a pool member might enter into only piecemeal agreements on the sharing of reserves, economic dispatch, and capacity expansion in order to minimize the potential for opportunistic behavior, by others, at its expense.

FIG. 12c ECONOMICS OF TRANSMISSION COORDINATION

CASE 3



IN CASE 3 IT IS FEASIBLE TO CONNECT ALL FOUR BECAUSE OF SHARING TRANSMISSION COSTS AND COORDINATED DEVELOPMENT OF GENERATION. YOU CAN INTEREST C AND D BECAUSE THEY HAVE MUCH TO GAIN.

PRINCIPLE NO. 5

THE ECONOMIC FEASIBILITY OF COORDINATED BULK POWER SUPPLY DEPENDS ON THE SIZE OF THE SYSTEMS AND THE DISTANCE BETWEEN THE SYSTEMS.

FIG. 12b ECONOMICS OF TRANSMISSION COORDINATION

CASE 2

IN CASE 2 IT MAY NOT BE FEASIBLE TO BUILD TRANSMISSION SYSTEM WHERE CONTINUED OPERATION OF ISOLATED GENERATION IS LESS THAN COST OF OPERATING LARGE SCALE GENERATION AND LENGTHY TRANSMISSION SYSTEM.

Achieving economies of reserve sharing and reliability in a pool is not a sure thing. Broad agreements and long-term contracts can be made, but there is no assurance that they will be kept. Trusting a neighboring utility to keep an agreeement to provide reserve at a particular time is not as safe as having one's own.

Imperfect information permits opportunistic behavior as to reserve sharing and deficiency purchasing obligations. Such obligations are based on the capacity of a member. The unit capacity available cannot be measured without an expensive performance test. Consequently, each member must rely on the integrity of the others in reporting capacity. It is not uncommon for members to report capacity at 5 or 10 percent below nameplate rating. This problem is magnified when utilities in certain regions experience shortages of condenser water. If a member with 2,000 megawatts of capacity is obligated to provide the pool with reserves equal to 15 percent of its capacity, and if the member understates his true capacity by 10 percent, the member could, in the course of a year, avoid paying the other members over one million dollars. If a pool member overestimates his available capacity, he can avoid paying deficiency charges.[10] The potential for this sort of activity could motivate pools to not entirely exploit economies of reserve sharing.

In the area of economic dispatch, problems of trust are also present. Probably the greatest deterrent to formal pool operation is skepticism regarding the fairness of determining and allocating the savings resulting from economic dispatch.

In a pool, the true saving from economic dispatch is the difference between the sum of the costs that would have been incurred by the individual members without interchange and the sum of the costs incurred in actual operation. Three general methods are used to allocate the savings to members: equal distribution of all pool savings to all participants, distribution on a split savings basis as a series of two-party transactions, and distribution of savings in proportion to member net generation.[11] Measurement problems plague these allocations.[12]

Trust is challenged in the area of long-term capacity expansion programs. If all economies of staggered expansion are exploited, the member who delays building its own new capacity runs a risk that the pool might dissolve before its turn arrives to build an optimal scale plant. In that event, it will have to supplement its own generation with much more expensive firm power from other utilities for a period of several years. Contract stipulations could cover this, but not completely. The very procedure of trying to cover every possibility of fraud or default breeds suspicion in the pool. A tendency might be present for suboptimal expansion programs.

The Problem of Size Disparities with Concomitant Benefits and Bargaining Power

As heretofore noted small utilities can provide only limited benefits to larger utilities.[13] The larger utility might prefer that the small utility abandon its capacity and buy all its requirements as firm power.[14] If the larger utility did pool with the small utility, the lowered production costs of the small utility would permit it to compete with the larger utility for industrial customers.

Another problem is that small systems often cannot provide other small systems with substantial benefits. Many are in small enclaves in the enormous service areas of large utilities far from the service areas of other small utilities. The cost of buying rights-of-way and building transmission facilities to the closest small utility would be prohibitive. Adjacent large utilities are reluctant to coordinate with or wheel power for small utilities;it may be in their own interest to retain small systems as captive wholesale customers or to acquire them.

Small utilities find themselves frequently unwelcome in pools, unable to form pools on their own, and operating in an environment in which larger utilities may impose price squeezes so as to cut off the small chances of attracting and retaining industrial customers.

THE ROLE OF COMPETITION IN THE ELECTRIC POWER INDUSTRY

In providing electric utility services, there are a number of opportunities for competition, some latent and some realized. Potential and actual competition occurs at the retail level, in wholesale bulk power sales, and in trading among bulk power supplies. As one would expect, this potential and actual competition affects relationships among electric utilities.

The nature of the rivalry among systems can determine their operating and capital costs, and consequently their rates. Sometimes it affects their very survival. Rivalry also provides comparative standards for judging the performance of power systems and may lead to more economic performance.

Retail Load Competition

Opportunities for retail competition are limited in the electric power industry. Local franchise requirements, service area certification by state regulatory commissions, and state antipirating laws frequently result in exclusive territories for retail distribution.

Retail load competition can occur for new customers who have not yet chosen a location, or on the borderline between adjacent utilities when residential, commercial, or industrial developments are built in previously undeveloped areas or when a municipality with its own distribution system annexes surrounding areas already served by another utility. Although such occurrences appear to be infrequent in any locality, they are important when summed over a region or nation, and over 5-10 year time spans.[15]

Retail load competition to attract industrial customers can be vigorous:

> Although electric power is a minor expense for the majority of manufacturers, the industries where it is important (more than 3 percent of sales) account for about half of total industrial load. Industrial electric rates are generally low because industrial demand is very elastic. That, in turn, reflects the ability of industrial customers to locate in any of many service areas or to generate their own power. The rates charged very large industrial customers are commonly negotiated between the company and the utility and then filed with the public utility commission. The competitive efforts of utilities to get new industrial load are often very vigorous.[16]

While power costs are a small part of the total costs of most firms, this is not the case for certain heavy industries: chemicals, metals, paper, petroleum, and stone, clay and glass.[17]

A recent examination of 49 cities served by two competing utilities where in most of the cities a consumer had a choice of being served by one firm or the other, found that up to a point where annual sales reached 222 million kwh average costs were lower for municipal systems that faced competition than for those that did not.[18] There was no net effect of competition beyond that level. It was also found that innovation (installing underground cable) by the municipal was quickly imitated by the competing investor-owned firm.

Utilities can limit and stifle retail rivalry in a variety of ways. Often, competition for industrial load is between the small utility and the large utility which supplies the small utility's energy. Power system managers--

whether of large or small systems--actively seek industrial customers because of their beneficial effects on system load factor. Indeed, it is possible for a large utility, which has succeeded in capturing the retail industrial market to the exclusion of small systems which are also its wholesale customers, to argue that its wholesale rates should be raised because of the poorer load factor of the smaller systems. This argument can be used to defend a price squeeze. The large utility can raise the wholesale rate for the small utility to a level above the large utility retail rate which the small utility must offer to land a prospective industrial customer. Such a "price squeeze" effectively prevents the small utility from gaining the customer and generally results in the prospective industrial firm becoming a customer of the large utility, possibly at a retail rate higher than the small utility would otherwise have charged.[19]

Large utilities can reduce opportunities for retail competition by refusing to wheel power from others to small utilities. If a large utility refuses to wheel power to a small utility in its service area, the small utility will be deprived of a cheaper source of power and is then unable (without resorting to illegal rate discrimination) to offer potential industrial customers retail rates lower than those possible under its own wholesale rates from the large utility. (This form of conduct also reduces wholesale competition).

Sometimes the larger system may refuse to interconnect with a smaller system except upon onerous terms. A more subtle practice is the discouragement of even minor ventures by wholesale customers into the construction of transmission facilities. Some utilities, for example, refuse to consider instituting a discount for delivery to the wholesale customer at a higher (transmission) voltage, even though under such arrangements the customer would assume the cost burden of building and owning the necessary stub lines and transformer stations. Absent the economic incentive to make a start in transmission, the wholesale customer is in a poorer position to seek to connect to a different bulk supplier or to join in a bulk power project with other small systems.

Large utilities sometimes reduce opportunities for retail competition by refusing to permit small utilities to seek to lower their bulk power costs by joining coordinating groups or by participating in the construction of new generating units. These forms of conduct will be discussed in more detail hereafter.

Finally large utilities can reduce opportunities for retail competition by inserting restrictive provisions in wholesale or wheeling contracts with small utilities. Such provisions may limit resales of power to existing customers, or they may prohibit the resale of the power to wholesale customers. Also, *de facto* market sharing provisions in coordinating arrangements--e.g., provisions for sharing new facilities or for allocating ownership of transmission, affect the potential for retail competition.

On-Site Industrial Power Installations and Utility Opposition Thereto

Industrial, and occasionally commercial, power consumers sometimes individually generate their own electric power. This is a form of retail competition.

About 4% of the installed capacity of electricity generation in the United States is at "non-utility" complexes--mines, mills, electric railways, office buildings, etc. Utilities have historically resisted such projects.

For example, parties attempting to install on-site units providing heating, cooling, and electric generation ("total energy" installation) have found it necessary to install their own standby equipment.[20] Similarly, obtaining supplementary power has been a problem for "total energy" users.[21] Consequently, most such units provide space heating and cooling, but not electricity.

According to Mr. Edward A. Myers, Jr., Vice-President of the Southern California Edison Company:[22]

> "... utilities have generally been concerned about the potential loss of base load, about the use of utility transmission facilities for wheeling, and about any idea that the utility system might be expected to provide backup to on-site generation without adequate compensation."

> "... if a project is both technically and economically feasible, then the utility will itself give serious consideration to installing the generation."

> "... Concern was expressed about frequency control, the danger that proliferating small units might pose to system dispatching problems, and the need to be 'fully compensated' in standby service."
>
> "... 'very large' customers with multiple plants in a utility's service territory may want to have wheeling and combined metering. This concept is not cost-effective or practical from an electrical stability viewpoint. Additionally, the concept poses numerous liability problems in the event of transmission problems. The customer also may not be able to afford his fair share of the costs of wheeling as do the various inter-connected utilities."[23]

Competition in Bulk Power Supply Markets

Electric power supply competition generally occurs in what we shall refer to as bulk power markets. Bulk power transactions are made among suppliers to retail markets.

Competition in bulk power supply markets requires that a utility system have a choice among sources of power and energy and of coordinating services. With such choices, it can enter into sales, purchases, or exchanges with the systems offering the lowest costs, and it in turn can sell or exchange power, energy, and service when its costs are lower than others. Likewise, with competition a utility can acquire access to and develop a variety of new power supply resources.

Utility system planners continually evaluate available power supply options in order to assure themselves of dependable, efficient, long-term sources of power and energy. These options include: wholesale purchases for resale, self-generation, purchases of reserves and other backup support, a share in a jointly-owned unit, an entitlement to output from another system's generating unit, power on an "interruptible" basis, power on a "firm" basis for a defined period, and various other types of arrangements which can be lumped under the "coordination" heading. The ability to pick and choose among these various options, by type and source, is a competitive process. This process can stimulate efficiency and progressiveness.[24]

Integrated utilities engage in active trading of capacity and energy, in order to minimize the costs of bulk power supply by preferential use of lowest cost generation resources regardless of ownership. Similarly, integrated utilities coordinate the planning of high voltage transmission and new generation jointly to reduce their costs. Transactions are made in this market for emergency or stand-by power, for ready and spinning reserves, for economy and "dump" energy and for economy power, for transmission services, for unit power or deficiency power, for joint enterprises to install large base load generating units.

Opportunities for wholesale and coordinating services competition have improved with advances in transmission technology and with the growth of interconnected transmission grids.[25]

Coordinating services may be separately traded, or, as is usually the case, bundled in a coordination agreement.

Because of system stability, transmission cost, and administrative burden problems, interconnection and transmission service arrangements are generally coupled with provisions regarding reserves and emergency services. Agreements for more extensive coordination, including those for pool-wide economic dispatching, short-term or unit power sales, and for planning almost invariably provide for the reserve and emergency coordination needed to keep the trading systems interconnected.

Grouping of various coordination services into a market, while recognizing that some of the discrete services so bundled can constitute distinct submarkets when separately traded (e.g., short-term power and energy) conforms with business practice. Such grouping of services is recognized in antitrust law as having a distinct value and constituting a market.[26]

A market is characterized by the substitutability of the items traded therein.[27] Coordinating services as a group are obtained in one agreement along with other economy transactions, short term purchases and sales, and unit or seasonal power arrangements.

The pool created by coordinating agreement constitutes the "area of effective competition" for many transactions particularly where a pool encompasses a wide geographic area.[28]

Treating coordinating services as one market, rather than as a series of markets, fulfills such practical indices of market as industry recognition, the grouped products peculiar characteristics and uses, the assemblage of production facilitites required, customers distinctive from those buying wholesale firm or retail power and energy, the relationship of terms of trade to the existence of a package, and the lack of alternate vendors.[29]

It should also be noted that by controlling access to bulk power markets through control of transmission or by direct and contractual control of sources of back-up power, a firm or group of firms controls coordination. The sub-market for high voltage transmission and backup is quite local, being limited by the costs and environmentally-related inability to implicate high voltage grids, and the necessity to obtain back-up from proximate sources not subject to large transmission losses and to outages. Transmission facilities and back-up facilities both are "bottlenecks" through which the commerce of bulk power must flow in any geographic area.

A firm with monopoly power in one market may not lawfully employ selective refusals to deal so as to expand that monopoly into another market. Lorain Journal v. United States, 342 U.S. 143; Eastman Kodak Co. v. Southern Photo Materials Co., 273 U.S. 359 (1927); United States v. Aluminum Co. of America, F.21 (CA 2, 1945).

Similarly, a firm or group controlling a "bottleneck" resource which must be employed to reach a market cannot refuse to grant access to this resource to competitors. Otter Tail Power Co. v. United States, 410 U.S. 366, 380 (1973); Associated Press v. United States, 326 U.S. 1 (1945); United States v. Terminal Railroad Association, 224 U.S. 383 (1912); Gamco, Inc. v. Providence Fruit &

Produce Building, Inc., 194 F.2d 484 (CA 1,1952), cert. denied, 344 U.S. 817 (1952). As noted in Associated Press exclusion from a bottleneck need only confer a 'competitive disadvantage' to be actionable.

Refusals to deal may also constitute unfair trade practices. Such refusals may occur both by outright means and by imposition of unfair or unworkable terms in contracts.

The above law teaches that refusals on the part of large utilities and power pools to afford coordination and transmission--essential for access to bulk power and retail markets--are not in keeping with the policies of the antitrust laws.

Absent development of smaller scale generating resources such as geothermal units, small systems must obtain their new base load generation from large coal or nuclear-fueled units.

Small system participation in the ownership of these large units would generally entail cooperation between large and small systems. In light of the history of anti-competitive conduct in bulk power markets such cooperation can not be relied upon to permit small systems to continue to exist as a competitive force. Dependence of small systems upon large ones would be fostered by reliance on large units. Especially with other forms of coordination being denied them, small systems are generally unable, alone or in association, to build large units.

Coordination need not preclude competition. With coordination, power systems are able to and do make choices among resource possibilities when they assemble their overall power supply package.

> "For a large area, there are often many ways of developing an efficient overall bulk power supply plan or pattern of development. The existence of a diversity of approaches and the freedom to shop for options provide a degree of competitive stimulus to search for new and better power supply alternatives. Hughes NRC 207, p. 40."
>
> Initial Decision in The Toledo Edison Company, NRC Docket 50-346 A et. al., p. 42 (January 6, 1977).

While some components of coordinating services are interchangeable and some are complementary, the different combinations of these components are substitutable one for another.[30]

The geographic scope of markets for wholesale bulk power and for coordinating services is defined both by the cost and availability of transmission and by the boundaries of interconnection and coordination agreements. Just as regards product markets, geographic markets reflect the limits of power pools within which trading occurs. The pools may contain the proximate load centers within economical transmission distance; pools may also be the areas within which facilities for the trading of bulk power and coordinating services are most developed.

The geographic area within which a small system can shop for coordination and bulk power is not as large as that for a larger power system. The transmission-cost limit on geographic markets are more constraining for these systems, with their limited ability to install their own transmission and their difficulties in obtaining transmission services from other

These limits make the geographic areas in which small system marketing occurs those of (a) their surrounding large utility and (b) the compact pool, if any.

However the bulk power/coordination market is defined, access to it may generally be blocked by exploitation of bottleneck facilities (i.e., transmission) in a small geographic area--that surrounding the system which seeks access both to power supply and to use of such bottleneck facilities for coordination purposes.

The first--and in many cases the only--market definition or market share investigation needed is

a. to establish the (narrow) boundaries of such local transmission and subtransmission market, and

b. to show whether the large utility controls it.

Relatedly, to show the large system's arrangement with neighboring utilities to prevent them from furnishing transmission which they might otherwise offer is to show crucial anticompetitive conduct.

Wheeling--use of one utility's transmission facilities by one or more other entities for energy transmission--is the key in bulk power competition.

Leonard W. Weiss states regarding wheeling arrangements that:

> The purchase of energy by the owner of the transmission line and its resale to a bulk power customer is not the same thing. If the energy is wheeled, any bulk power supplier in the region can compete for the business of the customer, but where it is purchased and resold, the owner of the transmission line continues to have a monopoly. At present wheeling agreements are voluntary and wheeling charges are not really regulated. About 3 percent of the energy generated by privately owned utilities is wheeled.[31]

This percentage has been expanding in recent years.[32]

The current structure of the industry, however, limits the development of wholesale competition along the lines set out here.

Large utilities generate, transmit and distribute power. Their vertical integration precludes wholesale competition. Approximately two-thirds of the sales to final customers involve electricity distributed by the utility that generates and transmits it.[33] The distribution network of a large investor-owned utility could be viewed as a set of smaller distribution systems interconnected by transmission lines, each system, perhaps, serving a distinct populated area. Each of these smaller distribution systems could, perhaps, operate independently, obtaining its power requirements as a wholesale customer from any of a variety of bulk power suppliers. The fact that it is not independent of the large investor-owned utility eliminates it as a potential wholesale customer.

The conduct of the industry also limits bulk power supply competition.[34]

As noted in one discussion of retail competition, arrangements among pooling utilities or among large utilities and their wholesale customers sometimes contain provisions explicitly or implicitly allocating customers.[35]

Some wholesale tariffs restrict the buyer's ability to acquire power from others or to install its own generation. Frequently such tariffs contain "all requirements" provisions explicitly preventing use of alternate generation, and long notice periods are provided for cancellation of agreements. Agreements to provide partial requirements service may not be offered. For instance, if interconnection is afforded, wheeling may not be offered and reserve-sharing may only be offered on a basis that is very onerous to small systems. Power pool agreements may forbid or sharply restrict participation by new members. New power systems have been refused interconnections and coordinating services in efforts to prevent their operation.

Anticompetitive obstructive tactics are not unknown in the electric utility industry. These tactics have involved political interference in competitive systems, filing of baseless legal proceedings, pre-emptive acquisition of power sites and political resistance to federal construction.

Predatory features have been employed in the design of rates for services to systems competing for other trade with the supplying utility. To understand these, it is first necessary to note that wholesale tariffs differ from coordination agreements in that wholesale customers usually pay rates based on average system costs while coordination agreements provide for trading on usually lower incremental cost bases. Coordinating utilities may purchase discrete blocks of firm power and other services to shape their supply to their loads. Wholesale tariff demand charges are based upon customer responsibility for system-wide peak loads; customers pay peak charges for power and energy which, in unbundled transactions, might otherwise be separately-acquired, off-peak supplies. Under "ratcheting" provisions in wholesale tariffs, peak demand charges are levied for each of a series of succeeding monthly billing periods based upon the customer's peak load incurred during his, but not necessarily his supplier's, peak.

The tariffs for wholesale and coordinating services are filed with the Federal Power Commission while rates for retail trade are filed with State or local bodies. Wholesale rates have been set, and rate increases have been so timed as to effect price-squeezes on wholesale customers.[36]

Yardstick Competition

The concept of yardstick competition in the electric power industry has its roots in the public power movement of the early 1930's which culminated in the creation of the Tennessee Valley Authority in 1933. Supporters of public power placed great weight on its potential role as "yardstick" for private power rates. Today, yardstick competition involves performance comparisons between and among various utilities; it occurs at all levels of the electric utility industry. The intense rivalry between public and private systems is manifest at the political level. Alfred E. Kahn notes that "competition-by-example or by threat of displacement by public enterprise has greatly improved the performance of the industry." [37]

Use of such comparisons is essential in regulatory proceedings where, usually, absolute criteria for the prudence of costs incurred or practices followed are not available.

Penn, Delaney, and Honeycutt summarize the role of yardstick competition as follows:

> The process of yardstick competition can provide regulators and the public with information about the range of feasible utility performance. In addition, it offers managers a means of evaluating their own market performance. How and to what extent regulators and managers use yardstick comparisons varies, but they are a potential tool for improving performance in the electric utility industry. [38]

<u>One Important Aspect of Yardstick Competition is Comparative Procurement Practice</u>

The electric utility industry uses tremendous amounts of capital, procures major quantities of fuel and heavy equipment, and must attract management capable of dealing with its manifold problems.

Rapidly escalating equipment and fuel costs, and high capital costs have caused rates to rise substantially in recent years, while securities ratings of utility systems have in many instances declined, and returns on investment have been less than those allowed by utility commissions. Both these facts result in upward pressure on rates, and both offer opportunities for management to gain a competitive advantage. By reducing as much as possible their outlays for fuel and other purchases, managements can maintain or increase return on investment. Lowered operating costs will increase sales of economy power and energy, thus improving the System Load factor. The most effective utility in the competition to reduce these costs, and to acquire low-cost supply factors, will furnish a yardstick for regulators (and investors) to judge the performance of other firms.

Short-term financing has traditionally been obtained through sales of commercial paper, bank lines of credit, and revenue anticipation notes. Long-term external financing has traditionally been obtained through sales of debt and equity, leasing, and long-term contracts.

With rising capital needs and high rates for hiring capital, utilities have embarked upon more novel forms of financing: such as nuclear fuel leases, creation of new special purpose subsidiaries which issue and sell debt, joint enterprises with bodies issuing tax exempt securities,[39] and various forms of joinder in the creation of large-scale generation facilities.

Utilities compete in attracting financing in their traditional capital markets, and in developing new forms of financing and access to other capital markets. If a utility competing to sell commercial paper or debt performs poorly, the ratings of its issuance may be lowered. Lowered ratings lead to higher costs of capital, can preclude purchases by certain classes of investors, and can adversely affect the value of common stock.

Lack of success in capital markets appears to be a major factor in determining (a) the size of some utility construction programs and (b) willingness to enter into joint enterprises for plant ownership.

In recent years, the potential for comparing utilities has increased because of more frequent requests for rate increases by utilities and more frequent financings. The potential investor interest in comparative studies has also increased due to erosion of earnings, escalating capital costs, and rising fuel prices.[40]

Competition in Fuel, Equipment and Management Personnel Markets

The costs of fuel have risen substantially as a share of overall costs of energy.

Utilities can compete to control fuel costs. They can seek better contract terms for purchases, a better mix of long and short term purchases, and vertical arrangements to locate and produce energy.

Fuel contract and fuel procurement practice terms vary; some contracts have terms far more favorable than others. In some parts of the country, utility enforcement of coal supply contracts has varied, with enforcement deficiencies being alleged.

Procurement practices differ in regard to the size of fuel contracts sought, and the extent of reliance on competitive purchasing methods.

A number of utilities have entered into the production of raw fuel. Entry into raw energy provides opportunities to compete for resources. Lower fuel costs also increase the number of bulk power sales.

The incentive to employ fuel holdings to compete on a cost basis may be subverted by greater opportunities available in passing high costs from captive mines on to consumers through fuel adjustment clauses.

Fuel acquisition practices can be compared by utility commissions seeking to hold costs down.

There are only a small number of firms manufacturing the very large capital equipment used by utilities. Equipment procurement and quality maintenance are tremendous cost items for utilities. In the past, the heavy power equipment industry has been subjected to price fixing. Several large utility systems have made material efforts to encourage new entry by European firms. By flexible design practice, some competitive bidding can be arranged.

There are wide variations in the costs (per kilowatt) for new equipment among utilities indicating opportunities for competition at the architect-engineer procurement level, in quality control over deliveries, and lesserly in purchasing.

Utility systems employ a mix of in-house and contracted-for architect-engineering services. Some systems contract out most of their work to one firm year after year, while others have developed a substantial in-house capability.

Often these latter firms realize far lower costs for new capacity. With rising scheduling problems and tight capital budgets, utilities will need to seek and train management capable of holding down costs. Sleepy procurement practices as described in Power Replacement Corporation v. Air Preheater Company, Inc., 356 F. Supp.872 (1973) should become a thing of the past if inflation is to be controlled.

Interfuel Competition

The foregoing has dealt with competition within the general framework of electricity services. Such competition proceeds within a larger framework of competition among forms of energy.

At the consumer level, fuel competition occurs for new installations of space heating, air conditioning, and applicances.

In times past, competition has been quite vigorous between oil, gas and electricity for space-heating load.[41]

Electric utilities with summer peak loads have sought to promote use of electric heating as a way of improving their annual load factors. The heating load does not contribute to annual peak loads and helps keep expensive base-load generation more fully employed.

Several factors affect the shape of interfuel competition in the future. The rising cost and declining availability of natural gas limits what was heretofore a major factor in applicance (including air conditioning), and space heating markets.

Pollution control costs and declines in the rate of scale economy realization tend to limit electric utility competition capacities but more directly limit use of coal for space heating.

In one area, the potential for interfuel competition has been, many suggest, severely limited--i.e., the combination of gas and electric utilities.

Where a utility owns both gas and electric distribution systems, it has the opportunity to discriminate in favor of one or the other service. Such combination utilities are considered to be generally anticompetitive under the Public Utility Holding Company Act of 1935, Section 11(b), and the SEC has ordered a number of such systems to divest their gas properties.[42] While divestiture may be deferred in times of gas shortage, the basic policy of Section 11 remains in force.[43]

Geothermal energy might in some circumstances provide interfuel competition. If an independent developer of a geothermal resource were to market it only to direct heating and similar uses, he would provide a local competitive alternative to oil, gas, coal, and electricity in a limited market. If the resource were controlled by a firm selling other forms of energy for the same and uses, such competition might be unwelcome--and the geothermal resource might not be developed. A geothermal resource exploited for power generation might provide a salable amount of waste heat for local use. This product might not be perceived as a threat to a utility's power sales. If the cost of by-product is very low, so that it might be sold in markets that electric energy cannot penetrate, it would open a new market for the utility rather than cutting into an existing one.

Utility systems will be primarily interested in encouraging uses of geothermal energy which complement existing power systems (e.g., in generation applications). They can be expected to be unenthusiastic about uses which would displace their services and may seek to design tariffs to influence the path of development.

Some have pointed to the future possibility of an "electric" economy. Given the very large market niche occupied by electric energy, and the limits on competing energy sources, interfuel competition at retail will not compensate for lack of competition in the bulk power sector.

Access to Markets for Bulk Electric Power and Coordinating Services

Geothermal energy will only be harnessed for electric power generation if the resulting kilowatts of power and kilowatt-hours of energy can be produced at a price less than that of alternatives. For the production or bus-bar price to be competitive, a developer utility must be able to receive power and energy on a continuous uninterrupted basis; that is, as "firm" power and energy.

Entry into the business of generating electricity for firm power and energy sales is only possible if an entrant is able to enter into trading relationships with other power systems. Inter-system trading is necessary to obtain coordinating services to permit firm service without constructing smaller units and redundant capacity. This trading is also necessary for access via high voltage transmission, to other buyers and sellers of bulk power and coordinating services.

Coordination arrangements depend upon contracts among utilities. These arrangements, "pooling" resources, vary as to their comprehensiveness and mode of execution. Systems excluded from them are at a competitive disadvantage and can be effectively precluded from installing their own generation.

If a system is purchasing part of its requirements from others, addition of a generating source will require at least limited coordination of planning with its supplier.

Access to coordination is thus essential to systems seeking to install new generating units. They need reserves to back up their units, supplemental power, outlets for excess capacity, and transmission services. To develop a geothermal field with several units they require planning coordination with other pooling systems over a period of time.

Reserves and transmission services can not be obtained without either trading among systems or duplication of facilities. Duplication is nearly always undesirable, and may be impossible, from an economic or environmental standpoint.

The need for trading of services among utilities and for wheeling places large utilities in a very advantageous position vis-a-vis their smaller rivals. Larger systems control transmission and power pooling and have often acted to exclude smaller systems.

Larger systems have not coordinated planning and operations with smaller ones, but have used the economic position obtained by their control of high voltage lines in a non-competitive manner.

Competition in bulk power supply has long been recognized as an important public goal. Unfortunately, federal power operations of the U.S. Bureau of Reclamation, intended by statute to help smaller public power systems, have become subservient to a few large power systems. The reluctance or refusal to trade on the part of larger utilities, coupled with the subservient power operations of the Bureau of Reclamation create very difficult barriers to would-be public-power entrants.

The problems of these entities are increased by government policy and practice regarding geothermal leasing, utility regulation, and loan guarantees--all of which favor large private entities.

An attitude favoring central planning--by big government and big industry--rather than competition in markets permeates federal-utility relationships. It should be replaced by one favoring competitive entry if innovation and "hustle" are to characterize efforts to meet bulk power needs.

THE POWER INDUSTRY ON THE WEST COAST

Here are located the major load centers in which geothermal energy would be marketed as electricity. These load centers are coupled with generation through a high voltage grid.

The high voltagegrid in the Western states is shaped like a giant doughnut centered around Nevada. The lines of this grid are "heaviest" in capacity in the populated areas of Central and Southern California, and in the Pacific Northwest, while lines running north and south through the Mountain states are "lighter." The heavy lines connecting California and the Pacific Northwest include a unique d.c. line.

Nuclear and hydro generating stations are found along the Pacific Coast and in the great river valleys of the Pacific Northwest, coal-fired stations are found in the Mountain states extending from Montana to New Mexico.

An extensive amount of oil and gas fired generation is found in the dense load areas of Southern and Central California. Oil and gas fired units and future nuclear units are located near the growing load centers of Southern Arizona, and along the Front Range in Colorado. There are a series of large hydro developments on the lower Colorado River.

The western leg of the "doughnut" (consisting of two 500 kv alternating current (a.c.) lines and one 750 kv direct current (d.c.) line) is known as the Pacific Northwest-Southwest Intertie.

The Pacific Intertie was a significant step in transmission development of the region. Its two 500 kv lines supplment the backbone transmission grid in California. Together with a 750 kv d.c. line, they provide interconnections between the hydro generation of the Northwest, and the steam-electric units in California. Because these lines are larger than parallel circuits, there are problems, not yet fully resolved, in realizing full use of their capacity.[44]

The future high voltage grid in the west will serve to transfer power from generating sites to load centers, to back up large nuclear plants built near load centers, and to permit exchanges of economy power and energy and peaking service.

Proposals are afoot to improve transmission links across southern Nevada connecting Utah coal fields to southern California; and to construct a second d.c. line from the Pacific Northwest to either Southern California or to Arizona. The overall developmental pattern reflects a tendency to develop transmission linking hydro and thermal resources, and to develop coordination among pools and firms.

The North-South alignment of the grid will be affected by construction of coal-fired capacity in the Mountain States to serve west coast loads. Stronger lines will connect Eastern Montana with the Bonneville Power Administration. The

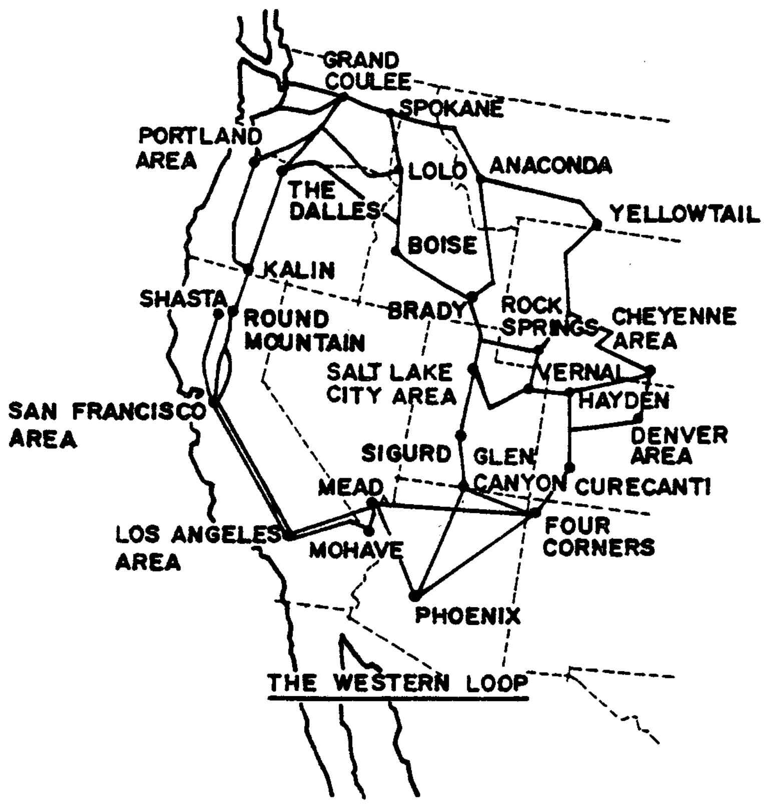


FIG 13. WESTERN HIGH VOLTAGE LINES (A.C.)

SOURCE: FEDERAL POWER COMMISSION
NATIONAL POWER SURVEY p. III-3-179.

large power units and long transmission distances involved in Western power system planning will encourage transactions to acquire reserve generation and alternate transmission routes for back-up purposes,[45] and will encourage interruptible or short term sales from systems having excess output capability with relatively low opportunity costs.

The evolution and increased importance of very high voltage transmission and large nuclear and coal-fired plants has increased interdependence and trading among power systems. This makes access to such trade necessary if smaller systems are to retain their identity and competitive viability.

With the increasing need to conserve transmission rights-of-way, coordinated expansion and higher line voltages will become increasingly important.

The doughnut shaped grid traverses many of the sites where geothermal resources are believed to exist, while other areas such as in Northern Nevada are not proximate to these lines.

The Western Systems Coordinating Council has forecasted that 33,623 megawatts of new generating capacity would be installed during the five-year period 1975 to 1979. This will be approximately 10.6% above the 93,544 megawatts of installed utility capacity at the end of 1976.[46] Thirty-seven percent of the total scheduled additions are hydro, 34 percent coal-fueled, 15 percent nuclear, 11 percent various forms of gas and oil-fueled units, 2 percent geothermal, and 1 percent undefined.[47]

For the longer term, the Western System Coordinating Council prospectus was:

Year Order	Year Calendar	Peak Load* MW	Generating Capability** MW	Reserve Capacity Before Maintenance MW	Reserve Capacity Before Maintenance Percent of Peak Load
10th	1983	124,000	162,000	38,000	30.6
15th	1988	168,000	214,000	46,000	27.4
20th	1993	223,000	279,000	56,000	25.1
Ten-Year Increase		99,000	117,000	18,000	

*Net Firm December Peak Load Less Any Firm Transfers into WSCC from Areas outside of WSCC.

**December Generating Capability (not reduced for scheduled maintenance).

Conceptual plans for the 11th through 20th year show resource additions by type as follows:

Type of Resource	Percent of Additions 1983-1992
Hydro and Hyro-Pumped Storage	20.3%
Nuclear	57.4%
Fossil-Fueled (Including Combustion Turbine, Diesel and Combined Cycle)	19.8%
Other (Including Geothermal)	2.5%

As can be seen, under present conditions in the electric power industry planned additions of geothermal generation are quite small. (Compare the potential usage of geothermal energy described in Table 3, supra.)

Western Electric Systems

The configuration and arrangements among Western power systems reflect their varying efforts to achieve the benefits of coordinated operations and planning. Table 25 lists the Western power pool members.

We will review first the power pooling arrangements of the Mountain and Pacific States, and among California utilities.

Each of the pools discussed is linked to the others and transactions occur between pool groups. The pools discussed are those whose geographic area includes likely sites for geothermal development.[48]

TABLE 25

Organization of the Utility Industry--Western United States Wester Power Pools and Their Members

California

California Power Pool (CALPP)

Pacific Gas and Electric Co.
San Diego Gas and Electric Co.
Southern California Edison Co.

Southern California Municipal Group (SCMG)

City of Los Angeles
City of Burbank
City of Glendale
City of Pasadena

Pacific Northwest

Pacific Northwest Coordinating Agreement (PNCA)

Bonneville Power Adminstrator
Division Engineer, North Pacific Division
Corps of Engineers, Department of the Army
The United States Entity, designated pursuant to Article XIV of the Treaty
City of Eugene, Oregon
City of Seattle, Washington
City of Tacoma, Washington
Public Utility District No. 2 of Grant County, Washington
Public Utility District No. 1 of Chelan County, Washington
Public Utility District No. 1 of Pend Oreille County, Washington
Public Utility District No. 1 of Douglas County, Washington
Public Utility District No. 1 of Cowlitz County, Washington

Puget Sound Power and Light Co.
Portland General Electric Co.
Pacific Power and Light Co.
The Washington Water Power Co.
The Montana Power Co.
Colockum Transmission Co., Inc., a subsidiary of
Aluminum Company of America

Northwest Power Pool (NWPP)
(Operating Committee--Voluntary Participating Systems)

Bonneville Power Administration
British Columbia Hydro & Power Authority
Eugene Water & Electric Board
Idaho Power Co.
Montana Power Co.
Pacific Power & Light Co.
PUD No. 1 of Chelan County
PUD No. 1 of Douglas County
PUD No. 2 of Grant County
Seattle Department of Lighting
Tacoma Public Utilities--Light Division
U.S. Army Corps of Engineers--North Pacific Division
USBR--BPA (Southern Idaho)
Utah Power & Light Co.
Washington Water Power Co.
West Kootenay Power & Light Co.

The Intercompany Pool (Interpool)

Pacific Power and Light Co.
Portland General Electric Co.
Puget Sound Power and Light Co.
The Washington Water Power Co.
The Montana Power Co.
Idaho Power Co.
Utah Power and Light Co.

Mountain States

Associated Mountain Power Systems (AMPS)

Idaho Power Co.
The Montana Power Co.
Pacific Power and Light Co.
Utah Power and Light Co.
The Washington Water Power Co.

Rocky Mountain Power Pool (RMPP)

Public Service Company of Colorado
Pacific Power & Light Co. (Wyoming Division)
USBR - Region 4
USBR - Region 7
Montana Power Co.
Consumers Public Power District
Southern Colorado Power Division of Central
  Telephone and Utilities Corp.
Colorado Springs Department of Public Utilities
Utah Power & Light Co.
Black Hills Power & Light Co.
Tri-State G & T Assn., Inc.
Colorado-Ute Electric Assn., Inc.
Cheyenne Light, Fuel & Power Co.

New Mexico

New Mexico Power Pool (NMPP)

Community Public Service Co.
El Paso Electric Co.
Plains Electric G & T Cooperative, Inc.
Public Service Company of New Mexico
USBR - Rio Grando Project

West

Western Energy Supply and Transmission Associates (West)*

Arizona Public Service Co.
Department of Water & Power, City of Los Angeles

* Planning Only

El Paso Electric Co.
Nevada Power Co.
Public Service Company of Colorado
Public Service Company of New Mexico
San Diego Electric & Gas Co.
Sierra Pacific Power Co.
Southern California Edison Co.
Tucson Gas & Electric Co.
Utah Power & Light Co.
Arizona Electric Power Cooperative
Arizona Power Authority
Burbank Public Service Department
City of Colorado Springs
Colorado - Ute Electric Association, Inc.
Glendale Public Service Department
Imperial Irrigation District
Pacific Power & Light Co. - Wyoming Division
Pasadena Municipal Power & Light Department
Plains Electric Generation & Transmission Cooperative, Inc.
Salt River Project
Southern Colorado Power Division of Central Telephone & Utilities Corp.

It should be noted that power pooling is more comprehensive and more accessible to public power systems in the Pacific Northwest than it is in the Mountain States or in the Southwest. In the Pacific Northwest, the high voltage grid of the Bonneville Power Administration ties the area together; while traditionally light load density has adversely affected power pooling prospects in the Mountain and Southwest states. In the Mountain states, large private systems have resisted cooperation with publicly-owned systems.[49]

Electric Utilities in California

The sheer magnitude of electric consumption in California and the location of major geothermal resources within its borders make the rate at which development of this resource progresses there critical to its overall employment.

The electric power industry of California consists of six investor-owned utility companies, 26 municipal systems, five irrigation districts, the Central Valley Project, and the State Water Project. They perform all or some of the usual public utility functions of providing generation, transmission, distribution, and power exchange services. California utilities also obtain substantial amounts of energy and dependable capacity from outside the State, particularly from the Bonneville Power Authority, other northwest sources, and the Hoover Dam in Nevada. Table 26 shows the dependable capacity of electric systems in California.

TABLE 26

ELECTRIC POWER INDUSTRY OF CALIFORNIA
1975-76 Winter
(Systems having generating capacity)

System	Dependable Capacity Before Sales and Purchases	% Total	Net Dependable Cap.	
PRIVATE				
SCE	12,276	37.2%	13,349	35.7%
PG&E*	10,143	30.8%	13,537	36.2%
SDG&E	2,106	6.4%	2,279	6.1%
SIERRA PACIFIC POWER**	550	1.7%	708	1.9%
PUBLIC				
CVP	1,200	3.6%	320	0.9%
LADWP	3,960	12.0%	4,698	12.6%
SMUD	1,295	3.9%	724	1.9%
SAN FRANCISCO***	315	1.0%	10	-
IMPERIAL I.D.	270	0.8%	318	0.9%
BURBANK	252	0.8%	257	0.7%
PASADENA	220	0.7%	261	0.7%
GLENDALE	207	0.6%	225	0.6%
TURLOCK-MODESTO I.D.	165	0.5%	275	0.7%

*The dependable capacity stated for PG & E includes that derived from the Oroville Wyandotte Irrigation District (67.5mw installed), the Merced Irrigation District (89mw installed), and the Yuba County Water Agency (370mw installed). The entire output of these entities is dispatched by and sold to PG&E.

**Primarily in Nevada

***Hetch Hetchy project dispatched by PG&E and obtaining power via exchanges with it.

PG&E, SCE and SDG&E have collectively 78% of net dependable capacity, and 74.4% of dependable capacity in California. Their shares in the northern and southern sections of the state where they are respectively located are greater. Municipal systems have 16.5% of net dependable capacity (dependable capacity net of firm sales) and 19% of dependable capacity in California. The Central Valley Project of the Bureau of Reclamation has 0.9% of net dependable capacity and 3.6% of dependable capacity. Irrigation districts, not captive to a utility, have 1.3% of capacity and 1.6% of net dependable capacity. Total electric energy use was 12,708 million kwh in December 1974; 39% was supplied through PG&E (including from PG&E, to San Francisco, the State Water Project and CVP loads); SCE supplied 35%; LDWP 11%, and SDG&E 6%.

Installed capacity, excluding a portion of the Sierra Pacific System (system totals 550 mw), in California totals 33,071 mw. Of this PG&E has 31% and contracts for output of an additional 2% (excluding capacity from SMUD and the California Water Department); Southern California Edison has 35%; LADWP 15%; and SDG&E 6.4%. 1974 generation totaled 156,578 million kwh, of which PG&E produced 36%; SCE 35%; SDG&E 5.4%, and LADWP 11%. 1974 peak loads in California totaled approximately 30,100kw. Of this,PG&E had 30%; SCE 31%; LADWP 11%, and SDG&E 5%.

All the municipal generating systems engage in transactions for power with the private utilities as well as the public agencies. In addition to the generating municipal systems, there are fifteen municipal systems, three rural electric cooperatives and one utility district which only engage in distribution, purchasing all of their power and energy.

Table 27 lists these California systems which obtain all of their power from others.

TABLE 27

1974 CALIFORNIA DISTRIBUTION SYSTEMS

System	Peak (mw)	Energy Use (kwh-10^6)	Sole Supplier
Alameda	63	333	PG&E
Anaheim	305	1,431	SCE
Azuza	30	128	SCE
Banning	12	50	SCE
Biggs	2	6	USBR
Colton	22	87	SCE
Gridley	5	19	USBR
Healdsburg	7	35	PG&E
Lodi	57	192	PG&E
Lompoc	10	64	PG&E
Palo Alto	133	737	USBR
Reading	48	231	USBR
Riverside	233	912	SCE
Roseville	33	105	USBR
Santa Clara*	162	1,037	
Shasta Dam PUD	4	18	USBR
Ukiah	12	71	PG&E
Anza Coop	2	10	SCE
Plumas Sierra	9	44	USBR
Surprise Valley	13	54	BPA

*Supplied by USBR and PG&E.

Pacific Gas and Electric Company (PG&E)

PG&E is sole supplier to five systems that purchase all of their requirements. These systems have an aggregate peak of 149 mw and used 695 million kwh in 1974. PG&E serves 47 counties in northern and central California; it operates a 17,000-mile transmission grid and is directly interconnected with Pacific Power & Light Company (PP&L), the federal Central Valley Project (CVP), the Sierra Pacific Pacific Power Company, the Sacramento Municipal Utility District and Southern California Edison Company (SCE). Additionally, via the Pacific Intertie it is interconnected with the Pacific Northwest. Wholesale sales are made by PG&E to eleven municipals and one cooperative-owned distribution system, while wheeling services are provided for the Central Valley Project and several other public agencies including the California Water Project. PG&E controls most of the high voltage transmission (230kv and over) in northern and central California.

The Central Valley Project of the Bureau of Reclamation (CVP)

The Bureau of Reclamation's Central Valley Project (CVP) consists of a series of federal hydro projects and some transmission facilities. This project has a total machine capability of 1471.2 megawatts.[50] In 1974, the total aggregate peak demand of loads served by CVP amounted to 1114 mw (energy load of 5.3 billion kwh).

Since 1951, CVP has sold electric power not needed for project irrigation pumping to its statutory preference customers which include 23 federal facilities, five state facilities, several municipalities, an irrigation utility district and one cooperative. The remaining power goes to the Pacific Gas & Electric Company.

The CVP facilities are integrated operationally with the PG&E system, and PG&E transmission is used for all project sales with the exception of sales to small federal agency load and to its two utility district customers--SMUD and Shasta Dam Area PUD.

The Sacramento Municipal Utility District (SMUD)

The Sacramento Municipal Utility District (SMUD) is a quasi-municipal corporation supplying electricity in most of Sacramento County and a small portion of Placer County, California, an area surrounded by PG&E's service area. SMUD's generation resources consist of six hydro plants with a total 649 mw of machine capability and 913 mw of nuclear capacity; SMUD purchases 360 mw from CVP, and also purchases 165 mw of Canadian Entitlement Power. It is interconnected and coordinates operations with PG&E.

Southern California Edison (SCE)

Southern California Edison (SCE) serves a 50,000 square mile area in Southern California. It operates a transmission network of 10,000 miles. SCE is interconnected with PG&E, Arizona Public Service Company, Nevada Power Company, San Diego Gas and Electric Company, and the Los Angeles Department of Water and Power. SCE serves at wholesale two cooperatives, six municipals having

having aggregate peak demand of 604 mw and energy loads of 2614 million kwh. SCE supplied over sixty percent of the requirement of municipal wholesale power in California.

Los Angeles Department of Water and Power (LADWP)

Los Angeles Department of Water and Power (LADWP) is the largest municipally owned electric system in the nation, with an extensive transmission network. LADWP is interconnected with the State Department of Water, Nevada Power Company, the Salt River Project, Southern California Edison, and the cities of Burbank, Glendale and Pasadena. It makes no sales at wholesale.

San Diego Gas and Electric Co. (SDG&E)

San Diego Gas and Electric Co. (SDG&E) serves southwestern California, is interconnected with SCE, and sells power at wholesale to the Escondido Mutual Water Company.

Other Electric Utilities in California

The Cities of Burbank, Pasadena and Glendale in southern California are interconnected with LADWP. They receive power from federal hydro projects and from the Northwest.

The Cities of Anaheim, Banning and Riverside are large wholesale customers of SCE. Some or all of them may enter into self-generation by participating in large coal-fuel or nuclear projects.

The Northern California Power Agency (NCPA) is a joint power agency established in 1968 that has twelve members: the cities of Alameda, Biggs, Gridley, Healdsburg, Lodi, Lompoc, Palo Alto, Redding, Roseville, Santa Clara and Ukiah, and the Plumas-Sierra Rural Electric Cooperative. While none of these systems currently generate power, they are, as a group, considering construction of or participation in a variety of other generation facilities. Certain NCPA members receive power supply from CVP,[51] and others are wholesale customers of PG&E.

The State of California Department of Water Resources operates the State Water Project which provides reservoir storage and water transportation, pumping and power facilities by which water from northern California is delivered to southern California. The project requires electric energy for pumping in excess of what its hydroelectric resources (1041 mw) will produce. The Department accordingly has arranged for power supply and has proposed to participate in the ownership of the proposed San Joaquin Nuclear Project.

Three irrigation districts, Imperial, Modesto and Turlock, produce, transmit and distribute power. The Imperial Irrigation District, the largest, in 1974 has a peak load of 300 mw and a net system input of over one billion kwh, of which 340 million kwh were purchased from several sources--United States Bureau of Reclamation, SCE and SDG&E. Modesto had a net system input of 933 million kwh, almost 90% of which was purchased from public agencies; the Turlock irrigation district had a net system input of 653 million kwh, of which approximately 60% was purchased (primarily from public agencies).

POWER POOLING IN CALIFORNIA

The three dominant concerns in California--PG&E, SCE, and San Diego Gas & Electric--have established a relatively loose pooling arrangement covering most of the state's area and population. These utilities collectively govern exchanges with the major external source of energy to date, the Pacific Northwest. Within the widespread network of the major utilities are a few public bodies disposing of significant energy supplies--Sacramento, the Central Valley Project, the California Department of Water Resources, and a group of municipalities around Los Angeles. There are also a number of irrigation districts (total municipal governments) which generate some electricity. The Los Angeles group has formed its own local pool.

The California Power Pool

Power pooling arrangements in California are somewhat complex. The three large power companies--PG&E, SCE and SDG&E coordinate certain phases of planning and operation through the "California Power Pool." These three firms have approximately three-fourths of California dependable capacity and 59 percent of California high voltage transmission.[52]

Coordination--The pool provides for both operating coordination and coordinated planning. It provides for no new members and coordinates operation with the four private utilities in the Pacific Northwest, so regulating use of the Pacific Intertie.

Reserve Sharing--Under the pool arrangments each member is initially responsible for serving its loads and providing adequate resources for its "area system."[53] Required resources including energy, capacity and spinning reserves[54] not so provided are acquired from the pool with a penalty on the deficient party.

Economy and Short-Term Transactions--The agreement provides for exchanges of emergency services for up to two hours, which are to be returned in kind; economy exchanges of capacity and energy; and transactions to purchase and sell short-term firm and standby power.[55]

"In order to protect the Parties from unknown and unreasonable risks, service to third parties outside its area system involving provision by a party of standby or protection of a supply of power from its Area System is prohibited, unless all Pool members agree."

Pacific Intertie Agreement

California Companies Pacific Intertie Agreement, dated August 25, 1966, and filed with Federal Power Commission on January 18, 1968, is an agreement among Pacific Gas & Electric Co., Southern California Edison and San Diego Gas & Electric Co. Its purpose is indicated to be to facilitate building and operating the Intertie, to transfer power and energy to and from the Northwest, to facilitate transactions among the companies, and to reinforce their own backbone grids.[56] Necessary coordination is sought to be accomplished through the California Power Pool, through intercompany assignments of power and transmission, and by economy transactions. Benefits are to be shared among the company-parties.

Joint Obligations--The California Power Pool members assumed certain obligations in the course of their effort to show that a privately owned set of linkages with the Pacific Northwest would provide as many benefits as would facilities owned by the Federal Government.

These obligations include, besides coordination with Bonneville Power Administration and other Pacific Northwest entities, (a) the exchange of company energy for Bureau hydro capacity, (b) transmission of Canadian Entitlement Power.[57]

The Intertie capacity is apportioned among the companies by prorating the Intertie rated capacity, (less assignments made under the agreement to other companies), in proportion to their relative size inter se.[58]

In the event of any modifications by a party primarily directed at increasing Intertie capacity, other parties shall have the right to participate in the costs thereof, and to share in the increased capacity. Sharing would be in relation to the contract shares of each party.

Each company may use vacant Intertie capacity as it sees fit so long as rights and performance of obligations of others are not impaired.

Joint Purchasing and Scheduling--The companies agree to jointly arrange contracts for transmission capacity with PP&L and the Bonneville Power Administration.

Each party has the right to a share in sales of line capacity to the State when such capacity is sold to the State to permit it to receive from the Northwest.

The contract is carried out through Coordination and Joint Accounting Committees.

The Coordination Committee will schedule Intertie operations. Transmission is to be scheduled for (a) power to or from north of California, (b) energy in exchange for Bureau of Reclamation peaking capacity, (c) Canadian Entitlement Power resold to the California Department of Water Resources (State) and (d) power delivered to SDG&E by SCE as part of an exchange for power that SDG&E arranges to have delivered into northern California.

Allocated Marketing--The parties to provide interconnections to the Intertie to serve non-party entities are specified as:

PG&E	SMUD
	Bureau of Reclamation
	California State Department of Water Resources
SCE	Metropolitan Water District
	Los Angeles Department of Water and Power

Limited Access--A party may dispose of its share of Intertie facilities unless such disposition would:

(a) reduce any other party's Intertie capacity,

(b) materially reduce reliability of transmission service over the Intertie: or

(c) impair any party's ability to perform its obligations to provide reserves to other parties, coordinate its use of power from north of California (and resales of such power to others) only in proproportions that will provide maximum benefits to all of the companies, or to meet certain joint obligations as defined below.

Other than for transactions involving specified transmission of dump energy for the State, SMUD exchanges and the Metropolitan Water District, transfer of Intertie capacity to others by a company is subject to approval by the company owning the facility to be used, and is subject to a right of first refusal by other parties.

Similarly, capacity contracted to the Bureau, State and SMUD, if unused, is to be offered to other parties who are given a further right of first refusal if one party does not wish to acquire its share of such capacity.

Rejected shares are to be offered other parties, subject to recapture by the rejecting party on five years' notice.

Seven-Party Agreement

Related to the California Power Pool is the Seven-Party Agreement establishing coordination for interconnection by the Pacific Intertie among the Pool members and four Pacific Northwest utilities:[59] Washington Water Power, Puget Sound Power and Light, Portland General Electric and Pacific Power and Light.[60] Under this agreement, the Northwest utilities, trading as a group, sell the California utilities, trading as a group, hydro energy at BPA rates and purchase excess steam-generated energy at seller's incremental cost plus 15 percent. Provision is made for new members.[61]

A schedule of curtailments for use in emergencies is provided.

The California State Department of Water Resources (DWR) Agreement

The Department of Water Resources is constructing and operating an extensive project to bring water to southern California.

As a project, DWR generates a significant amount of electricity. However, it has no transmission to integrate its facilities.

Transmission

PG&E, SCE, SDG&E and LADWP have entered into a 1966 contract to provide electric energy and transmission services to DWR. Additionally, under the agreement, DWR obtains transmission services over the Pacific Intertie.[62] This complementary service enables it to obtain hydro power from the Northwest.

The California suppliers also sell DWR off-peak energy, firm capacity and on-peak energy to supplement the energy available from DWR's generation, the Bureau of Reclamation, and Pacific Northwest facilities.

Energy use must be scheduled five years in advance, except for changes of no more than 10 mw, or 10% (up to 40 mw) of capacity which may be made on two years' notice.[63]

Distribution of DWR Energy--The contract provides for the exchange of energy from DWR plants into suppliers' systems in return for delivery of like quantities of energy to DWR elsewhere.

Limitation on DWR Access to Other Energy Sources--The sources of power for DWR are specified in the agreement.[64] Before the DWR may obtain generation from additional facilities of its own or from the Oroville-Thermalito hydro power plants, it must give suppliers five years' notice and negotiate terms and conditions for such use.

Use of other sources requires six years' notice and negotiation as to terms. If, after one year, subsequent to notice, negotiations are unsuccessful and DWR still wishes to use another source, suppliers may terminate the contract on five years' notice. Any new DWR plant or other source "may be connected to suppliers' interconnected electric systems only if the parties agree that such power sources meet electric industry standards for reliability and agree upon suitable standby arrangements for such power sources."

Specific provision is made for the possibility of a state thermal generating plant. In the event such a plant is proposed, suppliers are to be given six years' notice, and negotiations are to ensue as to transmission and standby services, plant operation and maintenance, sales of power produced in excess of project needs, and integration of the plant with suppliers' interconnected electric systems. If negotiations fail to produce agreement within a year and DWR intends to proceed with the plant, suppliers may elect to terminate the contract on five years' notice.

Each party is allowed to install and set as it sees fit protective relays for automatic separation of the parties' systems.

LADWP is only obligated to provide surplus, not firm, electric energy.

The arrangements between DWR and LADWP and the members of the California Power Pool indicate how an entrant system is dependent upon the arrangements it must make with firms providing transmission and operating coordination.

In this setting, PG&E, SCE, SDG&E and LADWP, in acting together, have at their disposal options which could make it quite difficult for DWR to substitute a new source of energy in competition with them. This is the case whether the source is developed and operated by DWR, or by others. In either event, permission from its existing suppliers is required.[65]

Sacramento Municipal Utility District

The Sacramento Municipal Utility District (SMUD) is surrounded by PG&E's service area, and is dependent on PG&E for access to external sources of power, and markets for power.

The Justice Department has alleged that a 1955 contract between SMUD and PG&E contained a clear-cut anticompetitive restriction, in Article 13(b), which prohibited SMUD from selling or wheeling power outside a geographic area delimited in the contract. Justice alleged that SMUD refused to wheel power in 1965 solely because of this restrictive contract.[66]

On August 1, 1967, SMUD executed a 38 year contract with Pool members for access to the Intertie. The Pool will provide up to 400 mw of Intertie capacity between April 1, 1971 and March 31, 1976, and up to 200 mw in other periods to wheel capacity and energy for SMUD to or from the Northwest. Imported Northwest power cannot be sold by SMUD outside its boundaries unless Pool members agree.

SMUD must provide the Pool five years' advance notification of Intertie shipments and must provide immediate notification of any contract with a Northwest entity. The contract also allows SMUD to resell excess Northwest firm power to Pool members provided that five years' advance notice is given before initial delivery. Once SMUD has notified Pool members that it is invoking the resale provisions, SMUD may not amend its purchasing contract with Northwest entities without consent of Pool members during a period less than 61 months in advance.

On June 4, 1970, SMUD executed an integration contract with PG&E, which provides for coordination of bulk power supply planning, and for provision to SMUD of the coordinating services required to support its first nuclear unit. The agreement arose as a result of SMUD's plans to construct nuclear units.

The 1970 agreement requires SMUD to sell to PG&E all capacity and energy generated by the resources of SMUD's system, including power purchased from CVP, in excess of SMUD's load. In addition, the agreement appeared to place a 830 mw limit on the second SMUD nuclear unit and to include all surplus energy from that unit in the power which must be sold to PG&E.[67]

Justice has alleged that this 1970 agreement prevents small utilities from participation in the construction of the second unit or purchasing power from it.[68]

In November of 1975, PG&E filed an amendment to the 1970 contract which, among other things, provides that capacity and energy surplus to SMUD's load from up to 400 mw of planned SMUD geothermal capacity be sold to PG&E. The price is to be midway between SMUD's cost and the cost PG&E would have incurred in generating an equal amount of capacity and energy from its own geothermal units, but in no event can the cost exceed PG&E's cost (even though PG&E's geothermal capacity consists of dry steam units whereas SMUD may have to use more expensive hot water units). This contract is discussed hereinafter.

Similarly, PG&E will acquire peaking energy from 150 mw of proposed SMUD oil-fired combustion-turbines at rates based on nuclear energy costs far below those for oil, only paying full costs for exceptionally long duration use of such turbines.[69]

Southern California Municipal Group

The Southern California Municipal Group engages in operating coordination, including economy transactions, emergency services and spinning reserves, and coordinates acquisitions of power from Hoover Dam and from Canada and the Northwest.

Smaller systems in this group can obtain wheeling over lines of the Los Angeles Department of Water and Power enabling them to acquire power and energy from the Northwest and elsewhere outside of Southern California.

Central Valley Project

The Central Valley Project has a major set of coordinating arrangements with Pacific Gas and Electric. The agreements provide for PG&E "firming up" CVP's hydroelectric capacity, bringing Pacific Northwest capacity and energy to CVP, and transmitting CVP power to publicly owned distribution systems. While these services are of substantial value to CVP, the terms of the agreements as such limit CVP access to new power sources, and its ability to increase service to existing and new customers and to trade with other systems. These matters are discussed further in the "conduct" section following.

CONDUCT IN THE POWER INDUSTRY IN CALIFORNIA

Small utilities in California operate in a hostile economic environment. Large investor-owned utilities in the area use their substantial market power in a pattern consistent with maintaining their dominant positions to the disadvantage of smaller systems. The Department of the Interior operates several major power projects in the Western states in a manner that has had the effect of reinforcing and extending the market power of the large investor-owned utilities. Significant proportions of project power and energy intended for "preference" (publicly owned) customers have been routed to large investor-owned utilities. These utilities, in turn, sell this power and energy to preference customers at higher prices and under restrictive contractual provisions.

Given this situation, the small utilities have an incentive to develop their own generating capacity, to provide themselves with a secure source of power and energy at reasonable costs in order to insure their survival and growth.

Northern California

The Bureau of Reclamation's Central Valley Project provides power to many small utilities. The evolution of a hostile environment for small utilities during the past twenty-five years has involved the Central Valley Project of the Bureau of Reclamation and its relationships with California Power Pool members.

Central Valley Project

The Central Valley Project (CVP) is a major Interior Department (Bureau of Reclamation) water conservation development in California.

CVP commenced generation in 1944. At that time, it lacked transmission and coordination needed successfully to market its surplus power to preference customers.[70] No preference customer had a system capable of providing the transmission and coordination needed. Efforts for federal construction of transmission facilities were successfully resisted by investor-owned utilities.

The amount of firm power that the Central Valley Project could provide if operated in isolation is quite limited in relation to its total installed capacity. This is because many CVP hydro developments only have sufficient storage to be run as peaking or intermediate power sources.

The Central Valley Project must coordinate its operations with base load resources if it is to obtain dependable capacity commensurate with the amount of its installed capacity.

When the CVP first sought coordination, it found that it must either erect a federal steam-electric system or employ the transmission grid and generation of PG&E.

No federal steam-electric system has ever been authorized except for the Tennessee Valley Authority. While base load generation might have been obtainable from the Pacific Northwest, that area's hydro resources were not as yet so developed as to permit export, and the transmission lines to the Bonneville Power Administration were resisted by PG&E before Congress.

Initial Contracts

After several years of negotiation, two contracts were executed in 1951 between the Bureau and PG&E, one for transmission and exchanges,[71] and one for sites and interchanges.[72]

While providing CVP with needed coordination, the two contracts were so phrased as to create a situation in which PG&E would be able to preserve and extend its great market power while the other small utilities in northern California would remain dependent upon it.

The transmission and exchange contract pertained mainly to the terms under which PG&E would transmit CVP power to preference customers.

Under the contract a uniform rate was established for transmission anywhere within a limited "service area."[73]

The service area to which this contract effectively restricted CVP encompassed the Central Valley and several counties in the Bay area.[74]

By so confining CVP sales to preference customers to a specified geographic area, it became (and predictably so) difficult for CVP to market power in a broader area in future years when its capacity was enlarged. Bureau representatives were aware of the fact that the wheeling provisions would provide PG&E with a strategic advantage in future negotiations concerning any change in the sale and interchange contract.[75]

The contract was to run for a term of ten years. It provided for wheeling service only to those CVP preference customers (1) served by PG&E on the effective date of the contract; (2) who were located and used the delivered power and energy beyond the corporate boundaries of municipalities served at retail by PG&E; and (3) who had a monthly maximum demand of at least 500 kw for three consecutive months in the 12 months preceding the date on which the requested service would commence.[76] PG&E was to decide within a 90-day period whether or not service would be available to new preference customers.[77] This provision provided PG&E with the ability to eliminate CVP as a potential wholesale competitor or a vendor to municipalities not covered by CVP in 1951.

The economic leverage possessed by PG&E in consequence of its control of transmission is seen in a report that PG&E took the position that it would not enter into a transmission service agreement unless there was "every possibility that a purchase and sale agreement were to be entered into."[78] One PG&E draft contract called for the transmission contract to be ineffective if an agreement for the purchase and sale of CVP power was not reached by the Bureau and the company.[79]

Sale and Interchange Agreement

The 1951 agreement,after a great deal of negotiation, provided essentially for the operation of the Central Valley Project as an element of the PG&E controlled power system. With its system so operated, the CVP would receive certain credit for power and energy-which it might sell over PG&E lines to preferential customers. Any remaining output from CVP generation for any remaining power received by CVP from the Northwest, would be acquired by PG&E in a rather peculiar manner hereinafter described.

Because preferential customers required firm power, the project's dependable capacity rating (PDC) defined its marketing ability. The PDC arrived at reflected a negotiating process, not an engineering calculation. The PDC the Bureau was able to negotiate was only 300 mw. This figure is substantially less than the amount that would have been credited to the CVP using either the total name-plate ratings of the CVP generators (450 mw) as had once been suggested by PG&E, or the total CVP system capability--originally estimated to be 500 mw by the Bureau and 400 mw by PG&E.[80]

As noted by the General Accounting Office, PG&E reports to the Federal Power Commission indicate that integration of CVP facilities into the PG&E system provided 518 mw of capacity.[81] There is no indication that the Bureau was compensated for benefits conferred on PG&E's system by the CVP. The Bureau was not able to acquire the firming capacity it sought to obtain--either from PG&E or otherwise.[82] Rather the company's position that PDC was to be limited to CVP and preferential customer needs was imposed.

Understating CVP project dependable capacity reduces CVP firm sales and thereby increases the purchases made by preferential customers from PG&E. Moreover, understatement of PDC results in PG&E's receiving free capacity.

The CVP hydro system provides non-dependable capacity in excess of its dependable ratings. This capacity is taken by PG&E but only paid for in limited circumstances. The final contract called for PG&E to pay for nondependable capacity made available to it only if PG&E receives at least 60 days' advance notice, and if the capacity is available for at least five consecutive calandar months.[83]

The GAO later charged that from July 1952 through December 1956 this payment arrangement enabled PG&E to take $963,261 worth of nondependable capacity for no payment since the capacity had been available for less than a five-month period.[84]

To this charge the Bureau responded, with a specious argument that the five-month period was necessary to allow PG&E to place plants on cold standby or to dismantle equipment for extended maintenance and that nondependable capacity had value only as dump energy.[85] This argument neglects both hydrological forecasting and the practice of short term capacity sales elsewhere.

It will be seen that preference customers would view this matter as an attempt by the Bureau to subsidize PG&E at their expense by forcing them to buy "federal" energy and power at higher rates from PG&E.[86]

Sale and Interchange Contract

In the negotiations for this interconnection agreement, much consideration was given to specification of the capacity and energy which would be credited to the Bureau and how these would be disposed. The Bureau did not receive credit for the amount of dependable capacity and associated energy derivable from CVP projects which resulted from the operation of CVP as part of a unified PG&E-CVP system in which CVP capacity could be used for peak periods. Instead, as noted above, CVP project dependable capacity was agreed to be 300 mw (as against the 518 mw PG&E reported to the FPC).

Implementation of the Initial Contracts

The implementation of the new contracts went forward after 1952 in a new administration, and with a new attitude on the part of the Bureau differing from earlier efforts to build an expanded federal system in contention with PG&E.

During the 1950's, CVP power was disposed of in a manner which violated the federal preference law. The House Committee on Government Operations found in

1960 that the Bureau had misled preference customers by issuing repeated statements to the effect that all CVP dependable capacity had been allocated to preference customers and that, consequently, none was available for sale. The Committee found that the Bureau knew that between 40 mw and 98 mw of dependable capacity would be available between September, 1960 and August, 1964 because prior allocations exceeded preference customers' maximum simultaneous demand. At the time, the Bureau was selling this power to PG&E, which is not a preference agency.[87]

The Bureau denied requests from the California State Department of Water Resources for interim or nondependable power. In so doing, the Bureau asserted that provisions of its contract with PG&E required preference customers to have generating capacity to replace the nondependable power when it became unavailable, a requirement the Department of Water Resources and most other preference customers would not meet.[88] Ignoring the peculiar interruptible nature of the DWR water pumping load, the Bureau asserted that supplying nondependable power to preference customers could burden PG&E, because PG&E might be called upon to supply capacity when the nondependable capacity was not available.

The substantial interest in and need for dependable capacity on the part of public entities is reflected in testimony by cities, cooperatives, utility districts and the State of California.[89]

The refusal to sell to the DWR is significant because of the potentially large size of the DWR power system and demand. The prohibition of sales of non-dependable power was only incorporated as a contract amendment in 1959 and it was then only made applicable to "new" preference customers for such power.[90] This amendment curiously would not bar CVP sales of non-dependable power to either PG&E or perhaps the Sacramento Municipal Utility District located in the district represented by CVP's principal critic, Rep. John Moss. The House Government Operations Committee, in analyzing the requirement that preference customers provide assurance of a supplemental power source as a condition for purchasing CVP power, noted (a) that this requirement was a contributing factor to a delay of several years in execution of contracts with preference customers for power they had been allocated; (b) that the requirement forced preference customers to contract with PG&E for supplemental power; and (c) that meanwhile PG&E purchased the subject CVP capacity at a price below that which the company would then sell power to preference customers contracting with it for a supplemental power source.[91] This requirement of supplemental power was dropped in 1959 after Bureau Commissioner Dominy conceded that it was not the Bureau's responsibility to compel customers to obtain supplemental power.[92] The House Committee also indicated its disagreement with requirements purporting to limit PG&E's responsibility for providing supplemental service only to those preference customers who would purchase all such power from that company.[93]

After the Congressional inquiry,[94] the Bureau partially corrected its misallocations of capacity. The Bureau also denied requests by certain muncipals for CVP power on the grounds that they were outside PG&E's service area, even though other systems would be willing to take delivery from PG&E and, in turn, wheel the power to the municipals.[95]

Another instance of the Bureau's unresponsiveness to preference customers involved the Shasta Dam Area Public Utility District (SDAPUD). In the late 1950's, SDAPUD had to curtail service to new customers and limit increased service to old customers. It was unable to obtain additional CVP power over existing Bureau transmission facilities. An appropriation was requested by the Bureau for FY1960 for construction of a line to remedy the situation. However, the request was withdrawn after PG&E offered to wheel Bureau power to the SDAPUD. SDAPUD protested that PG&E's offer was unacceptable because the wheeling rates would force the District to raise its own rates, and because the arrangement would force the District to become dependent on the discretion of its direct competitor , PG&E, for future expansion of its load.[96] These protests had no effect on the Bureau's decision to withdraw the request for a transmission line.

Implementation of the 1951 contracts was also accompanied by pressure from PG&E to prevent construction of federal transmission lines. Wheeling of CVP power to customers by PG&E in lieu of construction of federal lines had been assertedly justified on the grounds that it was cheaper. However, the House Committee on Government Operations, in a study of transmission of CVP power during the 1950's concluded that in many instances wheeling service cost the United States and its preference customers significantly more than direct delivery over government facilities would have.[97]

Bureau of Reclamation data showed that the United States realized savings of $2,947,750.81 from July 1, 1957 through November 30, 1959 following a change-over from wheeling by PG&E to direct delivery over government lines to Sacramento Municipal Utility District (SMUD). Cumulative savings projected to 1994 were estimated by the Bureau to exceed $95 million.

Northwest Intertie

Power from the Pacific Northwest might provide the CVP with a source of "firming" power alternate to PG&E. Construction of Pacific Northwest-Pacific Southwest intertie transmission lines permits the exchange of water-generated electricity from the Northwest for steam-generated electricity from the Southwest. The Intertie could also provide preference customers with an avenue to new sources of supply. Unfortunately, the arrangements entered into for the Intertie prevent the choice of alternative power sources by CVP or its preference customers.

Authorization for federal construction of the Intertie was conditioned upon the Secretary of the Interior's finding that such transmission could not be provided equally well over hired private lines. To compare federal versus private lines, the Secretary sent a federal yardstick plan and a related set of criteria for evaluating non-federal proposals to all utilities and other entities which had indicated an interest in building a part of the Intertie.[98] The yardstick plan was to serve as a model of a transmission system which would carry out the intent of Congress with respect to an Intertie system. Non-federal proposals were to be compared with it.

Ten utilities and other entities responded with proposals which were evaluated by Interior. The Secretary concluded in a report to the House and Senate Appropriations Committees that the proposal submitted by the California Power Pool would result in the most beneficial service to the Central Valley region of California.[99] In making its choice, the Department was on notice that the proposal it was accepting limited CVP's ability to serve new preference customers,[100] and placed an effective ceiling of 1050 megawatts on the amount of service CVP might provide existing preference customers. The agreement accepted by Interior did resolve the PG&E-public power struggle for wholesale markets, and appeared to resolve the power supply needs of preference customers then served by CVP until 1980.

The acceptance of the proposal was asserted by the Interior Department to cost less for CVP customers than would alternative approaches. However these alleged cost-savings are disputable, while the market of CVP was clearly limited.[101] The record makes it hardly disputable that PG&E sought and gained, through the agreement, the upper hand in determining system planning in Northern California. PG&E is in a position to determine future access to high voltage transmission--the control link in all power system combinations--both within Northern California and from external sources such as the Pacific Northwest.

Intertie construction started in 1964, involving 500 k.v. a.c. lines with a rating of 2000 Mw, and a 750 k.v. d.c. line, owned half by SCE and half by Los Angeles Department of Water and Power, with a rated capacity of 1,350 Mw. The d.c. line runs through Nevada to Southern California and can not be economically tapped into enroute. The price of the intertie was asserted by the National Rural Electric Cooperatives Association to be the preclusion of federal lines in California for twenty years.[102]

The Interior Department's acceptance of a privately controlled Intertie did not end PG&E resistance to federal transmission lines. In 1966, PG&E lobbied for public works legislation that would prohibit construction of a federal line between CVP and its Marysville dam if a local public or private agency could offer distribution and transmission service at a "low cost." In approving the Intertie arrangements, the Secretary of the Interior waived standard provisions in federal transmission line rights-of-way permits allowing the United States to transmit power over unused line capacity and to require expansion, at the government's expense, of line capacity.[103]

After approval of the Intertie proposal, the Bureau entered into negotiations with the California Power Pool for a transmission services contract, and a CVP-PG&E contract was negotiated. The members of the California Power Pool allocated shares of Intertie Capacity among themselves under an August 1966 agreement.[104]

Intertie negotiations found the Bureau having to argue for omission of a clause in the transmission agreement which would have allowed the pool companies to cancel their Intertie agreement in the event that the Bureau built or acquired an interest in any other high voltage lines in California.[105] After several years of negotiation, a contract was arrived at between PG&E and the Bureau for the sale, interchange and transmission of capacity and energy.[106] This contract will be referred to as Contract 2948A or the "1967 Contract."

The Justice Department has asserted that the 1967 contract is designed to restrict electric power sources alternative to PG&E's.[107] Justice alleged that this contract (1) gave PG&E a high degree of control over all marketable electric energy generated in California or imported into California by CVP for a 40-year period; (2) effectively limited the geographic area in which the Bureau can market electricity; (3) effectively limited the sources of capacity and energy which may be included in or wheeled in by the CVP system; and (4) effectively limited the maximum amount of capacity which CVP may maintain in its system.

While the contract does contain provisions which make it possible for some Bureau power to be wheeled by PG&E, Justice inferred that PG&E made these concessions as the only alternative to eventual construction of a federal generation and transmission network in the heart of its service area, an action which PG&E had strongly resisted. Although the contract had the effect of temporarily relinquishing certain resale customers to the Bureau, Justice noted that it secured PG&E's control over generation and transmission in northern and central California for many years.

Article 24(a) of the 1967 contract defines a geographic area in which PG&E has agreed to wheel CVP power to preference customers. This "wheeling area" excludes various preference entities which were and still are all-requirements wholesale customers of PG&E. Article 24(a)(1) provides that PG&E will only wheel CVP power to preference customers which were customers on April 2, 1951 and which, at the time of applications for wheeling, have no customers within their municipal boundaries which are served at retail by PG&E.

Justice alleged that Article 24(a) also effectively precluded access to CVP power by municipalities whose service areas lie outside the "wheeling area."[108] Bureau requests to PG&E to expand this area in 1967 were uniformly denied.

Article 12(a)(7) permits CVP, in lieu of making energy available from its own hydro plants, to substitute another source of power for delivery by PG&E to CVP customers. This source of power must be transmitted on the Intertie from the Northwest, Articles 12(a), 19(d) and 19(e).

Article 19(g) provides that capacity and energy from a new source to be sold or used in PG&E's service area may not be delivered over CVP's system without PG&E's consent. PG&E has used Article 19(g) to prevent CVP from agreeing to wheel NCPA geothermal power.[109]

The contract limits CVP's marketable system capacity to 1050 Mw. In 1971, CVP withdrew part of its allocation of power from the City of Santa Clara in order to meet other demands upon its system. The Cities of Biggs, Gridley, Palo Alto, Redding, and Roseville have commitments from CVP for supply of their entire load growth requirements until 1980, and to maintain the 1980 level of supply until 2004. However, if CVP's preference load reaches 1050 Mw before 1980, the commitment only involves continuation of supply to these cities at the level in effect at the time CVP reached its overall limit.

Justice has alleged that the effect of the 1050 Mw capacity restriction is to reserve to PG&E the load growth of all those preference customers which are presently served by CVP. Justice also asserts that this restriction is not necessitated by PG&E's obligation to provide backup for CVP's hydro generation. An arrangement by which CVP would notify PG&E of any addition to CVP's system capacity and would either compensate PG&E for the extra backup burden or secure the extra backup elsewhere would accomplish the purported purpose in a less restrictive manner.[110]

The staff of the House Subcommittee on Natural Resources and Power of the Committee on Government Operations has also criticized the CVP-PG&E 1967 contract. This Subcommittee expressed the view, before the contract was executed, that Interior had not applied the preference law principle as was required and as a result preference customers were not afforded the full protection they were entitled to under the circumstances.[111]

The 1967 arrangements between PG&E and the Bureau require that any power and energy imported by CVP from the Pacific Northwest or generated by it must either be used to serve immediate demands of Bureau customers or must be sold to PG&E. Moreover, rather than permitting an outright sale, the agreement credits such sales as "deposits" in non-interest bearing "bank" accounts from which the Bureau can theoretically call for power at some future time.

There are a series of such accounts; they are not planned to be withdrawn until the period between FY 1998 and FY 2005.[112]

Sales of capacity to PG&E for banking purposes are made at the same rates charged preference customers.[113] Capacity is to be repurchased by the Bureau at the price paid to CVP by PG&E plus a 14 percent service charge. Energy banked prior to the interchange contract may be repurchased at a fixed price; energy banked thereafter is to be repurchased at its original sales price to PG&E plus fourteen percent. However, rates for this class of energy are to also be adjusted to reflect changes in costs of generators in new PG&E units.

In the event that capacity provided for CVP pumping is not returned by the United States within five years of its delivery, an additional 15 percent service charge is imposed.

Limitation of CVP Marketing in 1967 Accords

The 1967 agreement maintained contractual limits on the quantity and geographic location of load CVP might serve.

In negotiations, PG&E maintained (successfully) that the contractual load limits applied to all loads served by CVP regardless of their location or PG&E's obligation to support a particular load.[114] All CVP output in excess of that required by its limited load was to be sold to PG&E under the "banking" arrangements. Moreover, PG&E proposed a contract provision that would prohibit CVP from repurchasing banked energy and capacity to serve customers outside of the agreed upon "service area".[115]

CVP preference customers can only purchase supplementary power from a supplier other than PG&E when the total demand of CVP's preference customers exceeds the load level PG&E is required to support; PG&E's obligation to furnish support only extended to preference customers in its service area. As in the earlier agreement, non-firm CVP power can only be sold to customers having "back-up" resources. The load carrying limitations in the 1967 agreement limit CVP's project dependable capacity to an amount that gradually expanded to reach 1050 Mw. This limitation on CVP loads is recognized within the Bureau as a marketing limit.[116] It is not a product of government engineering studies.

The contractual arrangements under which the Central Valley Project operates result in a situation in which a project with an installed capacity of 1437 Megawatts has only been able to obtain support capacity rising in steps to serve 1050 Megawatts of load. Indeed, the actual amount of support capacity has not risen above 925 Megawatts. The CVP load is supplied through the PG&E system which has exclusive sales authority to supply supplemental power to CVP customers.

The Central Valley Project is only credited with up to 850 Mw of project dependable capacity on the basis of non-extant studies. The PDC is, moreover, subject to downward revision for five years in the event of a drought, as is presently (1977) being experienced in California. All capacity, including 587 Mw of spinning reserve received by PG&E in excess of PDC is not paid for by that company.

The Central Valley Project finds itself paying for unit power from the Centralia coal-fired station which it then sells to PG&E for less than it costs.[117]

CVP does not make an independent evaluation of its PDC; rather, it relies upon a PG&E study.

When the evaluation study was sought by CVP preference customers, PG&E reported that the study was no longer available.

> "Project Dependable Capacity specified in the 1967 PG&E-CVP contract was based on plant capacity factors first established in the 1951 Bureau-PG&E contract and later modified in 1955 and 1963 amendments to that contract. Load curve data from which these capacity factors were derived were not retained in our files. These capacity factors assign CVP system plants to the peak portion of the area load curve." [118]

If studies of any substance were done, the engineering formulation supporting assignment of CVP hydro units to the peak portion of the load curve has not been carried over into PG&E-CVP contracts.

The 1483.7 Mw of installed CVP capacity should become increasingly dependable as peak load grows in the PG&E service area. This results from the decreased amount of energy that is required to provide dependable hydro capacity during short duration load peaks.

In 1967, the parties "agreed" not to reevaluate the amount of energy required to be associated with dependable capacity at CVP units (the capacity factors). Rather, "in the 1967 contract, Article 11(b)(2), the parties agreed that the capacity factors used in the 1963 amendment to the 1951 contract would be continued in the new contract and applied to then existing Project plants in all future redeterminations. Therefore, the Project plants that existed in 1976 have fixed capacity factors, not subject to renegotiation under the contract..." [119]

The large number of "nondependable" megawatt-months CVP has provided PG&E, (178 Mw-months in 1972 alone) and the large (400 Mw) difference between PG&E rating of CVP project dependable capacity and the installed machine generation capability of CVP projects indicate that the amount of CVP capacity that could be sold on a firm short-term basis has been understated. This indication is buttressed by PG&E's inability to produce the derivations of CVP PDC.

The limits on CVP project dependable capacity are embodied in agreements having an unusually long life--forty years. This agreement fixes PDC solely on the basis of federal hydro resources. In so doing, it may exclude from PDC non-federal hydro or steam-electric resources. Agreement, Article 14. CVP may not sell power on a temporary allocation to a new preference customer.[120] The Bureau will not reduce its sales to PG&E to increase sales to preference customers now served by PG&E; moreover, if able to purchase power from elsewhere, CVP could not raise its dependable capacity.[121]

The Bureau of Reclamation has not challenged contractual wheeling restrictions even though it has been informed that these restrictions may contravene antitrust law.[122]

Completing Market Division Arrangements

The conclusion of the 1967 CVP agreement still left open several avenues through which bulk power competition might enter Northern California. One such avenue was presented in the terms of federal transmission line rights-of-way permits to SCE and PG&E that permitted other parties to employ excess capacity in these lines.

Additionally there remained the remote possibility that a Northwest entity might attempt independently to enter California markets (e.g., by building a line or forcing allocations in Intertie facilities or contractual arrangements). Both avenues were closed in an arrangement that foreclosed access to Northwest power and resulted in market sharing by Northwest utilities.

Rapid conclusion of the Intertie agreements and Congressional action left some of California Pool members' commitments in oral form. One verbal understanding was that if they would enter into a series of agreements to plan and operate nonfederal lines in California in harmony with operations projected under their Intertie proposal, Interior would waive its usual requirement that permittees allow others to use excess line capacity for wheeling. One remaining agreement concerned the California proposal to make purchases from Northwest agencies on a generally pro rata basis in order to afford each Northwest agency a "fair share" of the sales to California.

This agreement, the Seven Party Agreement, was executed on January 14, 1969.[123] Under it the four Pacific Northwest utilities--Pacific Power & Light Company, Portland General Electric Company, Puget Sound Power & Light Company, and the Washington Water Power Company, trading as a group--sell the three California Pool members, trading as a group, hydro energy at Bonneville Power Administration (BPA) rates and purchase excess steam-generated energy at seller's incremental cost plus 15 percent.

The agreement posed the California pool and the private northwest entities as exclusive trading partners. This exclusivity was successfully opposed by the Bonneville Power Administration as regards sale to the south from the Pacific Northwest. No changes were made however to protect California preference customers.

Interior, at the apparent instigation of the Bonneville Power Administration (BPA), wanted direct contractual obligations between the major private companies in the Pacific Northwest group and the California group for sales and purchases to and from the Northwest on a fair and equitable basis. BPA was aware that California Pool members were trying to insulate themselves through the Seven Party Agreement from application of the preference law sections of the Bonneville Project Act and the Regional Preference Law.

These preference sections specify that any power added to the federal system is subject to the marketing priorities for BPA power which are first, Northwest preference customers public power systems, second, other Northwest entities, third, non-regional preference customers, and finally, other non-regional entities. These preference requirements would result in California public agencies' obtaining the largest share of Northwest exportable energy.[124] However, BPA did not secure access to Pacific Northwest energy for California preference customers. Sales of non-firm energy from the Northwest are credited pro-rata to all Northwest entities.

The Secretary of the Interior asserted, after these amending agreements were entered into, that subordinating the Seven Party Agreement to the two agreements would result in California public power systems having access to "by far the largest share" of the exportable energy available in the Pacific Northwest; and California Pool members would have access to Northwest exportable energy only after the demands of all California preference customers were met.

The Interior Department asserted that since the largest share of Pacific Northwest nonfirm energy is generated by BPA, such energy, together with that received by BPA from both the investor and publicly owned utilities under exchange agreements, is subject to the preference clause, and a substantial portion of the exportable energy delivered annually by

PP&L and Portland General will go to Los Angeles, Glendale, Burbank and Pasadena and any other public agency in California which contracts with BPA. Preference customers in California will have access to by far the largest share of exportable energy available in the Pacific Northwest. The California Companies will have access only to a portion of the exportable energy available from the Pacific Northwest investor-owned utilities. The California Companies will have access to the remainder of the Pacific Northwest exportable energy only after the demands of the California preference customers have been satisfied in full.[125]

In actuality, California preference customers did not obtain effective access to the Northwest energy exports. The agreements did not specifically provide for access by California preference customers to Intertie transmission, nor did they change existing arrangements among California Power Pool members and public power systems in California.

The California Pool members have not provided necessary coordination services and wheeling to other California systems. Without acccess to pooling or to wheeling, most California preference customers have no other artery to Northwest energy.

Even though PG&E is given access to Northwest exportable energy only after the "needs" of California preference customers have been met, the 1967 CVP-PG&E contract insures that preference customers will have minimal needs. Thus the agreements merely avoided dissension among Northwest entities.

During a roughly contemporaneous period, two other arrangements were made which tend to exclude competitive factors in California. These arrangements precluded access by Southern California municipal systems. One was the Interior Department's decision to waive federal wheeling requirements on lines of SCE into Southern California from the Southwest.

The second, described supra, limited marketing by the one large new intra-state source of generation, the California Department of Water Resources. DWR was permitted to obtain rights to use 300 mw of capacity of 500 k.v. Pacific Northwest Intertie, but DWR's use of the line was limited to interstate transmission; PG&E has consistently refused to permit DWR to use the California segment of the Pacific Northwest Intertie for any intra-state transmission, a refusal based solely on PG&E's desire to exploit fully its monopoly on transmission facilities."[126]

Preemptive Features in CVP-PG&E Contract

Under its contract with PG&E, CVP transmission to customers is dependent upon cooperation by a competitor - who has interpreted the coordination agreement as preventing CVP from seeking to compete for loads.[127]

Dominance of CVP by PG&E appears to be coupled with a go-along attitude on the part of the Bureau of Reclamation and the Interior Department.

This attitude is manifested in conduct toward PG&E and toward preference customers. One illustration of this is the handling of a request by the City of Santa Clara, California.[128]

The City of Santa Clara, which had been purchasing power from Pacific Gas & Electric Company, for its municipal power system, sought to obtain an allotment of power from CVP in 1964. To avoid problems relating to CVP's having allotted all of its firm power, Santa Clara sought an allotment that would be withdrawable by CVP at such time as the allotted power was required by more senior allottees.

PG&E vigorously opposed such an allocation, advising the Interior Department that it would not be in accordance with the City's contract with PG&E and that any such allotment would be counter to the Bureau's policy of not disturbing contractual arrangements.[129] The Company informed Santa Clara and the Interior Department that power transmission services would not be provided for this power under the CVP-PG&E contract, as PG&E was not obligated thereunder to wheel (transmit) Bureau power where such wheeling would terminate or affect an existing contract between PG&E and a preference customer.[130]

Santa Clara, questioning the lawfulness of the CVP-PG&E accords[131] persisted in its efforts. It obtained a withdrawable allotment of CVP power in December 1965.[132]

A Justice Department evaluation of PG&E's conduct cited Santa Clara's efforts first to break its long-term, all requirements contract with PG&E and then to force the Company to wheel Bureau power to the city as the only instance known to the Department of successful resistance by a municipal system to PG&E control tactics.

As a result of this experience, Santa Clara was concerned about provisions in the Intertie contracts. Santa Clara had been informed that in view of load growth forecasts, its temporary allocation would be withdrawn by 1970, and possibly as early as 1968, to meet the needs of preference customers who had not required some portion of their allotments prior to that time.[133] When the City applied to the Bureau for non-withdrawable power it was told that its application would be considered when more firm power became available as a result of the Intertie. Later, however, Santa Clara was told that the additional firm power would all be allocated to preference customers with existing non-withdrawable allotments.[134]

Santa Clara protested this action and formulated a plan whereby the City would build its own generating facilities and meet its needs through a combination of its own generation and purchased CVP power.[135] The City also proposed to provide the Bureau with the 400 mw of power the U.S. would be required to import under the Intertie agreement.[136] This proposal drew a negative response from the Interior Department.[137]

After some years of acrimony after which Santa Clara only received a temporary allocation, a proceeding was commenced in the United States District Court.

In this proceeding, the court has found that the Interior Department lacked even an official system for allocations and ordered that one be promulgated. City of Santa Clara v. Kleppe, N.D. Ca. Civ. No. C-76-1574-SC. Such a system was deemed a prerequisite to a determination of Santa Clara's eligibility.

Santa Clara was not the only preference entity whose misgivings about the Intertie and power supply problems seemed to elicit little protective response from the Interior Department.[138] The Bureau was aware that other municipalities also viewed the Intertie contracts with concern.[139]

CVP's Failure to Renegotiate Rates

The rates charged by CVP to PG&E could have been, but were not, renegotiated in 1971, under the terms of the PG&E-CVP contract.

CVP chose not to review rates with PG&E on April 1, 1971, as permitted under the 1967 contract. Such a review might have resulted in rate changes preventing the losses GAO records. Interior argues that the rate review was omitted because it believes all customers should be charged the CVP system rate rather than the cost associated with a particular source; because the cost of Centralia power was not accurately known in April, 1971;

and because by banking the power at a low rate CVP would reduce the charge to be paid to PG&E when it buys the power back.[140]

The "single rate" argument fails to distinguish among classes of services; for instance, PG&E, unlike preference customers, obtains unit capacity and energy from the Bureau's entitlement in the Centralia coal-fired generating station while CVP preference customers have not been able to obtain this capacity. Preference customers are largely wholesale purchasers taking all or most of their requirements from CVP. The prospect of future savings through the banking arrangmeent is no reason to compel present utility customers to pay for losses, especially when savings are speculative. Both present and future CVP customers are liable to benefit if CVP were to collect interest on its bank account.

Interior reports that PG&E gave notice that when the 1976 review procedure for Centralia rates got underway PG&E would ask for increases in other rates it charged.[141]

The underlying motivation for CVP's failure to renegotiate rates appears to be its lack of bargaining power vis a vis PG&E. This stems from PG&E's control of bulk power resources, particularly the Intertie.

PG&E's overall response to the various charges of subsidy is that the 1967 contract provides CVP and its preference customers with enormous benefits. Thus PG&E asserts that: (1) the power support provisions enable CVP to serve twice as much preference load as it could without such support. (2) The CVP may repurchase banked output at rates below cost.[142] (3) PG&E buys only power surplus to CVP needs, providing CVP with an assured market for all its surplus, (4) PG&E provides the CVP with all the power it needs to meet its fluctuating needs, and also with reserves.

PG&E has provided benefits to the Central Valley Project. It has done so only as part of arrangments wherein (1) PG&E precludes CVP access to such benefits, and perhaps greater benefits elsewise;[143] and (2) the competitive growth of CVP and preference customers is severely limited.[144]

The allocation of benefits of the coordination between CVP and PG&E runs disproportionately in PG&E's favor. Further, the understatement of values and failure to specifically identify the value of various benefits in CVP-PG&E arrangements also indicate the weak bargaining position and limited prospects of CVP.[145]

The ability of PG&E to threaten to retaliate with rate charges in other areas should one rate CVP charges it be changed reflects PG&E's great power over bulk power marketing in Northern California. PG&E is apparently able both to relate prices and terms of service for different services--i.e. to "tie" some services to acceptance of others--and to tie the price and terms of service it will accept to the price and terms of service it will offer.

By using its power over bulk power supply facilities to obtain below-cost or uncompensated services PG&E is increasing the CVP costs which its competitors, the preference customers, must bear, PG&E is better able thereby to undersell them.

Price Pressure on PG&E's Competitors

Retail rates charged by systems competing with PG&E are subject to conflicting pressures: the necessity of maintaining competition with the company forces rates down, while the costs of capacity and energy may force them up.

In 1973, CVP began to seek rate increases, from preference customers only. The bases for these increases were sharply questioned by its preference customers, apparently with some reason. In November 1974, the Interior Department revised the rate increase proposal so as to implement the increases in two steps, and announced it would seek rate increases from PG&E in their 1976 contract renegotiation.

At the behest of the preference customers, however, the U.S. Court of Appeals for the District of Columbia Circuit ordered a refund of the increase, relying on procedural deficiencies in Interior's actions.[146]

Quite novel justifications were advanced by Interior for the rate hikes. The increases, had they become effective, would have generated a $490 million surplus from preference customers over 35 years. Increasing costs to preference customers sufficiently to generate such a surplus--with no assurance that the customers would receive a return in the form of future electrical services--could obviously damage the preference customers' competitive position vis a vis PG&E.

The approaches and procedures followed by CVP seem to suggest an adversary relationship with its preference customers--not close, collective relations capable of jointly providing a competitive alternative to the dominant electric utility in the region.

GAO has concluded that, except for providing for about $78.4 million in deferred costs, power rates should not be increased to create a surplus, and that the concept of CVP's rate and repayment study is inconsistent with the criterion used by other Federal power projects and Congressional mandates respecting the proper concepts for a rate and repayment study.[147] The Bureau calculated that by abandoning one erroneous concept, it could scale increases down to 36 percent from the 51.6 percent proposed.[148]

Members of the Subcommittee on Conservation and Natural Resources of the House Committee on Government Operations during hearings on the rate proposal repeatedly asked Interior to produce the computer studies which supported the abnormal concepts used. Interior officials testified that they were not sure that one computer study had ever been made but that a second study probably had been made but had since been discarded.[149] Members also asked why the Bureau, in its rate and repayment study, did not plan on withdrawing some of the bank account energy to reduce costs. A Bureau official agreed that this would indeed reduce problems, but that amount of energy would have to be bought elsewhere later. Members then asked why the Bureau was trying to project potential savings into the distant future when dealing with the immediate problem of the proposed rate increase. A Bureau official testified that he did not know the answer to that question.[150]

Representative McCloskey, citing Bureau documents, established that in 1971 (though allegedly not at the time of the hearing) the Bureau entertained the purpose of obtaining funds, through rate increases, to construct new CVP units not yet authorized. The Bureau documents revealed a meeting--held <u>before</u> either the renegotiation of PG&E-CVP rates or data on the cost of Centralia power were available--to discuss programmed CVP rate increases. Another document cited by Rep. McCloskey disclosed a conscious Bureau decision to maintain surplus CVP revenues at about $350 million. Even though the surplus would foreseeably hinder customer acceptance of rate increases, it would aid in obtaining Congressional approval for future CVP additions to plant. The memorandum stated that the apparent conflict could be eased by "referring to the 'surplus' 'reserve' or 'contingency' with an explanation that this amount is considered necessary as a reserve fund which would be maintained in accordance with prudent business procedures and management." Representative McCloskey stated that the practice smacked of fraud; Representative Moss called it "an excellent example of gymnastics."[151]

NCPA alleged that it and its members were denied due process by the absence of hearing procedures on the rate proposals which would permit testing of conflicting presentations. Though repeatedly urged by Congressmen Reuss, Moss, and McCloskey, Interior refused to provide public hearings with a record and opportunity for presenting and cross-examining witnesses.[152] Interior responded that public hearings are not required by the law and that there was no need for the expense, delay, and rigidities that more formal proceedings, with such features as sworn testimony, cross-examination, rules of evidence, and written briefs, would entail.[153]

Representative McCloskey stated during the 1974 hearings on the proposed rate increase that "... I don't find any record, in all the testimony the Bureau has presented, that an orderly procedure was pursued initially to ascertain the basis for rates and then to increase rates."[154] Representative Moss stated at the end of the 1974 hearings that "I have never seen a poorer case for action by a department or agency of the Federal Government, and I have seen some bad ones in more than 20 years of service in this House."[155]

On February 14, 1975, District Judge Gesell set aside the 1974 CVP rate increases because of Interior's failure to accord due process.[156] The Secretary subseqently published procedural regulations which do not provide for trial type proceedings, cross-examination, discovery, or decision based on a record.[157]

Interior Wheeling Stipulations and Bureau Contracts

As prior discussion has indicated, smaller entities and new entrants require a complex of coordination arrangements, sometimes including "wheeling" of energy. As of October 1973, the Interior Department had never sought to have electric utilities having right-of-way permits perform wheeling service.[158] As of mid-1976 Interior had not provided wheeling for others on Bureau lines in California.[159]

The Bureau's position has been not to remove anticompetitive provisions from contracts until a problem develops; --i.e., someone seeks a service and is denied it under that provision.[160]

The overall approach followed by the Interior Department creates uncertainty for new entrants. This contributes to an environment discouraging new entry or expansion by entities other than the dominant power suppliers in California.

Hostility to Development of Geothermal Units--NCPA Efforts

Small utility systems in California are faced with a hostile environment in markets for transmission services and coordination when they seek to develop their own geothermal generation.

The Northern California Power Agency, and its member city, Santa Clara, have sought to obtain geothermal resources from potential suppliers in The Geysers area who are not under exclusive contract to PG&E. NCPA has recently entered into an arrangement with lessees in this area to participate in the financing of a drilling program; Santa Clara has recently obtained a lease from the State of California for acreage in this area. These entities are clearly in earnest in their efforts to develop geothermal generation. However, as the Justice Department has alleged, NCPA's attempts to develop such generation have been hindered and frustrated by PG&E's repeated refusals to provide NCPA with transmission services, or reserves and standby services.

When NCPA first approached Interior, in its efforts to enter into geothermal generation, Interior gave a favorable response.

Discussions in 1968 focused on geothermal resource development by NCPA, the Bureau, Geothermal Resources International, Inc., or joint effort of the three.[161]

NCPA's objective during these discussions was to develop energy sources to meet greater needs than could be met with Bureau power, and to obtain a Bureau commitment to participate actively in this effort. Suggested areas of Bureau involvement included: (1) wheeling NCPA power over Government lines, when finally constructed; (2) purchasing NCPA-generated geothermal steam power; (3) providing supplementary power to NCPA cities; (4) providing pumping power; (5) providing cooling water; and (6) assuring a preference for NCPA with respect to potential nuclear power plants.[162]

PG&E responded, on August 19, 1969, that the Intertie contract did not commit PG&E to participate in any particular program with NCPA; that PG&E would not wheel power from NCPA's project to CVP's system and thence to NCPA member systems; and that PG&E was unwilling in principle to wheel power from any hydro plant for which NCPA might recapture a license from PG&E in forthcoming relicensing proceedings.[163]

NCPA then developed an alternate plan to construct its own transmission lines to the CVP system and thence wheel over CVP's transmission system to its members. The feasibility of the alternate plan was shown in a joint study by NCPA and the Bureau.[164] This plan, per NCPA, could not be executed because of obstruction by PG&E which used its 1967 contract with CVP and an array of alleged technical problems on the interconnected system, according to NCPA, as a basis for preventing the plan's execution.[165]

The Bureau relied on Contract 2948A as grounds: (1) for refusing to use spare CVP transmission capacity to wheel NCPA power without PG&E's consent; (2) for refusing to arrange PG&E wheeling of CVP power to Agency cities not then receiving such power; and (3) for refusing to negotiate for purchase of capacity and energy from NCPA for delivery to preference customers or for replacing or augmenting Centralia power.[166]

The Department of the Interior, pointing out that NCPA's proposal involved more than wheeling, asserted that allegations that the Bureau refused to wheel NCPA power were inappropriate. The Bureau agreed that PG&E's approval was not required under the contract for CVP to wheel NCPA power;[167] but asserted that the barriers actually lay in NCPA's reserve and reliability problems. Interior was not able to assist NCPA with generation reserves, however, since all Bureau reserves were under contract.[169]

The Bureau declined to replace Centralia power with NCPA power, stating that it was bound to purchase up to a specified amount of Centralia power through Dec. 31, 1981.[170] The Bureau was willing to negotiate for purchase of NCPA power after that date,[171] assuming NCPA power would be available and competitive.[172]

Purchase of NCPA power for use other than as a substitute for Centralia power was limited by the Bureau's limited authority to provide bulk power to preference customers.[173] The Bureau was only authorized to dispose of (1) CVP-generated capacity and energy in excess of Project requirements, (2) the 400 mw of Northwest power, and (3) any energy acquired to firm up Project capacity.[174]

Purchase of firming energy from NCPA would require amendments to the Bureau's contract with PG&E, which provided that PG&E was to be the sole supplier of such energy.[175]

When NCPA has sought to raise a complaint before the FPC regarding PG&E wheeling restructure it has been met by administrative indifference and hostility. The FPC becomes involved because it regulates some of PG&E's wholesale rates and interconnection agreements. The Power Commission has declined to consider allegations of anticompetitive matters in rate cases. Rather, antitrust issues are placed in a separate proceeding, which is supposed to run in parallel to the relevant rate case. The rate cases are terminated one after another while the antitrust oriented proceedings go on at a snail's pace and never reach a decisive point. This has been the pattern where PG&E has sought to raise its rates to captive NCPA members,[176] where PG&E filed the agreement whereby PG&E controls all the output of the SMUD nuclear plant,[177] or where PG&E filed the agreement giving it control of the transmission from a power source in the Pacific Northwest.[178]

After PG&E objected, the Interior Department has failed to take any steps to implement the USBR-NCPA joint transmission plan, even though the features of the 1967 PG&E-CVP contract which purport to afford PG&E a veto over use of CVP transmission by others create bottleneck conditions thwarting economic development by other systems. Cf., Otter Tail Power Company v. United States.[179]

NCPA's attempt to engage in coordinated development of independent generation has been thwarted, as Justice has alleged by the California Power

Pool's denial of access to NCPA.[180] In 1970, NCPA requested participation in the Pool for the purpose of coordinating the development of generation and transmission resources. PG&E declined this request.[181]

NCPA has alleged that PG&E has used exclusive dealing provisions and pre-emptive tactics to severely limit NCPA's access to geothermal resources.[182] The facts here are that on May 11, 1970, PG&E executed a revised agreement for the sale of geothermal steam with Magma Power Company and Thermal Power Company, the entities from which it had been purchasing geothermal steam for several years, and an agreement with Union Oil Company for the sale of geothermal steam. The agreements stipulate that Union, Magma, and Thermal agree to develop steam exclusively for PG&E from any leases they then held, or might afterwards acquire in a 180 square mile red-lined area (unless PG&E fails to build additional generation capacity if the steam developers find at least enough steam for 50 Mw of power in a year). This 180 square mile area contains all of the Geyers land that had been previously developed for geothermal steam production and much land surrounding those steam wells. PG&E's obligation provides that it may defer construction for six years if (a) it does not need the additional capacity, (b) construction would be inconsistent with cooperation in the development of water resources, or (c) such facilities would not be competitive with the cost and comparative reliability of power from alternate sources, all as determined by PG&E. The contracts continue in effect for a period of 50 years beyond the date when PG&E places its last unit in commercial operation.

PG&E later entered into similar contracts with Pacific Energy Corporation and with Signal Oil and Gas Company. These contracts cover additional wells and areas within the red-lined area.[183]

NCPA has alleged to the California Public Utility Commission that the exclusive dealing provisions of the Magma, Thermal, and Union Oil contracts are inconsistent with the antitrust laws and the public interest.

The California Public Utility Commission held that it had no jurisdiction to determine the issues which NCPA presented.[184] The California Supreme Court reversed the Commission and instructed it to consider those issues.[185] The Commission on remand, held that Union, Magma, and Thermal's combined holdings (of 85 percent of the wells and 54 percent of the land) in the red-lined area were not a monopoly and that for PG&E to violate antitrust law or policy there would have to be a monopoly of all power resources in northern and central California.[186] The California Supreme Court denied review.[187]

The California PUC's decision is questionable on grounds relating to both antitrust policy and administrative procedure.

As regards administrative procedure, the PUC decision fails to discuss or make findings regarding the underlying facts in The Geysers area. It merely sets out its <u>ipse dixit</u> conclusions.

On antitrust grounds, the use of exclusive purchasing provisions for a substantial portion of a unique new energy source is inherently suspect. The questions of why these terms were sought and whether less pre-emptive terms would suffice should be addressed if the public interest is to be protected. They were not asked by the PUC.

Although the PG&E red-line agreements have not totally excluded others from the Geysers area, NCPA and Santa Clara were only first to obtain lease rights in that area years after the PUC decision. In the meantime, many wells developed for production, on red-lined acreage, have stood idle.

LIMITATIONS ON THE SACRAMENTO MUNICIPAL UTILITY DISTRICT

The Sacramento Municipal Utility District (SMUD) is a large public-power system in Central California. SMUD has the capability and interest to develop a geothermal plant on its own.

The SMUD is so located as to be surrounded by Pacific Gas and Electric Company service area and lines. To obtain coordination and the benefit of cheaper hydro power from the Northwest, SMUD requires access to the PG&E high voltage grid, including the Pacific Intertie. In order to build larger units having lower unit costs, SMUD must obtain coordination services, e.g., reserves and load growth coordination.

The contracts SMUD has obtained for coordination services preempt any SMUD output excess to its needs, limit SMUD's ability to market energy which the California Pool Companies wheel from the Pacific Northwest, and limit SMUD's flexibility in obtaining access to new energy sources (such as geothermal sources).

Terms for SMUD's access to the Intertie lines are set out as noted above in an agreement between SMUD and the California Companies as a group (PG&E, SDG&E, and SCE).

Under the contract, shipments south over this grid consist of (a) firm capacity sold for periods of not less than a year, (b) dump energy, and (c) power available from Northwest utilities (acquired under Canadian Entitlement Exchange Agreements).

The California Companies agreed to wheel only such capacity and energy as is acquired by SMUD "For use within its boundaries and for sale or assignment as agreed upon by the parties hereto," from any entity in the Northwest; and they also will accept from SMUD capacity and energy for delivery to any entity in the Northwest through the Intertie high voltage lines. The California Companies agreed to wheel up to 400 Mw of Intertie capacity, between April 1, 1971 and March 31, 1976 and other wise 200 Mw of such capacity.[188] Additionally up to 225 million kilowatt-hours per year of dump energy may be wheeled.

Except in regard to Canadian Entitlement Power, changes in quantities transmitted are to be made once a year only, generally in 25 mw increments.[189]

In the event that SMUD purchases Northwest firm power or Canadian Entitlement Power in excess of needs, it may resell all or part of the power to the California pool companies if (a) SMUD pays for transmission, (b) the power is intended for "future use by Sacramento within its boundaries," (c) notice is given by SMUD five years in advance of the initial date of delivery under the contract (for transmission clearance) and (d) if SMUD gives one-year advance notice in the event it wishes to change the amount of power it will resell.

Once SMUD has notified the companies that it is invoking the resale provisions, it must thereafter get the consent of the California pool companies before amending its contract for purchasing Pacific Northwest power for changes effective during a period less than 61 months.

The companies' obligation to purchase Canadian Entitlement Power that SMUD seeks to resell[190] is contingent on there being no change in the agreement by means of which Pacific Northwest utilities obtain Canadian power which would be unfavorable to the California pool companies in regard to prices, terms and conditions for the purchase of such power. The pool companies' obligation to purchase Northwest firm power from SMUD is also conditioned on there being no changes in quantities, times, prices, terms or conditions of sale. The pool companies only need purchase if a) they determine that they would have purchased such power in the same quantities and at the same contract terms for use in their own service areas, and, (b) the power is firm, with sufficient associated energy to enable the companies to use such power in their own service areas consistently with their other obligations.[191] The Canadian and Northwest power is purchased from SMUD at SMUD's cost.[192]

The contract provides that SMUD, may, until March 31, 1976, purchase Canadian Entitlement power from the California pool companies. Five years' notice is required for such purchases, unless SMUD is coordinating its load growth planning with PG&E--in which case only one year's notice is required.[193]

The contract prevents SMUD getting any greater quantity of Canadian energy (per kilowatt of Canadian-attributed capacity available to it) than PG&E obtains for its own system. The price of such power to SMUD is the pool companies' cost.

After the SMUD Intertie Agreement, the California Companies amended their Intertie agreement. This contract's flexible provisions for scheduling Intertie shipments are interesting in juxtaposition to the terms given SMUD.

The California pool companies arranged for San Diego Gas & Electric Company (SDG&E) to have access to Intertie transmission in this period when public entities were not using their alloted capacity.[194] SDG&E was permitted both to obtain assured capacity, and to make interruptible or short-term use of Intertie capacity not used by PG&E. Also it could use the line in emergencies.[195] SDG&E was not required to give long prior notice, and was permitted to fully share in line capacity that happened to be disused when SDG&E could employ the line to purchase cheaper Northwest energy. The flexibility afforded SDG&E but not SMUD, for short-term or dump, or emergency transactions, could be valuable for a power generating entity. For example, such flexibility would make it easier for SMUD to coordinate, or obtain complementary services, from an entity other than PG&E.

1975 Amendments to SMUD-PG&E Contract--Geothermal Units

SMUD's tentative plans to install up to 400 megawatts of geothermal generation prior to the date of its next nuclear unit are reflected in 1975 change in the SMUD agreement with PG&E. As noted above SMUD agreed to sell any of its geothermal capacity and energy not used to meet SMUD's load; sales would be made at prices which could be below cost. Surplus capacity must be sold to PG&E at a price midway between SMUD's cost and the cost PG&E would have incurred in generating an equal amount of capacity and energy from PG&E's geothermal generation so long as this is not in excess of PG&E's cost. Capacity purchased by PG&E each month will be considered to come first from geothermal and oil-fired generation, and secondarily from the first nuclear unit. Such purchases are to continue until SMUD installs its next large thermal resource, at which time any surplus power available for sale to PG&E will be deemed to come from SMUD nuclear resources.[196]

PG&E also has pre-empted the surplus output of SMUD's proposed 150 megawatts of combustion-turbine generation. PG&E will not only have the right to dispatch these turbines (at capacity factors up to 10% each month) but will also be entitled to purchase the turbines' output at the same rate as it pays for energy from SMUD's nuclear units[197] a sum less than the costs of oil. If PG&E dispatches the turbines at greater capacity factors, it is to pay SMUD's cost for all energy generated in excess of that associated with 10% capacity factor.[198]

Since the 1970 contract, costs for both SMUD and PG&E have risen substantially above the fixed ceiling prices there set for sales of nuclear output to PG&E.[199] This placed SMUD in a poor bargaining position--especially as it lacked an alternative coordination market for its planned new units.

In regard to nuclear sales, it is stated in the 1975 amendment filing with the FPC that, "As Sacramento's costs for capacity and energy from Rancho Seco are below Pacific's projected cost at Diablo Canyon, these amendments are in keeping with the underlying reasoning of the 1970 contract."

SMUD proposes that its second nuclear unit be 1,100 mw. The amended contract provides that after SMUD's second nuclear unit becomes commercially operable, capacity sales to PG&E from both SMUD nuclear units will be at a price midway between SMUD's average cost for its nuclear units and PG&E's cost for its ownership share of the second SMUD nuclear unit; surplus firm energy will be sold to PG&E at cost. Thus sales from the nuclear units, which will be separately dispatched, will not be at their separate incremental costs.

Nuclear energy not associated with the sale of firm capacity would be sold to PG&E at a price midway between SMUD's incremental cost for nuclear energy and PG&E's cost for using its fossil-fueled resources.[200] This price is stated as likely to be higher than the previous contract price of cost plus 10%. PG&E is not required to purchase this excess energy.

The original agreement with PG&E came into being when, subsequent to the Intertie agreement, SMUD in 1970 wished to construct two nuclear generation units and found that to do so, it must enter into coordination, or integration, contracts with PG&E. This arrangement envisages a crude form of load growth coordination between PG&E and SMUD, PG&E dispatching of SMUD units in connection with its own "revenue sharing," and coordination of unit maintenance.

Coordination of load resources planning was essential to SMUD because it could only economically put in nuclear units whose capacity would be substantially larger than SMUD could absorb at the time of construction. When SMUD loads grew larger than its capacity resources, it would have to defer building a second large new unit until it could employ a substantial share of that unit's capacity. Accordingly, SMUD sought to dispose of a portion of its first nuclear unit and to obtain energy and capacity from others in periods between nuclear units. SMUD also required reserves to back up nuclear units.

The resulting agreement reflects and fosters PG&E's control of bulk power marketing in Central California.

In return for PG&E's commitment to share reserves[201] and to supply SMUD with up to two million kilowatt-hours a year to cover SMUD needs between nuclear units, SMUD was required to permit PG&E to (a) dispatch SMUD generating units (b) control SMUD's acquistion of Northwest dump power,[202] and (c) to receive only limited credit for the firm capacity SMUD supplies SMUD-PG&E joint loads.[203] The contract placed the burdens of inflation in construction costs on SMUD by requiring sales of nuclear capacity and energy to PG&E to be made under fixed rate ceilings.[204] While SMUD must provide PG&E with six year's notice of SMUD plans to add capacity, PG&E apparently is under no reciprocal obligation to arrange its planning with SMUD so as to fit new SMUD capacity into PG&E's mix of generating resources. PG&E's consent is required before SMUD can increase the planned size of its nuclear unit.

PG&E is authorized to schedule and dispatch SMUD hydro-electric capacity as an integral mix of resources serving area load in the same manner as it schedules its own units. However, SMUD is not credited with the contribution to dependable capacity made when SMUD units are fitted into an area-wide load curve. Rather, SMUD is only credited with the capacity its units would have under SMUD's isolated load pattern.

Although credit for capacity is essential if SMUD is to amortize nuclear unit costs, SMUD capacity credits are restricted in that SMUD's nuclear units are to be dispatched by PG&E after preference is given to PG&E geothermal and "minimum fuel" consumption requirements, and to PG&E long-term power purchase arrangements.[205]

Subsequent to the 1970 agreement, SMUD has experienced severe operating problems with its first nuclear unit.[206] The second unit has now been indefinitely deferred and substitute capacity is required. To provide for this capacity, SMUD has had to renegotiate its integration agreement with PG&E. This renegotiation resulted in a 1975 agreement.[207]

The 1975 amendments allow SMUD higher prices for output from its nuclear unit, and permit SMUD to add non-nuclear generation including geothermal units. In addition to the output sales restrictions herein before mentioned, the 1975 amendments price output to PG&E at rates which may be less than production costs.

Capacity purchased by PG&E each month will be considered to come first from geothermal and oil generation, and secondarily from the first SMUD nuclear unit irrespective of actual dispatching. Such purchases are to continue until SMUD installs its next large imputed "thermal" (oil, coal or nuclear) resource, at which time any surplus power available for sale to PG&E will be deemed to come from SMUD nuclear resources. Geothermal and oil-fuel generation are likely to have lower capacity costs than present nuclear units. The capacity cost of an already built nuclear unit is likely to be lower than the cost of a new large nuclear unit. Thus, using imputed capacity sources as opposed to actual dispatched capacity enables PG&E to obtain capacity at less than cost.

As heretofore noted,[208] PG&E will likewise be acquiring energy from SMUD at prices below SMUD's cost.

As SMUD seeks to add other units, and coordination, its expansion will be subject to agreement with PG&E. The coordination agreement between PG&E and SMUD appears to be limited to specified levels of additional SMUD capacity.

Under the coordinating agreement, SMUD may only add generation when it forecasts that in seven years it would otherwise have deficient resources (of not less than two million kilowatt-months) to meet its own requirements. SMUD appears to be precluded from acting jointly with others to supply smaller deficiencies, or expanding its scope of operation at the wholesale power supply level.

Various contract terms are not consistent with both parties' obtaining the full benefits of coordination, and hinder SMUD capacity expansions. For instance, 100% maintenance reserves are required in the first year a SMUD unit is in operation.

Restrictive Contracts and Predatory Tactics

In addition to reducing the ability of CVP and SMUD to function as sources of bulk power supply to small utilities, the California Pool members appear to have fostered a hostile environment for small utilities by their direct dealings with the smaller, retail-oriented utilities.

Justice has alleged that PG&E's power supply contracts, by virtue of their all-requirements provisions, and their timing of renewals, have generally precluded attempts by small utilities to avail themselves of alternate sources of bulk power where such sources have become available.[210]

Alamada, Healdsburg, Lodi, Lompoc, and Ukiah, all municipal customers of PG&E, have been under five to seven year all-requirements contracts since 1955. PG&E, for many years, resisted these cities' requests for shorter contract terms and insisted upon terms precluding access to alternate sources of supply. Although PG&E has now reduced terms to two years or less, Justice has alleged that there is no certainty that PG&E will not again resort to long term all-requirements contracts to maintain its monopoly position; and that PG&E continues to refuse to offer all-requirements customers a resale contract with provisions which would allow the customers to provide for future load increases from an alternate source of supply.[211]

The pre-emptive nature of California Power Pool dealings with potential competition is seen in their 1966 contract with the California State Department of Water Resources (DWR) to provide transmission services over the Pacific Intertie, and to provide power from Pool members. This contract runs for seventeen years, and specifies the sources from which DWR may obtain power. DWR must give Pool members five to six years' notice and negotiate terms and conditions with them for use of generation from any additional facilities of its own or from any other sources.

The Department of Water Resources has set out, in a brief filed with the Nuclear Regulatory Commission, its view of action by PG&E and other major utilities in the California area in restricting competitive alternatives.[212] The course of action allegedly has included:

(1) PG&E contracting with DWR on terms preventing DWR competing with PG&E for bulk power supply, including provision for terminating the arrangement should DWR create its own "thermal" bulk power supply facility;

(2) PG&E forcing DWR capacity excess to DWR immediate needs to be sold to only one bidder, PG&E, by refusing to wheel the power to others.

(3) California Pool members agreeing on a pooling arrangement which preempts their capacity and energy for each other, excludes use of such by non-pool members, and denies equal access to the pool by non-members.

(4) PG&E using wheeling restrictions on entities other than DWR (CVP and SMUD) to limit their markets and competitive scope in a manner analogous to its conduct with DWR.

(5) California Pool members preempting access to Pacific Northwest power, by means of the Seven Party Agreement;

and thus eliminating potentially competitive use of Pacific Northwest power by others in California;

(6) PG&E's refusal to allow use of the Intertie facilities for interstate transmission; and

(7) PG&E's resistance to DWR and other utility attempts to gain ownership interests in major new additions to California and California-Pacific Northwest transmission facilities.

The Justice Department has in various proceedings made assertions closely parallelling those of DWR.

PG&E has contracted to purchase the entire hydroelectric output of seven California county agencies and districts which lack transmission and distribution facilities. PG&E maintains that exclusivity is necessary in order to provide a long term financial commitment which these agencies require in order to finanace their hydro projects, that no other utility has indicated interest in purchasing such power, and that where PG&E has rejected a proposal the project has not been built.

Justice maintains that both conduct by PG&E which inhibited attempts by others to develop non-hydro capacity, and refusals by PG&E to wheel power for others are relevant to the question of why no other utility has indicated an interest in purchasing this power.[213]

<u>Conduct in Southern California Limiting Development of Alternative Power Supplies</u>

In Southern California, as in the Northern part of the state, there have been problems of access to high voltage transmission. Although, the Los

Angeles Department of Water and Power has some high-voltage transmission, and is interconnected with the direct current leg of the Pacific Intertie, Southern California Edison has the bulk of the power generation and high-voltage transmission facilities in Southern California.

In the past, Southern California Edison has followed a course of refusing to coordinate with small systems in its area, requiring long-term, all-requirements contracts and refusing to wheel power from other bulk power suppliers. In addition, SCE had a territorial allocation agreement with an irrigation district in its area, sought to acquire small systems, and imposed a price squeeze on its wholesale customers.

SCE has all-requirements contracts with six municipalities (Anaheim, Azusa, Banning, Colton, Riverside, and Vernon) and one rural electric cooperative (Anza Electric Cooperative) for whom it is the only available source of bulk power supply and high voltage transmission.

Justice alleged that (a) SCE has pursued a policy of acquiring the systems of its competitors and customers. SCE attempted to block efforts of its all-requirements wholesale customers to receive bulk power from their own or other alternative sources.[214]

Between 1961 and 1971, SCE acquired four electric utility systems, two of which were all-requirements wholesale customers, and made offers to or indicated interest in purchasing the systems of two additional all-requirements wholesale customers.

SCE has denied requests to wheel federal power to Anza. Moreover, by means of renewing in 1967, for a 25-year term, a restrictive contract with Imperial Irrigation District whose service area borders Anza, SCE obtained agreement since rescinded, from Imperial not to sell or wheel power to any SCE wholesale customer, including Anza. SCE has also denied requests to wheel federal power to the City of Colton, another all-requirements customer. In 1964, SCE declined to agree to wheel a block of power from the Intertie to Riverside and Anaheim. SCE's all-requirements contracts with these two cities precluded later attempts to obtain Northwest power.[215]

A pattern of refusals to wheel and long-term all-requirements contracts, effectively preventing wholesale customers from obtaining alternate sources of bulk power, makes such local systems vulnerable to predatory practices aimed at eventual acquisition.

Justice has alleged that SCE imposed a price squeeze on its municipal wholesale customers in 1957; it raised their rates above SCE's rates to large industrial customers, thus placing the municipals at a severe disadvantage in competition with SCE to attract large industrial loads to their service areas.[216]

Justice Department allegations of price squeeze conduct are supplemented by reports from other sources. The Mayor Pro Tem of Riverside has recently alleged that SCE is currently imposing a severe price squeeze on Riverside, Anaheim, and other cities.[217]

Riverside found itself paying SCE 21.4 percent more for wholesale electricity than an industrial customer would under SCE's rate schedules. As a result, Riverside and other cities are presently at a severe disadvantage in competing with other communities served by SCE in obtaining new industries, new payrolls, and a broader tax base. Riverside recently lost a major industrial customer, Alcan Aluminum, that located nearby and is now taking electricity from SCE at a rate cheaper than Riverside could buy it.[218]

In July of 1963, SCE executed all-requirements contracts with wholesale customers which, among other things, prohibit the purchaser from operating any generating facilities in parallel with those of SCE. Consequently, any generation developed by a municipal would have to operate in isolation; it could not be integrated into the electric network supplied by SCE. Officials of the City of Riverside, a SCE wholesale customer, discussed possible development of peak-shaving generation with SCE during the 1963-1964 period, but SCE remained firm in its stand that it would not allow its resale customers to develop their own generation.[219]

In April of 1969, the City of Anaheim, another SCE wholesale customer, indicated to SCE that it was interested in participating in the Navajo-Four Corners coal-fired generation project to provide a portion of its future bulk power supply. SCE responded by offering Anaheim a new ten year all-requirements contract at a lower rate provided that Anaheim accept the offer within a short time frame, which would not permit Anaheim fully to consider participation in the Four Corners project. Anaheim made a counterproposal that it join with SCE in the construction and operation of future generating facilities. On May 28, 1969, SCE responded that such a proposal was beyond the scope of the subject under discussion.[220]

On February 2, 1971, Anaheim and Riverside requested participation in San Onofre Units 2 and 3 from San Diego Gas and Electric Company, and SCE refused the request because it was too late to alter the sizing of the units, but SCE indicated a willingness to discuss the matter. In March and April of 1971, SCE held five meetings with the cities at which it emphasized that although it would consider any specific proposal, it would be extremely difficult for the cities to make a feasible proposal. SCE set forth general criteria, on April 19, 1971, which any proposal by Anaheim and Riverside would have to meet to be acceptable to SCE.[221] The Justice Department has pointed out that SCE's position would require the transaction to accord significant benefits to SCE,including offsetting the loss of a full-requirements wholesale customer. This makes it just about impossible for a customer to submit a proposal which would satisfy SCE.

The Justice Department has further alleged that reserve requirements to which California Pool members have adhered, in dealing among themselves and with the small utilities, seem to allow little opportunity for a municipal wholesale customer to submit a workable offer of power supply coordination, though there is no technical necessity for such reserve arrangements.[222]

For fifteen years, SCE acted to prevent cities in Southern California from obtaining access to a potentially substituted new power supply, the Colorado River Storage Project (CRSP), or from steam-electric generation in Arizona and New Mexico.

SCE acted, at times in conjunction with other utilities and with the Interior Department, to reduce the amount of capacity available to preference customers. It did this by refusing to coordinate with the federal government, thus limiting CRSP capacity; by refusing to wheel; and by acquiring government power to the exclusion of others. The history of these actions is as follows.

The Interior Department was confronted, in the late 1950's and early 1960's, with the problems of how to obtain coordination with steam-electric generation for its Colorado River hydro projects, and how to obtain pumping power for the Central Arizona Project.

Because construction of coal-fired steam-electric power plants in the :w Mexico-Southern Utah-Arizona area requires permits from the Interior Department regarding transmission rights-of-way, and, usually, water rights, Interior was not without bargaining capability in seeking coordination.[223]

The utility systems or the Southwest locked to large coal-fired units for the future base-load generation required to meet their rapidly rising loads. An organization, Western Energy Supply and Transmission Associates, was created to permit joint government-utility planning for the construction of a six plant, 12000 megawatt scheme.[224] Under the provisions of the Colorado River Basin Project Act of 1968, 43 U.S.C. 1501 et seq., the Interior Department became a direct financial participant in one plant, the "Navajo" project[225] with the stated purpose of obtaining pumping power. The Bureau obtained a 561 mw entitlement, discussed hereafter.

The hydro plants of the Colorado River Storage Project must be "firmed up" through coordination with steam-electric systems if their dependable capacity is to be fully realized.

When the joint ventures owning large new coal-fired stations in the southwest came to Interior for permits required for these units and attendant high voltage transmission lines, these permits were provided, without the inclusion of provisions for coordination with CRSP.

Joint venturers in these plants are both private utilities and public power entities; they control the major power generation and transmission facilities in the area. In return for their commitment to a future coordination agreement with CRSP, the owners of these plants sought and obtained an exemption from wheeling requirements normally found in federal transmission right-of-way permits, for the high voltage transmission facilities associated with the two plants, including high voltage lines into California.[226]

Later, in 1968 and 1969, the Interior Department sought to obtain coordination agreements for integrating CRSP hydro together with Southwestern electric capacity. It was unsuccessful, and Interior instead agreed to sell surplus federal hydropower to non-federal systems.

According to the Interior Department, this refusal to consummate coordination arrangments rested on the private utilities' desire to avoid having federally-owned energy flow to their existing customers.

Assistant Commissioner of Reclamation N.B. Bennett, Jr. reported to the Secretary of the Interior, by a memorandum of July 29, 1968, that as regarded a power coordination agreement,

> ..."the sticky problem is still that the utilities will not commit themselves to supply energy to support federal capacity to pirate their customers."

Assistant Commissioner Bennett informed the Secretary, in a memorandum of October 21, 1968, that "freedom from the right-of-way regulations" and "even limited territorial integrity" were the two major features desired by participants in coordination discussions.[227]

During 1967 and 1968 negotiations for coordination, SCE took a vigorous stand in opposition to coordination and wheeling.[228] In this it was joined by the other participating systems.

On February 24, 1969, Mr. David Barry, of SCE, wrote to a member of a Navajo-Four Corners Task Force (No. 10) that before SCE would agree to participate on the Navajo project, the government must waive its wheeling stipulations.

Following collapse of efforts to obtain system coordination agreements, there still is not general arrangement for wheeling of power generation in the western and southwestern states.

SCE has taken further action to prevent smaller California systems from obtaining independent access to power generation east of California. For example, SCE was a member of a consortium to build the large Navajo coal-fired plant in Arizona, until the operators of the plant agreed to admit the city of Anaheim into the ownership consortium. Facing the prospect of being required to wheel Anaheim-owned power to Anaheim, SCE withdrew from the project. By letter of August 23, 1969, SCE refused to wheel any power to Anaheim. Anaheim then withdrew from the Navajo project--lacking any means of obtaining access to the plant's output.

After withdrawing from ownership participation in the Navajo plant, SCE effected purchase arrangements with the Bureau of Reclamation which gave SCE control of most of the energy from the Navajo plant moving into Southern California.

The Bureau of Reclamation

The Bureau of Reclamation participated in Navajo in order to obtain energy to pump water from Lake Havasu, on the Colorado River, to the Phoenix-Tucson area and points south. As it now appears this energy may not be needed for water pumping before 1985; this energy might be considered as potentially available for sale to government preference customers. However, the Interior Department currently is selling its 425 megawatts of Navajo capacity as follows:

Southern California Edison	336 megawatts
LADWP	75 megawatts
Nevada Power Co.	14 megawatts
	425 megawatts

The Interior Department never developed criteria for marketing its excess Navajo power and sold ("laid-off") that power without making any offer of sale to preference customers (except the Salt River Project and LADQP, which had entered into its own arrangements with SCE).

This procedure has been held to be in violation of the preference laws. Arizona Power Pooling Association v. Morton, 527 F.2d 721, modified on rehearing, 527 F.2d 728 (CA 9, 1975). It pre-empted an otherwise competitive source of power from reaching Southern California.

The Bureau of Reclamation will only market its Navajo "lay-off" power to entities providing their own reserves and transmission. In the absence of either an over-all system coordination agreement in the West-Southwest states area, or requirements for wheeling to California, the practical effect of this provision has been to prevent preference entities from obtaining this power.

RECENT ANTITRUST ACTION MAY IMPROVE BULK POWER COMPETITION IN CALIFORNIA

Antitrust proceedings inconjunction with nuclear plant applications have yielded agreements between Justice, Municipal systems, and SCE, and between Justice and PG&E, respectively, which are intended to be included as conditions to NRC licenses. The SCE license condition is final, while PG&E's proceeding is still pending, (May 1977) at the instance of municipal intervenors.

The conditions agreed to in general require that the utilities offer smaller systems an opportunity to participate in new nuclear generation plants. They also entail promises to afford coordination and wheeling services, and partial requirement sales contracts.

These conditions appear to hold out prospects for improved possibilities for entry and expansion of new smaller bulk power supply facilities, and other competitive elements in the electric utility systems in California (though not in other states).

However, it is still uncertain to what extent conditions will improve. The agreements to enter into future agreements with other electric utilities are rather general, and their efficacy remains to be demonstrated. They contain clauses which may allow a substantial amount of avoidance. Among these clauses are ones leaving undisturbed the limitations on respectively CVP, the power pool agreements, and other past arrangements. The companies signing the agreement have dominant positions allowing a great degree of freedom in planning and implementing their courses of activity: they still have opportunities for exclusionary conduct. The conditions involved for SCE, in paraphrase are:

> First, SCE agreed to permit participation in new nuclear units by any entities within or contiguous to SCE's service area which at that time do not have access to alternative comparably-priced sources of bulk power supply;
>
> Second, SCE agreed to permit interconnection and coordination of reserves by means of agreements for the sale and purchase of emergency bulk power with any entity within or contiguous to SCE's service area;
>
> Third, SCE agreed to sell bulk power to or purchase bulk power from any entity within or contiguous to SCE's service area.
>
> Fourth, SCE agreed to transmit bulk power between or among entities with which it is interconnected over its transmission facilities within its service area and facilitate such transmission over facilities outside its service areas.

In the agreement reached on June 27, 1974 by Justice and SCE, a set of pro-competitive license conditions are qualified by the following statement:

> "...SCE should not be obligated to enter into such an arrangement if (1) to do so would violate, or incapacitate it from performing any lawfully existing contracts it has with another party or (2) there is contemporaneously available to it a mutually exclusive competing or alternative arrangement with another party which affords it greater benefits." 229

Interpretation of these conditions is clouded by the qualification that SCE will permit participation in new nuclear units (not San Onofre units 2 and 3), sell emergency power, and wheel if the requesting party makes it an offer that is more desirable to SCE than alternative uses of its facilities.

The conditions do not call for admission of others to the California Power Pool. In a letter indicating agreement to these conditions, SCE states that "Edison does not intend to become a common carrier by reason of these conditions.[230]

SCE has entered into agreements with all of its large resale customers which call for, among other things, integrated operations and coordinated planning of customer and SCE resources, partial requirements service, transmission service, and participation by such customers in certain future SCE units.[231] Those agreements leave critical areas for future agreement or resolution before they can be implemented.

On August 2, 1972, the Justice Department provided antitrust advice on the application of PG&E to construct the Mendocino nuclear plant. The letter concluded that an antitrust hearing, should be held because conduct of PG&E had created a situation inconsistent with the antitrust laws which situation would be maintained by PG&E through operation of the Mendocino units. No hearing was held as the application was withdrawn.

Justice recommended at that time that license conditions should require PG&E to (a) grant access to Mendocino to the members of NCPA, (b) eliminate provisions in its contract with CVP which restrict importation, wheeling, and marketing of energy, and (c) eliminate provisions in its contract with SMUD limiting the generation SMUD may plan and construct.[232]

Justice commenced an investigation under the antitrust laws concerning whether PG&E was monopolizing the relevant markets for electric power, natural gas, and geothermal steam, and whether it was a party to certain contractual restraints of trade.

Prior to completion of this study, PG&E indicated a desire to facilitate licensing of the San Joaquin nuclear project in which it and seven other utilities were participating. Justice agreed to accept conditions in the San Joaquin license in lieu of an antitrust hearing. Under the conditions, PG&E would grant ownership access to San Joaquin to any distribution utility in its service area, would wheel participants' shares of San Joaquin power, would provide reserve support to participants' shares of San Joaquin power, and would purchase surplus San Joaquin energy from participants.[233]

On May 5, 1976, after completion of an antitrust investigation of PG&E, Justice issued its letter of advice on the application of PG&E to construct Unit 1 of the Stanislaus nuclear project. Justice advised that it had reached agreement with PG&E on a Statement of Commitments which Justice believed would obviate the antitrust problems posed by PG&E's activities, and would remedy the situation inconsistent with the antitrust laws which it believed had previously existed. The Statement of Commitments was requested to be included as conditions to the Stanislaus license in lieu of an antitrust hearing.

The Stanislaus conditions are quite extensive. PG&E agreed (1) to interconnect with utilities in or adjacent to its retail service area without imposing limitations on use or resale of capacity and energy sold or exchanged, or on further interconnections except for reliability considerations; (2) to sell full or partial requirements firm power, emergency power, reserves, and to coordinate maintenance schedules with any utility to which it is interconnected; (3) to wheel power for those to whom it is interconnected; and (4) to provide access to Stanislaus or to any other nuclear unit for which PG&E applies for a construction permit during the next 20 years.[234]

Certain further qualifications and omissions, however, should be noted. The Stanislaus conditions do not require PG&E to seek admission of new members to the California Pool, nor do they specifically require PG&E to void previous contracts which have anticompetitive provisions such as the SMUD or CVP contracts discussed above. The conditions do not require PG&E to wheel power or energy from PG&E hydro plants with expiring FPC licenses which may be licensed to others, or to wheel power or energy to any PG&E retail customers.

or to wheel power and energy related to the Intertie if such action would impair PG&E's own use of the Intertie.[235,236]

PG&E has agreed to sell short-term, limited, and long-term capacity and energy and economy energy to any generating utility in or adjacent to its service area under any rate schedule or agreement it files with the FPC. It has not agreed to provide such service to distribution utilities--who are the bulk of its wholesale customers.

The conditions do not preclude PG&E application of a price squeeze on a distribution utility. Moreover, nothing in the conditions prevents PG&E from attempting to acquire another utility.

PG&E's control of access to alternative power supply sources in Central California is unimpaired. All provisions are subject to "Good Utility Practice" stipulations. These stipulations allow PG&E to require as a condition of interconnection or transaction that the other party use practices, methods and equipment, including levels of reserves and provisions for contingencies, that are commonly used by PG&E, provided that such stipulations are prudent from the safety, reliability, conservation, and environmental standpoints. They are very complex, involving technical considerations on which there are no industry-wide standards. PG&E could, if it so desired, frustrate attempts by small utilities to obtain benefits under the license conditions by shrewd application of the "Good Utility Practice" stipulations. PG&E

found "technical problems" on an interconnected system to frustrate NCPA's attempt to construct its own transmission lines to the CVP system. It appears that the hostile environment for small utilities in California may not be completely eliminated by the license conditions.

A final qualification is that nothing in the license conditions affects PG&E's pre-emption of geothermal resources by use of red-lined areas as described above or its pre-emption of hydro sites. Even if the license conditions make it easier for a distribution utility to obtain the reserves, coordination, and wheeling services required to develop an independent generating capability, the utility still would have difficulties developing geothermal generation if PG&E pre-empts resources. Other parties to the Stanislaus proceedings before NRC have not agreed to the conditions of the PG&E-Justice accord, and the proceedings continue.

Other Western States

There is hostile environment for small utilities in certain other parts of the western United States as well.

We have described the situation regarding the Central Arizona Project and the exclusion of California preference customers from access to Navajo unit output. Preference customers east of California were similarly excluded when Interior privately sold power from its entitlement in the Navajo project.

Arizona Power Pooling Association (APPA), a non-profit Arizona corporation comprising Arizona Electric Power Cooperative, Electrical District Number Two of Pinal County, and the City of Mesa, in a suit joined by the Arizona Power Authority, a state agency, Intermountain Consumer Power Association, and Bountiful, Utah,[237] have alleged that Interior has violated a duty imposed by federal reclamation laws requiring preference to be given to entities such as APPA in the sale of federally-owned electric power. The suit seeks to compel Interior to negotiate with plaintiff for the purchase and sale of Navajo power. On September 24, 1975,the U.S. Court of Appeals for the Ninth Circuit reversed the judgment of the district court (which had held that Interior's decision with respect to which entities were to be allowed an opportunity to purchase power was not judicially reviewable, and that Congress had approved any possible violation of the preference provision by accepting Interior's plan for the CAP as submitted, and appropriating funds for its implementation.)

A key point in the Court of Appeals judgment was the undisputed refusal by Interior to offer APPA the opportunity to purchase the power prior to offering it to the private utility companies. In fact, the preference customers had sought, and had been refused, the chance to purchase the interim power.[238] Subsequent to the judgment, Interior has still not proffered this power to preference customers (May 1977).

Utah Power and Light

Robert Gordon, Corporate Secretary and Attorney for Utah Power and Light (UP&L), recently testified against proposed federal legislation that would mandate joint use of bulk power facilities, and access to transmission, and would authorize the FPC to prohibit unfair methods of competition.[239] He argued that the incentive for voluntary interconnection is already present without additional legislation, and that legislative action mandating access to generation and transmission would unfairly disregard the rights of existing customers who pay the full cost for these facilities and who should be entitled to their full benefits as their future load growth absorbs current surplus capacity.[240]

Prompted by this testimony, the Manager of Bountiful City Light and Power, a Utah municipal, described situations involving UP&L's "voluntary" behavior. Two days after UP&L announced plans to construct the Emery County coal-fired generating plant, in November 1975, Bountiful asked UP&L if Bountiful might join it (with a 5% interest) in construction of the project. The next day Bountiful appeared as a witness before the Utah Public Service Commission in a hearing on UP&L's application to proceed with the construction (which was already well underway). Bountiful supported UP&L's application and filed a petition with the Commission for an order requiring joint participation. On March 9, 1976, UP&L responded to Bountiful that all UP&L units up to and including its 1980 unit are fully committed, but that a modification or change could possibly occur and that UP&L would be happy to negotiate with regard to power from an unspecified 1982 unit. The short notice by UP&L to regulatory authorities have made it almost impossible for a small utility to succeed in gaining participation in a unit.[241]

Early in January of 1976, Bountiful attempted to purchase surplus energy for the summer of 1976 from UP&L. There was a certain sense of urgency in the attempt because the alternative was to purchase energy from the Bureau of Reclamation's Colorado River Storage Project (CRSP) and the deadline for applying for summer energy was January 23, 1976. On January 26, 1976, UP&L notified Bountiful that it regretted that time had run out before UP&L could decide whether to sell surplus energy or not. (In the meantime, UP&L continues to sell surplus power and energy to many utilities outside the State of Utah.)

When on February 5, 1976, Bountiful indicated to BPA that it would like to purchase 18 million kwh annually during the next two years on an "if, and when available" basis.[242] The BPA responded that it might have some surplus energy available but that transmission available to BPA on The Montana Power Company's facilities is fully committed to the Bureau and that Bountiful would have to make its own arrangements for transmission, perhaps with UP&L.[243]

Still seeking to obtain this BPA energy on March 10, 1976, Bountiful tried to get the Bureau to wheel 8 million kwh of "if-and-when-available energy" from BPA to CRSP reservoirs where it would be stored as water. The water could be used for generating energy to be delivered to Bountiful when needed. On March 26, 1976, the Bureau responded that this type of service is not presently available.

Bountiful requested, on May 10, 1976, that UP&L wheel the BPA energy to Bountiful.[244] UP&L replied that they were willing to negotiate. Unfortunately, the reply came on July 28, 1976, after the date established by the Bureau by which Bountiful had to commit itself to purchase energy during the 1976-77 winter from CRSP. The terms offered by UP&L for wheeling are 3.2 mills per kwh, maintenance of reserves which UP&L would sell at a rate above the pool rate, and installation of under-frequency relays more extensive than those employed by UP&L. The 3.2 mill rate is quite high compared to UP&L's 0.6 mill rate for wheeling CPRS power.[245]

The need for small utilities to approach UP&L to obtain transmission service needed to receive energy from the Bureau of Reclamation is a consequence of (1) the Bureau's refusal to sell economy energy to small utilities while it presently sells such energy to UP&L and other investor-owned utilities, and (2) Interior's failure to build federal transmission facilities after Congress appropriated funds in the early 1960's.

Bountiful is presently trying to obtain geothermal energy. It has bid on geothermal lands, but lost out to Phillips Petroleum.

Bountiful approached Phillips about purchasing heat produced at seven wells drilled at Milford, which apparently could sustain 65 Mw for 30 years. Phillips, however, appears to be holding out for higher prices. Prime Utah geothermal areas are leased to oil companies; other Utah areas are too risky for Bountiful to enter.[246]

It appears that the environment for small utilities in Utah is little different from the environment in California. The Manager of Bountiful City Light and Power testified that UP&L has been giving Bountiful the run-around on requests for participation in new units, and that valuable time and resources have been wasted as a consequence; that UP&L gives the same run-around on requests for transmission service; and that the Bureau of Reclamation has become as difficult to work with as UP&L.

Municipal and cooperative systems in Utah are members of the Intermountain Consumers Power Association (ICPA), a non-profit corporation. Most of these systems purchase power from UP&L lines. ICPA's arrangements with UP&L, described in our description of pools, exemplify the satellization of wholesale customers that substantially inhibits these firms from helping meet their needs through self-generation.

Long notice periods for introduction of new sources, lack of available tariffs for reserves coordination and short-term sales, and lack of an alternative transmission system all work to preclude economic pooling by ICPA members _inter se_ or with others.

Pacific Northwest

Unlike California and Utah, the Pacific Northwest offers a more favorable environment for small utilities. In this area, the small systems appear to be able to obtain transmission and coordinating services through the Bonneville Power grid. The Bonneville Power Administration (BPA) dominates regional transmission with over 12,000 miles of transmission facilities (about 80 percent of the region's bulk power transmission capacity). BPA markets power to 149 customers, mainly preference customers.

In this region planning for existing and future thermal and hydro resources is coordinated by a Joint Planning Council. Membership includes 5 investor-owned utilities, 110 publicly-owned agencies, BPA, and Washington Public Power Supply System (WPPSS) a municipal corporation and a joint operating agency of the State of Washington which engages in bulk power supply and is made up of 18 operating public utility districts in Washington and the Cities of Richland, Seattle, and Tacoma. There is a high degree of coordination and cooperation among utilities involved generation and transmission. Small utilities appear to have no difficulties obtaining power and energy, wheeling service, or participation in large new units. For example, 29 municipalities, 28 public utility districts, and 47 cooperatives will share in the output of a 1,250 Mw nuclear unit being constructed by WPPSS.[247]

BPA with its extensive transmission system, can prevent geographical isolation of small utilities within the service areas of large investor-owned utilities. Because BPA operates its own transmission system, it is not at a strategic disadvantage in bargaining with investor-owned utilities as is the case for the Bureau of Reclamation.

In the BPA area, utilities such as the Raft River Cooperative with its geothermal program or the utility system of Eugene, Oregon, with its program for using waste forest products for fuel, can build generating units with confidence that they will be able to market output. The Raft River Cooperative was able to get BPA's assurance that up to 150 mw of power could be transmitted west from its geothermal area at a very early stage in Raft River's planning. The Eugene, Oregon, system has been able to sell 50 megawatts of power to Burbank, California (over the d.c. leg of the Pacific Intertie).

To date, very high temperature geothermal resources have not been located in the BPA region. The development of less promising geothermal resources, as are sought in the Raft River Valley may be expected to go forward in the Pacific Northwest more rapidly than in the Southwest-- when the capacity costs of such power is less than that for alternative sources, which are also more readily accessible to small Northwestern systems.

A SUMMATION OF HOW GEOTHERMAL ENERGY DEVELOPMENT IS AFFECTED BY THE CONDITIONS IN BULK POWER MARKETS

Geothermal energy appears to be a resource that could be developed through installation of a number of 50 mw to 150 mw generating units. Up to 10,000 mw of such capacity appear to be attainable for less than the cost of more conventional coal-fired or nuclear power stations. Lead times on geothermal units should be several years shorter than the decade required for other base-load generation.

The limited size of geothermal units coupled with the regulatory process which must be gone through before a unit may be installed--which is comparable to that for a much larger unit--make geothermal power more attractive to smaller utility systems than to larger ones.

Fifty to 150 megawatt units can provide a small system with a way to enter into power generation and provide such a system with a means of hedging against prices of alternative fuels and delays in the development of coal-fired or nuclear units.

Large systems do not obtain a meaningful hedge from 50 to 100 megawatts of capacity. The efforts of their management are necessarily directed toward 800 mw to 1200 mw units.

Small systems are, accordingly, the market geothermal energy must principally look to for rapid development.

This market--in small systems--exists in part because small systems find new or expanded self-generation projects economically more promising than a wholesale power market largely shaped by anticompetitive practices. Development of geothermal resources for power generation would not, of course, be undesirable or superfluous even if conditions in the wholesale power market were more openly competitive. Rather, market conditions which small power systems now face make development of moderate-sized units a near necessity rather than simply a desirable adjunct to existing generation resources.

Anticompetitive conditions exist not only in the wholesale firm power market (in which all-requirements distribution customers of large systems are the purchasers) but also in such areas as transmission and coordination services (including load-growth coordination). These conditions severely hinder smaller systems in their efforts to supply some of their own types of generating units. Industrial firms, confronted with rapidly rising energy costs, face the same problems of securing access to transmission and coordination.

Conditions in the regulation of electric utilities leave wholesale-customer utilities and industrial firms with limited, time consuming remedies for maintaining a competitive yardstick in bulk power supply. In the meanwhile they are subject to the Federal Power Commission's shunting aside of issues relating to competition, and its slow review of rate increases which permits one unapproved rate increase to be made effective on top of another.[248]

Even where large utilities have accepted reactor license conditions which require that they engage in transactions with small utilities, small utilities have been subject to what they assert are exorbitant charges for service excessive uncertainty, and delay in negotiations for services. The Bureau of Reclamation, as part of the hostile environment, has been reluctant to provide such services even where restrictive contracts with large investor-owned utilities do not expressly forbid it.

Consequently, self-generation may be viewed as one of the only means of survival for small systems. Also, self-generation has advantages in cost and in unit size relative to other forms of generation which small systems require at a time when shortages of capacity are widely foreseen.

The difficulties confronting small utilities or industrial firms desiring to operate a geothermal unit are not limited to those arising from the grip fastened by large utilities upon transmission and coordinating services. Small systems and industrial firms will require access to the limited number of high quality geothermal sites to develop this resource at a level of risk they can bear. This risk is only attractive if it holds out the promise of a lower cost energy source.

In seeking such an energy source, would-be users are confronted by the present speculative pattern of resource leasing and development.

Notes:

1 David W. Penn, James B. Delaney, and T. Crawford Honeycutt, Coordination, Competition, and Regulation in the Electric Power Industry (NUREG-75/061) (Springfield, Virg.: NTIS, 1975, pp. 28-35).

2 U.S. Federal Power Commission, The 1970 National Power Survey, (Washington, D.C.: Government Printing Office, 1971), p. I-17-4. Frequency control is described in the FPC's opinion in Florida Power & Light Company, 37 FPC 544 564-66 (1967) appended.

3 Firm power is defined as a power supply considered to be continuously available to serve a particular load or demand of a particular size at a particular location. Users of electric power desire and expect such power to be continuously available. Initial Decision, Alabama Power Company, Nuclear Reg. Commission Docket 50-348A (April 8, 1977) at p. 46-47 (mimeo).

4 Geothermal wells cannot be quickly stopped and started, nor can they be kept in operation when not being harnessed for generation. Accordingly, a geothermally powered system must go to others for its ready reserves.

5 Under such contracts, reserves are to be sufficient to cover all combinations of unit outages except those whose likelihood of occurrence is remoter than an agreed upon level - usually one service interruption in ten years.

6 If a system A having two 10 mw units coordinates with a system B having four 10 mw units, system A's reserves decline from 10 mw to 3 1/3 mw and its load

carrying ability rises from 10 mw to 16 2/3 mw, while system B's reserve needs decline from 10 to 6 2/3 mw and its load carrying ability rises from 30 mw to 33 1/3 mw.

If system B has 6 to ten mw-units its reserve need in coordination with system A declines from 10 mw to 7.5 mw and its load carrying ability rises from 50 to 52.5 mw of 5T. System A's reserve needs decline from 10 mw to 2.5 mw and its load carrying ability rises 75% from 10 mw to 17.5 mw

If a 100 mw system shares reserves with a 1500 mw system carrying 15% reserves, the small system increases its load carrying ability 30.4% while the larger system may add nothing to its load carrying ability.

7 Moreover, with coordination, parties having excess capacity are more likely to be able to arrange to sell and transfer output to third parties.

8 As another illustration consider the situation of load growth coordination between two systems, A and B. Each has a 10% per year load growth rate: A, a 700 mw system, has a 70 mw annual load growth increment; and B, a 1500 mw system, has a 150 mw annual load growth increment. Absent load growth coordination, Systems A and B would separately install units whose size would be based on three years' load growth, that is 210 mw for A and 450 mw for B. With coordination larger more economic units are possible.

9 The Federal Power Commission's Glossary of Important Power and Rate Terms, Abbreviations, and Units of Measurement (1965) defines dependable capacity as: "the load-carrying ability of a station or system under adverse conditions for

the time interval and period specified when related to the characteristics of the load to be supplied. Dependable capacity of a system includes net firm power purchases."

10 If deficiency charges are less than new unit costs, a member may seek to rely on capacity of more conservative members--until the contract is refused.

11 *Ibid*.

12 Suppose Utility A experiences an increase in load for 1 hour. The pool central dispatcher will satisfy this extra load form the lowest operating cost unit not in use. Suppose his unit, B-3, is owned by Utility B. The true savings which result to the pool would be the difference in operating costs for 1 hour between the lowest cost unit not in use in Utility A, say A-6, and unit B-3. Suppose unit B-3 were nuclear. There is no known method for accurately measuring nuclear fuel costs for a period as short as one hour. Suppose unit B-3 were hydraulic. An argument could be made that the cost of one hour's generation was negligible. An argument could also be made that the cost was higher than the corresponding cost of one hour's generation from unit A-6. The true answer is that the cost was the opportunity cost of the potential energy lost by operating unit B-3. Since water can be stored for prolonged periods, the opportunity cost depends on the magnitude of the pool peak, equipment availability, and natural resupply of water over a period of several weeks in the future. By using the water now, the pool might have to bring its most expensive peaking unit into operation to meet peak demand in

two weeks. Standard methods can be stipulated in the pool contract, but there is much opportunity for disputes, contract renegotiation, and exercise of escape clause privileges.

Other potential problems include accounting for semi-variable costs such as start-up costs, station lighting, maintenance costs, and labor. Since union contracts vary from member to member, Utility B might have to pay the station crew overtime or even a full day's pay for, say, the last 15 minutes of operation because the business day for the full crew might end during the hour of generation.

All of the above possibilities could conceivably be stipulated in a pool contract, but there are always new possibilities arising which are not currently covered. Moreover, the basic problem of trust is involved, a great deal of detailed information is required to compute savings and allocations and much of one member's reported information cannot easily be verified by the other members. Note that these same costing problems must be solved, also in an integrated system.

13 See testimony of Bruce C. Netschert, Abraham Gerber, and Irwin M. Stelzer, in U.S. Congress, Senate, Committee on the Judiciary, Competitive Aspects of the Energy Industry, Hearings before the Subcommittee on Antitrust and Monopoly of the Committee on the Judiciary, Senate on S. Res. 334, 91st Congress, 2nd Session, 1970, pt. 1, pp. 215-227.

14 Current financing problems have apparently prompted some utilities to drop their resistance to jointly constructing projects with municipal or cooperative systems.

15 Bruce C. Netschert, Abraham Gerber, and Irwin Stelzer, "Competition in the Energy Markets: An Economic Analysis", in Leslie E. Grayson, ed. Economics of Energy: Readings on Environment, Resources and Markets, (Princeton, NJ: Darwin Press, 1975), pp. 54-55.

16 Leonard W. Weiss, "The Possibilities for Competition in the Electric Power Industry, "in William H. Shaker and Wilbert Steffy, eds., Electric Power Reform: The Alternatives for Michigan, (Ann Arbor, Mich.: University of Michigan, 1976), p. 211.

17 Booz, Allen Hamilton, Inc.; A Study of the Eastern Industrial Coal Market, (1967); Dow Chemical, Energy Industrial Center Study, Draft, p. 26 (1976).

18 Walter J. Primeaux, Jr., "A Reexamination of the Monopoly Market Structure for Electric Utilities, "in Almarin Phillips, ed., Promoting Competition in Regulated Markets, (Washington, D.C.: The Brookings Institution, 1975), pp. 175-200.

19 Both the substantive and procedural aspects of electric rate regulation by the Federal Power Commission allow ample opportunity for price squeezes. Rates for sales to other power systems often involve sales in interstate commerce. Federal Power Commission v. Florida Power & Light., 404 U.S. 453, 30 L.ed 2d 600 (1972); Federal Power Commission v. Southern California Edison Co., 376 US 205, 11 L.ed 2d, 683 (1974); and, United States v. California PUC, 345 US 295 (1953). Retail rates are filed with State Commissions. Under tariffs filed with the Federal Power Commission, the FPC can suspend rates for up to five months, after which the rates go into effect subject to refund. 16 U.S.C. 824 (d).

Rate proceedings often take far longer than five months and a second rate increase is often filed while a prior one is pending or just decided. When decided, rates allowed are usually less than those filed. As a result of this situation, wholesale customers find themselves having to pay high rates--and having to pass such high rates along to their customers. See GAO, Report Management Improvements Needed in Federal Power Commissions Processing of Electric Rate Increases Cases, EMD-76-9 (September 7, 1976). cf., F.P.C. v. Conway Corp., 426 U.S. 271 (1976) (F.P.C. required to consider price squeeze allegations in rate cases). In its Order No. 563 issued March 24, 1977 (F.P.C. Docket No. RM 76-29) the Commission prescribed its policy concerning "filings of comparative rate" information on cases of alleged price squeezes. Under the policy, customers intervening in a rate case must establish a prima facie case of price discrimination and its anti-competitive effects. This case must include a showing that the customer competes in the same market as the filing utility, and that retail rates are lower than proposed wholesale rates for comparable service.

When price squeeze allegations are made, intervenors are only given 30 days from the filing of the supplier's response to their data request to prepare and file their case-in-chief.

As stated in the Order, ... "the Federal Power Act does not permit any reparation for damages suffered by the complainants due to any price differentials in superseded rates."

FPC indicated that discovery should be limited to present, not past anti-competitive effects. It is not clear whether the FPC's policy and statement seeks to preclude consideration of situations in which a course of conduct involving price squeezes has excluded a customer from a market.

20 See Perch "Get the Standby Power You Need" Power Magazine (May 1970) at pp. 23-24; Federal Council on Science and Technology "Total Energy Systems, Urban Energy Systems, Residential Energy Consumption (Oct. 1972) at p. 124; Files of American Gas Association on Group to Advance Total Energy program; Telephone Interview with Mr. Frank Morse, Southern California Gas Company.

21 Echols, Problems of Total Energy, Part III, Actual Specifying Engineer (Jan. 1971). Mr. Echols wrote a three part series of articles on various problems of total energy systems. For a view opposite to Echols on many points see Chamberlin, In Defense of Total Energy, Actual Specifying Engineer (April 1971) (noting that several systems have been purchased by electric utilities at a profit to sellers and that several had been retired when lower electric rates were offered). Only limited amounts of natural gas for backup units are available. Southern California Gas Company wont back up another primary source of energy beyond a limit of 1000 cubic feet per hr. (about 100 kwh).

22 Mr. Myers' statement before Subcommittee on Energy and Power of the House Interstate and Foreign Commerce Committee (April 6, 1976).

23 Franchise requirements can thwart self-generation moves. For example, an effort to obtain coordinating sources for a total energy system in Utah was

thwarted because service outside of a single building was required, and this was deemed to require a franchise. No franchise was available because none would be issued in the service territory of an existing utility. Candlewood Mall Shopping Center v. Utah Power and Light Company, 440 F.2d 36 (CA 10, 1971).

A utility may be more amenable to using an industry's waste heat for utility generation than using the waste heat for industrial electricity generation.

The Los Angeles Department of Water and Power has announced that it is considering a 60 megawatt generating station utilizing heat produced during a petroleum coke calcinating process. Public Power Weekly Newsletter (Sept. 13, 1976), p. 7.

24 See e.g., David W. Penn, James B. Delaney, and T. Crawford Honeycutt, Op. Cit., pp. 23-25.

25 Wholesale loads are loads of utilities served by exchanges or purchase of power and energy from another utility. Transmission costs are directly proportional to distance and inversely proportional to the square of transmission voltage. Use of extra high voltage transmission lines has made it economical to transmit power to Los Angeles from the Four Corners plant in New Mexico 600 miles away and from the Columbia River 850 miles away.

26 See for example, Crown Zellerbach Corporation v. F.T.C., 296 F.2d 800 (1961) (clustering); and a series of commercial banking cases: United States v. Phillipsburg National Bank, 399 U.S. 350 (1970); and, United States v. Connecticut National Bank, 418 U.S. 656 (1974); United States v. Grinnell Corp., 384 U.S. 563

(1966) is authority for combining a number of serviced products into a single market where the combination reflected commercial realities.

27 In United States v. E.I. du Pont de Nemours & Co., 351 U.S. 377 (1956) the Court stated, "Determination of the competitive market for commodities depends on how different from one another are the offered commodities in character or use, how far buyers will to to substitute one commodity for another," and a "market is composed of products that have reasonable interchangeability for the purposes for which they are produced-price, use, and qualities considered."

28 Standard Oil Co. v. United States, 337 U.S. 239, 299 (1949).

29 Cf. Brown Shoe Co. v. United States, 370 U.S. 294, 325-26 (1962).

30 Cf. Penn., Coordination Competition, and Regulation in the Electric Utility Industry, NRC., p. 24 (NUREG-75/061, 1975). An Atomic Safety and Licensing Board in a recent Initial Decision, found there to be separate product markets for regional power exchanges (pooling), and bulk power services (individual contracts). The Toledo Edison Company, NRC Docket No. SO-346A (Initial Decision issued Jan. 6, 1977). p. 47-51. We believe that these groups are better categorized as submarkets for coordinating services with individual transactions being interchangeable with some aspects of pools.

31 Leonard W. Weiss, "The Possibilities for Competition in the Electric Power Industry," in William H. Shaker and Wilbert Steffy, eds., Electric Power Reform: The Alternatives for Michigan, (Ann Arbor, Mich.: University of Michigan, 1976), p. 210.

32 Wheeling is of particular convenience in the distribution of federally generated power from hydro projects to utilities having marketing responsibility. Such an operation is exemplified by the Bonneville Power Authority which distributes power to a number of private municipal and public utilities. Similar arrangements exist in the distribution of power into a number of non-generating cooperatives. The wheeling of power by privately-owned utilities is also widely practiced.

33 Or a like amount of power and energy as an interconnected grid.

34 The customary distinction between structure and conduct can be somewhat misleading if applied rigidly to the electric power industry. Structure, in the electric industry, is largely affected by the size, ownership, and interconnection of bulk power facilities. The economic use of these facilities requires a high degree of joint action and agreement among firms in the industry, the firms themselves are interdependent to a degree not common in other industries. The relationships among utilities are governed by contracts, as, in many instances, are the growth patterns of, and investments made by, individual firms (e.g., where a coordination agreement provides for staggered construction of facilities to match capacity growth to the load growth of the entire pool). Under these circumstances, the conduct of industry members in including or excluding entities from participation has a clearly determinative effect on structure. Looked at from the perspective of the excluded segment of the industry (that is, generally,

the small systems), their structure as essentially small scale distribution enterprises dependent on larger integrated firms for bulk supply is largely determined by the contractual and other conduct of the integrated enterprises.

35 Wholesale transactions occur between supplying system sellers and buyers who distribute at retail and either own no generation or whose generation can only partially carry their loads.

Wholesale contracts for all of a buyer's requirements typically contain separate rates for the purchase of energy and for the service of instantaneous load. Contracts for partial or supplemental service involve purchases of a block of firm power, or the purchase of transmission and back-up services so as to permit purchasers to use entitlements in third-party power sources. Additionally firm power may be purchased. Lindsay, Pricing Intrasystem Power Transfers in the United States (June 23, 1975).

36 The anticompetitive practices in the electric utility industry have long been known. This is evidenced by Congressional recognition of problems in the Federal Water Power Act of 1920 which seeks comprehensive development, and hydraulic coordination; and to restrict manipulation of power sites; and the Public Utility Act of 1935. Under the Federal Power Act, one part of this latter enactment, the FPC is supposed to consider the anticompetitive impacts of rate proposals, financings, and mergers. Under the Public Utility Holding Company Act, the other part of the 1935 enactment, the Securities and Exchange Commission was instructed to restructure holding companies along competitive

lines and to prevent mergers and acquisitions unless the mergers both did not lessen competition and provided positive benefits to the public. The legislation providing for licensing of the construction and operation of nuclear power plants provides for antitrust review by the Attorney General and the Nuclear Regulatory Commission. (Section 105 of the Atomic Energy Act, 42 U.S.C. 2011.)

David Penn of the NRC reported in a paper entitled "The NRC's Antitrust License Conditions and the Structure of the Electric Utility Industry" (March 10, 1976), that 69 large systems had been subjected to review and that license conditions had been required for 23 nuclear applications.

Regulatory and Sherman Act cases have dealt with market allocations, Pennsylvania Water & Power Co. v. Consol. Gas, Elec. Lt. & Power Co., 184 F.2d 552 (CA4, 1950); United States v. Florida Power Corp., 5 Trade Reg. Rep. 11971 Trade Cases) para.73637 (M.D. Fla., July 19, 1971) (consent decree), Georgia Power Co. v. FPC, 373 F.2d 485 (CA 5, 1967) (upholding FPC rejection of wholesale tariff's restrictions on resale), refusals to trade (and refusals to grant access to bottleneck facilities); Shrewsbury Municipal Light Dept. v. New England Power Co. v. FPC., 349 F.2d 258 (CA1, 1965); Otter Tail Power Co. v. United States, 410 US 366 (1973), and political interference, Otter Tail, supra, and c.f., Gulf States Utilities Co. v. Kauper, D.C.M.D.La., Civil Action 71-102, Antitrust & Trade Reg. Reporter No. 583, p. A-11 (Oct. 10, 1972)(granting discovery).

Courts have attempted on numerous occasions to instruct the FPC as to its duty to consider and foster competition in bulk power markets. See, e.g., FPC v. Conway Corp., ____US____, 48 L.ed. 2d 626 (1976) (price squeeze); Gulf States Utilities v. FPC, 411 US 747 (1973) (financing). Courts have upheld FPC action requiring coordination of operating reserves, Gainesville Utilities Dept. v. Fla. Power Corp., 402 US 515 (1971); and have required the SEC to consider exclusionary practices when it passes upon joint generation ventures. Municipal Elec. Assoc. of Mass. v. SEC, 413 F.2d 1052 (CADC 1969). In price squeeze cases, court action under the antitrust laws may supplement FPC jurisdiction. City of Mishawaka, Ind. v. Indiana & Michigan Electric Co., 1975-1 Trade Cases, para. 60318 (N.D. Ind., 1975).

37 Alfred E. Kahn, The Economics of Regulation, vol. 2, (New York: John Wiley & Sons, Inc., 1971), pp. 105-106.

38 David W. Penn, James B. Delaney, and T. Crawford Honeycutt, Op. Cit., p. 23.

39 Currently applicable tax legislation places limits on the use of this device.

40 A series of discussions concerning public utility productivity are found in Public Utility Productivity: Management and Measurement, a symposium published by the New York State Department of Public Service (1975). Papers given discuss the problems of measuring productivity.

41 The disputes between fuel suppliers were accompanied by allegations of unfair promotional practices. See Report on Promotional Practices by Public Utilities and Their Effect Upon Small Business, House Select Comm. on Small Business, H. Report. No. 1984, 90th Cong., 2d Sess. (1968).

42 The SEC employed a case by case procedure to determine if the statutory requirement of divestiture should not be followed, in order to avoid such a loss of economies as would make the separated systems non-viable. See generally, SEC v. New England Electric System, 384 US 176 (166); and 390 US 207 (1968) ; and Philadelphia Co. v. SEC, 177 F.2d 720 (CADC, 1949).

43 Union Electric Company, HCAR 18368 April 10, 1974; and Northern States Power, 36 SEC 1 (1975); and the Initial Decision in Delmarva Power & Light Company, Ad. Power File 3-3640 (June 26, 1974).

A number of differing positions have been put forward on the comparison of performance of combination and straight utility systems. With the advent of Alaskan production, gas systems may again seek new loads. Even when curtailing, gas systems may seek to shift from industrial gas to higher revenue customers. There are circumstances in which a combination electric and gas utility would have the economic incentive to promote the use of one form of energy at the expense of another. As long as the relationship between costs and benefits is different between the two markets, the utility may very well wish to promote one at the expense of the other. "If, for example, the costs for providing additional electricity were falling more rapidly (or rising less rapidly) than those associated with providing additional energy in the form of gas, the utility would, in the presence of regulatory lag, maximize profits by promoting electricity and retarding the use of additional gas. Likewise, if the utility can earn a high rate of return on additions to capital, it may promote that service which results in the largest accumulation of capital. In fact, this temptation to distortion will be present as long as allowed rates of return exceed the costs of capital. Where service improvements in one service might lead to a loss in sales to the other, the combination company has less incentive to undertake the service improvement than do single service utilities. Extensions of competing service may likewise be retarded to maximize profits. Certainly, one would expect a combination company to promote its products less vigorously than would a utility facing a competition in a wide range of its sales. In fact, one can argue that a combination company may very well lead the 'quiet life' of a monopolist and relax its concern with costs and service." Testimony of Dr. John Landon, Exhibit 22 7, Delmarva Power & Light Co., SEC Admin. Proc. 3-3640 (1973).

44 The Intertie's high voltage lines offer lower impedance to the flow of energy than parallel, connecting low voltage lines in the area. This difference in impedance between these large and the smaller parallel lines, combined with an inability fully to schedule energy flows, results in unscheduled spillovers of flow over the larger lines. Thus, not all their capacity is available for scheduled flows. These frequent unscheduled flows generate, over time, a counter-clockwise flow of electric power. The net effect is to reduce the power transferable from the Northwest to California.

45 In this regard the recent multi-party transaction in which municipal power systems acquire power from the Pacific Northwest, over the Pacific d.c. Intertie, backed-up by reserves acquired from the Nevada Power Company shows what can be done.

46 FPC News Release No. 23024 Power Production Generation Current Data for 1970 to 1975. (March 25, 1977) Industrial generation totalled 2118 mw in the Western System States at the end of 1976.

47 Schedules have subsequently slipped for many units.

48 Development of geopressured resources might also take place in Texas. Power pooling in Texas is in a state of flux. Heretofore, the power pool in much of Texas was isolated from other systems. However, the Central and Southwest Utility Holding Company System must either interconnect its system in the Texas power pool with its interstate system or face divestiture proceedings.

49 This resistance is reflected in coordination afforded the Intermountain. Consumer Power Association, and in the Hearing on Oversight of Electric Power Contract, Montana, Senate Interior Committee, 91st Congress, 2nd Sess. (1970). Its continued existence was also reported by interviews.

50 CVP has purchased 400 mw from the Centralia, Washington coal-fuel plant. This purchase expires in 1982.

51 CVP customers are Redding, Roseville, Biggs, Gridley, Palo Alto, and the Plumas-Sierra Cooperative. Additionally, Santa Clara receives a portion of its requirements from CVP.

52 Transmission capacity was crudely computed from circuit miles of transmission lines data reported in Federal Power Commission, Statistics of Publicly Owned Electric Utilities in the United States, 1972, line 54 of statements for individual utilities and in Federal Power Commission, Statistics of Privately Owned Electric Utilities in the United States, 1972, Section VII, line 66.

53 The area system of a party consists of its system plus (1) each third party system normally operated in parallel and which is by facilities and agreement, effectively integrated as to loads and resources, and (2) generation plants whose output is substantially all delivered to the party.

54 Spinning reserves are, per the Pool agreement, five percent of the sum of daily peak loads and interruptible receipts. Energy resources are to equal a party's monthly needs less energy resources unavailable due to maintenance plus 50% of the energy output of the largest system unit (if it is on line). Capacity resources must be satisfied or damages are assessed for the deficient month and for each of twelve months thereafter. Reactive power is the responsibility of each party.

55 Capacity charges for short term firm power are based on the higher of 80% of power commitments or the maximum actual demand prorated for the portion of the month over which it was incurred. Attendant energy is priced at 115% of supplier's incremental cost.

56 The Pacific Intertie is defined to consist essentially of the 500 kv a.c. circuit coming down from the Bureau of Reclamation lines to the Oregon-California

border; PP&L's 500 kv line linking this point to lines built by PG&E; a 750 kv d.c. line from Oregon via Nevada to Southern California; and a 230 kv a.c. SCE link in Southern California between the end of the 750 kv line and the 500 kv lines. The 500 kv lines were designed with a rated capacity of 2000 megawatts, and the d.c. line at 1350 megawatts (50% owned by SCE and 50% owned by the Los Angeles Department of Water and Power).

57 San Diego, being at the southern end of the Intertie, would receive all Intertie shipments through SCE power lines. SCE is only obligated to wheel for SDG&E such capacity as is within SDG&E's share of Intertie capacity.

58 This proportionality is specified in the contract to be PG&E - 50%, SDG&E - 7%, and SCE - 43%.

59 The members of the 1957 Intercompany Contract.

60 Pacific Power & Light Co., FPC Rate Schedule 105, dated June 29, 1972, filed July 3, 1972.

61 If SDG&E is unable to use its full share Intertie capacity for Canadian or firm power, it may reduce its share of Intertie participation or increase its exchanges of power delivered for it in northern California for power in southern California. This reduction is subject to arbitration at five-year intervals unless SDG&E's unused share exceeds 20 mw.

Also, if SDG&E can generate for less than the cost of Northwest Power (other than Canadian, or Bureau capacity exchange for energy) it may reduce its share or participation in the Intertie.

62 At times when there is unused capacity in the 750 kv d.c. line.

63 Rates are at fixed amounts:

On-peak and off-peak energy Firm capacity	Three mills per kwh; $1.477 per kilowatt per month with a 12-month ratchet provision for the 12 prior or coming months.
Extra capacity provided sans notice	Two dollars per kilowatt per month. In the event extra capacity is provided for over one-half hour for reasons on suppliers' systems, State Water Project emergencies or curtailments of States Northwest power, a 12-month ratchet is imposed. This $2.00 sum is only payable if the capacity is deliverable.

Under this ratchet, DWR is to pay $2.00 per month per kilowatt of extra capacity in the month it is taken and for each of the succeeding twelve months.

PG&E is billing agent under the contract. The contract rates are to be effective until March 31, 1983, subject to review on or before March 31, 1978. Rate revisions are to be effective five years later and are to be based upon anticipated fuel costs, and suppliers' generating efficiency and economies experience.

64 Plants are listed as:

a) Denominated state hydro plants
b) Bureau of Reclamation power
c) Northwest power via Intertie lines
d) Northwest dump power
e) Purchases from suppliers per this contract
f) Generation from Oroville-Thermalito or a state thermal plant

65 Representatives of the Northern California Power Agency have alleged that the unusual long term fixed rate provisions of DWR's power supply agreement may have been proffered as an inducement for DWR to forego construction of its own transmission grid or steam-electric facilities.

66 Department of Justice, Letter of Advice, Mendocino Plant, p. 8. This restriction was incorporated in Article 20 of a superseding contract of September 6, 1966, but expired in April of 1971.

67 In a proceeding before the Federal Power Commission (FPC Docket No. E-7597) on this contract, the Northern California Power Agency objected to the agreement as being an anticompetitive preemption of bulk supply sources by PG&E. In its response to this allegation, PG&E contended, inter alia, that the contract's reference to unit sizes of 830 megawatts was not intended to limit the size of SMUD units so as to prevent others from obtaining unit power entitlements or ownership in those units.

68 DJ Letter of Advice, Mendocino, pp. 9-10. In litigation pertaining to the FPC's acceptance of the 1970 contract as a tariff, the FPC was sustained in its contentions that it lacked the authority to compel load growth coordination or to mandate unit sizes and ownership such as to permit participation by others. NCPA v. FPC, U.S. App. D.C., 514 F.2d 184, (CADA 1975), affirming, Pacific Gas and Electric Company, 45 FPC 1157 and 48 FPC 1103.

69 PG&E Rate Schedule 45, FPC Docket ER 76-296.

70 Publicly owned electric systems, and REA cooperatives, have a preferential right to purchase output from federal power projects.

71 Contract 175r-2650, executed April 5, 1951.

72 Contract 175-3428, executed October 1, 1951.

73 The rate set, one mill per kwh, Contract 175r-2650 at Section 10(a), exceeded the 0.75 mill rate originally sought by the Bureau of Reclamation. The General Accounting Office later asserted that the one mill rate was too high and failed to fairly reflect both the load transmitted and the distance covered. G.A.O. AUDIT REPORTS ON CENTRAL VALLEY PROJECT FOR FISCAL YEARS 1953, 1954, 1955, and 1956 excerpted in Hearings on H.R. 6997, 7407, and 10005, Before the Subcommittee on Irrigation and Reclamation of the House Committee on Interior and Insular Affairs, 85th Congress, 2nd Sess. (1958), p. 231. (Hereafter cited as 1958 Hearings.)

The Bureau responded to this charge by arguing that the rate was a firm one, freely negotiated, and that a single-level transmission charge on a system-wide basis had been found most satisfactory in circumstances such as those contemplated by the Bureau negotiators. Ibid 231-32.

74 USBR Memorandum from E.K. Davis to Regional Counsel's files, Region 2, January 31, 1951. During negotiations, the Bureau of Reclamation's representatives stated that the Bureau did not feel bound to provide power to customers outside of the area that might be economically served by the Bureau's own

facilities. U.S.BR memorandum from E. K. Davis to Regional Counsel's files, Region 2, August 18, 1950.

75 USBR memorandum from E. K. Davis to Regional Counsel's files, Region 2, January 24, 1951.

76 Contract 175r-2650, Sec. 9 (c).

77 Ibid. This last provision represented a retreat by the Bureau from a position taken at a January 24, 1951 negotiating session. At that time the Bureau maintained that a restriction on PG&E's wheeling obligation such as one concerning service to new preference customers would be unacceptable. USBR memorandum from E. K. Davis to Regional Counsel's files, Region 2, Jan. 31, 1951.

78 U.S.B.R. memorandum from E. K. Davis to Regional Counsel's files, Region 2, February 2, 1951.

79 Ibid.

80 U.S.B.R. memorandum from E. K. Davis to Regional Counsel's files, Region 2, September 7, 1950.

81 1958 Hearings, p. 232. The Bureau responded to the G.A.O. asserting that integration benefits were reflected in the 300 mw PDC, as that PDC exceeded the PDC of the CVP operation in isolation. The Bureau further asserted that PG&E's 518 mw reflected better than normal stream flows, Ibid.

82 During the contract negotiations, the Bureau expressed its desire to firm up its hydro capacity to perhaps an amount in excess of the 450 mw nameplate capacity. It wanted to do this either by energy purchases from PG&E--to be

sold back to PG&E when the CVP had excess hydro energy, or by building a U.S. steam plant. Neither contingency was provided for. U.S.B.R. memorandum from E. K. Davis to Regional Counsel's files, Region 2, July 17, 1950. The Company's initial negotiating position made clear its opposition to any agreement which contemplated construction of a federal steam-electric plant. U.S.B.R. memorandum from E. K. Davis, January 5, 1950.

83 Contract 175r-3428, Sec. 10(b).

84 1958 Hearings, p. 233.

85 Ibid., p. 234.

86 Sales of short-term and "economy" capacity are well known among utility systems.

87 House Committee on Government Operations, Sale and Transmission of Power (Bureau of Reclamation, Central Valley Project, California), Hearings on H.R. 2221, 86th Congress, 2nd Sess. (1960), pp. 4-28. (Hereafter cited as 1960 Hearings.)

88 Ibid. 15-17, See Contract 175r-3428, Section 10(b) and Article 6 of Amendment 4 thereto.

89 House Hearings supra. The City of Redding was denied an allocation of CVP power in 1952 In 1956, the Bureau somehow found itself able to allocate 7250 kw to the City of Roseville aften an investigation by the House Government Operation's Committee House Committee on Government Operations, Availability of Power to Public Preference Customers from Central Valley Project

(Roseville, California), H. R. Rept. No. 218, 85th Congress, 1st Session (1957), cited in 1960 Rept. supra at note 5, p. 13.

90 Amendment 4, Contract 175r-3428.

91 Ibid., at 29.

92 Article 12(a) in Supplement No. 5 to Contract 175r-2650; Article 8 in Amendment No. 4 to Contract 175r-3428, cited in 1960 House Report, p. 30, 32.

93 Ibid., at 32.

94 House Rept. No. 2221 supra, at 28. The report stated that the Bureau should sell PDC to customers on a withdrawable basis if PDC exceeded other customers elements. Id. at 23.

95 Ibid., pp. 21-22.

96 Ibid., pp. 21-22

97 Ibid., pp. 39-46. Bureau of Reclamation data showed that the United States realized savings of $2,947,750.81 from July 1, 1957 through November 30, 1959 following a changeover from wheeling by PG&E to direct delivery over government lines to Sacramento Municipal Utility District (SMUD). Id. pp 34. Cumulative savings projected to 1994 were estimated by the Bureau to exceed $95 million.

98 U.S. Department of the Interior, Report of the Secretary to the House and Senate Appropriation Committees on the Pacific Northwest - Pacific Southwest Intertie, June 1964, Sec.11, p. 1.

99 Letter from Stewart Udall to Rep. John E. Moss, USBR-BPA attachment, June 25, 1964.

100 This results from PG&E's being obligated to only wheel to existing CVP customers in a limited area (delinated in the 1951 CVP-PG&E agreement), and load limits on CVP.

101 Rep. John E. Moss questioned the proposal's failure to reduce the wheeling charge from its present level or to make any change in the wheeling boundary. The National Rural Electric Cooperative Association, writing to Senator Warren Magnuson, cited GAO's view that the wheeling charge was possibly excessive. Interior in turn asserted that the charge was reasonable when viewed as the average cost of servicing all customers, and that the current wheeling area provided maximum benefits for the majority of preference customers while service to isolated loads outside the boundary could result in increased costs for all customers. A compromise involving a broader wheeling area coupled with different wheeling charges related to actual costs of transmission in different zones was not considered.

Rep. Moss questioned the proposal's restrictions on the Government's ability to change a preference customer's contract rate of delivery. Interior responded that this was necessitated by bookkeeping, scheduling, and planning problems. Ibid.

Rep. Moss also questioned whether the amortization plan in the proposal was less beneficial than that of the federal yardstick plan. Interior replied that the proposal was in reality of greater benefit to the Government when viewed over a 75-year period (50-year amortization, 25-year post amortization) yielding

$240 million more in benefits than the yardstick plan. Ibid. However, these benefits were based on proposals and assumed completion of contracts and additional commitments from systems not then parties to the negotiations. (Letter from Clyde Ellis, General Manager of the National Rural Electric Cooperative Association, to Sen. Warren Magnuson, July 6, 1964.) Interior claimed that preference customers would receive 55 percent (1,750 mw) of the proposed line capacity. (Letter from Charles Luce to Sen. Warren Magnuson, July 2, 1964.) However, only 47 percent (1,500 mw) would really be available for preference customers. Even this amount was subject to California exercising options which were to expire in 1967. Otherwise, the preference customers would only be entitled to 33 percent (1,050 mw) of the capacity. (Letter from Clyde Ellis to Sen. Warren Magnuson, July 6, 1964.)

102 Letter from Clyde Ellis to Senator Warren Magnuson, July 6, 1964.

103 Letter of Kenneth Holum to Senator Thomas H. Kuchel, October 11, 1966.

104 The California Companies Pacific Intertie Agreement, Agusut 25, 1966.

105 See, Interior Department, Remaining Major Issues with USBR regarding Contracts Relating to the Northwest Intertie (April 6, 1966).

106 Contract 14-06-200-2948A, executed July 31, 1967.

107 Department of Justice Letter of Advice concerning PG&E--Mendocino Power Plant Units 1 and 2.--August 2, 1972. (Hereafter cited as DJ Letter of Advice, Mendocino.)

108 Ibid., pp. 6-7.

109 Ibid., p. 11. This article preclude construction of a publicly owned steam-electric plant such as the proposed Delta steam plant, which is the only federal steam plant ever authorized by Congress outside the TVA system.

110 Ibid., p. 8.

111 Staff of House Subcommittee on Natural Resources and Power of the House Committee on Government Operations, 90th Congress, 1st Sess., Staff Memorandum Regarding Proposed Contracts Between the Bureau of Reclamation and Pacific Gas and Electric Company, Relating to the Pacific Coast Electric Intertie, March 8, 1967, pp. 1-4.

112 In 1973, the Bureau estimated that energy would flow into to "bank" account until FY 1977. After some withdrawals between FY 1977 and FY 1986, a small amount of energy deposits would be made through FY 1997. Then complete drawdown would occur by FY 2005.

Capacity account withdrawals would occur between FY 1973-FY 1985, and then deposits could resume.

113 Power produced in the Government's share of the coal-fired Centralia station in Washington is sold to PG&E at a rate, below its cost, which rate is derived by averaging costs of coal-fired and hydro generation.

114 USBR memorandum from C. H. Kadie to Commissioner of Reclamation, August 19, 1966.

115 Ibid.

116 USBR memorandum from Loy Kirkpatrick to Ray Coulter, September 1, 1966.

117 General Accounting Office Report on California's Central Valley Project--Proposed Rate Increase, G.A.O. Rept. B-125042., p. 10-11.

PG&E, unlike preference customers, purchases unit power. CVP preference customers have not been able to obtain allocations of Centralia power from CVP.

118 Letter of December 17, 1973, to Mr. J. Robert Hammond, Assistant Regional Director, Bureau of Reclamation, from J. D. Worthington, PG&E.

119 Ibid.

120 Memorandum to files from Assistant Solicitor, Power (January 11, 1972).

121 Letter of October 2, 1972 to Mr. Gillmor, Northern California Power Agency ("NCPA") from James R. Smith, Assistant Secretary of the Interior. This letter said that any supplemental service provided by CVP to NCPA in conjunction with NCPA self-generation efforts would first require tripartite "discussion" with PG&E, and tripartite agreement regarding reserves and reliability

122 Memorandum to Assistant Secretary-Water and Power Resources from Assistant Solicitor, Power September 22, 1972.

That Bureau power contracts with utilities are not immune to antitrust scrutiny was made clear in Otter Tail Power Co. v. United States, 410 U.S. 366, 378-379 (1973).

123 Pacific Power & Light Co., FPC Rate Schedule 105, dated June 29, 1972, filed July 3, 1972.

124 Statement of Rogers Morton before the FPC March 12, 1973, p. 28. At BPA's insistance, the seven utilities agreed (a) to afford all Northwest utilities access to the Intertie for exporting non-firm energy, and (b) to share with them all non-firm energy imported from California.

125 This explanation, which had generally appeared before, appears at page 30 of the Statement of the Secretary of the Interior in Pacific Power & Light Company. FPC Docket No. E-7796 March 12, 1973 (Proceeding on Seven Party Agreement filing). The letter of January 14, 1969 transmitting the Seven Party Agreement to the Administration of BPA simply spoke, in vague terms, of providing for sales to preference customers.

126 State of California Department of Water Resources, Petition to Intervene and Request for Hearing, In re Pacific Gas and Electric Company, NRC Docket No. P-56A-A (October 15, 1976).

127 Cf. Memorandum to files of Associate Solicitor, Water and Power, Nov. 4, 1965.

128 The earlier history of Bureau refusals to allocate power are documented in reports of the House Government Operations Committee referred to supra.

129 Letter of September 8, 1965 from Robert Gerdes to Stewart Udall.

130 Letter from Frederick T. Searls to Donald Von Raesfeld (Santa Clara's city manager), of September 20, 1965.

131 Letter of September 10, 1965 from Donald Von Raesfeld to Frederick T. Searls.

132 Staff Memorandum 60 (July 24, 1967) *supra*. and see 37 Fed. Reg 1624 (1972)

133 Staff Memorandum 66 (July 24, 1967).

134 Ibid.

135 Letter from Donald Von Raesfeld to Stewart Udall, June 7, 1967.

136 Ibid.

137 Memorandum from Edward Weinberg, Deputy Solicitor to Assistant Secretary for Water and Power Development, July 14, 1967.

138 The City of San Francisco was another preference customer with plans to develop additional capacity, in this case, at existing plants, switching the Hetch Hetchy plant to peaking operation. The city sought a banking and exchange arrangement with PG&E and municipal agencies. The Raker Act dictated the terms of this agreement, however, requiring that such a proposal: (1) provide for maximum development of the resources; (2) make benefits of low cost public power available to the area's public; (3) call for the city to retain full control of the marketing of the projects output; and (4) set up arrangements with PG&E and others on an exchange basis rather than a sale-and-subsequent-purchase-of-energy basis. Memorandum from Richard Pelz, Acting Assistant Solicitor, Power, to Harry Hogan, Dec. 6, 1966.

139 Letter from Donald Von Raesfeld, Santa Clara City Manager and President of the Northern California Municpal Electric Association, to Stewart Udall, July 28, 1967.

140 GAO, Rate Increase Study, p. 12

141 1974 Hearings, p. 452-53.

142 This assertion, neglects the time value of money. It is based on hypothetical suppositions regarding the price of returned capacity and energy. Hearing, p. 270.

143 If there had been a federal or a non-PG&E controlled or open access, Intertie arrangment, CVP might well have been able to obtain both reserves and other coordination elsewhere.

144 The "surplus" PG&E takes would not be surplus to CVP were it able to have more bulk power supply trading partners through use of more open wheeling arrangements, or federally owned transmission facilities.

145 When systems of equal bargaining power develop coordination arrangements, each component of coordination is separated and distinctly evaluated in the arrangements.

146 Sec. of Interior, NCPA (US. CA, DC. No. 75-1572)

147 GAO Rate Study, pp. 23, 32.

148 Ibid., p. 31.

149 Ibid., pp. 491-493.

150 Ibid., pp. 917-918.

151 Ibid., pp. 927-929.

152 Letters to Secretary Morton dated February 2, 1973, June 7, 1973, and July 5, 1973.

153 Letter to Chairman Reuss from Assistant Secretary Horton dated June 21, 1973.

154 1974 Hearings, pp. 918-919.

155 Ibid., p. 929.

156 NCPA v. Morton, 396 F. Supp. 1187 (U.S. Dist. Ct., D.C.), aff'd Secretary of the Interior v. NCPA (U.S.C.A., D.C., No. 75-1572).

157 40 Fed. Reg. 34431, August 15, 1975.

158 Memorandum of October 15, 1973 to Under-secretary of the Interior from Solicitor "Draft on Wheeling Stipulation." The stipulation had primarily been useful in bargaining for transmission for the Bureau of Reclamation.

159 Letter of May 7, 1976 to James F. Trout from M. A. Catino, Assistant Regional Director, Bur. of Reclamation.

160 See Memorandum of March 16, 1973 for Acting Assoc. Solicitor - Water and Power Resources to Asst. Commissioner of Reclamation from Asst. Solicitor, Power.

161 Minutes of NCPA meeting attended by NCPA officers and representatives and Interior Department personnel, including Kenneth Holum, Assistant Secretary for Water and Power, August 13, 1968.

162 Ibid. NCPA representatives were in agreement at that point that an atomic generating facility could be built in cooperation with Interior and PG&E.

163 DJ Letter of Advice, Mendocino, pp. 10-12.

164 NCPA Geothermal Power Project, Joint Transmission Study, April 1972.

165 1974 Hearings, p. 320.

166 Letter from Gary G. Gillmor, chairman, NCPA, to James R. Smith, Assistant Secretary for Water and Power, Sept. 7, 1972.

167 Memorandum from Richard Pelz, Assistant Solicitor, Power to Assistant Secretary, Water and Power Resources, Sept. 22, 1972.

168 Letter from James R. Smith, Assistant Secretary, to Gary Gillmor, Chairman, NCPA, Oct. 6, 1972.

169 Memorandum from William Wilson, Acting Deputy Assistant Secretary for Water and Power Resources, to Jared Carter, Deputy Under Secretary, Jan. 26, 1973.

170 Letter from James Smith, Assistant Secretary, to Gary Gillmor, Chairman, NCPA, Oct. 6, 1972.

171 Ibid.

172 Memorandum from William Wilson, Acting Deputy Assistant Secretary for Water and Power Resources, to Jared Carter, Deputy Under Secretary, Jan. 26, 1973.

173 PG&E's approval was required under the interchange contract but the company could not refuse consent unreasonably, or for reasons unrelated to engineering considerations, or to achieve monopolistic ends. Memorandum from Richard Pelz, Assistant Solicitor, Power, to Assistant Secretary, Water and Power Resources, Sept. 22, 1972.

174 Ibid.

175 Ibid.

176 FPC Docket E-7777, Order of September 28, 1973.

177 FPC Docket E-7597, Orders of June 8, 1971 and May 15, 1973.

178 FPC Docket E-7796.

179 410 US 366.

180 DJ Letter of Advice, Mendocino, p. 13.

181 Ibid.

182 1974 Hearings, pp. 314-322.

183 Ibid.

184 71 Cal. P.U.C. 543, Decision 77918, November 10, 1970.

185 NCPA v. PUC, (1971) 5 Cal. 3d 370, 96 Cal. Rptr. 18, 486 P.2d 1218, 91, PUR 3d 146.

186 Decisions 78402 and 78403, November 23, 1971, 72 Cal. PUC 704 and 718.

187 S.F. No. 22879, June 7, 1972.

188 SMUD is also to inform companies immediately of any contract with a Northwest entity for power or energy to be transported over the Intertie.

189 Transmission services are provided at a rate expressed in dollars per kilowatt of firm power shipped, and a sum per kilowatt-hour of dump power shipped.

190 "Lay-off" in trade. partance.

191 Northwest power is to be sold in increments of less than 5,000 k.v., and transmission losses are to be absorbed by SMUD to the California-Oregon border.

192 SMUD must purchase in 5000 kw. lots change only once a year.

193 The energy involved in MSUD resales counted against the maximum transmission capacity SMUD acquired.

194 This supplemental agreement covered a two year period. During this period the companies would be acquiring approximately 275 megawatts of Canadian power and associated energy from the California Department of Water Resources (State), and anticipated acquiring all of SMUD's Canadian Entitlement Power (CEP) approximately 10,200 kilowatts of capacity in 1968-69 and 38,800 kilowatts in 1969-70). During this period, the provisions of the California Companies' Pacific Intertie Agreement were amended. These amendments provided that SCE and SDG&E were to purchase, in proportion to their contract shares, CEP which SMUD and State might sell to the companies, together with associated transmission capacity. PG&E became obligated to resell to State a portion of the amount of CEP to be acquired by SCE and SDG&E, and PG&E also became obligated to sell SMUD the amount of power SMUD wished to sell companies from its assignment of CEP in excess of the CEP power acquired by SCE and SDG&E under this agreement.

195 SDG&E obtained from PG&E, in the second year of the contract period, nine megawatts of Assured Intertie Capacity (measured at the California-Oregon border) which it might use to acquire peaking capacity from the Bonneville Power Administration or the Northwest entities, provided SDG&E has first used its other Intertie capacity for CEP and firm power from north of California

The nine megawatts of transmission capacity would be available to PG&E for delivery of Northwest dump energy to its system unless the transmission was needed by SDG&E to supply load in an emergency when SDG&E would otherwise be deficient as to spinning reserve. In that event, SDG&E will later return energy in an amount equal to the dump kilowatt-hours foregone by PG&E.

While PG&E was to give SDG&E advance notice of its intention to schedule dump energy deliveries in this nine megawatts of transmission capacity, no notice period is specified.

If PG&E had not scheduled dump energy, SDG&E might schedule capacity in return for its energy. It could only use the nine megawatts to receive dump energy from north of California.

196 PG&E is not to pay more for geothermal power and energy than it would have cost PG&E to generate power using a dry system unit even if SMUD constructs a hot water unit. If PG&E does not purchase all the energy associated with capacity purchased by it, the remaining energy is (a) to be priced at an amount to be agreed upon, and (b) PG&E shall be entitled to subsequently acquire equivalent amounts of energy at a surplus energy price until a sum for equivalent firm energy is liquidated.

197 Capacity factor is determined by dividing the output of a unit by the product of its rated capability and the hours in the subject period.

198 The theory behind this turbine rate is that "for capacity factors of up to ten percent, it is reasonable to assume that the capacity and energy from Sacramento's combustion turbines are being used to serve Sacramento's load. This has the effect of making more base-load nuclear power available for sale

to Pacific. Therefore, if the turbines are operated at a capacity factor of ten percent or less, Pacific will purchase only surplus nuclear capacity and energy." Letter of PG&E accompanying filing of this contract with FPC.

It also appears reasonable--at least to us--that a system controlling its own resources would not operate its combustion turbines at times when it has excess nuclear capacity, unless it were making a sale to another system at a price covering its incremental costs for the sale plus a profit. Nuclear energy (KWH) costs far less than does combustion turbine generation. PG&E's statement amounts to an assumption that the area peak load (to meet which, combustion turbines would be operated and for which PG&E dispatches the SMUD turbines) coincides with SMUD's peak. This may or may not be the case, but in any event it can be determined as a matter of fact and need not be "assumed."

199 Under the 1970 Contract, SMUD sold energy to PG&E at cost plus 10%, but not in excess of 1.9 mills per kilowatt hour. Similarly, capacity was sold to PG&E at Sacramento's cost with a ceiling of $2.17 per kilowatt-month.

200 Unlike the normal practice of determining purchaser's decremental cost as of the time of sale of economy energy, the amended contract prices PG&E's decremental cost by use of monthly average fuel costs at PG&E plants--excluding units burning refinery by-products.

201 The contract provides for integrated operation of PG&E and SMUD generation and transmission resources. Reserves shared include reserves for (a) unexpected

load growth, (b) scheduled and unscheduled unit outages, and (c) construction delays.

202 Under the contract, SMUD may only purchase dump hydro energy when PG&E also is scheduled to acquire such energy; SMUD relinquished its right to import dump energy under the Intertie arrangements.

203 SMUD will only receive credit for supplying capacity to PG&E to repay capacity provided SMUD (between nuclear units) if PG&E has not otherwise provided for capacity to serve "area load."

204 After its first nuclear unit is in operation, SMUD is to sell capacity in excess of SMUD's imputed needs to PG&E at a price which is the lesser of $2.17 per kilowatt per month or cost; "excess" energy is to be sold to PG&E at the lesser of SMUD's cost plus 10 per cent or 1.9 mills per kwh.

205 The last limitation further reflects the lack of reciprocal planning obligations on the part of PG&E.

206 Rancho Seco No. 1.

207 Filed by PG&E with the FPC in November 1975 as PG&E Rate Schedule 45, FPC Docket O. ER 76-296.

208 If PG&E does not purchase the energy associated with capacity purchased by it, the remaining energy is (a) to be priced at an amount to be agreed upon, and (b) PG&E shall be entitled to subsequently acquire equivalent amounts of energy at a surplus energy price until a sum for equivalent firm energy is liquidated.

209 The amended contract states that it is anticipated that others besides PG&E and SMUD will be co-owners of the proposed second SMUD nuclear unit which appears to have a specified size of 1100 mw.

210 D.J. Letter of Advice, Mendocino, p. 4.

211 Ibid., pp. 4-5.

212 Petition of State of California Department of Water Resources to intervene and request a hearing; Pacific Gas and Electric Company, N.R.C. Docket No. P-564-A (October 15, 1976).

213 Ibid., p. 9.

214 Department of Justice, Letter of Advice concerning SCE and SDG&E, San Onofre Nuclear Generating Station Units 2 and 3, AEC Docket Nos. 50-361-A and 50-361-B, p. 38. (Hereafter cited as DJ Letter of Advice, San Onofre.)

215 Ibid., p. 3.

216 Ibid., pp. 3-4.

217 Riverside is at present an all-requirements customer of SCE and receives electricity at 66,000 volts over its own transmission lines which it delivers to its distribution substations, thus saving SCE the expense of facilities necessary to step down the voltage and, consequently, eliminating one possible justification for incurring higher rates than SCE's industrial customers.

218 Mayor Eric Haley, "Testimony" in Electric Utility Rate Reform and Regulatory Improvement, Hearings before the Committee on Commerce, Senate on S. 1666, S.

2208, S. 2502, and S. 2747, S. 3011, S. 3310, and S. 3311, 94th Congress, Sess. 1976, pp. 345-353.

219 Ibid.

220 Ibid., p. 5.

221 Ibid. p. 6.

222 Ibid. p. 11.

223 The Federal government owns, or holds in trust for Indians, the major portion of land in the Southwest. The U.S. also owns 45% of the coal. Dept. of the Interior Southwest Energy Study, Summary Report. (Nov. 1972).

224 Subsequently, one plant--the Kaiparowitz project--was indefinitely deferred.

225 The Navajo project consists of three coal-fired units of 770 mw dependable capacity each, several 500 k.v. transmission facilities. The Project is owned as follows:

Participants	%	Kilowatts
Salt River Project, manager	21.7	501,270
Los Angeles Dept. of Water & Power	21.2	489,720
Arizona Public Service Company	14.0	323,400
Nevada Power Company	11.3	261,030
Tucson Gas & Electric Company	7.5	173,250
U.S. Bureau of Reclamation	24.3	561,330
	100.0	2,310,000

226 By an exchange of letters; the first letter is dated April 7, 1966 and is from the Secretary of the Interior to SCE Vice President, Jack K. Horton;

the second is a letter of April 11, 1966 from Mr. Horton to the Secretary. Navajo Plant owners are: SCE, LADWP, Nevada Power Co., SCE, Public Service Co. of New Mexico, SRP, Tucson Gas & Electric Co., and El Paso Electric Co.

227 See e.g., Letter of March 11, 1967 of Howard P. Allen of SCE to the Secretary of the Interior.

228 Also see Memorandum of January 7, 1969 from Mr. Bob Bennett to Secretary Udall.

229 Agreement of June 27, 1974 between Justice Dept. and SCE.

230 Letter to Asst. Attorney General, Antitrust Division, from William R. Gould, SCE, dated June 6, 1974.

231 Ibid.

232 Letter of Advice, Mendocino, p. 16.

233 Department of Justice, Letter of Advice, San Joaquin Nuclear Project, NRC Docket No. P-499-A, November 24, 1975. Justice noted that PG&E was only a 23 percent owner of the project and that it would soon issue advice on the Stanislaus Nuclear Project, solely owned by PG&E.

234 Department of Justice, Letter of Advice, Stanislaus Nuclear Project, Unit No. 1, NRC Docket No. P-564-A, May 5, 1976.

235 The Intertie is now heavily loaded. Absent coordinated planning, the Intertie is unlikely to be developed so as be accessable to others.

236 Systems installing base-load geothermal generation would find the intermediate and peaking load carrying ability of hydro projects appealing. Good hydro sites in California are in general only available in relicensing proceedings.

237 APPA v. Morton, US Court of Appeals, 9th Circuit, Slip Opinion Nos. 74-1167, 74-1168, and 74-1173. Amici curiae briefs were filed on appellant's and intervenors' behalf by Anaheim, Riverside, and Banning.

238 Ibid., pp. 9-10.

239 Robert Gordon, "Testimony" in Electric Utility Rate Reform and Regulatory Improvement, Hearings before the Senate Committee on Commerce, on S. 1666, S.2208, S.2502, S.2747, S.3011, S.3310, and S.311, 94th Cong., 2nd Sess., 1976, pp. 364. (Hereafter cited as 1976 Hearings.)

240 Ibid.

241 Ibid., pp. 374-383.

242 On February 5, 1976.

243 On February 13, 1976.

244 Ibid.

245 Telephone conversation with Berry Hutchings, Manager, Bountiful City Light and Power, August 16, 1976.

246 Ibid.

247 WPPSS Unit No. 4. Sec. Dept. of Justice, Letter of Advice, WPPSS Unit 4, NRC Docket No. 50-513A, February 13, 1975.

248 William W. Lindsay of the FPC staff, testified that during the last six months of 1975, 79 wholesale rate cases were received, 29 cases were disposed of and 229 cases remained pending. Some cases have remained pending for over 30 months. Electric Utility Rate Reform and Regulatory Improvement, Compilation of Statements for Use of the Subcommittee on Energy and Power of the Committee on Interstate and Foreign Commerce, 94th Congress, 2nd Sess., pp. 775-790.

CHAPTER 4

THE RAW FUELS INDUSTRY AND GEOTHERMAL ENERGY

To obtain geothermal energy at a price related to its cost of production, rather than at a higher price tied to that of alternative fuels--that is to obtain geothermal energy in a manner that makes it attractive--a utility or other user generally must be prepared to become a fuel company. The user can not expect to be able to go to the petroleum companies and their affiliates and service companies--the group dominating lease holding--and obtain prices set on a basis other than the price of other fuels.

The raw fuel industry has little if any incentive to reduce utility fuel costs. It profits handsomely when these costs rise; it is so structured as to make it unlikely that a large fuel company will "undersell the market" while smaller petroleum firms are not likely to do so either.

Large petroleum companies are in an excellent position to warehouse prime domestic energy sites; as will be discussed, they have an incentive to avoid competition among the divisions of their enterprises. Smaller oil companies, as will also be discussed, are unlikely to undersell because (a) they are often dependent upon larger firms for leases and financing, (b) they are likely to view themselves as service companies for larger oil companies--providing exploration services and some risk capital; and (c) they sometimes have the cash flow to speculate on geothermal leases while the share of the market they see in the event of a price decline may not be sufficient to motivate them to cut prices to obtain such added sales. A price decline would also tend to depress the speculative value of their leases.

The independent enterprise specializing in geothermal work may be willing to undersell the market, or to enter into a joint venture with a co-venturer who seeks cheaper energy, to obtain a positive cash flow or perhaps even to "get the ball rolling."

However, even such an independent geothermal developer may be constrained from entering into such transactions. He may have his prospects tied up in a joint venture contract with a large oil company, or perhaps a large utility; or he may look forward to such an arrangement. Moreover, if an independent enterprise does act to sell its output for less, it foregoes the glimmer of outsized profits that may have attracted some of its capital--although this loss may only appear to be temporary and may be offset by the prospect of some cash sales.

The independent enterprise will generally require a financing partner in its project. That partner may have to be an energy user, if it is not to be an oil company or an oil-associated financial institution.

The partner could be a finanacial institution secured by federal loan guaranty but such guaranties do not appear to be large enough to cover both the delineation and development of a field. Lendors secured by a guaranty and associated with large petroleum companies, may constrain a debtors marketing.

The rate at which geothermal development goes forward appears to reflect the leasing and warehousing practices of larger oil companies. The slow development and concern with opportunity costs that appears to characterize their activity is to be anticipated from the nature of utility fuel markets and their control therein.

To understand the effects of large oil company ownership of other fuels--which we will sometimes refer to as cross-fuels ownership--we must begin with a look at utility fuel markets.

Western Electric Utility Industry as a Fuel Market

The electric utility industry consumes over 28 percent of U.S. energy production.[1] Utilities obtain about three-fourths of their generation from coal, oil and gas, consuming about 72.6 percent of domestic coal consumption[2] and 88.8 percent of residual fuel oil demand.[3] (1975)

Electric utilities constitute a distinct fuel market because of their aggregate size,[4] the size of their fuel purchase contracts, and the importance of fuel in overall generating costs. Distinct facilities and sources are, of course, devoted to the supply of this market. Only a limited number of firms compete to supply it (except for spot sales) and competition is limited to a few points in time: for example, when a new unit is being planned, or perhaps when a long-term agreement is lapsing. The utility fuel market has been growing with rising demand. Much of this growth is directed toward large generating units. For the nation as a whole, planned new capacity is in the following size ranges.

TABLE 4-7

FOSSIL AND NUCLEAR STEAM UNIT SIZE RANGES

FOR PROPOSED NEW CAPACITY*

Unit Size Range (Mw)	Fossil Steam Capacity**		Nuclear Capacity	
	Mw	%	Mw	%
399 Mw and less***	25953	15.61	630	0.41
400 to 599 Mw	60266	36.25	482	0.31
600 Mw to 799 Mw	56033	33.7	2808	1.81
800 Mw and over	23989	14.43	151018	97.46
	166241	99.9	154938	99.99

*Source: FPC: Staff Report on Proposed Generating Capacity Additions (Dec. 9, 1975)

**Excluding combined cycle units

***Although larger steam-electric generating units have clear economies of scale, a number of small fossil units are planned for the 1975-1984 period. The distribution of new units is as follows:

TABLE 4-7 (Continued)

Unit Size Range (Mw)	Fossil Steam Units No.	Fossil Steam Units %
399 Mw and less	132	36.27
400 to 599	123	33.79
600 to 799	82	22.53
Over 800 Mw	27	7.4
Total	364	99.99

The large number of small units evidences a lack of pooling and/or transmission services.

Fossil steam units comprise 43.2%, and nuclear steam units 40.26% of the 384,788 megawatts of capacity scheduled nationally for completion in the 1975-84 period. Geothermal units (1172 Mw) constitute 0.3% of this total.[5]

Growth estimates for electric generating capability in the later 1970's and early 1980's have been reduced, declining from a projected average annual growth rate to 7.7% in 1974 to a projected rate of 5.67% in 1976.[6] Similarly, 10 year energy growth rate projections were reduced to 6.15% from 6.73% in 1975.

Long term supply contracts increasingly dominate utility fuel purchases. A limited number of purchasers take a very significant share of sales on a national basis.

The twenty largest utility coal purchasers acquired 54.6 percent of utility coal purchases, paying 55.5 percent of coal fuel bills. These systems included The Pacific Power & Light Company and Arizona Public Service Company. The twenty largest utility purchasers of oil bought 67.8 percent of utility oil purchases, paying 69.0 percent of oil fuel costs. These systems included Southern California Edison (first in oil deliveries received), PG&E (ranked ninth), LADWP (ranked eleventh), and San Diego Gas & Electric (ranked 15th). It is interesting to note that the twenty largest utility purchasers of coal and oil did not appear to receive volumetric price discounts. Instead, they paid a greater share of fuel costs than is proportional to their energy receipts. This disparity may indicate that their extremely large contracts must be negotiated in an even more concentrated market than would smaller purchasers--there being fewer single suppliers capable of filling such a large order. If this is so, it may in turn indicate an excessive predilection for "one-stop shopping" by these large utilities.

Natural gas purchasing was still more concentrated. The twenty largest electric utility buyers of natural gas received 74.8 percent of the utility deliveries of gas paying 70.5 percent of gas costs. Among these utilities PG&E ranks fourth, SCE fourteenth, and Public Service of Colorado nineteenth.

Prices

Coal, gas, and residual fuel oil[7] prices are particularly relevant costs of energy alternatives to geothermal power for base-load generation. These are the fuel prices that utilities may seek to escape by adopting innovative energy sources. They are the prices which energy companies may seek to match in selling geothermal energy.[8]

Table 28 and Figures 14 and 15 show (1) the percentages of energy consumption accounted for by oil, gas, and coal for the 1973-1975 period in the Pacific and Mountain regions and the United States as a whole, and (2) prices and price trends in terms of cents per million British Thermal Units.

FIG. 14. AVERAGE ANNUAL PRICES OF FOSSIL FUELS DELIVERED TO ELECTRIC UTILITY PLANTS (25 MW OR GREATER)

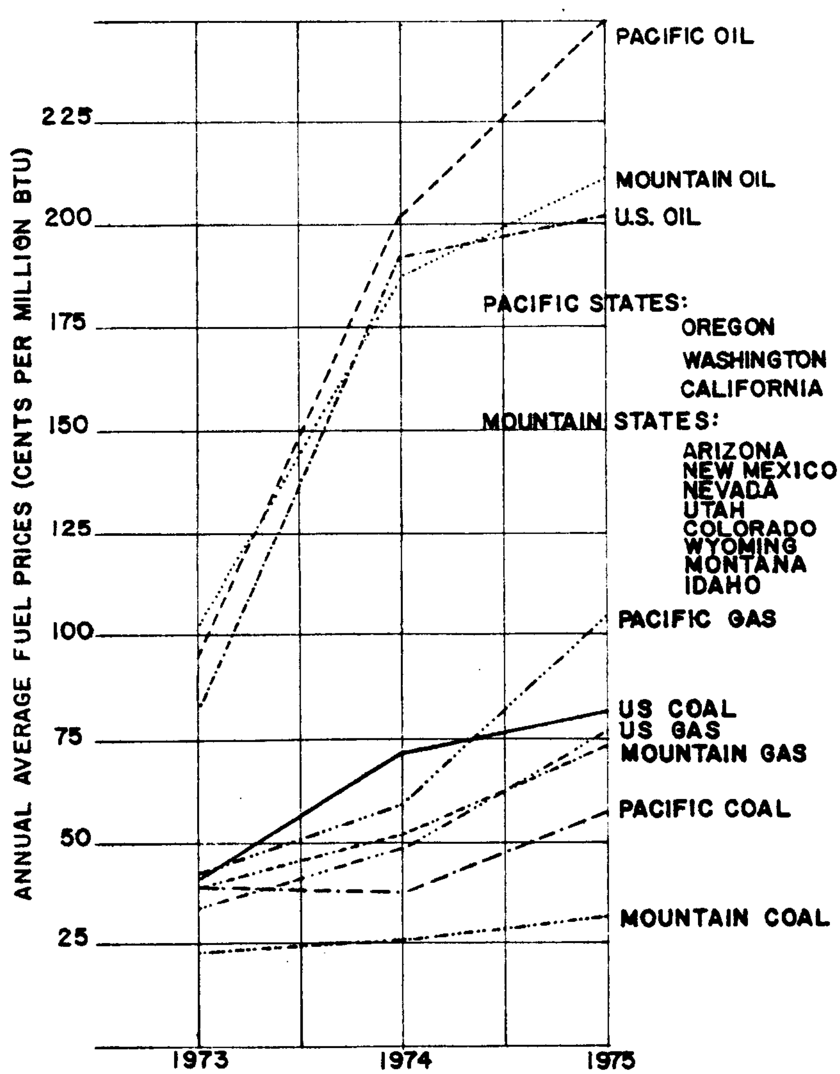


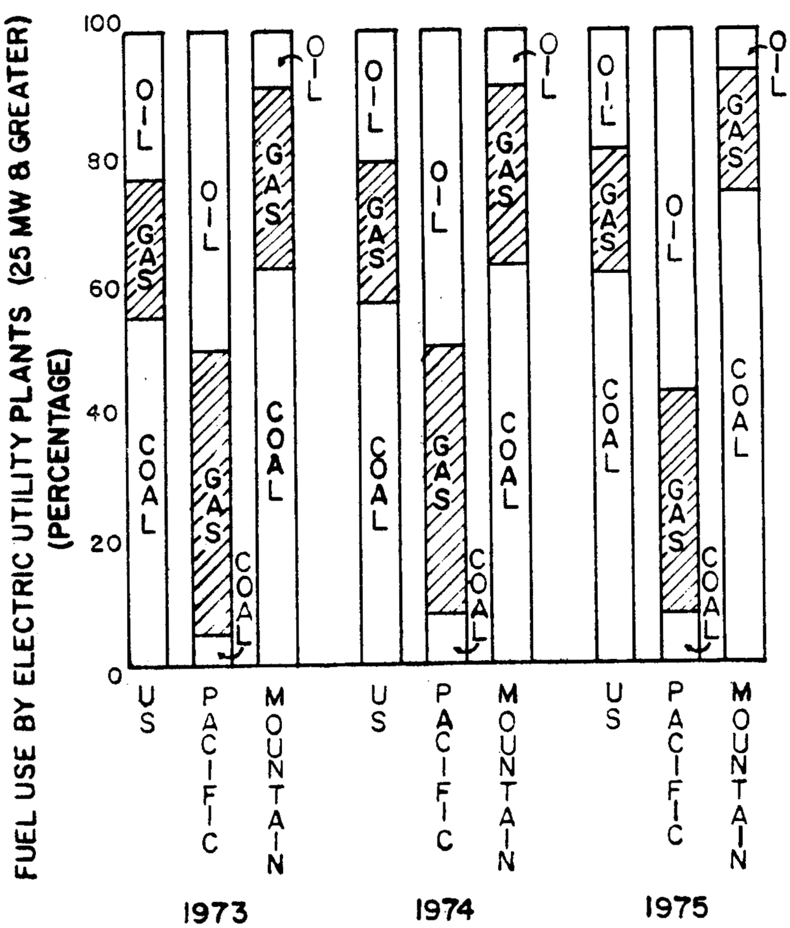
TABLE 28

UTILITY FUEL USAGE AND PRICES

Region	USAGE (% total Btu in Region)			PRICES (Cents per million Btu)		
	1973	1974	1975	1973	1974	1975
Pacific						
Oil	49.1	53.0	57.8	94.0	200.9	249.6
Gas	45.6	38.7	34.2	42.1	58.8	104.6
Coal	5.3	8.3	8.0	38.9	36.9	56.5
Mountain						
Oil	9.2	7.6	7.5	101.0	185.2	210.1
Gas	28.7	24.1	18.5	38.7	51.8	73.0
Coal	62.2	68.3	74.0	23.1	26.0	31.8
United States						
Oil	23.0	20.6	18.9	80.3	192.2	202.0
Gas	21.5	22.3	19.8	33.8	48.1	75.4
Coal	55.4	57.1	61.3	40.5	71.0	81.4

Source: FPC

FIG. 15 USAGE OF FOSSIL FUEL AT ELECTRIC UTILITY PLANTS (25 MW OR GREATER)



As the foregoing illustrates, on the West Coast, gas and oil prices are far higher than national averages.

Residual oil prices rose sharply between 1973 and 1975, while coal prices rose at a lesser rate. Western utilities, faced with declining gas deliveries, substantially increased their oil consumption while also increasing their use of coal.

Contract rather than spot purchases are the dominant mode for acquiring fuel oil in California[9].

In the Mountain States, coal is the dominant energy source--particularly in Montana, Utah and Wyoming. Coal usage has grown tremendously in the southwestern area of the Mountain States - Arizona, Nevada, and New Mexico.

The price of coal in the Mountain States has been far below national average levels, while oil and gas prices have followed national trends.

Factors Affecting Price And Usage

As other fuel prices escalate, they could increase the market area open to geothermal energy. However, this will be the case only to the extent that utilities are fuel cost conscious.

Utility incentives to control fuel costs appear to be lessened by the practice of passing rising fuel costs through to customers under fuel adjustment clauses in utility tariffs.[10] Fuel adjustment clauses are not uniform among utilities and may even differ among a single utility's tariffs for different services. The pass-through of increasing fuel costs by automatic fuel adjustment clauses has usually been accomplished without regulatory review. These adjustment clauses can permit evasion of regulation of utility profits. If a fuel adjustment clause is drafted so as to permit inclusion of non-fuel charges or of transactions arrived at other than by arms-length bargaining, or if the clause is otherwise allowed to be an avenue for profit, utilities have an incentive to seek out energy sources whose prices or patterns of sale will give rise to such profits.[11]

There is evidence that certain California utilities have used fuel adjustment clauses to pad their customers' bills. The Office of the Auditor General of the State of California in a report entitled "Adjustment of Electric Rates for Fuel Cost Charges" (August 1975) reported that charges by PG&E, SCE and SDG&E under fuel adjustment clauses exceeded actual fuel-cost increases by $270.6 million.

Auditors from the Federal Power Commission reported non-fuel-cost overcharges in fuel clause adjustments of several million dollars by SCE (in a fourteen month period ending June 1975).[12]

The FPC Audit reports that the sums attempted to be rolled in for SCE's Mono Power subsidiary included oil, gas and geothermal exploration advances of investment money for SCE to Mono Power.

A utility owning a raw fuel source can sell the fuel to itself or to others. Fuel sales among corporate affiliates are not required to be at cost-based prices, nor are fuel subsidiaries required to follow a uniform system of accounts or report regularly to utility commissions. Obtaining fuel from an affiliate can at times lead to high fuel prices, and vertical integration also can channel, to a degree, the financial assistance utilities sometimes offer fuel companies into utility fuel affiliates.

Advance payments and options payments to fuel producers and long-term contracts with broad escalation and force majeure clauses shift fuel industry risks first to the utility and then in turn to the utility customer. Advance payments to a utility's fuel affiliate (unlike advance payments to non-affiliates) can lead to future profits for the parent, through their inclusion in the utility rate base. This increases the incentive to integrate into raw fuels and channel financial assistance to affiliates.

A utility owning its fuel source is most unlikely to share the profits of that affiliate with ratepayers (even though undeveloped fuel resource lands may be in the rate base). The profits of the fuel affiliate may not be treated as utility income available to offset the revenue requirement to be recovered through rates. Even in intracorporate sales, the price of coal is often passed on through fuel adjustment clauses--with additional profits possibly arising from increased working capital allowances. A comparison by Whitfield A. Russell and Associates, of coal costs from "captive" (i.e.,utility controlled) and noncaptive mines shows that in 1973 captive mine costs were below those of noncaptive mines in 7 out of 10 cases. In 1974 the situation was reversed: captive mine costs were the higher, in 6 of 10 cases. In this sample the cost of captive mine coal rose along with that of coal from companies not owned by utilities; the percentage increase in prices for all major captive mine sales in 1973-1974 was roughly equal to that for non-captive contract sales.[13]

Unregulated captive-mine profits would seem likely to yield a higher return on investment than utility operations. As utility operations must be provided for in any event, further escalation in coal prices would create an additional incentive for utilities to enter the fuel business.[14]

Insofar as utilities are not pushed (by regulation or competition) toward lower-cost energy sources, they will have less incentive to determine whether geothermal energy could reduce their costs. Unregulated fuel adjustment clauses in an essentially noncompetitive environment could have this effect. In addition, attractive vertical integration prospects in coal or uranium will compete for attention and capital with geothermal development opportunities.

Large Long-Term Contracts

The utilities need for new capacity is matched by a concern on their part for assurance as to fuel supply. They have attempted to achieve this assurance largely through the use of long term supply contracts; they have used subsidiary firms to perform fuel supply functions to a smaller extent.

Large quantity long-term utility fuel contracts affect possibilities for entry into the utility fuel supply business. As the requirements for capital and time to assemble the resources needed to support such contracts increase, the number of entitites capable of participating in the market decreases.

Long-term contracts may be entered into with an intent to tie up supply or purchase markets. The contracts do involve situations which match up large, costly facilities which can best be used continuously; this suggests other than preemptive intent. On the other hand, the contracts typically have relatively broad excupatory provisions and seem highly protective to the seller in terms of price assurance. The agreements tend to shift risks of supply-cost increases and supply interruptions to buyers with detailed and comprehensive price escalation clauses sometimes including price escalation provisions for costs not otherwise identifiable.

Residual fuel oil suppliers have even been able to cause the price to utilities for residual fuel oil to include all cost increases in crude oil, even though residual fuel oil may account for only about 20% of the output of refined crude.

Shifting financial risk-via contract provisions or advance payments programs, enhances the seller's economic power and frees the seller's money to procure further resources. Moreover, the buyer's general lack of alternatives to long-term contracts raises questions about supply markets.

Joint Endeavors

Uranium and coal resources are sometimes developed by joint endeavors involving utility and raw fuel companies. These endeavors take forms which include joint ventures, contract mining of utility-owned reserves, and utility participation in providing or guaranteeing the debt portion of an energy project's financing.

Joint endeavors may tend to cause utilities to become solicitous of the needs of their joint endeavor partners and to be less prone to seek alternative avenues of supply. The utility might be motivated, in its energy supply planning, to protect a party whose debt it has guaranteed.

Joint endeavors among utility and raw fuel companies require mutual agreement and harmony among the participants. Development schedules must be mutually agreed upon, and must be framed to accommodate any strong desire upon the part of a party to withhold present supply in anticipation of future price rises - or in consideration of a party's alternative investment opportunities that promise a higher return on investment.

Joint endeavors appear to affect the extent to which utilities may encourage producer competition by credibly threatening to seek alternative suppliers, including utility-affiliated firms.

The community of interest among electric utilities and their fuel suppliers which long term contracts and joint enterprises tend to create is augmented by the disincentive on the part of the utility, resulting from fuel adjustment clauses, to bargain for lower fuel costs.

In light of this community of interest, a utility may be reluctant to enter into energy ventures that might be viewed as disruptive of present utility fuel supply arrangements or industry structures.

Western Region

Utility fuel markets appear to fall into regional patterns. The West Coast is a distinct area separated from others by population and transportation distribution factors, and since ther is indigenous production of raw fuel. The West Coast region differs from others in, among other things, the mix of utility fuel consumed, and a greater tendency toward large, long-term fuel contracts.

The terrain of the Rocky Mountains has largely separated Western and Eastern utility and fuel markets. For transportation cost reasons mines in Utah or the "Four Corners" area of the Southwest[15] will largely serve Western utilities, while mines in Northeastern Wyoming, Southeastern Montana and the Dakotas will serve the Plains States and the Middle West.[16]

Trade arrangements for West Coast fuel supply have involved a relatively few large coal mines, refineries, and long-term contracts. This trade pattern tends to limit this market to large firms capable of entering into such arrangements.

Traditionally, California utilities have consumed, in addition to hydro-generation, large quantities of natural gas, brought in from other states and Canada. As the better hydro sites have been developed, fossil fuels came to play an increasing role in power generation. Declining gas supply has been replaced by low-sulfur residual fuel oil, and to a quite limited extent by coal and nuclear power. This is unlike the situation in other regions where gas (not moving interstate) and coal were the dominant fuels.

Air pollution control regulations on the West Coast result in utility use of low sulfur residual fuel oil for plants there, and in the locating of coal-fired plants in the Mountain States.

In the Western States of Washington, Oregon, California and Arizona,[17] electric utilities received 60.6 percent (85,734.2 thousand barrels) of the 141,410 thousand barrels of residual fuel oil marketed.[18] Residual fuel oil is consumed in industrial and utility boiler furnaces. Lighter, more expensive petroleum products are consumed in turbine units.

If only because nuclear units will not be put into production in sufficient numbers to meet Western power demand, new coal and geothermal generation will be employed, using coal and geothermal resources from within the Western region.

Western coal production is almost entirely used for generating electricity. In the future, Western coal is expected to go to electric utilities as coal, or be converted to gas at the mine mouth.[19]

In 1975, coal mined in Arizona, Nevada, New Mexico, and Washington was delivered to plants in those states. Ninety-three percent of the coal mined in Colorado remained in that state; almost all of the balance went to Iowa and Nebraska. Fifty-eight percent of the coal mined in Utah remained there; while 17 percent left the region for eastern destinations.

The Northern Plains area, eastern Montana, eastern Wyoming and North Dakota, is a source of considerable amounts of coal for eastern utilities. North Dakota coal that is not consumed locally is shipped east (about 1/3 of production); all but 6 percent of Montana production is shipped east; while 56 percent of Wyoming shipments move east of Wyoming and Colorado.

Increased coal usage is forecast by the Western States Coordinating Council (WSCC). Tables 29, 30, and 31 list the new capacity planned for the West Coast. They show that an increasing number of units in states such as Utah and New Mexico are planned to produce energy for the West Coast consumer. Pending completion of coal-fuel and nuclear units, fuel-oil use by utilities on the West Coast has risen, reflecting the declining availability of natural gas, and delays in development of nuclear power.

TABLE 29

Present Fuel Usage and Future Capacity Plans

West Systems Coordinating Council

	Production of Electricity in 1975 by Energy Source (%)	Planned New Capacity For 1976-85 As Fueled (%)
Coal	17.44	33.3
Gas	11.56	0
Oil	15.01	9.27
Hydro	52.51	20.39
Nuclear	2.58	33.35
Other	0.90	2.59 (Geothermal)
		0.38 (Fuel Cells)
Undefined		0.41 (Waste Heat)

TABLE 30

Present Fuel Usage and Future Capacity Plans

California

	Production in 1975 (% Mwh)	Planned New Capacity* For 1975-84 (%)
Coal	0	30.67
Gas	22.04	- .3
Oil	38.53	16.73**
Hydro	31.98	8.42
Nuclear	4.84	37.43
Other	2.60	3.56***
Undefined		
	99.99%	

* Includes some Nevada capacity

** 10.28 - Combined Cycle

6.45 - Combustion Turbine

*** Geothermal

TABLE 31

PRODUCTION OF ELECTRICITY IN 1975 BY ENERGY SOURCE

	Mountain Region* (1000 Mwh)	% Mwh***	Pacific Region** (1000 Mwh)	% Mwh
Total	110,757	-	253,481	
Hydro	32,527	29.37	158,744	62.63
Coal	57,418	51.84	6,093	2.40
Oil	6,324	5.71	48,362	19.08
Gas	14,475	13.07	27,636	10.90
Nuclear	0	0	9,380	3.70
Other	14	0.01	3,266	1.29

	WSCC Region (1000 Mwh)	% Mwh
WSCC	36,238	
Hydro	191,271	52.51
Coal	63,511	17.44
Oil	54,686	15.01
Gas	42,111	11.56
Nuclear	9,380	2.58

TABLE 31 (Continued)

	WSCC Region (1000 Mwh)	% Mwh
Other	3,280	0.90

* States of Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, and Wyoming

** States of Washington, Oregon and California

***Megawatt Hours

Individual Fuels

We now describe with more particularity the market conditions affecting each of the major energy sources for electric utilities in the Western United States: residual fuel oil, natural gas, coal and nuclear energy.

All of the residual fuel oil ("resid") delivered to West Coast steam-electric plants in 1975 went to California destinations, (80,108.8 thousand barrels). In the Mountain States residual fuel oil was burned (7747.6 thousand barrels) extensively only in Arizona, Nevada and Colorado. Much of the resid consumed is replacing curtailed deliveries of natural gas.

The three large private utilities in California, Southern California Edison (SCE), Pacific Gas and Electric (PG&E) and San Diego Gas and Electric, as prevously noted, rank among the top utility fuel oil consumers. They consume far more resid than other users in the West.

Residual fuel oil used on the West Coast comes from refineries there.

PAD District V (Alaska, Washington, Oregon, Hawaii, California and Arizona), 1955 refinery production of residual fuel oil totalled 136,044 thousand barrels.[20] Imports of residual fuel oil were 10,645 thousand barrels with all but 1000 of these barrels going to California. Exports from PAD V totalled 4,758,000 barrels and refinery stocks of residuals in that District rose 3,021,000 barrels.

Two firms - Tesoro and Natomas--are particularly oriented to Western residual markets. Distinct transportation facilities are used to serve this market as is also the case of natural gas. In the future, petroleum production from the North Slope and from offshore California will bolster the unique market conditions that exist there - where 55% of refinery crude oil runs are still indigenous oil.

Domestic California crude oil production tends to be "heavy" and to have a high sulfur content. This crude oil generally must come to market through an interrelated grid of private pipelines owned by major firms, and requires desulfurization treatment in special units.

The unique fuels situation on the West Coast will be reinforced when deliveries of oil from Alaska's North Slope begin. Combined with new production from off-shore areas, the Alaskan crude oil will result in a relative abundance of crude supply on the West Coast.[21]

The rapid decline in availability of natural gas as a boiler fuel has eliminated gas as a fuel choice for new units. Utilities in California and the Southwest present a tremendous replacement market. Because of boiler design limitations, much of the gas supply lost must be replaced by oil if substantial reductions in capacity ratings are to be avoided when new capacity is developed.

If the growth in oil usage is to be mitigated, other fuels must be used for base-load power. Coal, geothermal and nuclear fuels, the alternative fuels for base-load units, are almost exclusively consumed by utilities.

The supply market for residual fuel oil for utilities is concentrated in the hands of a limited number of large integrated petroleum companies. The effects of horizontal integration by these firms into dominant positions in the holding of geothermal resources is best assessed in light of their position in the petroleum industry--which they dominate at the succession of levels.

Purchasing of Residual Fuel Oil By California Utilities

The three members of the California Power Pool, and the Los Angeles Department of Water and Power have substantial amounts of fossil fuel capacity that will consume increasing amounts of residual fuel oil as gas supplies decrease.

These systems are substantially dependent upon oil-fuel capacity.

Southern California Edison Company (SCE)

The Southern California Edison Company purchased more fuel oil than any other uitlity in 1975, producing 77.9 percent of its kilowatt-hour supplies in steam-electric units.

Seventy-seven percent of SCE generating capacity (12191 Mw) is dependent on gas and oil fuel, 13% on coal and 3% on nuclear fuel. SCE projects 5,900 Mw of additional capacity for commercial operation through 1985, 37% designed to use gas and oil, 20% coal,[22] 42% nuclear fuel and the remaining 1% to be hydro-electric.[23]

SCE received about one-half of its fuel oil requirements from one supplier in 1974. Its 1975 Annual Report indicats that SCE was negotiating a definitive contract with its principal supplier (SOCAL), that reportedly would obligate it to purchase fuel oil, contemplated to be primarily of middle eastern origin, in amount estimated to average 64% of its anticipated fuel oil requirements over a ten-year period commencing in 1976.

SCE anticipated that prices under this contract would be based on Saudi Arabian oil prices, with various adjustments for other factors similar to those under its existing contracts.

SCE is also reported to have entered into a ten-year contract to purchase approximately one-fourth of its fuel-oil requirements from Pertamina.[24]

"This marks the second large long-term fuel-oil contract negotiated by Southern California Edison this year. About 60% of SCE's fuel-oil needs will be filled by Standard Oil of California. SCE Vice President William Seaman says that prices paid to Pertamina will be lower than the Company average price ($15.20/bbl) paid for other fuel-oil but that those savings might be offset by the Standard Oil of Califonria contract prices, which are still being renegotiated."[25]

SCE's 1975 Annual Report states that the ten year contract with Pertamina is expected to provide 19 percent of its fuel needs for that period. In a financial report for the first quarter of 1976, SCE states that it has a long-term commitment through a letter of intent with Standard Oil of California for a minimum sum of $6.4 billion, and total long-term fuel purchase commitments of $7.3 billion.[26]

Pacific Gas and Electric (PG&E) Company

57.2% of PG&E's system net dependable capacity, at July 1975, and 39.8% of the system energy generation in the twelve months ending June 30, 1975, were derived from gas and oil-fueled units.[27]

PG&E's expansion program for the 10 years ahead envisages a 50% increase in capacity owned. Much of this capacity is nuclear. The system will still have a great deal of gas and oil combustion, and continued use of oil-fueled units.

In 1974, PG&E used approximately eleven million barrels of oil, or about one-sixth of the total oil used by California utilities that year. With declining natural gas availability, normal weather, and a normal flow water year, PG&E requirements for 1976 were projected to be approximately thirty million barrels.[28,29]

Fuel costs to the PG&E system have risen dramatically in recent years.[30] The cost of fuel oil rose from $0.49 per million Btu in 1971 to $2.09 per million Btu for the twelve months ending June 30, 1975. During this time, nuclear costs, after declining in 1971 and 1972, have remained flat at $0.20 a million Btu, while the price of natural gas more than doubled between 1971 and 1975.[31]

Table 32 shows PG&E's fuel oil purchases in the second quarter of 1974 and the first quarter of 1975, the latest obtainable period. As can be seen, the Atlantic Richfield Company, Phillips Petroleum, and Perta Oil Marketing (oil from Indonesia, acquired from Pertamina, the state company, and to a limited extent from Peru), supplying together over 72.45% of PG&E residual fuel oil. General Energy Company (a broker) provided over 12 percent; this oil was rather high priced.

PG&E largely purchases its fuel under long-term contracts,[32] e.g. with Arco and Union Oil. Under one agreement PG&E causes crude oil to be delivered (for PG&E's account) to the Pacific Resources refinery in Hawaii, and Pacific Resources in turn provides PG&E with fuel oil. There is evidence that oil prices charged PG&E are kept in line with those charged SCE.

TABLE 32

PG&E FUEL OIL PURCHASES

Second Quarter 1974 and First Quarter 1975

ARCO	4,132,716	44.96%
UNION OIL	438,326	4.78%
PHILLIPS PETROLEUM	1,324,868	14.41%
PACIFIC RESOURCES	432,644	4.71%
PERTA OIL	1,202,615	13.08%
SINGAPORE PETROLEUM	326,522	3.55%
UTILITY PETROLEUM AND REFINING	38,207	0.42%
WESTERN REFINING	150,000	1.63%
GENERAL ENERGY CORPORATION	1,145,796	12.47%
	9,191,694	100.01%

Mr. R.P. Benton, manager of PG&E's fuel procurement activity, testified in a proceeding before the California Public Utility Commission that PG&E has a contract with ARCO, its largest supplier, that runs through 1981, for 750,000 barrels per month.[33] Reduced fuel oil requirements in late 1974 combined with a widening gap between the price paid by PG&E to ARCO and the prices charged by ARCO to Southern California Edison (SCE) and to the Los Angeles Department of Water and Power (LADWP) were stated by the witness to have provided PG&E with a basis upon which it (in March, 1975) temporarily negotiated postponement of any increase in price beyond $12.88 per barrel (which became effective April 1, 1974). ARCO agreed to defer increases to PG&E pending negotiations between it and SCE. Later,he indicated, ARCO informed PG&E that if PG&E would not pay a high price from the point at which it was first intended to become effective, ARCO would terminate the contract and make no deliveries. PG&E acquiesced in paying the higher price. (SCE decided not to enter into a contract with ARCO. A contract for the sale of fuel oil to the LADWP is reported to have been negotiated to have a price of approximately $15.00 a barrel).

PG&E has an agreement with Union Oil Company of California providing for approximately 180,000 barrels per month through 1980.

As with the ARCO agreement, Union Oil obtained an upward renegotiation of the price of its oil supplied PG&E. Union initiated negotiations in June

1974, seeking to raise prices from $8.54 to $12.00 per barrel and 6 months later an additional $2.00 per barrel. After Union stated it would cancel the contract unless its requests for higher prices were acceded to[34] the Union contract was extended for six months to be renegotiated in the second half of 1975.[35] A sharp price increase resulted.

Phillips Petroleum Company supplied residual fuel to PG&E on a month-to-month basis at prices quoted each month ($13.50 at the refinery in March 1975).

PG&E has chartered a fleet of oil tankers, and has become a substantial importer of residual fuel oil.[36]

A large portion of PG&E's residual fuel oil supply is imported directly by the company from Indonesia. Some of this residual oil is purchased from Perta Oil Marketing at a price which has gone down from $15.45 to $13.00 a barrel. Another portion of this oil is obtained in return for crude oil supplied to Pacific Resources in Honolulu.

San Diego Gas and Electric Company (SDG&E)

All of SDG&E's 2,070 megawatts of net dependable capacity as of December 31, 1974, consumed oil or gas. At the beginning of 1975, SDG&E planned, by 1983, to add 456 Mw of nuclear capacity; and 992 Mw of fossil-fuel generation (including 700 Mw of coal-fuel units). It has plans for a nuclear plant with an initial capacity of 900 Mw in 1988, rising to 1,140 mw and has sought permission to build a 292 Mw fossil-fueled plant.

Under a contract with Tesoro Petroleum, SDG&E purchased, in the three years ended September 30, 1975, 3,516,000, 3,371,000, and 3,815,000 barrels of low sulfur resid. These purchases were made under a contract expiring June 1977, which provides for a base price plus adjustments, reflecting Tesoro's raw material costs.[37] The oil supplied by Tesoro apparently comes from Tesoro's Kenai, Alaska refinery.

SD&E has contracted with the HIRI refinery in Hawaii for HIRI to expand its refinery capacity and provide SDG&E with 10 million barrels of oil per year starting in 1977. This is a cost plus fixed price contract in which the refinery's profit will be renegotiated from time to time.

In late 1974, Union Oil entered into a contract to provide several million barrels of oil to SDG&E at $12.00 per barrel. Union, in 1975, was seeking a $2.76 increase in this price. SDG&E has a subsidiary, New Albion, in the fuel business.

Los Angeles Department of Water and Power (LADWP)

The LADWP, while not a member of the California Power Pool, is a major utility system in the state. In the year ending June 30, 1975, LADWP obtained 89% of the energy it generated and 72.3% of the energy it disposed of, from steam-electric units burning oil and gas.[38]

Its planned construction through 1988 consists of a pumped storage unit (1,325 mw), participation shares of 2,027 mw coal plants and 1,846 mw of nuclear.[39]

On February 27, 1975, LADWP said that it expected fuel oil purchases would increase by 95% for the 1975-76 fiscal year. This reflects declining use of natural gas.

In the 1974-75 fiscal year, a long-term contract provided one-third of LADWP's fuel oil, at a cost of about $5.35 a barrel. When the contract expired July 1, 1975, it was expected that almost all oil suppliers would be at current market prices: approximately $15.00 a barrel.[40]

California Utility Fuel Purchasing Power

The large utility consumers of residual fuel oil in California have not been able to employ buying power to hold resid prices down.

While national average delivered oil prices of resid rose 5.5 percent between 1974 and 1975 (from 190.6 cents per MBtu to 201.1 cents per MBtu) California utility fuel prices rose 25.5% (to 250.1 cents per MBtu from 199.3 cents for contract prices). Higher West Coast price increases may reflect the lower sulfur content of resid consumed on the West Coast and West Coast utilities, in this period, were increasing their resid consumption to replace natural gas. However, gas delivery declines were foreseeable, and sulfur content limitations on fuel use did not change. Accordingly, lack (or non-use) of West Coast utility buying power appears to be manifested. Long-term contract arrangements apparently have not prevented rapid price escalation.[41] Whether the limitation of alternatives involved in use of such arrangements contributed to a weak bargaining position is not clear.

Mountain States

Mountain State utilities (including the members of the Intercompany Pool) consume increasing quantities of petroleum. In the Pacific Northwest, Portland General Electric Company (PGE) consumes petroleum distillates in its combusition turbines (824 mw, of which 439 mw are to be converted to add 160 mw of combined cycle capacity).[42]

In the Southwest, Tucson Gas & Electric Company uses gas and oil for 727 of its 1,116 mw of capacity. In 1972, coal accounted for 19% and oil accounted for 12% of its total BTU's consumed with gas accounting for the remaining 69%. By 1975, coal's contribution to Btu consumption had risen to 51% and oil had risen to 33%, while gas had fallen to 16%. During this same period, the cost per million Btu's of coal had risen from 15 cents to 25 cents, oil had risen from 81 cents to 164 cents, and gas had risen from 39 cents to 58 cents. Most of the company's fuel oil is purchased from Southern Union Oil Products Company under a ten-year contract initiated in August 1974. The price under this contract is tied to the cost of crude oil to the refinery which supplies Southern Union. During 1973, 1974 and 1975, the utility received 58%, 47% , and 37%, respectively, of the natural gas it would have used for power generation, if available, from El Paso Natural Gas Co.[43]

Arizona Public Service Company (APS) has also had a sharp rise in its cost of fuel. Of its 2,260.6 Mw of capacity 1,092.7 Mw are fueled by oil and gas. In 1976, APS planned to add 225 megawatts of combined cycle capacity. In 1971, coal accounted for 76.1% of generation and cost 16.15 cents per million Btu's, gas accounted for 23.5% and cost 38.45 cents, and oil accounted for 0.4% and cost 46.63 cents. By September 30, 1975,coal accounted for 79.3% of generation and cost 25.77 cents per million Btu's, gas accounted for 7.7% and cost 74.15 cents, and oil accounted for 13.0% and cost 211.88 cents. APS receives all of its natural gas from El Paso Natural Gas Co. and had residual oil contracts for approximately half of its projected 1976 oil consumption, the balance being acquired on short-term bases, as and when storage capacity and transportation permit.[44]

Public Service Company of Colorado (PSCC) has increased its consumption of oil from 1% of its energy input in 1970 to 4% in 1975. During that period, the price per million Btu's rose from 38.8 cents to 233.4 cents. PSCC's subsidiary, Fuel Resources Development Co., is engaged in the exploration, development and production of gas and oil in Colorado, Wyoming, Utah and Montana, and has entered into a contract in October 1973 with an oil refinery and an exploration company wherein the refinery agreed to make scheduled deliveries of 207 million gallons of No. 2 fuel oil and 56 million gallons of residual fuel oil in exchange for the funding of a crude oil exploration program. PSCC has converted one plant from gas to residual fuel oil.[45]

Refinery Sources of Residual Fuel Oil to the West Coast

The feedstock employed by the West Coast refineries who supply utilities providing about 89 per cent of the fuel oil in 1975 comes from domestic and overseas sources of oil. West Coast refinery yields of resid are significantly higher than national norms.[46]

For PAD District V, in 1975, of the approximately 705.5 million barrels of new supply of crude oil, 310.8 million barrels per day (44.1%) come from foreign fields.[47]

Of the runs to refinery stills in California, 562.5 million barrels during this period, 372.5 million barrels per day (66.2%) were domestic and 191.2 million barrels per day (34%) were foreign oil.[48] 314.6 million barrels were of California origin.

There are a number of planned refinery expansions in California so that locally burned resid is likely to continue to be locally produced. Feedstock for West Coast refineries will come from the North Slope via the TAPS pipeline system, and from fields offshore of California. It appears likely that the percentage share of West Coast refinery feed stock held by imports will decline at least in the short term unless North Slope oil is exported in substantial quantity, or used to displace California production.

Ownership of the potential large new sources of crude, and of related new transport and refining facilities, is generally even more concentrated in major oil companies than existing production.

The large petroleum companies which have long-term fuel supply contracts with West Coast utilities are vertically and diagonally integrated among themselves, and control, individually and in joint agreements, the means of transportation and production of petroleum and natural gas. Their extensive interconnections, in a market with a small number of suppliers, promote parallel action, and give them significant market power. These same firms also own substantial interests in coal, uranium and (for some) geothermal energy.

Domestic Refining on the West Coast (PAD V)

Crude oil refining capacity in District V is characterized, in a recent FTC Staff Report,[49] as moderately highly concentrated[50] in spite of some decline in concentration during the decade ending in 1975. At the beginning of 1975, the four largest refiners accounted for 54.1 percent of District V's refining capacity and the eight largest for 76.5%.

These capacity shares represent apparent declines, over the preceding ten years, of 6.7% for the big four and 10.7% for the big eight.[51]

Concentration in ownership of PAD V refining is shown in Table 33.

TABLE 33

Largest Refining Companies in PAD V

(January 1, 1976)*

Company			Operating Capacity
SOCAL			526,500
Shell			268,400
ARCO			261,000
Union			219,000
Mobil			195,000
Texaco			128,000
Phillips Petroleum**			98,000
Exxon			88,000
			% PAD V
Top 4	TOTAL	1,274,900	55.25
Top 8	TOTAL	1,783,900	77.4
PAD V	TOTAL	2,304,642	

*Source: USBM

**Subsequently sold to Toscopetro pursuant to antitrust decree requiring divestiture.

The FTC Staff report, at page 15, states that throughout the past decade Standard Oil (California) has been the dominant refiner in District 5 with market shares of branded gasoline sales in excess of 20% in every period. Its share has gradually declined over time while the shares of the other top four refiners have remained virtually unchanged.

Concentration in refining may be higher than ownership figures indicate, because some of the small refineries in California may have little freedom as competitors. For instance, the small refinery that was supplying the City of Burbank is completely dependent upon the Atlantic Richfield Company for petroleum and pipelining. Indeed, Burbank had to institute a proceeding before FEA in order to require Arco to continue supplying this refinery so that the refinery could continue to supply the needs of Burbank's municipal power plant.[52]

Future shifts in relative strength may be expected as Phillips Petroleum complies with the Supreme Court's order to divest the Tidewater Oil Company refinery it acquired from Getty Oil. Phillips has agreed to sell the facility to Toscopetro.[53] Exxon's market share may be expected to increase in light of its shares of California off-shore resources and North Slope production, coupled with its indicated plans to expand its California refinery capacity.

New refinery construction in California is wholly through expansion of existing facilities. Crude oil refinery facilities are being built by USA Petroleum Corporation, 15,000 barrels per day; Lunday-Thagard Oil Company, 3,278 barrels a day; and Standard Oil of California, 350,000 barrels a day.[54] SOCAL's expansion is particularly interesting since it clearly reflects marketing expectations influenced by the Trans-Alaskan Pipeline.[55]

Alternate Refinery Sources of Residual Fuel Oil

Residual fuel oil cannot be pipelined for any long distance because of its very high viscosity. It must either be produced near its point of use or else be shipped by tanker or by barge. Thus a West Coast utility must choose between a District V refinery source or a distant, foreign refinery. The choice of a foreign source will be affected by fuel sulphur content restrictions. Table 34 presents West Coast sources of fuel oil.

TABLE 34

WEST COAST (PAD V) IMPORTS OF

LOW SULFUR RESIDUAL FUEL OIL

	1974		1975	
Country of Origin	Amount (000 bbls)	% Total	Amount (000 bbls)	% Total
Bahamas	--	---	949	9.1
Netherlands West Indies	3272	21.4	2930	28.1
Venezuela	4416	28.9	1110*	10.6
Peru	691	4.5	772	7.4
England	--	--	278	2.7
Belgium	--		273	2.7
Saudi Arabia	79	0.5	--	--
Singapore	20	0.1	483	4.6
Indonesia	4910	32.1	2084	20.0
Japan	--	--	1	--
Australia	--	--	1556	14.9
Virgin Islands	1596	10.4	--	--
	15304	100.0	10436	**

* Also, 205,000 bbls of 1% Sulfur content less oil imported

** Not equal to 100% due to rounding off.

The Dutch West Indies sources are most probably the two refineries there, owned respectively by Shell and Exxon, which operate principally on Venezuelan crude oil. The Venezuelan residual may have come from Venezuelan refineries owned by the four major companies, Shell, Standard Oil of California, Mobil or Exxon.[56] It should be noted that two-thirds of the Venezuelan refining capacity is either owned or marketed by Exxon and Shell Oil, and that Gulf, Chevron and Mobil also own substantial Venezuelan capacity. Indonesian residual fuel oil comes in part from Pertamina, the Indonesian national oil company. A number of West Coast refiners participate heavily in production done under contracts with the Indonesian government, from which Pertamina gets its product. They are Standard Oil of California, historically affiliated with Texaco in the Caltex Joint Venture, Shell Oil, Union Oil Company, Atlantic Richfield, Mobil, Exxon, Natomas and Tesoro.[57]

In 1973, Indonesia produced 1,339,000 barrels per day of crude oil. American companies account for about 80 percent of the foreign investment in Indonesian oil. P.T. Caltex Pacific Indonesia (CPI), jointly owned by Standard Oil of California and Texaco, is the biggest foreign producer. CPI production, all onshore and mostly on Sumatra, was 965,000 b/d in 1973. Nearly 410,000 b/d came from CPI's Minas field, the largest single producing field in the country. Other major U.S. companies are Union Oil (off eastern Borneo); Atlantic Richfield (Java Sea); Natomas Company (Java Sea and on Java); Mobil Oil (north Sumatra); and P.T. Stanvac, a consortium of Mobile Oil and Esso (mainly on-shore Sumatra). In addition, numerous American "independent" oil companies operate in Indonesia. Among the more important independents are Carver-Dodge Oil Company, Getty Oil Company, Genard Oil and Gas, Mapco Inc., North Central Oil, Southern Cross Ltd., and South Pacific Oil Company. Mapco, North Central, Southern Cross, and Trend Exploration (U.S.) are partners in drilling in Irian Jaya in a major new venture.[58] The Petroleum Economist reports Indonesian oil production as:

	Million b/d	Caltex only (Million b/d)
1974	1.37	0.90
1975	1.34	0.83

Productive capacity in 1975 was estimated to be 1.5 to 1.6 million b/d.

> "Production by the main producer Caltex, with fields onshore Sumatra, appears to have declined for the second year in succession, the slack being taken up by new producers which include Arco (Ardjuna field,)

Natomas (Cinta), Union Oil/Japex (Attaka), Huffo (Bakale), CFP (Bekapai), Pertamina, and Petromer Trend in Irian Jaya..."[59]

Indonesian production at mid-1976 is shown in Table 35

TABLE 35

Indonesian Production of Crude Oil

(Mid-1976)

Company	Production*
Stanvac** and Caltex***	830,000
Union	130,000
Arco	125,000
Natomas	105,000
Total	91,000
Petromer Trend	65,000
Asamera	14,500
Tesoro	8,000
Cities Service	3,500
AAR	1,150
Pertamina	90,000
Total	1,500,000

Top 4 - 72.3% of total production

Caltex and Stanvac - 55.33% of total production

* Barrels per day

TABLE 35 (Continued)

**Exxon and Mobil

***SOCAL and Texaco

The residual fuel oil imported from Australia probably was produced at one of that country's eleven refineries. Of the 750,935 b/cd of crude input capacity listed for Australia in the International Petroleum Encyclopedia (1974), 262,000 b/d (35%) are owned by Caltex subsidiaries, 153,335 b/cd (20.4%) by BP subsidiaries, 147,000 b/cd (19.6%) by Shell Oil subsidiaries, and 143,600 b/cd (19.1%) by a subsidiary owned jointly by Mobil (65%) and Exxon (35%). Of the other two refineries, one (25,000 b/cd) is owned by a subsidiary of Standard Oil of Indiana, and one (20,000 b/cd) by the Total Oil system - part of the French National CFP company.[60]

Peruvian refining is almost entirely done by Petroperu, using crude from that firm and Belco Petroleum (on the Pacific Coast). Petroperu and Belco are the most likely export sources. Occidental Petroleum has Peruvian crude production shipped out via the Amazon, pending completion of a pipeline west.

Singapore refineries are owned by Exxon, Mobil, Shell and BP.

<u>Petroleum Refining in PAD IV</u>

Because of geographic constraints, the Mountain States of Utah, Wyoming, Montana and Colorado have a number of refineries smaller than those found in Coastal regions.

These refineries are not so situated as to be likely to supply residual oil to the West Coast. Heretofore area utilities have not consumed much resid.

PAD IV refineries use little imported (Canadian) feedstock, and produce far less resid per barrel of crude oil than is the case on the West Coast.

The refineries in PAD IV do produce the No. 2 oil used for (a) diesel generation in small isolated power systems, and (b) peaking gas turbines.

Refinery ownership is rather concentrated for the region; smaller local markets can, of course, be even more concentrated.[61]

Transportation of Crude Oil to Refineries

Producing Residual Fuel Oil

Crude oil moves through pipelines or by water to refineries. Other modes of transportation are far more expensive. The Joint Committee on Public Domain of the California State Legislature conducted an inquiry in 1974 into the crude oil pipelines in California and control of crude oil markets, and it reported that "major oil companies control the California crude oil market by their ownership and control of the crude oil pipelines. This control artificially depresses prices paid to independent producers and restricts the supply of crude oil to the independent refiners."[62]

Transportation can be a significant percentage of total costs at a refinery. The Joint Committee's Report "Crude Oil Pipelines in California", pp. 7-8 reports:[63]

> The pipeline is the cheapest way to move oil over land. The cost of moving oil by pipeline is considerably less than by truck and rail.
>
> The following is a general cost relationship; short haul rates are higher:

	Cents per ton mile
Barges	0.15 to 0.60
Pipelines	0.17 to 0.60
Tank Trucks	3.00 to 5.00
Rail Tank Cars	2.00 to 7.00 [64]

Because of the cost advantage, pipelines have come to occupy a major place in the transportation system. Nationwide, they handle over 75% of the total crude oil tonnage. The cost advantage is important because crude oil is relatively heavy in relation to unit value and transportation can be a significant percentage of the total production cost.[65]

The sources of the 706,848,000 barrels of crude oil input to PAD V refineries in 1975 were (a) intrastate pipelines with 285,563,000 barrels or 40% of inputs;; (b) tankers and barges from overseas 250,632,000 barrels, or 35% inputs, pipeline carriage of 60,203,000 barrels of foreign crude or 9% input; (c) interstate tankers and barges, 46,799,000 barrels; or 7% inputs; (d) interstate pipelines, 6,886,000 barrels or less than 1% inputs; (e) interstate tank cars and trucks, 8,626,000 or over 1% input barrels; (f) intrastate tankers 36,807,000 barrels or about 5% inputs; and intrastate tank cars and trucks, 12,005,000 barrels or about 2% of inputs.[66] Foreign tankers and intrastate pipelines were responsible for approximately equal portions of the supply with over 70% domestic oil moving through intrastate lines.

The FTC Staff Report on the Western Petroleum Industry, and the California Report[67] discuss problems of non-majors in securing pipeline access to markets and supplies, to demonstrate that pipeline access is interrelated with the pricing of crude oil and the ability for government lease tracts. The degree of interconnection is such that even major firms cannot meet their refinery requirements without using pipelines owned by others. Pipelines control field prices for crude.

Three companies post prices paid producers in California.[68] These prices vary only slightly _inter se_.[69] Currently, the price differential for oils of different gravity is disproportionate. While the prices of high gravity (relatively light) crude oils in California are roughly the same as or higher than prices of high gravity crudes in the rest of the United States, large gravity price differentials (relatively large price differentials for increases in crude density), posted in California have resulted in prices for low gravity (relatively heavy) crude below prices for such oil elsewhere in the country.[70]

The inland production areas of California, such as the San Joaquin Valley and inland Los Angeles Basin, are not served by waterways, and pipelines are the only economically feasible method for inland shipping or for interurban transport. FTC Staff Report, page 42.

The crude oil pipeline system is dominated by majors. Except for three lines [71] the system is made up of private carriers rather than common carriers. In this private system, carriage of oil produced by others than the owner of the line is arranged through exchange, or purchase and resale. Crude oil is acquired from laterals by the firms owning trunk lines and resold to the owners of laterals at the trunk line's destination point.

This practice of exchanges is the basis of an integrated transportation system. It is illustrated in the California Report, supra, by reference to a Mobil pipeline linking the San Joaquin Valley and the Los Angeles Basin. The Mobil pipeline connects 34 lines owned by others in the basin. In this system no public tariffs are posted, and independent refineries are forced to purchase oil from majors' pipelines instead of from field producers.[72]

Periodic round robin settlement and clearance of exchange balances among companies reflect the crude supply interrelationships of firms.[73] Control by a few firms of transport may tend to reduce opportunities for transport cost differentials, and for reflecting any favorable supply conditions in sales markets. To the extent exchanges are made by or under the influence of a few dominant firms, opportunities for independent market challenges tend to be reduced.

The FTC states that the four largest companies, ARCO, Standard Oil of California, Union and Shell, control 70.1 percent of crude oil pipeline capacity in District 5; the eight largest companies (the others being Mobil Getty, Texaco, and Gulf) control 98.9 percent. The FTC Report states that it is suspected that these figures reflect the situation of the past 10 years or more. Most California pipelines are intrastate, are not common carriers,[74] and are not regulated. The possible utilization of the pipelines to exclude or limit competition is discussed in the FTC Report.

Crude oil currently coming to California from Alaska - e.g., from the Kenai Peninsula and Cook Inlet--goes to market through the Cook Inlet and the Kenai pipelines. The Cook Inlet Pipeline is jointly owned by

ARCO, Marathon,[75] and Mobil, and Union Oil. The Kenai Pipeline Company is owned by ARCO and SOCAL in even shares.[76] The Trans-Alaskan Pipeline is discussed infra in our section regarding new crude oil supply sources.

On a nationwide basis, it also appears that control of the lines through which crude oil flows provides control over crude oil. Independent producers typically sell their product to the owner of the gathering system serving the field. Through ownership of extensive crude gathering systems, major petroleum companies appear able to control disposition of a large amount of independently produced crude.

Both the Federal Trade Commission Staff and the Department of Justice have found little competition among gathering systems.

In the 1967 Report of the Attorney General regarding the Interstate Oil Compact Commission states:

> ...the field market for crude oil displays all of the indicia of a monopoly market. The physical pipeline connection and the basic division order may be the subject of competition initially, with occasionally real rivalry as to which purchaser-pipeline is to be chosen for the initial connection. But once installed, the expensive physical connections and the complex legal arrangements are long enduring, not easily responsive to supply-demand fluctuations or to price behavior.

Table 37 is a summary of independent crude sales. Commenting on this data, a FTC preliminary staff report states:

> The data indicate that the eight largest firms purchased an average of 42.5 percent of independently produced crude oil during the survey period (average of Table 1, Column 1). In most cases where the eight largest firms purchased crude from independents, they also owned the gathering lines used to transport it (Table 1). Other results of our survey indicate that once gathering lines are erected, there are few other buyers of crude from that particular field. Control of these gathering lines, in addition to ownership of approximately 52 percent of crude sources, gives the eight largest firms substantial control of domestically produced crude oil.[77]

TABLE 37

Independent Crude Producer Summary, 1967-71

	Crude Sales to 8 largest majors as percent of total sales (1)	Crude Sales to other majors as percent of total sales (2)	% of gathering lines operated by 8 largest majors (3)	% of gathering lines operated by other majors (4)
1967------	40.2	25.3	39.3	5.2
1968------	41.5	26.3	40.7	21.7
1969------	42.0	24.8	37.6	3.8
1970------	44.6	27.1	42.0	24.9
1971------	44.4	25.8	36.0	24.8

The report of the Senate Judiciary Committee on the Petroleum Industry Competition Act of 1976[78] refers to a series of statements by industrial personnel to the effect that control of pipelines is second only to ownership of proven and developed acreage in controlling crude oil supply.[79]

Like the gathering systems, the crude trunklines funnel the supply of crude oil to the major integrated firms. Table 38 indicates the extent to which the refining industry depends upon the major's controlled pipelines for crude supply.

TABLE 38

Shipments Originated in Major Oil

Company Pipelines, 1973*

	Million Barrels	Percent
Crude oil lines		
8 largest majors	1,897.4	64.3
8 other majors	442.5	15.0
Joint venture lines**	385.3	13.1
Total, 16 majors	2,725.2	92.4
U.S. Total	2,949.9	100.0

* ICC reporting lines, except Lakehead, Trans-Mountain, and Portland pipeline companies. Volumes exclude shipments received from connecting carriers.

** Lines owned or controlled by groups of 2 or more major companies.

Source: Interstate Commerce Commission, "Transportation Statistics in the United States for the Year Ended December 31, 1973, Pt. 6, Pipelines," 1974, hereinafter cited as "Transportation Statistics: 1973."

In 1973 over 92 percent of the crude oil pipeline shipments reported to the Interstate Commerce Commission originated in lines that were owned or almost completely controlled by the integrated majors.

Common carrier obligations[80] imposed on interstate pipelines are readily avoided: there are no certification procedures and a pipeline company need not jointly plan routes, capacity or operating cycles with non-owners. Likewise, the pipeline company need not and rarely does provide essential tankage. Devices available to a pipeline operator seeking to deny others access to its lines include: requiring large "minimum" tenders, granting irregular shipment dates, and imposing unreasonable "quality" specifications.[81]

Under the Hepburn Act, which imposes common carrier obligations on oil pipelines, a single company-owned pipeline transporting only its own oil is only a common carrier for reporting purposes, and cannot be required to file rates or to transport the oil for others.[82] The Attorney General recently concluded that special conditions to protect competition had to be put in licenses for operation of super-ports and their ancillary pipelines--since "a cursory examination of the ICC's present powers, however, understanding of past ICC regulatory efforts in this area reveal that the ICC cannot effectuate any of these (necessary) competition rules...the ICC has no power over the form of corporate organization, etc."[83]

Under Section 5(c) of the Outer Continental Shelf Act, 43 USC 1334 (c), oil pipeline rights-of-way may be granted by the Secretary of the Interior upon the express condition that such oil pipelines shall transport, or purchase without discrimination, oil produced in the pipeline in such proportionate amounts as the ICC may, after a full hearing due notice, determine to be reasonable.

This clause, providing for something less than common carrier operation, has been avoided by designating offshore lines as "gathering lines", which in effect exempts them.[84]

Levy, and the Petroleum Industry report, p. 27, document the powerful control of production held by OCS pipelines.

Many large pipelines are jointly owned by several petroleum companies. Joint ownership may be corporate or held as "undivided interests." The latter is arranged so that each co-owner files a separate tariff for its proportionate share of a system.[85] A would-be outside shipper must therefore not only seek to coordinate his shipment with the pipeline operating cycles but must also deal separately with co-owners for a portion of their "time-share" of the pipeline's shipping space.

Pipelines have significant economies of scale - so that access to large lines -e.g., joint endeavor ownership - can have a significant competitive impact.

<u>Sources of Crude Oil</u>

The crude oil needed for refinery inputs can come from a variety of sources. These sources, because of transportation mode configurations, vary among different regions.

On a national basis, domestic production comes increasingly from a narrow group of firms. The share of crude oil production of the four, eight and twenty largest firms rose between 1955 and 1974 from 21.2%, 35.9% and 55.7%, respectively, to 33.1%, 54% and 76.9%.[86]

Tables 39 and 40 present sources of crude oil for Western refineries.

TABLE 39

Crude Oil Input to Refineries in PAD V

(1975)

State	Total Input	Intrastate	Interstate	Foreign
California	562,462	313,638	57,988	191,190
Washington	105,792	0	3,683	102,448*
Other States	38,594	20,736	640	17,197
Total	706,848			

* 59,694,000 barrels to Washington refineries in 1975 were Canadian oil shipped by pipeline. These shipments are being rapidly curtailed by the Canadian government, and are likely in the future to be supplanted by Alaskan oil.

TABLE 40

Crude Oil Input to Refineries in PAD IV

(1975)

State	Total Crude Input	Intrastate	Interstate	Foreign*
		(Thousands of Barrels)		
Colorado	16,204	4,498	11,539	162
Montana	42,589	9,766	19,817	12,656
Utah	42,797	17,736	25,082	--
Wyoming	53,805	47,338	3,100	3,567
Total	155,395			

*Canadian oil

Domestic Crude Oil from California

There are seven major producers in California, who produced 53.4 percent of the state's crude oil output in 1974, and a large group of independents. In the older California fields, 13.2 percent of the state output was by unit operation. The 10 largest fields in the state accounted for some 61 percent of state production. They produced 561,692 barrels per day in 1974, down from 580,068 per day in 1973 (63 percent of the 1973 state total).[87]

Crude oil production in California is, and probably will continue to be, moderately concentrated in ownership.

Production shares of the seven major companies operating in California and the independents are shown in Table 41. There has been some shifting from their 1960 positions, owing principally to a decline in ARCO's share, perhaps reflecting ARCO's heavy investment in the North Slope.

Table 41

% California Crude Production

Company	1960	1972	1973	1974	1974	1974
	Percentage Production (b/d)				Production (b/d)	
	%				Unit	Total
ARCO	9.9	3.6	3.7	3.7	13565	33091
MOBIL	6.3	5.6	5.5	5.3	5605	46594
SHELL	8.9	7.6	8.5	8.5	2154	74751
STD. OIL (CA.)	14.0	14.0	13.4	13.2	16626	116971
TEXACO	4.9	4.5	5.0	5.3	4096	47127
GETTY	5.2	10.9	11.3	11.4	14099 (Tidewater)	100363
UNION	9.0	6.6	6.3	6.0	8118	52978
Total Seven Majors	58.2	52.8	53.7	53.4	64263	471879
Independents	41.8	47.2	46.3	46.6	52040	411734
State Total (b/d)	830736	947519	919839	883613	116303	

The exploitation of off-shore resources provides a major portion of domestic oil supply[88] and is expected to produce an even larger portion of future supplies.[89]

Alternate Sources: Offshore of California

The area offshore of Southern California in the federal and, to a lesser degree, the state domain is a potentially rich source of oil. The area off Santa Barbara County is particularly promising.

A review of the prior and recent leases and of drilling platform and mooring facilities indicates that major oil companies, alone and in joint ventures, control this resource. Through control of pipelines, moorings and refineries, major oil companies maintain an advantageous lease-bidding position; they can best afford the high costs and long lead times associated with remote offshore exploration.[90] Since the majors control transportation and refining, any other lessee would be selling them its production.

Ownership of oil tanker mooring facilities in the southern California coastal area has been reported by the Interior Department (1972) as shown in Table 42.

TABLE 42

OIL TANKER MOORING FACILITIES IN

SOUTHERN CALIFORNIA COASTAL AREA*

Operator	Function	Diameter (in.)	Length (ft)	Volume (bbl.)
Phillips	Crude oil loading	10	2,000	200
Getty	Crude oil loading	12	4,800	680
Shell	Crude oil loading	16	2,890	700
Signal**	Crude oil loading	11	2,530	300
Standard	Crude oil & refined	20	2,550	970
	products loading &	10	2,500	240
	unloading (3 ship			
	facility)			
Union	Crude oil loading	10 & 20	9,120	2,050
Getty	Crude oil loading	18	4,300	1,350
So. Calif.				
Edison	Fuel oil unloading	24	4,480	2,520

TABLE 42

(Continued)

Operator	Function	Diameter (in.)	Length (ft)	Volume (bbl.)
Standard	Crude oil & refined products loading & unloading (3 ship facility)	8	5,300	330
		12	7,780	1,090
		14	7,900	1,470
		16	2,100	530
		20	3,200	1,250
		26	7,780	5,100
Gulf	Crude oil unloading	24	5,950	3,320
San Diego G&E	Fuel oil unloading	20	3,000	1,160

* Excluding Los Angeles and Long Beach Harbors; based on Calif. Dept. of Conservation 1971.

**Now Aminoil

Operators of platforms for the production of oil and gas as listed by Interior (1972) are shown in Table 43.

TABLE 43

OFFSHORE PRODUCTION FACILITIES IN SOUTHERN CALIFORNIA

			Oil Pipelines***		
Operator	Facility	Function**	Diameter (in.)	Length (ft)	Volume (bbl)
Phillips	Platform Harry	Crude Oil	6	10,000	330
Texaco	Platform Herman;	Crude Oil	6	12,000	440
	20 ocean floor wells	Flow lines	2-1/2	39,000	200
Texaco	Platform Helen	Crude Oil	6	11,500	420
Atlantic-Richfield	1 ocean floor well	Flow lines	3	22,500	180
Standard-Shell	2 ocean floor wells	Flow lines	3	24,000	Gas Condensed
Standard-Shell	1 ocean floor well	Flow lines	4	13,000	Gas Condensed
Standard-Shell	5 ocean floor wells	Flow lines	4	13,000	Gas Condensed
Phillips-Pauley	4 ocean floor wells	Flow lines	4	57,600	Gas Condensed
Atlantic-Richfield	Platform Holly	Crude oil	6	26,400	960

TABLE 43 (Continued)

Operator	Facility	Function**	Oil Pipelines*** Diameter (in)	Length (ft)	Volume (bbl)
Atlantic-Richfield	3 ocean floor wells	Flow wells	2	34,700	140
Standard	Platform Hilda	Crude oil	6	26,400	960
	Platform Hazel	Crude oil	6	26,400	960
	2 ocean floor wells	Flow lines	4	9,200	130
Union*	Platforms A & B	Crude oil	12	62,000	8,700
Phillips	Platforms Houchin & Hogan	Crude oil	10	32,500	3,150
Standard	Platforms Hope & Heidi	Crude oil	10	21,500	2,090
Atlantic-Richfield	Rinson Island	Crude oil	6	3,000	110
Thums Long Beach Co.	Islands Grissom, White, Chaffee, & Freeman	Crude oil	6	3,700	130
			3	21,300	1,320
			12	20,400	2,860
			14	4,400	840
Humble	Monterey Island	Crude oil	3	8,700	30
Standard	Island Ester	Crude oil	12	8,000	1,120

TABLE 43 (Continued)

Operator	Facility	Function**	Oil Pipelines*** Diameter (in)	Length (ft)	Volume (bbl)
Union	Platform Era	Crude oil	3	18,000	1,120
Signal	Platform Emmy	Crude oil	14	7,000	1,190

Note: While utilities have unloading facilities, these are for fuel oil, not crude. If crude were sold for direct combustion, other products would be foregone and prices would be charged as if for crude.

* The U.S. Geological Survey notes that Operator should read "Union & Sun" and "Facility" should read "Platforms A,B, and Hillhouse".

** Flow lines from Standard-Shell and Phillips-Pauley facilities carry a combination of gas and crude oil (the volumes given are for the crude oil portion only).

***There are other submarine pipelines connecting the offshore production facilities to shore and serving various functions.

While no new producing platforms have been completed since 1972, Exxon is currently erecting one of the world's tallest platforms to exploit one of the three separate fields obligingly combined by Interior as the Santa Ynez "Unit"; and the Union-Socal combine which won the high royalty tracts in December 1975 OCS-35 sale is drilling offshore San Pedro with reportedly good production results.

Leases

The holdings of the 106 oil and gas leases in the Santa Barbara channel area, prior to the December 1975 federal lease sale, are set out in the following Table 44. The top four leasing groups held 53.8% of the leases and the top eight 69 percent. These groups comprised companies that alone and with others held another 27 leases (25%).

TABLE 44

Santa Barbara Channel Oil and Gas Leases

Lessee	No. of Leases	% All Leases
Atlantic Richfield		
Alone	1	0.9%
With Exxon and SOCAL	10	
With Marathon and Getty	1	
With Mobil Oil	2	
With Mobil and Aminoil	1	
With Aminoil	2	
With SOCAL	4	
	21	19.8%
Exxon		
Alone	21	
With Phillips	1	
With SOCAL	18	
With Texaco	1	
With Union Oil	1	
Subtotal	42	39.6%
With ARCO	10	
	52	49%

TABLE 44 (Continued)

Lessee	No. of Leases	% All Leases
Gulf		
With Mobil and Texaco	8	
With Mobil and Union	2	
With Union	1	
	11	10.4%
Others*	12	11.3%
Standard Oil of Calif. (SOCAL)		
Alone	4	3.7%
With Shell Oil	4	
Subtotal	8	7.5%
With ARCO or in group with ARCO	14	
With Exxon	18	
	40	37.7%
Mobil		
With Gulf Oil, Union and Texaco	8	
Union Oil Co. and Gulf Oil	2	

TABLE 44 (Continued)

	No. of Leases	% All Leases
Mobil (Cont.)		
With Union Oil	4	
Subtotal	14	13.2%
With ARCO	3	
Total	17	16%
Shell Oil Co.		
Alone	4	3.7%
With SOCAL	4	
	8	7.5%
Union Oil		
Alone	4	3.7%
With Exxon	1	
With Mobil	14	
	19	17.9%

* These include two leases for Texaco and two for a group consisting of Cities Service, Continental Oil, and Phillips Petroleum, three for a group headed by Ashland Oil and one for a group headed by Marathon Oil

** Data from Departement of Interior, Environmental Statement to proposed Plan of Development, Santa Ynez Unit, Santa Barbara Channel.

TABLE 44 (Continued)

Top four firms, alone and the groups they are in, control	80.1% of leases
Top five firms alone and in groups control	90.5% of leases

Significant segments of offshore production are controlled by joint ventures of the major oil companies: for example, the Santa Ynez[91] Unit's HAS group (Humble (now Exxon), ARCO and SOCAL) and THUMS of Long Beach (Texaco, Humble (Exxon), Union, Mobil and Shell.[92]

On December 11, 1975, leases offshore Southern California were sold at auction. An article in the Wall Street Journal of that date said, "The U.S. Geological Survey has indicated that there may be three billion to five billion barrels of recoverable oil in the area covered by today's lease sale, but the Western Oil and Gas Association, an industry group, has used a working figure of 14 billion barrels."[93] Joint bidding groups headed by Shell had high bids totaling $122.8 million and groups led by SOCAL had high bids of $111.2 million (there was a $105.2 million bid on one tract alone by a group composed of SOCAL (39%), Union (26%), Getty (22%) and Skelly (22%).)[94]

Texaco bid $93.5 million in a two-thirds/one-third venture with Champlin Petroleum; and Exxon bid $29 million to be high bidder on 12 of the 70 tracts bid on.

	Tracts	Bids rejected*
SOCAL alone	6	2
SOCAL-Union Oil	2	2
SOCAL- Getty	2	1

	Tracts	Bids rejected*
Oxoco group	3	
ARCO	11	
EXXON	12	3
Shell Oil	1	
Shell group	6	
Texas-Champlin	5	
Gulf	6	
Mobil group	7	3
Marathon	1	
Challenger Oil & Gas	5	1
Amoco (Std of Ind.)	1	1

*Wall Street Journal, December 22, 1975

As this list shows, the majors will continue to dominate lease holdings offshore of California.

The prevalence of joint enterprises in the development of OCS properties is noted by the FTC staff in their report Concentration Levels and Trends in the Energy Section of the U.S. Economy (1974), p. 42, and by the Senate Judiciary Committee, Petroleum Industry Report, p. 28-32 (1976). In reviewing the joint ownership of federal offshore leases, the Committee noted that:

"Only Shell, Exxon, Standard Oil of California, and Gulf held more than half of their leases independently. Mobil independently held 6 of the 52 leases in which it had an interest; Amoco held 3 out of 60; Arco had 3 out of 94; Cities Service, 1 out of 100; and Getty, 1 out of 119."[95]

Offshore leasing has a longer history in the Gulf than elsewhere, and may thus indicate the ownership patterns that will be characteristic of future offshore development on the West Coast.

The ownership of OCS production capacity from federally leased tracts in the Gulf of Mexico is concentrated while installed productive capacity (MPR) is substantially less than the maximum efficient recovery (MER) rates that production could be maintained at. Table 45 summarizes this information.

TABLE 45

Petroleum

Gulf of Mexico - Federal OCS

January 1, 1976

MER Rank	Firm Operating Leases	Maximum Efficient Recovery Rate (MER) (b/d)	% All OCS Oil MER's	Maximum (MPR) Production Rate	% All OCS Oil MPR's
1	Shell	215108	16.52%	148563	15.56%
2	Exxon	168053	12.91%	138827	14.54%
3	Continental	144414	11.09%	105701	11.07%
4	Chevron	143848	11.05%	145773 (sic)	15.27%
5	Gulf	114427	8.79%	73580	7.71%
6	ARCO	70535	5.42%	35914	3.76%
7	Marathon	63760	4.90%	52895	5.54%
8	Pennzoil	60080	4.61%	49839	5.22%
	TOTAL		75.29%		78.67%
	Total of all lessees*	1302040		954736	

TABLE 45

(Continued)

Source: USGS, Metairie, Louisiana, List of Approved Maximum Efficient Rates for Reservoirs and Maximum Production Rates (January 16, 1976)

* Other lessees include Union Oil (34147 b/d MER), Mobil (41145 b/d MER), Amoco (36220 b/d MER), Texaco (32514 b/d MER), Tenneco (42896 b/d MER), and Citgo (6190 b/d MER), Sun (3960 b/d MER), and Burmah (4440 b/d MER).

Alternative Sources of Crude Oil: PAD District IV

PAD District IV, the Rocky Mountain States, is largely self-sufficient. The FTC Staff Report indicates that the top four producers in District IV, Standard Oil of California, Standard Oil of Indiana, Shell, and Marathon accounted for 36.7 percent of production; and the top eight companies accounted for 54.5 percent. The report states that these data show a moderatly concentrated crude oil industry.[96]

District IV is not likely to provide a competitive source of oil supply for District V.[97] On the contrary, given the overwhelming quantity of Alaskan production, oil flows are likely to be to the East.

Alternative Sources: Oil From the Alaskan Arctic

The onset of deliveries of local oil through the Trans-Alaska pipeline from Alaska's North Slope region could herald a great change in West Coast patterns of petroleum supply.

The Alaskan North Slope in the Prudhoe Bay area is believed to hold as much as one-third of domestic oil reserves. Production could run to 22 million barrels per day from presently known resources. The Trans-Alaska Pipeline (TAPS), delivering this oil, is planned to be able to ship two million barrels per day in 1982.[98]

Production levels ultimately could rise to over five million barrels per day.[99]

Forecasts of crude oil production vary among enterprises and are shown in Table 46.

TABLE 46

Current and Future Crude Oil Production in PAD V

(Responses in mmb/d)

Respondent	Current	1978	1980		1985
Interior	1.06				
FEA	1.07	1.334	1.708		1.928-2.328
FPC*		1.679	2.565		3.490
Exxon	1.074	2.3	2.7		4.1**
Sohio	1.076	1.2-1.4	1.4	1982 1.3	***

* Based upon data supplied by Sohio

** Include a substantial volume of crude from yet to be discovered reserves and must be viewed as speculative.

***Have not attempted to forecast beyond 1982 since so many unpredictable variables would have to be considered.

Most of the oil in Prudhoe Bay appears to be owned, in proportions still subject to the outcome of the unitization discussions, by Standard Oil of Ohio (British Petroleum), Atlantic Richfield, and Exxon.[100] These utilization discussions have been taking place privately among these major firms. They envisage operation of the North Slope fields as a single coordinated unit with two operators planning production with and for the other lease holders. The single unit is curious as the North Slope appears to be composed of a number of pools and fields; moreover, the draft unitization agreement submitted to the State of Alaska does not specify how the shares of the companies in the unit are to be developed.

With the opening of the TAPS line, Standard Oil of Ohio (Sohio), a new entrant into western production will become the leading District V crude oil producer. However, the precentages of District V crude controlled by the top four crude producers may rise sharply. Moreover, since Sohio will be controlled by British Petroleum (BP), for many years the world's largest crude oil producer, this "new entrant" may not significantly alter the crude supply rules.[101]

According to FTC, in 1978 Sohio will have 29.9% of District V crude oil production, ARCO, 14.1%; Exxon, 11.7%; Texaco, 2.9%; and Aminoil (Burmah), 2.7%.[102] This would result in a decline in the production shares of the current top four companies on the West Coast. Aminoil 's share would decline from 5.6% to 2%, Getty's from 9.3% to 3.2%, and Shell's from 9.9% to 3.5%. Sohio's would go from 0 to 32% while Standard Oil of California's would decline from 15.1% to 5.3%.

Sohio is reported to estimated that it owns 53 to 54 percent of North Slope leases. [103]

TAPS

The effect of North Slope oil on West Coast fuel markets could be conditioned by how the TAPS line operates. Although TAPS is required to operate as a common carrier, it may not be subject to federal pipeline rate regulation.[104] TheTAPS system will be jointly owned with each owner separately filing a tariff with respect to its time-cycle share of TAPS capacity.[105] This means that there is no central pipeline company to which outside shippers may tender oil for shipment on this line. Rather, they will have to go to a particular owner's pipeline operating division to arrange transportation. If the potential shipment is large, it is easily conceivable that the outsider would have to make separate tender arrangements with each of the owners. Even with federal pipeline rate jurisdiction, joint tariff divisions would not be revealed.[106] The ownership of the Trans-Alaskan pipeline system is set out in Table 47.

TABLE 47

TAPS - PRESENT OWNERSHIP

Party	Percentage of Ownership	Design Capacity (Bbls/Day)
ARCO Pipe Line Company		
(formerly Atlantic Pipe Line Co.)	21.00%	252,000
Sohio Pipe Line Company*		
(formerly BP Pipe Line Corporation)	33.34	400,080
Exxon Pipeline Company		
(formerly Humble Pipe Line Company	20.00	240,000
Amerada Hess Corporation	1.50	18,000
Mobil Alaska Pipeline Company		
(formerly Mobil Pipe Line Co.)	5.00	60,000
Phillips Petroleum Company	1.66	19,920
Union Alaska Pipeline Company		
(formerly Union Oil Company of California)	1.66	19,920
BP Pipelines Inc. *	15.84	190,080
TOTALS	100.00%	1,200,000

TABLE 47

(Continued)

*With respect to the period from July 8 through July 16, 1974, Sohio Pipeline Company's and BP Pipelines Inc.'s percentages of Ownership and barrels of Design Capacity set forth above were held by Sohio Pipeline Company.

Source: Federal Trade Commission

There does not appear to be any governmental authority to require expansion of the TAPS line; and producers may become reluctant to increase production at a rate which would put downward pressure on crude oil prices.[107]

The ownership, operation, construction and expansion of TAPS are governed by the basic agreement among the co-owners, the "Trans-Alaska Pipeline System Agreement" dated August 27, 1970. By the agreement, the line is designed to permit expansion of capacity to approximately two million barrels per day. Article I.

A separate agreement for design and construction was signed, and a construction committee provided to oversee this work. Each owner obtained one representative in the committee, and ARCO, Exxon and Sohio/BP each obtained a second, in apparent recognition of their majority ownership of both the line and its shipping source.

Pipeline and terminal tankage capacity ownership is allocated to owners in porportion to each undivided interest in the project. Article III.

Sohio has proposed to build a port facility in Southern California to receive Alaskan oil. The port is proposed as a common carrier, able to handle petroleum greatly in excess of Sohio's allotment of North Slope production.[108] It also would be equipped to load, as well as unload, crude oil. Mr. Garibaldi of Sohio, briefing the California State Energy Conservation and Development Commission on November 19, 1975, indicated that an underlying reason for plans for a port larger than Sohio needs for itself alone is to "provide a system which can move the surplus oil off the West Coast, not necessarily to move our oil off the West Coast."[109]

Sohio proposes to ship 500,000 b/d of oil east to Texas and the Middle West, utilizing pipeline capacity that would be retired from interstate gas service for the purpose.[110] Use of the line will reduce the possibility of additional natural gas entering West Coast fuel markets.

The firms producing North Slope oil have not been required to disclose their marketing plans, and the firms owning and expanding West Coast refinery capacity have not been required to disclose what refining feedstock they plan to use, and what feedstock they could employ.

If the West Coast refiners do not arrange to run North Slope crude they may be "forced" to continue to import oil, and North Slope oil might either be delivered at high prices to other U.S. destinations, or it just might be sent to Japan, while imports from the Middle East into Atlantic coastal states rise.[111]

This fortuitous set of circumstances happens to be an excellent way of assuring the "stability" of OPEC oil prices in both West Coast and world oil markets, while avoiding local gluts of crude supply.[112]

Petroleum from the TAPS system will not totally displace foreign oil.

In Washington State, while ARCO will use Alaskan oil in its 100,000 bbl/d refinery, designed expressly for such feedstock, other refiners including Shell, Texaco and Mobil are reported to have indicated that they will not be using substantial quantities of Prudhoe Bay Crude.[113] However, Canadian exports of oil are declining, and FEA is allocating such exports to the upper middle west. Accordingly, Alaskan oil may be used by Washington refiners to replace Canadian supplies (188,899 b/d in 1974).[114]

The situation for the North Slope appears to be that while eleven companies have concessions in the Prudhoe Bay Field, nine-tenths of the oil is owned by three groups - BP/SOHIO, Exxon and ARCO. TAPS flow is to reach 1.2 million b/d by the end of 1977; the capacity is likely to be raised to 1.6 million b/d and then to 2 million b/d (about 1980). This two million b/d figure compares with west coast oil consumption which will reach 2.8 million b/d in 1980[115] if it rises by some 5 percent per year.

Considering California production of about 1.2 million b/d, other Alaskan production of 0.2 million b/d and estimated imports of 0.2 million b/d,[116] a surplus of 0.8 to 1.3 million b/d might occur in PAD V.

Of the three main North Slope producers, BP/Sohio has no West Coast refineries and apparently will be selling or exchanging that portion of its production (which will total almost one million barrels per day) to be refined on the West Coast. Exxon's surplus will reach 300,000 to 400,000 barrels, ARCO will be in balance, and the State of Alaska, after present commitments to Tesoro are met, will have a supply of 250,000 barrels per day.

ARCO crude oil (up to 120,000 b/d) may be available, by contract, to Southern California Edison.

Control of the TAPS line by a few companies with a large interest in maintaining high prices in the U.S. makes unlikely an expansion of this line at a size likely to lead to major price effects on the West Coast, or a major change in refining and marketing from the positions outlined here.

Alternative Sources: Foreign Oil

Foreign oil is supplied to the West Coast chiefly by Indonesia the largest supplier, Iran, Canada, and Saudi Arabia, with lesser amounts of production from countries such as Ecuador. Table 47 provides sources.

In general, production in these countries has been under joint ventures, or concessions controlled by major oil companies. The pattern has been shifting toward country ownership of fields, with the former concession holders having "off-take" agreements, and sometimes field operating agreements. "Off-take", or preferential access agreements, often give the oil company involved access to the bulk (90%+) of the oil it formerly produced (as owner or concession owner), at a rate price lower than that available to others. The avails of price increases are, in most cases, split between the owning country and the marketer. See our discussion of foreign residual fuel oil sources, supra.

TABLE 47

IMPORTS OF FOREIGN CRUDE OIL*

TO PAD DISTRICT V, 1975

Country of Origin	Thousands of Barrels
Algeria	399
Bolivia	1,940
Canada**	59,694
Ecuador	19,219
Indonesia	107,820
Iran	38,398
Libya	2,685
Malaysia	1,951
Nigeria	5,025
Oman	492
Qatar	3,989
Saudi Arabia	34,901
United Arab Emirates	18,217
Venzuela	16,105
TOTAL	310,385

* Reported to the Bureau of Mines

** The Canadian Government has declared its intention to curtail oil exports from Canada and has imposed heavy export duties.

Vertical Integration

The petroleum industry in California is substantially integrated with six firms being among the top eight enterprises at all levels. Standard Oil of California, Union Oil of California , Shell Oil and Atlantic-Richfield (ARCO) constitute the top four firms at each level (save production, in which ARCO is sixth).[117]

This same vertical integration is present througout the American oil industry, with integrated enterprises in control of pipelines, and as joint venture partners with each other and independent firms, increasingly controlling crude oil production.

Independent refiners are dependent upon these enterprises both for feedstock and for marketing products via sales and exchanges.

The major petroleum firms' control of successive stages of production in California is coupled with their control of alternative petroleum sources.

This vertical control of essential facilities is exercised through a system of coordinated operations among larger oil companies. Production and transportation of crude oil and refined products are scheduled in an interdependent manner. This is required by and accomplished through exchanges and joint enterprises. This interdependence leads to common problems and, in some instances, common outlooks.

The larger petroleum companies have a vested interest in high crude prices. They have preferred access to OPEC oil (through participation agreements in which they receive a share of price rises, in itself an incentive for price maintenance), and they have non-OPEC crude oil assets whose value is tied to the price of oil. This provides an important incentive for maintaining price.

Dominating refining and transportation, they can assure markets for their own and OPEC's high priced crude without fear of being undersold in substantial volume. By controlling and balancing off-takes from OPEC countries they pro-ration production to prevent supply gluts which could lead to price cuts.[118] Other firms, lacking large oil supplies, cannot substantially expand sales by price cutting and can find markets for their output at cartel prices, if and for as long as the large firms are pro-rationing OPEC production.

OPEC-country production capacity is currently worked at about 75% of capability. Lower production rates would put pressure on prices. The OPEC countries have never been able to agree on production levels for member states.[119] Major oil companies spread production.

Here a major question of international market structure and operation is presented. The production control necessary for OPEC prices is maintained perhaps in part, by OPEC member tacit consent, and definitely through major oil company concord in the off-take arrangements. To the extent that OPEC's control of prices depends upon the preferred areas given to major firms who are horizontally linked and integrated vertically, OPEC prices could not be maintained, should the oil company network break down.

If the oil industry were more diverse, with fewer joint enterprises, and more independent channels available for bidding on and taking OPEC crude, the price and supply of oil would be much more competitive.[120]

Professor M.A. Adelman of M.I.T, has suggested that a community of interest between the OPEC governments and major oil companies is partially responsible for a failure in realizing more competitive conditions in international oil markets.

As evidenced in the Attorney General's Deepwater Port report, similar efforts are made by major firms to restrict new supply in domestic markets. Plans for North Slope utilization, the Trans Alaska Pipeline System, and the subsequent distribution of North Slope oil have been made by the three large vertically integrated enterprises who own, jointly, that large increment to domestic supply. These companies will be entering into joint arrangements with other major oil companies in the West, enabling them to prevent destabilization of the market.[121] The extensive ties among financial institutions and larger petroleum companies make competitive capital formation less likely as is set forth in our financing appendix.

The control of incremental supply increases at the production and pipeline level will be jointly determined by these firms. That control, leveraged forward by vertical integration, creates the capability to effectively limit energy supply to maintain or raise its price.[122]

Natural Gas

In California and the Southwest, for many years large amounts of interruptible natural gas were burned as a principal utility fuel. The sharp decline in gas supply has resulted in substantially increased consumption of residual fuel oil in utility boilers and increased use of electric energy for space heating.[123]

Utilities in California have been supplied by three interstate gas pipelines,[124] and to a smaller extent by indigenous production.[125]

A fourth interstate pipeline which served California was acquired by its major competitor. Although suit was filed in 1957 to bar this merger, the subsequent proceedings were prolonged. Divestiture did not occur until February 1974 when the Northwest Energy Company acquired the Northwest Pipeline Corporation from El Paso.

In the intervening years, the two lines to Southern California, El Paso and Transwestern, alternatively expanded their pipeline capacity in a load growth sharing "minuet" while the FPC refused to certify a proposed pipeline ("PEMEX") intended to transport gas for electric utilities.[126]

The Pacific Gas Transmission (PGT) Company imports Canadian natural gas which it supplies to its parent, Pacific Gas and Electric (PG&E) Company[127] in Northern California. This gas is acquired from Alberta producers by a second PG&E subsidiary, the Alberta Southern Gas Company, which also arranges for transportation over lines owned in part by an El Paso subsidiary.

During the Federal Power Commission proceedings for the certification of the El Paso and Transwestern Pipelines, concern was voiced about the supplies of gas of these systems. This concern has proved justified.

In United States v El Paso Natural Gas Company, the court stated that:

> Presently, neither El Paso nor any of the applicates for acquisition have gas supplies available to serve any part of the unsupplied demands of the California market. ...competition among suppliers to serve the incremental demands of the California market no longer exists. 358 F. Supp. 820, 827 (D. Colo., 1972).

Intrastate Gas in California

California utilities obtain dry gas produced in northern California, and wet gas produced in conjunction with oil and natural gas liquids, in southern California.[128]

Except for limited competition from Dow Chemical, PG&E is the sole purchaser of gas in northern California. The price has risen in a few years from 30 cents to the current level of 75 cents per mcf, and production has declined.[129] PG&E's great market power in northern California gas fields is demonstrated by its ability to schedule deliveries from those fields only for its higher load periods. Contracts with gas producers provide for deliveries at the lower of (a) one-twentieth of field gas reserves or of (b) the installed production capacity of the field or well.[130] Contracts require that the buyer pay the producer for a contracted-for amount, or proportion of capacity, whether he takes that amount of gas or not.[131] Individual contracts may vary according to whether PG&E or the producer owns the gathering lines.

Future gas supplies may be expected to come from utility gas exploration ventures, and from novel use of liquefied and synthetic natural gas.

"Natural" gas from SNG,[132] LNG and Alaskan sources is likely to cost more than two dollars per mBtu, and will in some cases be priced with direct reference to the cost of foreign oil.[133] The possibility of high prices, plus the need to find gas to fill their pipeline systems has

has attracted California gas utilities, including PG&E and San Diego Gas & Electric, into the petroleum exploration business. The management of PG&E must also now contend with problems involved in the importation of LNG from Indonesia, and the construction of systems to transport gas from the North Slope.[134]

Currently there are plans to reduce the availability of gas pipeline capacity to California. The El Paso Natural Gas Company has requested the FPC to allow it to abandon gas service on 669.4 miles of large diameter pipeline and to transfer this line to a new subsidiary, apparently outside the FPC's jurisdiction. The new subsidiary would lease the facilities to Sohio, who would convert the line to carry oil from west (California) to east (Midland, Texas), where it would join lines to the Middle West. El Paso asserts that its gas supply is depleted and that an oil route into the Middle West would avoid a glut of crude oil on the West Coast, expected after the Trans-Alaskan Pipeline begins operation.

The leasing of facilities is divided into two phases, the second of which would require abandonment of gas service on additional portions of El Paso's system.

Rising gas prices and curtailments encourage utility diversification of power supply sources. They also, however, may encourage speculative withholding, "hedging" of fuel supplies and employment of tariff rates designed to obtain customer financing for energy exploration and development by established utilities - and their joint venture partners.

Coal

Coal is the major factor in U.S. utility fuel supplies. The mines, plants and transmission grids employed in coal-fired projects are and will be very large, and quite limited in number.[135] The pattern of ownership and control of coal resources will affect the rate at which coal resources are made available to customers. This pattern also will, among other things, affect the state of competition in the industry--and thus the interaction of coal prices with other fuel prices.

The pattern of coal ownership could conceivably have several different effects on development of geothermal energy:

(a) if owners of both coal mines and geothermal energy sites. perceive opportunity costs in those other holdings if cheaper geothermal energy sources are developed, they might wish to "warehouse" the geothermal sites; or

(b) if the coal owners with geothermal resources have sufficient market power to preclude utility development of alternative fuels, they could retard geothermal development; or

(c) if, but for ownership patterns, the state of competition and costs in the coal market would be such as to reduce coal prices to levels producing significant development of geothermal energy, noncompetitive ownership of coal could foster geothermal development.

The Western Coal Resources

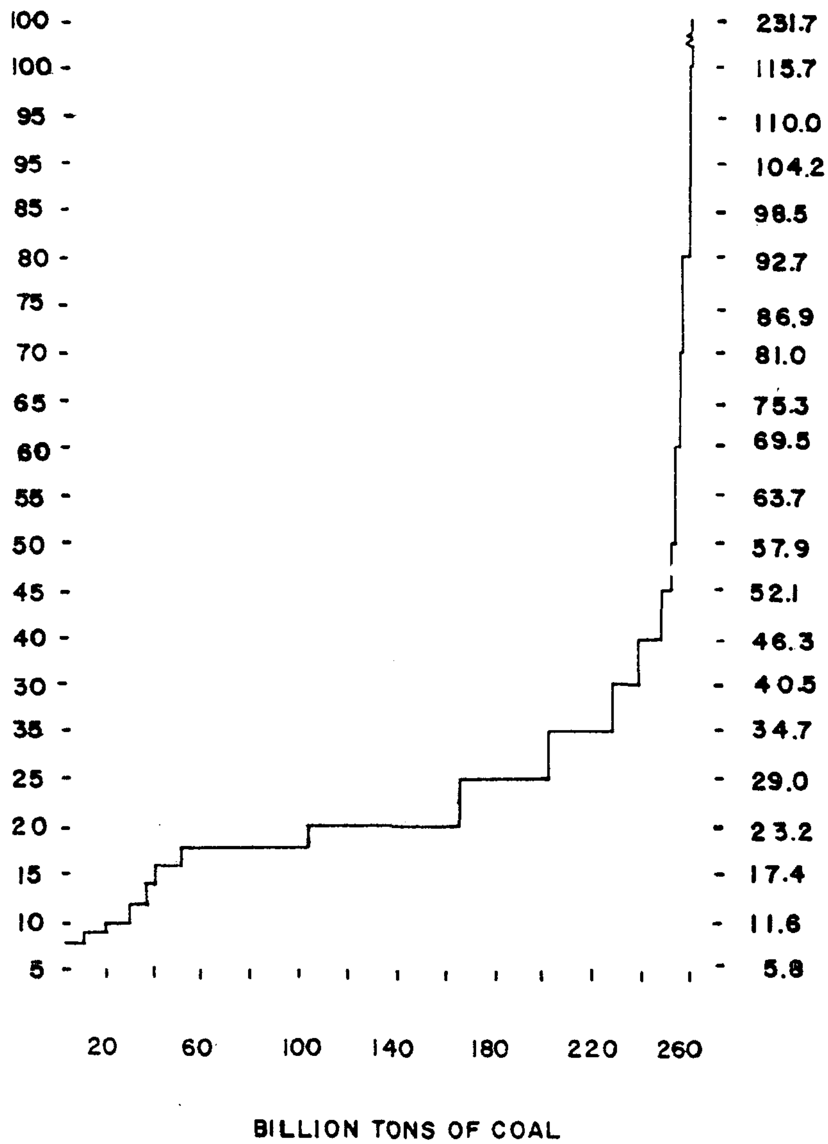
Coal deposits in the Pacific Coast states tend to be small and scattered.[136] Plans for coal generation by West Coast utilities generally involve coal from the Rocky Mountain province which contains an abundance and a greater variety of coal than any other province in the United States.[137] One plant[138] is proposed to be expanded for the Northern Great Plains Basin[139] (at Colstrip, Montana).

The tremendous coal reserves in the Northern Great Plains basin will initially serve mainly eastern utilities.[140] Coal energy from this basin (additional to that from the Colstrip plant) could potentially enter Western utility fuel markets, but this seems unlikely until Rocky Mountain Basin deposits have first been developed.

To determine the amount of coal that could be provided to Western utilities at different levels of costs (including a reasonable profit) we have had the Battelle Pacific Northwest Laboratories prepare figure 19 which shows the tonnage of coal that could be forthcoming at ascending costs

(1976 dollars) assuming physical delivery of the coal at a California point.

FIG. 16 SUPPLY CURVE OF COAL MINED IN THE WEST DELIVERED TO THE WESTERN U.S. (CENTRAL CALIFORNIA)



Notes to Figure 16

*Note to Charts

The delivered costs of coal are approximated on the supply curves for each state (using a distance, as was done for rail transport, that is from the "eyeball centroid of state coal areas to Central California".)

Rail transportation costs to Central California are shown below.

COAL AT MINE MOUTH = COAL DELIVERED-TRANSPORT

TRANSPORT = MILES . Rate

	MILES	RATE	(Rate x miles) TRANSPORTATION COSTS
Montana	1013.5	5.6654 mills/ton-mile	$5.7419
Colorado	979.4	5.7823 "	$5.663
Utah	681.7	6.7823 "	$4.170
New Mexico	876.5	6.0782 "	$5.328
Wyoming	944.4	5.848 "	$5.523

Notes to Figure 16

As an illustration, the data from the chart regarding Montana coal is arranged below

MONTANA

Millions Tons Available	Cost in California of $ or less	x Mine Cost of $ or less per ton
8610	9.00	3.26
18465	10.00	4.75
27979	12.00	6.26

Coal costs reflect fuel quantity

$3.26 per ton coal at 8000 btu/lb. costs 20.4 ¢/mbtu

9000 btu/lb. costs 18.1 ¢/mbtu

10000 btu/lb. costs 16.3 ¢/mbtu

At plant costs of 15 mills, and operating costs of 3.3 mills, (ERDA, "The Economics of Nuclear Power.") burning Montana coal would provide power at about 25-30 mills at the busbar in California. For nuclear power to meet this price, plant costs must not exceed $620 to $850 per kilowatt.

Notes to Figure 16

The translation from cents per million BTU for coal to mills per kilowatt-hour varies with the efficiency of conversion of coal to electricity (e.g., the heat rate of a generating unit expressed as Btu's per kilowatt-hour). The heat rate tends to decline as the size of coal unit increases. Power Technologies, Inc., recently reported coal-fired unit heat rates:

Size (MW)	Full Load Unit Heat Rate Btu/kWh	Average Unit Heat Rate Btu/kWh
500	8,830	9,700
700	8,780	9,605
1000	8,550	9,350
1500	8,700	9,350

At a heat rate of 9350 Btu/kwh, and rail rates of 9 mills per ton mile for 16 MM Btu per ton coal, transportation costs are 0.5625 mills per MM Btu per mile. At 11 mills/ton mile and 21.4 MM Btu/ton coal, the costs are 0.514 mills/MM Btu mile. For each 100 miles, haul costs are about 0.5 mills per kwh by train.

Prices may diverge from a cost-based competitive level.[141] Costs present reflect neither the unique start-up costs that would be encountered were coal mining to increase sharply, nor the future inflation that may be experienced as new mines are opened.

The selling price of western strip mined coal is expected to be lower than underground coal mine prices. A recent Bureau publication, noting the lower heat content and the shallow, thick seams of Western coal (e.g., averaging 55 feet in the Powder River Basin), quotes costs of $3.00 to $5.00 per ton (equivalent to about 17 to 28 cents per million Btu for 9,000 Btu/lb. heat content coal[142])).

While capital costs for western mines are lower per ton, they are large per mine.[143] With increases in required investment levels, participation by small producers is deterred.[144] and only firms with revenues in the hundreds of millions per year, such as Kennecott Copper Corporation, could be expected to be major new entrants. A court has upheld Federal Trade Commission findings that coal mining the the United States is becoming increasingly concentrated, partly as a result of increased capital cost requirements.[145]

Transportation Factors

Transportation charges can represent a sizeable portion of the delivered cost of coal, and are an important factor in the definition of coal markets.[146] The major alternative means of moving the energy in coal to western markets are by rail, usually, "unit trains", and transmission of electricity from a mine-mouth plant. Coal slurry pipelines have been proposed as a third major alternative.

The ICC discusses western coal shipments by rail in a recent report:[147]
The western mines are diverse geographically and generally the coal, in order to reach its markets, must be hauled via rail greater distances than in the east or south. For example, Burlington Northern's average haul per ton for 1973 was in excess of 525 miles. Its longest trainload haul was 1,430 miles. The unit-train concept has provided a means to effectively market western coal which, by 1980, could very well reach 150,000,000 tons per year or more.
Definite marketing territories for western coal are difficult to define because of varying influences in the present continuously changing market. Generally, western coal moves or will move into the territory east of the Mississippi because of its low sulfur content rather than a lower delivered price than for midwestern coal. This marketing boundary appears, however, to be expanding. Ibid.

Unit-train or trainload coal traffic in the West for the most part originates at a single mine and terminates at a single location.[148]

The scope of possibilities for coal slurry pipeline is not yet well determined. Only one major line in the West is now in existence. Costs relative to rail are not entirely clear. Several plans are in existence, but most seem tentative.

Reflecting air quality control restraints there is a clear tendency to use long distance transmission of electric energy generated at mine-mouth to serve the west coast. Large sources of coal are also planned to be used for coal gasification. Because of the distance to California, inter-mountain coal-fueled generation will require a long haul over high voltage transmission to coast markets[149] from southwest and Wyoming plants. High voltage lines are also projected to run from Montana coal-field plants to the Pacific Northwest.[150]

The costs of high voltage alternating current transmission must be determined with the aid of a load flow study (which considers how the flow is transported over parallel lines of varying impedence).

It is estimated that lines of 500 kv capacity will cost $280,000 to $3,000,000 per line mile, and that energy losses will run from 10% to 20% on extra long lines (600-800 miles). It is generally understood in the trade that at least 1000 Megawatts of capacity must be shipped to justify long distance transportation.[152]

Recent Battelle figures give unit energy transport costs (in mills per kwh per 100 miles) of up to:

0.3 - 0.36	for 700 kv
0.36- 0.48	for 500 kv
0.48- 0.66	for 345 kv
0.66- 0.9	for 200 kv

Battelle estimates a 765 kv line to cost $300,000 per mile in 1980.[153] These estimates agree reasonably closely with FPC figures. Transmission costs will vary with the distance hauled and the line voltages at which transmission occurs.[154]

Wheeling charges for firm service are normally quoted in terms of dollars per kilowatt.[155] Such charges may be readily converted into charges per kilowatt-hour by dividing the charge per kilowatt of transmission per year by the hours used (24 X 365 X Usage Factor).

In the Bonneville area, charges for short-term (one year) wheeling arrrangements range from 0.5 to 1.25 mills per kwh (5-9% line losses).

At high load factors, costs may be expected to be between $5 and $10 per kilowatt per year over a few hundred miles, or 0.5 to 1 mill per kwh with rates running about 20 percent more on private grids.[156]

These substantial capital costs for new transmission lines will set coal-by-wire prices, and they indicate that geothermal generating units must be located either near load centers or near high voltage lines. Because even large geothermal fields may be expected to be delineated and developed gradually, it is unlikely that new very high voltage lines will be built for substantial distances to serve such development. The new line capacity cost is too great.

However, given available pre-existing line capacity and conditions permitting it, power could be wheeled from geothermal units.

The addition of one or two mills to the deliverd cost to cover transmission losses would permit base-load geothermal energy to be transmitted 400-800+ miles (80% load factor) at Bonneville Power Administration rates, and 320-600+ miles at rates 20% higher over pre-existing lines.

The Pacific Northwest has a well-developed high voltage grid system which facilitates shipment of output from coal-fueled plants, such as those in Montana, to West Coast markets.[156]

Finally some have suggested processing coal into a synthetic crude oil, "syncrude". Pipeline transportation costs (and conditions in alternate markets) would largely determine where synthetic crude oil would be sold.

A 1974 study of Syncrude[157] markets, which used netback prices based on the price of petroleum in various markets, indicates that Syncrude from the Eastern Slope and even from the Four Corners area may command a higher price in the east. Syncrude brought south from Colorado would flow east using presently installed excess crude pipeline capacity; lesser amounts could flow to southern California, via the Four Corners pipeline[158] to compete with Alaskan crude oil.

Ownership of Coal

The Federal Domain

The United States is reported to own 50.5% of the coal acreage and 23% of the mapped and explored recoverable coal reserves in seven states -- Colorado, Montana, New Mexico, North Dakota, Oklahoma, Utah, and Wyoming.[159] These states in turn contain 53% of the nation's reserves.[160] Federally owned reserves, as a percentage of total recoverable reserves, are 59% in New Mexico, 82% in Utah, and 48% in Wyoming.[161]

Federal coal lands are developed by leasing to private parties. As stated in the Interior Department's Final Environmental Impact Statement: Proposed Federal Coal Leasing Program:

> Federal Coal until recently has not been a major part of overall coal supply. Federal production has been approximately 1 percent of total production. Federal ownership of the coal resource in the West is approximately 60 percent but because of

ownership patterns, Federal policy influences upwards of 80 percent of western coal. Federal coal is, therefore, inseparably tied to overall western coal development, p. 1-2. 7a.

Despite these facts, coal production from Federal leaseholds totaled only 21% of western state production in 1971. Prodution from federal leaseholds in the west, although increasing, did not keep pace with overall growth of the western coal industry between 1960 and 1972. Table 48 shows the extent of Federal ownership of coal lands.

TABLE 48

STATES WITH MAJOR FEDERAL COAL ACREAGES

	FEDERAL COAL * **		NON FEDERAL COAL		Total ***
	Million Acres	Percent	Million Acres	Percent	Million Acres
Alaska	23.4	97	.8	3	24.2
Colorado	8.7	53	7.9	47	16.6
Montana	24.6	75	8.2	25	32.8
New Mexico	5.5	59	3.9	41	9.4
North Dakota	5.6	25	16.8	75	22.4
Oklahoma	.4	4	8.9	96	9.3
Utah	4.1	82	.9	18	5.0
Wyoming	11.8	65	10.7	35	30.5
Totals	92.1		58.1		150.2

*Southwestern Energy Study, Appendix J, p. 48, 1972

**BLM State Office Estimates

*** Averitt, Paul, Coal Resources of the U.S., January 1, 1967:

TABLE 48

(Continued)

U.S. Geological Survey Bulletin, p. 32, (1969)

Source: Interior Department Final Environmental Impact Statement on Federal Coal Leasing Program.

The recently lifted Interior Department moratorium and the courts have both limited new coal lands leasing and development. However, a large number of outstanding leases have not been developed, as Table 49 shows, and development plans for much leased acreage is absent or leisurely.

TABLE 49

FEDERAL COAL LEASES - 1973

State	Number Leases	Number Producing* Strip	Underground
North Dakota	24	9	
Montana	18	5	
Utah	195		17
Wyoming	94	10	3
New Mexico	28	2	1
Colorado	132	2	12
	491	28	33
		61 producing leases	

*Table taken from county data in Coal Lease Regulations, EIS, leases and mines operating in more than one county are listed in each.

Several factors indicate that leases were acquired for speculative or warehousing purposes. Lease bids prior to the moratorium were low, and sales frequently drew only one bidder.[162] Production has been more likely to occur on competitively let tracts than on those otherwise let.

16.1 billion tons of recoverable reserves are under federal lease. Production from these leases in 1973 was 12.9 million tons. The reserves-to-production ratio was 1,248 to 1. If production grew in the future at 10 percent per year, it would take 51 years to mine 16.1 billion tons. BLM estimates the growth of production between 1973 and 1990 at 20 percent per year. At this rate, it would take 31 years to mine 16.1 billion tons.[163] This presumes no production from leases yet to be issued.

Of the 16.1 billion tons of leased recoverable reserves, 6.6 billion are in mines or prospective logical mining units (LMU's) which are now producing or have plans to produce. In these mines and LMU's the ratio or present reserves to planned production is 149 for 1975, and 53 for 1980.

State-by-state, the recoverable Federal reserve, 1973 production, and R/p ratios are shown in Table 50 (major western States only, million tons).

TABLE 50

FEDERAL COAL STATISTICS FOR WESTERN STATES

	Recoverable Reserves	1973 Production	R/P Ratio
New Mexico	335	0.3	1117
North Dakota	268	1.5	179
Colorado	1,650	1.8	917
Montana	1,181	1.9	622
Utah	3,604	2.4	1502
Wyoming	9,065	5.0	1813
	16,103	12.9	1248 *

* Hearings on Federal Coal Leasing Amendments Act of 1975, Senate Interior Committee, 94th Cong., First Session (1975), p. 490 (Interior Dept. Option Paper: "Diligence Requirements for Existing Coal Leases"). 1974 data presented in the Coal Leasing Regulations shows different, but high, leased coal reserves to production ratios. While production is slated to rise, committed acreage is huge, reflecting the tendency to hugh mines tying up tremendous reserves in an integration of mining operations with leases. Also, interim projections of future coal availability, tie a committed 40 year reserve to each gasification (36 plants, 8 million tons/yr., 12.8 billion tons) or power plant (3.2 billion tons) EIS, P. 1-81.

On 49 percent of the leases held by 128 separate lessees, production has occured or is planned for the near future; 51 percent "have not produced in the past and have not indicated any plans for future production." [164]

"A major finding of the analysis is that over 50 percent of the 467 leases, which are held by 66 lessees, cover 60 percent of the total lease acreage and contain 60 percent of the total coal reserves, have never produced and have not indicated any plans for development of production before 1990. Nearly all of the leases that have no plans for production were issued within the last 20 years and over 60 percent within the past 10 years. The average age is 11 years. The leases average 200 to 300 acres larger than the average size for all leases and are two to four times larger than the average 30 year old leases. Over 60 percent of the leases that have no plans for production were obtained through the preference right method as opposed to the past and currently producing leases, which were obtained primarily through competitive bidding. Most of the coal reserves of leases with no production plans are located in Wyoming and are surface recoverable coal. However, over one half of the leases and 27 percent of the coal reserves in this category is located in Utah and is underground mineable.[165]

Federal Coal Lessees

The FTC Staff Report ranks the twenty largest holders of federally leased coal acreage in seven western states (1974). The four largest hold 28.6% of the acreage. The eight largest hold 44.5%; the twenty largest 68.3%. Ranking by leased federal reserves (tons) results in the top four having 34.6%; the top eight, 56.6%; and the top 20, 81.7%, p. 631-32. The largest holders consist of large coal companies independent of oil and utility companies (19.5%),[166] utility systems (17.2%),[167] petroleum companies (18.0%)[168] and steel companies (6%)[169]

One interesting feature is that seven of these companies are not now producing from the federal lands held; and five of these seven companies are oil companies (Sun, ARCO, Carter, Bass, and Kerr-McGee). Five of the seven oil company users are not producing from their federal leases. Several of these companies have mining plans pending.

We do not have a comparable ranking for production in the seven western states. A listing of the twenty largest coal producers nationally shows a slightly different profile. Table 51.Non-oil and non-utility coal companies account for 24%,[170] utility related companies, 2.9%,[171] steel companies, 5.1%,[172] and oil companies, 22.9%.[173]

Table 52 shows from Bureau of Land Management reports, that concentration of lease-holdings is far higher at the state level than it is nationwide.

TABLE 51

U.S. PRODUCTION CONCENTRATION IN BITUMINOUS COAL, 1973

Rank	Firm or Operation Group	Bituminous Coal and lignite Production (Thousand tons)	Percent of total
1	Peabody Coal Co. (Kennecott Copper)	* 70,172	11.9
2	Consolidation Coal Co.(Continental Oil)	60,477	10.2
3	Island Creek Coal (Occidental Petroleum)	22,879	3.9
4	Pittson Co.	18,796	3.2
5	Amax Coal Co. (American Metal Climax)	* 16,404	2.8
6	U.S. Steel	16,222	2.7
7	Bethlehem Mines Corp.	14,129	2.4
8	Arch Mineral Corp. (Hunt Enterprises and Ashland Oil)	12,539	2.1
9	North American Coal Corp.	12,501	2.1
10	Old Ben Coal Corp. (Standard Oil of Ohio)	10,847	1.8
11	Eastern Associated Coal Corp.	10,640	1.8
12	Westmoreland Coal Corp.	8,809	1.5
13	General Dynamics Coal Co.	8,670	1.5

TABLE 51

(CONTINUED)

Rank	Firm or Operation Group	Bituminous Coal and lignite Production (Thousand tons)		Percent of total
14	Pittsburgh & Midway Coal Mining Co. (Gulf Oil Corp.)	8,064		1.2
15	Utah International, Inc.	7,389		1.2
16	American Electric Power	6,563		1.1
17	Peter Kiewit Sons Co.	6,113		1.0
18	Rochester & Pittsburgh Coal Company	4,666		.8
19	Western Energy Co. (Montana Power Co.)	4,600		.8
20	Ziegler Coal Co. (Houston Natural Gas)	4,272		.7
	Total, 20 largest**	324,752		
	Total, U.S.	591,000		
	Share of 4 largest		29.2%	
	Share of 8 largest		39.2%	
	Share of 20 largest		54.9%	

TABLE 51

(CONTINUED)

* Assuming the production of the Gibraltar Coal Co, a joint venture between Peabody Coal Co., and the American Metal Climax, can be allocated on a 50 percent basis to each company.

** May not add to total due to rounding.

Source: U.S. Coal Production by Company...1973, Keystone Coal Industry Manual (New York: McGraw Hill, 1974) pp 9-11; and Coal Facts, 1974-75 National Coal Association, Washington, D.C., p. 52.

TABLE 52

CONCENTRATION OF FEDERAL COAL LEASEHOLDS

Top 5 and 10 Lessees, By State

State	Federal Lessee	Fed. Lse. Acreage in State	Fed. Lse's in State	% of Fed. Lse. Acreage in State	% of Tot. Fed. Coal Lease Acreage
California					
	1. Dixie & Reeves	80 acres	1 lease	100%	0%
Colorado					
	1. Kemmerer Coal Co.	16,269 acres	10 leases	13%	2%
	2. Industrial Resources, Inc.	14,929	6	12	2
	3. Peabody Coal Co.	10,306	8	8	1
	4. Consolidation Coal Co.*	10,015	7	8	1
	5. U.S. Steel Corp.	9,471	15	8	1
	Top 5 Total	60,990 acres	46 leases	49%	7.8%

*Continental Oil Co.

TABLE 52 - Page 2

CONCENTRATION OF FEDERAL COAL LEASEHOLDS

Top 5 and 10 Lessees, By State

State	Federal Lessee	Fed. Lse. Acreage in State	Fed. Lse's in State	% of Fed. Lse. Acreage in State	% of Tot. Fed. Coal Lease Acreage
6.	Utah International, Inc.	8,071 acres	6 leases	7%	1%
7.	Atlantic Richfield	7,462	3	6	Less than 1
8.	Mid-Cont. Coal & Coke	6,065	8	5	Less than 1
9.	Garland Coal & Mining Co.	5,433	3	4	Less than 1
10.	United Electric Coal Co.	4,842	2	4	1
	Top 10 total	92,864 acres	68 leases	76%	11.9%
	State Total	121,470 acres	113 leases	100%	15.6%
MONTANA					
1.	Decker Coal Co.	13,610 acres	3 leases	38%	2%
2.	Western Energy Co.*	7,073	2	20%	Less than 1
3.	U.S. Steel Corp.	5,096	2	14	Less than 1
4.	Peabody Coal Co.	4,307	1	12	Less than 1
5.	Pacific Power & Light Co.	3,067	2	8	Less than 1
	Top 5 Total	33,153 acres	10 leases	92%	4.2%
	State Total	36,232 acres	17 leases	100%	4.6%

* The Montana Power Company

TABLE 52 - Page 3

State	Federal Lessee	Fed. Lse. Acreage in State	Fed. Lse's. in State	% of Fed. Lse. Acreage in State	% of Tot. Fed. Coal Lease Acreage
New Mexico					
1.	Western Coal Co.	12,289 acres	6 leases	30%	2%
2.	Consolidation Coal Co.	9,303	5	23	1
3.	Gulf Oil Corp.	8,156	4	20	1
4.	Seneca Oil Co.	6,336	1	15	Less than 1
5.	Peabody Coal Co.	2,044	1	5	Less than 1
	Top 5 Total	32,128 acres	17 leases	95%	4.9%
	State Total	40,958 acres	28 leases	100%	5.2%
Utah					
1.	Peabody Coal Co.	43,160 acres	31 leases	16%	6%
2.	Resources Co., et al.*	39,355	20	15	5
3.	El Paso Natural Gas	27,019	15	10	3
4.	Consolidation Coal Co.	25,533	11	10	3
5.	Consol. Coal & Kemmerer Coal Co.	18,746	10	7	2
	Top 5 Total	153,813 acres	87 leases	58%	20%

* Resources Co. owned by Arizona Public Services Co.

TABLE 52 - Page 4

State	Federal Lessee	Fed. Lse. Acreage in State	Fed. Lse's. in State	% of Fed. Lse. Acreage in State	% of Total Fed. Coal Lease Acreage
6.	Utah International, Inc.	16,157 acres	20 leases	6%	2%
7.	Kaiser Steel Corp.	14,617	9	5	2
8.	Nevada Electric	10,377	8	4	1
9.	North American Coal	8,905	8	3	1
10.	Jessee H. Knight	7,850	4	3	1
	Top 10 Total	211,719 acres	136 leases	79%	27%
	State Total	268,555 acres	197 leases	100%	34%
Washington					
1.	Wash. Irrigation & Dev. Co.	521 acres	2 leases	100%	Less than 1%
North Dakota					
1.	Knife River Coal Co.	7,792 acres	6 leases	48%	Less than 1%
2.	North American Coal Co.	2,843	3	17	Less than 1
3.	Kaukol-Noonan, Inc.	2,486	2	15	Less than 1
4.	Kerr McGee Corp.	2,034	1	12	Less than 1

TABLE 52 - Page 5

State	Federal Lessee	Fed. Lse. Acreage in State	Fed. Lse's. in State	% of Fed. Lse. Acreage in State	% of Tot. Fed. Coal Lease Acreage
5.	Consolidation Coal C.	601 acres	3 leases	4%	Less than 1%
	Top 5 Total	15,756 acres	15 leases	97%	2.0%
	State Total	16,235 acres	18 leases	100%	2.1%
Oklahoma					
1.	Galand Coal & Mining Co.	37,115 acres	21 leases	43%	5%
2.	Evans Coal Co.	12,622	8	15	2
3.	Lone Star Steel Co.	10,172	6	12	1
4.	Petroleum Int'l, Inc.	9,110	3	11	1
5.	Cameron Coal Co.	4,464	3	5	Less than 1
	Top 5 Total	73,438 acres	41 leases	84%	9.4%
	State Total	87,014 acres	53 leases	100%	11.1%
Oregon					
1.	Pacific Power & Light Co.	4,866 acres	2 leases	90%	Less than 1%
2.	Mandrones et al.	538	1	10	Less than 1

TABLE 52 - Page 6

State	Federal Lessee	Fed. Lse. Acreage in State	Fed. Lse's. in State	% of Fed. Lse. Acreage in State	% of Tot. Fed. Coal Lease Acreage
	State Total	5,403 acres	3 leases	100%	.7%
Wyoming					
1.	Pacific Power & Light Co.	27,761	15	14%	3%
2.	Peabody Coal Co.	23,76	7	12	3
3.	Richard D. Bass	20,701	1	10	3
4.	Carter Oil Co.[1]	15,491	3	8	2
5.	Sun Oil Co.	14,680	1	7	2
	Top 5 Total	101,779 acres	27	51%	13%
6.	Atlantic Richfield Co.	11,724 acres	3	6%	2%
7.	Ark Land Co.[2]	11,656	8	6	1
8.	Kerr McGee	11,255	6	6	1
9.	Reynolds Mining Corp.[3]	9,418	5	5	1
10.	Energy Development Co.[4]	8,683	1	4	1
	Top 10 Total	154,515 acres	50	77%	20%
	State Total	199,944 acres	91	100%	26%

[1] Exxon

[2] Partially owned by Ashland Oil

[3] Affiliate of R.J. Reynolds ("Aminoil") who recently purchased Signal Oil & Gas Properties from Burmah

[4] Arizona Public Services Co.

Wyoming is slated to provide the plurality of additional western coal production.[174] Most Wyoming coal will come from the Eastern Powder River Basin from 74 leases not previously produced. This area holds 12.4 billion tons of economically strippable coal - 28% of U.S. strippable resources.[175]

TABLE 53

EASTERN POWDER RIVER BASIN COAL LEASING

Action Status	Number	Acres
Issued Federal Coal Leases	42	93,075
Preference Right Coal Lease Applications	44	96,517
Outstanding Coal Prospecting Permits	28	64,252
Subtotal	114	253,844
Competitive Coal Lease Applications	20	157,861
TOTAL	134	411,705

Source: Interior Department Eastern Powder River Basin Environmental Impact Statement, p. I-21

Lease ownership is highly concentrated, as is the holding of preference rights--the right to lease after prior exploration. See Table 54. Thus, it is interesting to note that 21 lessees (of 42 in the State) have no plans to develop 62 of the 92 leases in the State. The 62 leases cover 128,070.39 acres (199,944.21 acres are leased in the state) and contain 5,126.83 million tons of strippable resources and 396.78 million tons of resources which must be mined underground.

TABLE 54

EASTERN POWDER RIVER BASIN - WYOMING

Federal Coal Leases

Lessee	Federal Lease Acreage	% Total Acres	No. Fed. Leases	% No. Leases
Atlantic Richfield	11684	12.55	3	7.14
The Carter Oil Company (Exxon)	15490	16.64	3	7.14
Pacific Power & Light	14440	15.51	8	19.05
Kerr-McGee	8695	9.34	5	11.9
Peabody	17281	18.57	6	14.29
Mobil	4000	4.30	1	2.38
Wyodak Resources Development Co.[1]	1920	2.06	4	9.52
Meadowlark Farms[2]	5960	6.40	2	4.76
Humac Corp.	3359	3.61	3	7.14
Sun Oil	6560	7.05	1	2.38
Others (4 parties)	3686	3.96	6	14.29
Total	93075	**	42	**
14 Lessees		Top 4 63.27% Top 10 96.04%		

TABLE 54

(Continued)

[1]Black Hills Power & Light

[2]A subsidiary of AMAX, Inc. (Standard Oil of California)

**Not Equal to 100% due to rounding

Wyoming's 5126.58 million tons of leased strip mineable reserves constituted 61.17% of the 8381.44 million tons of federally leased strippable resources. The 396.78 million tons are 56.38% of the 703.8 million tons of underground mine resources.

Information on federal leases in New Mexico, a state with significant coal resources that is near the southern California markets, shows that six of the thirteen lessees with about 28 thousand of the approximately 41 thousand acres leased in that state have no mining plans. These six lessees control about 192 million tons of strippable reserves, 70% of such leased reserves and about 56 million of the 58 million tons of underground mineable reserves there.

For Eastern Montana, where a 500 kv line is planned to be extended to the Pacific Northwest Coast, 17 lessees have no plans to develop 8 of 17 leases in the state containing 873.13 million of the 1,179.85 million tons leased.

Private Domain - Particularly Montana

We do not have data comparable to much of the foregoing for private coal development throughout the West. Some non-comparable data follow:

The Environmental Policy Center, Facts About Coal in the United States, revised February 1975, at 16, reports that private and state leases in the western states (Arizona, Colorado, Montana, New Mexico, North Dakota, Utah and Wyoming) add to almost 1.75 million acres. Some of the largest lease tracts are reported in Table 55.

TABLE 55

Largest Lease Tracts in Western States

	Estimated Reserves In Billions of Tons
Burlington Northern Railroad	11
Union Pacific Railroad	10
Exxon	7
Texaco	5
Pacific Power & Light	1.6
Western Energy	1
Utah International Const. Co.	1.1
Kerr-McGee Corp.	1.5
American Metals Climax	4
Peter Kiewit Const. Co.	N.A.
Peabody Coal Co.	N.A.
Continental Oil Co.	N.A.

In Montana, coal companies and a subsidiary of the Montana Power Company hold large lease tracts for mining as well as for future coal gasification facilities. Some reported private holdings are set forth in Table 56. Others include the Burlington Northern which holds large tracts.

TABLE 56

SOME PRIVATE COAL ACREAGE IN MONTANA

	Coal Leases	Surface Rts.	Exploration & Option	Other	Total
Consolidation Coal (Conoco)	35050	67195	71280	4960	178485
Western Energy (TMPC)			205178	4400	209578
Phillips Petro.	12526				12526
HFC	59400				50400
Tenneco	48116	56588			104704
Sun	29416				29416
Chevron	20131				20131
Wesco Resources	40696	45757	11555	6785	104793
Norsworthy Reger	35400	24720	4000		64120
Sentry Royalty	87480				87480
Valley Camp Coal			5060		5060

TABLE 56
(Continued)

	Coal Leases	Surface Rts.	Exploration & Option	Other	Total
Peabody Coal	2080			5280	7360
Westmoreland	640		9680		10320
Amax Coal Company	3840				3840

Source: Action for Eastern Montana, in Hearings on Federal Coal Leasing Amendments Act of 1975, Sen. Interior Comm. (1975), p. 167-76.

The coal holdings of western railroads such as the Burlington Northern, the Union Pacific, and the Santa Fe seem likely to be employed for utilities who take delivery by rail. They seem unlikely candidates to supply coal to power plants located near mines (mine-mouth plants); the plants which will serve utilities in the Mountain States or on the West Coast.[176]

Coal Holdings of Western Utilities

As noted heretofor, western utilities such as Pacific Power and Light Company and The Montana Power Company produce and sell coal from large reserves.[177]

Much of the utility involvement in coal production is in joint enterprises with other parties. Two such ventures are instructive. Western Coal Company, a joint venture between Public Service Company of New Mexico and Tucson Gas and Electric Company, owns extensive resources, and supplies coal to the San Juan Plant under a mining agreement with Utah International.

Another such joint venture is among, on the one hand, fuel subsidiaries of Southern California Edison (Mono Power Company), San Diego Gas & Electric Co. (New Albion Resources Company), and the Arizona Public Service Company (Resources Company);[178] and, on the other, Kaiser industries. This was to supply the proposed Kaiparowits Project.

Utility acquisition of coal reserves is spreading. PG&E has acquired coal reserves in Utah.[179] A group of public power and REA cooperatives have formed Western Fuels Inc., in order to acquire fuel resources for planned units. Similarly, Nevada Power Company (NPC) is planning two coal-fueled plants, with Los Angeles Department of Water and Power, and St. George's, Utah, respectively; both plants are to use coal produced by Utah International and an NPC subsidiary.[180]

Power generation and the conversion of coal to synthetic fuel require sizeable water flows.[181] In the west, rights to water are acquired by "appropriation" or by contract from the Bureau of Reclamation. One obtains an appropriation by filing with state officials, and then using the water claimed. For the rich coal beds in northeastern Wyoming and southeastern Montana, water rights have been secured largely by the oil industry and a few large utilities as shown in Table 57.

TABLE 57

INDUSTRIAL WATER APPROPRIATIONS, REQUESTS AND OPTIONS IN THE YELLOWSTONE RIVER BASIN

(All Figures in Acre-Feet Per Year)

River/Company	Appropriations Filed	Bureau of Reclamation Options	Bureau of Reclamation Requests	River Total
POWDER				
Utah International	80,375			
Reynolds (Lake DeSmet)	36,000			
Unknown (Moorhead Dam)			220,000	336,375
TONGUE				
Montana Power	4,175			
Norsworthy & Reger	223,000			227,175
BIG HORN				
Exxon		50,000		
Peabody Coal		80,000		
Gulf Oil		75,000		
Shell		48,000		
Westmoreland Reserve		30,000		
Kerr McGee		50,000		

TABLE 57 (Continued)

River/Company	Appro-priations Filed	Bureau of Reclamation Options	Bureau of Reclamation Requests	River Total
Reynolds		50,000		
Colorado Interstate Gas		30,000		
Ayshire (AMAX)		30,000	90,000	
Panhandle Eastern Pipe-line		30,000		
Norsworthy & Reger		50,000	10,000	
Cardinal Petroleum		50,000	92,000[1]	
Sun Oil		35,000	35,000	
Weld-Jenkins		50,000	50,000	
Mobil Oil		50,000		
Conoco			530,000	
Montana Power			50,000	
Atlantic Richfield			50,000	
Northern Natural Gas			20,000	
Pacific Power & Light			30,000	
(Unknown)			308,000	1,973,000

TABLE 57 (Continued)

River/Company	Appropriations Filed	Bureau of Reclamation Options	Bureau of Reclamation Requests	River Total
YELLOWSTONE				
Tenneco (Intake Water Co.)	80,650			
Montana Power:				
Forsyth	181,000			
Billings	283,600			
Basin Electric	36,200			
Hunt Oil	144,800[2]			
Getty Oil	92,000			824,250
Grand Total for Yellowstone drainage	1,167,800	708,000	1,485,000	3,360,800

[1]Intermountain Reservoir

[2]Approximately 6,000 for irrigation

Source: Compiled from the Bureau of Reclamation and County Courthouse files by Northern Great Plains Resource Program, Hearings on Federal Coal Leasing Program, Sen. Comm. Interior (1974)

Utility Purchasers of Coal

Some purchasers of coal consider the market as a "sellers' market" in which supplies are tight. Publicly owned systems and REA cooperatives report particular concern about coal supplies.

Mr. Kenneth Holum, General Manager of Western Fuels Association, Inc., a joint enterprise of municipal and cooperative power systems to secure coal, testified that

> "We did find it exceedingly difficult to secure coal that we needed from western sources."

In the future large increases in coal-fueled capacity are foreseen requiring substantial increases in western coal production. These increases may include the first coal-fired capacity (750 mw) in the area which includes PG&E and will include 48.9% of new capacity for Southern California between 1975 and 1984. See Table 58.

TABLE 58

MAJOR PLANNED COAL-FIRED PROJECTS

OF

WESTERN UTILITIES

Coal-Fired Project	Size (Mw)	Co-owners and their shares
Southwest		
San Juan No. 1	326	Public Service of New Mexico - 50% Tucson Gas & Electric - 50%
San Juan No. 3	466	Public Service of New Mexico - 50% Tucson Gas & Electric - 50%
San Juan No. 4	466	Same as San Juan No. 3
H. Allen 1	500	Nevada Power and LADWP
H. Allen 2	500	Nevada Power and LADWP
Warner Valley 1 & 2		Nevada Power, LADWP and St. Georges, Utah
Navajo No. 2	750	SRP - 21.7% LADWP - 21.2% Ariz. PS. - 14% Nevada Power - 11.3% Tucson G & E - 7.5%

TABLE 58 (continued)

Coal-Fired Project	Size (mw)	Co-owners and their shares
		USBR - 24.3%
Navajo No. 3	750	Same as Navajo No. 2
San Bernadino	760	SCE
	760	SCE
Mountain Colstrip 1,2	360 ea.	The Montana Power Co.
		Puget Sound P&L
Colstrip 3 & 4	770 ea.	The Montana Power Co.
		Puget Sound P&L
		Portland G.E.
		Washington Water Power
		Pacific P&L
Cray Station 1 & 2	380 ea.	Colo-Ute Elec. Assoc.
		SRP
		Tri-State Generation and
		Transmission Assoc.
		Platte R. Power Authority
Huntington Canyon 1-2	430 ea.	UP&L
Bridger 1-4	500 ea.	Pacific P&L

TABLE 58 (Continued)

Coal-Fired Project	Size-(mw)	Co-owners and their shares
		Idaho Power
Wyodak 1	330	Pacific P&L and Black Hills Power and Light Co.

Utility Coal Fuel Contracts

Present and planned large Western units are fueled with utility-owned coal or coal under long-term contracts from dedicated large mining facilities Coal supply contracts for these large generating units run for the life of the unit (generally 30 years) and provide for price adjustments to reflect the cost of labor, material, supplies and taxes.

Table 59 sets out some of the major long term coal supply contracts now extant in the West.

TABLE 59

Utility Coal Supply Contract Arrangements in West

State and Coal Company	Contract Duration (years)	Production (million tons)	Location Consumed
ARIZONA			
Peabody	35	5	Bullhead City, NV
Peabody	35	8	Page, AZ
COLORADO			
Utah Int'l		3	Craig, Colo.
MONTANA			
Western Energy [1]	30	0.7	Billings, Mt. (smaller plant)
Western Energy	30	3.0	Colstrip
NEW MEXICO [2]			
Utah Int'l	30	8.5	Fruitland
Western Coal Coal [3]	30	1.0	Fruitland
UTAH			
Peabody	30	1.2	Huntington
Utah P&L	30	1.2	Energy
Utah P&L	30	1.2	Carlson or Energy
Utah P&L	30	1.2	Carlson or Energy
Resources Co.	30	3.0	Kane

TABLE 59 (Continued)

State and Coal Company	Contract Duration (years)	Production (million tons)	Location Consumed
WASHINGTON			
Pacific Power & Light	35	4.8	Centralia
WYOMING			
Pac. P&L	30	3.5	Glenrock
Pac. P&L	30	31	Pt. of Rocks
Pac. P&L	30	2.5	Pt. of Rocks
Pac. P&L	30	1.9	Pt. of Rocks
Pac. P&L	30	0.4	Pt. of Rocks
Kemmerer Coal		2.5	Kemmerer
Wyodak	30	1.7	Gillette

[1] Owned by the Montana Power Company

[2] The El Paso Coal subsidiary's contract to supply a gasification plant in New Mexico is for 8.8 million tons per year.

[3] Owned by Tucson Gas & Electric Corporation and Public Services of New Mexico

Note: Additionally, AMAX has a contract to supply coal for 20 years to an Oregon plant of Portland General Electric.

The use of large quantity long term contracts in the west results in a utility's being served by only a few coal suppliers.[182]

The prevalence of long term contracts is coupled with the use of a number of clauses which shift production risks from mining companies and their investors and lenders to coal purchasing utilities. These clauses assure that debts connected with a coal project's financing will be repaid, they assure coal firms that their costs will be recovered. Financial assistance given to a limited number of firms having long term sales tends to place later entrants into mining at a capital cost disadvnatage.

In the period between 1960 and 1974, "This rather dramatic shift from small to large mines, and the development of numerous new, large strip mines was financed with a combination of internal cash flows, the sale of both short and long-term production payments financed by banks, and some private placements of long-term debt."[183]

> "Production payment financing, arranged by commercial banks, is rapidly becoming the favored way of structuring new mine development financing. ...In general, ... a typical arrangement provides for the advance sale of a stated amount of future income in the form of a production payment either from existing mines, new mines or a

combination, to an arms length third party who pays for the production payment with a bank loan, usually taken down in installments as the mine owner needs the funds for development. Repayment, plus interest, is from stated percentages of future mine income, usually for a total term (including the take down period) of 8 to 10 years. The lender is secured by a mortgage to the production payment and an assignment of the proceeds of production, backed up by strong commitments of the mining company to develop and continuously operate the mines, usually pursuant to the terms of a coal sales contract for a significant part of the output. . . . Thus the financing is based upon the value of the mines out of which it has been carved, and future mining income retires the debt. Aside from the financial burden of the specific obligations to fully develop and continuously operate the mines. . ., the mine owner usually is not directly responsible for the bank debt incurred. . .[184]

These large mines financed by production were often owned by companies not traditionally in the coal industry.

Coal companies are reported to require "take-or-pay" or even "hell-or-high-water" clauses[185] and to demand terms consonant with investment payout, as well as for non-remote sites and some price speculation.

Under long-term contracts, the utility sometimes guarantees mining company notes and purchases coal on a cost-plus basis, under agreements that may include most-favored-nation clauses.[186] These shifts of risk to utilities enable producers to use a very high proportion of bank debt in mine financing; the agreements also assure the producer of stable demand markets.

The coal contracts usually, if not invariably, have price escalation provisions. These provisions are quite extensive.

Table 60 provides a nationwide sample of long-term contracts and reveals many techniques of automatic price adjustments. Most typical was sole reliance on national price and wage trends.[187]

TABLE 60

TECHNIQUES OF ESCALATION OF ELECTRIC UTILITY

LONG-TERM CONTRACTS

	Coal Burn Tonnages of Reporting Companies	
	As % of Burn By Reporting Companies	As % Of Industry Burn
Predominately by national trends	39.6	27.3
by mine costs	20.3	14.0
Predominately by costs and national trends	18.6	12.8
Predominately by national trends and mine productivity	17.6	12.1
Use combination of national trends, mine costs, and mine productivity	3.8	2.6
Total Reporting	100.0	68.3

A report for the Federal Energy Administration, "Analysis of Steam Coal Sales and Purchases" (April, 1975), asserts that "the larger the coal requirements of an electric utility, the more likely this utility is to prefer contract purchases over spot purchases under normal circumstances for reasons of stability of supply and predictability of price. Nineteen of the 22 utilities interviewed prefer contract to spot purchases."[188]

"Only two respondents mentioned lower prices as the reason for preferring contract to spot purchases. Four of these 19 companies would like their purchases to be 100% contract. Fifteen companies prefer to have a large percentage of their purchases to be contract and a small percentage to be spot purchases. The respective percentage of each type of purchase varies among these companies anywhere between the combinations of 75 percent contract to 25 percent spot and 95 percent contract to 5 percent spot. These figures are not derived from any specific rule."

The preference for long term contracts is shared by coal producers, the overwhelming majority of whom prefer to have a large percentage of their tonnage (70-90 percent) sold by long term contract, with the small remainder sold on the spot market. Only three producers and two coal sales companies prefer the spot market.

Large producers need long term contracts to obtain bank financing.

Most coal sales companies also prefer long-term contracts for the demand security, while they prefer to keep a small percentage of their production on the spot market in order to enjoy high prices during good market conditions.

Coal ownership and production from large mines have come increasingly to be controlled by enterprises not principally in the coal business.

During 1974 the 50 largest coal mines collectively produced nearly one-fourth of the industry's total output; only five of these mines are owned by independent coal producers. The other 45 large mines are owned by subsidiaries of electric utilities, conglomerates and companies whose principal businesses are oil, steel and other types of mining. The ownership of vast coal resources has come under the control of large oil companies.[189] It has recently been reported that major oil companies control about one-third of leased coal,[190] This growth in the holdings of major companies stems in part from federal leasing practice and in part from numerous acquisitions of coal enterprises.[191]

What the Coal Industry Can Indicate About Geothermal Energy

The experience of the coal industry is instructive regarding geothermal development possibilities in a number of ways:

(1) Utilities show substantial concern with security in their fuel procurement. This produces a tendency to buy from well-financed, established enterprises.

(2) A favored procurement mode, large quantity long-term contracts, leads to favoring the large sellers who have better access to production payment financing.

(3) The major buyers, a limited group - have a heavy planning commitment to coal procurement.

(4) Procurement plans appear to evince an expectation of higher fuel prices in the future.

(5) Only a limited number of utility and raw fuel enterprises have coal mining plans.

(6) The matching of major generating stations with long-term coal contracts removes a large sector of the utility generation growth plan from access to geothermal energy.

(7) The ownership of prime coal resources is in substantial part in the hands of major oil companies and their development of production has not been rapid.

The channeling of commerce into large fuel procurement arrangements with a limited number of suppliers is not conducive to geothermal development. A novel venture, with innovation risks and substantial capital requirements, is apt to need substantial financial backing. If external capital markets tend to be oriented toward larger, more conventional projects, the anomalous ventures may tend to become, perforce, joint arrangements with those companies which have capital and skills but which also have their major interests in other energy sources.

Our study indicates that the bulk of coal available to the West is in the hands of large oil companies, a few utilities, and railroads. This may tend to prevent lowest-cost development of coal resources. If the coal market were sufficiently large and diverse holdings of companies from less competitive fuel sectors might be expected to have little effect on the coal market's competitiveness. However with relatively few entities in major coal markets and sub-markets, oil-coal cross-ownership effects, and non-competitive relationships among utilities may be expected to reduce competition in supplying and in purchasing utility fuel. To the extent coal prices are high, geothermal energy has a greater market opportunity but this is the case only if (a) geothermal prices are not similarly higher than necessary, and (b) utility fuel purchasers are cost conscious and not otherwise constrained in their fuel choices.[192]

Nuclear Energy

Nuclear units are run at relatively steady rates for base load service, where their low fuel costs and high capital charges are best employed.

Perhaps, unlike coal-fired units, nuclear plants can be erected in California. These units have substantial economies of scale and are built in very large sizes[193] requiring substantial transmission services.

Their large size and cost have led to a number of joint endeavors among utilities and to proceedings concerning smaller system access to ownership or unit output shares.

Portions of the industry providing fuel and equipment are highly concentrated, and entry is costly. Firms engaged in coal and petroleum hold major posititons in essential aspects of nuclear fuel supply.

High capacity costs, and, relatedly, schedule delays, as well as rising fuel cost and some fuel supply uncertainty have dampened nuclear generation growth.

Power Plants in Operation or Planned

West Coast nuclear generation began in 1967 with a small unit in Humboldt Bay.[194] There are now five operating units with a total capacity of 2,770 mw; six construction permits in effect, and application pending for an additional nine units in the Western states. See Table 61 below.

TABLE 61

LICENSES IN EFFECT FOR OPERATING REACTORS IN THE WEST[1]

Project	Owner	Maximum Dependable Capacity (mwe)	Type
Humboldt Bay	PG&E	63	BWR
Trojan	Portland General Electric	570	PWR
Fort St. Vrain	Public Service Company of Colorado	330	HTGR
Rancho Seco	Sacramento Municipal Utility District ("SMUD")	817	PWR
San Onofre - 1	Southern California Edison (SCE)	430	PWR

Construction Permits in Effect

Project	Applicant	Capacity (mwe)	Type
Diablo Canyon - 1	PG&E	1,084	PWR
Diablo Canyon - 2	PG&E	1,106	PWR
San Onofre - 2	SCE	1,100	PWR
San Onofre - 3	SCE	1,100	PWR
WPPSS - 2	Washington Public Power Supply System ("WPPSS")	1,103	BWR
WPPSS - 1	WPPSS	1,218	PWR

TABLE 61 (Continued)

Application for Construction Permits Pending

Project	Applicant	Capacity (mwe)	Type
Palo Verde - 1, 2 and 3	Arizona Public Service Company	1,238 each	PWR
Pebble Springs - 1 and 2	Portland General Electric	1,260 each	PWR
Skagit - 1 and 2	Puget Sound P&L	1,277 each	BWR
WPPSS - 3 and 5	WPPSS	1,242 each	PWR
WPPSS - 4	WPPSS	1,218	PWR

BWR - Boiling Water Reactor

PWR - Pressurized Water Reactor

HTGR - High Temperature Gas-cooled Reactor

MDC - Maximum Dependable Capacity

Source: Nuclear Regulatory Commission, "Facilities License Application Record" March 31, 1976.

[1]At Richland, Washington, ERDA has an 850 Mw unit selling steam to Washington Public Power Supply System for power generation. Nuclear powered generation is considered in the utility industry to have significant economies of scale.

Most West Coast nuclear units will be jointly owned.[195] See Table 62.

TABLE 62

Ownership of Planned Nuclear Projects

Project	Owners	%
Trojan	Portland General Electric	67.5
	Pacific P&L	2.5
	Eugene Water and Electric Board	30.4
Skagit	Puget Sound Power & Light	100
WPPSS - 1 and 2	WPPSS*	100
WPPSS - 3	WPPS	70
	Pacific P&L	
	Puget Sound Power & Light	
	Portland General Electric	
	Washington Water & Power	
WPPSS - 4	WPPSS and perhaps others	
San Onofre - 2	SCE	80
and 3	SDG&E	20
San Joaquin	SDG&E	
	LADWP	
	Others	

TABLE 62
(Continued)

Project	Owners	%
Palo Verde -		
1,2 and 3	Salt River Project	28.1
	Arizona PS	28.1
	Tucson G&E	15.4
	Public Services of New Mexico	10.2
	El Paso Electric	15.8
	"AEPC"	2.4
Rancho Seco - 1	SMUD contract with PG&E	100
Rancho Seco - 2	SMUD and others	
	(indefinitely deferred)	
Diablo Canyon	PG&E	100
1 and 2		

* Washington Public Power Supply System, an associated group

Generating Unit Costs

Costs for nuclear generating units are rising rapidly and by the mid-1980's are expected to reach $1,200 to $1,400 per kilowatt.[196] Major factors driving up costs are construction delays, fuel prices and forced outages.

Schedule slippages of both fossil and nuclear units are summarized in Table 63 (derived from data in the January 19, 1976 issue of Electrical Week). In addition to those listed, many utilities apparently have made other, unannounced cutbacks. In the first half of 1976, only one nuclear generating unit was ordered and no plans were announced for additional units.[197] Delays are especially costly on the more expensive nuclear units, since both interest during construction and escalation rates apply against larger costs per unit of capacity.

TABLE 63

DEFFERALS AND CANCELLATIONS OF

PLANNED FOSSIL AND NUCLEAR UNITS

	Number of Units affected	Capacity (mw)
Deferred 1 year or less	30	25,095
Deferred 2 years	5	6,060
Deferred more than 2 years	1	1,150
Indefinitely deferred	3	3,420
In-service date uncertain	2	2,400
Cancelled	8	8,220
Planning suspended	2	1,540
Totals	51	47,885

NOTE: In some cases, the deferrals reported are not the first in the history of the unit (e.g., some are listed as having been deferred for "another year"). Likewise, some cancellations are of units which had already been deferred in previous years.

These cutbacks are those announced in the second half of 1975 (with the exception of one 1,100 mw nuclear unit whose deferral was announced early in 1976).

Nuclear units have been subject to a high rate of forced outages.[198]

Nuclear Fuel Prices

Nuclear fuel prices have climbed quickly since 1974. The average price per pound of uranium oxide was $7.90 in 1974. An ERDA survey reports a mid-1975 average contract delivery price of $8.45 which rose to $10.50 by January 1, 1976.[199] Estimates for 1982 price are $19.20 (in 1975 dollars).[200] Prices of around $40 per pound have been indicated for 1978 delivery.[201]

The apparent effort at cartelization[202] and the Westinghouse announcement that it would not meet its delivery contracts push fuel prices higher.[203]

Price and supply after 1985-90 are uncertain, reflecting in part pending decisions as to the future role of government in the area of fuels enrichment, and uncertainty as to which means of preparing and reprocessing nuclear fuels will be used, the quantities available, and the associated costs. In response, some power companies are entering the uranium ore milling business and a few are acquiring mining properties.

While U.S. uranium fuel supply came, through the year 1975, from domestic sources,[204] commencing in 1978, uranium from other countries is expected to supply a part of domestic requirements.

Current high uranium prices, which run considerably ahead of the supply cost of $15 per ton estimated as adequate by ERDA, may rise further when importation begins. These ore prices are not inconsistent with the structure of the supply industry.

In 1973, 33 open pit mines accounted for about 63% of domestic uranium ore production. The remaining 37% of the ore was produced in 122 underground mines. Domestic mines with a capacity to produce about 9 million tons of ore a year are mining less than 7 million tons annually. About 75% of the ore is mined in New Mexico and Wyoming; an additional 15% is produced in Colorado and Utah.[205]

Uranium ore is milled to produce a semi-refined product. Haulage and other costs often cause mills to be located near the mines, in relatively remote areas.

Recently, PG&E and SCE (Mono Power) have acquired positions in uranium milling.[206]

Ownership of uranium reserves appears to be somewhat concentrated: The significance of information about reserve ownership is unclear. Rapidly rising prices may encourage new entry; but we do not yet know how diverse and numerous the entrants will be. Table 64 summarizes ownership data.

TABLE 64

THE URANIUM INDUSTRY

Control of Uranium Reserves, 1971

Companies Listed in Alphabetical Order	Percent of Low-Cost Uranium Reserves[1]
Anaconda Co.	
Getty Oil Co.	
Gulf Oil Co.	
Exxon Corp.	
Kerr-McGee Corp.	
United Nuclear Co.	
Utah International, Inc.	
Subtotal for 7 companies..................................	70.0
Atlas Corp.	
Contential Oil Corp.	
Cotter Corp.	
Dawn Mining Co.	
Federal-American Partners	
Homestake Mining Co.	
Rio AlgomCorp.	

TABLE 64

(Continued)

Companies Listed in Alphabetical Order	Percent of Low-Cost Uranium Reserves[1]
Susquehanna-Western, Inc.	
Union Carbide Corp.	
Western Nuclear, Inc. (subsidiary of Phelps Dodge Corp.)	
Subtotal for 10 companies	20.0
Total for 17 companies	90.0

[1]Low-cost reserves are those from which U_3O_8 could be obtained at a price of $8.00 per pound or less.

Source: Appendix A of the Testimony of Clarence E. Larson, Commissioner, Atomic Energy Commission, in U.S. House of Representatives, Select Committee on Small Business, Subcommittee on Special Business Problems, Concentration by Competing Raw Fuel Industries in the Energy Market and Its Impact on Small Business, Hearings, 92d Cong., 1st Sess. (1971). p. 214.

Recent data from ERDA as to the capacity of uranium milling facilites is provided in Table 65, together with milling capacity concentration ratios we have developed.

TABLE 65

U.S. URANIUM PRODUCTION PLANTS

Operating as of January 1, 1976

Company	Location	Nominal Capacity (Tons Ore Per Day)
Anaconda Company (ARCO)	Grants, New Mexico	3,000
Atlantic Richfield	George West, Texas	*
Atlas Corporation	Moab, Utah	1,000
Conoco-Pioneer	Falls City, Texas	1,750
Cotter Corporation	Canon City, Colorado	450
Dawn Mining Company	Ford, Washington	400
Exxon Company, USA	Powder River Basin Wyoming	
**Federal-American Partners	Gas Hills, Wyoming	950
Kerr-McGee Nuclear Corp.	Grants, New Mexico	7,000
Rio Algom Corporation	LaSal, Utah	700
Union Carbide Corporation	Uravan, Colorado	1,300

TABLE 65 (Continued)

Company	Location	Nominal Capacity (Tons Ore Per Day)
Union Carbide Corporation	Gas Hills, Wyoming	1,200
***United Nuclear-Homestake Partners	Grants, New Mexico	3,500
Uranium Recovery Corp.	Mulberry, Florida	****
Utah International, Inc.	Gas Hills, Wyoming	1,200
Utah International, Inc.	Shirley Basin, Wyoming	1,800
Western Nuclear, Inc. (Phelps Dodge)	Jeffrey City, Wyoming	1,200
TOTAL		28,000

* Uranium obtained by solution mining.

** A joint enterprise in which Federal Resources Corp. holds 60% and American Nuclear Corp. holds 40%.

*** A joint enterprise in which United Nuclear holds 70% and Homestake Mining Co. holds 30%

TABLE 65 (Continued)

****Uranium recovered from phosphoric acid.

Milling Capacity Concentration Ratios		
4-Firm	58%	% total U.S. nominal capacity
8-Firm	87.7%	

Petroleum companies have been reported to be doing the plurality of exploratory drilling for uranium.[207]

Fuel Fabrication and Reactors

Fabrication into fuel rods is done by Exxon Nuclear Company and by four manufacturers of light water reactors. Two firms, McGee Nuclear Corporation and Nuclear Field Services Inc., (now shut down plant owned by Getty Oil Company), provide chemical conversion services; Kerr-McGee also has a limited capability to make fuel assemblies.

Potential reprocessors are (1) General Electric, who has recently acquired Utah International; (2) Allied Chemical Nuclear Products/ Gulf General Atomics; and (3) a joint venture of Atlantic Richfield and Gulf General Atomics.

The reactor fabrication industry itself is limited to five firms. As of 1971, only nine firms were selling fuel for light water reactors.[208]

While utilities may be able to secure captive uranium mines and mills, they are still faced wtth concentrated industries in the reactor manufacturing and reprocessing segments into which entry is very expensive.

The Sectors Considered Together

"Uranium, coal, oil, gas and geothermal energy all serve the identical function in an electric utility powerplant - namely to produce heat for steam which turns a turbine-generator to produce electricity.

"Considered as a whole, it appears to us that there is a high and increasing level of interfuel competition such that it would seem entirely appropriate, for the purpose of assessing the competitive impact of energy mergers, to consider the energy sector as a single relevant market"[209]

Choices are made among fuels principally when generating units are being designed. A unit will use either nuclear energy, fossil fuels, or geothermal energy.[210] Fossil fuel units may be designed to use a variety of fuels, or they may be located or designed so as to effectively preclude fuel changes.

The decision on the choice of fuels, and the specific suppliers of fuel for a generating unit is often an infrequent, or even a one-time occurrence; but with many plants under construction at any given time, the number of initial purchase choices presents competitive opportunities for energy sales. This competition occurs (a) among firms selling a fuel, and (b) among fuels.

Fuels costs are a major component of utility production costs. A choice among fuels should be heavily influenced by the fuels' relative costs. Western coal and geothermal energy could be forthcoming to western utilities at costs (including return on investments) below those now paid for oil. However, supply cost curves do not reflect opportunity costs. Absent fuel price regulation producing the approximate effect of a competitive market, coal and geothermal energy will come to market at prices lower than oil only if their suppliers compete with other suppliers of oil and with each other. The probabilities for this turn on whether suppliers of coal or geothermal energy are situated in relation to one another and to suppliers of other fuels so as to be inclined to compete rather than to accommodate one another.[211]

At present, firms seeking to be competitive entrants in the geothermal energy sector are confronted with the economic power of the integrated oil and utility companies who respectively control many of the better resource sites and the high voltage power grid.

The Sectors

Petroleum

The large California utilities procure most of the resid consumed for electric generation in California. They purchase the bulk of this oil under very large quantity, long-term contracts principally with five very large oil companies: SOCAL, Union Oil Company of California, Exxon, Phillips and Atlantic Richfield.[212] The ownership of West Coast refineries which produce most of this resid is concentrated in the hands of firms who also own the Caribbean and Singapore refineries which could provide alternative resid sources.[213]

The crude oil flowing to West Coast refineries, and, to a limited degree, directly to utility boilers, is quite likely to flow through facilities owned by the large petroleum refiners.

West Coast production is largely shipped to market through an interconnected network of non-common carrier lines owned by these refiners. Oil imported into California is likely to come through mooring facilities owned by these same enterprises; or in the future through the TAP line system from northern Alaska.[214] The TAP pipeline system will be owned, in part, by large petroleum companies established on the West Coast, and, in part, by Standard Oil of Ohio (controlled by British Petroleum).[215]

Refineries obtain crude oil and distribute products through exchange agreements as well as by direct transport. Under these agreements Company A will deliver to Company B an amount of crude oil at one point in return for delivery of crude oil by Company B (or even C in more complex deals) to it at another point. The exchange system is necessarily dominated in California by the private carrier pipelines who have the facilities through which most such arrangements must be made.

Crude oil supply to the West Coast comes increasingly from the Pacific outer continental shelf, Alaska, and imports from Indonesia and from other locations where most production is by the major petroleum companies. Foreign oil is usually obtained under concession or operating agreements with foreign nations which effectively cause the additional revenues from oil price increases to be shared between the host country and the concessionaire company. The countries producing the low sulphur crude oil demanded on the U.S. West Coast are OPEC members.

National oil companies (e.g., Pertamina), a novel feature in international oil operations, may seek to increase their markets. Supply and price ramifications of their actions are unclear. However, they do not seem likely to supply large amounts of oil to the U.S. West Coast, where future import levels are very likely to decline with the advent of production from the Alaskan North Slope and increases in offshore California production.

Its holdings at various stages of production augment the market power a large refiner has at any one stage of production.

Regional independent refiners are sometimes dependent upon these large companies for crude oil supply and transportation. Independent producers in California are quite likely to have to sell their output into one of these refiners' private carrier lines. The dominance of these refiner-pipeliners is shown by the fact that only three companies post the field prices for crude oil in California.

The role of the independent refiner on the West Coast appears to be on a decline as new refining capacity is largely planned to be installed by the major refiners.[216] The role of the independent producer has similarly declined as a portion of total production.[217]

The new field production and pipeline facilities are frequently developed by joint enterprises among the large petroleum refiners. Some joint enterprises, such as ARAMCO, STANVAC and CALTEX go back many years. Newer production ventures such as THUMS and HAS offshore of California and the unitization of Prudhoe Bay production in Northern Alaska continue the history of joint action among major oil companies.

The pervasiveness of joint enterprises in petroleum production is extensively set out in the Senate Interior Committee's report "The Structure of the U.S. Petroleum Industry."[218]

Per this report, 69% of wells in which a major company held an interest in 1973 were jointly owned. On average, major companies obtained 45% of the product of the wells in which they owned interests.[219]

The combination of ubiquitous joint ventures in which major companies coordinate exploration field work, production and pipelining (which lead to extensive sharing of marketing information, including plans); together with extensive use of exchanges, all make it necessary for larger petroleum companies to extensively coordinate shipping and supply plans.

The extensive joinder of company supply and marketing arrangements affects the performance of the petroleum industry. It also has implications for that industry's relationship to and effects upon the geothermal energy industry.

The major interstate crude pipelines and proposed deep-water ports are invariably joint enterprises among major firms.

Onshore petroleum or geothermal exploration is frequently undertaken by joint enterprises among large and small petroleum firms. Small firms traditionally look to the large ones for subleased tracts to explore and for financing. In return, the small firms give the large firms a substantial share of any resulting production, normally coupled with an expectation of a purchasing option on the balance of production.[220]

A financial practice of the petroleum industry, being replicated in geothermal work, is for small firms to locate a resource and then, if they have not previously done so, enter into a joint venture or royalty arrangement with a large firm which has the capital needed for field development. Development can only go forward at the rate agreed upon by the firm providing financing; small firms are consigned to the acreage passed over or cast off by larger ones. Joint venturing - and related practices such as drilling contributions - tend to create a convoy system in which all firms steam together at one rate.

Large petroleum companies[221] are acquiring extensive and choice land positions - through higher bonus bids and by financing drilling by smaller firms.

Data from the Census Bureau's Annual Survey of Oil and Gas indicates that in 1974 the top twenty-four provided 78.2 percent of total expenditures for undeveloped acreages, 76 percent of the pre-drilling prospect evaluations, but only 41.3 percent of the exploratory drilling outlays. The eight largest firms made 52 percent of the expenditures for acquiring non-producing oil and gas leases.[222]

Geothermal field development costs are high, and cash flow lags are substantial so that obtaining a carrying partner is especially important to small firms; utility carrying partners seek lower risks of development and so require access to prime sites.

If a small firm can successfully acquire such a site,[223] it must still compete for any production loan financing as may be available for a newer technology. Bankers are more likely to permit such debt financing of a newer technology if they are familiar with the borrower - and then in all likelihood only for development not exploration.[224] Large banks - capable of larger loans - are more likely to be familiar with the large oil companies. The larger oil companies dominate the production sector while smaller firms have sought quicker pay-outs and tax shelters.[225] As and to the extent that this system is replicated in geothermal energy, development will be a side-line for larger oil companies.

Coal

Large Western coal mines with huge associated reserve fields are expected to be a principal source of energy for Western power generation in the future.

Much Western coal is owned by the federal government. Large amounts of the federally owned lands have been leased to private entities. Coal holdings are dominated by large petroleum companies, western utilities, and railroads, together with holdings of several large "independent" coal companies. Coal holdings, per federal lease data, appear to be moderately concentrated, when the Western United States as a whole is taken as the relevant market. Concentration ratios are higher for statewide or regional areas.

Major oil companies have leased some of the very finest tracts - particularly those of the Eastern Powder River Basin in Wyoming, and have acquired extensive water rights from the Bureau of Reclamation. Recently, several non-oil companies with large coal holdings have been acquired by large West Coast oil refiners.[226] The Federal Trade Commission recently approved the sale of the largest "independent" coal company to a group of oil and gas firms.[227]

As a result of the extensive leasing and acquisition activities of oil companies and the coal companies they control, coal firms owned by oil and gas companies now constitute seven of the fifteen largest coal companies in the United States.

Petroleum companies, as a group, produced about 23% of 1973 U.S. coal production from 7.1% of identified reserves. However, major oil companies such as Exxon, Texaco, Shell, Mobil and ARCO had little or no production from very large reserves.

In the Western states, coal development to date has been largely undertaken either by utility-affiliated fuel companies or by independent coal companies. Low coal-production-to-reserve ratios of large oil companies are a prominent feature of the situation, and are a matter of concern to those seeking competitive fuel markets.

TABLE 66

Coal production and reserves (1973) of some large oil companies were:

	Reserves (Million tons)	Production (Million tons)	R/P
Continental	12058	60.6	198.98
El Paso	4954	0	∞
Exxon*	7000	2.7	2592.59
Gulf	979	8.1	120.86
Shell	5000	0	∞
Texaco	2340	0	∞
SOCAL (and AMAX)**	5400	16.7	323.35
Kerr-McGee	1000	-	NA
Sun Oil	2000	-	NA

Source: Senate Interior Committee Print "The Structure of The U.S. Petroleum Industry."

* Exxon has recently indicated that it owns 12 billion tons of reserve while Mobil has indicated it owns 3 billion tons. Mobil has no mines; Exxon plans to mine 40 million tons per year in 1985. Wall Street Journal, May 20, 1977.

** Pre-joinder of these firms.

Because of the substantial involvement of utility companies and railroads in Western coal leasing, and the large unleased federal tracts remaining, petroleum companies do not completely dominate coal markets at this time. However, their long-range position is an important one: Utility coal holdings may be available for sale to other Western utilities only in conjunction with joint development projects involving the coal-holder. Railroad holdings tend to be situated where they are most likely to be shipped to middle-western and south-central plants. Entry into the large scale mining operations required to serve utility fuel contracts requires large capital outlays and three to five years of development time. With these aspects of the market in mind, it can be said that petroleum company holdings are a significant market factor.

Nuclear

The supply of nuclear fuel, like that of Western coal, comes from an industry in which oil companies have substantial holdings. Unlike coal, uranium resource control is heavily concentrated and future supplies may be affected by cartel efforts. The holdings of large petroleum companies are quite substantial and large electric utility companies have begun to acquire positions.

The conversion of uranium ore into fuel, and the reprocessing of used fuel, will require very high capital cost facilities likely to be very few in number. Major petroleum companies are undertaking all but one of the major initiatives looking toward future uranium ore enrichment and reprocessing facilities.

Geothermal Energy

While the geothermal industry is still taking shape, it is clear that major petroleum refiners will control, as owners and as operators of joint ventures, many of the limited number of better sites. Other participants, principally small utilities and independent petroleum companies, are not likely to outbid the major oil companies for choice new prospects on any regular basis.

Independent geothermal companies tend to perform "service" functions, relying on large petroleum companies or utilities for capital. The small utilities, who are most likely to find geothermal-sized units attractive, have problems obtaining access to bulk power coordination services requisite to development; and they must obtain a share of leases at good sites in order to have an opportunity to seek lower cost energy at a level of risk they can bear.

While the capital costs of geothermal development are high, they appear to be less than those for many other new supplies of energy such as off-shore drilling, or large coal projects. Risk, however, is present, and to alleviate it, control of prime sites becomes a key consideration, as does access to joint venture capital and intelligence.[228]

Thus, the marketing plans and modes of operation in the petroleum industry may be expected to have a substantial effect on the methods of operation, rate of development, and patterns of development of the geothermal energy sector.

Integration Among Energy Companies and Fuel Sectors

"Integration" --common ownership of otherwise competitive supply facilities and successive stages of supply--has been a major feature of the petroleum industry and a major center of public concern for nearly a century. The last decade has seen a new extension of this "integration" by by major petroleum companies--their expansion into energy sources competitive with petroleum.

This additional form of integration has, for obvious reasons, created additional public concern. Petroleum markets appear to have been, and are, far from competitive. Alternate energy sources offer major competitive benefits--increasing energy supply and lowering costs. If dominant petroleum firms own or control such alternative energy sources in a way which can substantially diminish the competitive thrust from the alternate concerns, we will have less energy at higher prices.

The acquisition of energy resources for future extraction is a logical course of conduct to an enterprise thinking of itself as an energy company. Large petroleum companies have money to invest, and know the fuels business.

By vertically integrating, petroleum companies act to assure themselves of supply[229] for facilities at subsequent stages, or outlets for supply. By integrating "horizontally", or into new and/or alternative energy sources, the company tends to extend its life in the fuel sector, and to hedge against competitive risks. Possibly it can help maintain prices.

Large integrated enterprises are able to internally mobilize substantial amounts of capital. They are able to achieve any economies of scale available in the securities markets. With supply security they may be better able to plan larger, more economic facilities for transportation and refining, and to support their own technical staffs - providing competition for "outside" engineering firms.

Integration through acquisition of different fuel resources does not necessarily provide expertise to the acquired sector.[230] The coal operations of integrated petroleum companies are not the recipients of any special mining expertise. Exploratory services are available from independent engineering firms. The mining technology involved is not similar to that in the petroleum or electric utility industries.

The technology involved in converting coal to an oil or gas may be applied to only a portion of the reserves acquired; is largely obtained from engineering equipment firms; and is sought to be financed through government research grants and loan guarantees.[231] The research being done to improve processes for making liquid or gaseous fuels from coal is supported by government, not petroleum industry money.[232]

For geothermal energy, technology is available from independent service organizations, is developed with government money, and in the future is to be subsidized with federal loan guarantees. No refining operations expertise is involved; the amount of private research appears small.

Of eighteen patents in the Patent Office's subclassification for geothermal power generation,[233] five were held by oil companies: Texaco-2, Chevron Research-1, Pure (now Union Oil)-1, and Gulf Oil-1.[234] One patent is held by Mitsubishi, one by Magma Energy Inc., and two others by small geothermal enterprises.

Enterprises such as Toshiba and General Electric Company have worked to adapt the technology of marine turbines to geothermal service. Several small enterprises have sought to promote the use of small units and binary systems.

"Recent efforts in geothermal energy recovery have been mainly directed to systems for increasing the efficiency of recovery. In the recovery of heat energy from hot brine within the earth, systems have been developed which reduce the corrosive action of minerals in the brine on energy conversion equipment...."[235] There is some question whether more research should be devoted to exploratory methods.[236]

Financial Support for Energy Sector Development

Integration may provide only limited benefits in the way of lower capital costs due to access to the credit of large enterprises and may lead to economically wasteful allocations of capital.

Integrated firms raise capital for new projects by (a) the sale of securities based on the credit and earnings of the firm as a whole, (b) the sale of securities based upon the earnings from a specific project, and (c) by internally raising cash (e.g., through depreciation reserves, deferred taxes, or retained earnings).

If project financing techniques are used, integrated firms should have no particular advantage in raising capital. Rather, the credit-worthiness of the project in question should be determinative.

If capital is raised through internal cash flows or through general corporate financings, reliance is being placed on earnings in other areas. Such reliance, e.g., on crude oil profits, precludes the discipline that competitive capital markets might otherwise impose - leading to wasteful investment allocations.

When capital is allocated by a corporate group and not by capital markets, the choice of projects to be financed may be limited to one set of investment goals. Such internal allocations of capital can contribute to a deterioration in the liquidity of capital markets for energy projects.

Limitation of capital flows to a few "integrated" channels may restrict the flow of information to capital markets. This may detract from the performance of capital markets which otherwise might be as efficient or more efficient than the company hierarchies.

Large, diversified capital markets can match up multiple capital sources and multiple investment opportunities and perform a substantial risk evaluation function.

"Integrated" energy enterprises can channel large sums into alternative energy sources. We cannot say that they will do so with unique efficiency; or indeed that primary reliance on them would yield as much capital, as well allocated, as reliance on market devices. The extensive use of highly leveraged project financing indicates that petroleum companies are not introducing substantial amounts of new equity money into coal.[237]

Large integrated oil companies are reported to have higher overhead and drilling costs than "independents". The large enterprises also have a practice of warehousing prospects, whereas smaller enterprises must economically produce or abandon a prospect.

Higher development costs and warehousing of prospects appear to be socially inefficient uses of capital.

Adverse Effects of Integration

The adverse effects of major West Coast refiners participation in other fuel sectors stem from the probability that this participation causes development of these resources to occur in a manner that results in less competition among fuels, and among the major refiners and other fuel suppliers. Less competitive development can result in a slower pace of new energy source development than might otherwise be the case.

Diminution of competition can arise in at least two distinguishable ways. First, a company or set of companies with a major investment in one sector can be expected to phase in new operations so as to maximize overall profit, and thus protect the profits of the sector in which it already has investment. Secondly, vigorous extension of such companies into alternate supply sources can create barriers to development by rival entities, by diminishing their opportunities to acquire factors of production.

Oil companies will not be eager to promote geothermal energy sales which return less profit than sales of other forms of energy foregone by reason of geothermal sale. Recent testimony by a petroleum company witness regarding coal holdings illustrates the point:

> Senator Abourezk (continuing). And ask you a question that goes right to the heart of these hearings and the heart of this legislation that we are considering today.
> Would Continental Oil, owning 2 percent of the petroleum market, controlling 2 percent of that market and 9 percent of the coal market, would Continental Oil direct its coal subsidiary,

Consolidation Coal Co., to undersell to utility companies that are buying oil from Conoco--would you direct your coal subsidiary to undersell them?

Mr. Hardesty. To undersell?

Senator Abourezk. On a BTU equivalent basis. Say you had a public utility, or a private utility, that was thinking of converting to coal, if it could find coal at a somewhat cheaper BTU equivalent than it buys oil for. Would you tell your coal subsidiary--or would you permit your coal subsidiary to undersell your oil subsidiary?

Mr. Hardesty. No, sir, under no circumstances.

Senator Abourezk. Thank you. Please continue.

Mr. Hardesty. I think I want to enlarge on that, and I hope that our discussions will explain what we do with our profits. Prices will reflect our costs; we recapture both our investment and our operating costs. These are returned to the corporation to put us into a position to replace that capacity or that resource as it might be worked out. That would be different for each of those energy sources, Senator, and they are not one related to the other.

Senator Abourezk. If on a cost basis, coal could sell for somewhat cheaper than a BTU equivalent of oil, would you still not direct your coal subsidiary to undersell your oil subsidiary?

Mr. Hardesty. You are dealing with actual circumstances. We would not direct a coal subsidiary, a nuclear subsidiary, to have its price changed, modified in any way, so as to either compete readily against, or not compete against, another form of energy. I think that broadly answers your question. We are not going to play one source of energy against the other.[238]

This control over intra-divisional rivalry can be extended to other enterprises over which the company has substantial influence. Such firms are those needing access to joint ventures for exploration and development, unitization agreements (including logical mining units), pipelines, moorings, refineries, and exchange agreements with their "competitors". In the geothermal area, such firms could include using petroleum company capital for exploration and development, and firms involved in joint field development by reason of unitization, information exchanges, or other reasons.

In the case of the petroleum industry, extensive interrelationships among major firms can create a situation of commonality or relative uniformity in the entire sector's approach to energy resource development. A recognition of widely shared joint interests can lead to a tendency not only to not gore one's own ox, but also to avoid goring its yoked neighbor.[239]

The petroleum industry has a history of being concerned with "over-production". It has underproduced OCD tracts and supported state prorationing. Larger companies appear to have acquired large undeveloped blocks of coal which is being held for future use.

Development financing by large oil refiners has been preferentially channeled to overseas ventures, where antitrust investigators have reported a history of supply restraint activity aimed at maintaining or raising prices.[240]

All this suggests that major petroleum companies may follow a pattern of phasing production from their extensive geothermal holdings in a manner geared to maximizing overall producer yields from their various operations, rather than--as an independent developer might--in a manner yielding the best possible return from each of their resources considered in isolation. (If there were no horizontally-integrated companies, this last model would be equivalent to competitive pricing.)[241] To the extent large petroleum companies influence the pace of geothermal energy development, that pace can be expected to be retarded by these considerations.

Barriers to Entry

Cross-fuels integration by a set of very large firms can retard development in a new sector, lessening the variety of development and the pace of activity, by limiting the access to factors of production available to non-integrated and non-dominant firms. Only by obtaining access to such factors can new entrants substantially alter market conditions.

The factors of primary concern are land (leases) and capital.

We have previously noted that development of geothermal fields requires that willing developers have access to fields (e.g., leases) that appear to present high quality resources and lower risk. It may be assumed that these sites are more conspicuous than others and will be among the sites first discovered and leased.

The geothermal industry is dominated by lease holdings of petroleum companies or of companies controlled by firms or persons actively engaged in the petroleum industry.[242]

The importance of such a strategic position can be very considerable.

The firms which get the choice prospects may get a permanent advantage of major consequence.

The pattern of bidding on geothermal leases indicates that petroleum companies can and do outbid other entities for choice sites. This presumably reflects a differential in available resources and market opportunities between the large integrated oil companies and others. Many prospective investors may not seek high prices based on costs of alternative fuels; or have equivalent profit streams to shelter or invest.

This situation is accentuated by federal leasing practices. The "bonus bid" system requires more capital from bidders than a system geared to return from production. This favors capital rich firms; while the lack of due diligence requirements promotes "warehousing".

A complementary exclusionary effect arises from the fact that "independent firms" are largely performing lease-broker and service functions for larger enterprises or are otherwise largely dependent upon them for financing - e.g., joint enterprises or bottom-hole contributions.[243] This service relationship is also a barrier to expansion by small firms. It curtails their independence in exploiting or otherwise dealing with the resources in which they have a proprietary interest.

Smaller firms in the geothermal sector have considerable concern about access to capital, for several reasons.

First, they note, and the data show, that the higher prices bid for properties by petroleum companies drive up the costs for entering the business. Second, they note that larger firms established in energy markets have lower costs of capital than smaller firms. This advantage may come in part from the wider and more extensive contacts with financial markets possessed by major established companies--particularly petroleum companies. The advantage may come in part from lower risks associated with "deep pockets"--the availability of large capital streams to remedy shortfalls or misadventures on which smaller enterprises break up. It derives in part from tax treatment enjoyed by large international petroleum companies and existing firms in general as opposed to new entrants.[244]

The prospect presented is a possible "two-tier" market in geothermal energy-- a higher cost, relatively thin market for smaller and less established firms, and a larger, lower cost market for larger, established petroleum based firms. Such a situation would complement difficulties new entrants experience in obtaining desirable leases.

A related concern is the possible influence of the petroleum sector on financial institutions' willingness to invest in independent operations in markets for sales of limited partnerships and other new equity offerings. A new entrant is required to take his plans to financial houses that have ownership, directorate, and business-dealing relationships with his competitors. According to testimony of an officer of a very large bank that is heavily engaged in such financing, petroleum-company-affiliated directors of banks are on bank boards because of their expertise; in the witness's bank, smaller petroleum loans are summarized for these directors and larger loan applications are presented to them in detail.[245]

Municipal systems do not receive tax reductions and accordingly must absorb all of their dry hole costs. In the event of a joint enterprise with a private firm, the municipal system may or may not be able to effectively share tax reduction derived savings.

Beyond this, there may be fear that the views of large financial houses (interlocked with the major oil companies) as to when and to what extent a new energy source will be developed may tend to proceed in step with each other.[246]

The resulting tendency for lockstepped progress may be especially strong as financing requirements rise and syndicates become more necessary to float energy project financings.

High profit expectations, growing out of the profit levels earned in non-competitive sectors where production may be withheld, can make difficult the task of a new firm seeking to raise money to fund a project to produce lower cost energy.

Much of the financing available comes directly from firms with a major stake in other fuels. To the extent a drilling or development firm is dependent for capital on such a firm, its own pace in the geothermal market may be constrained.

Conclusion

Geothermal energy's attraction is as a domestic source of energy and as a competitive stimulant in fuel markets. Its development can best go forward in the context of a diversified and unconcentrated industry. Channels for investment also need to be diverse.

Small firms have played a major innovative role in developing techniques for locating and engineering geothermal prospects.

The continuation of such work, and their participation in high cost development of fields, will require that small firms have access to land, capital, and purchasers. Absent small firms, we believe that the number of different approaches--and perhaps even the enthusiasm with which these approaches are tried--is likely to decline. Reliance for development on a relatively small number of large organizations is likely to diminish the scope of innovation and decrease the pace of enterprise.

Firms with a diversity of profit goals and perceptions of future returns, including firms seeking energy for use in production of their goods, may be expected to find a wider variety of prospects appealing.

The ability and extent to which small firms participate in geothermal development - in more than a service company role - will accordingly, we believe, have a substantial effect on the rate of development of this resource.

The recent series of mergers between major oil refiners and uranium and coal holding companies tends to extend their common viewpoint further, as do their extensive financial linkages.

At the same time, capital costs for entry into the fuel supply market on a scale large enough to serve utility contracts have dramatically risen so that established participants in a sector are less likely to be challenged by others.

This synthesis of attitudes and capital can be seen as tending to rationalize the investment and major operations of the large concerns involved in a noncompetitive manner.

Federal leasing and research programs do not appear to be organized in a fashion militating against unnecessary concentration of geothermal energy supply.

Horizontal integration across energy markets is an issue of substance in the geothermal energy sector; government policy may appropriately be aimed at preventing the harmful effects of such integration.

Notes - Chapter 4

1 Per the Bureau of Mines, News Release: Annual U.S. Energy Use Drops Again, (April 5, 1976) in 1975 electric utilities consumed 20.1 quadrillion Btus, some 28.3% of the 71.1 quadrillion Btus consumed in the United States that year.

2 This assumes utilities only burn bituminous coal and lignite. Inclusion of the small quantity of anthracite consumed would yield no material difference.

3 The Bureau of Mines reports residual fuel oil demand, not consumption. Total domestic consumption in 1975 of bituminous coal and lignite was 558,000 thousand tons (U.S. Bureau of Mines, Minerals and Materials, January 1976.) Domestic demand for residual fuel oil in 1975 was 887,963 thousand barrels. (Deliveries to steam-electric plants totalled 433,568 thousand barrels (Nos. 5 and 6 fuel oil.) Bureau of Mines, Crude Petroleum Products, and Natural Gas Liquids (December 1975) and FPC Annual Summary of Cost and Quality of Steam - Electric Plant Fuels, 1975.

4 Electric utilities alone use civilian nuclear plants. They use unit trains for coal, and are almost the sole present large market for steam coal, though in the future there will probably be other large coal sales for gasification units. The future of coal gasification is clouded as unit outputs may be limited by water requirements and output cost in

excess of alternative supplies. Utilities use low sulfur residual fuel oil in quantities overshadowing other markets. Utilities have distinct contractual supply arrangements.

5 In addition to eleven projected geothermal units (all in the West), 468 mw (390 in the West) of fuel cell capacity are forecast of which 180 mw (all in the West) will be equipped to burn refuse and 251 mw (all in the West) to employ waste heat.

6 Staff Summary of Electric Utility Expansion Plans for 1976-85 FPC News Release No. 22493 (July 16, 1976).

7 Utilities consume residual fuel oil (e.g., No. 6 oil or Bunker "C" oil) in their boiler furnaces while they use lighter oils for peaking gas turbines.

8 Geothermal pricing based on substitute fuel prices (perhaps in excess of geothermal production costs) might yield a rate of return on energy company investment commensurate with that found in production of crude oil. Such prices would maintain the stability of fuel markets.

9 The dominance of contract purchasing was reflected in December 1975, when 7,762.5 thousand barrels of residual fuel oil were purchased under contract by West Coast utilities, and only 59,000 barrels were purchased on the spot market.

10 Fuel adjustment clauses are based on variations from base fuel cost in

either the imputed cost of fuel burned per kilowatt-hour generated or the cost per Btu of fuel acquired. See discussion, Statement of Bierman and Stover, Hearings on the Utilities Act of 1975, Senate Gov't Operations Comm., 94th Cong., 1st Sess. (1975).

11 Fuel adjustment clauses have been thought to tilt the choice between higher fuel costs and capital equipment toward use of more fuel. This is reported to have been the case prior to 1973. The 1973 Annual Report of the FPC, p. 17. Also see General Utility Rate and Fuel Adjustment Clause Increases, 1974, Senate Gov't Op. Comm., 94th Cong., 1st Sec. (1975).

12 The audit report states that SCE passed through a variety of "ineligible costs" including: excessive charges for operation of SCE's fuel-oil pipeline system; interest charges for oil purchased through a financing trust; fuel-exploration charges attributed to SCE subsidiary Mono Power, which produced no fuel; outdated costs linked to pipeline operations; and tank maintenance charges. FPC Staff Audit Report on Fuel Adjustment Clause. This audit did not attempt to review the property of SCE fuel procurement practices.

13 Utilities' captive mine production was as follows:

	1973	1974
Million tons	33.5	34.6
Average price/ton	$6.77	$9.32
Total FOB plant costs (millions)	$227.0	$322.7

14 Some western utilities (e.g., Utah Power and Light, Pacific Power and Light, or The Montana Power Company) own huge coal reserves from which they will be selling fuel to others as well. And some utilities (e.g., PG&E and SCE) have entered into uranium ventures.

15 The junction of Arizona, Nevada, Utah and New Mexico

16 Geothermal developers are restricted in sales to utilities within limited transmission distance of their wells.

17 These states plus Alaska and Hawaii comprise Petroleum Administration for Defense (PAD) District V.

18 Residual fuel oil is a heavy petroleum product produced after lighter products, such as gasoline and distillate oil are extracted from crude oil. Residual fuel oil is consumed in industrial and utility boiler furnaces. Lighter, more expensive petroleum products are consumed in turbine units.

19 See Interior Department, Environmental Impact Statement on Eastern Powder River Basin Coal Mining, 1975 Annual Summary.

20 Domestic waterborne movement from the Gulf Coast added 626,000 barrels (includes No. 4 oil).

21 Recent long term contracts for the purchase and sale of residual fuel oil between Southern California Edison Company (SCE) and Standard Oil of California peg prices to those for Saudi Arabian crude oil, and may

deprive SCE of the benefits of changed conditions resulting from North Slope production. SOCAL reports building its two large California refinery expansions to use Arabian, not Alaskan type crude - although this assertion has been questioned. Supplies of Alaskan oil available to the West Coast may be reduced if Alaskan oil is shipped abroad in conjunction with oil exchange agreements.

22 The projected coal capacity included the Kaiparowits plant - which appears to be suspended.

23 Information regarding the sources of energy and the unit costs of fuels in the past five years is set forth in the following table:

	Percentage of Energy by Source					Average Cost Per Million BTU's*				
	1971	1972	1973	1974	1975	1971	1972	1973	1974	1975
Oil	23%	27%	45%	38%	46%	61¢	78¢	97¢	199¢	267¢
Natural Gas	41	39	21	17	13	34	37	39	58	87
Coal	10	16	15	15	14	18	21	23	27	31
Nuclear	5	4	3	5	5	19	19	17	11	17
All Fuels	79	86	84	75	78	39	46	66	119	176
Hydroelectric	9	7	9	10	8	—	—	—	—	—
Purchased and Interchanged Power	12	7	7	15	15	—	—	—	—	—
	100%	100%	100%	100%	100%					

* The Company's average fuel costs expressed in cents per kilowatt-hour for the year 1975 were 2.638 for oil; .886 for natural gas; .330 for coal; and .183 for nuclear. For the year 1975, the net cost of purchased and interchanged power (primarily hydroelectric) was .750 cents per kilowatt-hour. (1975 Annual Report).

24 Electrical World, December 1, 1975 at page 31, also reporting that "Next year's oil requirement is about 55 million bbl, or 62% of the utility's overall fuel needs."

25 Ibid. An appendix contains a more detailed description of fuel procurement agreements of PG&E and SCE.

26 SCE's Form 10-Q filed in the Securities & Exchange Commission for the first quarter of 1976.

27 On June 30, 1975, PG&E owned and operated 30 thermoelectric generating plants. PG&E's prospectus of October 1, 1975, for the sale of $175,000,000 first and refunding mortgage bonds, p.10.

28 PG&E 1975 oil deliveries totalled 13,447,000 barrels.

29 Before discussing PG&E's oil acquisition program, it should be noted that PG&E entered into agreement with the Island Creek Coal Company, a subsidiary of Occidental Petroleum, for the purchase of a coal property near Price, Utah, if the property is found to have deposits of at least 150,000,000 tons of coal.

30 The prospectus of October 1975 relates, pages 14-15, how shortages of natural gas together with delay in completion of nuclear units, have in-increased PG&E's reliance upon higher priced, low sulfur fuel oil.

31 A comparison of capital costs for nuclear and geothermal shows that the planned nuclear power units, at the Diablo Canyon plant, have estimated

costs of construction of $465.00/kilowatt (or at 80% load factor about 12 mills per kwh). The highest fixed charge for a Geysers Unit ($200/kw) compares favorably in this regard (using an 18% annual fixed charge rate) only 5.1 mills per kwh.

32 Some long-term fuel contracts of California utilities are summarized and discussed in the Appendices.

33 P.U.C. Application 55541, Direct testimony of Mr. Benton.

34 FEA regulations permitted higher prices than Union was offering. PG&E asserted to the California Public Utility Commission that it felt compelled to renegotiate, and, in addition, asserted that the price of $12.26 was not unreasonable, under the circumstances.

35 Letter of December 16, 1974.

36 Letter dated February 3, 1975, to the Federal Energy Administration (FEA), by Mr. Malcom H. Furbush, PG&E Associate General Counsel.

37 Tesoro Prospectus of December 17, 1975, p. 24.

38 F.P.C. Form 1-M

39 The LADWP is building a hydroelectric project (the Castaic Project) and is participating in the Navajo Project near Page, Arizona. These projects will tend to alleviate its relative dependency on oil.

40 LADWP acquired resid from SDG&E in 1975 when SDG&E found that it had purchased resid in excess of its own needs.

41 Spot sales were about 1% of the total deliveries.

42 PGE Prospectus of December 11, 1975, for sale of bonds.

43 Tucson Gas & Electric Co., Prospectus of September 17, 1975 for sale of preferred stock.

44 Arizona Public Service Company, Prospectus of November 20, 1975 for sale of bonds.

45 Public Service Company of Colorado, Prospectus of October 22, 1975 for sale of bonds.

46 In January 1976 and December 1975, West Coast refinery yields of resid were 21.7% and 21.4% respectively. U.S. total of yields were 11.2% and 10.5%. USBM Mineral Industry Survey.

47 In 1974, West Coast refinery inputs totalled 682,045,000 barrels, 400,971,000 barrels of domestic crude oil and 281,074,000 barrels of foreign crude.

48 USBM Mineral Industry Surveys

49 FTC Staff Report, Report to the Federal Trade Commission on the Structure, Conduct and Performance of the Western States Petroleum Industry (September 1975) at page 12 referred to thereafter as FTC Staff Report.

50 This study, however, was concerned only with record ownership of refinery facilities, and did not consider functional control of independent facilities by through-put, crude supply or product purchase contracts, nor did

it examine the regional variations, as, for example, the San Joaquin Refining market which is highly isolated.

51 Tidewater Oil Co. v United States, 418 US 906 (1974).

52 Absent data on through-put and exchange volumes, a complete picture of refinery control is not obtainable. However, some smaller independents have held crude oil purchase contracts with the majors which commit a substantial portion of the "uncracked residuum" back to the major for further refining.

53 United States v Phillips Petroleum Co., 1973 - 2 Trade Cases 74789 (C.D. CA., 1973), aff'd without opinion, 1974 - 2 Trade Cases 75143 (Sup. Ct., July 8, 1974) discussing competition by threat of entry in a market (motor gasoline), which few could afford to enter. Toscopetro has recently entered into an agreement to purchase crude oil from Natomas, after having acquired the Signal refinery and pipeline use rights from that company.

54 Petroleum refineries in the United States and Puerto Rico, January 1, 1976, in the Mineral Industry Survey Series, Capacity of Petroleum Refineries in the United States and Puerto Rico; Table 4 of that report.

55 The SOCAL expansion is limited to distillation units, and does not include increased cracking capacity. This indicates an intention to shift the refinery product mix toward a greater relative output of fuel oil. Frank Parker, SOCAL's assistant to the vice-president for refining is

reported in Business Week, January 12, 1976, p. 94, as indicating that SOCAL has a profit incentive to maximize the refineries' ability to produce more middle distillates and residual products in order to tap a utility and industry market that is expected to grow at about 6% annually because of dwindling natural gas supplies. SCE has recently entered into a substantial contract with SOCAL for the purchase and sale of residual fuel oil, with prices pegged on overseas crude oil prices.

SOCAL, of course, has substantial avails of Gulf Coast crude oil, deliverable to the Middle West by pipelines, and is therefore in a good position to acquire TAPS crude from BP on exchange, since BP has no West Coast refining capacity, but needs crude deliverable to Ohio. Exxon, also, could utilize SOCAL's Gulf Coast crude.

56 There is also a small refinery owned by ARCO and one each owned by Phillips and Gulf and a total of perhaps twelve enterprises in Venezuela that have refineries.

57 The Bahamas refinery source is owned 50/50 by SOCAL and New England Petroleum Company. See International Petroleum Encyclopedia (1974). Mobil and Exxon historically have been associated for on-shore Indonesian production in the P.T. Stanvac joint enterprise.

58 Congressional Research Service, A Study of the Relationships Between the Government and the Petroleum Industry in Selected Foriegn Countries:

Indonesia, Senate Interior Committee Serial No. 94-26 (92-116), 94th Cong., 1st Sess. (1975).

59 Petroleum Economist, April, 1976 at page 130.

60 Subsidiary relationships from Skinner, Oil and Gas International Year Book: 1973.

61 See FTC Staff Report.

62 Hearings on The Industrial Reorganization Act, Part 9, The Energy Industry, Senate Judiciary Committee, 94th Congress, 1st Session (1975) presents a series of reports on aspects of the petroleum industry in California.

63 Ibid., at pp. 97-98. The Joint Committee's Report "Crude Oil Pipelines in California" is hereafter referred to as the California Report.

64 Vulnerability of Total Petroleum Systems, Office of Oil, Department of the Interior prepared for the Defense Civil Preparedness Agency, Washington, D.C., 20301, May 1973, page 17.

65 Ibid. The "ton-mile" scale understates the pipeline's competitive position versus barges, since the latter are confined to waterways whose winding configuration increases mileage.

66 U.S. Bureau of Mines, Crude Oil, Petroleum Products, and Natural Gas Liquids: 1975 (Final Summary), February 24, 1977 at Table 14.

67 See Hearings of Senate Judiciary Committee, supra. And see,

California Crude Oil Market Control, Ibid., p. 24, et. seq.

68 Ibid.

69 Three major firms, Exxon, Arco and Socal are partners in the Santa Ynez joint production venture ("HAS") which could provide up to 10% of California's output by 1977.

70 The Federal Energy Administration recently issued special price rules for District V (California and Alaska) permitting adjustment of the gravity differentials. 41 F.R. 48324 (Nov. 3, 1976) This rule only authorized partial relief for the problem.

71 The Four Corners Pipeline, originally owned by SOCAL (25%), Shell (25%), Gulf (20%), ARCO (10%), Conoco (10%), and Superior (10%), but is now owned wholly by ARCO, which has announced its intention to reverse the line's flow, and two systems owned by SOCAL that terminate in private lines.

72 California Report, p. 22.

73 In such settlements,Firm A owing a balance of deliveries to firm C arranges for firm B which owes deliveries to A to make delivery to firm C instead.

74 While most of these lines apparently hold federal public land right-of-way permits, obligating them to perform as common carriers, there is no

ready access to records of such permits for private enforcement of the permit requirement. Interior has never brought such actions, nor has it formally published the operating regulations required by the Trans-Alaskan Pipeline Act of 1973 amending the Mineral Leasing Act, 30 USC 185.

75 Petroleum Industry, Sen. Interior Comm., 93rd Cong., 1st Sess., (1973); Vol. 3, p. 904.

76 In 1973, ARCO shipped 33.6% and SOCAL 31.52% of the through-put on the Kenai line.

77 The Preliminary Federal Trade Commission Staff Report on Investigation of the Petroleum Industry, p. 6.

78 Part I, Rept. No. 94-1005 94th Cong., 2d Sess. (1976) p 25-26 ("Petroleum Industry Report")

79 87% of domestic inputs moved by pipeline, Bureau of Mines, "Annual Petroleum Statement-1974 (Final Summary), Table 14.

80 Imposed by the Hepburn Act of 1906.

81 In one case, it is alleged that a firm was denied access because of oil "quality" to a line to ship crude from a field whose output had previously been purchased by the pipeline owner. Testimony of C. Siess, Part 8, Hearing on the Industrial Reorganization Act, Senate Judiciary Comm., 93rd Cong., 2d Sess. (1974) pp. 6241-42.

82 Testimony of George Stafford, 3 Hearings on Market Performance and Competition in the Petroleum Industry, 93rd Cong., 1st Sess. (1973). "Stafford Testimony." As the Petroleum Industry Report notes, individual interest systems may be similarly exempt. ICC Chairman Stafford referred to The Pipeline Cases, 234 US 548 (1914). See also Valvoline Oil Co. v U.S., 308 US 141 (1939). The Hepburn Act is part of the ICC Act, 49 USC 1-6.

83 Report of the Attorney General pursuant to Section 7 of the Deepwater Port Act of 1974 (November 5, 1976).

84 Levy, The Regulation of Offshore Crude Oil Pipelines and the Consequences for Competition (1975).

85 The Stafford Testimony, *op. cit.*, p. 910, provided the following information "to show the similarities and dissimilarities between joint venture pipelines and undivided interest pipeline systems."

Joint Venture Pipeline - A "joint venture" pipeline, as it is known in the industry, is a corporate entity consisting of two or more owners, usually oil companies, who control the pipeline through ownership of the majority of the stock. The stock is usually not traded publicly.

Undivided Interest Pipeline System - An "undivided interest" is similar to a joint venture but in itself is not a corporate entity. The pipeline facilities (assets) are owned in an "undivided interest" by two or more

Note 85 (cont'd)

pipeline or oil companies. This "undivided interest" does not separate or identify the physical assets by individual ownership. One company, a participant in the system, is usually selected and acts under an agreement as the agency operator of the pipeline facilities.

There follows a tabulation in which "joint venture" pipelines are compared to "undivided interest" pipeline systems concerning various aspects. Shown first are the similarities of both, followed by those in which they differ.

	Joint Venture	"Undivided Interest" System
Similarities:		
(a) Participated in by two or more oil and/or pipeline companies	Yes	Yes
(b) Shippers over the systems	Predominantly	Predominantly the participants or their affiliated or parent companies
(c) Throughput agreement among participants	Yes	Yes
(d) Certificate of necessity required by the ICC to construct or abandon pipeline facilities		

Note 85	Joint Venture	"Undivided Interest" System
Similarities (cont'd)		
which may lead to the discrimination of small shippers.	No	No
Dissimilarities:		
(a) Incorporated	Yes	No
(b) Stock issued	Yes*	No
(c) Original construction and sub-qequent expansion of system	Planning and supervision per-formed by company personnel, actual construction done by outside contractor.	Designated operator designs line which plan is subject to approval of partici-pants. Line is con--structed by outside contractor and supervised by operator personnel.
(d) Operation, maintenance and accounting	Performed by its own personnel	Performed by desig-nated operator

Note 85	Joint Venture	"Undivided Interest" System
Dissimilarities (cont'd)		
(e) Payment of expenses, invoices, advalorem taxes, etc.	Paid by corporate entity	Paid by designated operator who collects each party's proportionate share.
(f) Tariffs filed with ICC	Yes	Not by or for the system itself. Each participant files its own tariff as a separate common carrier, and collects its own revenue.
(g) Annual Report Form P and quarterly reports filed with the ICC.	Yes	Not by or for the "system" itself. Each participant records its proportionate share of the system in its own reports.

*Unlike many corporations where the stockholders are passive, the joint venture stockholders are active participants in the entire operation of the pipeline.

In the TAPS system, the operator, Alyeska Pipeline Company, is a corporate venture owned jointly by the "undivided interest" participants in the line in shares roughly proportionate to their "undivided interest"

86 Senate Judiciary Committee, Report on Petroleum Industry Competitive Act of 1976, Rept. No. 94-7005, 94th Cong. 2d Sess (1976) at Table 4.

87 The ten fields have 8,310 wells, of the state's total of 38,688 wells. In 1974, 855 wells were completed in the ten fields representing 56 percent of the 1,414 total completions statewide.

88 In 1975 offshore production of crude petroleum was 501,270 thousand barrels or 16.4 percent of total U.S. production (3,052, 048 barrels). 1975 California offshore production was 79,096,000 barrels (15,435,000 from federal and 63,661,000 barrels from state lands) which was 24.2 percent of total California production.

89 The National Petroleum Council, U.S. Energy Outlook, at Chapter Four, Domestic Oil and Gas Availability (1972) forecast, (Table 38) that of the 384.2 billion barrels of oil in place, 112.3 billion barrels were located offshore (or in south Alaska), 96 billion barrels on the North

Slope, and 176.9 billion barrels onshore. For the onshore Pacific Coast region, 21.9 billion barrels were forecast as discoverable, while offshore of that Coast, 47.7 billion barrels were so forecast.

On a world-wide basis, in 1973 some 14.8% (8.48 million b/d) of total oil production came from offshore. Petroleum Economist, Offshore: Over 20 million b/d in the 1980's? (February 1976) p. 49. This article reports a forecast by the Scottish Council that in 1980, some 24% of production will be from offshore areas (21.92 million b/d of 89.76 million b/d).

90 These can be seven to ten years in duration.

91 Published reports indicate that recoverable reserves for the Santa Ynez Unit may be as high as two billion barrels of oil and one trillion cubic feet of gas; however, reasonably accurate reserve estimates can be calculated only after additional drilling and some production has taken place. The Unit encompasses the separate Sacate, Pescado and Hondo fields.

92 See Testimony of William John Lamont, Hearings on Energy Data Requirements of the Federal Government, Part III, House Small Business Committee (1974) at p. 272, 303.

93 High bids totalled $438.2 million, Wall Street Journal, December 12, 1975 at page 98.

94 This last tract was one of three on which base royalty is 33-1/3% of

production, double that of other offered tracts.

95 For large pertroleum companies, and even more so for smaller ones, it appears that a substantial portion (over half the twenty firms with the largest sales, and 80% for smaller firms) of petroleum production occurs in situations of joint ownership. See, Sen. Interior Comm., The Structure of the U.S. Petroleum Industry: A Summary of Survey Data, Ser. No. 94-37 (92-127), 94th Cong., 2d Sess. (1976). at pp. 48-49.

96 The FTC staff also notes that with the recent acquisition of Pasco's crude operation, Standard Oil of Indiana's share of production would rise from 11.2 percent to 13.7 percent causing the top four companies to have 39.2 percent of production and the top eight 57 percent.

97 There is a small pipeline (65000 b/d) carrying crude oil from the Southwest to Southern California. The Four Corners Line was owned by ARCO (10%), Continental (10%), Gulf (20%), Shell (25%), Socal (25%), and Superior Oil (10%). It has recently been wholly acquired by ARCO which is reversing the direction of line flow.

98 See Senate Interior Committee Staff Report "The Trans-Alaskan Pipeline and West Coast Petroleum Supply, 1977-1982"

99 Per Mr. Chuck Champion, the State of Alaska's Pipeline Coordinator, (November 21, 1975) as reported in California State Lands Division, "A Preliminary Analysis of the "SOHIO" Project for the State Lands Division"

(January, 1976).

100 Besides offshore California and the North Slope, the other new source for West Coast refineries is Elk Hills, where production is expected to be able to reach to 160,000 barrels a day. However, it should be noted that 20% of the Elk Hills reserves is owned by Standard Oil of California, which also owns the only pipeline now connecting the field. Legislation is necessary to permit opening of full production from the reserve.

ALASKAN NORTH SLOPE SHARES ARE

AS FOLLOWS:

	Ownership of North Slope Oil	Ownership of TAPS Pipeline
Sohio	53.2	33.3
BP	--	15.8
EXXON	20.3	20.0
ARCO	20.3	21.0
Mobil	2.1	5.0
Phillips	2.0	1.7
Chevron	.08	--
Ten others	1.3	--
Union	--	1.7
Amarada Hess	--	1.5

Source: N.Y. Times, June 19, 1977, p 33.

101 The larger Prudhoe Bay producers BP/Sohio, Arco, Exxon, Mobil, do not seem to be very active in geothermal.

The major oil companies involved in geothermal energy, SOCAL, Phillips and Union for instance, have limited interests in the North Slope. It will be interesting to see how their geothermal efforts continue after the opening of offshore leasing in California for which both have recently submitted high bids.

102 However, since the majority of West Coast production will come from joint ventures in which these companies hold closely linked interests, particularly THUMS, Prudhoe Bay and Santa Ynez, the "individual" shares do not reflect the total competitive impact.

103 Per Mr. Chuck Champion, Alaska's Pipeline Coordinator (11/21/75) as reported in California State Lands Division, "A Preliminary Analysis of the "Sohio" Project for the State Lands Commission (January, 1976).

104 Section 28 (r) of the Mineral Leasing Act, as amended. See Report of FTC Western Task Force, Appendix (A).

105 In the operation of an "undivided interest" pipeline, each owning company is assigned a period of use of the basic facility corresponding to its basic ownership share.

106 The Attorney General's November 5, 1976, Superport Report characterizes these aspects as involving "inherent anticompetitive problems" (p. 103),

and, particularly, that "Undivided interest Pipelines present severe anticompetitive problems."(p. 112, emphasis supplied).

107 See Senate Interior Committee Staff Report *supra*. Again, in the November 5, 1976, Superport Report, the Attorney General reiterates that the "ICC's powers are severely circumscribed...(with) no power over the form of corporate organization...no power to order elimination of restrictive provisions in underlying agreements...no power to order frequent share distribution...(and) no power to order expansion of facilities."

108 A Preliminary Analysis of the "SOHIO" Project for the State Lands Commission, "State Lands Report" *supra*, p. 10 and cf p. 11.

109 The proposed port could handle 5-6 million b/d. *Ibid*. p. 15.

110 A "Northern Tier Pipeline" has been proposed to move Alaskan and foreign oil to Rocky Mountain and Mid-Continent areas. The line is envisaged as being about 1,500 miles long, and 36 inches in diameter, with a capacity of 800,000 barrels per day. This proposal, however, is made by a transportation company which is not among the TAPS owners. There is no assurance that the TAPS owners would in fact use this facility.

111 With planned additions, SOCAL's share of West Coast refining has been projected to increase.

112 Although reporting that SOCAL says that its new 300,000 b/d refinery expansion is designed only for imported, high-sulphur, light crude oil,

the State Lands Report, citing an article in the Oil and Gas Journal of April 7, 1975, observes that expansion built into the design would indicate that these refineries are capable of refining Alaskan crude oil. Ibid., p. 15.

113 California State Lands Commission, California and the Disposition of Alaskan Oil and Gas - A Working Paper (June 1976), Chapt. III.

114 Ibid.

115 SOHIO/BP projects a crude oil surplus on the West Coast of 300,000 to 600,000 b/d by 1978, and E. Stanley Tucker, writing in the November 1976 issue of the Petroleum Economist "Markets for Alaskan Crude", projects an 800,000 b/d surplus in 1980.

116 Tucker, supra.

117 ARCO and Exxon's respective crude oil shares in the West will increase dramatically when North Slope oil comes to market.

118 A number of observers, including the Senate Subcommittee on Multinational Corporations, have concluded that the international companies pro-rate production for the cartel. In its 1975 Report the Multinational Subcommittee concluded:

> The multinational oil companies... provide the OPEC with important advantages. As vertically-integrated corporations, the major oil companies guarantee OPEC members an assured outlet for

their production in world markets. The primary concern of the established major oil companies is to maintain their world market shares and their favored position of receiving oil from OPEC nations at costs slightly lower than other companies. To maintain this favored status, the international companies help pro-ration production cutbacks among the OPEC members.

Multinational Oil Corporations and U.S. Foreign Policy, p. 95. And see, Senate Judiciary Comm., Report on Petroleum Industry Competition Act of 1976, Part I, Report No. 94-1005, 94th Cong., 2nd Sess. (1976) p. 43-44.

In the Multinational Subcommittee's hearings, Professor Adelman testified that:

> The cartel governments use the multinational companies to maintain prices, limit production and divide markets. This connection, I submit, is the most important strategic element in the world oil market. The governments act in concert, the companies do not need to collude. The governments transfer oil to the companies at identical publicly announced prices. Thereby the governments can watch one another. The companies produce only what they can sell.

So long as the governments are content to accept the market shares that result from the companies' sales efforts, the cartel holds. Time is on their side. As the cartelist governments get richer, it becomes easier for them to accept output limitations or even cutbacks.

Hearings, Part II, p. 3.

119 The meeting of OPEC in Bali, Indonesia, is generally believed to have foundered on the inability of OPEC countries to devise price differential and pro-rationing schemes. This subject was a topic of frequent discussion in the June 2, 3 and 8, 1976 hearings of the Joint Economic Committee.

120 See statement of Senator Frank Church to House Antitrust Subcommittee (March 1975).

121 Joint arrangements are likely to include exchanges, refinery service transactions, and joint venture pipelines.

122 Federal petroleum price regulation does not provide a substitute for price competition nor does it initiate the role of competition in pricing or in production planning.

Federal regulation is only a temporary program to set ceilings on some of the prices charged for some domestic crude oil production and some upstream profits. Regulation does not extend to supply planning, pipeline, refinery, or well facility certification; nor does it specify prices. Indeed many oil sales are made at prices below those permitted by regulation. Efforts to raise prices by government action may not be expected to hold up in the face of competitive pressure to reduce prices. Indeed government action is as likely to mirror industry conditions as it is to determine them. This is so in part because federal petroleum regulation did not come into being as a response to perceptions of intrinsic abuses in the regulated industry, as did many other regulatory institutions. Being addressed to an emergency, federal petroleum regulation does not concern itself with changing industry structure.

123 Rising alternate costs of space and process heating may enhance secondary markets for geothermal energy.

124 El Paso Natural Gas Company, Trans-Western Pipeline Company, and Pacific Gas Transmission.

125 The history of the natural gas pipelines supplying California is too extensive to be fully treated here.

126 Transwestern Pipeline Company, 36 FPC 1010.

127 PGT is not entirely owned by PG&E: a member of the board of The Montana Power Company, another combination gas-electric utility with Canadian and U.S. production and extensive coal deposits, is on PGT's board.

128 In 1974 gas production was 52,454 mcf per day, considerably down from 60,983 mcf per day of 1973. Natural gas reserves in California are

only 1.6 percent of total U.S. reserves, and the California share declined 7.4 percent from 1973 to 1974.

129 The 75 cent price, which reflects the price of alternative fuels, prompted the issuance of a show cause order by the PUC as to why California producers should not be regulated, Decision 84616, July 1, 1975.

130 Interview with the late Colin Garrity, California PUC Gas Section. The California producers have sought to escape from their status as "peaking" resources for PG&E, in part by opposing PGT's applications to the FPC for authority to expand its throughput of Canadian gas. In one case, the producers attempted to persuade the FPC that PG&E was abusing its monopsony power. See California Gas Producers Association v. FPC, 421 F. 2d 422 (CA 9, 1970).

131 In the event gas is taken at a 100% load factor, prices are reduced by seven cents per mBtu.

132 Contracts for synthetic gas from this project set prices at the cost of service plus a 15% return on vendors' equity, irrespective of actual deliveries. The hell-or-high-water provisions were asserted to be necessary to project financing. cf, Trans-western Coal, FPC Docket No. CP 73-211.

133 Pending before the Federal Power Commission (Docket No. CP74-207) is a proposal by Pacific Lighting to import Indonesian LNG to be purchased from Pertamina (joint producer with Mobil) under a twenty year contract whose price is tied to the non-spot market export price for Indonesian crude oil and the Index of Fuels and Related Products and Power.

134 PG&E's vice-president for gas supply, Mr. John Sproul, testified before the California PUC that he believed the price of Alaskan natural gas delivered in the PG&E market area will be about equal to the cost at that time of an equivalent amount of fuel oil in the same market area.

135 A 1500 megawatt power plant requires about 4.6 million tons per year of good quality coal (12000 Btu/lb.).

Since 1965, only eighteen domestic coal mines with a capacity of two million tons a year or more have started production in the United States. Thirty -six domestic coal mines produced two million tons a year or more in 1974.

Presented by Gerald Gambs of Ford, Bacon & Davis, Inc., to Energy R&D Conference of the Atomic Industrial Forum, Washington, D.C. February, 1976, as reported. Weekly Energy Report (February 16, 1976) at p. 4.

For north eastern Wyoming, the Interior Department made the following projections:

	1974	1980	1985	1990
Number of Mines	3	10	12	14
Tons per year (millions)	8	88	122	150
Cumulative tons of Coal mined (millions)	-	297	858	1543
New Power Plants	2	2	3	4
Gasification Plants	-	1	2	2

Ergo, mines are forecast to produce an average of over 10 million tons per year each. East Powder River Basin EIS, P. I-56,57.

136 Alaska, particularly in the far North, appears to have extensive coal deposits.

137 These provinces are described in the Interior Department's Draft Environmental Statement on Proposed Surface Management of Federally Owned Coal Resources, DES 73-53 (October 1, 1975).

138 These Montana units will be jointly owned by the Montana Power Company, Puget Sound Power and Light, Pacific Power and Light, Portland General Electric Company, and the Washington Water Power Company. A 500 kv line is planned to transport power West.

139 The Northern Great Plains Basin includes the western Dakotas (Fort Union Region), northeastern Wyoming (Powder River Region) and central and eastern Montana. The Fort Union Region contains 440 billion tons of low specific heat content lignite--by far the largest coal resource in the

United States, DES 75-53, supra, p. II-108-109. Extensive coal beds also occur in eastern Colorado. Most of the coal on federal lands lies in the Northern Great Plains Basin.

140 The Interior Department's Environmental Impact Statement for coal mining in the Eastern Powder River Basin in Campbell and Converse Counties, Wyoming, reports that these two counties have estimated economically strippable coal reserves of 12.4 billion tons, that 13.3 billion tons are in the Northern Great Plains of Wyoming and that 36.5 billion tons (coal and lignite) are in in the Northern Great Plains of Montana, North Dakota, South Dakota and Wyoming. The national strippable coal reserve was estimated by the U.S. Bureau of Mines in 1971 to be about 45 billion tons.

The national reserve has been increased by new coal discoveries (sic) since 1971, but the Eastern Powder River Basin contains a significant portion of the nation's economically recoverable strippable coal reserves. pp. I-22-23.

141 Coal fuel costs were predicted to be 16.1 mills at Western mine-mouth plants in "Cost Comparison of Nuclear and Coal-Fired Plants" (Edison Electric Institute, March 1976) for plants going in between 1978 and 1985.

142 Campbell, Long-Distance Coal Transport: Unit Trains or Slurry Pipelines, I.C. 8690. (1975).

143 Mulholland, supra, p. 83,84.

144 Average investment cost for deep mines is estimated (in 1974) at $12 per ton of annual output and for strip mines at $6 per ton. Initial capital investment costs for western strip mines, per ton of output, are expected to be lower than the national average.

All coal produced in the Northern Great Plains, and most western coal, is strip mined. The Interior Department estimated, in 1975, that a 9.2 million tons per year Northern Great Plains sub-bituminous coal mine would require an initial capital investment of $42 million, and a total investment of over $78 million. Maximum negative cash flow is about $25 million, and with a 15% discounted cash flow rate of return (after taxes) a selling price of $3.99 per ton was estimated to be necessary.
Bureau of Mines, IC 8703, Basic Estimated Capital Investment and Operating Costs for Coal Strip Mines (1976). (If debt costs 11% and constitutes 75 percent of project financing, equity would earn 27 percent.)
Mulholland, Economic Report: March 1974; Concentration Levels and Trends in the Energy Sector of the U.S. Economy (an FTC Staff Report) p. 84, referring to National Petroleum Council, U.S. Energy Outlook, An Initial Appraisal, Vol. II, p. 136.

An underground mine producing 4.99 million tons of coal per year from a six-foot thick coal bed has been estimated to require an initial capital investment of $84,027,500, including land, interest during development and working capital. The maximum negative cash flow is $33,611,000 ($50,416,500 discounted at 15 percent).

Katell, Basic Estimated Capital Investment and Operating Costs for Underground Bituminous Coal Mines, Revision of Information Circular 8682A, U.S. Bureau of Mines (1975). Katell uses United Mine Workers wage scale which may not apply in non-union western mines. He derives a selling price, using a 15 percent after taxes return on investment, of $11.64 per ton.

Where coal seams are thick - seven feet or more - costs tend to be reduced.

Assuming a 95% recovery, recovery of about 1,644 tons of coal per acre foot is feasible. Seams of 52 feet are reported by Decker and Westmoreland, of 33 feet by Peabody, 28 feet by Western Energy, and 16 feet by Knife River. With a 24 foot seam, 48 acres yield 19,100 tons.

145 In Kennecott Copper Corp. v Federal Trade Commission, 1972 Trade Cases 74157 (CA10, 1972) the court upheld FTC findings of a nationwide line of commerce consisting of bituminous, sub-bituminous and lignite coal, which was becoming increasingly concentrated. "During the period 1954 to 1967, the top four companies increased their share of production from 15.8 percent to 29.2 percent. While during the same period the market expanded by 40.9

percent, the share of the top four companies grew by 160.5 percent..." The court noted that "a number of factors militated against new entry... The fact that the big demand was for consumption by utility companies involving long-term contracts, extensive reserves and ready ability to deliver all contributed. Thus, experience, know-how and equipment are essentials." It later held that only a company the size of Kennecott could enter the industry, noting that experiences of two other firms demonstrated a basic time requirement of from 10 to 15 years plus large utility contracts for large scale operations. Kennecott was required to divest Peabody Coal Company which it had acquired. This divestiture is still in process. In United States v General Dynamics, 341 F. Supp 534 (ND. IL, 1972), affirmed on other grounds, 415 US 486 (1976) the district court found that the relevant market is for energy, not for coal alone. Coal submarkets were viewed as being regional.

146 "Because of its bulk, the cost of transporting coal has historically been an important part of the total cost to the consumer. This relationship, however, has not remained constant and today rail transportation costs are of declining importance in the marketing of coal..." Interstate Commerce Commission, Investigation of Railroad Freight Rate Structure - Coal, Ex Parte No. 270 (Sub. No. 4)(decided December 3, 1974; Service Date March 14, 1975)p.94. (ICC Report).

147 ICC Report, p.210-24.

148 *Ibid*. p.212-13.

149 For purposes of reliability and economics, large, expensive coal-fired units tend to be owned jointly.

150 The Williston Basin and the Eastern Slope have more than enough resources for midwestern markets. To date, generation has been built or planned in the Four Corners area for wheeling to California, while unit trains have been employed to move Montana coal east.

In addition to transmission losses and other transmission costs, coal in the area between the Rockies and the Sierras is unlikely to compete in eastern markets because electric grids are not coordinated between East and West of the mountain region.

151 Were a direct current circuit to be used, it might provide for lower line losses, but it would be isolated from other lines. Estimates for the cost of such a circuit were recently made by Power Technologies, Inc. for the Central and Southwest System.

This study predicts that all base-load units of the Central and Southwest System's utilities will be coal-fired or nuclear. Costs for d.c. transmission for a distance of 855 miles were projected to rise from $210 million for 1000 mw. to $485 million for 3000 mw. For like loads moving 1315 miles, transmission costs were projected at $289 million to

$641 million.

152 Costs presented by Power Technologies, Inc., in November 1975, for a scheme to transport energy from 1000 mw. units in western low-sulfur coal fields over 500 kv. d.c. lines include line costs of $170,000 per mile and terminal costs of $65 per kilowatt. Line losses range from 6.5 mw. per 100 miles at 1000 amperes to 14.6 mw. per 100 miles at 1500 amperes. Terminal losses are 2.5% of kilowatt loading. Costs of rail transportation of coal to Texas from Wyoming, 9 mills per ton-mile in 1977 rising 6% per year, and from Colorado, at 11 mills per ton mile rising 15% per year, may make high voltage transmission the most economic way to move coal.

153 Some components of a transmission charge are independent of wheeling distance, for example, tranformers, switch gear, and metering.

154 Where the service is on an interruptible basis and transmission capacity is not set aside, charges are quoted in cents per kilowatt-hour.

155 The costs of high voltage transmission for mine-mouth units could be as much as 7 to 10 mills per kwh. Even so, coal-by-wire fuel costs to the West Coast (5 to 12 mills) would be about half of the cost of oil (about 24 mills).

156 The Montana Power Company, (TMPC), in whose service area lies much of the Montana coal fields, is synchronized with the high voltage grid in the Pacific Northwest.

157 By Foster Associates, Inc. for the then Office of Coal Research, "Prospective Regional Markets for Coal Conversion Plant Products Projected to 1980 and 1985."

158 ARCO has since acquired the Four Corners Pipeline, however, with the intention of reversing the direction of flow--thus foreclosing this possibility.

159 U.S. Dept. of the Interior, Draft Environmental Impact Statement on Proposed Federal Coal Leasing Program at p. 208.

160 U.S. Dept. of the Interior, U.S. Mineral Resources: FTC Oil Report, Chap. 5.

161 FTC Staff Report, p. 543 A.

162 See Coal Leasing Regulations Final EIS, p. 1-80.

163 If a mine were to be amortized over 30 years with fifty percent of the associated coal reserve recovered, a reserve to production ratio of 60 to one would be called for - if all mines were new.

164 BLM: Coal, An Analysis, supra, p. 23.

165 Ibid, p. 2.

166 Included are Peabody, Garland, and Utah International.

167 Included are Resources Co., Pacific Power and Light, Kemmerer, Western Coal, and Nevada Electric Investment. Kemmerer is a joint entrepreneur with utility systems.

168 Included are Consolidation Coal, Sun Oil, Richard Bass, Atlantic Richfield, Carter, Arch Mineral, and Kerr-McGee.

169 Included are U.S. Steel, Armco, and Kaiser.

170 Peabody Coal Co., Pittston Co., North American Coal Co., Eastern Associated Coal Corp., Westmoreland Coal Corp., General Dynamics Coal Corp., Utah International and Rochester & Pittsburgh Coal Co.

171 American Electric Power Co., Peter Kiewit Sons Co. (joint entrepreneur with utilities), and Western Energy Co.

172 U.S. Steel Co., Bethlehem Mines Corp.

173 Continental Oil, Occidental Petroleum, Hunt Enterprises and Ashland Oil, Sohio, Gulf Oil Corp., and Houston Natural Gas.

174 BLM, Coal: An Analysis, p. 28.

175 U.S.B.M. Strippable Reserves of Bituminous Coal and Lignite (1971). Wyoming holds 31% of such reserves.

176 The Hepburn Act's prohibition against a railroad's manufacturing, producing or mining a product it then hauls does not apply to railroad holding companies. 49 USC 8, construed in United States v. Elgin, J&E R. Co., 298 US 492, 80 L. Ed 1300 (1936), even though this may not seem entirely cogent. Should the sales be limited to delivery by rail, it could be held a violation of law.

177 The following table details the situation of one of the largest coal holding utilities, Pacific Power & Light Co:

UTILITY COAL HOLDINGS
Pacific Power & Light

Recoverable Coal Reserves[1]	Assigned or Dedicated (tons)	Unassigned or Undedicated (tons)	Percentage Sulfur Content by Weight (average %)
WASHINGTON			
Centralia Field near Centralia	Centralia Plant[2.3] 70,000,000[4]		0.7
WYOMING			
Jim Bridger Coal Field near Rock Springs . . .	Jim Bridger Plant[2.3] 133,000,000[4]	33,000,000[4]	0.6
Dave Johnston near Glenrock	Dave Johnston Plant[2.3] 117,000,000		0.5
Antelope northeast of Glenrock . . .		300,000,000	0.4
North Antelope[5] northeast of Glenrock . .		145,000,000	0.7
Cherokee west of Rawlins . .		250,000,000	1.8
MONTANA			
Decker near Decker*	Decker Coal Company* 165,000,000[4]	210,000,000[4.6]	0.4
West Decker near Decker		400,000,000	0.5
Totals	485,000,000	1,338,000,000	

Footnote cont'd

[1]Recoverable coal reserves represent the portion of total reserve estimates which, in the opinion of the Company, is substantiated by adequate information, including that derived from exploration, mining operations (in some cases), outcrop data, quality testing and knowledge of mining conditions. Reserve estimates are subject to adjustment as a result of continuing engineering evaluation, additional exploratory and development information and as a result of changes in economic factors affecting the marketability or utilization by the Company of such reserves.

[2]See "Property and Power Supply."

[3]The Company considers that the respective reserves assigned to the named plants are sufficient to provide fuel to these plants for their economically useful lives.

[4]Excludes reserves controlled by other participant in project.

[5]Nine non-contiguous reserve areas.

[6]Controlled by Decker Coal Company*, but not subject to contract for sale.

*Decker Coal Company is a joint venture, one-half owned by PP&L's subsidiary Western Minerals Inc. Source: Pacific Power & Light Company Prospectus of September 4, 1975 for sale of Common Stock.

Montana Power Company's subsidiary, Western Energy has coal leases for 610 million tons of recoverable reserves at Colstrip; 490 million tons are committed under contract. Pending federal lessee applications at Colstrip cover approximately 180 million tons.

Western Energy also has coal leases - in eastern Montana containing an estimated 250 million tons, while a subsidiary of Western Energy at Colstrip totalled 3,212,000 tons of which 505,000 were sold to Montana Power Co. By 1977, production is planned to reach 13 million tons per year. The Montana Power Company, Prospectus of December 10, 1975 for sale of First Mortgage Bonds.

178 Arizona Public Service Company has several coal subsidiaries: Bixco, Energy Development Co., and Resources Company.

179 From Island Creek Coal Company, a subsidiary of Occidental Petroleum Company.

180 This coal is to be transported by a slurry pipeline.

181 The following water requirements were hypothesized by the Interior Department for its East Powder River Basin Environmental Impact Statement:

Facility	Acre Feet of Water (Per Year)
Gasification plant (2 million cubic feet per day)	7,000
Power Plants (water cooled)	11 per megawatt
Slurry Pipeline (25 million tons of coal per year)	15,000
Per 1000 Population Increase	200

182 The Public Service Company of Colorado reports that while it receives coal under eight contracts it has an option to purchase 100 million tons from one firm (Amax). This compares with estimated future coal requirements of 165 million tons for all of its plants in being or under construction.

Utah Power & Light burned about 3.9 million tons of coal in 1975 (1.0 million tons at its Carbon, Gadsby, and Hale Plants; 1.8 million at Naughton; and 1.1 million at Huntington - first unit). Future needs include: Huntington - second unit and Emery - first and second units, 1.2 million tons each; Naughton - fourth and fifth units, 1.4 million each when in full operation. Coal for the Carbon, Gadsby, and Hale Plants comes from UP&L's lands and leases (1974 estimated recoverable assigned reserves, 18 million tons; sulfur

Footnote cont'd

content about 1/2% by weight). These reserves are estimated to suffice for the lives of these plants.

UP&L contracts and options initially cover about 330 million tons of 1/2% sulfur coal. One supplier sells UP&L coal for the three existing Naughton units and has agreed to provide all the fuel for those units up to the 80 million tons estimated as needed for the life of the units; the same supplier has agreed to a similar arrangement for the fourth Naughton unit (50 million tons), and has granted UP&L an option on a similar supply for the fifth Naughton unit (also 50 million tons). The fourth Naughton unit has been postponed three years, and UP&L is negotiating for a delay of deliveries.

Coal for the Huntington Plant is, and for the Emery Plant will be, bought from Peabody, which has agreed to provide all fuel up to the 150 million tons estimated as needed for the life of units totalling 2,000 mw, for a 35-year period following commencement of commercial operation of the second Huntington unit.

UP&L agreed to pay a penalty if less coal is purchased than would be required to operate the total plant at 55% of rated capacity, unless the outages are unscheduled. The utility will also pay Peabody's unrecovered fixed charges if, in the first 15 years of the contract, purchases are less than required for generation at 25% of rated capacity in any consecutive 12-month period (again, except for unscheduled outages). The Company has an option to purchase an additional 80 million tons of coal for the Huntington and Emery Plants. This amount is estimated to be sufficient for two 400 mw units for their entire expected lives.

183 Wallace W. Wilson, Mine Development Financing for the Coal Industry During the New Decade (March 1, 1976); referring in part to a study by Bankers Trust Company, "Capital Resources for Energy through the Year 1990." (1976).

184 Ibid. Small producer capital needs-for equipment and working capital and only rarely for mine development- "can best be provided" by local or regional banks, lender credit, and occasional private sale of equity. "...Many of the smaller producers would not have the financial resources needed to support the customary mine completion and operating convenants of typical production payment arrangements. When small producer requirements exceed the local banks' resources, the services of a larger correspondent bank usually can be arranged." Ibid.

Difficulty in obtaining production loan financing results in an indirect competitive disadvantage on top of direct financing impact. Production loans are viewed as comparable to direct debt in assessing a mining company's credit. Their effects on book earnings are nominal, and general credit and other assets are unimpaired. Accordingly firms with such financing may add materially to their debt capacity.

185 Under a "take or pay" clause, purchaser is liable to pay for tendered

contract quantities; under a "hell-or-high-water" clause, purchaser is liable even if seller does not tender contract quantities.

186 Office of Coal, FEA, "Analyses of Steam Coal Sale and Purchases, 1975." Numerous filings under the Public Utility Holding Company Act detail utility financial support to firms opening mines.

187 Ibid, at page 61.

188 The twenty-two utilities reported on consume 48 percent of domestic utility coal consumption.

189 Two of the top ten owners of coal reserves are Mobil (3 billion tons) and Exxon (12 billion tons). Mobil is just starting to develop its first mine while Exxon's mining plans call for the production of 40 million tons by 1985-a reserve to production ratio of about 225:1. See Wall Street Journal, May 20, 1977, p. 16, and 3.

190 The Washington Post, p. 1, May 22, 1977.

191 See Testimony of Peter Max, Hearings on Interfuel Competition, Senate Judiciary Committee, 94th Cong., 1st Sess. (1975), p. 31, 40-41.

192 It obviously is not in the national interest to have high coal prices for the purpose of stimulating geothermal development.

193 About 1100 Megawatts for nuclear units and about 800 mw for large coal units.

194 Owned by Pacific Gas & Electric Company. As of June, 1976, 60 nuclear reactors were operable, representing 8.1% of U.S. installed generating capacity. An additional 178 were planned or being built. ERDA News Release, No. 76-246 (July 28, 1976).

195 Public Service of Colorado alone owns the relatively small (330 Mw) Ft. St. Vrain unit - the only high temperature gas-cooled reactor in the West.

196 30.9 to 36.0 mills at 18% and 7,000 hours.

197 ERDA Press Release No. 76-246 (July 28, 1976)

198 These outages have reduced planned availability of nuclear units, even after shakedown periods, to 70 percent from earlier projections of 80 percent.

199 ERDA News Release 75-178, September 9, 1975.

200 ERDA Survey of U.S. Uranium Marketing Activity (April, 1976) News Release 75-178 supra.

201 Recent allegations of a cartel fixing overseas uranium prices add to price insecurity. The United States is opening its doors to foreign uranium and will be importing substantial quantities. As in petroleum, the low cost resource is predominantly located overseas. See EEI, 1 Nuclear Fuel Supply 42 (1976) and 2 Nuclear Fuel Supply, Table 4.23 at p. 72; Figure III-IV.

202 See, e.g., Washington Post, June 17, 1977, p. 1. The House Commerce Committee is currently investigating the alleged cartel and the participation therein of Gulf Oil Company.

203 The Intercontinental Energy Corporation (IEC) recently announced an agreement to supply uranium to PG&E, beginning in 1978. Under the announced agreement PG&E will advance IEC $12 million as a prepayment or future deliveries for use in acquiring leases and commencing production. The first 843,750 pounds of uranium production are to be sold for $40 a pound and further production from the subject leases are to be sold to PG&E for $40 to $50 per pound, the price being related to the market value of uranium at the time of delivery. Production is expected, for the subject lease, to be at a rate of 300,000 pounds of uranium per year.

204 U.S. Bureau of Mines, Minerals in the U.S. Economy (1965-74).

205 Atomic Industrial Forum, The Nuclear Fuel Cycle: U.S. Capital and Capacity Requirements 1975-1985 (1975) ("AIF Report").

206 PG&E obtained an option to acquire a 35% interest in a uranium joint venture with Minerals Exploration Co., a subsidiary of Union Oil Company. The venture involves Wyoming properties. Moody's Public Utility News Reports, June 25, 1976.

SCE's Mono Power Co. subsidiary and Rocky Mountain Energy Co., a subsidiary of the Union Pacific Corp., are in a joint venture involving a 1000 ton per day uranium mill in Wyoming whose output will go to SDG&E. Moody's Public Utility News Service (December 30, 1975).

207 Testimony of Honcrable Dixie Lee Ray in Hearings on Market Performance and Completion in the Petroleum Industry. Sen. Interior Committee, Part 2 (93rd Cong. 1st Sess. (1973)).

208 Ibid, p. 612.

209 Testimony of Peter Max, Hearings on Interfuel Competition, Senate Judiciary Committee, 94th Cong., 1st Sess. (1975).

210 Geothermal energy could be coupled with nuclear or fossil fuels-e.g., for preheating service, if a suitable site is located for both cycles. This would entail finding geothermal energy at a location where boilerfeed and condenser water could be otherwise provided for.

211 Fuel choices are limited by a number of factors, including air pollution control requirements and the availability and cost characteristics of various fuels. The latter characteristics are affected by their distribution in nature, transport costs, capital requirements for development, etc.

212 The oil supply arrangements of PG&E, Southern California Edison, San Diego Gas & Electric, are more fully described in the Appendix.

213 This concentration is also present at the national level; Report on

Petroleum Industry Competition Act of 1976, Sen. Judiciary Comm., Report 94-1005, 94th Cong., 2nd Sess. (1976) at Table 9, p. 49.

214 Some southern Alaskan production now reaches California through the Kenai pipeline jointly owned by ARCO and Union, and the Cook Inlet pipeline.

215 SOHIO lacks West Coast refineries and requires crude oil for its Ohio refineries. Accordingly it is expected to seek this feedstock through exchange agreements and a proposed pipeline from the West Coast east to established lines in Texas - i.e., it will not enter California refining.

216 See FEA, Trends in Refinery Capacity and Utilization (Dec. 1975).

217 As older California fields have become depleted, an increasing amount of production is coming from offshore, Alaskan and foreign fields held by the major West Coast refiners.

218 Sen. Interior Comm., The Structure of the U.S. Petroleum Industry, Serial No. 94-37 (92-127), 94th Cong., 2nd Sess. (1976).

219 Ibid.

220 The Petroleum Industry Research Foundation, Inc., in its recent report "The Role of Major Oil Companies and Independent Producers in Domestic Exploration Activities" (June 1976) refers to "the practices of majors funding predrilling preliminary work, with others taking over the drilling phases - with the majors drilling the prime prospects themselves and farming

out other acreage on which independents drill."

221. Census Bureau: Annual Survey of Oil and Gas 1974; MA-13K (74-1) (January 1976).

222. And Firms they have recently acquired a controlling interest in - Anaconda and, especially, AMAX.

223 The Bountiful Power & Light System (Utah) bid unsuccessfully against larger oil companies for geothermal leases - desiring to build a plant. It feels that noncompetitive lease sites entail too great a risk; it is interested in geothermal energy to avoid high oil prices but has sought terms of purchase from Phillips Petroleum.

224 Loan guarantees are not likely to affect his situation since loans are made on the likelihood of pay-back, not the prospect of realizations on foreclosure.

225 Larger firms shelter income with tax credits from foreign trade which they dominate.

226 ARCO acquired Anaconda and SOCAL acquired a controlling interest in AMAX. Additionally, a major manufacturer, General Electric, has acquired another large coal company, Utah International.

227 Kennecott's plan to sell Peabody to a group headed by Newmont Mining.

228 By acquiring geothermal resources, large petroleum companies assure their participation in the drilling programs of others. This is the case

because drilling programs are more difficult to finance if adjacent acreages are "proved up" and produced in a way draining the tract sought to be drilled. Large firms with extensive acreage must often be included in drilling efforts, to avoid this situation.

Once in a joint exploratory program, a firm obtains knowledge as to the plans and perhaps the capabilities of its partners. It may obtain the right to participate in drilling on tracts obtained by its partners in a broad "area of interest" set out in the joint venture agreement. New firms do not have this access to jointly held information.

229 Even if a firm does not employ the raw fuel it produces, as is frequently the case for refiners, raw fuel production makes it possible to trade with other producers on more even terms.

230 See Testimony of John F. O'Leary; Hearings on Interfuel Competition, Senate Judiciary Committee, 94th Cong., 1st Sess. (1975) p. 85, 86.

231 We deal elsewhere with the question whether large petroleum companies have an incentive to rapidly develop new forms of energy.

232 The Washington Post, May 20, 1977, p. 1.

233 Class 60, Sub 641, Power plants - natural heat.

234 Shell Oil Company holds a patent for use of geopressured energy in a "total flow system."

235 U. S. Department of Commerce, Patent and Trademark Office, Technology Assessment and Forecast, Sixth Report (June 1976).

236 The oil industry is a leader in geological exploration work and drilling. A recent article suggests that drilling success ratios are lower than would result from random sampling. Science, Scientific Uses of Random Drilling Models, October 24, 1975.

237 Cf., Testimony of John F. O'Leary, supra, p. 88.

238 Hearings on Interfuel Competition, Senate Judiciary Committee, 94th Congress, 1st Sess. (1975) at page 194.

239 If one ARAMCO partner were to increase his share of the West Coast utility fuel market by geothermal sales, there could likely be a reduction in oil imports to the detriment of both ARAMCO and Indonesian ventures of ARAMCO partners (e.g., STANVAC and CALTEX). The disruptive partner is likely to be crude-short elsewhere; or perhaps dependent upon exchanges with other partners to market in a region; or perhaps dependent upon a partner's concurrence to drill a prospect in the Gulf of Mexico (or Siam).

240 See, e.g., Blair, The Control of Oil (1976); and Senate Committee on Foreign Relations, Subcommittee on Multi-National Corporations, Report on Multi-National Oil Corporations and U.S. Foreign Policy, 93rd Cong., 2nd Sess. (1975).

Footnote cont'd.

The large integrated oil companies' pursuit of their profit goals is coupled with the knowledge that unutilized domestic resources are "money in the bank." These resources are secure and their value appreciates. This is not the case for overseas resources (or for domestic oil or gas fields subject to drainage). Other incentives for favoring foreign production also exist. Exploitation of foreign production often permits acquisition of oil under off-take agreements giving special price concessions not available to others while preventing that oil (and concession or agreement) from being transferred elsewhere. Also, under the Internal Revenue Code, the portion of the purchase price paid as "taxes" overseas is a dollar for dollar credit against federal taxes. Taxes on income accruing to partially owned overseas enterprises and tanker subsidiaries may be deferred for long periods of time. These incentives for preferring foreign production would tend to delay development schedules for domestic geothermal energy development.

241 Dr. Paul Davidson has stated to the Senate Antitrust Subcommittee that the current oil and gas supply situation and cartelized fossil fuel supply worldwide were due to the energy enterprises "becoming engulfed in speculative as well as monopoly practices." As a cure, Dr. Davidson advo-

Footnote cont'd

cated convincing petroleum producers that their current monopoly cannot last -- thus encouraging current production. The energy companies' present ability to reap the benefits of monopoly depends on the price inelasticity of demand for their product. This inelasticity, he stated, depends on two specific elasticities: income elasticity and substitution elasticity. Dr. Davidson stated that income elasticity for fossil fuels is approximately one -- i.e., a 1 percent increase in income will result in about a 1 percent increase in fossil fuel consumption. He found that at present there are no substantial amounts of substitutable goods competing with fossil fuels, and hence substitution elasticity is small. As a result, overall price elasticity is also small.

"A high substitution elasticity," Dr. Davidson stated, "requires independent producers who have no major vested interest in maintaining or improving the capitalized value of oil crude reserves in the ground. This requires breaking up the conglomerate energy companies in order to permit alternative energy supplies to be produced by independent firms that can have expectations and objectives which differ from the major oil and gas producers.... Now the cartel and the domestic producers of oil and gas value the oil and gas in the ground at a certain price, say $11 a barrel.

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That is the capitalized value, that is their assets.

"If the price of oil falls, they will take a capital loss on all that underground oil. If coal were to come in at a lower price, then that would imply a capital loss on the value of assets in the oil divisions of the same company.

"A rational producer observing that one of his actions causes the value of some of his assets to be lowered would not engage in selling that asset, and not take that capital loss. On the other hand, if these were independent producers, the fellow producing coal would have no compunction about worrying about imposing a capital loss on another industry."

Dr. Davidson summarized the matter by stating that the object of the conglomerate energy company "is to get a single price per BTU for all these things and maximize the profits of producing them all." See Testimony of Paul Davidson, Hearing on Interfuel Competition, Senate Antitrust Subcomm., 94th Cong., 1st Sess. (1975); Statement of Paul Davidson, appearing at pp. S1263-65, Congressional Record, January 24, 1977.

242 The better sites in Utah (Roosevelt Hot Springs), New Mexico (Valles Caldera), Nevada, Heber and Niland in the Imperial Valley, and The Geysers are entirely or largely in the hands of major oil companies' ventures. Only

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at Mono Lake, at some Imperial Valley, and at some Geysers locations do independents have holdings on very promising sites.

243 Recent federal lease data from Nevada, where a number of non-competitive geothermal leases have been rapidly issued, indicate that a number of persons are acting as lease brokers picking up leases to trade to others, or obtaining assignments from larger oil companies concerned about exceeding acreage limitations. Oil firms such as Chevron, Mobil, Al-Aquitaine, Anadarko Production, Phillips, Getty, Southern Union Production Co., Sun Oil and Union Oil have substantial holdings, and could exceed state maximum acreage limitations if they were to not depend upon such brokers to hold tracts the oil firms were not yet ready to explore.

244 The international petroleum companies have effective tax rates far below the general average.

At present our national tax laws provide substantial benefits to large international companies - DISC, Tanker Subsidiary, and Foreign "Tax" Credits are but a part of this picture. For domestic operations, investment tax credit, and accelerated depreciation and intangible drilling cost deductions are only available to firms established in drilling, while depletion deductions were (and as now limited still are) only available to producers. Exploration enterprises are encouraged to sell resources

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they locate to producing companies by IRC Section 632 which places a 33 percent limit on the tax rate for their gains - which occur after some intangibles have been expensed.

245 Testimony of Wallace Wilson, Sen. Judiciary Comm., The Industrial Reorganization Act: Part 9 - The Energy Industry, 94th Cong., 1st Sess. (1975).

246 The financial institutions on whose boards petroleum company executives sit have substantial direct investments in energy projects and, if banks, they control very substantial trust holdings; many of these investments are project financings, such as joint venture participations, production loans, or debt primarily secured and to be repaid by revenues from specific facilities such as pipelines or tankers. These institutions are not likely to invest in projects that might jeopardize their return on prior investments.

CHAPTER FIVE

GOVERNMENT AND ENERGY

While this study has dealt with technical as well as market factors, we have emphasized market factors. This is because market factors have major effects on the rate and scope of geothermal energy development.

The public means for controlling markets are antitrust law, regulation, and public ownership.

While antitrust action helps create or maintain competitive markets as resource allocative devices, administrative action can substitute public for private central planning as another allocative device.

Antitrust Law and Policy: Perspectives and Activity

> The Sherman Act was designed to be a comprehensive charter of economic liberty aimed at preserving free and unfettered competition as the rule of trade. It rests on the premise that the unrestrained interaction of competitive forces will yield the best allocation of our economic resources, the lowest prices, the highest quality and the greatest material progress, while at the same time providing an environment conducive to the preservation of our democratic political and social institutions.
>
> Northern Pacific Railway Corp. v. United States, 356 U.S. 1, 4 (1958).

This passage from a leading Supreme Court antitrust decision highlights the two essential functions of antitrust legislation and enforcement: economic efficiency and the maintenance of pluralistic and democratic institutions in an industrial society. The first of these goals is familiar to all who have even a passing acquaintance with antitrust doctrine; the second receives less emphasis in most discussions, but is at least equally important.

Americans have generally, and correctly, regarded it as axiomatic that economic power is translated into political power and, ultimately, government action. Concern about concentrating economic and political power in a few hands has been repeatedly voiced throughout our history.

Firms with economic power gain political power in part from the control of information that follows control of resources. Government cannot act responsibly without reliable information; accordingly, inaction may follow if information is kept secret, or if those possessing information publicize only such data as they deem likely to elicit government actions favorable to their interests. Control of resources also makes the public dependent on the plans and investments of the controlling firms. These plans and investment actions determine future supply; when sufficiently encompassing, they can make it difficult or impossible for the public markets or government to change industry conditions without disrupting vital supply lines. The threat of such disruption, when voiced by the firms which control both resources and the information needed to evaluate their extent and that of alternative resources, is a powerful influence on public opinion. In many areas -- not least in that of energy -- Americans have become used to abundance and are unwilling to sanction political experiments which they are told may curtail their usage of resources currently enjoyed. Under these conditions, dominant firms may use their economic power and control of resources to obtain and exercise broad discretion in planning their future conduct. There is no guarantee that this conduct will not diverge from the public interest. And the political power which they can acquire as a result of their economic strength can be used to thwart or subvert government antitrust or regulatory action.

Competitive organization of industry, therefore, can and should be regarded as an essential element in maintaining an industrial democracy.

Antitrust policies are instructional in considering how conditions in the petroleum and bulk power industries affect geothermal development.

A brief recapitulation of some major antitrust approaches to industry structures and practices will readily point to applications in areas with which we are concerned.

Antitrust law has long been concerned with the acquisition by one firm of sources of substitutable products, or the joining together of erstwhile competitors.[1] Such "horizontal" joinders are recognized as being capable of creating future as well as present antitrust problems.[2]

Competition can be curtailed by the acquisition or misuse of control of supply or sales outlets. This is particularly possible where there has been a merger movement.

Problems arising from vertical integration into control supply or outlets have been recognized.[3]

Preserving potential competition has been of particular concern in energy cases, where one is hard put to find actual competition.[4] See e.g., United States v. Phillips Petroleum Co., 1973 Trade Cases §74789 (C.D. Ca., 1973); United States v. El Paso Natural Gas Co., 376 US 651 (1964), and has been of concern in horizontal joint venture cases. United States v. Penn-Olin Chemical Co., 378 US 158, 194 (1963). Entry through acquisition by a large firm which potentially could enter on its own has been thought likely to discourage other entrants, and raises antitrust problems. FTC v. Proctor & Gamble Co., 386 US 568 (1967); Kennecott Copper Corp., v. FTC, 467 F.2d 67 (CA10, 1972). Cf. Phillips Petroleum, supra. So also does acquisition by marketers of a well-established fuel of the resources essential to a potentially competitive energy source that is obviously developable but not yet in general commercial use.[5]

Joint action, whether "vertical" or "horizontal," is of concern even where done through a commonly owned enterprise or a "joint venture". Timken Roller Bearing Co. v. United States, 341 US 593, 1950-51 Trade Cases §62837 (1951). Similarly, see United States v. Minnesota Mining and Mfg. Co., 92 F.Supp. 947, 1950-51 Trade Cases §62687 (D. Mass 1950):

> "The intimate association of the principal American producers in day-to-day manufacturing operations, their exchange of patent licenses and industrial know-how, and their common experience in marketing and fixing prices may inevitably reduce their zeal for competition inter sese in the American market."

Use of monopoly power, however lawfully acquired, to foreclose competition, to gain a competitive advantage, or to destroy a competitor is unlawful.[6]

A body of precedents dealing with "bottleneck" situations, in which control of a key economic function is used to extend market control to other sectors, is closely related to the law regarding "vertical integration." These cases teach that a party controlling a facility whose use is essential to reach markets cannot lawfully use its monopoly power to exclude others.[7]

Supply restraints will be allowed _if_ they are found to be "fairly necessary" to achieve a legitimate end.[8] If vertical power is employed to require purchases of other products from suppliers, and this exercise of power is considered to be very detrimental to competition in the tied product, the "restraint of trade can be justified only in the absence of less restrictive alternatives."[9]

Exclusive dealing arrangements, another way of extending market power into other markets, normally provide that a purchaser agrees to purchase exclusively or for a significant period of time from one supplier.[10] Such arrangements, not always anticompetitive, are not considered illegal _per se_. In determining their legality, courts look at the degree to which competition has been foreclosed and the substantiality of the share of the line of commerce affected[11], seeking to determine the agreement's net effects upon competition.[12]

Control of supply or outlets may also be used to encourage reciprocal trading at the uncontrolled stage.

Finally, the tying device is employed to use market power or leverage in one market to appropriate a position in another market. (This latter market frequently has a parallel or horizontal relationship to the tying firm's originating market.)

A "tie-in" is an arrangement in which the sale of a product or service over which the seller has substantial market control is conditioned upon the sale of a separate product or service from the seller or a designated party. See United States v. Loew's, Inc., 371 US 38, 55 (1962); and Northern Pacific Ry. v. United States, 356 US 1, 6 (1958). These arrangements are viewed with great suspicion under antitrust laws, as they are thought rarely to serve purposes beyond the suppression of competition.[13]

Tying arrangements "deny competitors free access to the market for the tied product, not because the party imposing the tying arrangements has a better product or lower price but because of his power or leverage in another market. At the same time buyers are forced to forego their free choice between competing products."[14]

The economic vice of tying arrangements is that they permit a party to extend its power in one market into another, by noncompetitive means. Profits from combined sales may be higher than those for separate sales (even by two monopolists). Tying also provides an opportunity for price discrimination.

Other reasons for seeking tying arrangements are that a vendor may seek to maintain quality control over a product it is associated with[15], or to obtain economies of jointly producing or distributing the two products. Tying may be sought to evade government controls over one product.[16]

The foregoing has dealt with the body of doctrine or approach to market situations -- built up in litigation under the general antitrust laws. A number of statutes have been interpreted as requiring an "accommodation" of antitrust law and policy;[17] and some have required a judgment as to whether particular situations or practices are "inconsistent" with antitrust law and policy.[18]

Responsibility for enforcing competitive policies is distributed in numerous places in the government. The Justice Department and the Federal Trade Commission are directly responsible for enforcement of antitrust laws. As noted, the Securities and Exchange Commission has substantial antitrust responsibilities under the Public Utility Holding Company Act, while other agencies -- the Interstate Commerce Commission (oil pipelines, trucks, and rail hauling), the Federal Power Commission (gas sale and transport, and sales of electricity for resale), the Federal Energy Agency (price, access to and marketing of crude oil and oil products), the Nuclear Regulatory Commission (nuclear construction and operation permits, nuclear fuel transportation), the Department of Transportation (deep-water ports), and the Interior Department (mineral leasing, OCS development, public land rights-of-way and administration of western federal power facilities) have statutory obligations to consider antitrust implications of their actions.[19]

Antitrust issues arising in the petroleum and bulk power supply industries can involve matters under the jurisdiction of federal and state regulatory agencies. In petroleum cases, issues may arise involving matters within the jurisdiction of foreign governments.

Determination of these issues first requires choice of decisional forums. The legal doctrines for determining decisional hierarchies as among courts and agencies are discussed in our Appendix on Primary and Exclusive Juristiction, State Action, and Foreign State Action Defenses. The doctrines constitute a serious impediment to those seeking redress under the antitrust laws as plaintiff's case may be deferred while administrative matters drag on for years; litigation is extended when efforts are made to defend practices complained of, on the grounds that the actions are permitted or mandated by state law, or are due to the sovereign actions of a foreign government.

Currently a defendent can assert that a matter should be tried before an agency, and not the court, or that the court should defer its case until agency proceedings are over.

We recommend that an antitrust defendant wishing to have the "primary jurisdiction"[20] doctrine invoked should be required to either request that an agency assert and support the application of the doctrine, or, alternately, request that a court ask the agency to set out and support its position on primary juristiction.

In this way, the court would not have to wait to deal with cases in which the agency doubts its jurisdiction so that a referral to it would be futile, or where the agency does not feel it can contribute something substantial to the resolution of the problems at hand.[21]

Such an allocation mechanism will also help assure that timely consideration of antitrust issues actually occurs. This is in line with the case law which reflects an intention to require antitrust aspects to be considered, either by refusing to allow courts to be ousted of jurisdiction, California v. FPC, 369 U.S. 482 (1962); United States v. Philadelphia National Bank, 374 U.S. 321, 350-51 (1963); Otter Tail Power Co. v. United States, 410 U.S. 366 (1973), or by requiring agencies to consider antitrust aspects. See e.g., Gulf States Utilities Co. v. F.P.C., 411 U.S. 747 (1973); and, F.M.C. v. Svenska Amerika Linien, 390 U.S. 238 (1968).

Use of factual evidentiary proceedings would lessen the dangers of primary jurisdiction being employed in a stereotyped manner in response to abstract "expertise."[22]

This recommendation could be implemented by uniform court action or by legislative direction. That primary jurisdiction is a judicial doctrine of long standing does not make it inappropriate for Congress to modify it. For example, after the Supreme Court's decision in Banco Nacional de Cuba v. Sabbatino, 376 U.S. 398 (1964), Congress expressly forbade the courts to invoke the well-established "act of state" doctrine as a bar to inquiry into the official acts of foreign governments unless the Secretary of State specifically so requests.[23]

When antitrust courts mandate actions for which tariffs or contracts must be filed with the Federal Power Commission, courts may be able to retain jurisdiction to make sure that the defendant and the agency actions comply with the court orders.[24]

Application of Pro-Competitive Policy to Major Markets Involved in Geothermal Energy Development

Pro-competitive approaches are relevant to geothermal energy development in a number of ways including: practices among firms developing geothermal energy; practices of firms now engaged in supplying other fuels and becoming involved in the geothermal sector; practices of firms purchasing geothermal energy and electricity generated with such energy; and government activity which affects practices in all these sectors.

In the field of power generation geothermal generating units could be developed by entities entering into the business of power generation or their development could be restricted to the rate of advance prescribed by existing generating firms. A pro-competitive policy would seek to foster entry so that development would not be restricted to the path prescribed by the needs and objectives of the large firms now dominating western bulk power supply.

In geothermal field exploration and development, a pro-competitive policy would seek the existence of a number of producing and purchasing entities operating independently of each other, which are not constrained by considerations of how sales of one fuel might compete with sales of other fuels. The antitrust approach is concerned both with contractual and sales practices and with ownership patterns.

Substantial lease holdings by a few large firms coupled with the existence of some other firms as "service companies" for the larger firms does not constitute a situation conducive to the diversity a pro-competitive policy would seek.

Foreclosure of entry by exclusive dealing contracts, warehousing of prime sites, unduly restrictive joint enterprise provisions, proliferation of joint enterprise relationships, or restrictions on the possibilities for smaller companies in allied fields of endeavor (e.g., petroleum) are subjects for antitrust concern.

Antitrust Enforcement

The Petroleum Industry

Historically, the petroleum industry has been considered -- in principle, at least -- subject to antitrust policies. Some substantial efforts have been made to achieve competitive supply conditions[25] but some quite substantial deviations from this approach[26] have also occurred.

While antitrust enforcement did lead to reorganization of the oil industry early in this century, it was blocked for several decades from interfering with state industry rationing of domestic petroleum supply. It has been unable effectively to challenge joint pipeline ownership arrangements, even though there were several attempts at the staff level to move in this direction in the 1950's and 1960's.

While some ameliorative provisions were included in the terms of the right of way permit for the trans-Alaska pipeline, and in deep water port permits, no structural changes were developed.

The Antitrust Division appears to be effectively precluded from dealing with basic international petroleum procurement arrangements among producer countries and major oil companies which appear to channel a major portion of crude oil supplies into the hands of major companies.

With fundamental government policy favoring an international "safety net" supporting high petroleum prices,[27] seeking loan guarantees for synthetic fiels, and encouraging large petroleum companies to meet together, here and overseas, to plan for contingencies,[28] antitrust enforcement would have seemed anomalous, had it in fact been undertaken. Even where legislation has been enacted to restrict joint bidding for OCS leases and mandating production from federal leases, the restrictions only pertain to the very largest firms acting together and do not restrict unitization of production or joint pipelines.

The Department of Justice has made an investigation of joint activity relating to the Elk Hills Naval Petroleum Reserve, and the Pacific Outer Continental Shelf but, to date, no action has been taken on these matters. The Justice Department has apparently declined to seriously inquire into possible antitrust problems arising from a joint bid by Union Oil Company and Standard Oil of California.[30]

As regards cross-fuels ownership, while not opposing coal acquisitions by larger oil companies, the Justice Department sought, unsuccessfully, to bar the acquisition of a coal company by General Dynamics. The district court in this proceeding was affirmed in its holding that the acquiring company was bringing its needed coal resources to a coal company that, having large mines, lacked the substantial uncommitted resources needed to make new large coal sales prerequisite to new large mines.[31]

The court did not affirm or deny the district court's holding that an energy market, not a separate coal sector, was the relevant market.

The Federal Trade Commission has instituted a major action to achieve divestiture or disaggregation in the domestic petroleum industry. This suit has proceeded extremely slowly.

The FTC and local United States attorneys have, over the years, brought numerous proceedings regarding anticompetitive local retail practices such as price fixing and wholesale tie-ins of accessories and tires to sales of gasoline to service stations.

The FTC successfully brought a proceeding to prevent a large copper company from acquiring Peabody Coal Company[32]; Kennecott is now preparing to sell Peabody, pursuant to court order, to a consortium including several large independent petroleum firms.

Antitrust activity in the petroleum industry has generally not penetrated to major structural arrangements in the last several decades.[33] This reflects the difficulty of assembling an adequately knowledgeable, far-sighted staff in a federal agency -- a major problem for decades -- and national and international concern over security of vital energy supplies.

The petroleum industry is notable for extensive "vertical integration" among stages of the industry and for a pervasive web of inter-firm linkages. These facts, together with the industry's large size and its wealth, have creted major concern for decades. This concern currently is reflected in, among other things, "divestiture" bills designed to break up major petroleum firms, introduced in Congress.

While there are pronounced differences between major oil companies -- particularly between those that have crude oil supplies in excess of refining capibility and those who do not, and the relative market positions of majors do change, the competition that does occur among them is quite constrained.

We recommend either cross-fuel divestiture by major energy companies or, alternatively, that cross-fuel ownership be restricted -- if such restriction can reasonably be expected to limit cross-fuel holdings so as to avoid substantial foreclosure of other firms, or diminution of inter-fuel competition. Furthermore, the restrictive approach should only be chosen if it can be expected to be effectively implemented in light of the prior lack of government action in petroleum matters. This implementation would, in all likelihood, require a non-political administration of the antitrust agency in charge.

So long as the petroleum industry is not competitive, and is commanding high returns on investment, geothermal development by petroleum firms is likely to be at a very deliberate pace and at prices set with reference to other fuels, not to costs of production. To the extent that prime geothermal resources are in the hands of large petroleum companies, this pace will largely govern geothermal development.

We would call attention, in any divestiture program, to the need to deal with petroleum company-financial market relationships, and with directorate relationships among major oil companies and large financial institutions.

Were petroleum industry divestiture legislation enacted, such legislation should provide for relatively impersonal, arms-length, and competitive underwritings of securities of the spun-off entities.

For example, public offerings should be sold to underwriters at competitive bidding (not negotiated sales), and should be sold in batches small enough to permit a number of firms to be the lead underwriter.

In addition, we suggest that antitrust enforcement bodies, and the Congress, take a longer-range view of the potential for competition among energy sources, and the need to preserve inter-fuel competition. Initial oil company acquisitions of coal companies were passed up by antitrust enforcement agencies at least in part on the hypothesis that coal and oil did not compete. Today that thinking can be seen to be obviously in error. In the future, all major energy sources must be potentially substitutable to provide electric power.

The Electric Utility Industry

The electric utility industry may be unique in the number and variety of trade restraints which have gone unchallenged for long periods of time.

In the bulk power industry, vertical integration of generation, transmission and distribution, with attendant control of coordination services, provides great market power to large enterprises.

This pattern of vertical integration is in large part the result of historical evolution in power technology. Early power systems -- using small-scale generation equipment and lacking any means of long-distance transmission -- were local in character and consisted of generating capacity connected more or less directly to low-voltage distribution lines. As long distance, high voltage transmission technology developed, carrying with it the possibility of capturing scale economies by coordinated use of larger and more efficient generating units to serve a number of local distribution areas, the pattern of combining bulk and distribution facilities under a single ownership was maintained.

Such a pattern, however, is no longer required by technological factors. At least two other patterns are possible under modern conditions: (1) Separation of the bulk power supply industry from the distribution industry, with competition between bulk suppliers for the distributors' business; and (2) joint ownership of bulk facilities in a region by local distribution entities, or increased use of smaller economic units (e.g., geothermal energy).

One result of adherence to the industry structure that arose under more primitive technological conditions has been -- as noted above -- to allow large vertically integrated firms to retain dominant market power.[34]

This power and control of facilities has been used to the detriment of small systems in a long series of market-foreclosing actions. These actions reduce the ability of small systems to enter into self-generation.

The concentrated structure and restrictive intercompany arrangements in the electric utility industry impede diversity and competitiveness in geothermal energy development. The number of buyers of geothermal energy is thereby limited by factors other than technical and organizational necessity, and the market possibilities of smaller purchasers are likewise limited.

Public Policy on Electric Utility Competition

Public policy toward electric utilities has sought to achieve economies of scale, avoid redundant investment, and maintain competitive conditions.

Achievement of the first two goals has been sought through state franchising of retail services, and state and federal power facility licensing procedures.

A major purpose of retail service franchises and licensing is to avoid local duplication of facilities. State franchising laws have been held to exclude generation or service by new entrants; and to prevent existing enterprises initiating service in new areas.[35]

State and federal agencies have acquired or reserved lands in order to secure suitable sites for large-scale operation. The FPC is to only license facilities which use the full economic capability of a hydro site in a manner consistent with the optimum development and operation of facilities at other sites on the waterway.[36] Site conservation is also a reason that permits for transmission line right-of-way across federal lands contain provisions requiring permittee to wheel power for the United States on the permitted line.[37]

Some aspects of federal law are double edged: they seek to secure both scale-economies and competitive results. These include requirements that some (but not all) agreements pertaining to joint utility enterprises be subject to regulatory review. Antitrust related provisions in hydro and nuclear licensing statutes encourage coordinated planning.

Federal statutory policy for disposing of federally produced power, and for federal research, evidences a pro-competitive intent. Federal statutes governing the disposal of output from government power projects have sought to maintain yardstick competition -- giving a preferential right of purchase to public-power bodies.[38]

Legislation pertaining to energy research conducted by or for ERDA contains clauses related to patents, inventions and know-how reflecting concern about competition. Continued Congressional concern is reflected in the amendments adopted by the Senate in June, 1976 requiring antitrust review in conjunction with any loan-guarantee for biomass conversion projects.[39]

> "Despite a continuing debate, it appears that the basic goal of direct governmental regulation through administrative bodies and the goal of indirect governmental regulation in the form of antitrust law is the same -- to achieve the most efficient allocation of resources possible. For instance, whether a regulatory body is dictating the selling price or that price is determined by a market free from unreasonable restraints of trade, the desired result is to establish a selling price which covers costs plus a reasonable rate of return on capital, thereby avoiding monopoly profits. Another example of their common purpose is that both types of regulation seek to establish an atmosphere which will serve to stimulate innovations for better service at a lower cost. This analysis suggests that the two forms of economic regulation complement each other. Northern Natural Gas Co. v. Federal Power Commission, 399 F.2d 953, 959 (CADC, 1968).

Accordingly, the problem of exclusion of smaller systems from coordinating services, and anti-competitive provisions in sales to them appear to be topics for redress by both antitrust and public utility regulation. In like manner, regulation of the disposition and use of the public domain should seek to foster competitive markets for the acquisition of leases and their exploitation.

Judicial Enforcement of Antitrust Policy

The judicial application of the antitrust laws to the electric utility industry goes back a number of years. Cf., Pennsylvania Water & Power Co. v. FPC, 343 US 419-20 (1952).

In related cases,[40] it was decided that contracts among utilities allocating territory and customers and reducing competitive growth were, *per se*, violations of the Sherman Act. The court held that:

"In short, the grant of monopolistic privileges, subject to regulation by governmental body, does not carry an exemption unless one be expressly already granted, from the antitrust laws or deprive the courts of juristiction to enforce them." 184 F.2d 560. The same court was faced with adoption by the Federal Power Commission of certain provisions of the contracts the court had previously found unlawful. A judgment holding the contracts void was nevertheless affirmed. The court recognized the public interest in the continuance of the pooling arrangement which the illegal contracts had created. It determined that further action by the FPC would be required.

"The problem of the Commission would then be to decree a plan which will affect the purposes of the Federal Power Act and at the same time conform to the antitrust statutes. This would not seem to be an impossible or unreasonable duty to perform. As was said in Southern SS. Co. v. NLRB, 316 US 31, 'Frequently the entire scope of congressional purpose calls for careful accommodation of one statutory scheme to another, and it is not too much to demand of an administrative body that it undertake this accommodation without excessive emphasis upon its immediate task.'" 194 F2d 89.[41]

The foregoing and other cases established that electric utility systems are subject to the general limits on use of monopoly power.[42]

The leading judicial decision on antitrust issues in the bulk power supply area is the Otter Tail case.[43] Otter Tail Power Company attempted to prevent municipalities it formerly served, and in particular the Village of Elbow Lake, Minnesota, from forming viable municipal power systems. To this end, Otter Tail used inter alia, its control over sub-transmission in the area as a bottleneck to keep the village isolated -- refusing to sell wholesale power or wheeling service to the village. Otter Tail also employed litigation, and agreements with the Bureau of Reclamation in an effort to foreclose entrant power firms.

The Court in Otter Tail denied, in a four to three decision, the assertion by defendants that (a) anticompetitive action could be justified to avoid losing customers, and (b) that the bulk power industry had a blanket exemption from the antitrust laws by virtue of FPC regulation. FPC regulation is not pervasive[44] and can be accommodated with antitrust remedies.

Otter Tail, the Pennsylvania Water cases, and other decisions thus show that such principles -- discussed above -- as the "bottleneck" doctrine, the policy against use of monopoly power in one market to monopolize another, and agreements allocating customers apply to the electric utility industry.

In discussing judicial performance under the antitrust laws, mention should be made of the constraints arising from state or local franchising.[45]

The role of antitrust law in the regulated industries is circumscribed by the existence of franchises and certificates.[46] However, state franchise limitations on antitrust law enforcement relate to retail trade, and not to interstate commerce.[47]

Utility Regulation

The federal regulatory agencies with the most substantial competitive policy responsibilities in the electric utility industry are the SEC, FPC, and the Nuclear Regulatory Commission.

The Securities and Exchange Commission administers the Public Utility Holding Company Act of 1935. Agreements among utility systems for joint enterprises to own electric utility plant are subject to approval under Sections 9 and 10 of this Act, since the joint enterprise -- a separate entity -- constitutes a subsidiary creating a utility holding company relationship. Utility mergers involving the creation or continuance of a holding company fall under this Act. The tests for permitting mergers and acquisitions, found in Section 10, are more stringent than those normally applied under antitrust law: there must be a showing of positive benefits, and not just a lack of substantial harm, or the threat of harm, to competition.

The Federal Power Commission is entrusted with the administration of the Natural Gas Act and the Federal Power Act.[48] Under the Federal Power Act, the FPC has the authority to license and regulate some aspects of non-federal hydroelectric power projects. It has authorities concerning transportation and rates for resale of electric energy in interstate commerce. It has some authority over the accounts of companies engaged in intrastate transmission and generation and companies with hydro licenses.

The Commission can pass upon the reasonableness of contracts, rates, and terms of service subject to its jurisdiction. In limited circumstances, it can require interconnection of facilities and sales of power. It cannot require planning coordination among utilities, or wheeling -- except as a condition to hydro licenses.

The FPC is required to approve the rates of some but not all federal power marketing agencies.[49] It also collects and provides information and reports to Congress regarding industry conditions and problems.[50]

The terms of electric utility coordination agreements (including agreements to which the Bureau of Reclamation is a party) and wholesale tariffs are subject to Federal Power Commission approval. The FPC is charged with the duty of reviewing these filings under a statutory standard that places maintenance of competition in an important role.[51]

Although the FPC has no power to adjudicate antitrust violations,[52] it can refuse to permit anticompetitive exclusionary pooling agreements, refuse to approve rates tying services, eliminate "no resale" or load growth restriction provisions, eliminate onerous notification terms before new sources of power may be used, and attempt to reduce the incidence of price squeezes.[53] It can also deny mergers.[54]

While it lacks the ability to mandate coordinated planning or wheeling, the FPC could require that power services not be bundled into a firm service tariff for full or partial requirements, but rather that the elements of firm service -- generation, transmission, and coordinating services -- be separately available. It can require that hydro licensees coordinate their units with others so as to obtain the optimum economic use of these facilities: e.g., their widest use as a source of ready reserves, their placement in the peak so as to maximize their dependable capacity rating, and their optimum use in substitution for fossil fuel.[55]

Though the FPC has authority, and has occasionally acted, to restrict anticompetitive tariff provisions, it has rarely made a serious inquiry into specific power pool agreements and has permitted numerous uncompetitive tariff provisions to stand for years without inquiry. For example, the FPC declined to take up the antitrust questions raised by public power systems when the 1967

Bureau -- PG&E integration contract was filed;[56] and made no independent inquiry.

The Commission has framed no objective standards for coordination agreements to guide companies away from anticompetitive conduct and toward conduct which would achieve efficiencies and open up diversity, with attendant flexibility and competitiveness, in bulk electric power markets.

Where a matter comes before an agency, such as the Federal Power Commission or a State utility commission, antitrust considerations often are given short shrift. The FPC has engaged in little factual inquiry in power pooling cases.

Access to the facts in a case is basic to achieving reasoned decisions grounded on a knowledge of conditions. A party's control of information as to the facts in a matter is often dispositive. In order for agencies to obtain the facts, they require the services of skilled personnel able and willing to understand the subject matter involved, to assemble and report data, and to analyze and consider the facts in light of competitive considerations.

The current system of administration is largely passive. Information pertaining to the planning of new bulk power facilities, or even the operation of power pools is largely unfiled.[57] No inquiry is conducted into the structure of the industry or its planning processes.[58,59]

Inquiry of course is pointless unless relevant information is being collected. Cost accounting under the present Uniform System of Accounts for Public Utilities does not encompass any details for fuel subsidiaries, and does not provide information on incremental costs. Accordingly, the exchange of coordinating services or economy transactions are burdened by dissimilar accounts between firms attempting to trade on the basis of incremental or decremental outlays. Even worse, there is no uniform system for determining available capacity from a generating unit, nor have uniform standards been adopted for setting load-shedding relays. Settings and capacity ratings are usually not audited.

The FPC has only a very limited number of personnel who understand power pooling; conducts few field investigations; and has developed a substantial backlog of rate cases.

Antitrust inquiries, even with motivated staffs, cannot be expected to go forward at a reasonable pace unless the party having the basic data -- the utility -- is motivated to cooperate. The FPC practice of separating antitrust inquiries from rate, financing, or even hydro-licensing proceedings, and undertaking to grant the application sought while the separate antitrust inquiry runs on, destroys such motivation.[60]

Improved agency antitrust performance will not be achieved easily. It would be helpful to develop (a) separate antitrust staffs within agencies, or (b) regular interventions by antitrust agencies,[61] together with specific statutory requirements that agencies make findings regarding competitive impacts of proposed actions, which should include, considering alternatives to proposals.[62] However, agencies have a history of protecting the status quo.[63] They are not likely to change their basic attitudes, while their pro forma findings might retard access to judicial remedies (by doctrines of primary and exclusive jurisdiction -- unless this development was precluded by specific statutory language).

Increased judicial supervision of regulatory agencies with more stringent requirements on appeal for reasoned decisions based on substantial evidence could improve agency decisions. However, courts are reluctant to become overly involved in agency matters[64] and agency responses to remands are often merely productive of further post hoc rationalizations.

So long as agencies tend to reflect the views of the industries they regulate, regulation of pooling seems likely to go forward only if industry views (i.e., structure) are non-uniform. In that circumstance, the agency would not be a mere interloper into the affairs of its friends when it inquired about power pooling transactions or their absence.

The structure of utility rates affects how cost conscious utilities are about energy procurement practices. Utilities making money under fuel adjustment clauses[65] and through integration backwards into raw fuels and fuel financing may lack some incentives for experimenting with potentially lower cost alternative types of energy.

Fuel procurement and ownership of fuel companies by electric utilities has received little surveillance by the FPC. The propriety of intra-system fuel transactions goes unquestioned, fuel contracts need not be filed, and no system of accounts is mandated for fuel subsidiaries. Only very broad statements as to procurement policy need be filed: essentially this area has been left to managerial discretion. While noting utility assertions that non-competitive fuel supply markets are a reason for not requiring fuel contracts to be submitted, the Commission has taken no action to encourage more competitive fuel procurement.[66]

While arguments could be made regarding the very participation of utilities in non-utility enterprises, with the current lack of competitive conditions it appears more sensible to insist that utility-affiliated fuel companies be true competitive entrants.

This can best be done by assuring that such fuel subsidiaries and their parent companies have an incentive to seek fuel supplies at prices lower than otherwise obtainable. This would be encouraged if fuel subsidiaries were required to conform their books to a uniform system of accounts. The sales of energy to an affiliate should be at prices set by cost (including a reasonable return) but not in excess of market. Otherwise, utility energy procurement should be required to be on a competitive basis, and no more than a limited percentage (say 10%) of large procurements should be purchased from one concern.

Competitive procurement is more likely to occur if it can be supervised by regulators. Such oversight requires considerably greater disclosure than is now obtained by utility commissions regarding (a) utility procurement practice, and (b) direct and indirect financial relationships among utilities and fuel suppliers.

<u>The Nuclear Regulatory Commission</u>

The Atomic Energy Act provides for a "prelicensing" antitrust review on applications for nuclear power plants.[67]

Nuclear license applications are sent to the Attorney General for review and advice as to whether issuance of the license would create or maintain a situation inconsistent with the antitrust laws.[68]

A number of antitrust related challenges have been made in nuclear licensing proceedings since 1970. Generally, the electric utilities involved have agreed to license conditions before a hearing has been conducted.[69] These conditions have been negotiated by the Department of Justice, the NRC staff, applicants, and, in some cases, members of the public (including smaller electric systems that intervene, or are potential intervenors).

Table 24 lists 23 primary applicants for licenses to construct and operate 54 nuclear generating units and arrays license conditions. All of the applicants are large investor-owned utilities. The average size of generating units involved has been 1041 megawatts. Many of the units are joint ventures between the primary applicant and other utilities.

The license conditions agreed to come under four headings: (1) "unit access", (2) "transmission service", (3) "coordination", and (4) "contractural provisions".

"Unit access" refers to the applicant's granting another electric system participation in a nuclear facility to be licensed. It also includes provision of such transmission service as is required to obtain, and reserve protection for, that nuclear unit's output.

Eighteen of the primary applicants have agreed to unit access conditions. Some agreed to permit ownership in a particular unit, others to permit purchase of power and energy from a particular unit. In a few cases, potential owners are offered the choice of ownership or purchases of unit power either as to the unit to be licensed or future units.

The "transmission service" category involves a wide variety of conditions. Some applicants are required to wheel power for all electric systems which request this service. Others are only required to wheel for certain designated systems. All but three of the applicants agreed to transmission service conditions.

The "coordination" category involves any of the following general commitments to other utilities: to interconnect and coordinate reserves (including, among other things, emergency and scheduled maintenance support); to engage in other bulk power transactions such as "economy" and "diversity" exchanges; and to participate in joint planning and development or generation and transmission facilities. All but four of the applicants agreed to such coordination conditions.

The "contractual" provisions category involves requirements that applicacants delete restrictive or discriminatory language from existing contracts, avoid using such contract language in future dealings, and make affirmative statements regarding intentions to enter into agreements to deal. Provisions disallowed include restrictions against interconnection and coordination agreements, restrictions on power pool membership, restrictions on the use or resale of transmitted power and energy, and refusals to deal with systems engaged only in distribution.

The direct beneficiaries of the conditions agreed to by nuclear license applicants are the small utilities located in the service areas of the applicants--mainly municipals and cooperatives. The pervasiveness of the antitrust challenges in licensing proceedings and the scope of the conditions agreed to suggest a widespread general pattern in which large investor-owned utilities have systematically acted to isolate, control and/or acquire municipals and cooperatives by a variety of forms of conduct.

The license conditions obtained in the Nuclear Regulatory Commission proceedings may serve to thwart certain forms of conduct by certain large utilities directed against certain municipals and cooperatives. However, their efficacy is largely untested.

Even where coordination conditions have been agreed to, there are usually qualifying statements that prescribe reliability or duration characteristics necessary for transactions involving distribution systems. These qualifying statements could require unrealistic equipment conversion expenditures by small utilities which have the effect of negating the purpose of the license condition.[70]

The net result is that many small utilities are still eagerly searching for new sources of economical power and energy.

While no NRC antitrust cases have gone completely through litigation, and three are pending (awaiting Commission action after decision by a _nisi prius_ licensing board[71]), a number have been settled. Settled cases include a proceeding involving the Southern California Edison Company in which that firm agreed (1) to afford smaller power systems an opportunity to participate in ownership of nuclear generation, and (2) to provide wheeling and back-up services.

In a pending NRC proceeding, where the Justice Department has entered into a limited, somewhat vague, settlement agreement with PG&E, public power intervenors continue to litigate.[72]

TABLE 24
CATALOGUE OF ANTITRUST LICENSE CONDITIONS AGREED UPON

Applicant	Agreement Date	License Conditions Effected: Unit Access	Transmission Service	Coordination	Contractual Provisions
Arizona Public Service Co.	4/3/75		x	x	x
Carolina Power and Light Co.	8/18/72		x	x	x
Commonwealth Edison Co.	2/22/74	x			x
Detroit Edison Co.	8/31/71				x
Detroit Edison Co.	3/21/74	x	x	x	x
Duke Power Co.	4/16/74		x	x	x
Florida Power Corp.	12/6/71		x	x	x
Florida Power and Light Co.	2/25/74	x	x	x	x
Georgia Power Co.	4/30/74	x	x	x	x
Gulf States Utilities Co.	1/29/75	x	x	x	x
Gulf States Utilities Co.	3/20/74	x	x	x	x
Illinois Power Co.	4/5/74	x	x	x	x
Louisiana Power and Light Co.	2/3/75	x	x	x	x
Mississippi Power & Light Co.	5/22/73	x	x	x	x
No. Indiana Public Service Co.	11/5/71	x			
Northern States Power Co.	8/9/74	x	x	x	x
Philadelphia Electric Co.	5/20/74	x	x		
Public Service Co. of Indiana	3/18/75	x	x	x	x
Southern California Edison Co.	6/6/74	x	x	x	x
Texas Utilities Co.	1/15/74	x	x	x	x
Virginia Electric and Power	11/14/73	x	x	x	x
Virginia Electric and Power	7/26/74	x	x	x	x
Wisconsin Electric Power Co.	2/7/75	x	x	x	x

Source: David W. Penn, James B. Delaney, and T. Crawford Honeycutt, "The NRC's Antitrust Review of Nuclear Power Plants: The Conditioning of Licenses," NRC Staff Report (Preliminary). See text for interpretation.

State Utility Regulation

State utility commissions influence bulk power supply in a number of ways. They, not the federal government, certify construction of most power plants and transmission. In this capacity they can attempt to block entry or they can encourage load growth coordination.

State utility regulation encompasses directly, or through municipal corporations, the franchising of utility retail service areas. Franchise restrictions can severely retard the ability of non-utility customers to enter into self-generation--especially if they want to string lines across a public road. In the past, franchise disputes have led to territorial allocations among utilities.

In the western states, engaging in the sale or exchange of electric energy, with certain exemptions for industrial plants, makes one a public utility.[73] Public Utility Commission certificates of convenience and necessity required before new plants or transmission lines can be built, may not be forthcoming because of territorial allocations of utility service areas. Such allocations have defeated efforts by new entrants, or even existing firms, to serve areas or build plants.[74]

State agencies are often small, overwhelmed by utilities and lacking in planning evaluation abilities. In some mountain states they have been very ready to permit rapid rate increases. New Mexico has gone so far as to permit utilities to raise rates to achieve allowed rates of return without further proceedings.

State utility commissions have not required that gas or electric utilities submit tariffs to provide supplemental power to firms seeking to use geothermal or solar total energy systems, for all or part of their own energy requirements. For instance, Southern California Gas Company will not back up another primary source of energy beyond 1,000 cubic feet per hour.[75]

A survey of western power companies indicates that some do not offer a tariff for backup for on-site energy sources. Among those who do, rates can be from $2.00 to $5.00 per kilowatt per month (2.7 to 6.8 mills per kwh at 100% load factor).

Users of total energy systems generally either restrict themselves to a partial application, (i.e., heating and cooling but not electric power), or they install their own backup units.[76]

In the field development sector of the geothermal industry, State governments could employ their unitization and pro-rationing either to protect parties from being excluded from production units, or to restrict production in an anticompetitive manner--as has occurred with petroleum production.

The Securities and Exchange Commission (and State "Blue Sky" Commissions)

Firms seeking to publicly offer their securities[77] are required to register those securities with state "Blue Sky" commissions, and generally, with the Securities and Exchange Commission. Mwreover, they must annually file financial reports with these commissions.

While some state commissions pass upon the suitability of proposed public offerings, the SEC is restricted to mandating appropriate disclosure in the prospectus (or offering circular) and registration statement.

Information disclosed pertains to the description of the offeror, the nature of its business, its financial statements, and proposed use of the proceeds of the offer.[78] Material documents, such as contracts of substantial importance to the offeror, are also to be filed.

Information disclosure burdens, of necessity, fall heaviest upon smaller offerors. They have fewer security sales over which to allocate attendant costs; more of the details of their business are material to investors, and their shenanigans are less likely to be hidden.

While some utilities file coal supply agreements, major petroleum companies do not file their joint-venture, concession, or buy-back agreements in conjunction with either registration statements or annual reports to the SEC.

Small firms are required to disclose the profits of their one or two lines of business, and even to disclose the particular geographic areas where they wish to conduct exploration. Large firms merely report aggregate financial results. The competitive advantage is obvious.

Growth of project financing may some day lead to disclosure of financial results in narrower areas; however, its initial impact is to reduce disclosure by substituting off-the-balance-sheet financings and contingent liabilities for long-term debt.

Disclosure of financial results is essential if investors are intelligently to compare investment alternatives and efficiently allocate capital. They may be hindered in doing so by aggregate reports of widely integrated firms.

The quality of disclosure by petroleum joint ventures has not been universally such as to bolster investor confidence. Only recently, and then only after criticism, did the SEC require that firms disclose or discuss variations regarding reserves quantities reported to different government agencies.[79]

In the area of exploration and development of energy resources it should be noted that neither SEC, FPC, nor FEA has developed a uniform system of accounts.

Lack of agreed-upon accounting systems impairs the ability to compare firms, and precludes effective cost-based regulation of transactions among affiliates.[80] The SEC has been directed to assure the development and use of a system of accounts for the sectors of the petroleum industry locating, developing fields, and producing crude oil.[81] This work appears to be awaiting action of the private Financial Accounting Standards Board--as is contemplated in the SEC's authority.

In the electric utility area, the SEC largely relies upon the FPC to supervise utility accounting.[82]

The Executive Agencies

While other executive agencies have jurisdiction that affects geothermal development (e.g., the Treasury Department through tax and loan guarantee policy, and the Federal Energy Agency, primarily through its informational and inter-governmental coordination responsibilities) the Interior Department and the Energy Research and Development Administration play major roles.

The Department of the Interior

The Interior Department has a determinative role in the rate at which geothermal energy will be produced. It is responsible for carrying out the Geothermal Steam Act, for leasing alternative domestic sources of energy,[83] for granting and supervising use of rights-of-way for transmission lines and pipelines, and for managing western federal power projects. It is also responsible for obtaining and making available information concerning energy production and use, and the resources of the federal domain. Interior has far-reaching discretionary authority to affect the ability of small geothermal and electric power systems to hold their own in energy markets.

In each of its areas of responsibility, the Department is by law directed to maintain a pro-competitive stance, or to give preference to public entities.

Several factors indicate that the Interior Department has acted in a manner inconsistent with fostering diversity in industrial organization.

For many years, the Interior Department has been assigned, by a history of political action, the role of governmental patron of the petroleum industry.[84] The Department has historically viewed its fuel information responsibilities more as a service performed for industry than as a means of providing necessary background for public policy decisions.

For example, the Interior Department for years has maintained an information system well adapted to displaying demand, stocks, and supply data in a way useful to State prorationing schemes; but did not see fit to develop the energy data reporting needed for planning energy policy.[85] The Bureau of Mines has been content with a voluntary system of sometimes stale reports in which information on reserves or exploration effort has been largely lacking.

Interior's management of federal geothermal, petroleum, and coal resources has features inconsistent with realizing competitive conditions in the lease market, or expeditious development of the leased resources.

In no federal leasing activity has there been sustained effort to secure production at maximum efficient levels.

Leasing, in both coal and oil, has persistently lacked adequate compensation and "due diligence" features which might secure the value of locational rents for the public and prevent concentration of leaseholding, and inventorying of "speculation."[86] Leasing is also commonly carried out on the basis of bonus, rather than royalty, bidding. This favors large bidders with ample supplies of cash.

The General Accounting Office has reported that no effort is made to enforce maximum acreage limitations on holdings of federal on-shore oil and gas leases, nor are adequate lease records maintained.[87]

Similarly, and contrary to Outer Continental Shelf leasing legislation, no effort is made to require access for non-owners to off-shore pipelines.[88]

Investigators' reports about Interior Department lease supervision activity on the Outer Continental Shelf are disquieting in their implications for the geothermal area. Disarray, lack of public information, and lack of regulation of a highly concentrated group of lessees are asserted.[89,90]

In addition, the GAO has reported that the provisions of the Organic Act of 1879, 43 U.S.C. 31, prohibiting ownership by USGS employees of stock in companies with a principal interest in the mining or production of materials generally classified as mineral resources, have not been enforced.

Scrutiny of the federal geothermal leasing program shows that many of these more general deficiencies are visible in the geothermal area, and may be expected to hamper speedy and sound resource development.

As with coal and petroleum, the federal government has no comprehensive program for locating and evaluating its geothermal resources.[91] Lack of such a program encourages speculation and creates information entry barriers for small entities. Speculative withholding cannot be restrained by due diligence requirements absent both (a) the basic information needed to determine when and if a resource is capable of development, and (b) effective regulations.

Leasing of better geothermal acreage has been by bonus bidding[92]--where large firms have a capital accumulation advantage. Though leases have been widely issued, there has been no government effort made or proposed to direct them to lessees most likely to develop resources.

Deadening delays encountered by firms seeking to obtain administrative approvals necessary for exploration work are particularly difficult for small firms to bear.

The extensive energy resources remaining on unleased portions of the federal domain could be developed in ways that could stimulate competition and diminish the present concentration of control of energy resources.

A pro-competitive leasing policy in which diversity of lease ownership and diligent lease development are sought is essential if small systems and firms are to be able to attempt geothermal energy development. Such a program (akin to those sought in recent coal legislation, and in pending legislation regarding the Outer Continental Shelf) could be implemented by Interior Department action, or, if necessary, amending the Geothermal Steam Act to require (a) royalty lease bidding, and (b) enhanced federal exploration which could provide information required to effectively compel every lessee to either develop his leasehold at a reasonable rate or relinquish it.

In order to reduce the barriers to entry resulting from risks of exploration, the Interior Department (and state governments) should increase the amount of government sponsored testing of public lands, and disclose the results of such tests. Increased testing of public lands, called for in both recent coal leasing legislation and proposed OCS legislation, would increase the ability of the public land managers to design alternative competitive bidding systems, and lower entry barriers.

The Interior Department (as well as ERDA) should act to create an enlarged market for specialized geothermal services. To this end we recommend that the United States enter into a program of purchasing geophysical studies, well logs, and related analyses. The information so purchased should be publicly filed and should principally relate to unleased public lands. The opportunities to sell information to the government should be competitively available.

Exploration leasing might advantageously be separated from development leasing, and should be tried at several prime sites. This would permit first a determination of the existence and general extent of a site; and then determination of how that site be developed in a manner most consistent with comprehensive development of the resource. Exploration could be done by government and by holders of exploration permits.

Separation of exploration from development could have several benefits. It could permit informed federal leasing, and avoid the substantial commitment of bonus money to unproductive areas.[93] Publication of government exploration results would permit a more informed market for development.

Separation of exploration from development is practiced overseas with great success. It has been suggested for the OCS on a trial basis.[94] If employed for geothermal leasing, it might enhance the competitive prospects of smaller enterprises.

If done in an informed manner, separating development leasing from exploration permits could assure lease development. Presently due diligence is sought indirectly as a product of lease bonuses and rents. Theoretically, the Department of the Interior could commence an administrative proceeding on the lease after it has not been developed for a period of some years. However, geothermal rents and lease bonuses are generally low, lease bonus bids may represent the value appraised less imputed carrying costs for speculative holding of the tract, and due diligence proceedings must be attempted on the basis of very vague guidelines and against a burden of proof resting on the government.

If development and exploration were split there could be competition for development. Comparative proceedings regarding development could be conducted (on the basis of written submissions to conserve time.)[95] Because of their scope, such proceedings could be approximately coincident with proceedings regarding development under the National Environmental Policy Act.

For such a proceeding to work, decision-makers must be available who are in a position to make difficult choices promptly. This will require that the decision-maker(s) be placed high enough in bureaucratic order to be publicly accountable, and that he is not principally engaged otherwise, and that he has sufficient tenure of office to withstand political pressure. These same requirements are needed if due diligence requirements are to be seriously pursued Because similar decisional problems will be arising in leasing other energy sources, a tribunal independent of the Interior Department is called for. Splitting exploration and development licensing will probably require legislative amendment of the Geothermal Steam Act; as would creation of an independent licensing tribunal.

Lastly, as to leasing, it is in view of the highly concentrated electric utility market in the Western United States, and the history of anticompetitive actions in that market, public power entities should be afforded preferential access to geothermal energy leases.

Electric Power Activities

The federal power facilities of the Bureau of Reclamation have not been so employed as substantially to diminish or ameliorate the concentrated conditions in bulk power supply in the Western states. Rather, federal facilities have been employed in a manner limiting access of smaller, potentially competitive entities to alternative sources of energy, and limiting the development of bulk power supply facilities and practices which could afford competitive opportunities for new energy sources. A substantial portion of the benefits of the federal facilities--it appears an unnecessarily large portion--have gone to the dominant utilities in the area.

Federal power marketing agencies should be taken out of the Interior Department (or the Department of Energy), reorganized as independent federal corporations and authorized to construct transmission so as not to be dependent upon their competitors for integration of federal systems. Our reviews of Interior Department documents indicates that the professional staffs of these agencies have usually resisted, in vain, decisions by political appointees which have repeatedly accommodated the desire of large private utilities to be free of competitive alternatives.

Stipulations in federal right-of-way permits will pertain to almost all, if not all, new western high voltage lines. These stipulations should require that permittees offer transmission services and attendant planning and operating coordination services to others. Public transmission line corridor planning proceedings should be promptly undertaken to seek the best layout and use of the limited number of high voltage transmission corridors in the West. These planning proceedings, which could be undertaken in a NEPA framework, should seek to assure the development of corridor plans which are sufficient for regional needs, and which are so laid out as to (1) permit looping of lines to meet growing loads, and (2) permit access by line owners and non-owners via spurs of reasonable length.

Proposed right-of-way permit terms should be publicly noticed with opportunity to comment. Formalized planning--if undertaken in advance of needs--

need not result in administrative delay, while it can discourage the tendency to waive wheeling provisions on key lines.

Power marketing authorities should review all present federal power contracts and rights-of-way to determine whether they are consistent with antitrust law and policy, and whether the representations given to the United States, and relied upon when the contracts or rights-of-way were let, have been adhered to. Where the contracts and rights-of-way are found to be inconsistent with antitrust law, or to contain provisions induced through false or erroneous representations, action to abrogate these agreements, as contrary to public policy and law should be carefully considered. Particular attention should be paid right-of-way provisions waiving wheeling requirements.

Major federal power marketing contracts and right-of-way permits should only be granted after public notice and opportunity for comment on economic as well as environmental aspects.

The power marketing agencies should be authorized to develop geothermally driven capacity to augment and "firm-up" their hydro capacity.

The lack of Bureau efforts to study coordination among Bureau systems or to provide California public entities with alternative routes to bulk power coordinating services, independent of the California Power Pool, significantly retards the ability of industrial, municipal, or smaller private utility firms economically to develop firm geothermal bulk power supplies.

The Energy Research and Development Administration

The Energy Research and Development Administration ("ERDA") is charged with the formulation and execution of most of the federal research program relating to geothermal energy and to bulk electric power supply. This authority is given under a rather broad writ regarding procedures, and very general policy guidelines.[96]

ERDA-funded projects may be expected to comprise a very great portion of total geothermally related research.

ERDA states that the goal of the National Geothermal Energy R&D Program is:

> "To work with industry to provide the Nation with an acceptable option which, if exercised, would permit the timely exploitation of our substantial geothermal resources."

Whether the industrial structure which is being fostered by ERDA research will permit future options is not clear. To work with industry, one first should determine the type of industry one wants to work with.

Federal energy research programs have an important subsidizing role in the development of the geothermal industry. In some of these programs, such as loan guarantees or project assistance contracts, the subsidy to some firms can be quite direct. It is obviously important that federal research be carried out in a manner that provides for equal treatment of all potential beneficiaries,[97] and in a manner that encourages a competitive industrial organization conducive to entry by innovators.

Care is required both in allocating subsidies and in choosing what types of subsidies should be employed.

An example of problems in the allocation of subsidies is seen in the program for guaranteeing loans for geothermal projects. The ERDA regulations for that program appear to preclude loan guarantees to publicly owned enterprises.

An example of problems in the choice of subsidies is the orientation of ERDA programs toward supporting work by private firms while not pursuing development of authorized government demonstration projects.[98]

No effort is made to combine the carrot of federal subsidies with the yardstick of federal demonstration plants.

ERDA's predecessor, the Atomic Energy Commission, instituted programs at two National laboratories to locate and develop two geothermal resources to the actual point of having two demonstration generating stations in operation.

A program was begun in 1973 by the Lawrence Berkeley Laboratory to find a site for a 10 mw geothermal demonstration plant in North-Central Nevada. At the reported behest of the Office of Management and Budget the plans to carry the project through to the demonstration plant plans were dropped, when ERDA came into being.

The field stages of the project did continue. To assure the availability of adequate land for the eventual development, in 1973 some 88,000 acres of public land were withdrawn from the federal leasing program until December 1975, at which time only 5000 acres would be retained for development work.

The program proceeded to develop and test geochemical, geophysical and geological techniques for searching for geothermal resources. With the use of these experimental techniques, interest came to center on the Grass Valley area where extensive tests were conducted.

The logical culmination of these experiments would be the drilling of several wells to corroborate or refute the experimental results. This was recognized by both ERDA and LBL personnel.

The oil industry had not been sitting by, however; it had lobbied for cessation of the LBL program and against any withdrawals of federal land from leasing or any deep drilling.

When the LBL program came up for assessment, a review panel was convened, consisting of several representatives of universities funded by industrial money, a representative from the U.S. Geological Survey, and two represenatives from industry: one from Standard Oil Company of California and one from its affiliate, AMAX.

This meeting was quickly converted by the head of the ERDA geothermal reservoir assessment program, Dr. John Salisbury, from a review of LBL's work to a general, albeit unannounced, advisory meeting on the propriety of federal drilling and lease withdrawals.

Panel members generally agreed that a coordinated drilling program was in order, but that first further work should be done to pick the location and type of holes to be drilled: it was suggested that a series of moderate depth holes precede deeper drilling.

The panel unanimously agreed that LBL had done an excellent job and had acquired an impressive data base with a very broad range of techniques. They recommended that LBL determine the cost and configuration of the holes which should be drilled and that further consideration then be given to the drilling program.

The ERDA manager in charge of the LBL program recommended that the program be wound up. While urging LBL to analyze all existing data and plan final field programs so as to provide the best possible reservoir models, particularly in Grass Valley, and to recommend the location and configuration of confirmation drill holes, he stated "It is further recommended that the laboratory plan and coordinate the drilling program with industry." He recommended that all withdrawn parcels be released for public leasing, since a government demonstration plant is no longer being considered for the area.

The ERDA program manager's recommendations, and the subsequent termination of the LBL program reflect the strongly stated views of the head of ERDA's program of assessing geothermal reservoirs, Dr. John Salisbury.

At the review panel meeting, Dr. Salisbury outlined petroleum company opposition to the LBL program's withdrawal and assessment of public lands; on the grounds that it would raise the price of leases for tracts explored. He then indicated his opposition to the program as it was not in step with his ideas of the ERDA program.

Mr. Salisbury stressed that the orientation of ERDA was to "foster industry," and that the Northern Nevada program was politically a "negative factor," and "clearly since it is our purpose to foster the geothermal industry we are not going to continue to pursue this program."

He later stated "quite clearly (that) within the economical, political and philosophical context of the ERDA program as it should be, this Northern Nevada project is kind of an embarrassment frankly,"[99] and that the Northern Nevada program did not fit into the framwork of the ERDA program.

Subsequently, the LBL program budget was cut to $300,000 per year from $700,000 and wound up without drilling. The land in Grass Valley ceased to be withdrawn and is proposed to be leased by the Bureau of Land Management without any special conditions regarding drilling or the availability of drilling results.

The lack of leasing conditions is interesting. The review panel member from Chevron (Standard Oil Company of California), while urging against withdrawing large areas of public land, and in favor of reliance on industry for drilling, suggested that "where so much basic data has been obtained at public expense, a well within the block should be required to a specific depth within the first year after issuing the leases."

No provision has been made for obtaining drilling results from a lessee to corroborate or refute LBL's research.

The ERDA geothermal resource assessment program is proposing to provide part of the financing for drilling by private entities in southern Utah in return for data from the drilling. The proposed program would most directly aid the limited number of firms with whom subsidy contracts are to be negotiated, and the time delay before acquired data is published may be expected to be a point of negotiation.

The orientation of ERDA's reservour assessment program to the subsidization of a limited number of private wells and away from federally sponsored evaluation and demonstration development of federal lands has gone on with little comment. ERDA has embarked upon a course of "working with industry," not of leading it. This approach is fraught with opportunities to turn the agency into a "welfare department" for chosen firms, with its employees being tempted to be zealous "welfare" workers.

The geothermal program's decision to subsidize, rather than to provide a yardstick or a prod, raises important questions as to the balance of approaches undertaken to foster development of new domestic energy sources. Pro-competitive research programs whose benefits are accessible to entrant enterprises are more likely to occur if research programs are formulated in a framework of publicly revealed data and rationales regarding a program's competitive impact, its costs and benefits, and, relatedly, its alternatives. Such procedures might direct federal programs toward subjects having a range of capital requirements comprehending the potentials of small as well as large firms, and toward more competitive procurement practices.

Procedures for government research grants and contracts are more informal than those for other types of government procurement. This informality reflects a legal view concerning the nature of grant-making and research contracting--that such grant-making and contracting are matters committed to the widest discretion of the government agencies involved. Grants, unlike contracts, in this view are not considered to confer legally protectable "rights" upon recipients. Research contracts have been exempted from normal government procurement requirements for competitive bidding, and can be let after non-publicly disclosed negotiations.

As the role and extent of grants and research have developed, there appears to be a tendency toward greater formalization of processes and increased use of public notice before grants or contracts are let, so as to make their procurement more competitive. The law is also starting to inquire into the evenhandedness among putative beneficiaries with which grant programs are administered.[100] The discretion vested in grant-makers has been subjected to legislative criticism.

Informal processes and broad discretion may expedite decision-making. Unfortunately, they appear to preclude external discipline and give the appearance of being arbitrary and even capricious. Decisions not supported by reasoned discussion are likely to be questioned where large sums of money are involved and where important policy factors should be taken into consideration.

Formalization, and on-the-record proceedings, are likely to come into greater vogue for such decisions. Their use might reduce the possibilities for lobbying by one segment of an industry to the detriment of another,[101] or possibilities for conflicts-of-interest.

Federal law governing the acquisition of services and property has long favored competitive acquisition.[102] Similarly, a pro-competitive policy has been established for the sale of federal plants and other "surplus property,"[103] and power output. In the research area, Congress has mandated a pro-competitive policy regarding resulting patents.[104]

Conclusion

For geothermal energy to provide the portion of Western states power generation that it economically might, development must be carried out by small utilities or industrial power users matched with small geothermal firms at sites sufficiently promising to embolden these firms to risk development capital. These firms can only engage in geothermal development if they have access to bulk power coordination and transmission services proffered on reasonable terms.

Larger utilities take a more deliberate pace in geothermal efforts; large oil companies warehouse resources. Small utilities and industrial firms confront a number of problems in seeking geothermal self-generation. However, small specialized technology firms and small utility systems have shown considerable interest in developing geothermal power.

Small geothermal firms are not generally able to out-bid large oil companies for leases or to match them in warehousing tracts. The holdings of the smaller geothermal exploration and development companies are dwarfed in size by the hundreds of thousands of acres held by large petroleum companies such as Socal, Phillips, or Gulf Oil. The "independents" present are either substantial petroleum companies or partners of a large entity.

The smaller geothermal enterprises are generally directed toward functioning as service enterprises for either larger petroleum companies or utilities.[105]

Entry barriers relating to capital and land, coupled to some extent with the extension of habits carried over from other industries, have resulted in the geothermal field exploration and development sectors being organized on the pattern of the petroleum industry.

Larger petroleum and utility enterprises have acted in ways that appear to increase entry barriers for smaller firms. They have preempted many of the better sites, and in joint enterprise agreements have partially limited the availability of services of technological enterprises.

Entry barriers encountered in the early days of geothermal development may permanently disadvantage smaller firms. The acquirers of prime geothermal sites may be expected to have a leg up in obtaining--internally or by purchase--the highly essential know-how that will be a prerequisite to economic entry into present or future geothermal exploration and development.

The dominance of oil companies in geothermal resource holdings is cause for concern both because it may tend to produce a concentrated structure in geothermal energy development, and because larger petroleum firms are not likely to unilaterally reduce the price of a marginal utility fuel, and thereby directly affect their returns from their primary product.[106]

The attractiveness of geothermal resources is largely related to their potential as a lower cost energy source.

Both large oil companies and small independent geothermal developers seek oil-based prices for geothermal energy. Larger oil companies have preferred to prove up their geothermal reserves, on their own drilling schedules. They have not sought to enter into joint ventures with small power systems. Smaller geothermal developers must and do enter into joint ventures to obtain capital and land tracts. In such ventures they can only charge for their, and not the power system partner's share of production. Small developers' needs for cash flows may reduce their ability to successfully bargain for prices far above costs.

Large petroleum companies exercise control over the West Coast petroleum industry, limiting the competition from others in that market, and influencing supply routes and volumes, without effective government check. They are extending their relatively concentrated influence over energy supply to the Outer Continental Shelf, and to Alaska (by leases and the Trans Alaska pipeline agreement).

The practice of controlling supply is logically extended when oil earnings are used to acquire alternative energy sources, buttressing market power as barriers are raised to access by others--first to resources and then, as a product to technology.

Joint acquisition and maintenance of energy market power by major oil companies and large utilities, in these respective areas, has been little resisted, and on occasion actively assisted by government action. The government has conducted its resource management and its regulatory programs in ways that buttress entry barriers and retard participation by small enterprises.

Application of antitrust law and policy has been far less than that required to produce more competitive conditions. Parallel, if not collusive, conduct has been encouraged through efforts such as the International Energy Agreement, the National Petroleum Council,[107] and FEA marketing regulations.

More competitive energy supply markets would be conducive to geothermal development. Such markets may only be anticipated if the energy companies dominating utility fuel markets are reorganized by government.

In the electric utility area, power pooling (sharing of resources) and coordination practices have been such as to discourage both the development of power generation by smaller systems, and the development of federal or state transmission through which the smaller power systems could coordinate and pool geothermal generation.[108] Moreover, federal power marketing and right-of-way practices have accommodated efforts of large utilities to dominate bulk power supply.

Diversity and competition in bulk power supply can only exist if access to coordination services is available. Such is necessary if more than one buyer is to be available in The Geysers area or in other geothermal regions. Absent more than one buyer, contracts for the sale of geothermal energy are likely to continue--as is the case in The Geysers--to place all the risks of carrying charges for field investment associated with delays in the construction and operation of generating units on the field developer.

Access to power pooling can only be opened with the help of government. Effective government action for more competitive and efficient industry structure and practices will only come about if the government has data and articulated policies that are consistently implemented. Efforts to obtain uniform cost data are just beginning to get under way in both the fuel and utility industries.[109]

Creating a government approach to energy industries that seeks diversity and competition is a massive undertaking. Such an approach must overcome agencies' habit of "getting along" with the industries with which they are in contact.

We do not paint an encouraging picture for geothermal development. Rapid development requires that independent developers and small industrial or utility power systems develop projects not yet begun. They must overcome a number of obstacles in government and in the environment for entry and innovation in the fuel and bulk power industries.

Development of new sources of energy, especially those that could provide a decentralized alternative to large projects and rising prices, requires action going counter not only to the general flow of much of present government action, but also to the perceived interests and economic power of large and dominant firms.

Development of geothermal energy for bulk power supply could provide: first, a useful new energy source; second, competition in the supply of fuel for power generation; third, diversification of ownership in the fuels sectors; and fourth, perhaps in the long run, a type of government planning that favors individual choice in decisions to consume and produce, avoiding government ownership and control of resources excessive political influence on the part of a relatively few private entities.

NOTES:

1 In a leading case on the acquisition of a substitutable product, a large can company was prohibited from acquiring a glass container manufacturer. United States v. Continental Can Co., 378 US 441 (1964).

Joint ventures have been analyzed as akin to horizontal mergers. United States v. Penn-Olin Chemical Co., 378 US 158 (1963).

2 Brown Shoe Co. v. United States, 370 US 294 (1972) (look to industry trend); and United States v. Von's Grocery Co., 384 US 270 (1965).

3 Ford Motor Co. v. United States, 405 US 562 (1972); United States v. E. I. DuPont de Nemours & Co., 353 US 586 (1957); United States v. Bethlehem Steel Corp., 168 F. Supp. 576, 1958 Trade Cases §69189 (SDNY, 1958) (foreclosure of supply to independent manufacturers); United Nuclear Corp. v. Combustion Engineering, Inc., 1969 Trade Cases §72969 (E.D.Pa.); and United States v. Kimberly-Clark Corp., 1967 Trade Cases §72081 (N.D. Ca., 1967) (acquisition of outlets in merger trend). Bottleneck cases are discussed infra.

4 Neither the letter of the law nor its purpose distinguishes between strangling a commerce which has been born and preventing the birth of a commerce which does not exist. United States v. General Dyestuff Corp., 57 F.Supp. 642, 648 (S.D.NY, 1974); United States v. United Shoe Machinery Co., 247 US 32, 53 (1918).

5 We say obviously developable in order to eliminate the suggestion that proceedings could be maintained on the basis of highly speculative impacts on trade. Although acquisition of novel forms of energy may affect their rate of development, until these forms of energy reach a state where they are clearly developable commercially, antitrust action against their acquisition would be quite difficult to maintain.

6 United States v. Griffith, 334 US 100, 92 L ed 1236; United States v. Klearflax Linen Looms, Inc., 1944-7 Trade Cases §57407 (D. Minn., 1945). United States v. Southwestern Greyhound Lines, Inc., 1952-53 Trade Cases §67470 (N.D. Okla. 1953); Terminal Railroad, infra. Concerted group action is similarly illegal. Fashion Originators Guild v. Federal Trade Commission, 312 US 457, 85 L ed 949 (1941). Misuse of monopoly power is not legitimated by the existence of a business motive, United States v. Arnold, Schwinn & Co., 388 US 365, 375 (1967); Otter Tail, supra at 380 (1973) (refusal to deal).

7 United States v. Terminal Railroad Association, 224 US 383 (1912); Lorain Journal Co., v. United States, 342 US 143,96 L ed 162 (1951); Associated Press v. United States, 326 US 1, 89 L ed 2013; United States v. Aluminum Company of America, 148 F.2d 416 (CA2, 1945); and Otter Tail Power Co. v. United States, 410 US 366 (1973).

8 Standard Oil Co. v. United States, 337 U.S. 293 (1949); United States v. Arnold, Schwinn & Co., 388 US 365 (1967); and Anderson v. American Automobile Ass'n., 1972 Trade Cases 73793 (CA 9, 1972).

9 Siegel v. Chicken Delight, Inc., 448 F.2d 43, 51 (CA 9, 1971), 1971 Trade Cases §73,703, cert. denied, 405 US 955 (1972); Copper Liquor, Inc. v. Adolph Coors Co., 506 F.2d 934, 942-43, (CA 5, 1975), 1975-1 Trade Cases §60128.

Anderson, supra, teaches that:

"To sustain the restraint, it must be found to be reasonable both with respect to the public and to the parties and that it is limited to what is fairly necessary, in the circumstances of the particular case..." Dr. Miles Medical Co. v. Park & Sons Co., 220 US 373, 406 (1911).

"The promotion of self-interest alone does not invoke the rule of reason to immunize otherwise illegal conduct. It is only if the conduct is not unlawful in its impact in the market place or if the self-interest coincides with the statutory concern with the preservation and promotion of competition that protection is achieved." United States v. Arnold, Schwinn & Co., supra, at 375.

10 See, A.B.A., Antitrust Law Developments (1975), p. 43.

11 Standard Oil Co. of California v. United States, 337 US 293, 314 (1949).

12 Cf., Tampa Electric Co., v. Nashville Coal Co., 365 US 320 (1961); and, Antitrust Law Developments, supra, p. 44-45.

13 Standard Oil Co. v. United States, 337 US 293, 305-6 (1949).

14 Northern Pacific Ry. v. United States, 356 U.S. 1, 6 (1958).

15 United States v. Jerrold Electronics Corp., 187 F. Supp. 545; affirmed per curiam, 363 US 567 (1961) (new product).

16 Scherrer, Industrial Market Structure and Economic Performance (1971), p. 505-6.

17 Accommodation of regulatory and antitrust legislation is sought in cases such as Ricci v. Chicago Mercantile Exchange, 409 US 289 (1973) (primary jurisdiction); Cantor v. The Detroit Edison Company, supra (state regulation); Northern Natural Gas Co., v. PFC, 399 F.2d 953 (CADC, 1968); and FPC v. Conway Corporation, 426 U.S. 271 (1976).

18 Silver v. New York Stock Exchange, 373 US 341 (1963); Gordon v. New York Stock Exchange, 422 US 659 (1975); and U.S. v. National Association of Securities Dealers, 422 U.S. 694 (1975).

19 These duties are either implicit in a "public interest" standard, or explicit. Northern Natural Gas Company v. FPC, supra; Gulf States Utilities v. FPC, 411 US 747 (1973); FPC v. Conway Corporation, 426 US 271 (1976), 1976-1 Trade Cases 60912 (public interest standard); Mineral Leasing Act of 1920, 30 USC 181, 184 (h), (k), 185, 202, 43 USC 970 (forfeit pipeline rights-of-way if antitrust laws violated). Cf., Denver Petroleum Corp. v. Shell Oil Co., 306 F. Supp. 289 (D.C. Colo. 1969); 43 USC 1334 (c) (oil pipelines); 43 USC 31 (The Director and members of the Geological Survey shall have no personal or private interests in the lands or mineral wealth of the region under survey, and shall execute no surveys or examinations for private parties or corporations); 43 USC 485 (h),522 (preference for public agenices and REA cooperatives); 43 USC 617 (d) (transmission line use from Boulder Canyon (Hoover Dam) Project); Deepwater Ports, 33 USC 1501, 1503 (c), 1504 (c), 1505 (i), 1506-07, 1511, 1513.

20 By this we mean a claim of need for preliminary reference of matters to an agency for determination before court action proceeds, rather than the question of whether the agency jurisdiction includes any court action at all--or "exclusive (agency) jurisdiction."

21 Cf., Otter Tail Power Co. v. United States, 410 U.S. 366 (1973); Ricci v. Chicago Mercantile Exchange, 409 U.S. 289 (1973); Jaffe, Primary Jurisdiction, 77 Harv. L. Rev. 1037,1043-47 (1964).

22 Jaffe, Primary Jurisdiction Reconsidered, 102 U. Pa. L. Rev. 577 (1954).

23 See 22 U.S.C. 2370 (c) (2).

24 See, Litton Systems, Inc. v. Southwestern Bell Telephone Co., 1976-2 Trade Cases para. 61084 (CA 5, 1976) wherein the court suggests this approach. It is not clear how far the courts may do so under the present Federal judicial code. Cf. FPC v. Transcontinental Gas Pipe Line Corp., US, 46 L. Ed. 2d 533 (1976). Legislation could easily remedy any deficiencies in that respect.

25 This concern is reflected in provisions of the Hepburn Act making oil pipelines common carriers, the Federal Water Power legislation which culminated in the Federal Water Power Act of 1920 (now Part I of the Federal Power Act), the 1911 antitrust proceeding against the Standard Oil Trust, the provisions of the Mineral Leasing Act of 1920, and the reports of government agencies and Senator LaFollette's Committee on Manufacturers; S. Report No. 1263 (67th Cong. 4th Sess., (1923) cited in Report on the Petroleum Industry Competition Act of 1976, Sen. Judiciary Committee, Part 1, Rept. 94-1005, 94th Cong., 2d Sess.

26 See e.g., the Connally Hot-Oil Act permitting state pro-rationing of production, the Natural Gas Act requiring certification of interstate gas pipelines, oil import restrictions imposed in the late 1950's, and provision of the Outer Continental Shelf Act not requiring the Secretary to use other than cash bonus bidding when leases are let, and not requiring offshore pipelines to be common carriers. 43 USC 133, 1334(c) and 1337.

27 Oppenheim, Why Oil Prices Go Up: The Past: We Pushed Them, 25 Foreign Policy 24 (Winter 1976-77). The Safety Net Proposal is discussed in Senate Foreign Relations Committee, Multinational Oil Corporations and U.S. Foreign Policy, 93rd Cong., 2d Sess.(1975) p. 4; and, Joint Economic Committee, the State Department's Oil Floor Price Proposal: Should Congress Endorse It? 94th Cong., 1st Sess. (1975); 2nd Sec. Testimony of Dr. M. A. Adelman before Joint Economic Committee, January 12, 1976, reprinted at pages S.956-59, Congressional Record, Vol. 122 (January 18, 1976). Under this concept high oil prices are sought to encourage conservation and to encourage investment in synthetic fuels.

28 Under the International Energy Agreement, justified as a burden-sharing program in the event of another oil embargo or general shortage, the IEA operates through a "voluntary agreement" among major petroleum companies to develop a worldwide emergency contingency plan and, to that end, to exchange information so as to permit firm coordination of production, transportation and refining. Actions taken pursuant to the voluntary agreement (41 FR 13998, April 1, 1976; 41 FR 24772, June 18, 1976) have antitrust immunity. Energy Policy and Conservation Act of 1975, Sec. 252. These actions such as meetings of company representations have received sparse supervision from the Justice Department and from the F.T.C. During a recent "trial" run of the contingency plan, the companies were permitted to communicate with each other

and to exchange data directly without government supervision. Section 5, Voluntary Agreement and Plan of Action, as amended, and see 41 FR 41459 (Sept. 22, 1976). While the need to prepare for emergencies certainly may justify waiver of antitrust law provisions in appropriate cases, the general approach of such matters is that waivers should never go beyond the scope essential to meeting the emergency, nor should antitrust supervision of side effects be neglected.

29 Energy Policy and Conservation Act, Public Law 94-163, 89 Stat 871 . *et seq*.

30 Letter of March 2, 1976 to Senator John Tunney from Assistant Attorney General Kauper.

31 *United States v. General Dynamics*, 415 U.S. 486, 39 L. ed 2d 530 (1974) (Acquisition of United Electric Coal Companies in 1959 by firm owning Freemont Coal Mining Corp., which firm in turn was acquired by General Dynamics which thereby became the nation's fifth largest coal producer).

32 *Kennecott Copper Co. v. FTC*, 467 F.2d 67 (CA10, 1972). 1972 Trade Cases 97415), cert. denied, 416 US 909 (1974).

33 The paucity of antitrust activities of the Federal Trade Commission and of the Justice Department which sought to go beyond local price fixing schemes has been criticized by Congressional Committees. This history has been recounted in the Senate Judiciary Committee's Report, Petroleum Industry Competition Act

of 1976 Report No. 94-1005, 94th Congress, 2d Sess. (1976) p. 94 et seq.; the report of the Subcommittee on Multinational Corporations, Senate Foreign Relations Committee Multinational Oil Corporation, and U.S. Foreign Policy, 93rd Congress, 2d Sess., (1975) p. 33 et seq.; the reports of the Special Subcommittee on Integrated Oil Operations, Senate Interior Committee, The Burmah-Signal Merger, 93rd Cong., 2d Sess. (1974), p. 5-7; and An Analysis of the Proposed Standard-Occidental Merger, 94th Cong. 1st Sess. (1975); the Report of the Subcommittee on Consumer Economics, International Economics and Priorities and Economy in Government of the Joint Economic Committee, 93rd Congress, 2d Sess. (1974); and the report of the Subcommittee on Special Small Business Problems, House Select Committee on Small Business, Anticompetitive Impact of Oil Company Ownership of Petroleum Products Pipelines, 92d Congress, 2d Sess. (1972) p. 29-31.

34 The Public Utility Holding Company Act of 1935 (15 U.S.C. 79 et seq.) was aimed at rationalizing the industry structure. It struck at the acquisition and retention of scattered, non-integrated properties through the "single integrated system" standard of §11 (15 U.S.C. 79k). Thus it tended to promote vertical integration by restricting the activities of a firm to an area where such integration was feasible. In recent years, the merger and acquisition sections of the Act have been found (i) to require SEC scrutiny of joint generation projects that might adversely affect distribution competitors precluded from participation in a joint generation enterprise and (ii) to limit horizontal

acquisitions having anticompetitive consequences. For example, the SEC has barred a merger of several New England systems. New England Electric Systems, ___ SEC ___ (1976). In Municipal Electric Assoc. of Massachusetts v. SEC, 413 F.2d 1052 (C.A.D.C., 1969), the SEC was instructed to consider the anticompetitive effect of creating a jointly-owned nuclear power generating company on a municipal power system excluded from participation therein.

35 See Cottonwood Mall supra; Gelmar v. PSC, 67 Utah 222, 247 P.2d 284 (regulated monopoly, not competition is Utah policy); San Miguel Power Assn. v. PSC, 292 P.2d 511 (Utah, 1956) (Co-op is not a public utility and so can not object before PUC to extension by Utah Power and Light Company into its service area); Public Service Co. of Colo. v. PUC, 350 P.2d 543 (Colo., 1960) (excluding co-op from cities and from company's unserved but certified area); and, Western Colorado Power Company v. PUC, 411 P.2d 785 (Colo., 1966) where Colorado-Ute, an entrant generation and transmission co-operative sought to build a 150 mw unit. This unit was opposed by Western Colorado Power Company (then a subsidiary of Utah Power and Light) and by Public Service Company of Colorado on grounds of duplication, asserting that the co-ops should get power via wholesale purchases from them. The court held that the protestants were regulated monopolies, that new markets should be protectively secured for existing suppliers, and that there was no "need" for the new entrants'

facility as protestants could provide alternative sources of power. For a discussion of state franchises, and territorial restrictions see Meeks, Concentration in the Electric Power Industry: The Impact of Antitrust Policy, 72 Col. L. Rev. 64 (1972).

36 Section 10 (2) (a) of the Federal Power Act, 15 U.S.C. 803 (a).

37 See e.g., 43 CFR 2851.1-1(a)(j)(71). In Utah Power and Light Company v. Morton, 504 F.2d 728 (CA9, 1974), the Company unsuccessfully contested the Secretary of the Interior's right to require a private utility seeking a right-of-way across public lands for construction and operation of electric transmission lines, to wheel energy from a federal hydroelectric generating facility over the proposed lines' excess capacity. The wheeling provision was found by the court to be within the Secretary's authority (under 43 USC 961). For purposes of conservation and power marketing, the Interior Department also reserves the right to increase, at government expense, line capacity. However, a permittee need not wheel to its own non-preference customers (e.g. industries) and it can utilize all of the line capacity. This authority to require wheeling has not been used by the Bureau of Reclamation in California.

38 See e.g., Flood Control Act of 1944, Section 5, 16 USC 825(s); the Reclamation Laws, 43 USC 485 (h) (c); and the Bonneville Act, Sec. 4, 50 Stat. 731 *et seq.*, 16 USC 831-833.

39 122 Cong. Rec. S10615, 10620 (June 25, 1976).

40 Pennsylvania Water & Power Co. v. Consolidated Gas, Electric Light & Power Co., 184 F.2d 552 (C.A. 4, 1950), supplemented, 186 F.2d 934, cert. den., 340 US 906, and, Consolidated Gas, Electric Light & Power Co. v. Pennsylvania Water & Power Co., 194 F.2d 89 (C.A. 4, 1952), cert. den. 347 US 690.

41 Affirmed Pennsylvania Water & Power Co. v. Federal Power Commission, 353 US 414, 96 L Ed 1042 (1952) (the Court noted that the control over Penn Water by Consolidated had been terminated, and upheld the FPC in requiring reduced rates under a continued policy arrangment, over a dissent arguing that FPC approved arrangements perpetuated the antitrust problems. Cf. Northern Natural Gas Company v. FPC, 399 F.2d 953, 959-961 (C.A.D.C., 1968).

42 Monopoly power is the power to control prices or to exclude competition from the market. U.S. v. E. I. DuPont de Nemours and Co., 351 U.S. 377, 391 (1956).

43 410 U.S. 366 (1973), affirming, in part, 331 F. Supp. 54 (D.C. Minn., 1971).

44 For instance, the FPC cannot compel wheeling or construction of new capacity (load growth coordination).

See, Otter Tail, supra; and Otter Tail Power Company v. Federal Power Power Commission, 473 F.2d 1253 (CA8, 1973).

45 In granting certificates for facilities, federal, and California state authorities must consider antitrust allegations. See, e.g., Northern California Power Agency v. P.U.C., 5 C.3d 370, 96 Cal. Reptr. 18, 486 P.2d 218 (1971).

(PUC must consider and make findings on antitrust allegations made in Geysers units certification proceeding); Northern Natural Gas Co., v. FPC, 130 US App. DC 220, 399 F.2d 953 (1968); California v. FPC, 369 US 482 (1962); and McLean Trucking Co. v. United States, 321 U.S. 67 (1944).

46 In the absence of state legislative authority, a territorial allocation agreement among two utilities filed and approved by the Florida Public Service Commission was successfully attacked by the Justice Department in a Section 1 Sherman Act suit. The suit which asserted that sales for resale were beyond the state commission's jurisdiction was settled by consent decree, United States v. Florida Power Corp., (M.D. Fla., Tampa Division, Div. No. 68-297-T); 1971 Trade Cases, 73,637 (August 19, 1971).

47 Under the doctrine of Parker v. Brown, 317 US 341 (1943), state mandated action can result in an exemption from antitrust laws. The action must be mandated, not just permitted. Goldfarb v. Virginia State Bar, ___US ___, 44 L.ed 2d 572 (June 16, 1975) (must be action of state as sovereign); and see Kinter, The State Action Antitrust Immunity Defense, 23 Am U.L. Rev. 527 (1974). Also, the decision must be effectively that of state officers, not of "private business advisors" whose decision is adopted by the state. See ABA Section of Antitrust Law, Antitrust Developments 1955-1968, 211; Cantor v. Detroit Edison Co., 428 U.S. 579 (1976).

48 15 USC 717 et seq. and 16 USC 793 et seq. respectively.

49 See e.g., the Bonneville Act, Section 6 and 7; the Fort Peck Act of 1944, Section 5, 16 USC 833d.

50 See Section 311 of the Federal Power Act, 16 USC 825 (j).

Section 30 of the Public Utility Holding Company Act of 1935, 15 USC 79z-4 authorizes and directs the SEC to make studies and investigations of public utility companies, the territories they serve or can serve, and the manner of service; these investigations are to concentrate on structural features of the industry.

51 Gulf States Utilities v. FPC, 411 U.S. 747 (1973); FPC v. Conway Corp., 426 US 271 (1976); City of Huntington v. FPC, 498 F.2d 778 (CADC 1972).

52 California v. FPC,369 US, at 486; cf., Pacific Gas and Electric Company, Project No. 2735 (Order issued April 1, 1976).

53 See, e.g., Georgia Power Company v. FPC, 373 F.2d 485 (CA 5, 1967).

Current case law seeks to require that agencies consider effects on competition as part of the public interest. FMC v. Aktiebolaget Svenska Amerika Linien, 390 US 238 (1968); McLean Trucking Co. v. United States, 321 US 67 (1944); Denver & R.Gr.RR v. United States, 387 US 488 (1967); Northern Natural Gas Co. v. FPC, 399 F.2d 953 (CADC, 1968); City of Pittsburgh v. FPC, 237 F.2d 741 (CADC, 1956); and, Marine Space Enclosures, Inc. v. FMC, 420 F2d 577 (CADC, 1969) (Licensing cases).

54 Section 203 of the Federal Power Act, 16 USC 824 (b). This section has been construed to not encompass local distribution facilities, Duke Power Co.

v. FPC, 401 F.2d 930 (CA 4, 1968), and to not require a showing of positive benefit, Pacific Power & Light Co. v. FPC, 111 F.2d 1014 (1940).

FPC approval of a merger, with SEC approval, does not confer immunity from attack under the Clayton Act, §11, 15 USC 21 California v. FPC, 369 US 482 (1964); California v. FPC, 367 US 482 (1962). In the recent case of Kansas Power and Light Co. v. FPC, CADC #75-2080, decided April 7, 1977 the court held that while the FPC need not defer its proceeding pending district court action, it could excercise its discretion so as to defer its proceedings pending Court proceedings.

55 Section 10(a), Part I, Federal Power Act, 16 USC 803(a). Licensed projects should not be a part of a program by pool members of preemption of generating alternatives, or other enhancement of their market position, 16 USC 803 (h).

56 Pacific Gas and Electric Company, Docket E-7435 (Order Accepting Rate Schedule for Filing and Denying Request for Suspension and Hearing, issued November 6, 1968).

57 For instance, neither the operating guidelines of pool dispatches, nor pool planning documents are filed with the FPC.

58 The State Commissions lack jurisdiction over extra-state members of power coordinating groups, nor do they have jurisdiction over pool agreements as these are filed with the FPC. Accordingly, their role in planning is attenuated.

59 FPC Electric Power Surveys are conducted by industry advisory committees. Regional surveying is only done by regional industry advisory groups.

60 In Pacific Gas and Electric Company, Project No. 2735 (Order issued April 1, 1976) the FPC said it would grant a license for a new pumped storage facility, without deciding antitrust claims advanced. It did this even though resolution of such claims against licensee might necessitate changes in project operations and electric equipment, and even though the FPC's ability to retroactively require new license conditions, absent licensee consent, is open to some doubt. Antitrust claims were merely set for later hearings.

61 Along the lines of Section 105 of the Atomic Energy Act.

62 Cf., Report on S.2028, supra.

63 Council of Economic Advisors, 1970 Economic Report of the President, pp. 107-08.

64 More extensive judicial scrutiny appears to be available in environmental than in economic regulatory cases. Compare Citizens to Preserve Overton Park v. Volpe, 401 US 402, 415, 28 L. Ed 2d 136, 152 (1971) with FPC v. Transcontinental Gas Pipeline Corp., ___US___, 46 L. Ed. 2d 533 (1976).

65 The Congressional Research Service has estimated that of the $9.2 billion of increased electric rates in 1975, $5.9 billion were derived from Fuel Adjustment Clauses. "Electric and Gas Utility Rate and Fuel Adjustment Clause Increases," 1975. The FPC has recently (Federal Register, May 5, 1977) terminated a proposed FAC rule making instituted in 1975 when fuel adjustment clauses were under

congressional scrutiny. In ending the rulemaking the FPC noted that those seeking more disclosure of fuel purchasing data lacked specific cases of FAC abuse, that staff audits, restricted to checking vouchers against fuel bills and not reviewing fuel purchasing practices, had turned up only minor discrepancies, and that disclosure of fuel purchasing contracts might harm purchasers in non-competitive fuels markets.

66 Federal Power Commission termination of rulemaking proposal, filing of rate schedules, fuel adjustment provisions (April 26, 1977 at 42 F.R. 22897, 22899, May 5, 1977). Contrary to the FPC in this notice, the audit reports for fuel adjustment provisions indicate no review of the adequacy of procurement policies.

67 42 USC 2135.

68 The Nuclear Regulatory Commission's predecessor Atomic Energy Commission held that there must be a nexus between the complained-of practices and the activities under the license which are alleged to create or maintain a situation inconsistent with the antitrust law. Louisiana Power & Light Co., Dkt. 50-282 A, Memorandum and Order RA I-33-9.619 (28 September 1973). In the Wolf Creek proceeding the NRC appears to have concurred in the view that once it is established that activities under the license would create or maintain a situation inconsistent with the antitrust laws, the Commission is required to seek to remedy the situation, and relief need not be limited to the activities under the

license which create or maintain a situation inconsistent with the antitrust laws. Initial decisions have also been rendered by hearing boards in cases involving the power pool in Northern Ohio, Toledo Edison Co., Docket 50. (January 6, 1977), and Alabama Power Co., Docket 50. (April 8, 1977).

69 As of March 10, 1976, there had been only three full-scale evidentiary hearings.

70 This topic was discussed by the Working Group on Joint Action Among Utilities of the Conference on Research Relating to Small Energy Utilities. See Proceedings, NSF Conference on Research Relating to Small Energy Utilities, (Washington, D.C.: National Planning Association, October 1975), Proposal 15, p.11. Implementation of agreed upon license terms often will require filings with the FPC, an agency not noted for its concern for antitrust matters. Cf. Richmond Lt. & Pr. v. FPC, 481 F.2d 490 (C.A.D.C., 1973).

71 The Board has found against the applicant in Toledo Edison Company, and the Alabama Power Company cases while holding for the applicant in a case involving Consumers Power Company.

72 San Diego Gas & Electric Company has recently announced plans to sponsor a nuclear power plant, and so will be subject to antitrust review. No action was recommended in conjunction with a review of a nuclear plant LADWP sponsored.

73 Arizona Rev'd Stat. Anno., Sec. 40-281 and 40-360. (Plant of 100 mw or more and have 115 kv or more); Colo. Rev'd Stat., 40-5-101; Ore. Rev'd Stat.

758-015 (transmission lines for which land is condemned); 6A Utah Code Anno. 59-4-25; New Mexico Stat. Anno. (1953) 68-7-1. In California, a heating company is a utility, Sec. 244, Public Utility Code. The Public Resources Code, Sec. 25000 et seq. provides for licensing of power plants in California by the California State Energy Resources Conservation and Development Commission. PUC certificates of convenience and necessity are required for new plants, sec. 1001, California Public Utilities Code. In California, for instance, a permit is required from the State for construction of any plant over 50 mw. California Electric Power Co., 61 Ca. PUC 799 (1963) (Public utility if in power interchange agreement for purchase, sale or exchange of capacity and energy on short-term basis).

74 See e.g., Tucson Gas, Electric Light and Power Company v. Trico Electric Cooperative, 406 P. 2d 740 (Az App., 1965); Western Colo. Power Company v. Public Utility Commission, 411 P.2d 785 (Colo. 1966) (Reversing PUC order permitting cooperative to build plant where other utility claimed it was ready to provide wholesale service); Western Colo. Power Company v. Public Utility Commission, 428 P.2d 922 (Colo., 1967); Western Power and Gas Company v. Southeast Colo. Power Association, 435 P.2d 219 (Colo., 1968); Public Service Company of Colo. v. Public Utility Commission, 485 P.2d 123 (Colo. 1971), (restricting, inter alia, size of load cooperative could service). and cf., Cottonwood Mall Shopping Center v. Utah Power and Light Company, 440 F.2d 36 (denying anti-trust claim based on refusal of power company to provide supplemental service to shopping

center providing power to tenants because shopping center is acting as utility in contravention of power company service area monopoly under Utah law).

75 Telephone conversation with Mr. Frank Morse, Southern California Gas Company, March 4, 1976.

76 Telephone conversation with Frank Morse, supra., who stated that utility electric power for backup carries charges in excess of normal power costs.

77 The term "securities" under the federal laws is broadly defined so as to include transferable instruments of debt, and various types of joint venture offerings.

78 See Securities Act of 1933 and Regulations thereunder.

79 GAO Report, "Receipt and Coordination of Natural Gas Reserve Data: Federal Power Commission, Securities and Exchange Commission,"B-178912 (April 30, 1974).

80 The historic SEC policy, under the 1935 Public Utility Act of restricting utilities to utility operations and requiring that non-utility subsidiaries be operated for the benefit of utility or pipeline companies, is being eroded. For instance, intrasystem prices may now be at "market" and tax savings of non-utility subsidiaries need not be shared to benefit affiliated utilities.

81 Energy Policy and Conservation Act of 1975, Section 503, 42 USC 6383.

82 SEC decisions regarding utility holding company accounts govern the FPC. Sec. 305, Federal Power Act.

83 The Forest Service, Department of Agriculture, must approve leases on lands within its jurisdiction.

84 The oil industry has often spoken through the National Petroleum Council. The announced purpose of the NPC is to act as an advisory council to Interior. NPC working groups of company representatives meet sans public notice or a transcript of their proceedings.

Also the Interior Department provided advice for the maintenance of oil import restrictions through its very small Office of Oil and Gas--where policy was formulated by and with personnel on one year loan from major oil companies. This continued for over a decade.

85 GAO, Improvements Still Needed in Federal Energy Data Collections, Analysis, and Reporting (June 15, 1976).

86 In 1976, the Interior Department issued due diligence requirements in the coal area. Coal leasing legislative proposals were then pending in Congress.

87 G.A.O., Acreage Limitations on Mineral Leases not Effective, RED-76-117 (June 24, 1976). This report states that limits are widely avoidable through three exclusions: (1) Inclusion in a unit plan of development, (2) holdings in the name of individual family members, (3) holdings of fractional interests which are chargeable only if they exceed 10% of the lease and then only in a share proportionate to charged parties' ownership share in the lessee. "The

Department stated that, with the complexities of vertical, horizontal, and conglomerate ownerships--which are common in the mineral industry--establishing ownership for the accounting of acreage holdings could be a difficult task..." In Utah and Wyoming, 38,748,593 acres have been leased by the federal government (June 30, 1975). Nationwide, over 88 million acres had been leased for oil and gas. Interior suggested that acreage limits on options to lease should be eliminated. Ibid.

88 Levy, The Regulation of Offshore Crude Oil Pipelines and the Consequences for Competition (1975).

89 Interviews with Messrs. H. Banta, W. Measday, Senate Antitrust Subcommittee, and J. Galloway, House Commerce Committee.

90 USGS files on OCS operation (at Metairie, Louisiana), are not kept in order. Information developed and maintained by the government on the economic ability to produce federal OSC leases is quite limited and derived from unverified industry data; this information is essential if the United States is to collect maximum royalties and prevent speculative withholding of production. Supra at p. 7.

91 The Coal Leasing Amendments Act of 1975, P.L. 94-377, 90 Stat. 1083,directs the Secretary to conduct a comprehensive exploratory program on federal coal lands. The Secretary is further directed to prepare and publish detailed maps of federal coal lands. 30 USC 208-1, 90 Stat. 1087-88. No such clear and

explicit mandate has been imposed with respect to geothermal energy resources.

92 The Geothermal Steam Act of 1970, 30 USC 1001, 84 Stat. 1556, requires that lands within any known geothermal resources area be leased to the highest responsible qualified bidder by competitive bidding. Lease royalties are, for energy, restricted to between 10 and 15 percent of the value of the energy. These provisions limit but do not eliminate the use of alternatives to cash bonus bidding.

93 This money could be spent on productive properties to the benefit of consumers, shareholders, and the public interest.

94 Office of Technology Assessment, An Analysis of the Feasibility of Separating Exploration from Production of Oil and Gas on the Outer Continental Shelf (May, 1975).

95 The comparative proceedings could take into account matters such as the scope of development, royalties, bonuses, potentials for adding competition to the market, and the like. If appropriate preference to public bodies could be allowed. Cf., Section 7(a), Federal Power Act, providing a licensing preference to State or municipal bodies, and Section 7(b) providing that where in the FPC's judgment development should be by the United States, licenses shall not issue and the FPC shall submit its findings to Congress. 16 USC 800(a), (b).

96 See, e.g., Federal Non-nuclear Energy Research and Development Act of 1974, Public Law 93-577, 42 USC 5901 et seq.

97 A case can be made for a federal policy giving preferential treatment of small enterprises and publicly owned power systems.

98 Appropriations are authorized for two federal geothermal demonstration plants. Public Law 94-187, 89 Stat. 1063, et seq.

99 The above quotations are taken from a tape recording of the proceedings of the panel reviewing the LBL project. The tape was obtained from ERDA under Freedom of Information Act requests by the Environmental Action Foundation and Dr. Joseph Lerner, economic consultant.

100 See, Mason, Current Trends in Federal Grant Law--Fiscal Year 1976, 35 Fed. Bar J.163 (1976) for a resume of federal grant law.

101 Joint efforts to influence public officials do not violate the antitrust laws even though intended to eliminate competition. United Mine Workers v. Pennington, 381 US 657, 670 (1965); and see, Eastern Railroad Presidents' Conference v. Noerr Motor Freight, Inc., 365 US 127 (1961). But a Sherman Act violation may be found if what appeared to be joint political activity directed toward influencing governmental activity is a mere sham to cover what is actually nothing more than an attempt to interfere directly with the business relationship of a competitor. Noerr, supra at 144. And see, United States v. Otter Tail Power Co., 410 US 366,380 (1973); California Motor Transport Co. v.

Trucking Unlimited, 404 US 508 (1972); Woods Exploration & Producing Co. v. Aluminum Co. of America, 438 F.2d 1286, 1296-98 (CA 5, 1971), cert. denied, 404 US 1047 (1972) (holding Noerr-Pennington doctrine inapplicable to alleged filing of false gas production forecasts); and George R. Whitten, Jr., Inc. v. Paddock Pool Bldrs., Inc., 424 F.2d 25,33 (CA 1), cert. denied, 400 US 850 (1970). Disclosure is also consonant with enforcement of the provisions and policy of the Federal Advisory Committee Act, 5 USC App. I, 2,4,9 and 10.

102 See e.g., United States v. Georgia Public Service Comm., 371 US 285 (1963).

103 With limited exceptions "no executive agency shall dispose of any plant, plants or other property to any private interest until such agency has received the advice of the Attorney General on the question whether such disposal would tend to create or maintain a situation inconsistent with the antitrust laws..." 40 USC 488 and see United States v. Aluminum Co. of America, 91 F.Supp. 333 (S.D. N.Y., 1950) (construing the Surplus Property Act of 1944, 58 Stat. 765 which is the precession to current surplus property legislation).

104 See Section 9, Federal Non-nuclear Energy Research and Development Act of 1974, 42 USC 5908.

105 They also serve industrial enterprises, particularly Dow Chemical and AMAX. AMAX, however, now is subject to control by Standard Oil of California, so that Dow, a substantial producer of oil, is the sole large industrial firm not principally involved in oil that is engaged in geothermal activity in a large manner; particularly through its holdings in the Magma companies.

106 Independent developers are not likely to be able to postpone production while waiting for smaller utility systems to overcome entry barriers.

107 This group, established as an industry advisory committee under the Interior Department, has a largely private, substantial existence. While there was for a time some dispute as to its existence as an Interior or as a Federal Energy Administration entity, and the requirements imposed on FEA committees would have substantially affected its character and operations, it has since lapsed safely back into its role as "adviser" to Interior. NPC activities have involved substantial exchanges of information among its members regarding subjects such as storage capacity, transport facilities, geology, refinery capabilities and "emergency" preparation.

108 E.g., California Department of Water Resources.

109 The Energy Policy and Conservation Act, Public Law 94-163, Sec. 503, 42 USC 6383; 89 Stat 871, 958-59 (1975) mandated that the SEC assure the development of accounting standards to be used by petroleum companies from the prospecting through production stages.

The Uniform System of Accounts for Public Utilities is a system for financial accounting and does not give variable and fixed cost breakdowns needed for cost accounting.

APPENDICES

APPENDIX A

PHYSICAL TYPES OF GEOTHERMAL RESOURCES

The several types of geothermal resources vary widely in availability and recoverable energy per unit extracted, as well as in the progress made toward their commerical use.

Vapor-dominated (dry steam) systems produce steam which (with some clearing) can directly drive a turbine. It is a rare resource, having been discovered domestically only in The Geysers area and Yellowstone National Park. Commercial development at The Geysers shows that, despite the low pressure of the steam and environmental and regulatory problems, power can be produced there for about half the cost of power generated from imported residual fuel oil.

Very hot water convection systems (temperatures over 150°C) are more plentiful than dry steam. They would be exploited by extracting the water, whose pressure drop as it rises through the well by natural convection would cause part of it (usually about 20%) to flash into steam. The remaining water--often contaminated with minerals--must be disposed of in some economical and environmentally acceptable way. Low steam temperatures and low pressures sharply limit [37] the amount of heat recoverable from a hot water pool. Still, hot water and electricity are being produced at operating plants in Wairakei, New Zealand; Cerro Prieto, Mexico; Japan (4 plants operating in 1975), and Iceland. Large, but unexploited, hot water resources are available in the Imperial Valley of California.

Lower temperature (under 150^{o}C) geothermal water resources will not flash directly into steam. To drive a turbine, they must be used in a binary cycle, to heat a second (working) fluid which has a lower boiling point such as isobutane (used experimentally in a Russian 0.75 mw plant) or xylene (employed in an experimental 3.8 mw plant in Japan). Lower temperature resources are widely distributed, however, and thus some research into its commerical potential has been conducted.

Water at either high or lower temperatures can be used for secondary applications (e.g., space heating and cooling), in combination with the primary power-generating application. Of course the utility of hot water for space heating depends upon these being a demand for that service in the neighborhood of the wells.

A common problem in geothermal hot water systems is the presence of heavy solutions of mineral salts (hot brines). These brines can corrode metal equipment in wells or generating equipment, and cause scale and fouling. Development of heat exchangers to handle them is a principal research objective.

Dry hot rock is an impermeable, unfractured magma body which, at least in theory, could be used to heat water injected from the surface and subsequently extracted. It is very widely distributed, but its exploitation remains strictly a research topic.

Sealed or trapped systems of hot water under great pressure are believed to exist--at depths of 5000 to 20,000 feet--in parts of the Gulf Coast. These geopressured zones offer a threoretical source of mechanical and thermal energy, as well as small amounts of dissolved natural gas. The economics of exploitation of geopressured zones are uncertain, but some estimates have been made by oil company investigators. The economic promise held out by these estimates turns on the price of natural gas, a joint product, and the well-spacing estimated as necessary.

UTILITY FUEL CONTRACTS

APPENDIX B

This Appendix provides descriptive and background material regarding fuel oil procurement by the major private utilities in California.

The Atlantic Richfield Company (ARCO) - Pacific Gas and Electric (PG&E) Contract

The price adjustment provisions in the Atlantic Richfield - Pacific Gas and Electric resid procurement contract originally provided that the original base price would "increase or decrease concurrent with and by the same amount per barrel as the combined average of the posted pricrs for 35.0 - 35.0 Gravity Crude Oil as posted by Atlantic Richfield Company at Cook Inlet Pipeline Company and Kenai Pipeline Company, plus the average of the ICC common carrier rates from Cook Inlet Pipeline Company and Kenai Pipeline Company to ships rail." It further provided that "in the event that the average posted price of said Gravity Crude Oil as posted in Cook Inlet Pipeline Company and Kenai Pipeline Company by all producers of greater than 10% of the total monthly production of such crudes at those points, except Atlantic Richfield Company, is $1.10 or more per barrel below the average price posted by Atlantic Richfield Company, the average of the posted prices of these companies, other than Atlantic Richfield Company, shall be the basis for price changes under this provision."

Commencing April 1, 1974, prices began to increase or decrease by the same percentage as the percentage increase or decrease in the average cutter stock shipped by various concerns, Arco supplied oil to PG&E in the first quarter of 1975 for $14.71. The contracts between PG&E and

Arco and Union Oil were described in the additional prepared testimony of Mr. John F. Roberts, Jr. given to Public Unitility Commission in 1974. Contracts with Atlantic Richfield and Union Oil were centered into in April and November of 1972, respectively. The PG&E contract with Arco was to terminate in 1976, but in June 1973, a new contract was negotiated extending the contract term through 1981 and increasing the volume of oil to be supplied to 8,400,000 barrels for the calendar year 1974 and to 9,000,000 barrels per year thereafter thru 1981.

"At a meeting on November 9, 1973, Arco advised us that posted price of crude oils, such average being weighted on the basis of twenty percent (20%) for the average of the Alaskan Crudes as identified in the next preceding paragraph, and eighty percent (80%) for the average of Canadian marketable crude oil (U.S. Dollar Price) having a quality of 42° or higher API Gravity and containing less than .5% sulfur by weight, as posted at Edmonton Terminal, Canada by all producers of ten percent (10%) or more of the total monthly production available at that point."

Also, beginning April 1, 1974, the applicable prices were further adjusted by applying eightly percent (80%) of any change in any duty, tariff, or other charge imposed by any governmental agency on Subject Canadian Crude Oil.

The result of the above mentioned adjustments and other factors is a weighted formula based 20% on Alaskan and 80% on Canadian crudes. The formula price is given as the new crude price in Alaska X 20% + new crude price in Canada X 80% divided by the base crude price multiplied by the initial price for low sulfur fuel oil.

It should be noted that the Edmonton price is set by the Provincial Government after it negotiates with the federal government of Canada; the current price ($8.00) pertains to 82% of Alberta production with the remaining 18% of production being set by a few private companies, notably Imperial (Exxon) and Shell Oil. These private postings follow the Canadian Provincial Government postings.

The government posting is based on a net back price from Ontario markets intended to keep the price in Ontario comparable to the price in the United States across the border from Ontario. That price has been gradually heading toward the price that pertains in Canada east of what is known as the Ottawa line, where foreign oil is used.

The contract further provides that prices must track any duty or tariff imposed by the Canadian or U.S. governments. Renegotiation clauses are included regarding technical breakthrough changes in refinery technology, extreme variation in the market price of low sulfur fuel oil with the same specifications as covered herein, equivalent volume term changes in import regulations and changes in product specifications. In the event that any of the above occur and mutual agreement is not reached within 60 days, the contract may terminate two years and 60 days after the initial discussion date. The fuel is a low ash, low sulfur fuel with a 6,000,000 Btu per barrel heat content.

The contract contains in article 11 an exculpatory clause excusing buyer from performance when California or federal or other law prevents it from burning the fuel oil supplied. The force majeure clause includes the usual range of activities plus acts of Public Administrators.

The clause also includes interference by foreign nations; abnormal increases in cost of transportation caused by war or hostilities between any nations; shortage of fuel oil deliverable due to shortages of refined products, crude oil, natural gas or raw products comprising the fuel oils agreed to be delivered, lack of capacity in equipment used, or insufficient equipment for producing, manufacturing refining, or transporting oil and its products.

Seller, in the event that it is unable to make delivery to all of its customers, is authorized to pro-rate its deliveries among its customers; and buyer acknowledges in the agreement that seller is currently unable to meet all contractual demands for certain hydro-carbons and, as a consequence, is allocating products in accordance with the voluntary allocation policy.

The remaining provisions are typical for such a contract: harmless clauses, imposition of sales tax on the buyer, and the like, except that specific reference is made to two of ARCO's tankers, specifying the amount of time they can be tied up before buyer shall pay seller demurrage and setting forth the rate for demurrage for each of the two ships. The demurrage rates are subject to adjustment as established by the seller's marine department.

The price of oil when the ARCO agreement took effect was $5.07 a barrel, but in April of 1974, it had jumped to $12.88 a barrel. The $12.88 price was maintained at least until October of 1974.

Correspondence, filed with the California Public Utility Commission indicates that the first announcement of a price rise, to $5.42, was in a letter dated October 5, 1973, and it paralleled a rise of 35% in the posted prices of Alaskan Oil. The commencement of Canadian tax burdens is mentioned in a November 20, 1973 letter that refers to an export fee of up to $1.50 a barrel to become effective December 1, 1973. Another letter of November 20 from ARCO to PG&E states that ARCO is raising its posted price in Alaska by $1.30 a barrel for new and released oil.[1]

By telegram of March 8, 1974, Atlantic Richfield sought to explain the basis of its price escalation provisions in the June 1973 contract. The telegram states that the crude oil escalation provision is the basic index mechanism intended to maintain prices reasonably in line with the finished product market place and at the same time to recover some measure of its increased crude and other costs. While the index is tied to specific designated crude oils and percentages, it does not necessarily reflect the actual mix of feed-stocks, since use is made of a mix of feed-stocks from Alaskan, Canadian and other foreign crude oil. The telegram goes on to state that ARCO is purchasing foreign low-sulfur oil at a delivered cost of $13.32 a barrel; we are paying as much as $15.45 a barrel for other foreign crude oil, but no quantities are stated.

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[1] Letters and memoranda between ARCO and PG&E have been filed in various PG&E fuel adjustment proceedings before the California Public Utility Commission, beginning with the application in case number 55222. See Exhibit 12, App. No. 55222.

The PG&E company acquiesced by telefax on March 12 changing the starting date from April 1, 1974 to January 1, 1975.

> At a meeting on November 9, 1973 ARCO advised that its costs for crude were increasing so greatly that it would be necessary to renegotiate the price provision in our June 1, 1973 contract. Early this year, ARCO pointed out that the oil it was importing from Canada was subjected to a $6.40 per barrel export tax and, furthermore, that there was an extreme variation between the market price for low-sulfur fuel oil of the same specifications as covered by the contract and the effective price under the contract price provision.

Atlantic Richfield was then seeking an immediate pass-through of the increases. As negotiations progressed, this was extended to February, then finally to April 1, 1974. In these negotiations PG&E feared that it was paying more than the price to other utilities. This fear is reflected in an ARCO communication of March 26, 1974 to PG&E stating that ARCO was making every effort "to renegotiate increases in current contract prices for low sulfur fuel oil to its other utility customers" in keeping with our increased costs. On March 27, 1974, ARCO refused a request by PG&E to include a most-favored-nation clause to the effect that the price charged by seller, excluding spot sales to other purchasers in District V for low sulfur oil in quantities over 50,000 barrels per month, would not be exceed by the price charged to PG&E. ARCO's rejection is stated to be in part based on its legal department's opinion that the provisions requested were unlawful under the anti-trust laws. The company merely stated it was attempting to renegotiate its other contract prices.

The contract price rose on April 1, 1974 to $12.88, based on a Canadian crude price of $6.81 with an export duty of $4.00 a barrel and no change in the posted price in Alaska. The June price increase to $13.85 appeared to be based on an increased Canadian export duty and on a $1.20 increase in the duty on crude, and in July, prices rose to $14.69. However, ARCO stated in a July 16 letter that it was granting an allowance of $1.14 per barrel "off of our contract price," thus temporarily maintaining the $12.88 price per barrel. On August 12, the discount was removed increasing prices to $14.02, with the provision that 348,000 barrels of July volume owed PG&E would be billed at July prices, and that deferral might be made for payment of prices in excess of $12.88 a barrel until such time as ARCO's negotiations to increase Southern California Edison's current contract price are concluded. Mr. Benton in his testimony in application No. 5541 in March of 1975 states that the price of $14.02 became effective from ARCO January 1, 1975.

He described the previous discounting in the following manner. In mid-1974 PG&E reduced fuel oil requirements combined with a widening gap between the price being paid by PG&E to ARCO compared with the prices charged by ARCO to Southern California Edison Company and the Los Angeles Department of Water and Power caused PG&E to negotiate the postponement of any increase in price beyond the $2.88 per barrel which had become effective on April 1, 1974. The negotiations resulted in ARCO's agreement to waive price increases in June and July and ARCO withdrew the temporary allowance in August but agreed to permit deferral of any payments in excess of $12.88 per barrel until it had negotiated a price increase with Southern California Edison. By letters dated November 14, 1974 and December 2, 1974, ARCO served notice that the deferred payment arrangement was terminated as of November 1, 1974 and that termination of the contract would be recommended if PG&E failed to pay the price demanded. PG&E agreed to make this payment on or before December 30, 1974, feeling it was obligated by contract to pay the deferred price effective August 1, 1974. [1]

PG&E has, besides its contract with ARCO, low-sulfur fuel oil contracts with Union Oil, Phillips Petroleum and Perta Trading Company.

This basis agreement with Union Oil is dated November 1, 1972, and runs from January 1, 1973 to December 31, 1980. The original terms of the contract, which has been substantially amended with regard to price, provide for delivery of 480,000 barrels of low-sulfur fuel oil in 1973 and between 2 and 2.2 million barrels for each year thereafter. [2] Delivery is generally to be in 100,000-barrel cargo lots, [3] or in 19,000 barrels lots to PG&E barges.

The initial price was set at $4.47 for barge lots and $4.61 for tank ship deliveries, with escalation based on the price of crude oil from Alaska.

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[1] ARCO, it should be noted, never entered into a contract with Southern California Edison and their then current agreement expired by its own terms on the 31st of December 1974. Subsequent deliveries to Edison would be under FEA allocations and ceiling prices which are in excess of the price PG&E pays ARCO under the contract. Apparently, LADWP renegotiated its contract with ARCO and is now paying up to 280 cents per btu ($14.80 per barrel).

2 The fuel oil is required to have 10° APO minimum gravity, maximum sulfur content of 0.5% by weight, and contain 6 million BTU per barrel.

3 Demurrage is specified at $350 per running hour.

The escalator clause tracked, penny for penny, the price of Alaskan crude oil, which is determined by averaging four posted prices plus applicable pipeline tariffs of the Cook Inlet and the Kenai Pipelines. The posted prices are those of Union Oil at the entrance to the Cook Inlet Pipeline, plus the tariff to the Drift River Terminal; the average of prices posted by ARCO at two entrances plus the pipeline tariff to the Drift River Terminal, and the price at the entrance to facilities of the Kenai Pipeline, plus the pipeline tariff to the Nikiski Terminal; the price posted by Mobil Oil Corporation at the entrance to the facilities of the Cook Inlet Pipeline, plus the tariff to the Drift River Terminal; and the price posted by Standard Oil Company of California at the entrance to the facilities of the Kenai Pipeline, plus the tariff to the Nikiski Terminal.

Price renegotiation may be requested by either party six months before the end of any contract year. If agreement is not reached within 90 days, either party may cancel the agreement upon 90 days' notice.

Performance is excused if Union is prevented from or delayed in producing manufacturing, transporting or delivering in its normal manner any product or products covered by the contract or the materials from which those products are manufactured.

Exhibit No. 9, dated March 24, 1975, in the proceeding upon Application No. 55511 of PG&E before the California Public Utility Commission, submitted by a PG&E witness, Mr. Benton. The exhibit purports to set out price negotiation memoranda and correspondence between PG&E and Union Oil pertaining to the agreement, described above, for the purchase and sale of residual fuel oil. [1]

In June 1974, Union began renegotiating in an attempt to raise prices to a level of $16.32 per barrel, effective January 1, 1975, with a temporary discount of $3.74 per barrel. Union also sought to change the price escalation provision so that, instead of tracking Alaskan, it would follow, penny for penny, the "Established Eastern Hemisphere Export Price" for Sumatran Light Crude Oil as established by Caltex Indonesia Oil Company for purchasers utilizing such crude oil in the Eastern Hemisphere or reselling it for such utilization.

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1 The price of residual fuel oil from Union rose to $8.54 by the fall of 1974, with deliveries being less than the contract called for because of FEA allocations. Exhibits 2 and 10, Application No. 55541, California Public Utility Commission.

When PG&E personnel, at a meeting on September 26, 1974 with Union Oil personnel, inquired, "Did Union Oil not secure sufficient quantities of Alaskan crude oil to meet this contractual obligation prior to execution of the contract in November 1972?" Union is reported to have replied by stating that Alaskan crude production has diminished and has adversely affected their source of supply. Memorandum of October 3, 1974, PG&E Materials Department, Exhibit 9, App. 55541, supra.

Union, according to this memorandum (1) expressed interest in modifying its renegotiation request so as to link price escalation to its average cost of crude, and (2) indicated its intention to supply quantities of resid in excess of contract volumes -- perhaps doubling contract volumes in 1975 and 1976.

Subsequent to this meeting, Union sent a letter in which it sought a price ranging between $12.26 and 12.58 for the first half of 1975, and rising by $2 per barrel on July 1, 1975. Union is said to have noted, at a November 22, 1974 meeting, that its price for low sulfur fuel oil to customers assigned under the FEA allocation program was $13.76 per barrel. Exh. 9, supra.

On December 16, 1974, Union Oil asserted in a letter to PG&E that it could cancel the agreement as of December 31, 1974; that letter states that PG&E's initial basic problem with Union's proposal was that the discount could fluctuate upon 30 days' notice; and that subsequently, Union might charge PG&E a price greater than its average price to other utilities.

On December 20, 1974, PG&E acquiesced in Union's proposal. In testimony to the California Public Utility Commission, Mr. Benton of PG&E (in Exh. 2, App. 55541) states that the primary consideration of PG&E's decision to agree to this price change, was

> continuation of the contract, which yields a price significantly lower than that which Union would charge under Federal Energy Administration allocation and price regulations in the absence of a contract. We also considered the certainty of paying a price higher than $12.26 per barrel to replace Union flow combined with the additional certainty of being unable to negotiate a contract term longer than two years with some other supplier.

The Union contract provides for up to 2 million barrels of oil per year.

PG&E purchases fuel oil from Phillips Petroleum on the basis of Phillips' monthly postings for such oil. [1] An agreement for the purchase and sale of low sulfur fuel oil was entered into between these parties for the eight-month period April 1 to December 31, 1974.

Phillips Petroleum had a contract with PG&E under which 2.7 million barrels of oil were delivered during 1973 and 450,000 barrels in the first quarter of 1974. This contract expired and the renegotiated price terms provided for use of a posted market price for high-sulfur oil with a premium for low-sulfur content.

On January 4, 1974, PG&E contracted with Perta Oil Marketing Corporation to acquire resid purchased by a Bahamian firm -- Puerta Oil Marketing Corporation Limited -- from the Indonesian State Company "Pertamina."

Under the contract which expires October 31, 1976, PG&E acquires a rather light (30.2 to 20.5° API gravity) oil with a very low sulfur content

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[1] The residual fuel oil is to have a maximum 25° API and a maximum sulfur content of 0.5% by weight.

(0.2% by weight) in quantities of 200,000 barrels per month (± 10%), at an initial price of $13.70 per barrel subject to Pertamina postings. [1] PG&E takes delivery in Indonesia Exh. 10, App. 55222, filed October 16, 1974.

PG&E also has a contract, dated May 28, 1974, to purchase low sulfur crude oil from Perta which, in turn, has acquired the oil from its Bahamian affiliate which again in turn, purchases from Pertamina and from Tesoro Petroleum Corporation. This low sulfur oil is purchased in quantities of 180,000 barrels per month (1 10%) at a price which begins at $13.25 per barrel and tracks Perlamina's price. Delivery is in Indonesia and this oil, at least in part, appears to be used in an exchange or processing agreement with a refinery in Hawaii, Pacific Resources under which PG&E receives resid. [2] The contract with Pacific Resources commenced October 1974, and runs through March 1977, with minimum total delivery of approximately 3 million barrels of Indonesian oil. Because this is essentially an exchange agreement, the delivery quantity is tied to production in certain Indonesian fields.

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[1] The price declined in 1974.

[2] The contract is reproduced as Exhibit 11, App. No. 55222 before the California Public Utility Commission.

Other purchases by PG&E consisted of foreign source fuel oil at generally prevailing world market spot prices.

Because of delays in scheduled nuclear units, long-term agreements were entered into with foreign sources in 1973, including two involving Indonesian crude and fuel oil. Indonesian fuel oil carried an average delivery price of $14.75, and the crude sold for $17.50 per barrel, with prices escalating in response to Indonesian posted prices.

San Diego Gas & Electric Company (SDG&E)

SDG&E, lacking hydroelectric resources, is more dependent upon fossil fuels than are other California Power Pool Companies. In early 1975, SDG&E was purchasing resid from Union Oil at $12.24 per barrel, from Tesoro Alaskan at slightly less, and from HIRI at $11 per barrel.[1] Exhibit 2B, Application No.55506, Ca. P.U.C.(April, 1975).

SDG&E has followed a policy of using long term contracts for fuel purchasing. See Exhibit 6, page 3-1, Application No.55506, Ca. P.U.C.

SDG&E apparently had an oversupply of petroleum in 1974, which

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1 In 1974, Indonesian oil was purchased from Edgington Oil Company.

allowed it to sell 730,936 barrels of resid to SCE, and to sell 2,271,876 barrels to major refineries for further processing into other petroleum products.

SDG&E purchases most of the crude refined at the Tesoro Alaska refinery. Its contract with the Tesoro Alaskan Petroleum Corporation provides for the purchase of 250,000 to 300,000 barrels of resid made from Alaskan crude. The resid price rises with Tesoro's costs and with tariff rates on the Kenai pipeline. Tesoro sold SDG&E 3,815,000 barrels of resid in the year ending September 30, 1975.

Under its contract with SDG&E, HIRI has been required to expand its Hawaiian refinery, increasing crude runs from 45,000 barrels per calendar day in 1974 in a series of steps to 75,000 bpcd in 1977. Production of fuel oil is to rise from 12,500 bpcd in 1974 in a series of steps to 28,000 bpcd in 1977. SDG&E is to purchase fuel from HIRI at a mark-up of 87 cents over HIRI's weighted average monthly crude prices (for the period August 1, 1974 through July 31, 1984). This mark-up is to be renegotiated in 1976.

A contract between Union Oil and SDG&E provided for the purchase and sale of one million barrels of fuel oil in the second half of 1974 and a like quantity in the first half of 1975. Prices, initially set at $12 per barrel, before taxes, subject to a $3.26 discount revocable on thirty days notice, were to be renegotiated in 1975 or the contract would end.

Union, on October 15, 1974, proposed a price of $15 per barrel with a discount of $2.76 revocable on 30 days notice; the discount was reduced to 76 cents effective April 1, 1975. The $2 increase was deferred following a March 19, 1975 meeting between Union Oil and SDG&E personnel. SDG&E assigned or resold a portion of this resid to LADWP.

Southern California Edison Company (SCE)

Following are some observations on contracts made by the Southern California Edison Company for the purchase of residual fuel oil. These contracts were filed with the Oversight and Investigations Subcommittee of the House Committee on Interstate and Foreign Commerce in 1975.

SCE has contracts with Standard Oil of California for 22.2 million barrels per year, with Texaco for five million barrels per year, with Arco for four million barrels(1974), with Exxon for 6.3 million barrels per year, with Coastal States for 16,560,000 barrels per year, and with MacMillan Ring Free Oil Co. for 3,500 barrels per day.

The SOCAL and Texaco agreements began respectively on April 1, 1971 and December 12, 1970. Both expired December 31, 1975, forcing SCE to enter a seller's market for a tremendous quantity of fuel. The partners in Caltex, SOCAL and Texaco, appear to supply so high a portion of SCE's oil as to be inconsistent with normal practices of seeking a diversity of sources. In this regard, it should be noted that the force majeure clauses in these contracts excuse performance by a seller in the event that either normal supply or normal transportation surces are in short supply.

The quality specifications for resid, in these contracts, vary. There are no specifications for specific gravity in the contracts with ARCO and SOCAL.

Fuel reports filed with the Federal Power Commission (Form 423) indicate that SCE gets residual fuel oil having a lower heat content than do PG&E or SCE. Very importantly, since its 1967 contract with SOCAL, Edison has not included a clause in its fuel purchase agreements providing for price adjustments tied to the heat content of delivered fuel.

Price Adjustments

A contract normally entails mutuality of obligation among the parties. The price escalator, force majuere, and price renegotiation provisions of SCE fuel contracts place all risk and obligation on the buyer.

Prices uniformly rise, penny for penny, with increases in prices of crude oil, even though only a small portion of a barrel of crude is refined to resid in U.S. refineries.[1] Crude oil escalator clauses are frequently pegged to an arrangement in which SCE guarantees the transportation expenses, indeed paying phantom freight charges[2] and tax expenses, and SOCAL some ambiguous portion of refinery equipment costs. The arrangement is subject to cut off by marginal supply interruptions, to supply allocations by its vendor and to numerous price escalator clauses which do not descend below "minimum" provisions while SCE, with a utility's duty to serve, purchases resid in contract quantities so large as to prevent substitution of vendors.

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1 Use of Indonesian tax reference prices as a cent for cent escalation by SOCAL for crude oil is interesting because (a) these prices do not represent direct increases in costs to sellers, being at most only partially reflected in sellers' costs. Similarly, use in the SOCAL contract of an escalation pegged to prices of Signal Hill California crude is interesting as SOCAL posts the price and controls the marketing of this crude (through a private carrier pipeline) which is only a small segment of California "low-sulfur" production.

2 Under this contractual phantom freight provision, SCE guaranteed the "peak" of SOCAL's tanker rates. These peaks could be further hiked by cross-chartering arrangements.

The escalator clauses for taxes and crude prices are too vague to be audited; they attribute the entire costs of crude and its transport to resid. Price escalators based on either New York prices (Texaco) or on tankerage rates from the Carribbean to north of Hatteras use indices that are under the joint control of major oil companies. This is the case because the tanker rates are set so as to compete with rates on the Colonial pipeline, a joint venture of the majors; and the New York harbor price is set by these transportation rates and by production from a very highly concentrated Carribean refining industry that is dominated by major companies.[1]

Use of phantom shipping, taxes and pricing (e.g., Exxon contract provision tied to posted prices in Boston harbor); loading of oil costs onto crude oil; the use in contracts with SOCAL of escalators for the price of natural gas and California crude (e.g., apparent commodity -- value pricing); coupled with the direct and indirect board interlocks and mutual relations among SCE, banks, and vendor oil companies do not bespeak competitive field prices posted by sellers, while crude sources are unspecified and their prices unverifiable. The same applies to tax escalation clauses.

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1 Use of posted prices where these are set in whole or part by vendor is also peculiar. SOCAL sets many field prices in California and California crude prices are one escalator in SOCAL contractors. See, California Crude Oil Market Control, Report of St. Comm. Public Domain, CA Legis. (1974).

Just as crude price escalations are "phantom," so are tanker rate escalations, but with an additional twist, which is the tendency to use the rates from the Carribean to the U.S. north of Hatteras (N.Y. Harbor rates) as do Texaco and Exxon, or from Dumai, Indonesia to El Segundo, irrespective of crude source (SOCAL contract).

Reductions in resid prices are unlikely because (a) tanker rate clauses only go up from high rates, (b) minimum prices occur; (c) no correction is made for the use of larger, cheaper tankers, or more efficient refining; and (d) there are most-favored-buyer clauses (SOCAL and Texaco contracts).

The combination of price reopener provisions and huge contracts also works to that end.[1]

Resid prices paid by SCE exceeded those paid by neighboring utilities.

Use of crude oil prices as the basis of penny-for-penny price escalation indices is peculiar since resid is only just one product.[2]

1
The use of phantom costs indices is reflected in the Exxon contract provisions for renegotiating prices on the basis of those Exxon posts in N.Y. Harbor (#6 oil) or Boston #4 rise. The tanker indices used refer to rates for single voyages, not the lower term charters that would be actually used in whole or part.

2
In the first half of 1975, the Mineral Industry Surveys report runs to stills in California of 372,085,000 barrels (247.41 million domestic, and 124.675 million foreign crude oil, and PAD District V refinery inputs of 466, 359,000 barrels (263,982,000 domestic and 202,377,000 foreign). Residual fuel oil production was 91,292,000 barrels (and foreign imports were 7,713,000 barrels). Thus, resid output was 19.6% by volume of runs to stills.

The long-term contracts for the purchases of resid by SCE are quite similar to each other with the exception of one contract with a small refiner.

Essentially the contracts with Standard Oil Company of California, (SOCAL) Texaco, Exxon, and to a lesser degree, Atlantic Richfield and MacMillan Ring Free Oil reflect one-way street bargaining. So does the fact that SCE has acquired an option to purchase all of the resid produced by an independent refiner, MacMillan.

The imposition of arms length bargaining and competitive fuels procurement -- cannot readily go forward so long as fuel adjustment clauses make "cozier" arrangements attractive.

APPENDIX C

FINANCE*

*Much of the following discussion is taken from a paper, Bierman and Stover, A Preliminary Review of the Relationship Among Banks and Petroleum Companies (Spring, 1976: unpublished). Work on that paper was supported, in part, by the National Science Foundation, RANN Program Grant GI41470. The material, opinions and conclusions in the paper are those of the authors and do not necessarily reflect the view of the National Science Foundation.

APPENDIX C

Finance

The large scale involvement of the petroleum industry with the financial community of the United States is both necessary and unavoidable in some respects, and, at least in some degree, is a potential barrier to major competitive enterprises.

A major portion of petroleum company-finance company relationships can be briefly categorized as follows:

(1) Long-term debt accounted for about 28% of capital employed by huge petroleum companies in 1970. Such debt is often intimately tied to specific projects and associated income expectations.

(2) Banks and trust departments have substantial equity interests in most major petroleum companies -- on occasion over 10% of stockholdings.

(3) Petroleum companies hold large quantities of marketable securities, at any given time; and these accounts are growing.

(4) There is an extensive far-ranging set of "interlocks" between bank and petroleum company board of director personnel.

(5) The course of dealings involved in the above-sketched relationships involves extensive information exchanges and a community of viewpoint, among financial intermediaries and the petroleum companies.

The institutions involved in these relationships reach from the country bank to the peaks of the financial pyramids. The very largest financial institutions are included, as is to be expected. Because of this, the relationships between leading banks and petroleum companies will affect the set of correspondent bank relationships through which leading institutions mobilize capital throughout the commercial banking system. These close relationships are a mixed blessing. They help mobilize capital -- certainly they are intended to do so. But in an industry with competitive restraints, they also may tend to add to inertias, keeping the capital flow in existing channels. When there is a need for alternatives to existing energy sources, the alternatives may face greater difficulties in mobilizing capital than would prevail if the dominant industry were more competitive; if extensive director interlocks did not exist, and if financial institutions had less of a stake in the success of existing enterprises. This is especially the case for new entrants lacking established financial connections.

The Relationships Among Banks and Petroleum Companies

Historically, the petroleum industry has turned to banks for a substantial portion of its external financing. This tendency appears to be getting stronger.

For the Chase Manhattan group of large petroleum companies, in the period 1956-70, outside funds provided 16% ($24 billion) of the $150 billion of cash available. Sources of outside funds were the public (50%), banks (33%), insurance companies (5%), and 12% from other sources.[1]

As shown on Table B, external financing of large oil companies included little equity money. Large oil companies do not raise capital by issuance and sale of additional common stock. As shown in Table B, the number of shares of common stock outstanding by larger oil companies have been fairly level between 1970 and 1974. Annual reports of larger oil companies indicate that such rises in the number of outstanding shares as occurred were frequently made up of shares issued for acquisitions, or pursuant to stock option plans, or upon the conversion of a senior security.

While long-term debt provided 14% of the funds available in the period 1956 to 1970, its share rose from 3.3% of new financing in 1959 to a high of 23.7% in 1968. Long-term debt first exceeded 20% of total capital employed in 1970. At the same time, use of "off-balance-sheet" financing provided largely through leasing services of financial institutions (largely banks) expanded greatly.[2] If long-term leases are treated as long-term debt, total debt rose from 20 to 28% of the total capital employed by large petroleum companies in the 1958-1970 period.

The rising dependence of large petroleum companies on bank financing is shown by the general tendency for lease rentals to be an increasing part

TABLE B

COMMON STOCK SHARES OUTSTANDING
(THOUSANDS)

Company	1973	1970
Amerada Hess	21,661[2]	12,606
American Petrofina	9,157[1]	7,657
APCO Oil Corp.*	2,837[1]	2,810
Ashland Oil	22,703[2]	21,195
Atlantic Richfield	46,640[2]	45,186
Belco	7,500[1]	7,500
British Petroleum	386,100	358,844
Cities Service	26,084[2]	27,993
Clark Oil	7,108[2]	7,118
Clinton Oil	50,426[1]	51,556
Commonwealth Oil	13,296	12,455
Continental Oil	50,405[2]	49,796
Crown Central Petroleum	1,530	891

*Adjusted for stock dividends.

[1]Average number shares outstanding in year.

[2]Number of shares issued at December 31.

TABLE B (Cont'd)

Company	1973	1970
Diamond Shamrock	14,855[1]	14,592
El Paso N. Gas	27,869[1]	26,390
Exchange Oil & Gas	5,253[1]	5,252
Exxon	224,089[1]	221,704
Forest Oil	6,857[1]	4,855
General American	6,122[2]	5,609
Getty	18,669[2]	19,038
Gulf Oil	197,250[1]	207,593
Hamilton Brothers	3,381[1]	3,362
Kerr-McGee	24,989[2]	22,147
Kewanee Oil	8,402[1]	6,691
L. L. & E.	36,275[2]	18,126
Marathon Oil	30,472[3]	30,293
McCulloch Oil Corp.	16,607	6,892
Mission Corp.	3,425	3,425

[1] Average number shares outstanding in year.

[2] Number of shares issued at December 31.

[3] Not stated if average or year-end.

TABLE B (Cont'd)

Company	1973	1970
Mesa Petroleum Co.[4]	10,975[2]	2,535
Mobil Oil	101,856[2]	101,313
Murphy Oil	5,859[2]	5,348
Pennzoil Company	23,969[2]	19,476
Phillips Petroleum	75,709	74,062
Rock Island Ref'g.	80[5]	--
Shell Oil Company	67,365[1]	67,385
Standard Oil (Indiana)	69,801[2]	68,848
Standard Oil (California)	169,839[2]	169,674
Standard Oil (Ohio)	27,539[1]	18,008[6]
Sun Oil Company	36,834[2]	30,973
Tenneco, Inc.	67,698[1]	58,404
Texaco, Inc.	271,904[1]	272,344
Union Oil Co. of California[2]	28,407[1]	28,318

[1] Average number shares outstanding in year.

[2] Number of shares issued at December 31.

[4] Mesa sold 2 million shares in 1973.

[5] Voting shares; also 720,000 non-voting shares.

[6] Included special stock held by BP Oil Corporation.

of capital costs, in many cases exceeding debt interest expenses.[3] See Table C comparing interest costs of debt securities and loans with net lease rentals.[4]

The continuing importance of banks is seen in recent oil industry financings such as Ashland Oil's financing of the $2 million cost of Alaska lands by loans from institutional investors for 80% of lease costs in return for a 90% interest in net revenues to pay-out and then a 50% net revenue interest with the proviso that if not paid out in seven years, the investors may exchange unrecovered notes for Ashland's common stock at set prices. Other examples include:

(1) BP obtained a loan from a bank consortium for the Forties field with payments of about 60% of oil flows; (2) BP domestically has obtained a $200 million production loan payable with 50% of production from Columbia Gas for the North Slope; (3) bridge financing of $450 million obtained by American Natural Gas Production Co., Hamilton Bros., and Placid through a bank line of credit (including demand provisions); (4) a $300 million credit arrangement between Standard Oil (Ohio) and a group led by Chase Manhattan Bank for Alaska work; and (5) a $150 million loan by a group of banks to Occidental Petroleum's British subsidiary to develop the Piper field in the North Sea.

TABLE C

INTEREST AND LEASE EXPENSES OF SELECTED COMPANIES

Company/Year	Company Interest Expenses ($ million)	Company Lease Rents (Net) ($ million)
Amerada Hess		
1973	38	83
1972	35	70
Ashland		
1973	25	--
1972	20	--
Atlantic Richfield		
1973	65	37
1972	62	31
Clark		
1973	4	18
1972	4	12
Cities Service		
1973	45	25
1972	43	26
Conoco		
1973	65	93
1972	56	68
Exxon		
1973	122	503
1972	81	422
Gulf		
1973	135	93
1972	147	103

TABLE C (Cont'd)

Company/Year	Company Interest Expenses ($ million)	Company Lease Rents (Net) ($ million)
Marathon		
1973	29	--
1972	24	--
Mobil		
1973	97	239*
1972	86	230
Phillips		
1973	62	51
1972	59	50
Shell Oil		
1973	61	34
1972	59	32
Standard Oil (Indiana)		
1973	79	109
1972	67	79
Standard Oil (California)		
1973	69	186[1]
1972	73	144

*Rent on financing leases of $50 million and $48 million in 1973 and 1972 respectively.

[1]Does not include interest expense on Trans-Alaska pipeline and interest on advance sale of Prudhoe Bay crude oil ($13 million in 1973; $10 million in 1972).

TABLE 6 (Cont'd)

Company/Year	Company Interest Expenses ($ million)	Company Lease Rents (Net) ($ million)
Standard Oil (Ohio)		
1973	12[1]	31
1972	21	37
Sun Oil Company		
1973	16	31[2]
1972	5	24
Tenneco		
1973	179	36[3]
1972	151	32
Texaco		
1973	363	143
1972	288	108
Union Oil Co. of California		
1973	41	32
1972	41	27

[1] Does not include interest expense on Trans-Alaska pipeline and interest on advance sale of Prudhoe Bay crude oil ($13 million in 1973; $10 million in 1972).

[2] Approximation from annual report notes to financial sheets.

[3] Total rental expense.

Petroleum companies make extensive use of private placements. Because banks (and life insurance companies) are among the biggest buyers at private placements, Institutional Investor Study, H.R. Doc. No. 92-64, 92d Cong., 1st Sess. (1969), their frequent ownership of petroleum company securities is therefore to be anticipated. The use of private placements is also paralleled, as shown infra, by a lack of equity sales. Only 12.4% of all private placements were equity in 1972 (up from an average of 5.9% in the 1965-72 period). 31 S.E.C. Statistical Bulletin No. 3, at 18, 19.[5]

The reliance on debt for external financing is traditional for smaller drilling contractors.[6]

The importance of bank loans to small and medium size oil companies has been increased with the drying up of an alternative financing mechanism which once appeared to have great promise: the drilling program.[7]

Commencing in the mid-1960's, at least several billion dollars of capital have been raised for drilling exploratory and development wells through drilling programs.[8] These programs generally consist of an oil company general partner and a group of limited-partner investors, although some such programs are set up as incorporated investment funds. These drilling programs have provided significant funding for smaller oil companies, many of whom have been basically management companies for annual drilling programs. At the same time drilling programs have offered a source of financing to the general-partner oil company and a tax shelter, primarily through the allocation of intangible drilling costs, to the limited-partner investors.[9]

A review of oil company annual reports and SEC Form 10-K annual reports indicates that the number of offerings, and the amount being raised by drilling funds, have been falling off.

The amounts raised through such programs are not great when compared with the total sums spent for exploration and development in North America (the area where programs have funded work). However, these funds have been an important source of financing for the exploration and development work done by smaller companies such as Petro Lewis, Calvert Exploration Company, and Beacon Resources. The funds further provided a type of financing that partially shielded these companies from downside risk; they were an alternate source of funding to the sale of mineral interests to other oil companies (see, e.g., Calvert Exploration Company Annual Report for 1973), or to private placements with companies that are substantial users of energy.

Such private placements do not appear to be conducive to corporate independence and, in fact, may harm the public interest by replacing arm's-length buying by a situation in which the management of the energy-using firm can only justify its oil investment by pointing to higher oil prices.

Corporate independence will not be furthered when the inevitable equity sweetner is included in the price of money.[10]

For large companies such as Pennzoil, a drying up of the market for drilling programs means the impairment of a source of leveraged financing that did not dilute equity, and which provided the industry, in nine POGP-type offerings, $584 million between 1970 and 1972.[11]

The series of amendments of the plans for one of the last such offerings-which progressively shielded investors-may further indicate how the market for such ventures has soured.[12]

While the petroleum industry is reliant upon bank financing, as shown in the table below, many large petroleum companies have been picking up substantial amounts of marketable securities. These "quick" assets, as specifically reflected in annual reports of some companies, include large amounts of certificates of deposits[13] sold by banks. For the large firms listed in Table E, holdings of marketable securities rose $2,713,904,000 between 1972 and 1973. These holdings of marketable securities would appear to create a continuing active relationship between petroleum companies and banks.

Petroleum companies have other major "quick" assets. The Chase Manhattan Bank's group of thirty-seven petroleum companies increased their total current asset holdings by some 9.9 billion dollars between 1972 and

1973.[14] Current assets consist of cash, marketable securities, and notes and accounts receivable.

Interlocking Relationships Between Banks and Petroleum Companies

Interlocks between boards of directors of banks and petroleum companies are frequent, and as shown in Table G, involve every substantial petroleum company. Interlocks exist both with major banks and with smaller "country" banks. The directorate interlocks raise questions about anti-competitive consequences of board loan and investment policy decisions, and anti-competitive effects of special information going to banks.

Directors of banks who are also affiliated with petroleum companies are in a position to influence bank loan policies and company investment policies in ways disadvantageous to potentially conflicting investments of bank customers -- e.g., competitive energy supply projects.

Harmonizing of investment projects to advance the interest of both the bank and the petroleum company is an inviting path.

As shown on Table G, banks are frequently numbered among the largest holders of equity and debt securities of petroleum companies. This also obviously creates some community of interest.

Because of the use made by petroleum companies of bank financing, banks receive, as creditors and potential creditors, financial and operating

TABLE D

REGISTRATION ACTIVITY IN TAX SHELTER SECURITIES 1971-73
(Dollar amounts are in thousands of dollars)

Oil and Gas Exploration and Extraction	1971	1972	1973	Percent Change 1971-72	Percent Change 1972-73
Number of Registrations Filed	107*/	110**/	95***/	+2.8	-13.6
Value of Registration	$908,823	$978,336	$707,365	+7.7	-27.7
Amount of Cash Sales	855,594	853,153	621,030	-0.2	-27.2

*/ Six registrations were withdrawn, with value of $34,900,000 and proposed cash sales of $29,000,000.

**/ Five registrations were withdrawn, with value and proposed cash sales of $48,150,000.

***/ Four registrations were withdrawn, with value and proposed cash proceeds of $7,650,000.

information from loan-seeking petroleum companies. This information is not generally available to the public, and to the extent that it is received by bank directors affiliated with oil companies, it could give them special knowledge regarding present or potential competitors.[15]

According to the testimony of an officer of a very large bank heavily engaged in such financing, petroleum company affiliated directors of banks are on the bank board because of their expertise. In the witnesses' bank, the board routinely summarizes for the petroleum company directors smaller loans involving petroleum; and presents larger loans in detail, for petroleum company director review.[16] This is entirely understandable. It also might present conflicts of interest; and provide the petroleum people in the bank board with unusual market information opportunities.

Indeed, the presence of petroleum-bank interlocks may readily be expected to have a discouraging effect on persons considering seeking bank loans for petroleum operations, but not wanting to show their books to competitors. This discouragement could occur irrespective of actual bank practice regarding loan information provided board members.

The local would-be driller-producer, if he goes, as is usually the case, to a large country bank for financing,[17] might be affected in his proposal by the fact that on the bank's board is a representative of an oil company which is a competitor in production or an owner of area gathering and transportation facilities.[18] Similarly, persons considering larger projects must turn to major regional banks and New York banks where, also, oil companies are represented on boards of directors. The psychological impact on project planners of such bank interlocks, whether justified or not, could readily affect the competitive nature of plans; and board members will have both a legal obligation and a psychological tendency to harmonize their responsibilities to all of the firms on whose boards they sit.

Correspendent Banking

Just as there are extensive joint venture relationships between large and small petroleum companies (e.g., farm-outs of drilling prospects, or oil exchanges), there are extensive relationships between banks, and among banks and utilities. Table G.

The relationship between small and large banks is a product of the practice of correspondent banking.[19] Correspondent banking is an interbank practice whereby "city" correspondent banks provide a cluster of services to smaller "country" banks in exchange for interbank deposits. Correspondent banking is not, however, clearly dichotomized into "country" and "city" bank categories; instead, the system exhibits a pyramidal structure wherein moderate sized institutions normally play a double role by supplying services while themselves relying on large banks for correspondent aid.[20]

A standard part of the service package of correspondent banks is participation by the larger banks in the smaller bank's loans, and occasional farming out of participation in the other direction.[21]

By and large, the country bank is required to hold demand deposit balances with the city bank as a means of payment for correspondent services. These services include: collection services, providing credit information, purchase of currency, trust facilities, real estate mortgage funds, purchase and sale of government bonds and securities, safe keeping facilities, demand deposits, financial counsel, office facilities, loan participations, deposit referrals, repossession facilities, and forms and audit systems information. Correspondent Relations: A Survey of Banker Opinion, Subcomm. on Domestic Finance, House Comm. on Banking and Currency, 88th Cong., 2d Sess. (1964).

The average number of banks with whom correspondent relations are maintained increases with the size of the bank. A Report on the Correspondent Banking System, Subcomm. on Domestic Finance, House Committee on Banking and Currency, 88th Cong., 2d Sess. (1964).

The relationship between smaller petroleum companies and smaller banks may buttress the relationship between smaller and larger petroleum companies arising out of joint operational endeavors. This buttressing could arise through the smaller petroleum company and smaller banks being mutually aware of their reliance on larger banks and petroleum companies -- with whom larger banks have interlocks.

Just as the smaller bank looks to larger banks for services, smaller petroleum companies must rely upon larger companies for direct or indirect (exchange) transportation services, farm-outs of drilling opportunities and some geophysical prospecting, among other things. Also, larger banks must be looked to for major financing. Thus the interests of both are such as to be conducive to their adopting a cooperative approach to relations with bigger petroleum firms.

The linking of inter-petroleum-firm relations to inter-bank relations, through petroleum firm financing practices, securities holdings, and ownership and board interlocks with banks, coupled with correspondent banking practices, creates a danger of an anti-competitive "community of thought." Cf. Austin article supra at 387-88 citing Phillips, Competition, Confusion and Commercial Banking, J. Finance, Mar. 1964 at 32; and, Solomon, Bank Merger Policy and Problems: A Linkage Theory of Oligopoly, J. Money, Credit & Banking, Aug. 1970, at 323, 331.

Development drilling is a fairly sure proposition, and explorationists have traditionally obtained outside funding for development and production through the sale of production loans to banks. A production loan is a nonoperating interest in production which is limited in total amount (in terms either of money, time, of physical limits of production). The production payment is expressed either as a certain amount of money (with or without explicit interest) or a certain number of units of product; a production payment holder is free of the burden of development costs and production expenses and is entitled to a fraction or percentage of gross production. Porter, Petroleum Accounting Practices (1965) at 73-74 and 188-95.

Production payments put lenders into the petroleum business, and give them a stake in preventing supply gluts driving down the price of petroleum and thereby reducing the lenders' security and loan profits.

There has been some concern in several quarters with tendencies toward channeling capital flows to a relatively few large companies. This sort of concern was recently addressed by the Senate Finance Committee, as follows, in dealing with the "institutional investor" issue.

> Institutional investors - trust departments of large U.S. banks, insurance companies, mutual funds, pension funds, large endowment funds, foundations - today dominate market transactions, accounting for over 70 percent of the dollar value of New York Stock Exchange trading, compared with 35 percent in 1963.
>
> ********
>
> "In the name of playing safe with their clients' money, large institutional investors have been concentrating their activity in an ever-narrowing circle of investment choices," says James Needham, Chairman of the New York Stock Exchange. * * *

According to an article in Business Week * * * the 10 leading institutional investors are as follows:

The Leading Institutional Investors:
Most of the top 10 are banks

Institution	Investment Portfolios (billions of dollars)*
Morgan Guaranty Trust....................	$27.2
Bankers Trust............................	19.9
Prudential Insurance.....................	18.3
First National City Bank.................	17.2
U.S. Trust of New York...................	17.0
Metropolitan Life Insurance..............	16.5
Manufacturers Hanover Trust..............	10.9
Mellon National Bank & Trust.............	10.5
Investors Diversified Services...........	9.7
Chase Manhattan Bank.....................	9.2

*Excludes real estate investments

These 10 institutional investors hold $156.4 billion in their portfolios. Chairman Paul Kolton of the American Stock Exchange estimates that total equity holdings of financial institutions today are $310 billion, with banks holding $170 billion, mutual funds $45 billion, insurance companies $42 billion, and with foundations investment counsellors and smaller institutions holding the rest. This $310 billion - 36 percent of the total amount outstanding ($1,160 billion) is disproportionately concentrated in the small companies. Thus, there has been created a "two-tier" market. * * *[22]

A "two-tier" market in energy supply ventures is more than a mere possibility. The well established positions of establishing petroleum companies, and the large capital requirements and risks associated with entrants into alternative energy sources, with outsiders dependent on bank loans (with equity markets limited) or loans from major companies[23] seems to point toward such a situation.[24]

Entrant firms are faced with having to go to banks having an interest in the well-being of their competitors, and, perhaps more importantly, through interlocks and the course of business over time, a shared viewpoint as to what is and is not feasible.

TABLE E

COMPANY HOLDINGS OF MARKETABLE SECURITIES
($000)

Company	1973	1972	(1) - (2)	1 + 2
Amerada Hess	45,000	9,956	35,044	4.52
Atlantic Richfield	201,555	20,104	181,451	10.03
BP 1/	261	88	173	2.97
Cities Service	144,480	89,568	54,912	1.61
Clark Oil	12,904	11,900	1,004	1.08
Continental Oil	154,889	114,327	40,562	1.35
Exxon	2,525,429	1,210,379	1,315,050	2.09
Getty	129,209	199,699	(70,490)	0.65
Gulf Oil	921,000	562,000	359,000	1.64
L. L. & E. 2/	41,466	17,345	24,121	2.39
Marathon Oil	53,168	90,960	(37,792)	0.58
Mobil Oil	624,409	449,846	174,563	1.39
Murphy Oil 3/	102,394	62,750	39,644	1.63

1/ Treasury Bills and Government Securities.

2/ Certificates of deposit (CD).

3/ Includes CD's of $83,538,000 in 1973 and $52,324,000 in 1972.

TABLE E (Cont'd)

Company	1973	1972	(1) - (2)	1 + 2
Pennzoil Co. 4/	55,643	169,401	(113,758)	0.33
Phillips Petr.	68,162 5/	50,764	17,398	1.34
Shell Oil Co.	383,542	356,384	27,158	1.08
Standard Oil (Indiana)	452,932	293,774	159,158	1.54
Standard Oil (California)	430,972	205,222	225,750	2.10
Standard Oil (Ohio)	101,941	--	101,941	--
Sun Oil	61,070 5/	26,052	35,018	2.34
Tenneco, Inc.	13,428	44,482	(31,054)	0.30
Texaco, Inc.	324,852	283,619	41,233	1.15
Union Oil Co. of Calif.	78,141	14,813	63,328	5.28
		Total Increase of:	2,713,904	

4/ Temporary cash investments.

5/ Short-term investments.

TABLE E

FINANCIAL HOUSE DIRECTORATE INTERLOCKS AND SECURITIES HOLDINGS IN PETROLEUM COMPANIES

Petroleum Company	Financial Houses With Whom Petroleum Company Director Is Affiliated	Financial Houses Among Largest Corporate Equity Holders	Financial Houses Among Largest Corporate Debt Holders
Allied Chemical	Bowery Savings Bank (N.Y.) Chase Manhattan Chemical Bank Donaldson, Lufkin & Jenrette, Inc. Fidelity Union Bancorp. First National Bank (Southaven, Ms.) First National City Corp. Loeb, Rhoades & Co. N. Y. Life Ins. Co.	Bankers Trust Co. Chase Manhattan Lazard Freres & Co. Loeb, Rhoades & Co. Merrill Lynch Morgan Guaranty Trust National Shawmut Bank of Boston State Str. Bank & Trust (Boston) Swiss Bank Corp.	Chase Manhattan Liberty Mutual U.S. Trust Co.
Amerada Hess	Com'l Union Assur. Co. Ltd. Chemical Bank First Nat'l Bank of Jackson, Ms. First Nat'l State Bank of N.J. Lamar Life Ins. Mutual Benefit Life Ins. Co. N.Y. Life Ins. Co. Thos. Jefferson Life Ins. Co.	Bank of California, N.A. Bank of Delaware Bank of New York Chase Manhattan Equit. Life Assur. Soc. Manufacturers Hanover Morgan Guaranty Trust Prudential Ins. Co. State Str. Bank & Trust (Boston)	Chase Manhattan Chemical Bank Equitable Life Assur. Soc. First Nat'l Bank of Chicago First Nat'l City Bank Metropolitan Life Ins. Morgan Guaranty Trust

Petroleum Company	Financial Houses With Whom Petroleum Company Director Is Affiliated	Financial Houses Among Largest Corporate Equity Holders	Financial Houses Among Largest Corporate Debt Holders
American*** Petrofina	None		American Nat'l Ins. Co. Chase Manhattan** Dry Dock Savings Bank (N.Y.) European-American Banking Corp. First Nat'l Bank - Dallas (Lease trustee for eight insurance companies*) Mass. Mutual Life Ins. Co. Nat'l Bank of Detroit Southwestern Life Ins. Co.

* Pacific Mutual Life Ins. Co., Penn. Mutual Life Ins. Co., Commonwealth Ins. Co., State Farm Ins. Co., Acacia Mutual Life Ins. Co., Country Life Ins. Co., Lutheran Mutual Life Ins. Co., United Benefit Life Ins. Co.

** For Prudential Ins., N.Y. Life Ins. Co., Penn. Mutual Life Ins., and Conn. Gen'l Life Ins. Co.

*** American Petrofina Holding Co. is listed as largest equity holder.

Petroleum Company	Financial Houses With Whom Petroleum Company Director Is Affiliated	Financial Houses Among Largest Corporate Equity Holders	Financial Houses Among Largest Corporate Debt Holders
APCO Oil	American Nat'l Fire Ins. Co. Central Nat'l Corp. (N.Y.) Continental Reinsur. Co. Federated Capital Corp. Great American Ins. Co. Jefferson Ins. Co. of N.Y. Lehman Bros. Loeb, Rhoades & Co.	Bache & Co. Bank of Montreal Brown Bros. Harriman & Co. Central Nat'l Corp. (N.Y.) Chase Manhattan First Nat'l City Bank E. F. Hutton & Co., Inc. Loeb, Rhoades & Co. Madison Fund, Inc. Merrill Lynch Morgan Guaranty Trust Pershing & Co., Inc. Wilmington Trust Co. (Del.)	Bank of Montreal Chase Manhattan First Nat'l Bank of Chicago Wilmington Tr. Co. (Del.) Loeb, Rhoades & Co. Madison Fund, Inc. Merrill Lynch Metropolitan Life Ins. Co.
Ashland Oil	Bank of Bluegrass (Lexington, Ky.) Criterion Ins. Co. Drovers State Bank (Minn.) First Security Nat'l Bank & Trust Co. (Lexington, N.Y.) First Union Nat'l Bank of N.C. (Charlotte) GEICO GE Financial Corp. & Gov't. Employees Life Ins. Co. May Ave. Bank & Trust (Ok. City) Second Nat'l Bank (Ashland, Ky.) Second New Haven Bank (Ct.) Security Ins. Group (Textron) Security-Conn. Life Ins. Co. U.S. Trust Co. of N.Y.	Bank of N.Y. Cede & Co. Continental Bank (Ill.) Morgan Guaranty Trust Nat'l Shawmut Bank (Boston)	Bank of Delaware Bankers Trust Co. Chase Manhattan Dresdner Bank of Germany

Petroleum Company	Financial Houses With Whom Petroleum Company Director Is Affiliated	Financial Houses Among Largest Corporate Equity Holders	Financial Houses Among Largest Corporate Debt Holders
Atlantic Richfield	Not Reported	Bankers Trust Co. Cede & Co. Chase Manhattan Manufacturers Hanover	Aetna Life Ins. Co. Amsterdam-Rotterdam Bank N.V. Chase Manhattan Metropolitan Life Ins. Co. Morgan Guaranty Trust N.Y. Life Ins. Co.
Beacon Oil	None	P.H. Greer Co., Inc.	
Belco Petr.	None	U.S. Trust Co. of N.Y.	Aetna Life Ins. Co. Chase Manhattan El Paso Nat'l Bank First Nat'l City Bank Morgan Guaranty Trust
Champlin Petr. (Union Pacific Corp. Subsid-iary)	Amer'n Bkrs. Ins. Co. of Fla. Brown Bros. Harriman & Co. Bus. Men's Assur. Corp. Chemical N.Y. Co. Colo. Nat'l Bank (Denver) First Nat'l Bank of Oregon First Nat'l City Corp. First Sec. Bank of Idaho, N.A. First Sec. Bank of Utah, N.A. First Security Corp. First United Bancorporation Guarantee Mutual Ins. Co. Irving Trust Co. Charter N.Y. Corp. Metropolitan Life Ins. Co. Mutual Life Ins. Co. Omaha Nat'l Bank	Bank of N.Y. Brown Bros. Harriman & Co. Chase Manhattan Equit. Life Assur. Soc. of U.S. Manufacturers Hanover Merrill Lynch Nat'l Shawmut Bank of Boston State Str. Bank & Trust (Boston)	

Petroleum Company	Financial Houses With Whom Petroleum Company Director Is Affiliated	Financial Houses Among Largest Corporate Equity Holders	Financial Houses Among Largest Corporate Debt Holders
Champlin Petr. (Cont'd)	Real Banc, Inc. The Seaman's Bank for Savings Security Pacific Corp. United Mo. Bancshares (Kansas City) W. Omaha Nat'l Bank White Weld & Co., Inc. World Service Life Ins.		
Cities Service Oil Co.	Canadian Imperial Bank of Commerce First Nat'l Bank of Tulsa Harlem Savings Bank Kuhn Loeb Loeb, Rhoades & Co. Manufacturers Hanover Trust Morgan Guaranty Trust J. P. Morgan & Co. New Amsterdam Casualty Co. State Nat'l Bank-Greenwich, Ct.	Bank of New York Brown Bros. Harriman Cede & Co. Manufacturers Hanover Morgan Guaranty Trust	Chase Manhattan First City Nat'l Bank (Houston) Metropolitan Life Ins. U.S. Trust Co. of N.Y.
Clark Oil	Association Life Ins. Co. Loewi & Co.	Cede & Co. Marine Nat'l Exchange Bank (Milwaukee)	Aetna Casualty-Aetna Life Nat'l Bank of Chicago Jefferson Std. Life Ins. Lutheran Mutual Life Ins. Mass. Mutual Life Ins. Nat'l Life Ins. New England Mutual Life Ins. Northwestern Nat'l Life Ins. Prudential Ins. Teachers Ins. & Annuity

Petroleum Company	Financial Houses With Whom Petroleum Company Director Is Affiliated	Financial Houses Among Largest Corporate Equity Holders	Financial Houses Among Largest Corporate Debt Holders
Clinton Oil	Central State Bank (Wichita) City Bank & Trust Co. (Jackson, Mi.) First Nat'l Bank of Wichita Gude, Winmill & Co. Northern States Bancorp (Detroit)	Cede & Co. Merrill Lynch	First City Nat'l Bank (Houston) Reserve Life Ins. Co. Rothschild Intercontinental Bk. Ltd.
Common-wealth Oil	Banco Credito y Ahorro Ponceno Banco de Economia de P.R. Banco Popular de P.R. Carib. Fed. S & L First Penn Corp. Fireman's Fund American Ins. Co.'s First Boston Corp. First Nat'l Bank of Boston First Nat'l City Bank Puerto Rico Inv. Funds Inc. Putnam Tr. Co. (Greenwich, Ct.)	Bache & Co. Blyth, Eastman Dillon Union Sec. & Co. First Nat'l Bank of Boston Loeb, Rhoades & Co. Merrill Lynch Pitcairn Co. (Wilmington, Del.)	First Nat'l City Bank* New York Life Ins. Co. Riggs National Bank (D.C.)
Continental Oil	Bankers Trust Co. Canada Life Assurance Canadian Imperial Bank of Commerce Cont. Ill. Corp.	Bank of New York** Bankers Trust Co. Cede & Co. Chase Manhattan*** Mellon Nat'l Bank & Trust (Pittsburgh)	Bankers Trust Co. Chase Manhattan First Nat'l City Bank Mellon Bank Morgan Guaranty Trust

* In group for credit agreement with Chase Manhattan, Chemical Bank, 1st Nat'l Bank of Boston, B. Credito y Ahorro Ponceno, Banco de Ponce, Banco Pop. de P.R.

** Nominee for: General Investors Company, Inc.; The Johnston Mutual Fund, Inc. Petroleum Corporation of America; United Funds, Inc.; and The United States Fund.

*** Nominee for: American Mutual Fund, Inc.; Chemical Fund, Inc.; Eberstadt Fund, Inc.; Equity Fund, Inc.; International Resources Fund, Inc.; and Investment Company of America.

Petroleum Company	Financial Houses With Whom Petroleum Company Director Is Affiliated	Financial Houses Among Largest Corporate Equity Holders	Financial Houses Among Largest Corporate Debt Holders
Continental Oil (Cont'd)	Federated Capital Corp. Johnson City Bank (Tx.) Morgan Guaranty Trust J. P. Morgan & Co., Inc. Putnam Trust Co. Royal Globe Ins. Co. Trust Co. of Ga. U.S. Trust Co. of N.Y.		
Crown Central Petr. Co.	Chase Manhattan, N.A. Hallgarten and Co. Union Trust Co. of Md.	Barclay's Bank Co. (N.Y.) W. E. Hutton & Co. Loeb, Rhoades & Co. Merrill Lynch Tom and Barut, Ltd. Union Trust of Md.	Aetna Life Ins. Co. Conn. General Life Ins. Equitable Life Assur. Interstate Life & Accident Ins. Jefferson Std. Life Ins. Co. Mutual Life Ins. Co. New England Mutual Life Ins. Co. Penn. Mutual Life Ins. Co. Union Trust Co. of Md.
Diamond Shamrock Oil & Gas	Cleveland Trust Co. First Nat'l Bank of Amarillo, Tx. First Nat'l Bank of St. Louis First Union Corp. Mellon Nat'l Corp. St. Louis Union Trust Co. Society Nat'l Bank of Cleveland	Amer. Bk. & Tr. Co. of Pa. Bank of N.Y. Cede & Co. Cleveland Trust Co. First Nat'l Bk. of Chicago Irving Tr. Co. Mellon Nat'l Bk. & Tr. (Pittsb.) Pittsburgh Nat'l Bk. State Str. Bk. & Tr. Co. (Boston) Swiss Bank Corp. Wilmington Trust Co. (Del.)	Bankers Trust Co. Chase Manhattan Morgan Guaranty Trust N.J. Nat'l Bank Savings Bank Tr. Co. Wilmington Tr. Co.

Petroleum Company	Financial Houses With Whom Petroleum Company Director Is Affiliated	Financial Houses Among Largest Corporate Equity Holders	Financial Houses Among Largest Corporate Debt Holders
El Paso Natural Gas Co.	American Bank - (Odessa, Tx.) Bank of New York Desert Ins. Co. Ltd. El Paso Nat'l Bank (Tx.) First City Bancorporation of Texas First State Bank Home Savings & Loan (Odessa) Int'l Ins. Agency, Inc. Mellon Bank & Trust Co. Pacific Mutual Life Ins. Co. Permanent Bank & Trust Co. (Odessa, Tx.) San Angelo Nat'l Bank TX Comm. Bank N.A. TX Comm. of Houston TX Comm. of Lubbock Western Bancorp (CA.)	First Nat'l City Bank Merrill Lynch Reynolds Securities	Aetna Life Ins. Co. Chase Manhattan Conn. Gen'l Life Ins. Co. Equitable Life Assurance John Hancock Mutual Life Ins. Metropolitan Life Ins. Co. Mutual Life Ins. Co. N.Y. Life Ins. Co. Northwestern Mutual Life Ins. Sun Life Assurance Co. of Canada Travelers Ins. Co.
Exchange Oil & Gas	American Tidelands Life Ins. Co. Hibernia Nat'l Bank in N.O. Wertheim & Co.		
EXXON	American Gen'l Ins. Co. Chase Manhattan Chemical Bank Dry Dock Savings Bank (N.Y.) Equit. Life Assur. Soc. First City Bankcorporation of Texas First Nat'l City Bank Metropolitan Life Ins. Morgan Guaranty Trust	Bank of New York Bankers Trust Co. Cede & Co. Chase Manhattan Bank Chemical Bank First Nat'l Bank of Boston Manufacturers Hanover Morgan Guaranty Trust State Str. Bk. & Tr. (Boston) United States Trust Co.	Bankers Trust Co. First Nat'l City Bank John Hancock Mutual Metropolitan Life Ins. Mutual Benefit Life Ins. Travelers Ins. Co.

Petroleum Company	Financial Houses With Whom Petroleum Company Director Is Affiliated	Financial Houses Among Largest Corporate Equity Holders	Financial Houses Among Largest Corporate Debt Holders
EXXON (Cont'd)	J. P. Morgan & Co. Prudential Ins. Co. Texas Commerce Bancshares, Inc.		
Farmland Industries	Farmers Elev. Mutual Ins. Co. Farmers Life Co. Farmland Life Ins. Co.		Bank of the Southwest Bankers Trust Co. Chase Manhattan Bank Commerce Bank (Kan. City) First Nat'l Bk. of Chicago First Nat'l City Bank Omaha Bank for Co-ops St. Louis Bank for Co-ops Wichita Bank for Co-ops
Felmont Oil Corp.	The Franklin Corp.	Cede & Co.	
Fletcher Oil & Ref'g. Co.	Idaho Fidelity Corp.		Northwestern Nat'l Life Ins. Co.
Forest Oil	Nat'l Bank of Commerce (San Antonio)	Bank of CA Bank of NY Cede & Co. First Nat'l Bank of Nev. Metropolitan Life Ins. Co. State Str. Bank & Trust (Boston)	Chase Manhattan, N.A.* Federal Life & Cas. John Hancock Mutual Lehman Bros., Inc. Metropolitan Life Ins. Co. Morgan Guaranty Trust Mutual Life Ins. Co. Northwestern Mutual Life People's Home Life Ins. State Str. Bank & Trust (Boston)

* Nominee for: Manufacturer's Hanover Trust Company; Marine Midland Bank (Western); First National Bank and Trust Company of Tulsa; National Bank of Commerce (San Antonio).

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Petroleum Company	Financial Houses With Whom Petroleum Company Director Is Affiliated	Financial Houses Among Largest Corporate Equity Holders	Financial Houses Among Largest Corporate Debt Holders
General American Oil Co. of Texas	American Nat'l Bank of Jacksonville Blyth Eastman Dillon Co. Deposit Guaranty Nat'l Bank (Miss.) The Excelsior Life Ins. Co. Matthews & Co., Ltd. (CAN) The People's Nat'l Bank Tyler Tx. Republic Nat'l Bank of Dallas Standard Life Ins. Co. State Bank of Jacksonville (Fla.)	Cede & Co. Chase Manhattan New England Merchants Nat'l Bank (Boston) Republic Nat'l Bank of Dallas	
General Crude Oil	American General Ins. Co. Glenmede Trust Co. (Pa.) Meyerland State Bank Manufacturer Hanover Corp.	Bank of New York Glenmede Trust (Pa.) Manufacturers Hanover	None
Hamilton Bros. Petr. Corp.	Chase Int'l Inv. Corp. First Nat'l Bancorp. First Nat'l Bank in Dallas Lamar Life Ins. Life & Casualty Co. of TN Nat'l Shawmut Bank of Bos. Trust Co. of N.Y.	Not reported	Bank of Montreal
Hunt Oil Co.	Exchange Bank & Trust Co. (Dallas)		Federal Savings & Loan Assoc. (Thibodeau, La.) Mutual Life Ins. Co. N. American Life & Casualty Co.

Petroleum Company	Financial Houses With Whom Petroleum Company Director Is Affiliated	Financial Houses Among Largest Corporate Equity Holders	Financial Houses Among Largest Corporate Debt Holders
Husky Oil	Cont. Ill. Nat'l Bank & Trust First Security Corp. (Utah)	Bank of Montreal Can. Imp. Bank of Comm. Chase Manhattan Cont. Ill. Nat'l Bank & Trust Royal Bank of Canada Montreal Trust Company Canada Permanent Trust Co.	Bank of New York Cont. Illinois Nat'l Bank (Chicago) Federal Life & Casualty Co. First Sec. Bank of Utah Morgan Guaranty Trust New York Life Ins.
Kerr-McGee Corp.	American Bank of Edmond (Ok.) American Fidelity Assur. Co. American Fidelity Ins. Co. Capital Hill St. Bank & Trust Co. (Ok. City) Citizens Bank of Ok. City Fidelity Bank, N.A. (Ok. City) First Nat'l Bank, Alex., Ok. First Nat'l Bank & Trust, Muskegee, Ok. First State Bank, Blanchard, Ok. First State Bk. & Tr. Co. of Ok. City F & M Bank of Tulsa Lehman Bros, Inc. Liberty Nat'l Corp (Ok. City) Reserve Nat'l Insurance Co. Soc. First Nat'l Bank of L.A. S.W. Title & Trust Co. (Ok. City)	Cede & Co. Chase Manhattan Fidelity Bank, N.A. First Nat'l Bank of Boston Lehman Corp. State St. Bk. & Trust (Boston) Metropolitan Life Ins. Co. Wilmington Trust Co. (Del.)	Bank of Southwest First Nat'l Bank of Chicago First Nat'l City Bank John Hancock Mutual Prudential Ins. Co. of America N.Y. Life Ins. Co.
Kewanee Oil	Blyth Eastman Dillon & Co. Philadelphia Nat'l Bank Tanney, Montgomery, Scott, Inc.		

Petroleum Company	Financial Houses With Whom Petroleum Company Director Is Affiliated	Financial Houses Among Largest Corporate Equity Holders	Financial Houses Among Largest Corporate Debt Holders
Lion (Tosco Subsidiary)	Exchange Bank & Trust Co. (Dallas)		The Equitable Life Ins. Soc. The First Nat'l Bank of St. Paul
Lone Star Gas Co.	Bank of Commerce Employers Casualty Co. Republic Nat'l Bank of Dallas San Angelo National Bank Texas Employers Ins. Assoc.	Chemical Bank (trustee) Equitable Life Assur. Soc. First Nat'l Bank in Dallas First Nat'l City Bank Mellon Nat'l Bank and Trust (Pittsburgh) Merrill Lynch Nat'l Shawmut Bank Northwestern Pa. Bk. & Tr. Republic Nat'l Bk. of Dallas	Mellon Nat'l Bank & Trust (Pittsburgh)
Louisiana Land & Exploration	American Life Ins. Co. of N.Y. Bank of New York Citizens Nat'l Bank of Hammond, La. Depository Trust Co. Dry Dock Savings Bank First City Nat'l Bk. of Houston Hibernia Nat'l Bk. of New Orl. La. & Southern Life Ins. J.P. Morgan & Co. N.Y. Life Ins. Northern Ins. Co. of N.Y. Whitney Nat'l Bank (New Orleans)	Bank of New York Bankers Trust Co. Brown Bros. Harrison & Co. Cede & Co. Chase Manhattan Delaware Trust Co. Goldman Sachs & Co. Harris Tr. & Svgs. Bk. (Ch'go) Lehman Bros. Lewco Securities Corp. Manufacturers Hanover Trust Maryland Nat'l Bank Mellon Nat'l Bk.& Tr. (Pittsb'g) Merrill Lynch Morgan Guaranty Trust Nat'l Bank of Tulsa Nat'l Bk. of Rutherford (N.J.)	Bank of New York First Nat'l Bank of Commerce (New Orleans, La.)

Petroleum Company	Financial Houses With Whom Petroleum Company Director Is Affiliated	Financial Houses Among Largest Corporate Equity Holders	Financial Houses Among Largest Corporate Debt Holders
Louisiana Land & Exploration (Cont'd)		N.W.'ern Nat'l Bk. of Minn. Savings Bank & Trust Co. Spencer Trask & Co., Inc. State Str. Bank & Trust Co. (Boston). U.S. Trust of N.Y.	
Marathon Oil*	The First Boston Corp. First Nat'l Bank of Findlay (Ohio) Nat'l City Bank of Cleveland N.Y. Life Ins. Co. Philadelphia Nat'l Bank Sears Bk. & Tr. Co. (Chicago) Toledo Trust Co.	Nat'l City Bank of Cleveland	
McCulloch Oil**	Bache & Co.	Cede & Co. Merrill Lynch Mutual Life Ins. Co.	Bank of America Chase Manhattan City Nat'l Bank & Trust (Kansas City) First Nat'l Bk. in Dallas Mellon Bank & Trust Co. (Pittsburgh) Merrill Lynch Savings Bk. & Trust Co. State Str. Bank & Trust (Boston)

* Only partial public response.

** Only partial response.

Petroleum Company	Financial Houses With Whom Petroleum Company Director Is Affiliated	Financial Houses Among Largest Corporate Equity Holders	Financial Houses Among Largest Corporate Debt Holders
Mobil Oil	American Sec. & Tr. Co. (D.C.) Bankers Trust Co. Brooklyn Savings Bank Chemical N.Y. Corp. Federal Ins. Co. First Nat'l City Corp. Schroder Trust Co. Vigilant Ins. Co.	Not Reported	Not Reported
Monsanto	Bank of America, N.Y. Boatmen's Nat'l Bank of St. Louis Charter Nat'l Life Ins. Co. Equitable Life Assur. Soc. First Nat'l Bank (St. Louis) First Nat'l City Bank Great American Ins. Co. Liberty Mutual Fire Ins. Liberty Mutual Life Ins. Mercantile Bancorp Inc. (St. Louis) Merchants Nat'l Bank (Cedar Rapids, Iowa) Metropolitan Life Ins. N. Y. Life Ins. Co. St. Louis County Nat'l Bank St. Louis Union Trust Co.	Bankers Trust Co. Brown Bros. Harriman Chase Manhattan Merrill Lynch Nat'l Bank of Detroit	Chase Manhattan Commerzbank, A.G. Metropolitan Life Ins. N.Y. Life Ins. Northwestern Mutual Life Ins.
Murphy Oil	Allied Bank Int'l First Nat'l Holding Co. First Nat'l Bk. of El Dorado First Tennessee Nat'l Corp. La. & Southern Life Ins. Co.	Bankers Trust Co. Cede & Co. Ft. Worth Nat'l Bank First Trust Co. of St. Paul Merrill Lynch	Equitable Life Assur. First Nat'l Bank of Chgo. Mercantile Bank of Canada Mitsubishi Bank Ltd. Nat'l Westminster Bk. Ltd.

Petroleum Company	Financial Houses With Whom Petroleum Company Director Is Affiliated	Financial Houses Among Largest Corporate Equity Holders	Financial Houses Among Largest Corporate Debt Holders
Murphy Oil Co. (Cont'd)		Morgan Guaranty Trust United Mo. Bank (Kans. City)	Royal Bank of Canada Union Bk. of Switzerland
Occidental Petr. Corp.	Cleveland Trust Co. Florida Nat'l Bank of Jacksonville Home Life Equity Fund National Liberty Corp.	Cede & Company* Chase Manhattan Merrill Lynch	Aetna Life Ins. Co. Chase Manhattan Conn. Gen'l Life Ins. Equitable Life Assur. Soc. First Nat'l City Bank John Hancock Mutual Mutual Life Ins. Co. N.Y. Life Ins. Co. Teachers Inst. & Annuity
Panhandle** Eastern Pipe Line	Commerce Bancshares Eur-American Banking Corp. Morgan Guaranty Trust	Bankers Trust Co. Cede & Co. Chase Manhattan Chemical Bank Fidelity-Phila. Trust Co. First City Nat'l Bank Irving Trust Co. Manufacturers Hanover Mellon Nat'l Bank & Trust Co. (Pittsburgh) Morgan Guaranty Trust Nat'l Shawmut Bank of Boston Wilmington Trust Co. (Del.)	Aetna Life Ins. Co. First City Nat'l Bank Life Ins. Co. of Va. Metropolitan Life Ins. Co. N.Y. Life Ins. Co. Savings Bank Trust Co. (N.Y.) U.S. Trust Co.

* Cede & Company holds common stock for a number of companies, including Bache & Co., E.F. Hutton, Merrill Lynch and Reynolds Securities, Inc. who each have 800,000 or more shares of common stock.

** Partial response only.

Petroleum Company	Financial Houses With Whom Petroleum Company Director Is Affiliated	Financial Houses Among Largest Corporate Equity Holders	Financial Houses Among Largest Corporate Debt Holders
Pennzoil Co.	Brit. Assur. Trust Ltd. C.A. Casualty Ins. Co. Commonwealth Assur. Co. Federal Capital Corp. First Bancorp (Tulsa) First Nat'l Bank (Midland) Mellon Nat'l Bank & Trust (Pittsburgh) Valley Forge Insurance Co.	Brown Bros. Harriman E.F. Hutton & Co. First Nat'l City Bank First Nat'l Bank of Shreveport (trustee) State Str. Bank & Trust (Boston)	Chemical Bank First Nat'l Bk. of Chicago Lincoln Nat'l Life Ins. Mass. Mutual Life Ins. Co. Merrill Lynch Mutual Benefit Life Ins. New England Merchants Nat'l Bank Savings Bank Trust State Str. Bank & Trust
Phillips Petr.	American Reinsurance Co. First Bancshares, Inc. (Bartlesville) First Nat'l Bank in Bartlesville First Nat'l Bank & Trust Co. of Tulsa First Nat'l City Bank & Citicorp Franklin N. Y. Corp. Nat'l Bank of Tulsa Teachers Inst. Annuity Assoc. Union Nat'l Bank (Bartlesville, OK) Zions Utah Bancorp	Bankers Trust Co. Chase Manhattan First Nat'l Bank, Bartlesville Fidelity Bank (Phila., Pa.) Merrill Lynch U.S. Trust Co. of N.Y.	Chase Manhattan Cont. Illinois Nat'l Bank First Nat'l City Bank Metropolitan Life Ins. N.Y. Life Ins. Co. Prudential Ins. Co.
Rock Island Refinery	American Fletcher Nat'l Bank & Trust Co.	First Nat'l Bank in Wichita Mercantile Trust Co.	None

Petroleum Company	Financial Houses With Whom Petroleum Company Director Is Affiliated	Financial Houses Among Largest Corporate Equity Holders	Financial Houses Among Largest Corporate Debt Holders
Shell Oil Company*	Bank of California NA Bank of the Southwest Capital National Bank, (Austin, Tx.) Charter N.Y. Corp. Chase Manhattan Chemical Bank Conn. Mutual Life Ins. Co. Dean Witter & Co. Inc. Lehman Brothers Ranger Ins. Co. Seaboard Surety Co.	Manufacturers Hanover Trust Co.	Bankers Trust Co. First Nat'l City Bank Irving Trust Co. N.Y. Life Ins. Co. U.S. Trust Co.
Southland Oil Company	First Nat'l Bank of Jackson (Miss.) Lamar Life Ins. Co.	Lamar Life Ins.	Chemical Bank First Nat'l Bank-Memphis Whitney National Bank
Standard Oil (CA)**	Banca D'America e d'Italia Bank of America NT & SA Bank of California Crocker Citizen's Nat'l Bank Crocker Nat'l Corp. Equitable Life Ins. Fireman's Fund Amer'n Ins. Fireman Fund Ins. Co. First Nat'l City Bank Seattle First Nat'l Bank United CA. Bank	Crocker Nat'l Corp.	Bank of Int'l. Settlements (Switzerland) Caisse Gen. d Epargne et. de Retraite (Brussels) Mediobanca Sp. A. Soc. Nationale de Credit L'Industrie (Brussels) U.S. Trust Co. of N.Y.

* Shell Petr. N.V. which owns 69.6% of Shell Oil, is in turn owned 60% by Royal Dutch Petr. Co. and 40% by the "Shell" Transport & Trading Co., Ltd. Shell Petr. N.V. has pledged 43.2% of Shell Oil common stock to Morgan Guaranty Trust under a trust indenture of Shell Funding Corp.

** Partial response only.

Petroleum Company	Financial Houses With Whom Petroleum Company Director Is Affiliated	Financial Houses Among Largest Corporate Equity Holders	Financial Houses Among Largest Corporate Debt Holders
Standard Oil (Ind.)	American Nat'l Bank & Trust Co. (Chicago) Bank & Trust Co. of Arlington Heights, Ill. Chase Manhattan Chemical N.Y. Corp. Chicago Bank of Commerce Continental Ill. Corp. First Nat'l Bank & Trust Co. of Tulsa Harris Trust & Savings Bank (Chicago) Nat'l Blvd. Bank of Chicago Union Cent. Life Ins. The Wilmette Bank (Ill.)	Cede & Co. Chase Manhattan First Nat'l Bank of Chicago Prudential Ins. Co.	Chemical Bank Metropolitan Life Ins. Mitsubishi Bank Ltd. S. Nationale de Credit a l'Indus. Bank The Sumito Bank, Ltd. U.S. Trust Co. of N.Y.
Standard Oil* (Ohio)	Central Bancshares Corp. (Cleveland) Cleveland Trust Co. Lincoln National Corp. National City Bank of Cleveland	Bankers Trust British Petr. (Oversea) N.Y. Chase Manhattan Nat'l City Bank Wilmington Trust Co. (Del.)	Chase Manhattan Chemical Bank First Nat'l Bank - Chicago First Nat'l City Bank Morgan Guaranty Trust U.S. Trust Co. of N.Y.

* British Petr. (Oversea) N.Y. is largest holder of equity shares.

Petroleum Company	Financial Houses With Whom Petroleum Company Director Is Affiliated	Financial Houses Among Largest Corporate Equity Holders	Financial Houses Among Largest Corporate Debt Holders
Sun Oil Company	Bay State Corp. Fidelity Union Life Ins. First Nat'l Bank & Trust Co. of Tulsa Girard Bank (Pa.) Glenmede Trust Co. (Pa.) Mutual Life Ins. Co. Northeastern Bank of Pa.	Not reported	Chase Manhattan Fidelity Union Trust Co. Metropolitan Life Ins. Co. U.S. Trust Co. of N.Y.
Tenneco Inc.	American Gen'l Life Ins. Employers Ins. - Wisconsin Houston Nat'l Bank Harris, Upham & Co. First Wisconsin Mortgage Trust N.W. Bancorp. TX Commerce Bank	Cede & Co. Houston Nat'l Bank Merrill Lynch Stone & Webster	Aetna Life Ins. Bankers Trust Co. Conn. Gen'l Life Ins. Co. Equitable Life Assur. John Hancock First Nat'l City Bank Metropolitan Life Ins. Prudential Life Ins. Teachers Ins. & Annuity
TESORO Petr.	E.F. Hutton & Co., Inc.	Not reported	The First Jersey Nat'l Bank First Nat'l Bank, Ft. Lauderdale First Nat'l Bank of Topeka Harris Trust & Savings Bank E. F. Hutton & Co. Janney Montgomery Scott, Inc. Merrill Lynch

Petroleum Company	Financial Houses With Whom Petroleum Company Director Is Affiliated	Financial Houses Among Largest Corporate Equity Holders	Financial Houses Among Largest Corporate Debt Holders
Texaco	Bessemer Securities Corp. Brown, Harriman & Int'l Banks, Ltd. Continental Ill. Corp. Equitable Life Assur. Soc. Financial Gen'l Bancshares First Nat'l Bank of Washington Gen'l Reins Corp. Mutual Life Ins. of N.Y. Nat'l Blvd. Bank of Chicago Nat'l City Corp. Sun Life Assur. of Canada State Bank of St. Charles, Ill. United Services Life Ins. Co.	Not reported	Not reported
Texas City Ref'g.*			American Nat'l Bank of Mobile First Nat'l Bank of Memphis Mutual Life Ins. Co.
Texas Oil & Gas Co.	Spencer Trask & Co., Inc.	Bankers Trust Co. Bank of N.Y. Cede & Co. Chemical Bank Ford Foundation First Nat'l Bank (Denver) Manufacturers Hanover Morgan Guaranty Trust Phicar & Co. (Newark, N.J.) Wall St. Trust Co. U.S. Fidelity & Guaranty Trust Co.	American Nat'l Ins. Co. Bank of Delaware Cleveland Trust Co. Jefferson St. Life Ins. First Nat'l City Bank N.J. Nat'l Bank U.S. Trust Co. of N.Y.

* Partial response only

Petroleum Company	Financial Houses With Whom Petroleum Company Director Is Affiliated	Financial Houses Among Largest Corporate Equity Holders	Financial Houses Among Largest Corporate Debt Holders
Total-Leonard (Subsidiary of Total Petr. Ltd.)	Bank of Alma, Mich. Isabella Co. State Bank		Aetna Life Ins. Co. Conn. Mutual Life Ins. Fr. Amer'n Bkg. Corp. Lincoln Nat' Life Ins. Mich. Nat'l Bank
Union Oil Co. of California	Bank of America Benefit Trust Life Ins. Co. Canadian Imperial Bank of Comm. Korea Exch. Bank of CA Pacific Mutual Life Ins. Palatine Nat'l Bank Suburban Nat'l Bk. of Woodfield Union Bancorp, Inc. Western Bancorp.	Bank of N.Y. Cede & Co. First Nat'l City Bank Merrill Lynch Prudential Ins. Sec. Pacific Nat'l Bank	Chase Manhattan John Hancock Metropolitan Life Ins. N.Y. Life Ins. Co. U.S. Trust Co.

TABLE G

SOME INTERLOCKING DIRECTORATES

Following is a table listing interlocks, both direct and indirect, of board directors among bank holding companies, electric utility systems, and energy companies. Our investigation of such interlocks is still in progress. What follows is a list, not necessarily complete, of interlocks existing in 1973 per Annual Reports to the Federal Reserve Board, with some updating to 1974 as reported in Annual Reports of Electric Companies to the Securities and Exchange Commission.

INTERLOCKS AMONG BOARDS OF DIRECTORS

BANK	UTILITY	ENERGY COMPANY
Ban Cal Tri-State Corp. (Bank of California)	San Diego Gas & Elec. Co.	Natomas Co. Baker Oil Tools, Inc.[1]
Bank America Corporation	Southern California Edison Co.	Dillingham Oil Company Getty Oil Co. Kaiser Industries Standard Oil (CA) Union Oil Company of California
Bankers Trust New York Corp.	Baltimore Gas & Elec. Co. Consumers Power Co.	Continental Oil Co. Hudson's Bay Oil & Gas Co., Ltd. International Paper Co. Mobil Oil Corp. Universal Oil Products Co.
Bank of New York Co.	(none)	El Paso Natural Gas Co.[2]
Boatmen's Bancshares Inc.	Union Electric Co.	Capital Coal and Coke Co.
Central Bancshares of the South, Inc.	(none)	(none)
The Chase Manhattan Corporation	(none)	Allied Chemical Corp. Exxon Corp. R. J. Reynolds Industries, Inc. Shell Oil Co. Standard Oil Co. (IN)
Chemical New York Corporation	Consolidated Edison	Amerada Hess Aramco Exxon Mobil Oil Corp. Texas Gas Transmission Corp. The Hillman Company Union Pacific Corp.

1/ Equipment supplier

2/ Gas pipeline

BANK	UTILITY	ENERGY COMPANY
Clevetrust Corp.	(none)	Diamond Shamrock Corp. Standard Oil Co. (Ohio)
First Chicago Corp.	Commonwealth Edison Co.	Northwest Industries, Inc. Burlington Northern, Inc. Atlantic Richfield Co.
First City Bancorporation of Texas	(none)	Exxon, Co. (USA) United Gas, Inc. Texas Eastern Transmission Corp. Panhandle Eastern Pipeline Co. Quintana Petroleum Co. Robertson Coal, Inc. PetroLewis Corporation The Superior Oil Company Halliburton Company[3] Highland Oil Company Northwest Exploration Coquina Oil Corporation Seven Oil, Ltd. El Paso Natural Gas Company Transco Companies, Inc.
First International Bancshares, Inc.	Dallas Power & L. Co. Duke Power Co.	SEDCO, Inc. Blue Crown, Inc. Blue Crown Petroleum, Ltd. Various Delhi Oil Concerns Gas Producers Corp.[4] Hamilton Bros. Petroleum Corp. Murchison Oil Co. Thermal Energy Co. Baptist Foundation & Affiliates of Texas Vaughn Petroleum, Inc. American Liberty Oil Co.

3/ Oil field equipment and services.
4/ Ownership interest.

BANK	UTILITY	ENERGY COMPANY
First National Bancorporation, Inc. (Denver)	Public Serv. Co. of Colorado	Denver & R.G.W. RR. Co. Hamilton Bros. Oil Co.
First National Boston Corp.[5]	Stone & Webster, Inc.[6] Boston Edison Co. New England Elec. System	International Paper Co. Cabot Corp. Mississippi River Transmission Corp.
First National Cincinnati Corp.	Cincinnati Gas & Electric Co.	Roberta Coal Co.
First National City Corp.	Consolidated Edison Co. of N.Y. Stone & Webster, Inc.[6]	Union Pacific Corp. Monsanto Co. Exxon Corp. W.R. Grace & Co. Standard Oil Co. of Calif. Phillips Petroleum Co.
First Oklahoma Bancorporation, Inc.	Oklahoma Gas & Elec. Co.	Eason Oil Co. Mustang Fuel Corp. Katy Industries[7] Oceanography International
First Pennsylvania Corp.	Philadelphia Electric Co.	Berwind Corp.
First Tulsa Bancorporation	Central & South West Utilities Corp. & its subsidiary, Public Service Co. of Oklahoma	Reading & Bates Offshore Drilling Co. Apache Exploration Co. Pennzoil Co. Sun Oil Co. Helmerich & Payne Inc. Phillips Petroleum Co. Mabee Petroleum Corp. Skelly Oil Co.

5/ Trust accounts (market value, 12/31/74: Exxon Corp. $123,400,000, Texaco $35,800,000

6/ Utility design & engineering (service co.)

7/ Oil field equipment and services

BANK	UTILITY	ENERGY COMPANY
First Tulsa Bancorporation (continued)		Cities Service Co. Williams Companies Warren-American Oil Co. Oriole Oil Co. Standard Oil Co. (IN) Bigheart Pipe Line Corp. & Affiliates
J.P. Morgan & Co.	Niagara Mohawk Power Corp.	Continental Oil Co. Louisiana Land & Expl. Co. Airforce Pipeline, Inc. Exxon Corp. Cities Service Co. Burlington Northern, Inc. Texas Gulf, Inc. Panhandle Eastern Pipe Line Co. Canadian Pacific, Ltd.
Manufacturers Hanover Corp.	Consolidated Edison Co. of N.Y. Public Serv. Elec. & Gas Co.	Cities Service Co. General Crude Oil Co. Southern Pacific Co.
Mellon National Corp.	Duquesne Light Company	Continental Oil Company Diamond Shamrock Corp. El Paso Natural Gas Co. Gulf Oil Corp. Lone Star Gas Co.
National City Corp. (Cleveland)	Cleveland Electric Illum. Co.	Beatrice-Pocahontas Co. Marathon Oil Co. Dow Chemical Co. Texaco, Inc. Ariel Petroleum Co., Ltd. Hanna Petr. Co. & Affiliates Standard Oil Co. (Ohio) & Affiliates

BANK	UTILITY	ENERGY COMPANY
Republic National Bank of Dallas [8]	Dallas Power & Light Co.	Lone Star Gas Co.
	Southwestern Public Service Co.	Developers Oil Co.
	Texas Power & Light Co.	Rainbow Oil Producing Co.
		Halliburton Co.
		Gen. Amer. Oil Co. of Tx. & Affiliates
		Exchange Oil & Gas Co. Funds MNOP & Q
		Petro Oil & Gas Co.-Fund A & B
		Excalibar Oil Corp.
		Neuhoff Oil & Gas Corp.
		Concho Petroleum Co.
		Ranchers Explor. & Develop. Corp.
		Kirby Petroleum

8/ Owns United Petroleum Corp., Boyce Oil Co., and McBean Oil Co.

1 Cossey, Financing Oil and Gas Exploration -- Past, Present, and Future, Southwest Institute (1973).

2 Lease financing is generally obtained from commercial bank-affiliates. Shapiro and Reisman, Equipment Leasing, New York (PLI) (1973), p. 184.

3 That is, rental paid under an arrangement where a bank or banks acquire and hold title to a property and lease it to a petroleum company. A concise description of personal-property lease financing from the banker's point of view appears at Bank Administration Institute, Bank Administration Manual (1970), pp. 516-519.

4 Zeppa, The Drilling Contracting Business, in Slovenka, Oil & Gas Operations: Legal Considerations in the Tidelands and on Land (1973), reports the importance of bank loans to small exploration companies.

5 And see, regarding sales to institutions, Friend, Investment Banking and the New Issue Market, 337 (1967); Note on Private Placements, 59 U. Va. L. Rev. 886 (1973).

6 Traditionally, the financing of small drilling contractors who drill incremental wells has been based on internal cash flow, bank loans, or farm-outs. See, e.g., Zeppa, The Drilling Contracting Business, in Slovenka, Oil & Gas Operations: Legal Considerations in the Tidelands and on Land (1973). These firms look to both banks and large oil companies for financing. Zeppa

also relates how farm-outs are needed by independent oil operators who can drill but lack the resources to bid for leases or to do seismic or other exploratory work. Majors benefit by farming out properties from vast land inventories, enabling evaluation of these domestic holdings while they drill overseas. The ability to finance drilling through farm-outs is hindered when independents have difficulties getting drilling equipment.

7 Tax Code provisions for depletion allowances and deduction as expenses of intangible drilling costs do not provide initial funding for a project or firm. The allowance for depletion (26 U.S.C. 3613) refers to a depletion deduction from "gross income from property," which means income from the sale of oil and gas actually extracted therefrom. Big Four Oil & Gas Co. v. United States, 118 F. Supp. 958 (W.D. Pa., 1954); I.R.S., Regs. § 1.613.3 (a). Similarly, the option to expense intangible drilling costs (26 U.S.C. § 263 (c)), may be exercised as to: ...expenditures made by an operator for wages, fuel, repairs, hauling, supplies, etc., incident to and necessary for the drilling of wells and the preparation of wells for the production of oil or gas. (I.R.S., Regs. § 1.612-4(a).)

8 A few funds also operate to purchase producing properties.

9 The general partner frequently obtains a non-recourse loan for this share of expenses.

10 See, e.g., terms of $12 million loan to Ashland Oil for Alaskan exploration work, or the reported carried interest given the insurance company lender by Tenneco in 1972 for offshore leases.

11 POGO is Pennzoil Offshore Gas Operators, Inc.; Pennzoil, subsequent to POGO, in 1972, organized PLATO -- Pennzoil Louisiana and Texas, Inc.

12 Increased rates of capital outlay by larger oil companies, and successful private placements by smaller firms, show that profits are adequate to bring forth investment in oil exploration. The use of internal financing from depreciation and retained earnings, in lieu of a more balanced capital structure for financing capital expenditures with sales of securities, may be expected to drive up the price of oil.

13 See, e.g., Van Horn, Financial Management and Policy, 334 *et seq.* (1968).

14 Some of these thirty-seven firms do not separately disclose marketable security holdings in their annual reports.

15 Loan volume data, alone, could at times be highly informative -- e.g., the amount of standby lines of credit obtained before federal leasing sales.

16 Testimony of Wallace Wilson, Sen. Judiciary Comm., "The Industrial Reorganization Act: Part 9 - The Energy Industry," 94th Cong., 1st Sess. (1975).

17 E.g., production loans.

18 Persons planning local projects upstream of production will frequently find the representatives of established local refiners on bank boards.

19 Austin, A New Antitrust Problem: Vertical Integration in Correspondent Banking, 122 U. Pa. L. Rev. 366 (1973).

20 Ibid, at page 376.

21 Ibid, at 368-69.

22 The Role of Institutional Investors in the Stock Market, Senate Comm. on Finance (July 24, 1973).

23 E.g., advance payments or drilling partnerships; see New Drilling-Money Spout Opening for Independents, The Oil and Gas Journal, p. 15 (Sept. 2, 1974).

24 Cf. The Role of Institutional Investors in the Stock Market, ibid at 4-5.

APPENDIX D

PRIMARY AND EXCLUSIVE JURISDICTION, STATE ACTION,

AND FOREIGN STATE ACTION DEFENSES

Primary and Exclusive Jurisdiction

Judicial enforcement of antitrust laws in regulated sectors of the economy involves some particular problems, which we now discuss.

In regulated sectors of the economy, including the electric utility industry, attempts to enforce antitrust policy in the courts raise questions as to whether a matter should be tried there or before a regulatory agency. The courts in these cases are concerned about the proper court-agency division of responsibility for making decisions.

The allocation of decisional responsibility in cases where like matters come, or could come, before both courts and agencies has spawned a considerable volume of law. This law, under the respective headings of primary and exclusive jurisdiction, seeks to allocate decisional functions by determining either which tribunal may hear a matter, or which tribunal must hear all or part of a matter first before it may be taken up in a second forum.

Because of the costs involved, and the legal restraints and proclivities of different *fora*, decisions determining jurisdiction to hear a matter may determine its eventual outcome - or even whether it will be heard at all.

Like most legal doctrines, the doctrine of primary and exclusive jurisdiction has been developed through a series of judicial decisions seeking to balance conflicting needs and interests so as to reconcile several statutory schemes.[1, 2]

Until recently, the lessons of these decisions for future matters have been less than clear.

Exclusive jurisdiction defenses to antitrust complaints can be maintained in situations in which only a federal administrative agency has authority; and having acted, its actions can only be subjected to judicial review by direct appeal, not by collateral antitrust action.

See Gordon v. New York Stock Exchange, 422 US 659 (1975); U.S. v. National Assn. Securities Dealers, 422 US 694 (1975); Hughes Tool Co. v. T.W.A., 409 US 363 (1973); Pan American Airways v. United States, 371 US 296 (1963); and, Schwarzer, Regulated Industries and the Antitrust Laws - An Overview, 41 I.C.C. Prac. J. 543 (1974).[3]

These cases hold that the antitrust laws are repealed by implication but only when and to the extent necessary to permit schemes of regulatory acts to work. Silver v. New York Stock Exchange, 373 US 341 (1963) and cases, supra. Courts look to find either a pervasive regulatory scheme, Gordon, supra at 689, Otter Tail Power Co. v. U.S., 410 US 366, 373-75 (1973), or a specific statutory provision and regulation thereunder. Assn. Securities Dealers, supra; and cf., FMC v. Seatrain Lines, Inc., 411 US 726 (1973). The statutory provisions must be plainly repugnant to antitrust provisions (U.S. v. Philadelphia

National Bank, 374 US 321 (1963); Gordon, supra at 682; cf., Georgia v. Pennsylvania R. Co., 324 US 439 (1945)), or the regulation pervasive, National Assn. Securities Dealers, supra.

With the decision in Otter Tail, exclusive jurisdiction problems are unlikely to arise on the basis of assertions of "pervasive regulations" of electric utilities.[4] However, the issue could still be raised in regard to wholesale rates filed with the FPC. In that situation, the Courts limited retreat in the National Association of Securities Dealers case from its requirement of active regulatory supervision (not just statutory authority) voiced in Gordon and Seatrain, could prove difficult for plaintiffs.

Where a regulatory statute explicitly provides an antitrust immunity flowing from agency action, prior agency approval is usually required for immunization from antitrust prohibitions. Clayton Act, 15 U.S.C. §18 (1970); Coultas, "The Doctrine of Primary Jurisdiction: Determination of Express and Implied Immunity from the Antitrust Laws: 39 J. Air L. 559 (1973); Gordon, supra; and, Keogh v. Chicago & Northwestern Ry., 260 US 156 (1922).

Antitrust and other issues before courts sometimes involve issues of fact also relevant to matter before federal administrative agencies. The allocation of decisional functions between courts and agencies is treated generally under the doctrine of "primary jurisdiction".

"Primary jurisdiction...applies where a claim is originally cognizable in the courts, and comes into play whenever enforcement of the claim requires the resolution of issues which, under a regulatory scheme, have been placed within the special competence of an administrative body; in such a case the judicial process is suspended pending referral of such issues to the administrative body for its views." United States v. Western Pacific Railroad Co., 352 US 59, 64 (1956).

The doctrine of primary jurisdiction has been stated in United States v. Radio Corporation of America, 358 US 334 (1959), to have originated in the case of Texas & Pacific R. Co. v. Abilene Cotton Oil Co., 204 US 426, and to be grounded on the necessity for administrative uniformity, and per Justice Brandeis in Great Northern R. Co. v. Merchants Elevator Co., 259 US 285, 291, in the need for administrative skill "commonly to be found only in a body of experts" in handling intricate facts.[5] Also see, Far East Conference v. United States, 342 US 570, 574-75 (1952).

No fixed formula exists for application of the doctrine of primary jurisdiction. In every case the question is whether the reasons for the existence of the doctrine are present and whether the purposes it serves will be aided by its application in the particular litigation. United States v. Western Pacific Railroad Co., 352 US 59 (1956).

The basis of the doctrine in the argument for uniformity overlooks the fact that administrative agencies are, unlike courts, not bound by their prior decisional law. As to the argument of agency expertise, it should be noted that the Justice Department and the Federal Trade Commission are the expert agencies on antitrust matters (and are primarily prosecutorial rather than regulatory bodies), while the courts are the governmental bodies experienced in deciding such cases. California v. F.P.C., 369 US 482 (1962).

Davis, in his Administrative Law Treatise, §19.05 (1958), states:

> *** At the heart of the problem of primary jurisdiction in antitrust cases lies the choice of substantive policy in favor of either (1) enforced competition, (2) regulation, or (3) some mixture of enforced competition and regulation. In the fields for which Congress has provided a considerable amount of regulation, making this choice in particular contexts is often difficult.

However, the literature appears to use (or seek) a priori approaches to the doctrine, which is considered to be a confused one.[6]

While noting the notion of Federal Maritime Board v. Isbrandtsen Co., 350 US 481, 498 (1958), that practical considerations may dictate a division of functions between courts and agencies, under which the latter make a preliminary, comprehensive investigation of all the facts, analyse them, and apply them to the statutory scheme as it is construed, the literature does not discuss policy considerations of divisions of labor but turns largely on whether administrative jurisdiction exists. See, e.g., Coultas, "The Doctrine of Primary Jurisdiction: Determination of Express and Implied Immunity from the Antitrust Laws", 39 J. Air L. 559 (1973) and matter therein cited; Schwarzer, "Regulated Industries and the Antitrust Laws -- An Overview", 41 I.C.C. Prac. J. 543 (1974).

> *** What is at stake in terms of the primary jurisdiction doctrine is that the resolution of the question of which law applies be properly allocated between the two tribunals, so that the location of the interface between the antitrust and regulatory statutes be decided in the most efficient, orderly, and equitable manner. Less a manner of substantive law than of judicial administration, procedure, and esthetics, it is yet of compelling importance to court, agency, and litigants.

Kestenbaum, "Primary Jurisdiction to Decide Antitrust Jurisdiction: A Practical Approach to the Allocation of Functions", 55 Geo. L. J. 812, 814 (1967).

As noted by Kestenbaum, much of the writing in this area concerns the location of the boundary between antitrust jurisdiction and antitrust immunity in specific cases under specific statutes. Confused merging of the question of jurisdiction with repeal of antitrust laws is noted -- e.g., as arising in cases where the court, after finding jurisdiction in the courts, proceeds to discuss primary jurisdiction, even though recourse to an agency lacking jurisdiction would be futile. An agency should not be asked to decide issues unless the issues are material to the question of antitrust immunity and unless the agency can contribute something substantial to their resolution. Id., and see Otter Tail Power Co. v. United States, 410 US 366 (1973) (lack of FPC jurisdiction); Jaffe, "Primary Jurisdiction", 77 Harv. L. Rev. 1037, 1043-47 (1964); cf. Ricci v. Chicago Mercantile Exchange, 409 US 289 (1973). In Ricci v. Chicago Mercantile Exchange, 409 US 289, 34 L. Ed. 2d 525 (1973), a proceeding under Section 1 of the Sherman Act, 15 USC §1, was stayed pending administrative proceedings deemed available under the Commodity Exchange Act, 7 USC §1 et seq. Administrative proceedings were pending, and their institution was a matter of administrative discretion. Upon a proceeding, the agency could order that the complained of action be ceased.

The complaint alleged that plaintiff was deprived of his membership on a commodity exchange contrary to the rules of the exchange, the Commodity Exchange Act and pursuant to an anti-competitive conspiracy.

> "The problem to which the Court of Appeals addressed itself is recurring. It arises when conduct seemingly within the reach of the antitrust laws is also at least agreeably protected by another regulatory statute.... (footnote omitted). Id. at 299-30."

The Ricci court held that a stay was appropriate when three premises are found to pertain:

(1) the regulatory scheme is somewhat incompatible with the maintenance of an antitrust action;

(2) some facet of the dispute in the case is within the agencies jurisdiction; and

(3) adjudication of the dispute by the agency promises to be of material aid in resolving the immunity question.

It was held that the issue of whether the action complained of was done pursuant to a valid rule must be first addressed before the question of implied immunity can be reached (409 US 303-04). Furthermore, the Court sought to obtain the assistance of the agency's superiority in gathering the relevant facts and in marshalling them into a meaningful pattern -- citing Fed. Maritime Bd. v. Isbrandtsen Co., 356 US 481 (1956).

After Ricci, the law appears to remain that where the activity challenged is not "arguably lawful" under a regulatory scheme, reference of issues to an agency is not appropriate. Carnation Co. v. Pacific Westbound Conf., 383 US 213 (1966); Kestenbaum article, supra, at 823-25; Coultas article, supra, at fn. 54.

In spite of the delays occasioned by occasional references to agencies, the case law does reflect an intention to require antitrust aspects to be considered, either by refusing to allow courts to be ousted of jurisdiction (California v. F.P.C., 369 US 482 (1962); United States v. Philadelphia National Bank, 374 US 321, 350-351 (1963); Seatrain Lines, Inc. v. F.M.C., 411 US 726 (1973)), or by requiring agencies to consider antitrust aspects (see, e.g., Gulf States Utilities Co. v. F.P.C., 411 US 747 (1973), F.M.C. v. Svenska Amerika Linien, 390 US 238, 245 (1968); Conway, supra.

Northern Natural Gas Co. v. F.P.C., 399 F.2d 953 (CADC, 1968)[8], Marine Space Enclosures, Inc. v. F.M.C., 420 F.2d 577 (CADC, 1969), Stickells, Antitrust Laws (1972), at §527-35.

In "Judicial Doctrine of Primary Jurisdiction as Applied to Antitrust Suits", Staff Report to Subcommittee No. 5, House Judiciary Committee (1957), the authors call for an end to the use of the doctrine of primary jurisdiction in cases where the United States sues "in vindication of policies whose enforcement Congress has expressly reposed in the Attorney General through resort to the courts. The sole reliable counterweight to industry-mindedness of specialized agencies is provided by this mandate to the unspecialized law enforcement agency." And cf. Schwartz, "Legal Restriction of Competition in the Regulated Industries: An Abdication of Judicial Responsibility", 67 Harv. L. Rev. 436, 464-71 (1954).

Several legislative measures attempt to improve agency antitrust policy enforcement by mandating a role for the Department of Justice in licensing or merger proceedings. See, e.g., Atomic Energy Act §105 (42 U.S.C. 2135 (c)), and the Bank Merger Act, 12 U.S.C. §1828.[9]

Aggrieved parties having access to federal courts are far more likely to achieve redress of antitrust grievances than parties confined to administrative agencies. As noted by the four dissenting Justices in Ricci, access to be effectual must be timely. The expense and delay of a prior administrative proceeding are more than many persons and enterprises can bear. The anti-competitive tendencies of administrative agencies are well-documented. See Report of the Senate Judiciary Committee, Competition Improvements Act of 1976, S.2028, Report No. 94-1045, 94th Cong., 2d Sess. (1976).

The rule of California v. FPC, that primary responsibility for trying antitrust cases is in the courts is essential if remedies are to be practically afforded.

State Action Defense

Antitrust claims are sometimes defended on the grounds that the action complained of was taken pursuant to the mandate of state law.

This defense reflects an effort by the courts to reconcile apparent conflicts between federal antitrust law and state regulation. It serves a decision allocating role, and is parallel in that respect to the doctrine of primary jurisdiction. As an attempt to balance state and federal law it is anomalous to the general supremacy of federal enactments in areas of conflict with State law.

This anomaly is derived from the legislative intent of the Sherman Act.

The state action doctrine has been raised against attacks on anticompetitive practices for which tariffs were filed. See, Canter v. The Detroit Edison Company, US (July 6, 1976); Gas Light Co. v. Georgia Power Co., 440 F.2d 1135 (CA 5, 1971), cert denied, 404 US 1062 (1972); and, Washington Gas Light Co. v. Virginia Electric & Power Co. 438 F.2d 248 (CA 4, 1971); and see Mazzola v. Southern New England Telephone Co., 1975 Trade Cases 66926 (Conn. Supr. Ct. August 19, 1975) (and telephone cases cited therein).

The doctrine which traces its origin to the case of Parker v. Brown, 317 US 341 (1942), has been subjected to narrowing in recent cases. It is applicable only insofar as the action taken was mandated by action of a state in its sovereign capacity, and not merely prompted. Goldfarb v. Virginia State Bar, 421 US 773, 446 Ed 2d 572 (1975). Under the recently decided Cantor case, supra, the Supreme Court examined the doctrine.[10]

In this case, the court was concerned about (a) the fairness of holding a citizen to obeying a federal law in disobeyance of the command of state law, and (b) whether Congress intended to supervene state regulation.

The first concern was rejected as contrary to the basic effect of antitrust law and precedent even in the event of government participation, Continental Ore Co. v. Union Carbide and Carbon Corp., 370 US 691. The Cantor court noted the active role played by utilities in initiating rate practices. "Nevertheless, there can be no doubt that the option to have, or not to have, such a program is primarily respondent's, not the Commission's." Ibid. This statement corresponds to the requirement of Goldfarb, supra, that more than passive state approval or even prompting is required.

State regulation was held to not, a priori, ousting the applicability of 11
antitrust law. It was noted that regulation and antitrust may be consistent. Even with inconsistency, antitrust laws remain applicable in essentially unregulated areas such as the market for light bulbs, and exemptions are not lightly implied elsewhere.

The standards for determining the existence and scope of an implied exemption because of conflict between state regulation and federal antitrust policy "must be at least as severe as those applied to federal regulatory legislation."

"The Court has consistently refused to find that regulation gave rise to an implied exemption without first determining that exemption was necessary in order to make the regulatory act work "and even then only to the minimum extent necessary."

The Cantor decision was accompanied by two concurrences, and a dissent by three justices. The plurality opinion, in a section concurred in by the majority, would restrict the state action defense to state officials; one concurring Justice stressed the ancillary nature of the practice attacked; one Justice in concurring urged that a test be applied in which the benefit of state sanctioned anticompetitive activity would be weighed against its potential harm. Ibid.

The appraoch taken in Cantor restricting the state action to cases reconcilable with federal antitrust policy where the two are in conflict[12] was presaged by several court decisions limiting the doctrine. In Woods Exploration & Production Co. v. Aluminum Co. of America, 438 F.2d 1286 (CA 5, 1971), cert denied, 404 US 1047 (1972) it was held that regulatory decisions based on false information supplied by defendants create no defense. In a series of cases it was held that the defense may not stand in the absence of a clear statement by a state of its intention to preclude competition. Traveler's Ins. Co. v. Blue Cross, 298 F. Supp. 1109 (W.D. Pa. 1969); Geo. R. Whitter, Jr., Inc. v. Paddock Pool Builders, Inc., 424 F.2d 25 (CA 1), cert denied, 400 US 850 (1970); and, cf., Hecht v. Pro-Football, Inc., 444 F.2d 931 (CADC, 1971), cert denied, 404 US 1047 (1972).[13] In International Telephone and Telegraph v. G.T. & Elec., 351 F.Supp. 1153, 1202 (D. Hawaii, 1972) prior commission approval of an ownership structures was held not dispositive when antitrust issues were not addressed.

The defense of prior state action is only available when the state regulatory program is not contrary to constitutional limits on state action. U.S. Const. art. VI, Cl. 2.

This analysis consists of first identifying the field in which the challenged state action operates or has its effects and determining whether there is a federal policy in that field.[14] Rice v. Santa Fe Elev. Corp., 331 US 218 (1947).

Second, the court must determine if the federal policy was intended to be exclusive. See Hines v. Davidowitz, 312 US 52 (1941); or if national conformity is necessary, see e.g., Burbank v. Lockheed Air Terminal, Inc., 411 US 624 (1973); Perez v. Campbell, 402 US 637 (1971); Huron Portland Cement Co. v. Detroit, 362 US 440 (1960); Rice, supra; Hines, supra, or if federal regulation of the area is pervasive.[15]

If an area is not totally preempted, the court then determines if the state program stands as an obstacle to the attainment of a Congressional objective. Fla. Lime & Avocado Growers, Inc. v. Paul, 373 US 132, 141 (1962).

Thus constitutional preemption encompasses both areas essentially federal, and areas subject to federal regulation.[16] However, where federal antitrust policy has been construed as not ousting state regulatory jurisdiction, Cantor, supra, the two legislative schemes must be conformed or accommodated to one another.

In electric utility matters, federal antitrust and regulatory policy apply.

Federal regulatory policy clearly perceives a role for state regulation. The Public Utility Act provided for joint federal-state regulatory proceedings,[17] and gave the states a major role in determining the structure of utility systems primarily operating within one state. However, the 1935 statute setting out basic federal utility regulatory policy, written when interstate power pooling was far rarer than today, clearly foresees interstate commerce operations governed by federal law;[18] 15 USC §79 (a)(i); SEC v. New England Electric System, 384 US 176 (1966); under a national policy of free and independent competition, id., and see Gulf States Power Co., supra.

The 1935 Act does not provide for bulk power supply franchising. Federal power policy, embodied in earlier and later legislation pertaining to federal power marketing and nuclear licensing, recognizes that the aims of competition and regulation can be mutually supportive. It has been specifically held that territorial allocations of bulk power supply trade are contrary to the Sherman Act.[19]

Litton Systems, Inc. v. Southwestern Bell Telephone Co., 1976-2 Trade Cases para. 61,084 (CA 5, September 23, 1976) is a recent example of induced efforts to accommodate state regulatory and antitrust policy. There the doctrine of primary jurisdiction was held to be inapplicable, and prior reference to state agencies was held to be improper in a case involving allegations of unlawful tying and predatory pricing of a package of telephone branch exchange equipment and telephone service. The court noted that the case did not involve a situation where the suit ought to have been prosecuted exclusively or initially before an administrative body, and as regards the latter point it noted that the case did not present the need, found in Ricci, to accommodate federal antitrust policy with federal regulatory policy. The court, however, did not end its consideration of the propriety of requiring prior reference to state agencies at this point. Rather, it went on to consider the Ricci tests for prior agency reference in light of the possibility that the doctrine of Parker v. Brown might require deference to state agencies.

To determine whether the purpose served by the doctrine of primary jurisdiction would be aided by its application, see United States v. Western P.R.R., 352 US 59 (1956), the court inquired as to whether state law was incompatible with the maintenance of an antitrust action, whether some facets of the matters in dispute are within state regulatory jurisdiction, and whether adjudication of such disputes promises to be of material aid in resolving the immunity question.

The court found that no useful purpose would be served by requiring prior reference to state agencies. This is the case because it is Bell's conduct that is being challenged, not the conduct or policy of any state agency or official. The system being attacked was devised by Bell which then garnered near-automatic approval from the state agencies. Thus a failure to grant immunity from antitrust actions would not be unfair to Bell, Cantor v. The Detroit Edison Company, 1976-1 Trade Cases para 60,947, U.S. 96 S.Ct. 3110 (1976), since its tying activities were not the product of regulatory coercion, and secondly, since ending the tying relationships would not undermine state regulation (and therefore in inconsistent state and Sherman Act regulation).

The state regulatory agencies, by their silence with respect to the issue before the court, "have 'spoken' once, and the laudable goal of 'judicial accommodation' would become a nightmare of judicial paralysis were we now to force the agencies to suggest reasons why the tying *** may be necessary to the regulation of that service."

The court found that the district court would not be incapacitated in the absence of the assistance of state "expertise." In regard to the possible need to implement the district court's decree through the filing of tariffs with state agencies, the court found no significant problem:

> The district court's order here could simply direct the defendant to file satisfactory tariffs with the state commissions and retain jurisdiction pending the agencies' consideration of the new tariffs. If the tariffs without the tying provisions are rejected, the district court would then be able to decide anew whether implied antitrust immunity exists. State officers enforcing the regulatory schemes could be joined as parties-defendant at this point in the proceedings.

The goals of the federal antitrust laws are to encourage efficiency and low prices and to hold economic power in check. Where available, competition works better than regulation to achieve these goals because it operates swiftly, because it rewards skills and innovation, and because it returns profits to those who produce what the public wants and buys. While competition is not a spur in the relatively few "natural monopolies" there is still a very large part of the regulated sector where competition can serve as an effective spur to efficiency and innovation.[20]

The state action doctrine, accordingly, should be limited to matters in which the action is complementary to the pro-competitive policy of federal antitrust and utility law. Restraints on trade should not be permitted where alternative means exist to achieve a goal.

The Cantor decisions, while advancing antitrust law from a state of confusion in which one court indicated that filed tariffs, per se, confer immunity, Washington Gas Light, supra, leave important questions unanswered.

The outcome of disputes regarding limitations on state filed tariffs restricting industrial self-generation or permitting anti-competitive rate levels and rate structures is unclear. Disputes may also arise in the context of state certifications to build bulk power facilities.

The defense of prior state action does not seem appropriate in proceedings regarding planning and access to bulk power supply facilities. Utilities operate as part of an interstate flow of electricity and other trade. They best function as part of groups whose plans and operations do not stop at state lines. The economic regulation of a multi-state grid is beyond the capability of state agencies.

There is no unfairness due to retroactivity in requiring that these prospective actions be carried out in a competitive manner. There is no reason why costs of related service could not be recovered, protecting utility investment. If such services are priced at their costs, and customers can choose between buying or generating, society is better off. Avoiding or reducing load growth no longer presents a "cream skimming" problem:[21] customers benefit from reduced construction budgets, expedited development of innovative small source technology. The growth of plant sizes, if affected, will not be likely to harm customers since economies of scale are questionable beyond current unit sizes which are being replicated, not increased. Furthermore, if unit power sales are offered in competition with geothermal energy, economic growth of unit sizes will not be adversely affected. Customers may expect competition for service to large loads to hold down general operating costs.

State action restricting sales to retail customers -- except in certified or franchised service areas, would present a barrier to any putative new power supplier. Restricting bulk sales -- e.g., to industrial or large commercial users burdens the interstate commerce in which high voltage lines operate and does not serve a valid purpose: protecting loads of gas and oil-fired systems from geothermal competition would not be in the public interest. Geothermal entrants could mount a serious challenge against such trade restrictions.

Defense of Foreign State Action

Antitrust jurisdiction is asserted over the subject matter where the domestic or foreign commerce of the United State is substantially affected.[22]

Actions attacked may occur outside of the United States,[23] may involve foreign as well as domestic firms or associations,[24] and may be entered into here[25] or abroad.[26]

Most cases have involved restrictions on exports,[27] and their marketing.[28] Others have dealt with restraints on transportation.[29] The courts have been more likely to find an effect on U.S. domestic or foreign commerce if a U.S. firm is involved.[30]

A foreign company may be a party to a restraint of trade by a United States company by virtue of its contractual relationships with other U.S. firms where the foreign company knew or should have known that its activities were a substantial contribution to an illegal plan in the U.S. markets and that its activities had a direct and substantial effect upon trade.[31]

Personal Jurisdiction

For a court to have jurisdiction over a person, that person must be amenable to service and service must in fact be made.

A foreign firm is amenable to service if it is carrying on business of any substantial character in a judicial district into which the U.S. is divided up.[32]

If found in this country, a defendant may be served at its home office abroad.[33]

Special Defenses

In foreign trade matters, special problems arise in regard to participation by governments in business ventures and in regard to conflicting mandates of foreign law.

A foreign sovereign is generally immune from suit, without its consent, in U.S. courts.[34] Generally, where a foreign government participates in a business venture on a commercial basis the defense of sovereign immunity does not apply.[35] An exception to this general rule may be found where a foreign government participates in a commercial venture for national security purposes.[36]

In the event that a complained of act involves the action and motives of a foreign government acting in its sovereign capacity in its country, U.S. courts will not hear the case.[37]

Thus portions of complaints dealing with government actions regarding international boundaries and petroleum concessions have been dismissed.[38] The related actions of private firms giving rise to contractual disputes or to other restraints of trade remain actionable.

Compulsion by a foreign government of a locally incorporated subsidiary constitutes a defense.[39] Likewise, a decree will only be enforced as regards foreign matters to the extent permitted in loci forii.[40]

However, agreements made by a U.S. firm with foreign firms to restrict imports to the United States are not protected by the authorization or acquiescence of a foreign government.[41]

Similarly, the delegation of discretionary power by a foreign government is not a defense.[42]

Even in the event of actions taken pursuant to foreign government direction, actions taken in the United States commerce are not immune.[43, 44]

Joint Ventures and Mergers

Under the U.S. antitrust law, mergers tending to substantially lessen competition are prohibited. These prohibitions apply to acquisitions involving foreign firms as acquiring or acquired parties.[45] They also apply in the case of mergers of U.S. subsidiaries of foreign firms.[46]

Joint ventures among competitors or potential competitors have been a subject of concern under American antitrust law.[47]

Some joint enterprises have been attached as market division schemes.[48]

Allegations have been made that U.S. antitrust law, particularly as it pertains to joint ventures, weakens the ability of U.S. firms to trade abroad. The Justice Department which together with the Federal Trade Commission, is charged with enforcing basic antitrust laws, has denied these allegations.[49]

The Justice Department has also questioned the usefulness of the Webb-Pomerance Act which provides a limited exception from antitrust law for associations for foreign trade registered with the Federal Trade Commission operating per approved bylaws and not attempting to set prices or fix output levels.[50]

Conclusion

The increasing importance of international trade, and the substantial involvement of governments in such commerce may be expected to gradually lead to a balancing-of-interests test to determine the appropriate choice of laws. At present sovereign actions of a state within its borders are not attackable in U.S. courts[51] while actions of private firms are if the actions are directed to and have a substantial U.S. impact.[52]

In this regard, American courts will assert jurisdiction over a firm if as a practical matter the firm carries on a business -- directly, through an agent or through a closely directed subsidiary -- in the United States. The U.S. government has taken an apparently lenient attitude toward overseas joint ventures. However, joint ventures allocating trade and territories may be prosecuted.

FOOTNOTES

[1]*A priori* rules are sought through a series of *ad hoc* and *post hoc* determinations.

[2]The problem of overlapping jurisdiction among federal agencies has usually been treated as a political problem in the absence of conflicting agency actions. However, recently the Federal Trade Commission was held to be collaterally estopped from seeking to investigate data relating to trade association estimated proved reserves because the Federal Power Commission, per the Court, had determined that the data was reliable. *FTC* v. *Texaco*, F.2d , CADCC No. 74-1551 (August 8, 1975).

[3]In connection with judicial review, two relevant and much-discussed doctrines are "ripeness" and "exhaustion of remedies". The doctrine of ripeness means simply that to obtain judicial review of administrative action, the effect of that action on the party seeking review must be sufficiently concrete, and the question sufficiently clear for judicial review. *Abbott Laboratories, Inc.* v. *Gardner* 387 US 136; *Toilet Goods Ass'n* v. *Gardner*, 387 US 158; and, *Garner* v. *Toilet Goods Ass'n*, 387 US 167; *Bantam Books* v. *Sullivan*, 372 US 58 (1963). The exhaustion-of-remedies doctrine performs a similar "traffic cop" function for judicial caseloads, and by requiring a full use of existing administrative remedies before judicial appeal, reflects *a priori* Congressional allocations of workload. *McKart* v. *United States*, 395 US 185 (1969).

[4]A district court has rejected this defense in an oil pricing case in which pervasive FEA regulations was asserted.

[5]A good historical discussion of the doctrine of primary jurisdiction is found in Convisser, "Primary Jurisdiction: The Rule and its Rationalizations", 65 Yale L.J. 315 (1956). This article generally casts doubt on the validity of the doctrine as well as its practical value.

[6]See, e.g., Kestenbaum, "Primary Jurisdiction to Decide Antitrust Jurisdiction: A Practical Approach to the Allocation of Functions , 55 Geo. L.J. 812 (1967).

[7]The Ricci Court noted that there was no Congressional intent to confer general antitrust immunity in the relevant area; the Act contains no categorical exemption, and the Administrative authority is not particularly focused on competitive considerations. Cf., California v. FPC, supra. 409 US at 302, fn. 13.

[8]This case also highlights the need for coordination between the SEC and the FPC.

[9]The Bank Merger Act provides for de novo antitrust review by district courts at the behest of the Justice Department after approval of mergers by the Federal Reserve Board. 12 USC 1879. Cf., U.S. v. Citizens National Bank, 422 US 86, 45 L. Ed. 2d 41 (1975).

[10]Cantor, a retail druggist selling light bulbs, alleged that defendant is using its monopoly power in the distribution of electricity to restrain competition in the sale of bulbs. Defendant distributes light bulbs at no separate charge to its customers -- thereby foreclosing a market. The bulbs distribution program had long been in tariffs filed with the Michigan Public Service Commission.

[11]There is no logical inconsistency.

[12]In regard to this approach see Note on Parker v. Brown: A Preemptive Analysis, 84 Yale Law Jour. 1164 (1975) which urges that state action be permitted to stand only if it serves to protect the interests forwarded by antitrust policy; low prices, efficient resource allocation, and protection of small firms. Also see, Posner "The Proper Relationship Between State Regulation and the Federal Antitrust Laws," 49 NYU L. Rev. 693 (1974).

[13]This requirement of a clear statement was criticized in a concurring opinion by Justice Blackman in Cantor who suggested that it neglect situations where a statement was deemed unnecessary due to obvious need.

[14]As explained in Note: Parker v. Brown, A Preemption Analysis, supra.

[15] See, Note on Federal Preemption of State Laws; The Effort of Regulatory Agency Attitudes on Judicial Decision Making. 50 Ind. Law Journ. 848 (1975). It is suggested that the attitude of the agency having jurisdiction in the field in question heavily influences the judicial outcome of preemption decisions.

[16] State regulation can also be preempted by federal procurement policy. United States v. Ga. Public Service Comm., 371 US 2851 (1963).

[17] Section 209, Federal Power Act, 16 USC 824(h).

[18] The Federal Power Act, part of the 1935 enactment, was preceded by the Supreme Court's decision in Public Utilities Commission v. Atteboro Steam & Electric Co., 273 US 83 (1927) that a state attempt to regulate the sale of electricity from a Massachusetts plant to a Rhode Island utility imposed an unconstitutional direct burden on interstate commerce.

[19] Pennsylvania Water & Power Co. v. Consolidated Gas, Elec. Light & Power Co., 184 F.2d 552 (CA 4, 1950).

[20] Baker, Competition and Regulation: Charles River Bridge Recrossed, 60 Cornell L. Rev. 159 (1975).

[21] As noted by Baker, supra, one class of service should not be called upon to subsidize another. Competition increases the availability of opportunities for joint action to reduce costs -- i.e., open pooling.

[22] The farthest statement of the point is found in the Alcoa case. "It is settled law that any state may impose liabilities, even upon persons not within its allegiance, for conduct outside its borders that has consequences within its borders which the state apprehends. United States v. Aluminum Co. of America, 148 F.2d 416 (CA 2, 1945).

[23] Continental Ore Co. v. Union Carbide and Carbon Corp., 370 US 69, 1962 Trade Cases 70362 (1962).

[24] United States v. Watchmakers of Switzerland Information Center, 63 Trade Cases 70600, (D.C.N.Y. (1962)); OCCF, FTC Docket 6106 (exclusive supply contract between domestic scrap dealers and office for European steel mills.)

[25] Timken Roller Bearing Co. v. United States, 341 US 593, 1950-51 Trade Cases 62837 (1951).

[26] Hazeltine Research, Inc. v. Zenith Corp., 239 F. Supp. 51 (N.D., Ill., 1965), 65 Trade Cases 713 55; rev'd on other grounds, 388 F.2d 25 (CA 7, 1967), 1967 Trade Cases 72310, rev'd 395 US 100, 1969 Trade Cases 72800 (1969); vacated 418 F.2d 212, 1969 Trade Cases 72849 (CA 7, 1969).

[27] Hazeltine, supra.

[28] United States v. Minnesota Mining and Manufacturing Co., 92 F. Supp. 942, 1950-51 Trade Cases 62687 (D. Mass., 1950); United States v. Gulf Oil Co., 1960 Trade Case, 69851 (D.C.N.Y., 1950); and, United States v. Anthracite Export Ass'n., 1970 Trade Cases 73348 (D.C. P.A. 1970).

[29] United States v. Pacific and Arctic Railway and Navigation Co., 228 US 87 (1913); and, Pacific Seafarers, Inc. v. Pacific Far East Line, Inc., 404 F.2d 804 (D.C. Cir., 1968), cert. denied, 393 US 1093 (1969).

[30] Fugate, Foreign Commerce and the Antitrust Laws (rev'd ed. 1973). A foreign firm only needs a general intent to act so as to affect U.S. commerce, if affects occur.

[31] United States v. General Electric Co., 82 F. Supp. 753 (D.C.N.J., 1949) 1948-49 Trade Cases 62353.

[32] United States v. Scophony Corp., 333 US 795 (1948). Venue lies in any district, 28 U.S.C. 1391 (d); Brunette Machine Works, Ltd. v. Kockum Industries, Inc., 406 U.S. 706 (1972).

[33] International Ford Tractor Sales Co. v. Massey-Ferguson, Ltd., 210 F. Supp. 930, 939 (D. Utah, 1962), aff'd per curiam, 325 F.2d 713 (CA 10, 1963); Fed. Rules of Civil Procedure 4(i).

[34] Banco Nacional de Cuba v. Sabbatino, 376 U.S. 398 (1964) (Act of State doctrine).

[35] United States v. Deutshes Kalisyndikat Gesellschaft, 31 F.2d 199 (S.D.N.Y., 1929); In re Grand Jury Investigation of the Shipping Industry, 186 F. Supp. 298 (D.D.C., 1960).

[36] In re Grand Jury Investigation of World Arrangements with Relation to Production, Transp. Ref., and Distrib. of Petroleum, 13 F.R.D. 280 (D.D.C., 1952) (subpoena quashed when Anglo-Iranian Oil Company asserted it had been ordered by British Government not to produce documents not located in U.S. and not related to business transacted in U.S.). When the successor British Petroleum Company acquired control over Standard Oil Co. (Ohio), the U.S. government resisted the mergers and a settlement requiring partial divestiture was made. United States v. Standard Oil Co., 1970 Trade Cases 72988 (N.D., Ohio, 1970).

[37] Occidental Petroleum Corp. v. Buttes Gas and Oil Co., 1971 Trade Cases 73525, 331 F. Supp. 92 (C.D., Ca. 1971), aff'd per curiam, 461 F.2d 1261 (CA, 9), cert. denied, 409 U.S. 950 (1972); and, Hunt v. Mobil Oil Corp., 1975-2 Trade Cases 60591 (S.D.N.Y., 1975).

[38] Hunt, supra. (The parts of the complaint pertaining to a sharing and sales agreement among Libyan producer-concessioners was not dismissed.)

[39] Interamerican Refining Corp. v. Texaco Maracaibo, Inc., 307 F. Supp. 1291, (D. Del, 1970).

[40] United States v. Imperial Chemical Industries, Ltd., 105 F. Supp. 215 (D.C.N.Y., 1952) 1952 Trade Cases 67282; United States v. General Electric, 115 F. Supp. 835 (D.C.N.Y., 1953) 1953 Trade Cases 67576; and United States v. Watchmakers of Switzerland Information Center, Inc., 1965 Trade Cases 71352 (S.D.N.Y., 1965) and 1965 T.C. 80491.

[41] United States v. R.P. Oldham Co., 152 F. Supp. 818 (N.D., Ca., 1957) 1957 Trade Cases 68790 (conspiracy in Japan, and lawful there, among five U.S. importers of wire nails, an American subsidiary of a Japanese nail exporter, and a number of Japanese firms).

[42] Continental Ore Co. v. Union Carbide and Carbon Corp., 370 U.S. 690 (1962).

[43] Sabre Shipping Corp. v. American President Lines, Ltd., 285 F. Supp. 949 (S.D.N.Y., 1968), 1968 Trade Cases 72493.

[44] The recently enacted Foreign Sovereign Immunities Act, Public Law 94-583, 90 Stat 2891 limits immunity of foreign governments to commerce activities having direct affects on the United States or carried out in the United States. 28 USC 9605. The Act does not change the law regarding actions of nongovernment entities.

[45] United States v. Standard Oil (Ohio), 1970 Trade Cases 72988 (N.D. Ohio, 1969) (consent decree on British Petroleum acquisition of control of Sohio); United States v. Asiatic Petroleum Corp.; 1971 Trade Cases 73689 (D. Mass., 1971) (Royal Dutch Shell Co. subsidiaries acquisition of oil distributor: consent decree); United States v. Schlitz Brewing Co., 253 F. Supp. 129, aff'd, 385 U.S. 375 (1966), (acquisition of Canadian brewer); and In re Litton Indus., Inc., FTC Docket 8778 (April 10, 1968).

[46] U.S. v. CIBA Corp., 1970 Trade Cases 73269 (S.D.N.Y., 1970).

[47] United States v. Penn-Ohio Chemical Co., 378 U.S. 158, 12 L. Ed 2d 775 (1964); and United States v. Monsanto Co., 1967 Trade Cases 72001 (D. Pa., 1967), (divestiture ordered in joint venture of Monsanto and Bayer).

[48] Swiss Watchmakers, supra; Timken, supra; Minnesota Mining and Manufacturing, supra; and, United States v. Imperial Chemical Industries, Ltd., supra.

[49] See appended Department of Justice letter of April 26, 1974.

[50] A 1972 "Memorandum of the Department of Justice Concerning Antitrust and Foreign Commerce" is appended. The Webb-Pomerano Act is found at 16 UCA 61-65; the basic US antitrust laws are found in Title 15 of the United States Code.

[51] Save for expropriations of property.

[52] The problem of conflicting foreign law is somewhat paralleled by problems arising when state laws conflict with the pro-competitive thrust of federal antitrust law. When State laws restrain trade the courts have held that they are not necessarily preempted by federal antitrust law. The lead case in this regard is Parker v. Brown, 317 U. 5341, 87 L.Ed 315. The ability to raise a state law defense to a complaint grounded in the federal antitrust law has been closely limited in recent cases. Cantor v. Detroit Edison Company, U.S. , 49 L.Ed 2d 1143 (1976).

APPENDIX E

INFORMATION ON ENTERPRISES IN GEOTHERMAL ENERGY

The following is a brief run-down of activity by various firms as of 1975. While this run-down may not be complete, it does indicate the types of activities geothermal enterprises engage in.

Aerojet Nuclear

Aerojet has been active in Idaho. It acts as a contractor for ERDA on the Raft River Electric Cooperative Project.

Amax

This firm, in which Standard Oil Company of California recently acquired a controlling interest, has actively leased tracts in a number of states. Amax holds 300,000 acres of geothermal prospect lands including fee lands southeast of the main Geysers production area. It is reported to be the third largest land owner at the Geysers. It also has a projection in Napa County.

Amax participated in an unsuccessful joint venture well in Arizona, and has a joint venture with Petro Lewis in Colorado near its Climax molybdenum mine and mills.

Amax has state leases in Oregon and New Mexico. It has also entered into a joint enterprise under which it may obtain an interest in tracts in Oregon and Washington, upon completion of exploration work.

rican Thermal Resources

American Thermal Resources (ATR) holds leases in California and Nevada otalling approximately 51,000 acres. The duration of the leases vary, but each may be extended beyond its primary term if a producing well is completed on the acreage. All leases include a 10% landowner's royalty. ATR has filed lease applications for approximately 23,200 acres of federal land in California and Nevada.

ATR has engaged in joint ventures with Chevron, Dow, Mapco and Gulf, the latter resulting in a "cold" hole drilled by Gulf in Surprise Valley, California.

A summary of ATR's leaseholding, as found in its registration statement filed for the year 1974, is 19,734 acres in California and 31,106 acres in Nevada. Some leases expire if successful drilling does not occur by a date certain. Annual rents were usually under $2 per acre per year.

Anschutz Corporation & Nancy Anschutz

In 1973 Anschutz completed a review of 1,250 prospects in twelve Western States. It then entered a leasing program in the States of Idaho, Colorado, New Mexico, Nevada and Oregon. Anschutz has talked to several utilities concerning the possibility of establishing joint ventures. Additionally, Anschutz is involved in a joint venture with Gulf Oil Corporation.

Anschutz holds five federal leases in Colorado, three in Idaho and eight in Nevada. Nancy Anschutz holds seven federal leases in Idaho. Anschutz has drilled one well in Idaho.

Austial Oil Company

Austial holds about 10,000 acres of geothermal prospect lands in Colorado.

Burmah Oil & Gas Co. (Aminoil)

Burmah properties, acquired from Signal Companies, have in turn been acquired by Aminoil, and affiliate of R.J. Reynolds Company. Burmah holds four federal leases in California and four in Nevada. Burmah is drilling jointly with Pacific Energy Company in an area dedicated to PG&E. In its 1974 Annual Report, Burmah states that four of five steam wells drilled in California were successful, making a total of 13 wells completed. Burmah Oil and Gas Co. was recently sold to R.J. Reynolds Co., a holding company with large oil producing interests ("Aminoil").

California Geothermal, Inc. (CGI)

California Geothermal, Inc. is owned by the Canada Oil Group which consists of: Albany Oil and Gas, Canada N.W. Sand, Francona Oil and Gas, Siebers Oil and Gas and TransCanada Resources. CGI holds approximately

500,000 acres distributed in California, Idaho, Nevada, Oregon and Washington. CGI has filed for an additional 506,000 acres of federal lands.

Chevron Oil Company (Standard Oil of California)

In its 1975 Annual Report, Standard Oil of California states that it had leased or applied for geothermal bases on 250,000 acres. Presently, Chevron holds leases on federal lands as follows: Colorado (1), Nevada (9), Oregon (5) and Utah (5). In various locations it has joint ventures with Geothermal Resources, Inc., American Thermal Resources, Utah International, Mountain States Resources, Dow and Phillips, the latter stemming from acreage abutment. Chevron has drilled two wells as of 1975.

Dow Chemical Company

Dow has joint ventured with Chevron and ATR at "Beowawee" in Nevada. Dow holds one federal lease in California and seven in Idaho. Dow is a significant shareholder in Magma Power Company.

Dowdle Oil

Dowdle Oil holds 10,000 acres in Klamath County, Oregon.

Geothermal Kinetics, Inc.

Geothermal Kinetics, Inc. (GKI) is a subsidiary of United Siscoe of Canada Mines. GKI has leased several million acres in the West and holds federal leases in Colorado (4) and Utah (3). GKI has engaged in joint ventures with Amax, Arizona Public Service Company, the Salt River Project, and Tucson Gas & Electric (The Chandler Project). In addition to those joint ventures in Arizona, GKI is engaged in a joint venture with Anaconda which encompasses the State of Montana. GKI has drilled one well in Utah and two in Arizona.

Geothermal Power Corporation

Geothermal Power, through its affiliate, Kelly Hot Springs, has a joint venture with Natomas Company in Modoc County, California. Geothermal Power holds leases in New Mexico and Utah.

Geothermal Resources International, Inc.

GRI reported in 1974 that it leased, in whole or in part, 20,705 acres and, in addition, holds preference rights on approximately 1,000 acres of federal land. GRI's leases generally have terms of two to ten years and for so long thereafter as steam is produced and sold. All of the leases require drilling within nine months to ten years; or the lessor may terminate.

GRI has been engaged in a number of joint ventures, drilling seven wells with Occidental and one with Natomas. GRI states in its 1974 Annual Report:

> "Because of the substantial expense involved in drilling for steam and time delays encountered by environmental considerations, the Company has not in the past three and one-half years undertaken drilling by itself. The Company seeks to develop these properties jointly with major oil companies."

GRI lease holdings as of 1975 are set out below. In addition, GRI had a 2.5% overriding royalty interest in 32 California, Oregon and Nevada leases assigned to others. To GRI's knowledge, none of the lessees are contemplating development. GRI has a 10% overriding royalty interest on 1,100 acres of land in the Geysers. Two leases in this area contain seven commercial wells that are shut-in waiting for a PG&E generating unit. GRI also has a production payment interest on $5,000,000 principal, payable from 5-30% of the gross sales from these 1,100 acres in the Geysers.

GRI has also retained petroleum-type net profit and overriding royalty interests on other California property.

GEOTHERMAL RESOURCES INTERNATIONAL, INC.

Name of Resort	Location County State	Number of Leases	Working Interest	Gross Acres	Gross Annual Rental
Round Mountain	Lake, CA	4	50%	1,030.00	$ 5,150.00
Round Mountain	Lake, CA	3	100%	422.48	$ 422.58
Round Mountain	Lake, CA	12	100%	1,485.00	$ 5,385.00
Round Mountain	Lake, CA	1	100% (1)	5,101.00	$25,505.00
Round Mountain	Lake, CA	5	100%	906.75	$ 4,533.75
Calistoga	Napa, CA	2	100%	939.63	$ 2,818.99
St. Helena	Lake, CA	2	100%	1,080.99	$ 3,560.27
Klamath Falls	Klamath, OR	7	100%	2,939.99	$ 8,400.00
Lowa Lake	Lake, CA	7	100%	1,238.56	$ 6,192.80
Mono-Long	Mono, CA	2	50%	3,712.00	$ 7,424.00
Brady-Hazen	Churchill County, NV	1	100%	1,852.22	$ 3,704.00

Getty Oil Company

Getty Oil has joint ventured with Southern California Edison, taken an assignment on leased property from Geothermal Resources, Inc. and appears to hold some acreage in the Geysers area. Getty Oil holds leases on federal lands as follows: California (2), Nevada (8), Oregon (2) and Utah (1).

Gulf Oil Corporation

After an early series of unsuccessful wells, Gulf is now generally limiting its activity to holding leases; it is not initiating new projects on its own or in any joint ventures. In Gulf Oil's 1974 Annual Report on p. 17, the company states that it has under lease 2.6 million acres in the West where one wildcat well has been drilled and several other drill sites are under review. Gulf has one federal lease in Idaho and one in Nevada.

Magma Companies

Magma has reported activities in the West and South. Since 1973, it has drilled four wells in Nevada and one in Oregon. It is drilling exploratory wells in the West under contract with Dow Chemical. Magma Power Company and Gulf Geothermal Corporation are involved developing geopressurized areas of Texas and Louisiana in joint venture with Gulf Thermal, "Magma Gulf," has leased 100,000 acres of land in four areas of Texas and Louisiana and expects to raise $10,000,000 toward testing these areas. Magma Power Corporation is engaged in a joint venture with Union Oil Company in the Brady-Fernley area of Nevada.

The leasehold interest of Magma Power and its subsidiaries are substantially as follows:

(a) Leasehold interest in which the company or its subsidiaries own 100% working interest:

Name of Area	Number of Leases	Number of Acres
Magma Power Company		
California	1	2,560 (fed. land)
Nevada	7	15,080
Utah	2	2,320
Magma Energy, Inc.		
California	8	5,195.77
Nevada	18	6,246
Oregon	6	1,353.7
Utah	8	2,237

(b) Leasehold interest in which the company or its subsidiaries own 50% working interest:

Magma Power Company		
California		
Imperial County (East Mesa area) (To be assigned to Imperial Magma)	3	5,064.72 (fed. land)
Imperial County (Niland area) (Assigned to Imperial Magma on January 29, 1975)	13	2,977.83
Magma Energy, Inc.		
California		
Imperial County	46*	21,244.18
Lake County (Konocti area)	7	3,865.84
Modoc County	9	2,876.20
Nevada		
Churchill County (Brady area)	3	8,059.50
Churchill and Lyon Counties	14	6,804.13

* Two (2) of these leases are subject to a 5% working interest.

Lease Provisions

The leases in all areas are substantially in the same form, granting to the company the exclusive right to drill for, produce, utilize and sell geothermal resources, and to extract and sell minerals, if any, present in the geothermal steam or fluids. The leases grant easement and surface rights required for these operations. Generally they are for a 25-year term (although some are for shorter terms) and as long thereafter as there is commercial production or extractible minerals. They provide for completion, generally within five years from date of lease, of one or more wells, which lessee deems of commercial value, and for sale of, or a bona fide agreement to sell, steam or other geothermal fluids, if any, generally within ten years from date of lease. Until drilling is commenced, the leases usually provide for a 10% landowners' royalty payable on proceeds from the sale of steam, geothermal fluids or by-products, if any. Some leaseholds are subject to overriding royalties of one to three percent. The leases permit the company to surrender them without penalty.

Magma Power has five federal leases in Nevada and three in California.

Mapco

Mapco holds six federal leases in Colorado and three in Oregon.

McCullough

McCullough has been active in joint ventures in Utah.

Mobil Oil Company

Mobil holds a substantial amount of federal lease acreage in Nevada.

Natomas

Natomas Company reported that, in 1974, it had geothermal leases totaling approximately 12,500 acres: together with its wholly owned subsidiary, Western Geothermal, Inc., royalty interests on 4,800 acres, and applications and accepted bids on 30,338 acres of federal land in California, Utah, Nevada and Oregon.

The Natomas subsidiary Thermal Power Company, a co-venturer in the Geysers with Magma and Union Oil, has lease interests through that project on approximately 4,100 acres of federal land. Many of the private leases contain drilling requirements. Natomas has Indonesian petroleum operations and recently acquired some domestic operations.

Nix

Nix has drilled one well in Arizona.

Pacific Energy Corporation

Pacific Energy Corporation (PEC), in affiliation with Hughes Aircraft Corporation, holds over 20,000 acres in the Geysers, part of which is committed to PG&E. PEC holds one federal lease in Oregon. PEC has one joint drilling project with Burmah Oil. John Callon, President of Callon Oil and Gas, controls the Pacific Energy Corporation.

Pacific Power and Light Company

Pacific Power and Light (PPL) has joint ventured in Oregon, with Portland General Electric and Weyerhauser Lumber. PPL has not sought federal leases although it has filed applications for state lands.

Petro-Lewis

Petro-Lewis had an agreement, now lapsed, to evaluate prospects with Public Service Company of Colorado. PL has priority geothermal applications filed for 20,000 federal acres. It has joint ventured with Amax in Central Colorado.

Phillips Petroleum Company

Phillips Petroleum is reported to have about 6,000,000 acres under lease or option. Phillips has four federal leases in Arizona, four in Colorado, two in Idaho, eight in Nevada and nine in Utah.

Phillips has an arrangement with Southern Pacific Land Company (SP) under which Phillips will evaluate prospects on 1.5 million acres of SP land and may drill if SP is first offered an opportunity to participate in the well.

Phillips' 1974 Annual Report disclosed that it had drilled two commercially unsuccessful geothermal wells on land in California and Nevada. It has also drilled one well in Oregon.

Republic Geothermal

Republic Geothermal is one of the few enterprises to have successfully sold a geothermal limited partnership placement thereby raising $3.6 million. It has joint ventured with the City of Burbank and Mapco, as well as with its limited partners. The Los Angeles Department of Water and Power (LADWP) made a $25,000 bottom hole payment on a well drilled by Republic with Burbank on acreage adjacent to LADWP lands.

Republic holds leases on federal land as follows: California (4), Nevada (3), Oregon (6) and Utah (7).

Southern California Edison

Southern California Edison has made a drilling contribution of $150,000 in return for an option on production. It has also joint ventured with Getty

Oil (1972-Mondake area wells were dusters).

In addition, Southern California Edison is exploring 35,000 acres in the Imperial Valley, California through its subsidiary Mono Power Co. and two joint ventures, Southern Pacific Land and Phillips Oil. Additionally, firms such as Mobil Oil, ARCO and Exxon Oil which have federal leases may also have some other tracts.

Southern Union Production Company

This firm has drilled one well. It held one federal lease in California, seven federal leases in Nevada and three in Utah.

Sun Oil Company

Sun Oil is not working beyond the pre-drilling stage on its acreage. It has farmed out Northern California acreage for drilling by others, Signal Oil and Gas, and Acquitaine.

Sun Oil through its subsidiary Sunoco Energy Development Company holds six federal leases in Idaho and eight federal leases in Nevada. Through its subsidiary Calvert Geothermal Resources, Inc., Sun Oil holds one federal lease in Nevada.

Thermex

Thermex is reported by ERDA to control 75,000 acres of geothermal prospects in the states (1976).

Union Oil Company

Union Oil Company (California), reported by ERDA to control 120,000 acres of geothermal prospect lands, owned seven federal leases in California, one in Idaho, nine in Nevada, two in Oregon and twelve in Utah. Union has drilled one well, in Nevada, with Magma who has now acquired Union's interest in the tract. Union has been active in New Mexico where it drilled oil test wells at the Boca site in 1960, 1963 and 1964.

Western Geothermal and Power Development Corp.

Western Geothermal has two tracts in Idaho totaling 19,800 acres. Western Geothermal, Inc. has two federal leases in Utah.