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MANAGING GEOTHERMAL RESOURCE RISK - EXPERIENCE FROM THE UNITED STATES

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SUMMARY/ABSTRACT

Commercial geothermal power has been produced in the United States since 1960. Today, about 3,000 MW of geothermal power capacity exist in several geologic provinces in the United States, and several hundred MW of additional capacity is anticipated in the next few years. The body of experience that results from this level of development has enabled best practices to be adopted for the exploration, development and management of geothermal resources, which has helped reduce resource risk. Regulatory changes requiring investor-owned utilities to buy power from independent producers, favorable government-mandated power purchase contracts and tax credits have spurred the development of more geothermal power: profitable projects could be developed, providing a reason to accept resource risks. Government support for exploration and R&D activities has helped mitigate both exploration and operational risks. A government-sponsored Loan Guarantee Program enabled a few development projects to move forward. A long history with natural resource development in the United States has led to an acceptance that resource risk is an inherent part of geothermal development. Other than well control insurance, which is commonly obtained, insurance is neither readily obtainable nor used for risk reduction. In addition to government support for exploration in some projects, US geothermal developers mitigate resource risk (which is greatest during the exploration phase) through commercial approaches, such as equity partnerships, joint ventures and risk pooling. Project financing can be obtained once the resource is confirmed by deep drilling; such confirmation significantly lowers the level of risk. In the operational phase, risk is mitigated by collection and evaluation of resource performance data, and innovative changes in wellfield operations.

HISTORY OF GEOTHERMAL DEVELOPMENT IN THE US

The first commercial geothermal power plant in the United States began operating at The Geysers geothermal field in northern California in 1960. Thereafter, development proceeded relatively slowly until the 1980s, when favorable legislative and regulatory changes resulted in an increased development pace. By the end of the decade, about 2,800 MW had been developed in the US, and another 200 MW were gradually added over the next few years. The development of new geothermal projects slowed in the 1990s, owing primarily to low prices for natural gas, and the lack of favorable power purchase contracts. Increases in natural gas prices, a new round of tax credits and legislation requiring utilities to have a certain percentage of renewable in their energy portfolios has led to a resurgence of geothermal exploration and development in the 2000s, including newly explored fields and those that had been explored earlier but passed over in favor of others. The locations and approximate capacities of existing geothermal projects are shown in Figure 1, and fields being explored or developed today are shown in Figure 2.

COMMON GEOTHERMAL RESOURCE RISKS

Geothermal resource risks fall into three general categories: 1) drilling and well completion; 2) initial well characteristics; and 2) resource degradation over time. While there are significant risks associated with the drilling activities themselves, this category of risk is not discussed herein as it is not a resource risk per se; instead it is a function of the experience and expertise of the developer and the drilling contractor. Therefore we focus on the last two, which are fundamental risks in any geothermal development, particularly (but not exclusively) those that are being developed for the first time.

The resource risks associated with initial well characteristics are:

- Inadequate temperature. Although temperature gradients may be known from shallow or deep drilling in the area, the effects of lithologic variations and convective heat flow can lead to inaccurate temperature projections. For example, shallow, hot aquifers can create temperature reversals, and steep, lateral gradients may be encountered where barriers to flow are present.

- Inadequate pressure. The static reservoir pressure may be insufficient to enable flow at commercial rates.

- Inadequate flow capacity. Flow capacity is the product of permeability (the relative ease with which fluid flows through the rock) and the thickness of the productive reservoir. Either of these two quantities may prove too low to enable commercial production.

- Chemical quality. The produced fluid may not be chemically benign, but instead contain high levels of total dissolved solids or non-condensable gases, or elements that make the fluid corrosive or prone to scaling, either in the reservoir or in the power plant system.

Resource degradation risks include higher-than-anticipated declines in production rates, premature cooling (either from injection water breakthrough or from incursion of cool groundwater), and adverse chemical changes (increases in non-condensable gas levels, changes in reservoir conditions leading to scaling, etc.). These can occur at various times during the exploitation history, but some indication that they are occurring or will occur can typically be detected during the first few years of production.

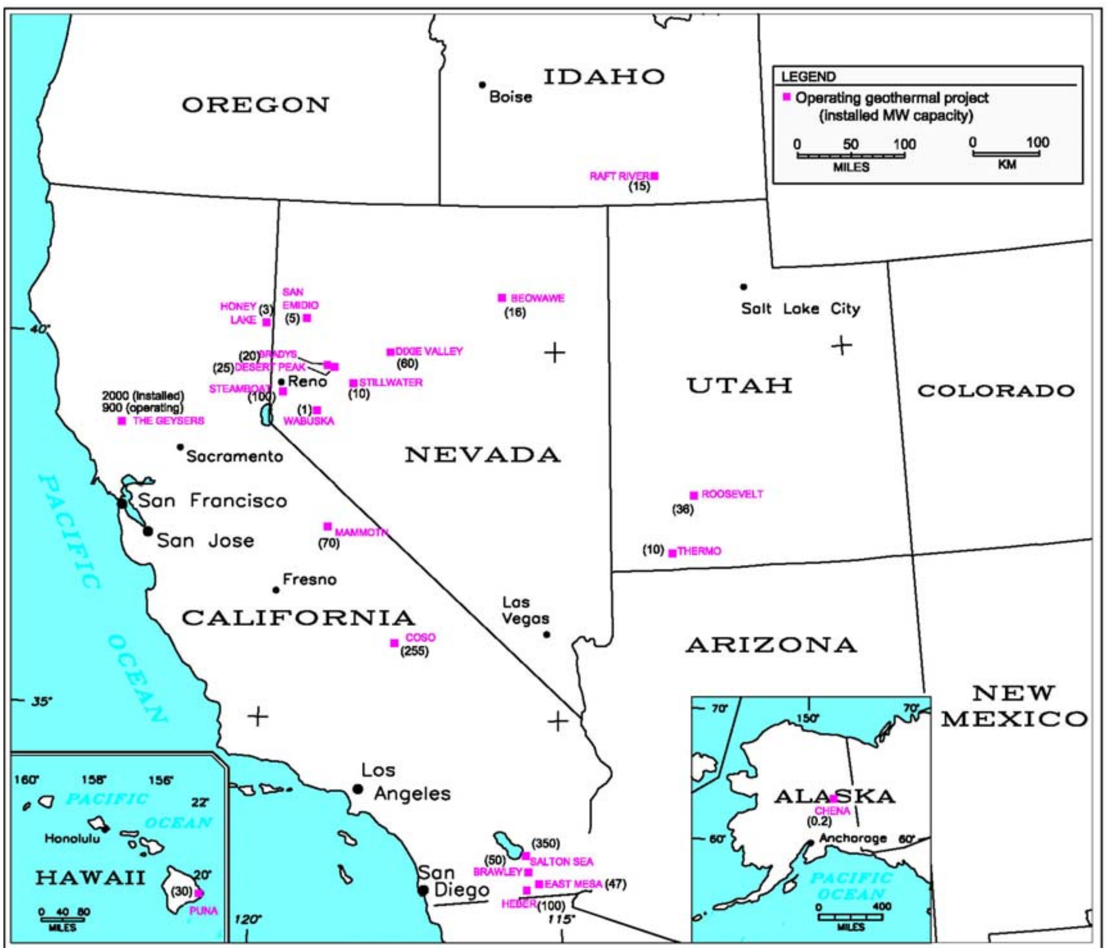

Figure 1: Currently operating geothermal projects in the United States

PHILOSPHY OF GEOTHERMAL RESOURCE RISK MITIGATION IN THE US

Owing to a long history of exploration and development of natural resources, resource risk is accepted by US geothermal operators as an inherent part of geothermal development. Of course, operators still seek to reduce resource risk: developers begin by collecting surface exploration data (geological, geochemical, geophysical) to help understand the resource before making decisions about if and where to drill. Nevertheless, eventually one must drill to determine if a commercial resource exists. In new fields, non-commercial wells are relatively common (perhaps 50 to 75% of initial holes come up dry). Success rates improve as more drilling occurs; even so, non-commercial wells may occur about 20% of the time in fields that have been shown to host successful wells. The potential reward for success is the sole reason to accept this kind of risk.

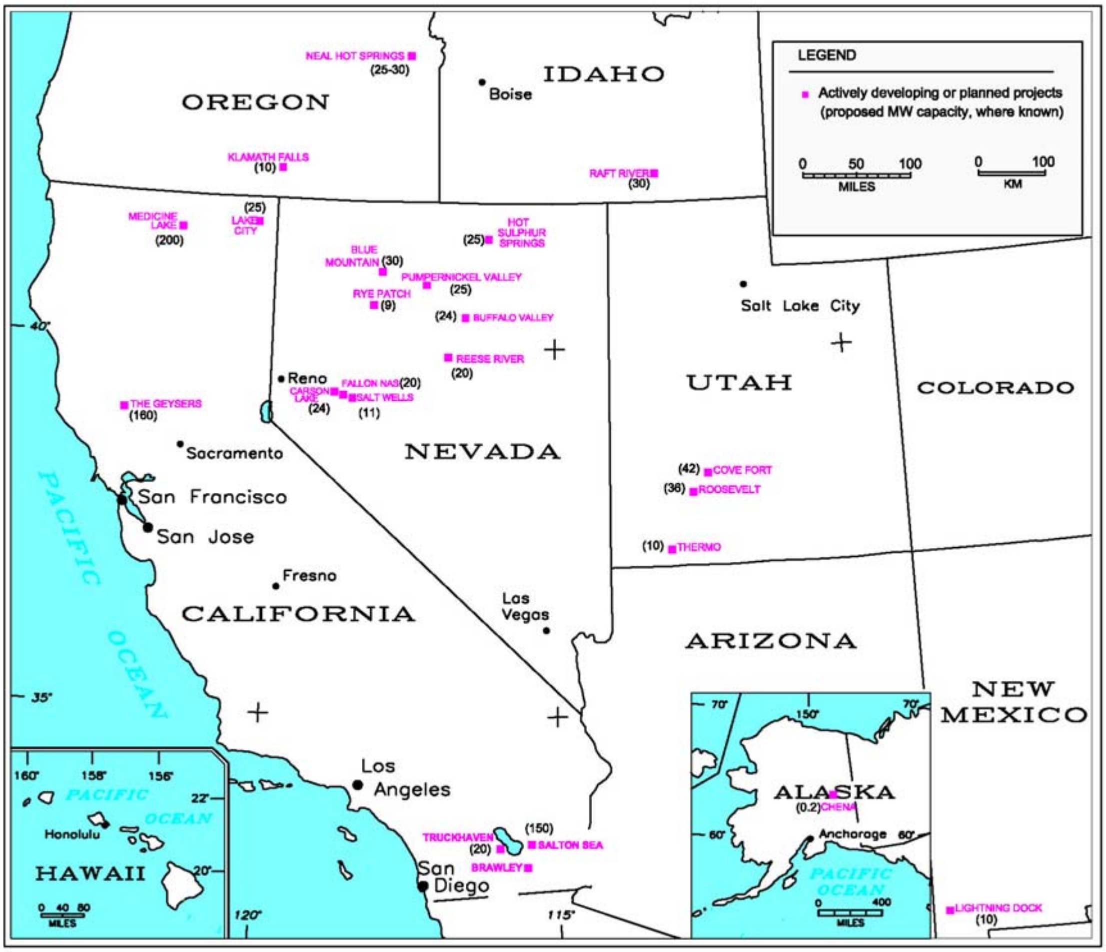

Figure 2: Developing and/or planned geothermal project in the United States

In contrast to the US, the development of geothermal resources for electric power is relatively new in Germany. There are a handful of small geothermal power projects that use conventional hydrothermal resources, and projects based on "Enhanced Geothermal Systems" (EGS) are being investigated. The 2.5 MW Landau geothermal power project used a combination of conventional and EGS techniques to develop its production-injection doublet. However, there is quite a long history of using conventional hydrothermal resources for district heating. It has become common for German geothermal resource developers to mitigate resource risk by purchasing geologic risk insurance. Such insurance policies may insure against insufficient initial temperature, insufficient initial flow rate, or both. Although this kind of insurance has been provided only for conventional hydrothermal projects, it is possible that EGS projects will be insured in a similar way in the near future. Although there is a remarkably high feed-in tariff for renewable power in Germany, geothermal developers tend to be small companies without the financial resources to support drilling activities. Furthermore the private investment climate appears to be more risk-averse than in the US; therefore bank loans are sought to support drilling. Since the banks require that the developer insure against resource risk, a market for geothermal resource risk insurance has developed.

We know of no case in the US where insurance has been used in this way. Although the level of resource risk may be similar in the US to that elsewhere, the economic and physical environments in the US probably lead to more acceptance of resource risk. The large oil companies active in the early phase of geothermal development in the US had significant experience with resource risk, and had the financial strength to withstand it. Smaller, entrepreneurial developers typically would form joint ventures or equity partnerships to support drilling activities, thus sharing the risk. The only kind of resource-related insurance commonly used in the US is well control insurance, which protects the operator from liability in the event of an uncontrolled discharge from the well. This type of coverage is consistent with the US attitude that insurance is appropriate for rare and catastrophic events. We can see several potential pitfalls associated with resource risk insurance, including:

- <u>Difficulty in defining criteria for success vs. failure</u>. For example, a well that has insufficient temperature to supply a flash-steam plant (if such was planned) could be perfectly appropriate for a binary power plant.

- <u>A requirement by the insurer for continued, costly interventions</u>. A US developer would be reluctant to relinquish control for making decisions about how long to try to improve a poor well, and how much to spend on such improvements (e.g., re-drilling, stimulation, etc.).

- <u>Transfer of an undue burden from the developer to the insurer</u>. While a developer may seek insurance for the first well or two in a project, it may not perceive a need for insurance for later wells, meaning that an insurer would always be covering the highest-risk activity.

- <u>Cost</u>. The cost for such insurance in the US might be unacceptably high relative to the overall economics of the project.

TECHNICAL RISK MITIGATION STRATEGIES

The basic technical approaches typically used in the US to mitigate resource risk include:

- securing an adequate land area to ensure the availability of sufficient productive ground and to minimize the risk of interference from any competing development;

- developing and continually modifying the conceptual hydrologic model of the field, to guide drilling and field development activities;

- developing fields in an incremental way, typically beginning with a project of relatively modest size, and gradually building up a body of understanding about the resource and how to exploit it;

- if a sufficient production history exists, relying on forecasts of reservoir performance using a well-calibrated numerical reservoir model; and

- developing innovative operational strategies to optimize field output and minimize operations and maintenance (O&M) costs.

These methods have been applied to geothermal resources developed in several geologic provinces in the US, where empirical data from early development has been used to reduce resource risk for later developments. For example:

- <u>The Geysers</u>. This was the first field to be developed for geothermal power in the US, and is located in the Coast Ranges of northern California. Here the reservoir is found greywackerich rocks of the Franciscan Formation, typically found beneath serpentinite rock and mixed lithologic units (these are loosely referred to as “melange”). In some parts of the field, an intrusive (felsite) body is tapped. More than 400 wells have been drilled at The Geysers, leading to a significant level of knowledge about conditions within and overlying the reservoir, and information about the top of the steam reservoir (from steam entry data in other wells) and mineralogical data are used to help determine when potentially productive depths are being reached by wells. Many of these wells are drilled directionally, and techniques to re-drill low-productivity wells and in some cases undertake “forked” or dual completions (with two open “legs” instead of one) have been developed.

- The Imperial Valley. Another geologic terrane explored and developed in the US is the sedimentary basin of the Imperial Valley in southern California, where low-permeability mudstones and shales are inter-layered with higher permeability sands and sandstones. In this location, a body of knowledge was developed about the thickness of a pervasive low-permeability shale/mudstone cap rock, and the relative abundance of sands or sandstones (relative to shales and mudstones) in the zone below. At the Salton Sea field, the reservoir fluid is an extremely hot and hyper-saline brine found within highly metamorphosed sandstones that are dominated by fracture permeability. Various methods of handling the brine were developed with funding from USDOE and innovation by Unocal and Magma Power Company, which developed the first power projects at Salton Sea using different techniques to handle the salinity. Gradually, more directional wells were drilled as the fault and fracture systems became better understood. Furthermore, different materials selection for well casings led to longer well lives and the need for less periodic well workovers. In the East Mesa field, the reservoir fluids have lower salinity and are produced from shallower units, sometimes comprised of unconsolidated sands. Therefore methods were developed to mitigate the production of unconsolidated sands in pumped wells, and the Heber and Brawley projects both benefited from this experience.

- Hawaii. In the Puna field, both exploratory and full-diameter well drilling revealed the presence of relatively narrow, sub-vertical rift fractures containing extremely high-temperature fluids. The boundaries of the productive zone correlated closely with the rift boundaries, and these could be identified from surface collected data. After some difficult wells, suitable completion methods were developed.

COMMERCIAL APPROACHES TO RESOURCE RISK MITIGATION

As mentioned above, resource developers accept risk because of the potential reward (commercial opportunity). However, risks can be shared in a number of ways. Perhaps the most common way is to attract equity partners, who invest money in exploration and early-stage drilling in exchange for a certain level of participation in the project. Alternatively, some sort of risk-pooling approach (as used in the petroleum industry in the US) may be used, either by the developers themselves (if they have a suitably large portfolio of exploration projects) or by investors and financiers, who may participate in several geothermal projects. These project participants generally understand the resource risk, and can tolerate some dry holes early on in the project. A critical element of risk reduction for all these approaches is obtaining good due diligence that fully clarifies risks, before investments are made.

GOVERNMENT SUPPORT FOR RESOURCE RISK MITIGATION

Government support to reduce geothermal resource risk in the US has a history nearly as long as that of geothermal development itself, and has been implemented at both Federal and State levels. The main Federal agency involved is the US Department of Energy (USDOE), through its Geothermal Technologies Program, whose initiatives at various times have included:

- Geothermal Loan Guarantee Program. This was implemented in the 1970s, and was designed to enable fledgling geothermal projects obtain financing for exploration activities. Several projects were funded this way, with mixed success. Two successful projects (*i.e.*, those that proceeded to development and paid back their loans) can be cited: the first 55 MW development by the Northern California Power Agency (NCPA) for its geothermal project at The Geysers; and the first 25 MW developed at the East Mesa field (Ormesa I project) in the Imperial Valley. The Ormesa and NCPA projects continue to operate today, and both have been expanded. The Loan Guarantee Program required a 20% equity investment by the developer.

- Industry-Coupled Drilling Program. This program, which ran from the late 1970s through the early 1980s, was designed to reduce the financial risks of geothermal exploration, particularly outside the State of California, where investigations were more advanced than in other states. This program supported work at 14 different geothermal fields in Nevada and Utah, including the drilling of temperature-gradient wells and full-diameter explorations wells, and evaluation of new and existing geologic, geochemical and geophysical data. Six of the fields that were supported by this program are producing geothermal power today: Roosevelt Hot Springs (Utah); Beowawe (Nevada); San Emidio (Nevada); Soda Lake (Nevada); Stillwater (Nevada); Dixie Valley (Nevada); and Desert Peak (Nevada). A seventh field (Cove Fort, Utah) produced electricity between 1985 and 2003, and a re-development of this field is planned by the current operator.

- Cascades Drilling Program. Although the volcanic Cascade Range of the northwestern US has long been considered to have significant geothermal potential, it has few thermal manifestations, probably because of the high rainfall in the area. To "see" beneath the so-called "rain curtain," USDOE supported the drilling of five deep, slim exploration wells in Cascades in the late 1980s and early 1990s. Two wells were drilled at Newberry Crater, and one each at Mt. Jefferson, Santiam Pass and Crater Lake. The zone affected by infiltrating rainfall was found to extend to 500-700 m, and temperature gradients ranging from 50 to more than 200°C/km were measured in the deeper sections of the wells. Despite this effort, the geothermal potential of the Cascade Range remains untapped to this day.

- Geothermal Exploration and Definition (GRED) Program. In support of a goal of getting more geothermal resources on-line, USDOE made awards in three separate rounds of solicitation and funding under the GRED program between 2000 to 2007. Work was supported in 10 fields in Nevada, four in California, one in Utah, two in Arizona, two in New Mexico, and one each in Idaho and Alaska, and included exploratory drilling (slim holes only), well testing, new geophysical and geochemical surveys, and re-evaluation of existing data. The geothermal projects at Raft River (Idaho) and Blue Mountain (Nevada) are examples of developments that moved forward significantly as a results of the GRED program.

- Enhanced Geothermal Systems (EGS) Initiatives. EGS represents the future of geothermal energy and has been supported by USDOE in field demonstrations and supporting R&D. The first field project was Fenton Hill, New Mexico, where Los Alamos National Laboratory pioneered the first-ever EGS development (then called Hot Dry Rock or HDR), developing many of the techniques that have been adapted for use in EGS developments today. After a long hiatus in EGS work, the USDOE conducted a multi-year program of field demonstration work, including projects at Coso (California), The Geysers (California), Desert Peak (Nevada) and most recently the Bradys (Nevada) and Raft River (Idaho) fields, USDOE has also funded supporting R&D undertaken by the National Laboratories and Universities directed toward overcoming some of the barriers associated with EGS development, including zonal isolation in high-temperature wells, development of logging tools, increasing the production rates and temperatures of downhole pumps, characterizing and imaging fractures in the EGS reservoir, tracer testing techniques, and forward modeling of hydraulic stimulation.

- Basic Research. The National Laboratories and many universities have been funded from time to time to conduct research into various technical areas that focus on overcoming barriers to geothermal development. Work has included advance drilling and logging technology, development of reservoir simulation software, geochemistry of geothermal systems, power systems, and many other topics, most recently relating to EGS developments.

Through the California Energy Commission (CEC), an agency funded via a small surcharge on the electricity bills of all Californians, the State of California also funds projects aimed at reducing geothermal resource risk, through two programs. The first is the Geothermal Resource Development Account (GRDA) program, which provides cost-shared funding for three types of projects: 1) resource development; 2) planning; and 3) impact mitigation. Projects that get funded typically focus on reducing the cost of geothermal resource development, increasing the efficiency of energy extraction and utilization, and improving the environmental compatibility of geothermal development.

The second CEC-sponsored program is the Public Interest Energy Research (PIER) program, which provides cost-shared funding to various kinds of organizations (including individuals, businesses, utilities, and research institutions). The PIER program focuses on energy efficiency, renewable energy technologies, environmentally preferred advance generation technologies, energy-related environmental research, and strategic energy research, and has funded various research and studies designed to promote the use of geothermal energy. Perhaps the most widely used geothermal study is GeothermEx (2004), which presents an analysis of geothermal fields and prospects in California and western Nevada. In support of a larger initiative to bring more renewable energy on-line in California, this evaluation served to quantify nearly 100 separate geothermal resource areas in terms of minimum and most-likely generation capacity, estimated costs of exploration and confirmation, and development costs. The database included with the report provides a single, concise source of public information for each area, and has been used extensively by geothermal project developers to select and evaluate individual project areas, thus promoting their development.

Other states in the western US have programs that support geothermal through energy agencies or state geological surveys.

REGULATORY AND LEGISLATIVE APPROACHES

There have been several regulatory or legislative initiatives in the US that have served to offset geothermal resource risk, mainly by providing the framework for its development and financial incentives for taking risk.

The first was the Public Utility Regulatory Policies Act (PURPA) of 1978, a landmark piece of Federal legislation designed to promote the use of renewable energy. Recognizing that utilities preferred to control their own generation, and were slow to accept new generation technologies, PURPA mandated that utility companies must buy power from independent power producers (IPPs) at rates that correspond to the average cost of generation within their own facilities ("avoided cost"). In the early 1980s, PURPA provided an environment that allowed financing of renewable energy projects because of the guaranteed power price. In California, PURPA led to the development of favorable, long-term contracts that provided fixed power prices that were higher than the purchasing utilities' avoided costs for the first 10 years of the contract, reverting to avoided costs thereafter. Many geothermal projects came on line during the 1980s and early 1990s as a result of this legislation, including many of the Imperial Valley projects and several in Nevada that fed power into the California market via wheeling (transmission) agreements, and in one case (the 60 MW project at Dixie Valley, NV) by the construction of a dedicated transmission line to a Southern California Edison substation in eastern California. At least 2,500 MW of geothermal power came on line as a result of PURPA.

California benefited from PURPA more than other states, because it is well-endowed with geothermal resources and because the State legislature took a proactive stance by mandating favorable power purchase contracts. Because of energy market conditions, avoided costs at the end of the first 10 years of the contracts were uneconomic; geothermal power producers responded by reducing operations and maintenance (O&M) costs as much as possible, and putting expansion plans on hold until power prices increased enough the merit the required level of investment.

The second approach involved favorable tax treatment for renewable energy projects. These include the Investment Tax Credit ("ITC"), a Federal tax credit of 10% of new capital investment in renewable power generation, and the Production Tax Credit ("PTC"), which provides a tax credit of $0.019 (recently increased from $0.018) per kW-hour of energy generated from renewable sources. The recent (October 2008) extension of the geothermal PTC means that tax credits can be earned for new geothermal projects that begin operating before the end of 2010 (the old PTC had a cutoff at the end of 2008).

The extension of the PTC comes at a time when the third legislative approach is beginning to take hold. We refer here to legislation, either existing or proposed, that provides incentives for developing, using and buying renewable energy. Perhaps the best example is legislation developed in many states requiring utility companies to increase their generation from renewable sources to a target percentage (ranging from 10% to 33%) of their entire generation portfolio; this is commonly referred to as a Renewable Portfolio Standard (or RPS).

Renewable Energy Certificates or Credits ("RECs") are also in place in nearly 20 states and are being considered by at least a half-dozen others. These credits accrue to the generator or the utility, and can be traded. Utilities will offer higher prices for renewable power if they retain the RECs (rather than the developer). The combination of RPS and REC programs has piqued the interest of utilities in pursuing geothermal opportunities, not only as purchasers of power from IPPs, but also in developing their own geothermal projects. This trend includes both investor-owned and municipal utilities.

Carbon credit mechanisms have been proposed but not yet implemented in the US. These are likely to take the form of a "cap and trade" program, in which a gradually lowering ceiling (or cap) is placed on overall carbon emissions, and emissions allowances would be issued and traded between entities that can easily reduce their carbon emissions (sellers) with those who cannot (buyers). The buying and selling of allowances would establish a market price for carbon, create incentives for emissions reductions, and encourage investment in renewable technologies.

While PURPA and tax credit approaches have been in use since the 1980s, the RPS, REC and carbon credit mechanisms are relatively new, and probably represent the future of legislative approaches to geothermal risk reduction.

CONCLUSIONS

Geothermal resource risk management is achieved in the US in several ways, the strongest of which are:

- the regulatory and legislative approaches that provide the financial incentives (*e.g.*, PURPA, ITC, PTC, RPS, etc.) to take risk and therefore find and develop new geothermal resources; and

- a commercial and private investment climate that has led to a familiarity with and willingness to accept resource risks, and the development of mechanisms for sharing risk.

The result is a very active environment for geothermal exploration and development in the United States. Publicly funded R&D activities helped to overcome certain risks, and provided the foundation for solving certain technical problems that have enabled the level of geothermal generation we see in the US today. Public funding will continue to contribute to risk reduction in EGS projects.

REFERENCES

GeothermEx, Inc., 2004. New Geothermal Site Identification and Qualification. California Energy Commission, Public Interest Energy research Program, Report No. P500-04-051.