OVERVIEW

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DISCLAIMER

TECHNOLOGY ADVANCEMENTS TO SUPPORT GROWTH IN GEOTHERMAL POWER SALES IN A DYNAMIC UTILITY MARKET

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INTRODUCTION

We are assembled today to discuss the opportunities and challenges for expanding the sales of geothermally-generated electric power in a competitive utility market. First, however, I would like to note that growth in geothermal sales might not be a germane topic were it not for the early participation in the development of the geothermal industry by utilities themselves. Without their contributions to research and development, environmental breakthroughs, and, perhaps, above all, their early use of geothermal power and continuing investment in the industry, we might still be at "Square One" -- confronting inhibiting doubts of the energy utilization industry. I feel certain that utility involvement has served to inspire far greater confidence in the reliability of the resource on the part of other utilities and other investors than could have been generated by federal programs and/or the resource developer arm of the geothermal community.

While acknowledging that we have not completely resolved all problems which geothermal energy faced 20 years ago -- confidence, institutional restraints, environmental compliance, and technical and economic uncertainties -- this audience and our predecessors have addressed them, individually and collectively, and, to a large extent, we have surmounted them. But it took generation or contracted purchase of geothermal power by utilities -- whatever their discrete reasons for doing so -- to demonstrate to the public and government regulators that there is a place for geothermal power in the service areas of large utilities. In addition, in using an alternative fuel, the participating utilities have already exposed themselves to changing concepts and practices in their industry.

MAJOR CHANGES FORESEEN FOR UTILITIES IN THE 1990'S

According to industry analysts, this decade will bring extraordinary changes to the traditional mode of electric utility operation -- driven both by market factors and potential regulatory changes. In fact, as Eric Zausner, president of Strategy Performance Management, a San Francisco consulting and investment firm, observes, "Change is the only constant for the utilities in the '90's."

A major market transformation that is already being felt is suggested by our theme for this meeting -- i.e., competition in an industry commonly considered to be composed of "pure" monopolies. As John W. Motter of Sierra Pacific Power called to our attention during this session last year, the industry is facing more competition than ever before -- with fuel switching and cogeneration options available to some customers, the competition engendered by increasing deregulation, and the concomitant emergence of the independent power producer (IPP). The industry's response to these challenges will be shaped to a large extent by other regulatory trends -- the impact of conservation requirements, permitted or required inclusion of externalities in evaluating costs of resource options, and potential further deregulation of the IPP's -- both utility-affiliated and non-affiliated.

The sales of non-geothermal IPP's are already growing nationwide due to several advantages they offer over new plant construction by regulated utilities -- cheaper power, protection from the risks of cost overruns and rejected power increases, and, in some cases, greater availability factors. The hot water geothermal industry as it is currently constituted is part of the IPP industry, the advent of which has provided greater opportunities for geothermal and alternative energy companies than would otherwise have been available.

This industry was created by the Public Utility Regulatory Policies Act which provided exemption from some of the more onerous utility-type regulation, but its growth has continued to be impeded by regulation under the Public Utility Holding Company Act. Now, however, pending federal omnibus energy legislation contains provisions to promote further development in this industry by exempting it from the PUHCA. If enacted, it will mean that IPP developers would no longer have to limit their ownership in projects to less than 10 percent or otherwise structure projects to avoid Securities and Exchange Commission regulation.

At this writing, only the Senate version of the legislation -- the National Energy Security Act of 1992 (S. 2122) -- has been passed. The Department of Energy generally supports the Senate bill and believes that it reflects the major goals and initiatives contained in the National Energy Strategy. While the bill reported by the House Energy and Commerce Committee (H.R. 776) would also exempt IPP's from PUHCA, it would not be prudent at this juncture to attempt to predict how some specific issues will be resolved. These include, among others, pre-approval of utility contracts with IPP's by cognizant state agencies, treatment of utility contracts with its unregulated affiliates, required debt-equity ratios of IPP's, and, particularly, improved transmission access to third parties.

In sum, however, the restructuring of the utility industry appears to favor geothermal power where the resource is co-located with increased power demand -- and is economically competitive. I strongly support the views of Mr. Zausner that "new entrants in the utility industry [such as geothermal IPP's], innovative traditional players, changing economics, and new technology will result in price competition, service unbundling, and cost reduction."

OTHER PROVISIONS OF SENATE ENERGY ACT WOULD EXPAND DOE'S GEOTHERMAL COOPERATIVE R&D PROGRAMS

Thus far I have addressed the nearly 600-page pending omnibus energy legislation only in terms of its potential deregulation of IPP's. Let me emphasize, however, that the Senate bill contains other provisions designed to promote the development of commercially sound renewable energy systems to overcome the artificial economic and regulatory barriers that have prevented wide-scale adoption. These provisions amend the Renewable Energy and Energy Efficiency Technology Competitiveness Act (P.L. 101-218) to expand the authority of the DOE Secretary to fund joint venture projects in each of several renewable technologies.

The purpose of the joint ventures is stated as "oil displacement." In the Senate bill, at least one joint venture is authorized for oil displacement by both high-temperature and low-temperature geothermal energy. In each case, the stated purpose of the joint venture is to design, test, and demonstrate critical enabling technologies for the production of geothermal energy for commercial application in uses that have substantial prospects for displacing the consumption of oil." Three million dollars are authorized for each technology for each of fiscal years 1992, 1993, and 1994.

However, the geothermal joint ventures are omitted altogether in the House bill as reported by the Energy and Commerce Committee. Since several other House committees are yet to act on the bill, the House itself is likely to consider floor amendments, and the conference committee will resolve the Senate and House differences, it is too early to suggest the final outcome.

Earlier, funds were provided in the FY-1992 energy appropriations bill for the first year of a three-year program "to demonstrate the economic benefits of improved electric generators in geothermal application." The Geothermal Division is in the process of implementing this program with a solicitation to be issued by the Idaho Field Office. The solicitation is currently in final review and is expected to be published in the Federal Register in about eight weeks.

We are pleased that Congress recognizes the continuing need for R&D funding to further commercialize geothermal power generation, and we look forward to participating with industry in any and all ventures that will foster the economic competitiveness of the industry.

TECHNOLOGY ADVANCEMENT AS A KEY GOVERNMENT ROLE IN SUPPORTING GROWTH IN GEOTHERMAL POWER SALES

Although the regulatory barriers that historically buffered the vertically integrated electric utility are collapsing, and doors are being opened to new participants and new technologies, the doors will only be fully opened to geothermal energy when and where it meets the economic competition. Thus, I see technology advancement as one of the key roles available to government to support increased geothermal sales in a dynamic utility market. Technology improvement and innovation that translate into reduced costs are therefore our continuing research focus.

To this end, our R&D priorities are established in accordance with what we understand to be industry's major cost-sensitive technology areas. In order to assure that our understanding and planning in fact satisfy industry's most pressing requirements, we need and solicit industry's continuing input and support.

In fact, I see the geothermal research program itself -- beyond the limits of potential ventures such as those discussed above -- as a joint industry-government R&D program. Since in that sense it is your program, please feel free to suggest changes to me, my staff, or others in the Department of Energy. We want you to be satisfied that you are receiving the best support in cost reduction that we can provide within the R&D funding available, as shown in Table 1 for FY 1992.

HYDROTHERMAL R&D DESIGNED TO REDUCE COSTS THROUGH TECHNOLOGY ADVANCEMENTS

It is not my intent in this session to "steal the thunder" of the DOE-sponsored researchers who will provide you with the details of their specific areas of R&D activity during our program review today and tomorrow. However, I would like to share with you, briefly, our rationale for pursuing cost reduction objectives in three key hydrothermal technology areas and our general approach for achieving the objectives.

Exploration Technology

Industry has repeatedly informed us that increased near-term development is highly dependent upon cost-effective tools for proving additional reservoirs. Most of the reservoirs in development today were identified and delineated through earlier industry efforts and a cooperative government/industry exploratory drilling program. Today's costs for determining the producibility of new reservoirs and acquiring long-term power sales contracts are extraordinarily large. This is because the costs are still dependent on drilling and testing one or more deep wells -- at a cost of $1.5 to $3.5 million each.

In response to the critical need to reduce exploration costs, our R&D program is undertaking to select the most innovative methods to locate and characterize undiscovered resources. We are investigating the range of optical, electromagnetic, geochemical, gravitational, and biological methods that may offer promise as exploration techniques. Industry is actively involved with us in technology development to produce the new generation of instruments necessary to discover hidden geothermal systems, and we are planning to conduct a cooperative venture designed to confirm the existence of a suspected hydrothermal system. An RFP will be issued asking industry to propose a favorable exploration target based on its information up to that point. An area will be selected for completing exploratory work that has not been done, and finally a deep hole will be drilled to confirm the findings of the less expensive technologies or to determine where those methods failed.

Our current planning anticipates that this innovative research into improved exploration techniques will be continued and expanded as future resources permit to meet industry's needs for this function during the next decade and beyond.

Reservoir Engineering and Management

The need for improved methods, equipment, and materials for geothermal reservoir engineering and management is demonstrated conclusively by the current problems at The Geysers. And the need can only become more critical as hot water fields begin to mature and new reservoirs are identified bringing their own sets of characteristics and complexities to be delineated and managed in developing and implementing exploitation strategies. Thus, a very high priority continues to be given to the development of new techniques for locating and characterizing fractures and reservoir boundaries, to assess fluid recharge, and to understand complex reservoirs.

Research related to a better understanding of The Geysers system is continuing to be emphasized to aid the industry in managing the field for sustained production. Geophysical and geochemical studies related to fractured geothermal systems are investigating phenomena unique to vapor-dominated systems and the generic need for injection of water into all fractured geothermal systems to efficiently recover the resource. The benefits of this effort will extend beyond The Geysers and provide field management guidance for other major U.S. producing fields which depend on fracture permeability.

The research will include studies for the identification of fracture systems early in the exploration and drilling stages, the development and refinement of methods of model flow of reservoirs, and the development of tracers which can be used in high-temperature hydrothermal reservoirs.

Drilling

The successful accomplishment of a major objective of the FY 1992 drilling R&D will advance both exploratory drilling and field management techniques. This objective is the development of downhole memory instrumentation to improve logging of geothermal wells.

The drilling experts at Sandia National Laboratory report that downhole measurements are not commonly used in the geothermal industry even though they possess a demonstrated capability of providing data important to development and maintenance of geothermal fields. Log data, for example, can provide the basis for engineering and permitting decisions involving corrosion control and the design/evaluation of cement bonding operations. In addition, log data on parameters such as fracture density, size, and orientation can guide well placement.

The use of logs in geothermal fields has been inhibited by the lack of high-temperature tools as well as uncertainty as to their value. However, a Sandia review of the logging literature indicates that similar uncertainties initially existed with respect to hydrocarbon applications, but as the ability developed to make downhole measurements, the interpretation of the data often produced unexpected beneficial results. A similar experience is expected in regard to geothermal applications.

The Sandia approach to instrumentation for high-temperature wells is to use a downhole memory unit that stores the data in a computer system. This technique is potentially inexpensive and does not require extensive uphole equipment or an expert crew, attributes which may lead to applications beyond use in geothermal wells.

DOE is funding, in conjunction with industry, the design and construction of a high-temperature spectral gamma tool based on the downhole memory concept. It will be designed for 400°C operation and will be compatible with small diameter coreholes in response to industry's needs for reduced exploration costs. New higher temperature tools being developed for deep gas wells will be evaluated by a cooperative arrangement among Sandia, geothermal operators, and a logging company.

Another element in the FY 1992 drilling R&D directed toward reducing exploration costs is the consideration of advanced coring concepts utilizing high-speed coring rigs to drill small, less expensive holes. It will be determined whether an industry cost-shared field test can be developed to compare directly productivity from the same formation in large and small wells. The field test would include injectivity/productivity correlations and use downhole instrumentation to supplement the wellhead measurements for better definition of the flow conditions in the wellbore.

POTENTIAL OF GEOPRESSURED RESOURCES AND HOT DRY ROCK TO MEET FUTURE UTILITY/INDUSTRIAL NEEDS

Commercial use of the advanced geothermal resources -- geopressured brines and hot dry rock -- for power generation still lies in the future. However, a brief examination of potential roles for these resources in devising electric utility responses to regulatory issues may be pertinent.

An economic supply model developed in support of the National Energy Strategy estimated that in 1990 power derived from the most economically attractive HDR sites would have had an average break-even price of just over 8 cents/kWh. But, by 2010, the price could drop to about 5.3 cents/kWh, and the long-run cost could be as low as 4 cents/kWh if all the postulated technology developments occur. "Long-run" is interpreted to mean about 2030. In the meantime, however, an event such as the imposition of a carbon dioxide "tax" on utilities, as has already been imposed in some European countries could advance the competitiveness of these projected HDR costs, with technology developments, providing a more cost-effective response than CO_2 abatement from the use of other fuels.

The current focus on geopressured R&D is the feasibility of using these resources in direct applications such as desalinated water production and/or combinations of direct uses in agricultural or aquacultural applications. In addition, if the energy demand of an integrated geopressured facility were large enough, a power generation unit could be added that would produce power at a cheaper cost than purchase of power at a utility rate. Thus, while the feasibility of such applications is yet to be demonstrated, they may hold promise as contributors to both supply-side and demand-side utility solutions to emerging regulatory requirements.

WHEN ENERGY PRICES REFLECT FULL COSTS, GEOTHERMAL WILL BE A WINNER

The trend in various states to assign a dollar value to "externalities" -- cost adders for identifiable environmental and social costs -- greatly enhances the competitiveness of environmentally-benign power generation technologies. For instance, as Darcel Hulse of Unocal reminded us last year, with environmental incentives such as those provided by Massachusetts, geothermal power could be priced 4 cents/kWh higher than coal and still be competitive.

Thus, when energy prices reflect full costs, geothermal energy can beat the competition, is a clear winner, and has a bright tomorrow.

GEOTHERMAL ENERGY -- FY '92
($ in millions)

• Hydrothermal Systems		
Hard Rock R&D	$3.0	
Reservoir Technology	7.1	
Conversion Technology	5.4	
Direct Use	1.3	
Subtotal		**16.8**
• Geopressured Research		5.0
• Hot Dry Rock Research		3.6
• Capital Equipment		0.8
• Program Direction		1.0
Total		**$27.2**

GEOTHERMAL ENERGY MARKET IN SOUTHERN CALIFORNIA PAST, PRESENT AND FUTURE

Vikram S. Budhraja
Southern California Edison
Vice President of System Planning & Operations

Thank you, Ted. Good morning. I'm pleased to be here as your keynote speaker from the utility industry. Today is fitting to discuss the role of an alternative/renewable energy resource such as geothermal. Three years ago today, the Exxon Valdez oil tanker spilled 11 million gallons of oil into Prince William Sound, Alaska. This ecological catastrophe was another of those periodic jolts that underscores the importance of lessening our nation's dependence on oil and increasing the use of cost-effective, environmentally benign alternative/renewable energy sources.

Alternative/renewables have come a long way since the first oil crisis in 1973. Today, they provide 9 percent of electric power used in the United States. That's nearly double the figure of just two years ago. And since 1985, one-third of all new capacity has come from geothermal, solar, wind and biomass facilities.

Nevertheless, geothermal supplies only about three-tenths of a percent of the country's electric power, or roughly 2,800 megawatts (MW). And most of that is in California. In fact, geothermal is California's second-largest source of renewable energy, supplying more than 5 percent of the power generated in the state.

Today, I'd like to discuss the outlook for the geothermal industry, framing it within Southern California Edison's experience with geothermal and other alternative/renewable energy sources.

Southern California Edison has been a leader in developing and advancing renewable energy since 1913, when Edison started the Big Creek hydroelectric system. Today, Edison uses nine different energy resources: natural gas, oil, hydro, coal, nuclear, biomass, solar, wind and geothermal. No other utility has a more diverse resource mix.

Edison's geothermal energy strategy for the 1980s included developing geothermal resources in the Imperial Valley and buying geothermal power from Mexico. Our contract in 1986 with the CFE, the Mexican electric utility, to purchase 70 MW of electricity generated at Mexico's geothermal fields near Mexicali marked the first international sale of geothermal power in North America.

Edison's 10-MW Brawley geothermal plant in the Imperial Valley became the first utility-owned central station generating system in the United States to operate on steam converted from a hot water geothermal source, as distinguished from a pure steam resource. It ran from 1980 to 1985.

Our 10-MW Salton Sea project, which ran from 1982 to 1987, demonstrated double-flash-cycle technology. Unocal, a partner in the project, now owns and operates the plant.

And, the plant at Heber, at 47 megawatts, was the largest of the three demonstration projects we participated in during the last decade. It was the first commercial binary plant and operated from 1985 to 1989. Some of you may have been involved with the project because DOE funded half of the $189 million cost.

These research and development projects established the foundation for geothermal development using lower temperature/higher salinity steam than produced at the geysers. Edison now has 633 MW of geothermal capacity on its system, or 3.2 percent of our system capacity mix. More than half of that is in the Imperial Valley. Nearly 30 percent is in Coso Hot Springs (near China Lake).

Elsewhere in renewables, we use more wind and solar energy than any other utility. And, we are California's leading investor-owned utility in purchasing renewable resources from third-party developers. Currently, we receive 21 percent of our energy from renewables, more than twice the national average. And we receive more than 40 percent of our energy from renewables when cogeneration technologies are included. This diversified resource mix helped reduce Edison's dependence on oil for electricity generation from 58 million barrels in 1977 to 114,000 thousand barrels in 1991.

Our progress in developing alternative/renewable energy sources, while gratifying, has not come cheaply. We have spent more than $180 million on research over the last 12 years and have leveraged this to obtain more than $560 million in outside funding. That's over three-quarters of a billion dollars.

We now have more than 5,000 MW of alternative and renewable generation connected to our grid. An important question is whether our customers have benefitted from these developments. Much of our alternative and renewable generation is governed by expensive standard offer contracts, which require payments equivalent to oil at $60 to $70 a barrel rather than $20 where West Texas Intermediate crude trades.

Last year, geothermal-generated electricity cost Edison customers 10 cents a kilowatt-hour (kwh). That compares with an average generation cost for natural gas of 3 cents per kwh. In 1991, geothermal-generated electricity cost our customers approximately $600 million -- several hundred million dollars more than the same amount of natural gas-generated electricity would have cost.

These contracts are one reason our rates are the sixth highest in the nation. From this perspective, our customers enjoy the diversity provided by alternative/renewables, but have not benefitted from the price.

As we look ahead, we need to design public policy approaches that align the interests of the resource developers, utilities and customers to assure cost-effective development and benefits for all.

When additional supply-side resources are needed, Edison wants to be able to add cost-competitive generation to its resource mix.

Renewable generation is not an infant industry. It is a $4-to-$5-billion-a-year industry in California. It is the equivalent of 10 nuclear power plants, twice the number that exist in California. But many renewables continue to be subsidized as they were when the industry was in its infancy. If we want to subsidize renewables, let's do it by sensible funding mechanisms, not by regulatory mandates. A production tax credit or an investment tax credit are two appropriate possibilities that have been helpful in the past and are again being considered on a federal level.

Another approach would be to remove incentives, such as depletion allowances, that exist for fossil fuels. A new idea under consideration is to tax air emissions. A geothermal plant, for example, does not release smog-forming fumes and emits less than one percent of the carbon dioxide that generally comes from an oil- and gas-fired plant.

The subsidy issue presents a major public policy question on geothermal and other renewables: Should we spend money to commercialize them if they are not cost-effective, or should we spend money to improve their cost-effectiveness?

As you're probably aware, resource additions in the Biennial Resource Plan Update (BRPU) ... now proposed by an administrative law judge to the California Public Utilities Commission (CPUC), would require Edison to add up to $2 billion worth of unneeded new generating capacity, including geothermal and wind energy facilities, to our system over the next eight years.

Among other requirements, the BRPU would require us to solicit bids for the addition of 300 MW of new geothermal resources and 50 MW of wind. The $2 billion worth of new power plants will achieve $10 million worth of emission benefits.

I, for one, do not believe pursuing renewables only for environmental benefits, without regard to the cost, is a sustainable policy. The real challenge for the geothermal industry is to be cost-competitive in an era of low gas prices. The geothermal industry must adapt to changing business conditions by lowering its costs of power to market prices.

The geothermal industry is a capital intensive industry competing against several generation technologies with significantly lower installation costs, such as wind, repowering and combined cycle. It also faces intense competition from conservation and cogeneration technologies.

Edison views cost-effective conservation and energy efficiency programs as the most environmentally and economically sound means of deferring costly power-plant construction in Southern California in the 1990s. In fact, conservation represents the greatest economic and environmental challenge to further geothermal development. Last year, our 55 energy efficiency programs saved our customers about 4 billion kilowatt-hours (kwh). These programs cut customers' electric bills as well as air pollution.

By 2000, conservation programs will cut annual electric consumption an additional 10 billion kwh, or enough to supply the energy needs of more than 1.5 million homes. Over the next eight years, these programs will reduce carbon dioxide emissions by 38 million tons and nitrogen oxides emissions by **34,000** tons.

If the geothermal industry is competitive, then it should not be seeking subsidies. If it is not competitive, utilities, the geothermal industry and government need to work together to make it so, through research and development. We need to reexamine the goal of the geothermal industry vis-a-vis the utility industry. What is our future relationship to be? We have been partners. Now our roles are more suppliers and buyers -- they supply, we buy.

We like the diversity geothermal provides, but if it's more costly than other options, building more capacity would be imprudent. The most prudent method for obtaining alternative/renewables is to eliminate set-aside requirements and pursue renewable development that is cost-effective through the bidding process.

The geothermal industry is here to stay. It plays an important role in Edison's and the nation's resource mix. And geothermal has steadily grown more efficient since 1985. Its capacity factor on our system last year was an impressive 95 percent -- higher than wind or solar. For our part, Edison wants to work with the geothermal industry to find ways to increase dispatchability of geothermal energy and to reduce the industry's high capital costs.

One challenge to the geothermal industry from a utility perspective is that most new geothermal generation will be located away from load centers. This could increase the geothermal capital cost by necessitating more transmission facilities.

I applaud the Department of Energy's goal to provide 22,000 MW of geothermal to our nation's generation resource mix by 2030 and believe partnerships offer the best solution for further development and advancement of the alternative/renewable industry. By 2030, renewables are projected to account for at least 15 percent of total U.S. energy use.

Partnerships for developing and advancing alternative/renewables have been a tradition for Edison and the Department of Energy (DOE). Currently, we are working with you on a demonstration program for our Solar Two project in the Mojave Desert near Barstow. Funding for this $40 million project is being provided on a 50/50 cost-share basis with you and other interested electric utilities. We plan to convert the 10-MW Solar One pilot plant from a water/steam system to a more advanced cycle using molten salt.

Solar Two, slated for completion in 1994, could be the model for larger plants capable of generating enough electricity for 100,000 to 200,000 homes by the end of the decade.

As electric utilities plan to meet growing electricity demands in the next several decades, we are pleased with the progress renewable energy technologies have made in the last decade. But it is vitally important that federal funds be directed to drive down the cost of renewables to assure they will play a meaningful role among the generating options available to utilities throughout the country.

Utilities cannot be expected to add higher-cost renewables if this only increases costs and erodes our competitive positions, making us more vulnerable to bypass generation. Higher-cost renewables can be a burden to our customers and the economy and can adversely affect our international competitiveness as well.

Edison's renewable resource strategy is aimed at making renewables cost-competitive so they can be economically integrated into our future resource mix. To drive the cost of geothermal down, Edison will continue to work with the geothermal industry, our customers and the government to:

- Develop promising new technologies and improve existing technologies. And,

- Support a national energy strategy that provides broad-based funding for renewables...and enables sustainable and cost-effective introduction of renewable technologies without hurting competitive relationships.

To the extent public policy favors large-scale installation of renewable resources before they are cost-effective, Edison supports public funding mechanisms that will help defray the differential cost between renewables and other more cost-effective resource options.

Federal funding of higher risk R&D projects through collaborative research programs is important. The next crucial step for these types of technologies to become more competitive is to transfer them from the laboratories and demonstration projects to the marketplace.

The renewable industry has suffered from a lack of access to sufficient capital. Commercial demonstration projects are expensive, and investment partners are essential to help reduce the economic risk for these projects. Joint venture funding can play a key role in helping commercialize renewable technologies and find market niches for applications of these projects.

While the United States has focused its financial resources on basic laboratory research, it has not traditionally followed through by moving the technology from the laboratory to the market, except when the government is the market. However, if we are to realize the benefits of these and future technologies, we must do a better job of moving technologies from laboratory to marketplace.

DOE can play an important role by helping reduce the economic risk assumed by private investors and by leveraging private financial resources.

In closing, the future of alternative/renewables, in general, and the geothermal industry, in particular, looks bright. We have the commitment and technological know-how to advance geothermal and other alternative/renewable resources. All we need are the proper partnerships and policies -- and I'm confident in our abilities to develop those partnerships and policies.

TAKING THE HIGH GROUND:
GEOTHERMAL'S PLACE IN THE REVOLVING ENERGY MARKET

Richard Jaros
California Energy Company, Inc.

It's a genuine privilege for me to be here today. As Dr. Mock mentioned, I have been President of California Energy for not yet three months and have a total tenure in the industry of only one year. As a newcomer to the industry, I am honored to address this group and share my views on "The Opportunities and Challenges for Expanding Geothermal Energy". You will see that my outlook for our industry is generally optimistic, shaped in part, perhaps by a newcomer's enthusiasm, but largely I think by my analysis of the opportunities which are open to us as an industry.

Many of you and your predecessors over the last 20 years pioneered the geothermal industry in the United States. The risks were great, the results sometimes rewarding, sometimes disappointing. Government and the private sector forged an alliance that moved the industry ahead. Developers, utilities and federal land managers worked together to bring projects on line.

Government helped identify geothermal areas, in many cases doing exploration work. The geothermal pioneers had to form entirely new, multi-disciplinary teams to solve problems unique to this resource. From discovery of fields, to environmental mitigation, to management of reservoirs and all of the steps in between, new teams had to be assembled. Geologists, geochemists, hydrologists, reservoir engineers and drilling technologists now apply their skills. Even anthropologists and biologists routinely get into the act in the environmental assessment phase of development. The care that our industry is taking today to do the job right reflects a maturing industry with high standards of performance.

To be sure, mistakes were made in the early years, but the industry learned from them. We all know the value of responsible development and resource management to the long-term future of our industry. Improvements in technology and more efficient operations have helped lower our costs and improve our competitiveness.

Our industry's progress has also been affected by outside factors. The price of and demand for electric power has fluctuated through economic cycles and changes in fuel prices. As our industry evolved and matured, we experienced a shakeout of ownership, with new companies arriving on the scene.

We can be encouraged that today, some stable companies with solid projects lead in the development of the earth's natural steam. As more geothermal companies offer projects in competitive bidding, their names are becoming familiar to utility executives. Names like UNOCAL, Magma Power, Oxbow, Calpine, OESI, and yes, my company, California Energy. We compete, but we also benefit from one another's successes. Well-run, cost-effective geothermal plants elevate our small industry. We have matured from experimenting with emerging technologies to providing an established, reliable source of power.

Let's take a closer look at the evolution of our market. Stimulated by market forces and assisted by public policy, we have seen renewable resources develop steadily in the past 20 years. In the early 1970's, the skyrocketing cost of fossil fuels boosted the development of alternative resources. In our nation's quest for energy independence, we recognized the value of home-made energy. The federal government stepped up funding for research and development of many alternative energy resources. In the 1980's, California's Standard Offer 4 contracts gave impetus to that state's renewables. Some 3,000 average megawatts of geothermal electric power is available today in the United States, and most of it has come on line since the early 1970's.

Estimates are that another 4,800 megawatts remain to be tapped in the next 10 to 20 years. All of that is in the West, where population and demand are also expected to grow rapidly. I think that number may be attainable, and perhaps even more. But capturing it will require a new initiative.

I see signs that the combination of market forces, assisted by good public policy, will again help our cause. Let's review the situation, and you'll see why I'm optimistic.

There's no doubt that our nation is reassessing the way it will meet its energy needs in the 1990's. Utilities and their regulators learned some hard lessons in the last two decades. The new thinking in the utility industry is illustrated by such phrases as: "least-cost planning", "externality costs" and "environmental adders", phrases foreign to the utility world two decades ago. The new thinking is creating acceptance and opportunity for geothermal energy. And, that brings me to the theme of my remarks to you today. To meet the opportunities which are opening to us in the marketplace, we, as an industry, must take the high ground--the high ground in terms of our environmental performance, in terms of the reliability of our supply, in terms of our increasing costs competitiveness, and in terms of a responsible approach to how we manage our business and conduct our commercial relations.

We must aggressively use that position on the high ground to push geothermal to the top of our nation's energy agenda. As an emerging industry, we have accomplished much but have much progress left to make. And, as an emerging industry, we need the help of all of you in this room, as well as our other constituencies to stake and maintain our position on the high ground.

It is heartening for me to see government, independent energy companies and environmental groups making headway in efforts to open the market to geothermal and other renewables. This cooperation must increase if we are to overcome the obstacles that hinder our progress. A good example of this cooperation is the Coalition for Energy Efficiency and Renewable Technologies, or "CEERT". This is an organization of environmental groups, energy companies, and technology companies that have joined together to accelerate the development and application of conservation and renewable technologies.

CEERT seeks to re-direct energy regulatory policy in order to integrate environmental and energy needs at least cost to society. CEERT is active in California and a similar group is forming in the Pacific Northwest.

Throughout the nation, we are seeing this kind of effort bear fruit. State energy agencies are applying both moral and regulatory persuasion on behalf of conservation and renewables. Progressive utilities are voluntarily putting renewables in their least-cost plans. To their credit, some utilities today are beginning to recognize the lower environmental and life-cycle costs of renewables. But most utilities' plans still fall short.

The fact is, that geothermal energy does not always compare well with other alternatives available under current pricing mechanisms. The high front-end capital investment required for geothermal and other renewables keeps us at a disadvantage in competitive processes. Over time, or course, we compare very well due to lower operating and environmental costs. We need more help from government to introduce these into the selection process for power supply.

In California, the Public Utilities Commission is considering resource plans for major investor-owned electric utilities. These plans balance traditional objectives of providing least-cost, reliable energy services with environmental concerns. The Commission has declared that in the interest of improving air quality, it will embrace the objective of accounting for environmental effects and encourage diversity of energy sources.

In recommendations to the Commission, administrative law judges have written resource agendas for three major investor-owned utilities -- Pacific Gas & Electric, San Diego Gas & Electric and Southern California Edison. Both renewables and co-generation must be considered in competitive bidding. The judges went a step further. They recommended improving air quality by reserving megawatts of load to be met by renewables. However, as strong as the recommendations are on policy, they fall short on concrete results. Only 300 megawatts were set aside for renewables.

Longer term, the Commission will require utilities to get roughly 75 percent of their future resources from conservation, and set aside 50 percent of the remainder for renewables. That will equal about 1,000 megawatts of renewables in the 1990's. Beginning in 2000, the Commission projects that geothermal resources could become more cost-effective than new gas-fired resources. The additional geothermal fields, located in the Coso, Mammoth and Imperial Valleys, could contribute up to 1,200 megawatts by 2005.

In several other states, including Nevada and Oregon, public utility commissions are considering regulations to include environmental or societal costs in resource decisions of utilities. Nevada, for example, could place a value of 5 cents per kilowatt-hour on conventional coal plants; 1.6 cents on combustion turbines and zero on geothermal. Environmental adders such as these could substantially improve the economic comparisons of renewable resources.

In Oregon, the debate rages over the appropriateness of environmental adders. While utilities concede that these costs exist, they prefer not to have them codified. Utility opposition at both the state and federal energy policy levels is strong. We must improve our data on environmental costs and make a much better case in regulatory and legislative proceedings.

In the Pacific Northwest, the Northwest Power Planning Council is a strong proponent of renewables. It issues an electric energy plan for four states served by the Bonneville Power Administration: Washington, Oregon, Idaho and western Montana. The plan calls for the acquisition of 430 megawatts of renewables by the year 2000, and 830 megawatts by 2010.

Pacific Northwest utilities are heeding the urgings of the Council and their state energy agencies. They are accelerating acquisition of conservation and renewables in their newly minted least-cost plans. As an example, California Energy Company was recently selected by the Bonneville Power Administration to develop, finance, contract and operate a 30 megawatt pilot geothermal project at Newberry Crater in central Oregon. BPA would acquire 20 megawatts, and our utility partner, Eugene Water & Electric Board, would purchase 10. It is our objective to make this project the flagship for other projects in the potentially geothermal-rich Cascades. Hoping to define geothermal fields elsewhere in the Cascades, Bonneville selected two additional companies to do pilot projects.

In Washington, the Washington Utilities and Transportation Commission encourages utilities to include renewables in their least-cost plans. Puget Sound Power & Light Company, which serves the booming metropolitan Seattle area, has selected geothermal resources in each of its two requests for proposals. In the last short list, announced just this month, Puget included 28 megawatts of wind, 19 megawatts of geothermal and 15 megawatts of hydropower. Along, with several waste conversion projects and conservation, the total of "high-efficiency" resources was 123 megawatts, compared to 155 megawatts of small gas-fired cogen projects.

In the gas-turbine arena, Puget Power, in its recent call for resource proposals, expressed a preference for "high-efficiency cogen" -- resources with a high percentage of industrial process steam relative to steam for electric energy. Puget defines a high efficiency cogenerator as one which devotes a minimum of 20 percent of the total energy output of the project to thermal processes, and which boasts a minimum total fuel conversion efficiency of 54.6 percent at 20 percent thermal output. Under this standard, the fuel conversion efficiency must increase along with the quantity of process steam.

Burning of gas for electrical generation is not in every case the most efficient use of gas, although it is relatively low-cost. Puget's standards are designed to encourage efficiency and demonstrate the efficacy of cogen. The Puget standard goes far beyond the federal so-called "PURPA Machine" standard for cogen, in which the threshold for usable steam is only five percent and the efficiency standard is correspondingly lower.

The Washington Utilities and Transportation Commission has expressed interest in cogen as an efficient use of thermal resources. The Commission has not yet adopted a structure such as Puget's, but is expected to revisit the issue in the near future. Such structures for cogen will make renewables more competitive by requiring them to be more efficient.

Clearly, we can see more renewables on the planning horizon, with geothermal looming large in the West. To turn plans into plants, we must aggressively state our case and improve our case. We must demonstrate through performance our ability to responsibly explore, develop, build and operate our facilities. We must demonstrate through performance the excellent reliability of our resource. We must demonstrate through performance the reliability of our conduct in commercial relations with customers, regulators and our other constituencies. And, perhaps most importantly at this juncture, we must help create a level playing field for geothermal to compete in the marketplace.

There are two market inefficiencies we must overcome to "level the playing field". As I said earlier, we must overcome the fact that customers are focused on short-term costs and benefits. Geothermal power is very cost competitive over a long life cycle. The lack of an ongoing fuel cost over the life of a project compensates for somewhat higher front end capital costs per megawatt, but this fact is not always persuasive. The second market inefficiency is the fact that today's energy market does not do an effective job of pricing the societal costs which are incurred by the greater amount of pollution caused by fossil fuels.

Our nation continues to rely on nonrenewable fossil fuels, despite the lessons of the 1970's when we got a dose of reality in the form of an Arab oil embargo. Markets adjusted to higher prices for fuel with greater efficiency and diversification of energy resources. But today, the supply of oil is again plentiful, prices are low, and our nation is seeing its oil imports climb above 50 percent of supply. Meanwhile, utilities rely increasingly on gas turbines to meet their growing need for generation.

Coal plants built in the 1970's and 1980's are posing environmental questions, short and long term. Our nation has in its generating inventory, 110,000 megawatts of fossil fuel generating plants that are 20 to 30 years old. Many of these will be retired or need substantial improvement in the new decade. Only in the last decade or so have we begun to face up to the environmental costs of burning coal. We have yet to tackle the tough issues surrounding CO_2 and other greenhouse gases. Concern about these gases is growing.

In the last two years, over 50 percent of the utility industry's new needs were met by independent power producers. That's good new for developers of renewables. However, natural gas accounts for half of the independent power projects. In itself, that is not harmful to our industry. With U.S. electricity consumption expected to rise from 2.7 trillion kilowatt-hours in 1990 to nearly 4.5 trillion kilowatt-hours in 2010, natural gas will most certainly play a leading role. But to the extent that utilities fail to account for the environmental costs of burning gas and coal, they will impede the development of renewables. Our growth will be limited.

The national labs and private industry have done a good deal of work to identify the environmental costs of burning fossil fuels. This work helped provide the basis for passage of the Clean Air Act. We need to see more research done on CO_2 and its effect on the atmosphere. Again, we have to be better prepared to make environmental our case. I said we needed to take the high ground, and we need some friends up there with us. We and our friends should be active in many arenas -- technical, political, regulatory, environmental and financial, to name a few. Here are some of the tasks that we need to accomplish together in the next few years for us to maintain the high ground as an industry.

Least-cost plans should explicitly include the environmental costs of fossil fuels. These adders should be determined by state regulators and applied uniformly. In the alternative, a credit should be applied to the cost of renewables. A credit of 10 percent is already being given to conservation by the Bonneville Power Administration.

Renewable set-asides patterned after the California model are a good start. However, the more effective way to boost renewables is to directly value their environmental costs.

More federal help is needed to reduce drilling costs and identify the geothermal resources of this nation. Rather than have government drill the holes, let the federal investment come in the form of payments per foot drilled. This would help reduce our costs. And, it would provide us with the kind of tax incentives traditionally used to spur oil and gas production.

Because the capital costs of renewable resources are relatively high, geothermal companies should receive investment and production tax credits. Extensions of the investment tax credit help, but implementation of a production tax credit should also become part of our national energy strategy. It took such help to promote our oil and gas resources; geothermal energy also needs such assistance. We must convince the Administration and Congress that better support for geothermal energy is both economically and environmentally beneficial. Production credits would reward success, and not failure, by providing a benefit only to projects that produce electricity. They would provide an incentive to those who run reliable, first-rate projects.

We developers must work with our utility customers to balance the risks and rewards of exploring and proving up geothermal reservoirs to commercial viability. To clear the high hurdles in financing and bringing projects on line, utilities need to offer contracts that absorb some of the risks of developing this important resource. Developers are willing to risk their capital to prove up a viable resource, but they need an acceptable contract to justify the risk. Such contracts would provide adequate levels of assurance to financial institutions that geothermal fields are reliable and dry hole risks are low. Prudent reservoir management must be assured by developers. These types of contracts could be combined with stipulations for unitization and independent reservoir review.

We developers can help ourselves by behaving responsibly in marketing our products. False promises, low-ball bids, and change orders can destroy the reputation we have worked so hard to establish with customers. We must be open and honest with our customers in the early phases of developing a new field -- open about likely resource potential, open about likely power costs, and open about how much risk a developer is willing to take to bring up a field.

While geothermal has outstanding environmental characteristics, we must continue to adapt and improve existing technologies to make us even cleaner than is mandated by state and federal air quality regulations. In some cases, we need to modify existing regulations designed for continuous discharge so that they recognize the needs of environmentally clean geothermal facilities to have intermittent discharge standards.

We need more federal support for research into geothermal exploration, reservoir assessment and management. For example, better drilling technology is essential to lowering the costs of finding and recovering this resource. Improvements in injection technology are also needed to extend the life of geothermal fields. Given the levels of support for solar and wind technology, I think more could be done for geothermal technology, particularly in the early, high-risk stages of exploration.

The DOE slim hole drilling program should be expanded and its budget increased such that it could provide not only cost share programs for industry to define additional reserves, but an exploration program for special public entities like municipals, rural electric cooperatives, and indian reservations which may have land or leases which have significant geothermal potential.

Several of these public entities are very interested in developing geothermal resources but unable to participate in resource exploration and development because of public charter and other fiscal limitations. For example, the Warm Springs Confederated Tribes in Oregon and the Yakima Tribe in Washington have large land areas within their reservations which contain significant geothermal exploration potential. These tribes could benefit greatly from an expanded DOE slim hole drilling program, where a small investment by the DOE could result in discovery of significant geothermal resource assets. Geothermal projects could stimulate major economic benefits.

We need to make progress in opening up the transmission grid to give independent producers access on a fair basis. You can't move a geothermal resource so you must be free to move the power to those utility companies willing to pay a fair price for geothermal power.

Finally, the public needs much more public information on the value of geothermal energy. Geothermal's operating record is excellent and getting better every year. It is available for more than 95 percent of each year, compared to 75 percent for coal plants and 65 percent for nuclear. We are also performing better than most other renewables. Yet the problems associated with some geothermal, such as The Geysers and Puna, continue to dominate the news. And, in public opinion surveys, solar energy, even though it produces far less energy than geothermal while burning a substantial amount of supplemental fossil fuel, consistently rates higher in public acceptance. We need to do a much better job of extolling the virtues of geothermal energy to the public and decision makers.

We have a big job ahead of us and a lot of territory to cover. From the Cascade Mountain Range to the Salton Trough, from the Northern Rockies to the Basin and Range of the Great Southwest, geothermal exploration is only beginning. If we are to realize the potential of this great resource, all of us will have to rededicate ourselves to meeting the needs of our industry.

By "all of us", I mean our entire community of interest -- Department of Energy officials and staff, other federal and state agencies, the scientific and environmental community, developers, utilities and others. The market is there. The cleaner, more efficient resources are there, too -- up on the high ground. Now is the time to press the march along the high ground in our nation's quest for new energy resources.

Thank you.

RECENT DEVELOPMENTS IN JAPAN'S HDR PROGRAM

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New Energy and Industrial Technology Development Organization

Introduction

Japan is one of the most active volcanic countries in the world, and it is understood to have very abundant geothermal energy. In Japan, where only a limited amount of other natural energy resources are domestically available, geothermal energy is one of the nation's purely indigenous energy sources. Its development therefore, has, been anxiously urged. Geothermal energy is classified generally in several types: vapor dominated type resources, which are mainly used to generate electric power, and low grade hydrothermal fluid and hot dry rock type resources, most of which are not used at present in Japan.

NEDO, the New Energy and Industrial Technology Development Organization, promotes the technological development of geothermal energy utilization in order to increase the use of this type of energy, particularly in such technical fields as the development of a power plant that uses hydrothermal fluids. This type of plant will enable the effective use for power generation of not only steam, but also geothermal fluid, so as to permit the use of hot water that flows out in great quantities together with useful geothermal steam.

The vast volume of geothermal water with medium to high temperature left intact underground will also be possible to utilize. Research themes promoted by NEDO, the Geothermal Energy Technology Department and the budget for FY 1991 (from April 1991 to March 1992) are listed below.

1) Development of 10MW Class Binary Cycle Power Plant ($2.0M)
2) Development of Down-hole Pump ($3.0M)
3) Development of Technology for increasing Geothermal Energy Recovery ($5.9M)
4) Development of Measurement While Drilling System ($0.4M)
5) Development of Hot Dry Rock Power Generation Technology ($7.1M)

The total amount of 18.4 Million dollars is allocated for FY 1991 ($1 = 130 yen). Figure 1 shows the budgets from FY 1990 to 1992 (requested). The total amount of budgets listed above is grouped into 'Technology R & D' in Figure 1. Figure 1 also shows the budgets for 'Survey & Promotion' items conducted by NEDO.

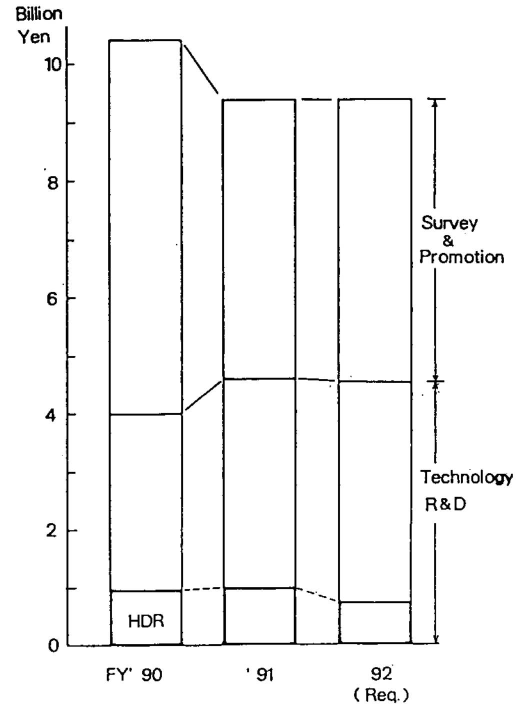


Fig. 1 NEDO's budgets for geothermal energy

This paper reviews the history of HDR development in Japan and summarizes the recent development of NEDO's HDR project.

Since FY 1985, NEDO has been conducting research to develop basic technologies for hot dry rock geothermal power generation at Hijiori, Okura Village in Yamagata Prefecture. The main purpose of this research is developing a heat extracting circulation system in hot dry rock of depth and temperature similar to those expected for a commercial scale operation. Within this scope, NEDO developed fundamental technologies for creating an artificial geothermal reservoir, establishing hydraulic communication between wells, logging boreholes, observing acoustic emission (AE) events for fracture mapping, evaluating flow through the reservoir, and estimating geothermal heat recovery.

In the hot dry rock geothermal project, especially in Japan, it is important to understand how pre-existing fractures affect hydrofracture development. At present, there are a number of methods that can be employed to understand the fractures, but it is necessary to evaluate which are most appropriate and accurate. Since FY 1989, we have been performing small-scale fracture characterization experiments on-site in I-itate Village, Fukushima Prefecture, where the granite basement rock outcrops.

The locations of the Hijiori and I-itate test sites are shown in Figure 2. Figure 3 shows the schematic history of the Hijiori project, together with other HDR work in Japan.

Fig.2 Locations of Hijiori and I-itate sites

Brief History of HDR Project and Study Program

Since FY 1978, the Hot Dry Rock geothermal power project performed field tests to develop technology at the northwestern foot of Yakedake Mountain in Gifu Prefecture. This work is a part of the Sunshine Project of the Agency of Industrial Science and Technology, Ministry of International Trade and Industry. From 1981 to 1986, NEDO participated in the Hot Dry Rock geothermal energy development program at the Fenton Hill test site in the USA (a joint study program of Japan USA and Germany under the agreement of IEA).

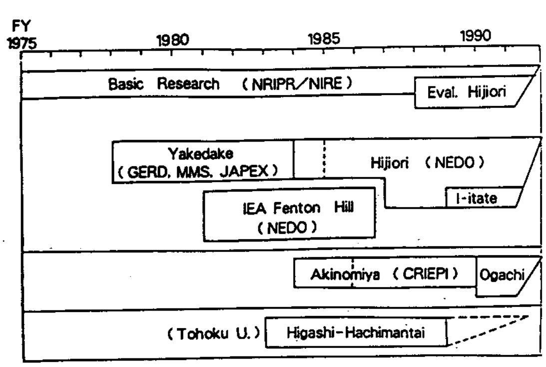


Fig.3 Schematic history of Hijiori project

Based on the results of the Yakedake and the IEA studies, NEDO has been establishing the basic technologies for developing Hot Dry Rock geothermal energy under the conditions of high temperature, high pressure and geological structures of Japan. For this purpose, NEDO has been carrying out field test work at Hijiori since FY 1985, with the support of the Sunshine Project. The Hijiori project site is located at the southern edge of Hijiori Caldera which has two kilometers of diameter formed about ten thousand years ago (as shown in Figure 4)

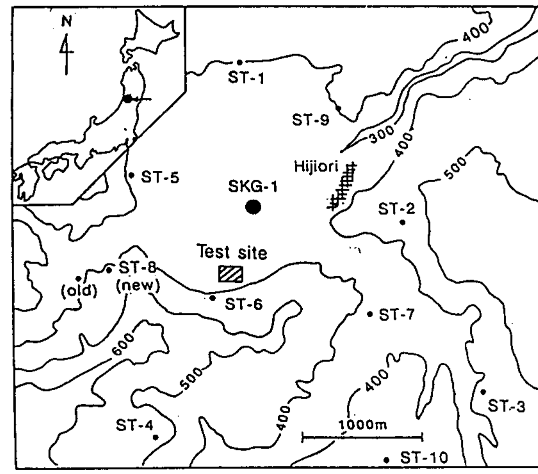


Fig.4 Hijiori test site at Hijiori caldera

From 1985 to 1986, a seven-inch casing was installed in the existing SKG-2 well (1,802m deep, bottom hole temperature of 253°C), which had been drilled to exploit a conventional hydrothermal reservoir. A hydraulic fracture was created from a 14m uncased zone at the bottom hole.

In FY 1987, the HDR-1 (1,805m deep) was drilled into the hydrofracture to create an artificial reservoir. NEDO successfully circulated water between the two wells through the fracture. The distance between the two wells is about 35m in the neighborhood of the bottom of the holes.

In FY 1988, NEDO conducted a heat- extracting circulation test for two weeks. In this test, hot water and steam at a maximum temperature of 180°C were recovered. However, the test data could not be used to identify the reservoir's characteristics because the hot water and steam from the production well blew out intermittently. After the circulation test, well HDR-1 was deepened to 2,205m, and a PBR casing liner was installed leaving the bottom 50m of the hole open.

In FY 1989, well HDR-2 was drilled to confirm the location of the fracture created by hydraulic fracturing, and to begin steady production. HDR-2 intersected very closely to expected position, thus confirming the results of fracture mapping by AE. After completion of the HDR-2 drilling (1,909m deep), a circulation test was carried out during a period of 29 days. Heat energy of 4.5MW was produced from hot water and steam at a temperature of 160°C to 170°C. A recovery rate of fluid during the circulation test remained at 32%. The flow was nearly continuous over the duration of the test.

In FY 1990, well HDR-3 (1,907m deep) was newly drilled to enhance the recovery rate. At this point in time, a multi-wellbore circulation system, which consists of 1 injection well (SKG-2) and 3 production wells (HDR-1, HDR-2, HDR-3) was completed. A small amount of water was injected into well SKG-2 to examine the pressure response of well HDR-3. It seemed that there were good connections between wells SKG-2 and HDR-3. The history of development is summarized in Figure 5.

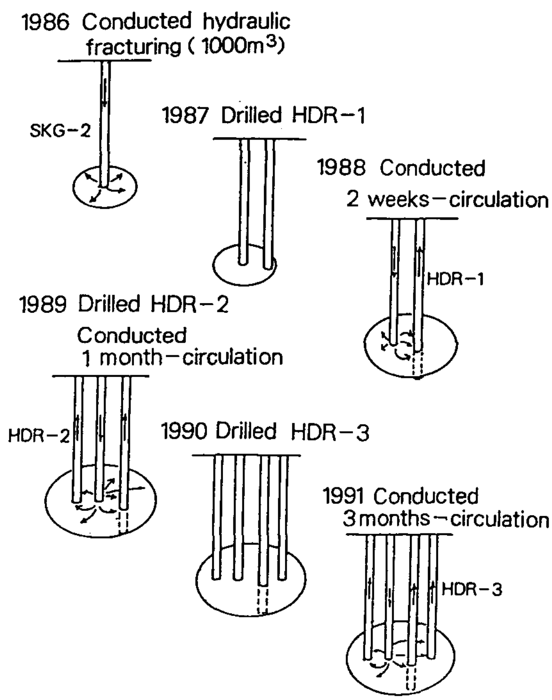
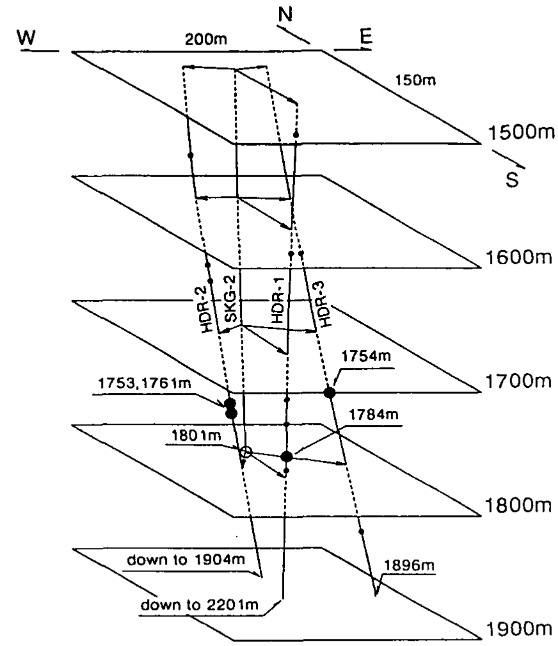


Fig.5 Summary of Hijiori development

Progress in FY 1991

In FY 1991, a 3-month circulation test was conducted, using SKG-2 as an injection well and HDR-1, HDR-2, and HDR-3 as production wells. The schematic view of the wells is shown in Figure 6. This circulation test was begun on August 6 and conducted until November 3. The total amount of water injected during this circulation test was 134,500 tons. The injection flow rate had been basically kept constant at 1 ton/min over the circulation test. The injection water recovery rates and the thermal output are summarized in Table 1. Table 1 also shows the result of the circulation test conducted in FY 1989 for comparison. In FY 1989, the production well HDR-3 had not been drilled yet. As shown from Table 1, the recovery rate during the 90-day circulation test was almost 77%, which is almost two times higher than those of the 2-production well system conducted in FY 1989. The thermal output, which was defined as the enthalpy extracted from the hydraulic fractures, was almost 8MW.



O Injection point
● Main feed points
• Feed points

Fig.6 Schematic view of Hijiori wellbores

Table 1. Summary of two circulation tests

	Test in 1989	Test in 1991
Pumping duration	29 days	90 days
Wells	SKG-2 HDR-1, HDR-2	SKG-2 HDR-1 ~ HDR-3
Injection flow rate	1 m^3/min.	1 m^3/min.
pressure	5 MPa	3 MPa
Recovery	32%	77%
Production temp.	160-175 °C	160-190 °C
Thermal output	4.5 MW	8 MW

Figure 7 shows the wellhead temperature changes of each well during the circulation test. Although the wellhead temperature of HDR-2 and HDR-3 are decreasing slightly, HDR-1 was increasing over the circulation test. The temperature of the injection water into SKG-2 had been kept almost constant at 50°C.

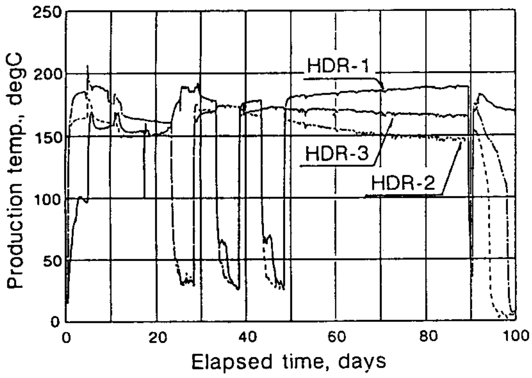


Fig.7 History of wellhead temperature

Figure 8 shows the production rates of 3 wells. Fifty days after the beginning of the circulation test, the production rates of HDR-2 and HDR-3 were almost the same, and twice as much as HDR-1 production rate.

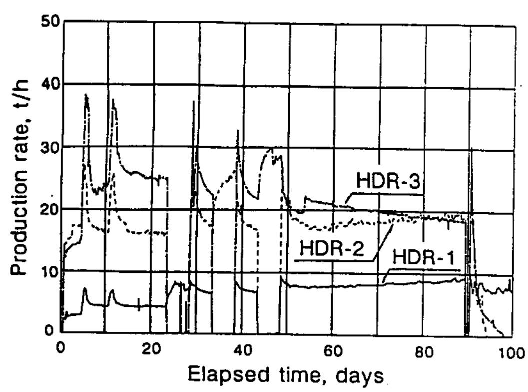


Fig.8 History of pruduction rate

The pressure temperature and flowrate (PTS) loggings were conducted frequently during the circulation test. Figure 9 shows the temperature profiles within the three production wells. The dotted lines in this figure show the initial temperature profiles, and the solid lines show the temperatures of the final stage in the circulation test. This figure shows the temperature profiles between 1,500m and 1,900m. In this interval of depth, HDR-2 and HDR-3 have uncased zones. The profile of HDR-1 was somewhat vague because of a PBR casing liner inserted in FY 1988. As seen in Figure 9, all production wells had multiple production zones indicated by arrows. The bold arrows show the main production zone in each well. The distances between the bottom hole of SKG-2 (injection point) and the main production zones of HDR-1, HDR-2, and HDR-3 were 61m,

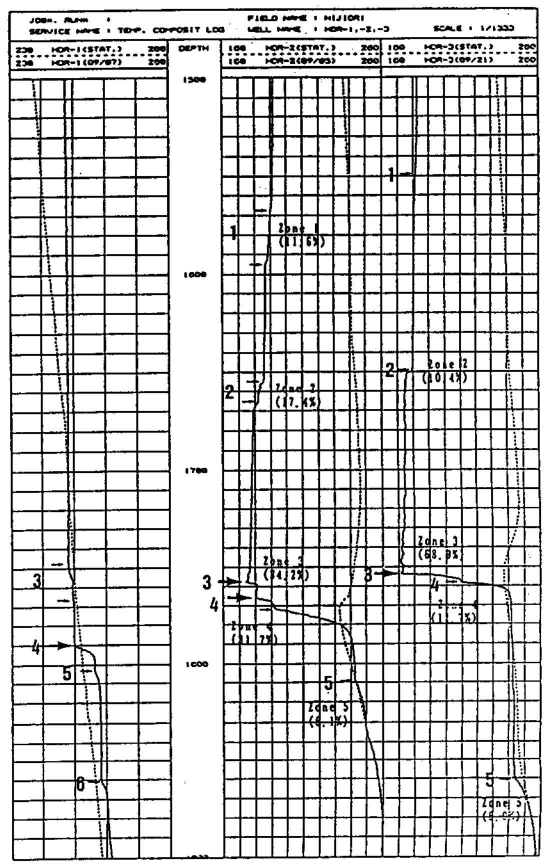


Fig.9 Temperature profiles of production wells

47m and 71m, respectively. Figure 10 shows the history of the fluid temperatures estimated at the outlet of each fracture zone in HDR-3. Figure 11 shows the feed ratio (contribution) of each production zone within HDR-2 and HDR-3.

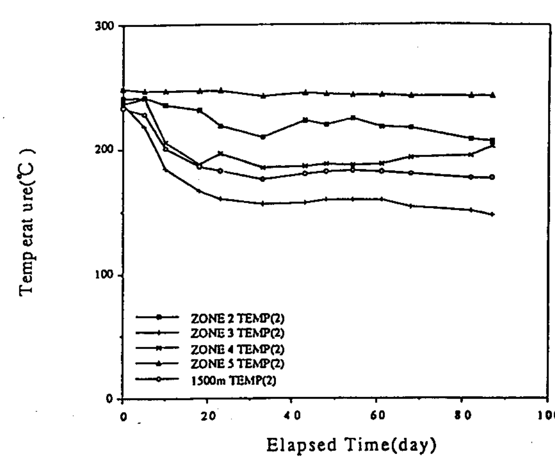
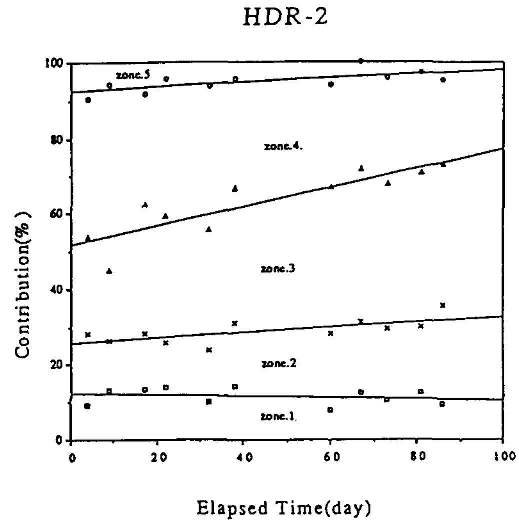


Fig.10 History of downhole temperatures (HDR-3)



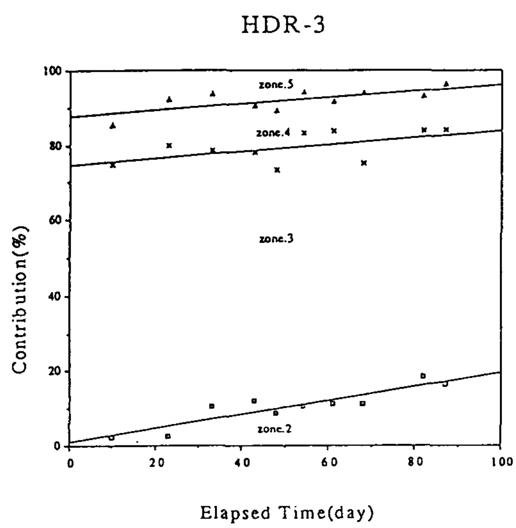


Fig.11 Contribution of each zone (HDR-2 &HDR-3)

Acoustic Emission (AE) had been monitored during the circulation test by a surface net which consists of 10 stations, and by a double-sonde downhole system in SKG-1 which consisted of tri-axial component AE sonde and a single component hydro-phone sonde. Because the recovery rate was so high compared to the circulation test conducted in FY 1989, AE activities had not been observed during the circulation test. On the last day of the circulation test, all the wellheads of the production wells were completely closed and the injection rate into SKG-2 was increased to 3 tons/min to promote the AE activity. In this stage, about 50 AE activities had been observed and located.

Future Plan

In FY 1991, the 90 day circulation test was conducted using the fractures around 1,800m depth. In FY 1992, we will create a hydrofracture from a from a 50m uncased zone (2110m to 2200m) at the bottom of hole HDR-1.

Acknowledgement

This document describes the work of many individuals involved in NEDO Hijiori Hot Dry Rock Program. The specific contributions of Isao Matsunaga (National Institute for Resources and Environment) and Makoto Miyairi (JAPEX) are gratefully acknowledged.

The HDR project in Hijiori is supported by the Sunshine Project, AIST, MITI. We thank the Sunshine Project Promotion Headquarters.

OPTIONS IN THE ELEVENTH YEAR
FOR INTERIM STANDARD OFFER NUMBER FOUR CONTRACTS

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The Interim Standard Offer Number Four Contracts (IS04), under which most of the geothermal industry is selling power (outside of The Geysers), has an initial ten year period of known fixed energy payments. In the eleventh year, the price goes to the Avoided Cost of the buying utility. The specific contract language is "Seller will be paid at a rate equal to the utilities' published avoided cost of energy as updated and authorized by the Commission (CPUC)".

The first geothermal contract will reach the end of the initial 10 year period in early 1994, a few will end in 1995 and 1996, and the majority will end in the 1997-2000 period. This is beginning to be focused upon by the utilities, lenders and, of course, the operators themselves. The prime reason for focusing on the issue is that avoided costs of the utilities directly track the delivered cost of the natural gas, and most forecasts are showing that the price of gas in the eleventh year of the contracts will be significantly lower than the last year of the fixed period of energy payments.

There are many forums in which the predication of natural gas prices are discussed. In the State of California, the agency responsible for the official forecast is the California Energy Commission.

Every two years, the CEC holds hearings for input into its biennial Fuels Report (FR) which establishes the forecast of natural gas prices in addition to other parameters which are used in the planning process. The attached Exhibit I is an excerpt out of the 1991 Fuels Report (FR91). Figure 1 compares the forecast of FR89 and FR91 for the Utility Electric Generation (UEG) in PG&E's service area, and Figure 2, the forecast in the SOCAL service area. The FR91 SOCAL service area forecast indicates a bottoming of the gas price in 1994 at $2.50/mmbtu. Recent prices in 1992 are already at these levels. Converting this to an avoided energy cost brings about a price of 2 to 2-1/2 Cents/kWh. The 1992 energy price in the ISO4 contract is 9.3 Cents/kWh.

Decisions on the course of action, relative to the eleventh year potential drop off in energy price, will be based on the seller's belief of:

1. What the avoided costs will actually be in the future, and
2. What, if any, options the seller has on modifying the contract.

A discussion within our industry on these two issues is appropriate and will become a major part of the industry dialogue as time passes, if the natural gas price doesn't show signs of rebounding. There are some contracts at The Geysers which are under the ISO4. All the geothermal coming out of the Imperial Valley, Coso Hot Springs. Mammoth and Dixie Valley are being sold to SCE under the ISO4 contracts.

GAS PRICE FORECASTS

In the March 16, 1992, Forbes, Frederick E. Rowe, Jr. indicates in an article on page 168 that whenever natural gas producers meet, the following joke is almost invariably told. The president of the Independent Producers Association of America asks God two questions: "Will the natural gas surplus ever dissipate and, if so, when?" God replies: "The answer to your first question is probably; and, the answer to your second question is, not in my lifetime." Rowe, apparently under the belief that this levity was not to be added to the Canon, goes on to say, "In my opinion, the free-fall in the price of natural gas is about to end. During the last decade, the spot (market) price of natural gas has fallen from more than $4 per mcf to less than $1. I am bullish on the price of natural gas and on the natural gas producing companies that survive the industries current depression. Natural gas is now a deregulated commodity. The current downtrend in supply (capacity) and uptrend in demand (consumption) will produce a predictable result -a dramatic rise in natural gas prices that should occur next winter."

There are many things that have contributed to the natural gas supply glut. The very high price in the middle 80's created a major surge in exploration, and we are now producing that gas at very disappointing prices for those who did the drilling in anticipation of the 80's prices holding. Tax incentives approved by Congress on drilling for coal seam gas makes those gas sales profitable even if the price drops below $1. A recent New York Times article indicates that several large companies have kept gas flowing at high rates to generate cash from domestic gas fields, to invest into more promising fields abroad. In that same article, Andarko Petroleum was quoted as saying they are cutting back on their gas sales in March by nearly half. I would anticipate that all producers who can shut in their production will be doing so.

Last year, Magma, under the auspices of the Geothermal Resources Association, retained a consultant from Dallas to provide a view of the Independent Producers in the informational hearings of the CE 1991 Fuels Report. He has been involved in gas operations since the late forties and provided a number of statistics about the business over the years. The number of drilling rigs in operation, the price of gas, reserves to production ratios, reserves per well and the life of wells all give evidence that gas prices have a high potential of having step functions in pricing. The smooth curves associated with projections as developed in the Fuels Report are not the norm when looking at history. The consultant intimated that there are a lot of producers laying behind logs in the gas fields with large clubs in their hands, ready to strike with higher prices at any instance that provides the opportunity.

What can a person wanting to know the facts conclude from all of this about the future of natural gas prices, and, therefore, what the utilities' avoided costs are going to be for the last 20 years of the contract? Southern California Edison has recently presented their view of the future. Exhibit II indicates the avoided cost to be at 4 cents/kWh in 2000 and 8 cents in 2010. With this projection, the drop in annual revenue for a 50-megawatt plant will be approximately 40 million dollars between the tenth and eleventh years. Exhibit III is a composite graph showing the SCE actual avoided costs from 1980 through 1991, ISO4 prices from 1983 through 1999, and the SCE projection avoided cost from 1992 through 2010. This gives a good historical perspective and shows that, from a historical context, the future avoided costs should be greater than the SCE projection. My own view is that the next two years will be needed to provide a shake out in the impact of the current abnormally low price in the long term. In that time, we in the geothermal business need to become very knowledgeable about the factors going on in the gas business and the impact that they will have on future price.

MODIFYING THE CONTRACT

Modifying the contract will require the agreement of the purchasing utility and likely the CPUC. For some time, SCE has been expressing their concern as to the viability of the QF power after the initial 10-year period and have suggested the idea of a QF being willing to drop the price in the initial 10 years, for some certainty on price following the first period. The QF component of power is a significant portion of the utility power supply. The utilities will want to have assurance that the supply is going to continue to be viable after the tenth year.

The "Amendment" paragraph in ISO4 reads as follows: "If at any time during the term of the Agreement, a change in circumstances, not anticipated at the time this Agreement was executed, significantly alters the rights or obligations of either Party, the terms of the Agreement which are directly affected by the change shall be amended by mutual agreement." I don't believe anyone anticipated that in absolute, non inflation adjusted prices, avoided costs which are being projected in the year 2000 will be the same as those of 1980 - twenty years previous.

CONCLUSION

To my knowledge, there has not been any modification of contracts. A problem, which many in the QF industry faces, is the obligation to lenders on their projects who are looking to the first ten-year cash flow for assurance of repayment of debt. Another difficulty is that the time period involved is twenty years, and that is too long a period to forecast what the avoided costs are going to be. Reason indicates that with a natural resource, presently being priced as a commodity, there will be some major increases in prices with a twenty year period. As long as there is an impression that gas may take a major step increase between now and the end of the ten year period, it will be very difficult for QFs to reduce their anticipated revenue in the short term to gain greater certainty in the long term. I can see lots of spread sheet scenarios being developed to address this and decision analysis programs being marketed to the QF industry.

I have a few recommendations:

1. Discuss this issue with your lenders and the purchasing utility.
2. Become knowledgeable about what is going on in the natural gas industry.
3. Become familiar with how the avoided cost of your buyer is determined and participate in the regulatory arena where that is done.
4. Be prepared within the next one to two years to make a conscious decision on a course of action, and finally, since resource developers have a great deal in common with farmers, "lay up in the good times for the droughts are always going to come!".

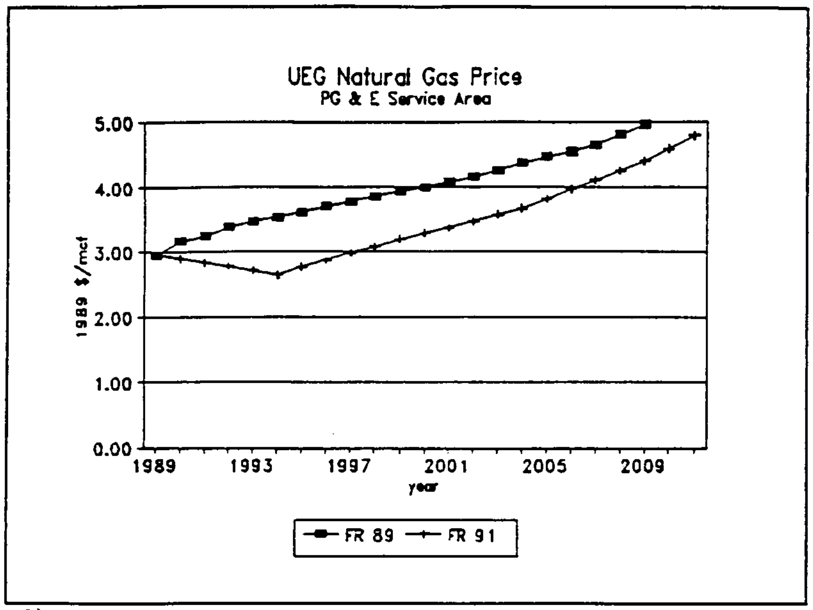


Figure 1

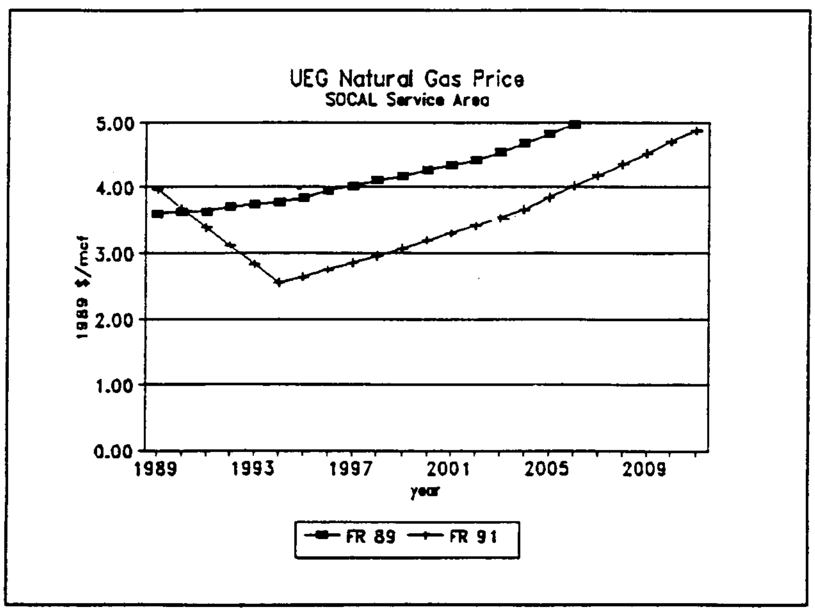
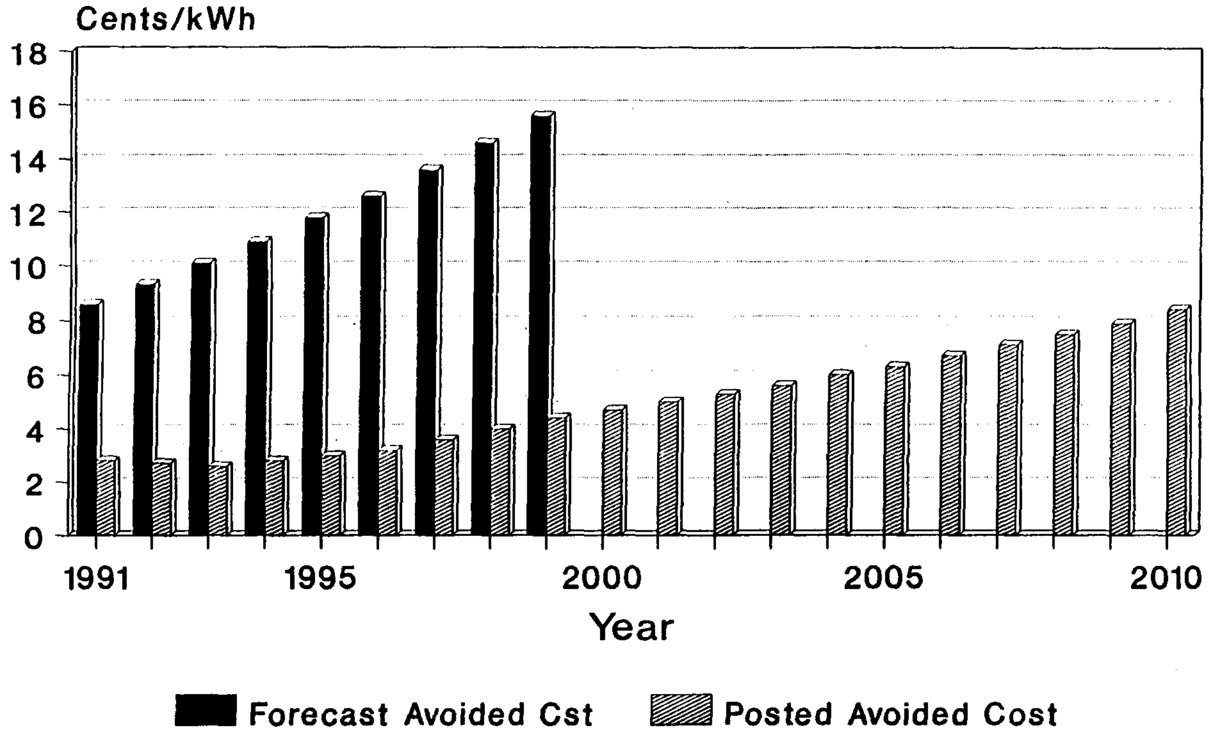


Figure 2

Natural gas price forecast,Fuels Planning Committee Workshop, 9/18/91, page 9

EXHIBIT I

Forecast & Posted Avoided Cost



Based on SRI Spot Glut Forecast

EXHIBIT II

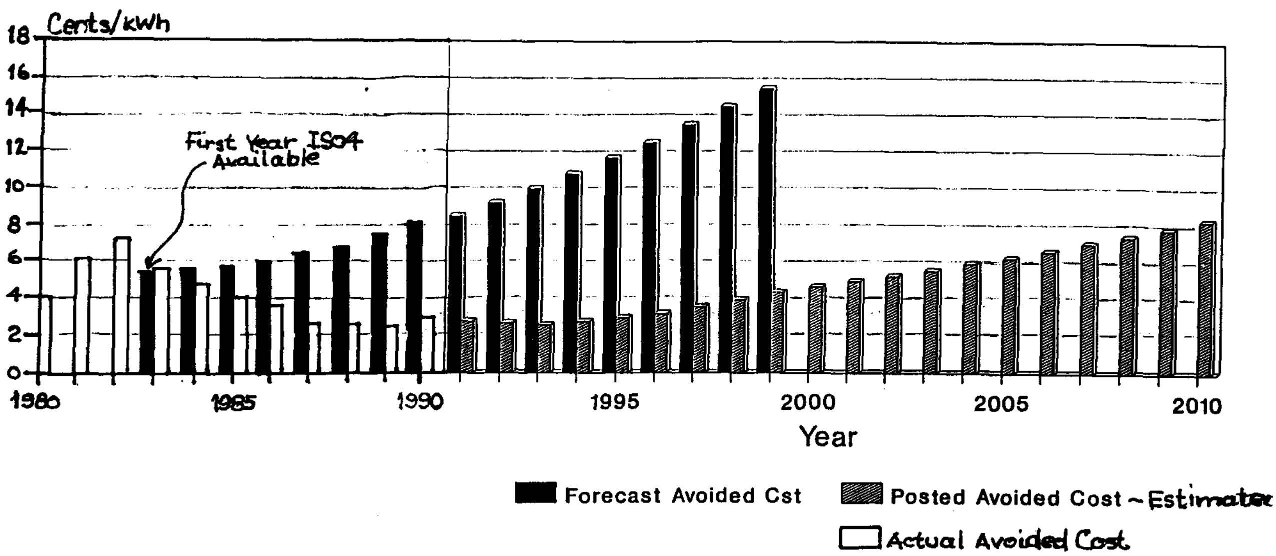


EXHIBIT III